Hydrogen in Remote Communities: Illustrative Case Studies

FINAL REPORT

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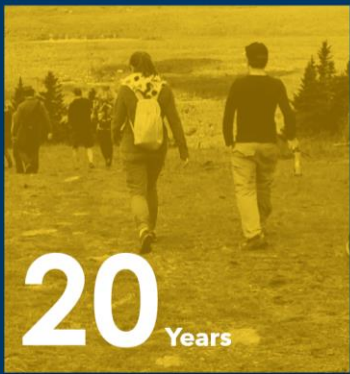
About Dunsky



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EXECUTIVE SUMMARY

Hydrogen has emerged as a tool that could potentially contribute to the decarbonization of our global energy systems. However, to date there has been limited exploration of the potential role clean fuels can play – and hydrogen in particular – in decarbonizing remote communities. This study explores the potential for hydrogen to contribute to transitioning remote communities off of diesel in a cost-effective manner.

Specifically, this work is an extension of the "Hydrogen for Remote Communities" research report completed by Dunsky Energy + Climate Advisors for the Fraser Basin Council in March 2024. Through the first report, we developed a three-step framework for assessing the feasibility of hydrogen in remote communities and identifying the pathway most suitable for a given community based on its unique characteristics. This report is a progression of that work where we quantitatively assess the technical and financial feasibility of the preliminary pathways assessments for two community archetypes; a remote off-grid community and an end-of-line community.

The case studies in this report focus on modeling hydrogen specifically for power generation applications, excluding its use for transportation and heating. Based on our assessment and the findings of our engagement, we conclude that it is unlikely for hydrogen to play a major role in decarbonizing transportation or buildings sectors in remote communities as it is less practical and not cost-competitive with alternative technologies (further discussed in Section 2).

Opportunities in Remote Communities (Case Study 1)

The findings from our analysis affirm that renewable energy and battery storage offer a cost-effective pathway to decarbonize remote communities and achieve British Columbia's goal of reducing diesel consumption in remote communities by over 80% (relative to 2019) by 2030.[1] Specifically, the modeled renewable energy plus battery storage scenario results in a levelized cost of energy (LCOE) that is 30% lower than the current diesel system ($0.438/kWh relative to $0.649/kWh), even when considering the necessary capital expenditure (Figure 1).

Our analysis also indicates that integrating hydrogen into the energy mix could potentially result in a LCOE comparable to scenarios using only renewables. However, this cost competitiveness largely depends on the 40% federal Investment Tax Credit (ITC) assumed for clean hydrogen projects. If future projects are ineligible (or qualify for a reduced tier) for this tax credit, it could impact the economic feasibility of hydrogen. This suggests that hydrogen could play a role in reaching the target of reducing diesel use by 80%, but further community-specific studies are necessary to confirm this potential.

While the provincial targets aim to achieve an 80% emissions reduction, scenarios that achieve full greenhouse gas (GHG) emissions reductions were also explored (i.e. 100%

[1] CleanBC Remote Community Energy Strategy (RCES). Accessed February 2024. https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/community-energy-solutions/remote-community-energy-strategy-rces

diesel-free). Our analysis highlights that achieving full decarbonization of remote communities with renewables and battery storage alone requires significant over-build of wind, solar, and batteries to satisfy peak demand requirements, leading to a cost of service higher than the current diesel system. **However, with the inclusion of hydrogen in a full decarbonization scenario, we find that hydrogen alongside renewables offers a cost-effective pathway for delivering emissions reductions beyond the provincial target and achieving a 100% diesel-free electricity system.**

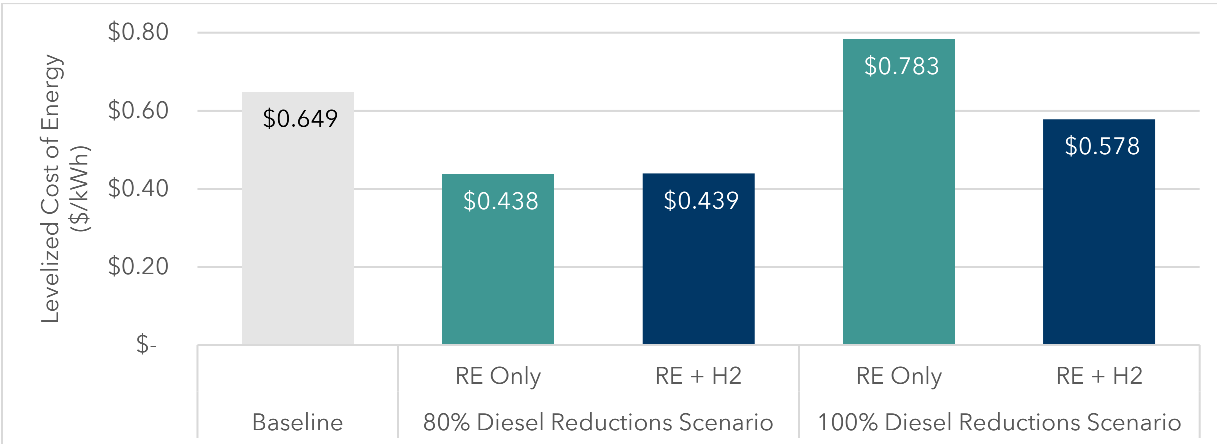

Figure 1. Summary of LCOE for Remote Communities (Case Study 1)

Opportunities in End-of-Line Communities (Case Study 2)

End-of-line communities are communities that are connected to the grid, however they rely on backup diesel microgrids to provide reliable power during outage events.[2] For the modeled end-of-life community, we evaluated the role of hydrogen as a backup resource to meet the outage load of the community under two different scenarios: (1) assuming hydrogen is generated from excess grid electricity and stored on-site, and (2) assuming hydrogen is produced elsewhere and then imported and stored locally.

From an economic perspective, we find that both hydrogen options represent cost increases for end-of-line communities as compared to the baseline diesel system. Locally produced grid hydrogen represents a 7% LCOE increase when compared to the baseline, whereas imported hydrogen reflects an approximate 54% LCOE increase (Table 1). The economic advantage of local production stems from the avoided cost of transporting hydrogen to the community, which represents one-third of the lifetime costs of the project. **However, from a decarbonization lens, hydrogen could present a viable opportunity to eliminate diesel use in end-of-line communities when compared to a renewable plus battery-only scenario** (due to the significant build-out of resources needed).

[2] Typically associated with extreme weather events and prolonged downtime due to their remote location.

Table 1. Summary of LCOE for End-of-Line Communities (Case Study 2)

Scenario	LCOE ($/kWh)
Baseline	0.482
Renewables Only	3.929
Imported H2	0.741
Grid H2	0.516

Looking Forward

The long-term viability of using hydrogen in remote decarbonization efforts remains uncertain. In this body of work, its economic feasibility hinges on the hydrogen ITC, which we assume projects will be eligible for the highest tier covering 40% of hydrogen technology costs. The success of these projects will depend on overcoming financial, technical, and logistical challenges, as well as aligning with community priorities. Research from our "Hydrogen for Remote Communities" report identified several key challenges to decarbonizing remote communities including but not limited to resource availability, access to capital, and provincial- and utility-community relationships. Despite its potential, hydrogen's role in deep decarbonization will be determined by the presence of favourable conditions and continued support. Our engagement efforts with communities identified that the current capacity to support the operation of a hydrogen system is limited but desired and would be a key enabling condition for potential deployment.

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1. Introduction

Remote communities are off-grid and are not currently connected to the North American electrical grid or piped natural gas network.[3] These communities operate independently of centralized energy infrastructure and often rely on localized sources of power generation, predominantly diesel generators or sometimes renewable energy systems. In British Columbia (BC) there are three different sub-classifications of remote communities:

- **Independent** communities own and operate their energy systems or have partnerships with private entities,
- **Non-integrated Areas (NIA)** are a subset of remote communities served by isolated microgrid systems owned and operated by BC Hydro, and
- **End-of-line** communities are located at the terminus of provincial transmission lines and occasionally rely on diesel generators (owned and operated by BC Hydro) for backup generation.

The majority of remote communities rely on diesel to support their energy needs either as a primary or secondary source of energy. Diesel offers a reliable, scalable, and easily transported fuel that provides these communities with a stable energy source. However, diesel consumption has many harmful effects including air and noise pollution, and volatile, high costs which require significant subsidization to maintain affordability. Further, the high dependency on diesel fuel imports poses an energy security risk in the event that local reserves drop and access to the community becomes restricted or if deliveries are delayed.

There is broad consensus that renewables and energy storage, coupled with investments in energy efficiency, offer a cost-effective pathway to decarbonizing remote communities and can help achieve the province's goal of reducing diesel consumption in remote communities by over 80% (relative to 2019) by the year 2030.[4] However, to date, there has been limited exploration of the potential role clean fuels can play to achieve this target and further decarbonize remote communities.

This analysis focuses on assessing the potential for hydrogen to serve as a complementary solution (working in conjunction with renewables) to transition remote communities away from diesel reliance and to contribute towards cost-effective emissions reductions. Specifically, this report is an extension of the "Hydrogen for Remote Communities" research report conducted by Dunsky Energy + Climate Advisors for the Fraser Basin Council which examined the potential of hydrogen in the decarbonization of remote communities. The report included the following elements:

- A summary of the diverse hydrogen production pathways, storage and transport methods, potential demand cases, and end-uses; and

[3] Except end-of-line communities, a subclassification of remote communities unique to BC.
[4] CleanBC Remote Community Energy Strategy (RCES). Accessed February 2024. https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/community-energy-solutions/remote-community-energy-strategy-rces

- The identification of the enabling conditions required for establishing hydrogen ecosystems in remote communities.

The goal of this second phase of work is to:

- Gauge the interest levels of remote communities in establishing hydrogen ecosystems, and
- Examine the potential contribution and cost-effectiveness of hydrogen in remote communities through the development of two case studies.

2. Potential Role of Hydrogen

Hydrogen has emerged as a tool that could contribute to the decarbonization of global energy systems. On a pathway to net-zero, hydrogen's ability to provide reliable, scalable, and storable energy makes it an attractive complement to intermittent renewable energy sources like wind and solar, as well as a potential fuel for hard-to-electrify sectors.

In remote communities where energy access, reliability, and sustainability are ongoing concerns, hydrogen could offer a compelling value proposition. Its ability to be produced from renewable energy resources and stored as fuel offers a dependable energy source during power outages, periods of low renewable energy generation, and/or high energy demand. Hydrogen's versatility allows it to be used for power generation or across end-uses such as transportation, building, and industrial sectors. By incorporating hydrogen into their energy profile, communities could reduce their reliance on diesel, thus lowering carbon emissions. The high cost of the existing diesel ecosystem in remote communities could create opportunities for cost-effective uses of hydrogen that may not emerge in grid-connected communities.

Despite the promising value proposition, the use of hydrogen in remote communities faces significant barriers that need to be addressed. The nascent nature of hydrogen technologies poses a significant hurdle, as the sector lacks the maturity, experience, and widespread policy support that more established renewable technologies benefit from. This makes hydrogen systems less competitive in terms of cost for production, storage, and distribution. The high upfront investment required to build hydrogen infrastructure, such as electrolyzers, safe storage solutions, and distribution networks, is a major barrier, especially in remote areas with limited financial resources and existing infrastructure. Additionally, harsh climates and logistical constraints in remote regions can complicate the deployment and operation of hydrogen systems. Ensuring that hydrogen infrastructure can withstand extreme weather conditions while maintaining reliability and efficiency is critical but challenging.

To navigate these complexities, a structured framework is required to assess the feasibility of hydrogen in remote communities. The "Hydrogen for Remote Communities" prequel report proposes a three-step framework – shown below in Figure 2 - for assessing the feasibility of hydrogen in remote communities and identifying the pathway most suitable for a given community based on its unique characteristics.

This framework begins with an Enabling Conditions Analysis, which evaluates the key factors influencing hydrogen deployment, such as community size, climate, energy infrastructure, accessibility, and resource availability. Understanding these enabling conditions is crucial for identifying the opportunities and constraints for hydrogen integration. Following this, an evaluation of the different hydrogen production and utilization options that align with community specific conditions and decarbonization goals. This includes analyzing the scalability and reliability of potential hydrogen systems, as well as their cost-effectiveness compared to other energy options. Finally, a Quantitative Analysis that involves identification of required technologies and components is essential to determine the most suitable technologies, such as electrolyzers, storage systems, and distribution networks, for the selected hydrogen pathway. This framework ensures that hydrogen solutions are tailored to the unique needs of remote communities, enhancing the viability of hydrogen as a key element in their decarbonization strategy.

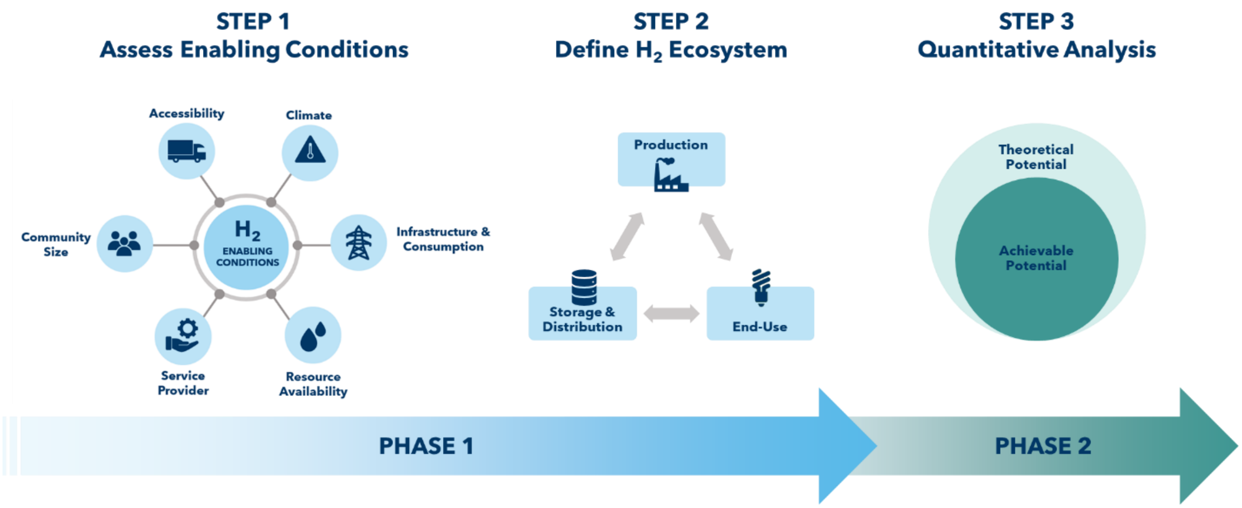

Figure 2. Three-step framework for assessing the feasibility of hydrogen energy systems in remote communities.

The "Hydrogen for Remote Communities" report identified multiple community archetypes in BC and conducted preliminary illustrative enabling conditions and pathways assessments. This report complements that work by completing Step 3 (Quantitative Analysis), where we quantitatively assess the feasibility of the preliminary pathways assessments for two of the community archetypes. This offers tangible insights into the technical and financial feasibility of specific hydrogen pathways, validating or disproving the previously identified theoretical role of hydrogen.

NOTE ON THE ROLE OF HYDROGEN IN TRANSPORTATION AND BUILDINGS

The case studies in this report focus on modeling hydrogen specifically for power generation applications rather than hydrogen's use for transportation and heating. **Based on our assessment, we conclude that is unlikely for hydrogen to play a major role in decarbonizing transportation or buildings sectors in remote communities**.

Engagement findings, combined with the results from the first phase of work, have revealed that transportation infrastructure in many remote communities is either severely limited or non-existent, with some communities relying on only a few kilometers of road, and/or off-road vehicles for local travel. In many cases, residents often find it more cost-effective to travel by air, when access to services and amenities outside of their communities is needed. For communities with sufficient road infrastructure, the adoption of electric vehicles (EVs) has already begun, making hydrogen-powered transportation even less viable, as the integration of only a few hydrogen vehicles within a community's fleet is not cost-competitive. Therefore, we do not consider hydrogen as a likely option for transportation, especially given the increasing accessibility and affordability of EVs.

Similarly, hydrogen for domestic heating was not modeled as it is less efficient and more costly when compared to electricity. Converting electricity to hydrogen, then storing and transporting it for use in boilers results in significant energy losses. This makes hydrogen less competitive against more efficient technologies such as heat pumps, which are already widely available. Heat pumps provide higher efficiency space heating and cooling, and do not face the technical challenges or costs associated with large-scale hydrogen storage. Current research confirms these findings, where a review of 54 studies on hydrogen for heating conducted by Jan Rosenow, and the International Energy Agency Net Zero Roadmap both indicate that there is no substantial role for hydrogen in domestic heating applications in a net zero future.[5] Additionally, as remote communities are not connected to provincial natural gas pipelines, hydrogen blending is not an option, and therefore introducing hydrogen for heating would require a significant investment in infrastructure upgrades.

[5] Jan Rosenow, A meta-review of 54 studies on hydrogen heating, Cell Reports Sustainability, Volume 1, Issue 1, 2024, 100010, ISSN 2949-7906, https://doi.org/10.1016/j.crsus.2023.100010.
IEA (2023), Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach, IEA, Paris https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach, Licence: CC BY 4.0

3. Community Perceptions of Hydrogen

As part of this project, we conducted community outreach and engagement to:

- Gauge hydrogen awareness among remote communities and build awareness of hydrogen as a potential decarbonization solution;
- Identify communities interested in pursuing hydrogen projects; and
- Collect information on key considerations (or enabling conditions) that may impact the feasibility of local hydrogen systems across different remote communities in BC.

In total, eight communities were invited to participate in separate, community-specific virtual engagement sessions. The defining characteristics among the communities varied, including their sub-classification (independent, non-integrated area, or end-of-line), climate, community size, infrastructure, energy consumption, resource availability, and service provider. We received a 50% response rate, with three communities indicating their willingness to participate and one community indicating they were not interested in participating. Of the three communities who participated, one community expressed some reservations, which was the emphasis of the discussion in that particular session.[6]

The format for engagement consisted of three main segments:

- A brief overview of the "Hydrogen for Remote Communities" report (completed March 2024), the goals of this project, a discussion about funding, and how the work will be used;
- A discussion of the current energy landscape within the participating community, including their energy needs and priorities; and
- A high-level overview of some of the opportunities and challenges associated with hydrogen systems, including understanding how familiar the community is with hydrogen as energy and perceived challenges of implementing a hydrogen ecosystem.

NOTE ON ENGAGEMENT FINDINGS

Below we summarize the findings of our engagements, however, we note that there are 44 remote communities in BC, all of which have a diverse set of characteristics, concerns, priorities, and needs.[7] Given the limited response rate, we caution attributing the findings of these engagements more broadly across all remote communities, and reinforce the need for proactive and meaningful engagement on a community specific basis.

[6] Reservations expressed were largely focused on community privacy, information sharing, and community priorities.
[7] CleanBC Remote Community Energy Strategy (RCES). Accessed July 2024. https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/community-energy-solutions/remote-community-energy-strategy-rces

The engagement sessions highlighted three key themes:

1. **Communities are actively exploring alternative forms of clean energy.** All three communities indicated that they are actively exploring options to secure reliable, clean energy. Despite the varied energy systems and infrastructure across the three communities, each community is either independently or in collaboration with external partners investigating opportunities to incorporate new clean energy systems such as solar, wind, geothermal or hydro.

   Energy sovereignty was also a theme across the communities, with each one expressing a desire not only to incorporate new energy sources, but also to be involved in the development, operation, and/or ownership of the project. There was also an acute awareness of the resources (e.g., water reservoirs, solar, land constraints) within their communities and a strong desire to both protect and utilize them.

2. **There is interest in, but limited awareness of, hydrogen within the communities.** All three communities expressed interest in hydrogen and were cautiously optimistic about the prospect of hydrogen and its ability to support their energy goals. However, there was little to no direct experience with hydrogen systems. General awareness of hydrogen fuel and technologies varied significantly, with some having no knowledge of hydrogen technologies to some who had conducted extensive research. It was mentioned that there would need to be local information sessions to inform the community of the key components of hydrogen ecosystems to build community buy-in.[8]

3. **Current capacity to support the operation of a hydrogen system is limited but desired.** While there are no community members with pre-existing hydrogen experience, there is a strong desire to participate in training and develop expertise within the community. One community indicated that there is a local who supports the operation and maintenance of diesel generators, which could lend to a similar role for future energy systems. This desire to participate in all aspects of the energy system aligns with energy sovereignty and resource protection goals.

[8] The absence of prior experience with hydrogen presented as a barrier to further, more detailed community input during the engagement on the perceived challenges and opportunities associated with integrating hydrogen into the community energy landscape.

4. Techno-Economic Assessments

To assess the feasibility of hydrogen in remote communities, we developed two illustrative case studies; one for a remote community and one for an end-of-line community. These case studies represent techno-economic assessments that complement the preliminary research as explored in the "Hydrogen for Remote Communities" report. Each of the case studies captures an archetype community that broadly reflects conditions and characteristics observed in the various types of remote communities within BC, but does not represent a specific community.[9]

OVERVIEW OF MODELING APPROACH

To conduct this analysis, we used the Hybrid Optimization of Multiple Energy Resources (HOMER) software. HOMER is a model used to simulate the operations of a hybrid microgrid at hourly intervals to identify cost-effective solutions to meet energy needs. HOMER software can simulate multiple energy sources including renewables, grid power, and storage to explore all possible combinations of equipment, and present hundreds to thousands of configurations that can be selected to identify the optimal energy system for a community.

The techno-economic inputs assumed in the HOMER model and the technologies used for each optimization scenario can be found in Appendices A and B. Technology costs for renewable generation and storage technologies are assumed to benefit from a 30% Investment Tax Credit (ITC) based on the Canada Clean Technology ITC, a refundable tax credit for capital invested in the adoption and operation of new clean technology (CT) property in Canada.[10] Hydrogen components including the fuel cell, hydrogen tank, and electrolyzer each have a 40% ITC discount applied based on the Clean Hydrogen ITC.[11] Both ITCs are available to components that are acquired and become available for use in a qualified clean energy project from March 28, 2023 to December 31, 2034.

The HOMER model was then used to derive optimized renewable energy and hydrogen system configurations for the two case studies. The model assumes existing grid conditions (e.g., no additional transmission capacity). The HOMER model generated approximately 2,000 project configurations for each case study. Configurations vary by renewable energy

[9] Should a community decide to pursue the development of a hydrogen energy system, a more detailed technical study with community-specific parameters (e.g., climate, load profiles, cost of service, generator model, etc.) will be required to validate the opportunity.
[10] Clean Technology Investment Tax Credit, accessed at: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc/clean-technology-itc/about-ct-itc.html. Employers who elect to meet the labour requirements can avoid claiming the reduced tax credit rate, see: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc/clean-technology-itc/claiming-credit-ct-itc/maximize-credit-rate.html
[11] Clean Hydrogen Investment Tax Credit, accessed at: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc/clean-hydrogen-itc.html. The entire 40% credit is achievable for the production of clean hydrogen with a carbon intensity of less than 0.75 kg of CO2e per kg of H_2 produced; as such, due to clean production sources such as renewable and BC grid, the highest tier has been selected. Effective November 28, 2023, employers who elect to meet the labour requirements can avoid being limited to the reduced tax credit rate.

technology, project size, diesel configuration, and system dispatch model, among other variables. For each case study, we identified configurations optimized for an 80% greenhouse gas (GHG) reduction target, and for a 100% GHG reductions target. The results were compared relative to a baseline scenario reflecting the current diesel system.

4.1 Case Study 1: Remote Community

The first case study represents a remote community with 100% diesel dependence. The role of hydrogen in this community model was for renewable balancing. Renewable energy is the primary source of power generation within this community. When renewable generation exceeds community demand, the excess electricity is utilized to produce hydrogen that is stored on-site. This hydrogen can later be used to generate electricity during periods of peak demand (exceeding renewable output) and periods of low renewable generation (e.g., overcast days with low solar output) to maintain system reliability. The stored hydrogen in this community, offsets diesel consumption. Table 2 shows the key assumptions for the community.

Figure 3. Approximate location of the remote community in Case Study 1.

Table 2: Remote community characteristics and model assumptions.

Variable	Assumptions
Climate Zone[12]	5
Annual Consumption	2,000,000 kWh
Peak Load	528 kW
Baseline Diesel Generation	100%
Existing Diesel Generator(s)[13]	3 x 250 kW

Based on the characteristics and assumptions in Table 1, a baseline scenario that reflects the current community energy system was modeled to reflect a 'business as usual' case and the current costs to meet the community's energy needs. There were four decarbonization

[12] BC climate zones are defined in the BC Building Code based on the average heating degree days below 18°C experienced within a community. Accessed at: https://www.betterhomesbc.ca/faqs/climate-zone/
[13] Note that this was the modeled generator setup in HOMER to meet the annual consumption, however, may not reflect the true conditions in remote communities within the province.

scenarios modeled for this community to compare cost-effectiveness and emissions reductions against the baseline. The four scenarios include:

1. **Renewables only (RE_80):** the lowest cost pathway to achieve 80% GHG reductions; considers a combination of wind turbines, solar panels, and lithium (Li)-ion batteries.
2. **Renewables plus hydrogen (RE+H2_80):** the lowest cost pathway to achieve 80% GHG reductions; considers renewables plus the addition of hydrogen fuel cells, electrolyzers, and storage tanks.
3. **No diesel, renewables only (RE_100):** the lowest cost pathway to achieve 100% GHG reductions with a combination of wind turbines, solar panels, and Li-ion batteries.
4. **No diesel, renewables plus hydrogen (RE+H2_100):** the lowest cost pathway to achieve 100% GHG reductions with a combination of hydrogen plus wind turbines, solar panels, and Li-ion batteries.

METRICS

- **Levelized Cost of Energy (LCOE):** The average cost per unit of energy generated over the lifetime of a power generation asset, including capital, operational, and maintenance costs.
- **Capital Expenditures (CAPEX):** The total upfront cost required to build or acquire a power generation asset, covering equipment, infrastructure, and installation.
- **Operational Expenditures (OPEX):** The ongoing costs of operating and maintaining a power generation asset over its lifetime, including fuel, labour, and maintenance expenses.
- **Water Requirement:** The volume of water required as a feedstock to produce electrolytic hydrogen.
- **GHG Reductions:** Emissions reductions achieved as compared to the baseline scenario.

Table 3 highlights the system configurations that were considered most cost-effective under each of the modeled scenarios, while Table 4 highlights key system metrics. Outside of the baseline, a combination of wind, solar, and battery capacity was utilized to meet the GHG reduction target in each scenario. For scenarios utilizing hydrogen, storage tanks are also included in the techno-economic analysis ($/kg) however, are not included in the tables as the number of tanks will vary based on the manufacturer and model.

Table 3: Generation sources for Case Study 1 community under different scenarios.

Scenario	Wind (kW)	Solar PV (kW)	Battery Storage Capacity (kWh)	Fuel Cell (kW)	Electrolyzer (kW)
Baseline	-	-	-	-	-
RE_80	600	1,044	2,730	-	-
RE+H2_80	700	987	2,100	250	250
RE_100	1,500	1,975	10,920	-	-
RE+H2_100	1,100	1,946	3,990	500	500

Table 4: Key system metrics under different scenarios for Case Study 1.

Scenario	LCOE ($/kWh)	CAPEX ($M)	OPEX ($/yr)	Water Requirement (L)[14,15]	GHG Reduction (%)	Diesel Consumption (kilo-liters)	Fuel Cell Production (kWh/yr)	H2 required by Fuel Cell (kg/yr)
Baseline	0.649	-	392,370	-	0%	569	-	-
RE_80	0.438	5.4	181,165	-	82%	108	-	-
RE+H2_80	0.439	6.2	174,089	170,624	87%	78	110,694	4,649
RE_100	0.783	13.4	236,107	-	100%	0	-	-
RE+H2_100	0.578	10.5	185,572	155,337	100%	0	100,777	4,233

[14] Hydrogen Reality Check: Distilling Green Hydrogen's Water Consumption - RMI
[15] Among the different types of electrolyzers, PEM electrolysis has the lowest water consumption intensity, using approximately 17.5 litres of water per kilogram of hydrogen. Alkaline electrolysis follows PEM electrolysis, with a water consumption intensity of 22.3 litres per kilogram of hydrogen Water for hydrogen production

The results confirm that renewables and energy storage offer a cost-effective pathway to achieving an 80% reduction target, resulting in an LCOE that is 30% lower than the current system ($0.438/kWh relative to $0.649/kWh for the baseline), even when considering the necessary capital expenditure. This is primarily due to the substantial reduction in diesel fuel costs. Adding hydrogen to the renewable energy scenario (RE+H2_80) offsets some solar and battery storage deployment and offers a LCOE comparable to the RE_80 option, however, is dependent on the higher ITC available for hydrogen.[16] Under this scenario, hydrogen only contributes about 5% of the community's electricity needs, only becoming cost-effective when renewable generation cannot meet peak demand, and the decision to pursue this scenario versus the RE_80 scenario would likely be determined by community specific goals and considerations.

While the province's target aims to achieve an 80% reduction in emissions, scenarios that achieve full decarbonization were also explored. As shown under the RE_100 scenario, achieving this level of emission reductions solely with renewables and energy storage requires significant over-build of wind, solar, and batteries to satisfy peak demand requirements and maintain system reliability without diesel.[17] This leads to considerable capital expenditure and substantially increases the LCOE to $0.783/kWh, which is more costly than the current diesel system.

However, the inclusion of hydrogen (RE+H2_100 scenario), reduces the need for over-building renewable capacity, providing a more balanced and economically feasible approach to full decarbonization and maintaining reliability. It is worth noting that hydrogen production is not increased in the 100% decarbonization scenario relative to the 80% decarbonization scenario; remaining at nearly 5% of annual electricity consumption (Figure 4).[18] This demonstrates that hydrogen only becomes cost-effective when renewable generation cannot meet the peak demand of the community. In this case, a small contribution from hydrogen is more cost-effective than oversizing renewables to meet peak demand and maintain reliability without diesel.

[16] While the results are comparable, given the high uncertainty surrounding the costs for hydrogen, the feasibility of a hydrogen project will be circumstantial and dependent on the counterfactual renewable projects that it is compared to.
[17] Roughly double the wind and solar capacity, and five times the storage capacity that would be needed to achieve the 80% reduction.
[18] The sizing of the fuel cell is doubled in RE+H2_100 to meet peak demand needs without diesel.

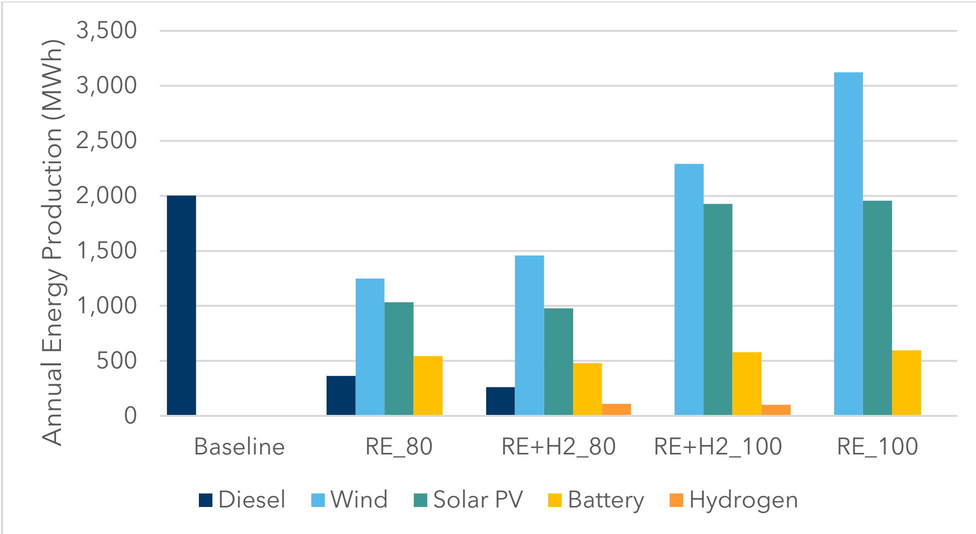

Figure 4: Energy production by source for different system configurations.

4.2 Case Study 2: End-of-Line Community

For this case study, an inland end-of-line community with an average of five days of outage per month is modeled as a community archetype. The baseline assumes that 100% of the outage load is met by the use of diesel generators. In this case study, hydrogen is strictly modeled as a back-up resource to meet the needs of the community exclusively during outage events.

Figure 5. Approximate location of the end-of-line community in Case Study 2.

For this community, an alternate approach was used to derive the costs and system requirements for the hydrogen scenarios. Since the HOMER model requires that electrolyzers receive only excess electricity produced by the system, this limits the functionality of the model to draw additional electricity from the grid during non-outage days to operate the electrolyzer. Accordingly, due to these limitations, iterative calculations for the grid-generated hydrogen were completed in Microsoft Excel utilizing the same assumptions for hydrogen components as in the HOMER model.

Table 5. End-of-line community characteristics and model assumptions.

Variable	Assumptions
Climate Zone	6
Annual Consumption (Total)	18,289,834 kWh[19]
Annual Consumption (Outage)	2,980,959 kWh
Overall Peak Load	4,372 kW
Peak Load (Outage)	4,050 kW
Outage (days per month)	Five
Diesel Generation for Baseline	16%
Existing Diesel Generator(s)[20]	5,800 kW (5 x 1,010 kW, 1 x 910 kW)
Hydrogen needed per year (kg/year)[21]	125,956

[19] Data provided by BC Hydro.
[20] Note that this was the modeled generator setup in HOMER to meet the annual consumption, however, may not reflect the true conditions in end-of-line communities within the province.
[21] Based on 60% fuel cell efficiency and 39.4 kWh/kg hydrogen energy content. Hydrogen content value available at: https://nap.nationalacademies.org/read/10922/chapter/21

Based on the characteristics and assumptions outlined in Table 5, a baseline scenario was modeled to reflect 'business as usual' circumstances and current costs to meet the community's energy needs. Three decarbonizations scenarios were developed to compare cost-effectiveness and emissions reduction to the baseline scenario, including:

1. **Renewables:** Local deployment of renewables and energy storage sized to meet an unmet load[22] during outage events;
2. **Imported H2:** Hydrogen is assumed to be transported to the community from a regional facility in Prince George; and
3. **Grid-generated H2:** Electricity from the grid during non-outage days is used to produce hydrogen locally that can be stored to meet community needs during outage events.

A renewables and/or energy storage-only system sized to meet unmet load during outages requires a significant build-out of resources including, 36 MW of solar capacity and 230 MWh of storage capacity (Table 6). This requires a significant CAPEX investment and results in an extremely high LCOE.

Meeting the entire outage load of the community using hydrogen generated from excess grid electricity, or hydrogen produced off-site then transported and stored locally, both cost more than the baseline (Table 7). With an LCOE of $0.516/kWh, locally produced grid hydrogen represents a 7% increase when compared to the baseline, whereas imported hydrogen reflects an approximate 54% increase. The economic advantage of local production stems from the avoided cost of transporting hydrogen to the community, which represents one-third of the lifetime costs of the project (Figure 6).

From an economic perspective, both hydrogen options represent cost increases as compared to the baseline, however, from a decarbonization lens, hydrogen represents a viable opportunity to achieve 100% GHG reductions when compared to a renewable-only scenario.[23]

[22] Unmet load is defined as the community energy consumption during outage events which is no longer fulfilled by the electrical grid, rather the backup diesel generation system.
[23] The hydrogen generated off-site at the regional facility is assumed to be electrolytic hydrogen, produced from clean electricity and transported to the community with the use of non-emitting vehicles. This would achieve near 100% GHG reductions.

Table 6. Key generation sources of Case Study 2 community under different scenarios.

Scenario	Wind (kW)	Solar PV (kW)	Installed Battery Storage (kWh)	Fuel Cell (kW)	Electrolyzer (kW)
Baseline	-	-	-	-	-
Renewables	0	36,378	230,361	-	-
Imported H2	0	0	0	4,050	-
Grid H2	0	0	0	4,050	250

Table 7. System characteristics under different energy scenarios for Case Study 2.

Scenario	LCOE ($/kWh)	CAPEX ($M)	OPEX ($/yr)	Water Requirement (L/yr)	GHG Reduction (%)	Diesel Consumption (kilo-litres)	Fuel Cell Production (kWh/yr)	H2 required by Fuel Cell (kg)
Baseline	0.482	-	119,370	-	0%	826	-	-
Renewables	3.929	119.3	2,487,768	-	100%	0	-	-
Imported H2	0.741	8.7	80,454	-	100%	0	2,980,959	125,956
Grid H2	0.516	9.0	91,089	4,622,585	100%	0	2,980,959	125,956

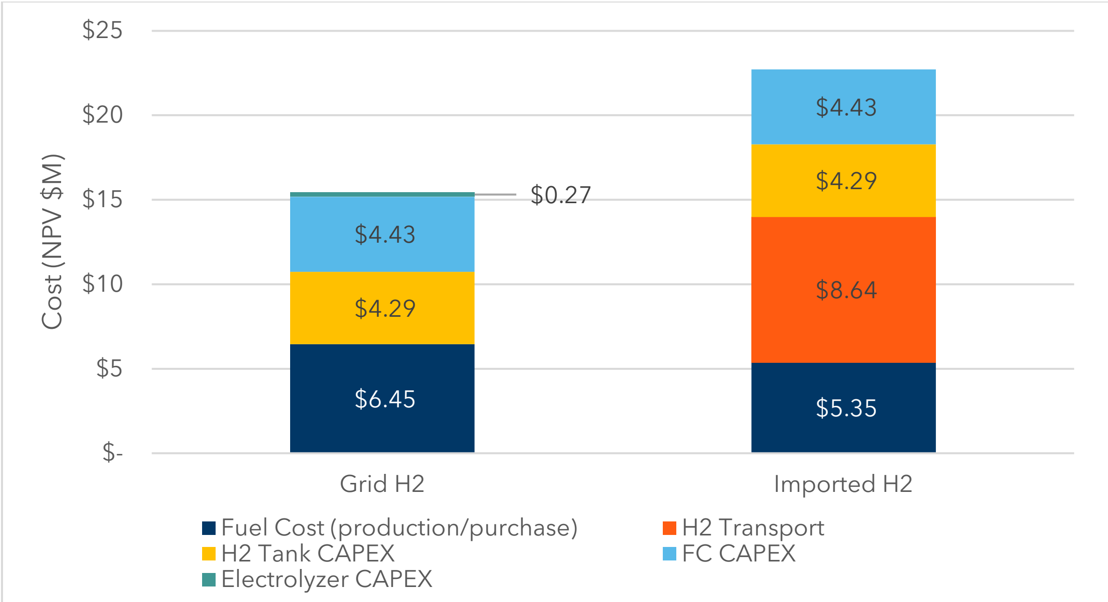

Figure 6: Breakdown of costs for local vs. import system configurations for Case Study 2.

NON-ECONOMIC CONSIDERATIONS

There are a number of non-economic considerations that will significantly impact the realization of hydrogen projects. In particular, this case study assumes that the availability of transmission capacity will always be sufficient to supply excess electricity after outage events to replenish hydrogen reserves. However, this assumption requires validation and further analysis.

To enable import scenarios where hydrogen is produced off-site and transported to the community, a regional hydrogen production facility must be established. To date, all such facilities are exploratory, and none have been established. For the purposes of assessing the economic feasibility of an import scenario, this project assumes that a hub will be developed, and that the hydrogen supply risk associated with transmission capacity is reduced when becoming a dedicated off-taker from a regional facility.

5. Conclusion

Our analysis confirms that renewable energy and battery storage provide an economically viable route for reducing diesel usage in British Columbia's remote communities by over 80% by 2030, aligning with provincial goals (Figure 7). Integrating hydrogen could reduce reliance on solar and batteries while maintaining comparable LCOE, however, this is contingent on a 40% federal Investment Tax Credit (ITC) for clean hydrogen projects. The role of hydrogen in meeting reduction targets shows promise, though community-specific studies are essential to assess its practical viability.

We also considered full decarbonization scenarios beyond the 80% diesel reduction target. Achieving 100% GHG reductions with only renewables and battery storage necessitates substantial overbuilding of wind, solar, and battery resources, resulting in a cost of service higher than the diesel baseline. However, incorporating hydrogen offers a more cost-effective path to eliminate the final 20% of emissions, making it an efficient addition in a scenario aiming for 100% diesel-free energy systems in remote communities (Figure 7). While it is a fairly small contribution (only 5% of annual electricity consumption), hydrogen would be critical for providing a more balanced and feasible approach to full decarbonization while maintaining reliability.

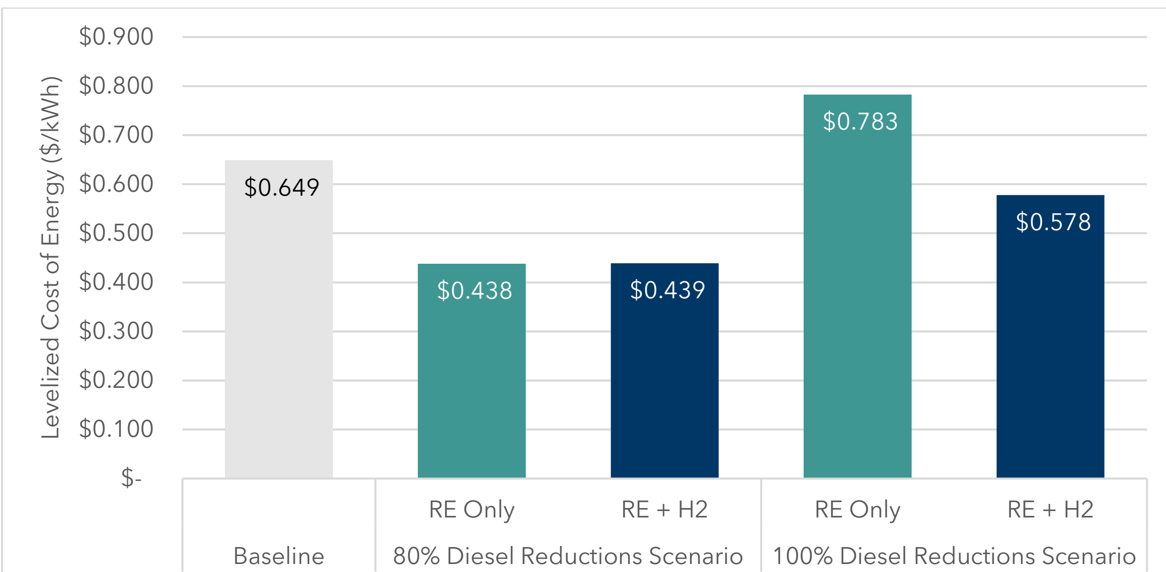

Figure 7. Summary of LCOE for Remote Communities (Case Study 1)

End-of-line communities (case study 2) connected to the grid but reliant on backup diesel microgrids present similar challenges. We evaluated hydrogen as a backup solution under two approaches: hydrogen produced from excess grid electricity and stored on-site, and imported hydrogen stored locally. Economically, both options show cost increases compared to diesel, with locally produced hydrogen increasing LCOE by 7% and imported hydrogen by 54%. Nonetheless, hydrogen enables complete GHG reduction potential, providing a feasible decarbonization option where renewable and battery-only configurations require extensive resource builds and are not economically competitive.

The results of our community engagement (while limited) suggest that that remote communities are actively exploring options to secure reliable, clean energy and are interested in being involved in the development, operation, and/or ownership of their local energy system. While hydrogen awareness is still limited, there is community interest in hydrogen and its ability to help achieve community energy goals. There is also a strong desire to participate in all aspects of the energy system, while also prioritizing energy sovereignty and resource protection. Nevertheless, the long-term viability of hydrogen in remote decarbonization efforts remains uncertain. The success of these projects will depend on overcoming financial, technical, and logistical challenges, as well as aligning with community priorities.

Next Steps

For remote communities interested in exploring hydrogen, it is recommended that they refer to the three-step framework outlined in the "Hydrogen for Remote Communities" report. Communities should start by evaluating enabling conditions, examining key factors such as resource availability for local hydrogen production. Once these conditions and their implications for hydrogen systems are well understood, these communities should identify specific hydrogen production and end-use options tailored to their unique needs, including on-site production from excess renewable energy or hydrogen import options. Finally, a community-specific quantitative analysis, akin to the case studies within this report, will provide a clear picture of hydrogen's achievable potential and cost-effectiveness based on local energy needs, infrastructure, and financial parameters.

Appendix A: Model Inputs

To derive the load profiles used in HOMER for the two case studies, the shape of existing electrical load profiles from nearby communities in BC were scaled based on the average annual consumption values for each case study. The annual consumption values for both communities were acquired from BC Hydro. For case study 1, the annual electricity consumption is based on a representative value for coastal remote communities, while annual consumption data for case study 2 was collected from a BC Hydro data request.

Common Variables	Value
Economics	
Nominal discount rate	8%
Expected inflation rate	2%
Project lifetime	25 years
Hydrogen system	
Electrolyzer efficiency[24]	73%
Fuel cell efficiency	60%
Hydrogen fuel slope	0.042 kg/kWh
Emission Penalties	0 $/t
Fuel Cell CAPEX	1,095 $/kW
Fuel Cell OPEX	19.87 $/kW
Electrolyzer CAPEX	851 $/kW
Electrolyzer OPEX	42.54 $/kW
Hydrogen Tank CAPEX	409 $/kW
Minimum load Ratio for Diesel Generators	30%

Technologies modeled in the HOMER optimization.

Technology	Optimization
Wind Turbine	100 kW, 32m hub height, 20-year lifetime
Solar PV	Generic flat-plate PV, with 80% derate factor[25], 25-year lifetime
Battery Energy Storage (BES)	210 kWh/50 kW (4-hr), 10-year lifetime

[24] An additional 3 kWh/kg was applied to the electrolyzer efficiency to account for compression losses from compressing hydrogen into high-pressure tanks. However, no decrease in efficiency was applied to the electrolyzer stacks to account for degradation over time.
[25] HOMER applies the derate factor to the PV array power output to account for reduced output in real-world operating conditions, such as soiling of the panels, wiring losses, shading, snow cover, aging, etc., compared to the conditions under which the PV panel was rated

Hydrogen Fuel Cell	250kW, 500kW, 750kW, 25-year lifetime (50,000 hrs)
Hydrogen Electrolyzer	50kW, 150kW, 250kW, 500kW, 15-year lifetime
Hydrogen Storage Tanks	Level 1 Hydrogen Tanks[26]

[26] Level 1 or Type I hydrogen tanks are made up entirely of metal and consist of a metallic liner with no outer wrapping thus allowing fairly simple construction and manufacturing and therefore also comparatively low cost.

Appendix B: Technology Cost Data

The cost information provided below is the result of applying a 30% ITC on wind, solar PV and battery storage systems based on Canada Clean Technology ITC, and a 40% ITC discount on hydrogen system, based on Clean Hydrogen ITC.[27]

In addition to standard technology costs, cost multipliers were added to account for the remoteness of communities. Cost associated with Balance of Systems, installation rental equipment, labour, overhead and contingency are typically higher in remote communities often stemming from increased transportation costs of both parts and skilled labourers. Multipliers of 1.1x to 2x were applied to certain cost components, based on disaggregated renewable energy costs by individual cost components, published by Clean Energy Canada in 2023.[28] Based on the multipliers used at granular levels (e.g., labour) and using Dunsky expert judgment, an overall 1.25x multiplier across the different renewable technologies was used.

Technology	Unit	Capital Cost (2024 CAD)	Annual O&M (2024 CAD)	Source
Wind Turbine	$/kW	4,615	69	NREL Annual Technology Baseline[29] + Remote Community Multiplier (1.25x)
Solar PV	$/kW	2,816	41	NREL Annual Technology Baseline + Remote Community Multiplier (1.25x)
Battery Energy Storage	$/kWh	310	8	NREL Annual Technology Baseline + Remote Community Multiplier (1.25x)
	$/kW	1,183	30	
	$[30]	271,345	6,784	
Hydrogen Fuel Cell	$/kW	1,095	20	U.S Department of Energy Technical Report, 2022 Grid Energy Storage Technology Cost and Performance Assessment + Remote Community Multiplier (1.25x)
Electrolyzer	$/kW	851	42.5	U.S Department of Energy Technical Report, 2022 Grid Energy

[27] Government of Canada, Clean economy investment tax credits (ITCs). Accessed at: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc.html (2024).
[28] Cost of Renewable Generation in Canada, Clean Energy Canada, Accessed at: https://cleanenergycanada.org/wp-content/uploads/2023/01/RenewableCostForecasts_CleanEnergyCanada_Dunsky_2023_SlideDeck.pdf
[29] National Renewable Energy Laboratory's Annual Technology Baseline (2024).
[30] Fixed initial capital cost.

				Storage Technology Cost and Performance Assessment + Remote Community Multiplier (1.25x)
Hydrogen Tank	$/kg	409		International Journal of Lightweight Materials and Manufacture: "Review of common hydrogen storage tanks and current manufacturing methods for aluminium alloy tank liners" + Remote Community Multiplier (1.25x)
Diesel Generator	$/L	N/A[31]	1.595 (Fuel costs only)[32]	Dunsky internal database for remote communities

[31] This work does not consider the long-term replacement/refurbishment costs associated with diesel generators.
[32] Diesel costs ($/L) attained from Dunsky FBC Pathways to 2030 (2020) study and inflated to 2024 dollars.

Appendix C: Hydrogen Costs

Cost to produce electricity from the grid (2024) and import hydrogen.[33]

Variable	Grid H2	Imported H2
Transportation costs ($/kg)[34]	-	6.4
2024 Import Cost of Hydrogen ($/kg)	-	7.34
2030 Import Cost of Hydrogen ($/kg)	-	2.71
2040 Import Cost of Hydrogen ($/kg)	-	2.87
2050 Import Cost of Hydrogen ($/kg)	-	2.34
BC Hydro Large Commercial Energy Charge ($/kWh)	0.0653	-
BC Hydro Large Commercial Demand Charge ($/kW)[35]	13.3	-
Basic charge per day ($/day)	0.2882	-

[33] Import costs are based on the green hydrogen prices from CER – Canada's Energy Futures 2021 and 2023 using an average of electrolysis from grid and from dedicated renewable technologies in the Canada Net Zero scenario. Costs from 2024 - 2034 include a Dunsky professional judgement of 20% cost discount resulting from hydrogen ITC benefits that would be expected to be passed through to end-users.
[34] Regional transportation costs from a Hydrogen Council report assuming at-scale production and transportation infrastructure: https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf
[35] BC Hydro Large Commercial rate, assuming a 2% annual escalation. Table 4 shows the key assumptions for the community load.

"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.

Dunsky is proud to stand by our work.