OPPORTUNITIES AND BARRIERS FOR THE DEPLOYMENT OF GREEN HYDROGEN IN CHILE'S MARKETS SMALL AND MEDIUM GRIDS

TASK 3: ISOLATED GRID STUDY

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1 Executive Summary

1.1 Introduction

Chile is faced with the challenge of securing affordable access to low-carbon electricity to all its inhabitants. Due to its geographical complexity, dispersed population, and size, many of these inhabitants are located in small- and medium-sized isolated grids.

To understand how renewable energy deployment supported by green hydrogen storage on small and medium isolated grids in Chile could create a positive impact, Arup conducted an analysis consisting of three primary activities:

1. Review of green hydrogen implementation in 4 existing international isolated grids
2. Modelling of green hydrogen implementation in 5 isolated Chilean grids to identify potential opportunities
3. Review of the regulatory environment to identify barriers to implementation

1.2 International Isolated Grid Review

A literature review of existing green hydrogen projects on isolated grids around the world was conducted. This study highlighted 4 grids that have demonstrated applicability to the Chilean small and medium grids context. The reviewed grids ranged in applications and reduced grid reliance on hydrocarbon imports, establishing ancillary industrial and transportation markets. The analyzed demonstration grids are located in Europe and North America and include:

- Raglan Mine, Canada – An isolated arctic mining micro-grid utilizing two 3 MW wind turbines combined with flywheel, battery, and hydrogen storage to minimize the use of high-cost diesel generation.
- Froan Island, Norway – A remote grid utilizing 225 kW of wind generation and 85 kW of solar generation combined with battery and hydrogen storage to eliminate the need for installation of an undersea power supply cable.
- Big Hit Orkney Islands, Scotland – 900 kW tidal turbine generators supplying a green hydrogen generation system employed to provide fuel for marine vessels and automobiles, energy and heat to two buildings, and feedstock to local industry.
- Bright Green Levenmouth, Scotland – A 760 kW wind turbine and 180 kW solar array used to provide power and heat to an 8 building microgrid and 350-bar refueling station for an automobile fleet of 17 vehicles.

The following primary insights were derived:

- Green hydrogen can be financially viable and enhance operations grid systems with significant renewable penetration.
- Learning from demonstration facilities is key for regulators, operators, and the workforce to adapt to the new operational considerations.
- Coordination between stakeholders, data driven analysis, and application-specific design are fundamental to success.

1.2.1 International Isolated Grid Review Main Conclusions

The review showed that a primary driver for using hydrogen storage in international isolated grids was to reduce reliance on imported energy. Reduction of fossil fuel imports for electricity generation can de-risk supply chains, avoid cost spikes, and enhance national security by increasing energy independence. These benefits are amplified in certain remote areas with isolated electrical systems like those in Chile. For example, Froan Island, Levenmouth, the Ragland Mine, and Orkney Island are sites where projects were successfully developed to use renewable energy and hydrogen storage to minimize risk associated with fuel supply.

Literature indicated that pilot projects were key to achieving scale and realizing the benefits of a hydrogen economy. The pilots facilitated collaboration of select entities to develop best practices, thereby identifying and removing barriers to the deployment of hydrogen storage and utilization.

The review also showed that there were instances where hydrogen deployment currently lacks feasibility. Hydrogen-based solutions that required multiple stakeholder coordination and extensive infrastructure modifications had significant risk of success while hydrogen is not yet widely utilized or well understood. Projects that financially relied on multiple hydrogen end uses faced delays, overspending, and even cancellation.

Hydrogen storage can be integral to cost-optimal energy production in remote locations. In locations where costs of importing fossil fuels was highest and renewable generation was possible, the opportunity to use hydrogen storage to enable renewable power and stabilize grid operations was greater.

Projects that placed learning at the center of execution helped to enable wider uptake of hydrogen. Leveraging the incorporation of hydrogen storage into isolated grids to develop best practices, standards, and job training specific to hydrogen helps to de-risk hydrogen uptake in other contexts and supports transition.

1.3 Isolated Grid Modelling

Findings from the international grid review were used to shape the second activity, which consisted of identifying cost-optimized combinations of renewable power, batteries and green hydrogen system in Chile's isolated grids under different scenarios. These future pathways tested included multiple macro-economic trends developed to simulate (1) the impact of specific enabling policies focused on removing key economic factors and (2) the technical barriers associated with significant renewable penetration on electric grids.

The modeling exercise was devised to estimate the socioeconomic impacts and benefits associated with the deployment of renewable generation coupled with storage in 5 isolated grids. The results illustrated the role that green hydrogen can play in the future, and how it might be enabled through certain policy and regulatory modifications. It is important to note that the modeling did not assume hydrogen storage as the default solution, but instead optimized the inclusion of both battery and hydrogen storage, as portrayed by the modeling results.

The 5 analyzed grids were:

- Punta Arenas
- Puerto Natales
- Aysén
- Isla de Pascua
- San Pedro de Atacama

The model was run under different scenarios to provide an understanding of the impact of regulatory and technological changes on the cost of energy. While the systems were optimized for cost of energy, the results provided information on the associated reduction in emissions, deployment of solar and wind generation, and deployment of battery and green hydrogen storage.

Each scenario was built off an assumption that was then used to draw a comparison from a baseline model. The scenarios were as follows:

Table 1
Scenario description and justification

Grid Analysis Scenarios			
Scenario	Carbon Tax	Cost of renewables [1]	Cost of H2 Technology [2]
Baseline Scenario 1	Low	Consensus Forecast	Consensus Forecast
Scenario 2	High	Consensus Forecast	Consensus Forecast
Scenario 3	High	Optimistic cost reduction	Consensus Forecast
Scenario 4	High		Optimistic cost reduction

1 Sourced from IRENA, see Appendix for exact scenarios

2 Sourced from combination of IRENA, IEA and DOE, see Appendix for exact scenarios

These scenarios provided insight into the composition of a future grid in different macroeconomic trends through the lens of five isolated grids in Chile. This was done for the year 2030 for all the scenarios, the results of which are summarized in the following section and discussed in detail in the Appendix.

1.3.1 Grid Modelling Key Technical Results & Findings

The analysis indicated that hydrogen can contribute to both lower electricity costs and lower carbon emissions in all of the grids that were analyzed. It was found that the inclusion of hydrogen storage and fuel cell generation can play a significant role in minimizing hydrocarbon generation, lowering carbon emissions, and optimizing energy costs in most scenarios modeled.

Grids with highly variable renewable generation can particularly benefit from incorporation of hydrogen storage. Grids with less-variable renewable generation such as hydropower or combined wind and solar relied less upon hydrogen storage for cost optimization. Additionally, grids with access to natural gas generation benefited the least from the incorporation of hydrogen storage due to the lower cost of natural gas relative to hydrogen storage and generation.

These findings indicate that hydrogen production, storage and fuel cell generation can be a significant and cost-competitive component of an optimized grid, particularly when high imported fuel costs are paired with variable renewable generation.

Figure 1 illustrates the optimized distribution of generation type for each investigated grid.

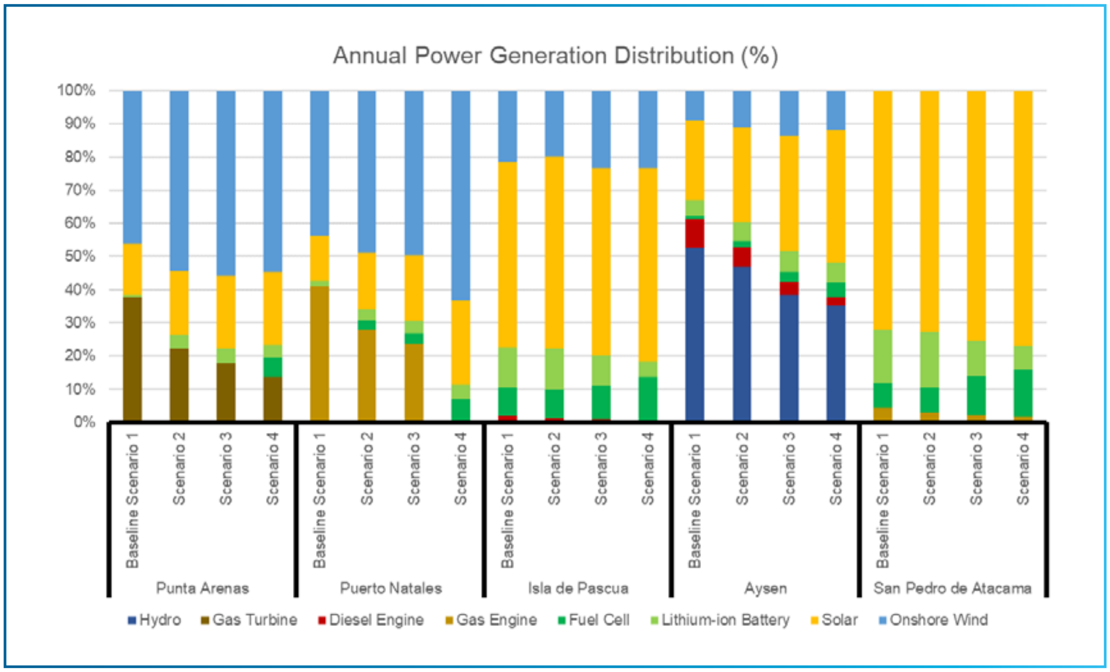


Figure 1:
Cost optimized power generation by technology for 2030 (%)

In the case of Punta Arenas, fuel cell generation was only included in the most optimistic scenario. This was due to the balance of wind and solar generation coupled with low-cost gas turbine generation. The combination of low-variability and low-cost generation allowed lithium-ion batteries to maximize the penetration of renewable energy. Hydrogen became cost effective under the most optimistic cost assumptions in Scenario 4 by facilitating the greatest reduction in hydrocarbon generation and, therefore, the highest emissions reduction.

Puerto Natales, similarly to Punta Arenas, has well-balanced renewable resources combined with natural gas generation. Therefore, need for hydrogen fuel cell generation in the cost-optimized system was low. However, because of the lower efficiency of gas engines compared to gas turbines, combined lithium-ion battery and hydrogen storage could be used to efficiently displace hydrocarbon generation in Scenarios 2, 3, and 4 with an almost complete elimination of hydrocarbons in Scenario 4.

Isla de Pascua is an example of a grid that heavily favors the use of hydrogen for energy storage due to the reliance on solar and the high cost of imported diesel fuel. In all scenarios the reliance on diesel generation could be substantially reduced by renewable generation and storage.

Aysen illustrates the potential for renewables and storage to complement hydropower in the cost-optimized grid. Combined battery and hydrogen storage can allow renewables to compete with hydropower while also lowering the need for diesel back-up generation.

Finally, the Atacama grid, which has extremely high solar resources, could complement these resources with battery and hydrogen storage to virtually eliminate the need for hydrocarbon generation in all scenarios. While solar directly supplied the grid needs during the day, battery and fuel cell generation met the lower demand levels at night. Gas engine generation provided peaking generation only when demand exceeded the capacity of the storage system. Due to the abundant solar resources, solar and storage was more cost effective than hydrocarbon generation in all scenarios. The increase in hydrogen storage relative to battery storage in Scenarios 2-4 was due to the optimistic cost reduction of hydrogen systems assumed in the scenarios.

Contribution to Emissions Reduction

This analysis demonstrated that the inclusion of hydrogen-based storage systems can provide substantial, cost-effective carbon emissions reduction benefits by reducing dependance on fossil fuels and enabling greater renewables uptake. The carbon reduction potential is shown in Table 2. The scenarios with more favorable economic environments showed decreased emissions corresponding to the increased utilization of hydrogen. As illustrated in Table 2, significant reductions in carbon emissions can be facilitated by inclusion of renewable generation and storage assets. In all scenarios, the majority of the reduction can be realized in the Baseline Scenario, with or without the use of hydrogen storage. While the reduction of emissions attributable to green hydrogen storage depends on the variability of the renewable generation, it was found that green hydrogen could also contribute to lowering of the cost of energy for the consumer.

Scenario	Projected Grid CO2 Emissions, kt/year				
	Punta Arenas	Puerto Natales	Isla de Pascua	Aysén	San Pedro de Atacama
2030 Projection	153.61	46.17	16.91	26.59	7.74
Baseline No H2	-	-	1.19	-	0.58
Baseline Scenario 1	71.84	37.72	0.56	10.66	0.57
Scenario 2	47.25	28.60	0.32	7.88	0.40
Scenario 3	38.44	24.52	0.27	5.51	0.31
Scenario 4	35.59	21.91	0.22	3.43	0.26

Table 2 :
Reduction of carbon emissions compared to projections associated with current generating portfolios, kt Co2 / year

It is important to note that hydrogen was found to be more applicable in some regions than in others. To optimize the benefit of hydrogen deployment, it is critical to understand what the opportunities are and how to enable them in an environmentally and socially sustainable manner.

Potential Hydrogen Storage Market Size

Table 3 provides an estimate of the potential market size for the analyzed grids in the baseline and best scenarios. In most scenarios, there is green hydrogen storage market potential associated with cost-optimal electricity production driven by the renewable energy incorporation. Three of the five grids could establish hydrogen storage markets under the Baseline Scenario 1 conditions. Under the most optimistic Scenario 4 conditions, the potential hydrogen storage markets could be very large. Production of hydrogen on the scale indicated in Scenario 4 would be capable of catalyzing other use cases, such as automotive fueling, marine bunkering, and fertilizer production. Additionally, complete replacement of hydrocarbon generation would further increase the hydrogen demand, especially in Punta Arenas where significant gas generation remains in Scenario 4.

Grid	Hydrogen Storage Market (kg H2/year)	
	Baseline	Scenario 4
Punta Arenas	N/A	1,300,000
Puerto Natales	N/A	570,000
Isla de Pascua	170,000	280,000
Aysen	95,000	490,000
San Pedro de Atacama	90,000	190,000

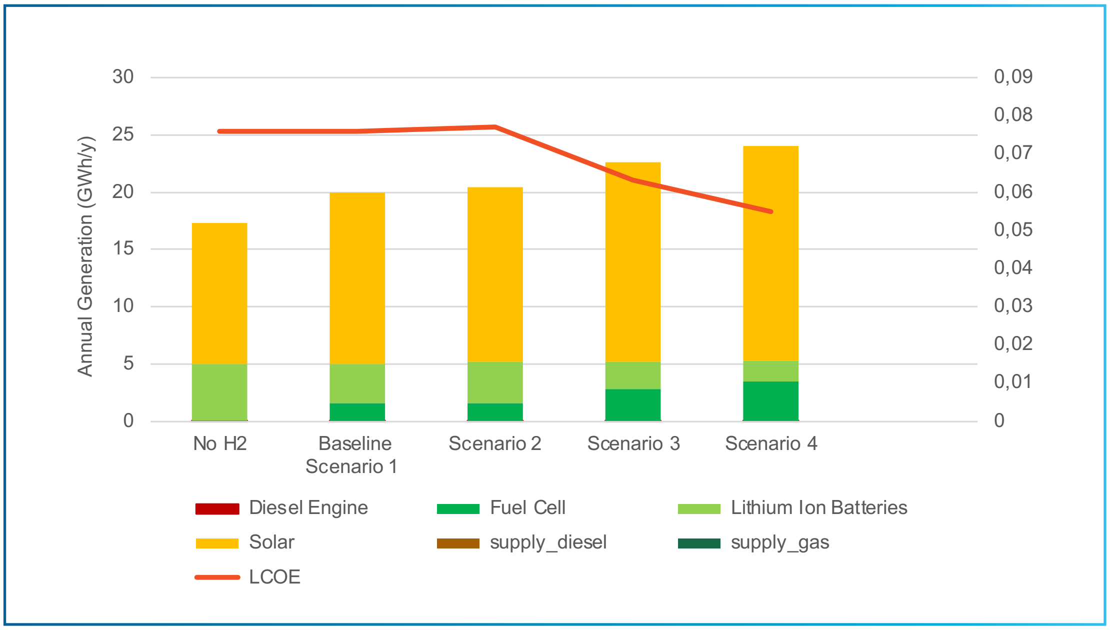
Table 3:
Estimated hydrogen storage market size (kg H2/year) per grid for Baseline and Scenario 4

Baseline Contribution to Emissions and Cost Reduction

In the two grids where hydrogen played the most significant role, San Pedro de Atacama and Isla de Pascua, an additional scenario was run to understand the Baseline Scenario impact of hydrogen storage on cost and carbon emissions. This scenario was identical to the Baseline Scenario except it excluded hydrogen as a pathway.

In San Pedro de Atacama, the use of hydrogen storage resulted in emission savings of 2% compared to batteries alone. Because San Pedro de Atacama has an abundance of solar generation potential, relatively consistent weather conditions and high fossil fuel import costs, the carbon emissions savings associated with the deployment of hydrogen storage are not significant. Battery storage is capable of managing the daily shifts in generation to meet most of grid demand at night without significant reliance on fossil fuels. However, the cost benefits of hydrogen storage are more significant under the optimistic Scenario 4 conditions, providing a cost savings of 12% due to the comparatively higher cost of the battery storage systems. The lower projected costs demonstrate that a combination of hydrogen storage and battery storage could potentially meet the needs of the gird in a more cost-effective manner than batteries alone if the price of hydrogen generation decreases over time. Figure 2 illustrates the relationship between storage capacity, hydrogen generation, and LCOE. It should be reiterated, however, that the reduction of LCOE in this analysis is driven by the optimistic pricing for hydrogen facilities included in scenarios 3 and 4.

Figure 2
San Pedro de Atacama Grid Supply and LCOE



In Isla de Pascua, the vast majority of the emission savings was driven by incorporation of renewables, regardless of the type storage used, as illustrated in Figure 3. The use of hydrogen storage resulted in an additional estimated emission reduction of 49%, significantly higher than was observed in San Pedro de Atacama. The primary reason for the decrease in emissions is the high variability of renewable generation (solar and wind) that drives a higher reliance on long term storage. In the absence of stored hydrogen, a 100% increase of diesel generation was required to maintain grid operations.

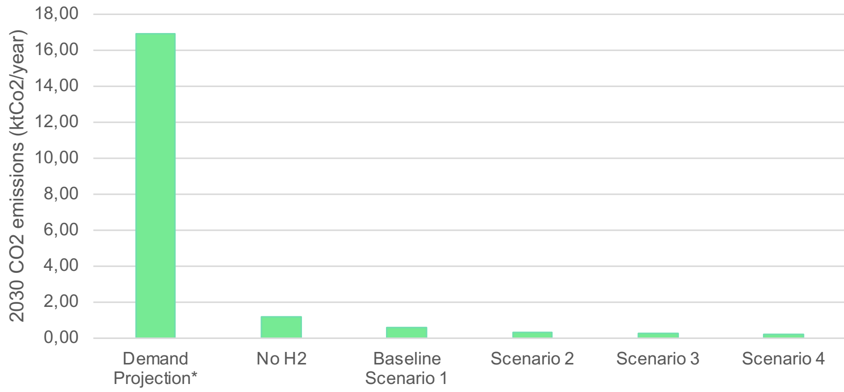


Figure 3:
2030 Isla de Pascua carbon emissions (ktCO2/year) per scenario *(demand projection figure assumes 2020 infrastructure makeup based on Formularios para Isla de Pasua in 2020)

Jobs Creation

An estimate of the "green jobs" that are associated with manufacturing, construction, and installation (MCI) and operations and maintenance (O&M) of the scenarios was developed based on industry estimating standards, including IRENA (as referenced in the modeling assumptions presented in the Appendix) and is shown in Table 4.

Table 4:
Green job creation breakdown per grid per scenario

Scenario	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
	MCI	O&M	MCI	O&M
	Punta Arenas			
Baseline Scenario 1	0	0	1465.3	27.4
Scenario 2	50	5.75	2057.1	44.6
Scenario 3	50	5.75	2606.3	53.8
Scenario 4	50	5.75	2667.7	49.2
	Puerto Natales			
Baseline Scenario 1	0	0	710.4	13.2
Scenario 2	50	5.75	1030.0	23.9
Scenario 3	50	5.75	1340.6	29.4
Scenario 4	50	5.75	1408.8	30.6
	Isla de Pascua			
Baseline Scenario 1	50	5.75	416.3	12.4
Scenario 2	50	5.75	439.4	12.8
Scenario 3	50	5.75	1617.3	13.2
Scenario 4	50	5.75	1712.5	13.6
	Aysen			
Baseline Scenario 1	50	5.75	707.9	17.8
Scenario 2	50	5.75	890.1	21.1
Scenario 3	50	5.75	1224.0	26.9
Scenario 4	50	5.75	1525.9	31.9
	San Pedro de Atacama			
Baseline Scenario 1	50	5.75	205.8	8.5
Scenario 2	50	5.75	214.4	8.7
Scenario 3	50	5.75	241.0	9.1
Scenario 4	50	5.75	252.9	9.2

It should be noted that there is considerable additional opportunity for job creation related to the administrative activities associated with:

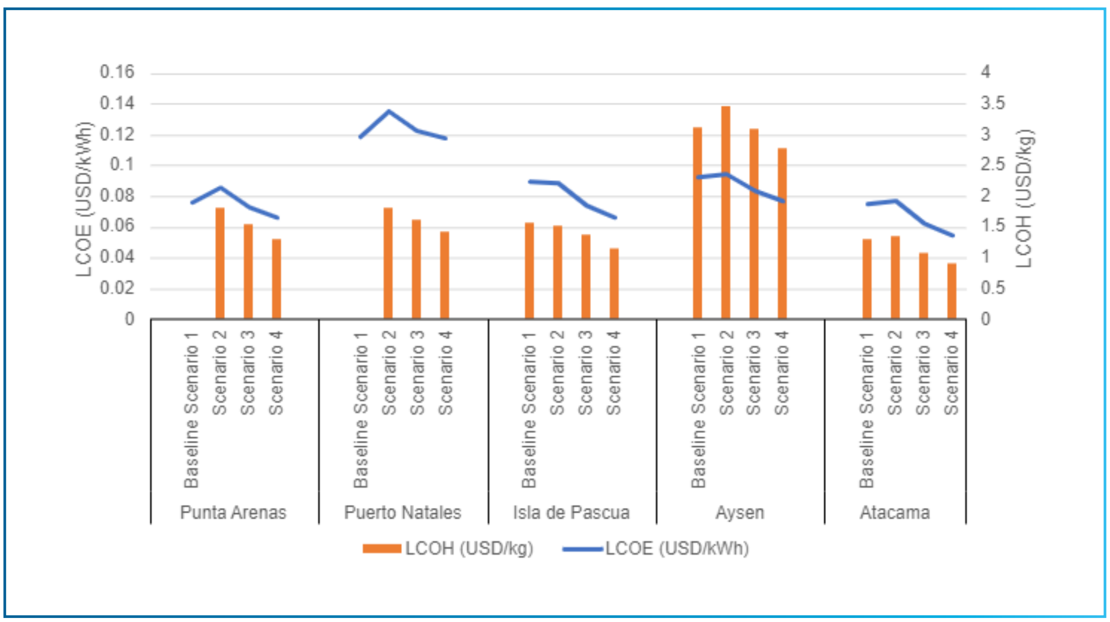
- Verification and auditing,
- Development of training material for workers,
- Safety cases and research

It is recommended that Chile develops a gap analysis to determine which current skills and organizations could be repurposed for a green economy. This analysis is key to understanding the locations best suited to pilot projects with maximum benefits.

Levelized Cost of Energy

As depicted in Figure 4 below, lower levelized costs of electricity (LCOE) can be achieved by incorporating renewables and storage depending on the assumptions in the particular scenarios. The use of carbon tax alone (Scenarios 1 and 2) was not sufficient to significantly lower the LCOE and, as can be expected, resulted in increased costs in the grids most heavily reliant on hydrocarbon generation. However, in grids more reliant on renewable generation, the increased carbon taxes coupled with optimistic cost projections for renewables and hydrogen resulted in decreases in levelized energy costs. In addition to the lowered LCOE, reduced emissions and increased energy security will also be realized.

Figure 4:
Levelized cost of hydrogen (orange bars & right axis) & levelized cost of electricity (blue lines and left axis) for each grid and scenario



The analysis indicates that, in addition to the significant reduction of emissions associated with the incorporation of renewables, the cost of energy to the consumer can also be reduced.

It is recommended that government support of renewable generation infrastructure and hydrogen infrastructure be made available to projects that support cost-effective decarbonization of isolated grids. This government support mechanism could be underpinned by a carbon tax on equivalent lifecycle CO2 emissions from fuel consumed in power generation facilities serving appropriate small- and medium-sized grids without increasing energy costs to the consumer. Alternatively, existing subsidies for imported fuels could be redirected to support renewable generation and storage assets. Regional context, especially regarding the planification and tariffication process, is critical for determining the best solution and allocation of financial support.

1.4 Regulatory Review

The regulatory review is limited to those concepts and elements related specifically to the implementation of hydrogen in small and medium grids, together referred to as "isolated grids" in the context of the Chilean infrastructure.

A robust National Energy strategy[3] to develop market conditions conductive of the development of renewable energy generation and battery storage assets is currently being developed in Chile. It is beyond the scope of this study to contribute to that strategy development beyond the contribution of elements that relate specifically to green hydrogen implementation. The implementation of the reforms to isolated grids must be made in a thoughtful manner, and potentially customized to the attributes of each isolated grid, in order to provide the cost and reliability benefits to the rate payers.

The implementation of green hydrogen in isolated grids requires a system that is intricately linked between generation, storage, and offtake. The planning and design of the grids will take on new attributes that have not been previously considered and are not compatible with the current laws and regulations related to planning and tariffs. Among the non-compatible attributes are:

- Planned over-generation,
- Redundant transmission, and
- Storage capacity fees.

These points are discussed below. While these are true of all renewable generation and storage schemes, they are amplified by the nature of isolated grids, the long-term nature of hydrogen storage, and the low round-trip energy efficiency of hydrogen storage.

1.4.1 Grid Design Considerations Affecting Regulations

Because of the specific attributes of green hydrogen storage systems, special consideration should be given to the design of the grid to enable incorporation. The consideration should be focused on three areas that have been indicated in the grid modeling and evaluation effort, including hydrogen generation and storage assets, renewable generation coupled with green hydrogen systems, and transmission infrastructure. Finally, the market design to provide compensation for grid services supplied by long-term, low-frequency hydrogen storage systems must be considered.

3 Gobierno de Chile, Ministerio de Energía, 2020: « Estrategia de flexibilidad para el sistema eléctrico nacional »

Hydrogen Generation and Storage

Hydrogen storage systems are best suited for long-term, low-frequency storage and may be operating for months, converting excess power to hydrogen before any energy is discharged to the grid. Therefore, the revenue streams to support the investment must be different than those typically associated with hydrocarbon generation and short-term battery storage.

Consistent revenue based on the capacity of the hydrogen storage system (inclusive of both the generating and storage assets) will be required to underpin the capital investment and the operating expenses.

Development of hydrogen storage systems, including coupled wind and solar generation, require long-term purchase agreements to facilitate financing. Typical agreements for renewable power storage projects are 15-30 years. The revenue models can be structured to provide flexibility in pricing based on variable costs but must be firm enough to satisfy financial institution requirements.

Renewable Generation Associated with Green Hydrogen

It is unlikely that merchant green hydrogen facilities based on curtailed renewable generation or pricing arbitrage will be financially viable in small and medium grids due to the close planning between generation and loading. With the primary purpose of long-term hydrogen storage being energy supply during low wind / solar generation periods, over-capacity will be required during normal wind / solar generation periods to provide energy to hydrogen production. The generation over-capacity is the result of several factors, including capacity of variable renewable generation, energy losses associated with round-trip hydrogen production, and the inclusion of hydrogen fuel-cell generation capacity. As described in the report below, the incorporation of long-term storage results in significant generation over-capacity in the grid system while also lowering average energy costs. The generation over-capacity factor for the green hydrogen system will be at least 50% and potentially higher depending on the variability and intermittency of the generation and discharge.

The planification process must provide mechanisms to assess the benefits of over-capacity to enable green hydrogen storage. Additionally, the tariffication process must provide mechanisms for compensation for power while in storage and for power lost in the hydrogen conversion processes.

Transmission Assets

Hydrogen storage systems can be co-located and directly coupled with renewable generation assets. In this case the over-generation will be stored as hydrogen prior to ever entering the grid transmission system. However, there is also the potential that hydrogen storage will provide the highest value to the grid when placed centrally between several generating sites or behind points of potential transmission congestion. In these cases, power will be transmitted through the infrastructure between generation and storage systems prior to conversion to hydrogen. When the energy is finally dispatched to the end-user it will be at least 50% less than the originally-transmitted amount because of the energy losses. Properly designed, the use of green hydrogen storage will alleviate over-all grid congestion and defer capital expenditures associated with the transmission system.

Thus, the planification process should consider upgrades needed to the system to enable hydrogen storage that provides over-all increased benefits to the grid. Also, the tariffication process should consider the cost structure for power being delivered to storage, including the losses experienced during hydrogen production, to prevent redundant charges that could render hydrogen storage uncompetitive.

1.4.2 Considerations for Market Competitiveness

The construction of the grid planning process must include an openness to innovative developments that provide benefits to the grid. This openness must be able to accommodate the consideration of novel designs and asset configurations, not only for hydrogen-based solutions but other storage systems as well. As demonstrated in Section 2 of this report, optimal power cost will likely be achieved by a mix of short term and long-term storage.

Because of the need to finance and recover the cost of the storage systems over a long period, the ability to provide long-term purchase agreements is needed to underpin investments. The market design will need the ability to provide long-term storage capacity purchase agreements. The agreements will be related to the services that the storage system is ready and able to provide, rather than (or in addition to) the actual services performed.

Market design should provide support for transmission of renewable power bound for hydrogen storage. Pricing should consider the benefits that storage can bring to the grid by relieving congestion and lowering peak pricing and emissions.

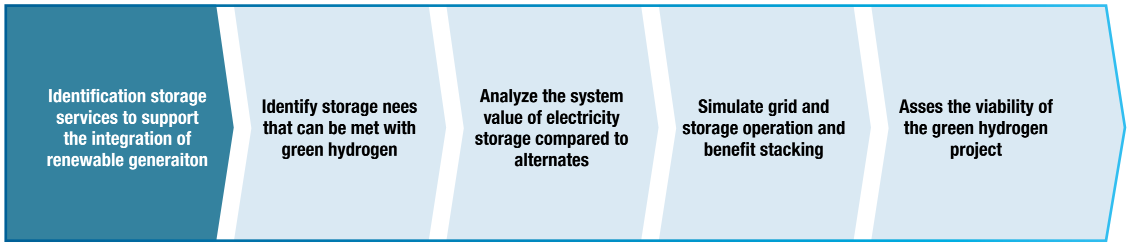
Finally, support should be provided for demonstration projects that may not be otherwise financially viable. Demonstration projects are useful to fully understand the application and benefit of long-term storage in a specific grid. This can be especially beneficial when applied to facilities that can be expanded after the demonstration period and incorporated into a fully functional facility.

1.4.3 Pathways for Implementation

The implementation of green hydrogen storage into isolated grids will require modifications to the planification and tariffication processes that consider the specific attributes of green hydrogen.

To frame this, it is worth looking at the International Renewable Energy Agency's (IRENA) "Electricity Storage Valuation Framework in 2020", that provides general guidelines for evaluating and planning renewable energy storage systems. Although the IRENA report does not address hydrogen systems, the framework can be adapted for that use. The IRENA framework includes a 6-phase evaluation process that can be adapted to green hydrogen systems as shown in Figure 5. The detailed process provided by IRENA will require augmentation to address hydrogen by evaluating critical elements as a system.

Figure 5:
Green Hydrogen Valuation Process.
(Adapted from IRENA Electricity
Storage Valuation Framework 2020)



Specifically, the green hydrogen framework will need to start with a focus on the supply of storage services to enable integration of renewable generation (Step 1). The first steps should promote the concept of maximizing penetration of renewable energy in the grid on the assumption that doing so will lower emissions and cost.

The second step is to identify long-term, low-frequency storage services that can be met by green hydrogen.

The framework will then need to allow a comparison to other storage technologies (Step 3). This step would employ analysis techniques similar to those employed in this report to balance the variability of the renewable generation with the most appropriate storage technology. This step would consider ancillary services that could be supplied by other storage technologies as well as location of storage to best utilize transmission and distribution assets.

The next phase of the analysis would be to simulate the grid operations with the renewable generation and storage to determine the benefits. The benefits of the storage could include emissions reduction, energy security, deferred investment in transmission infrastructure, and reduction in subsidies.

The final step would be to assess the financial viability of the project including the market mechanisms to support the investment. The financial viability and market mechanisms will be closely interlocked and include balancing the capital and operational costs with the revenue generated by capacity and generation purchase agreements.

Incorporating a results-focused renewable framework into the planification and tariffication process would encourage the transition of the grids and result in increased value and security to the consumers.

International Isolated Grid Review

This section of the report investigates international experiences and best practices for the promotion and replacement of fossil fuels through the utilization of renewable energy to produce hydrogen in international isolated grids.

The following four projects were analyzed to understand which features of each are relevant to Chile's isolated grids:

- Raglan Mine, Canada – An isolated, arctic mining micro-grid utilizing two 3MW wind turbines combined with flywheel, battery, and hydrogen storage to minimize the use of high-cost diesel generation.
- Froan Island, Norway – A remote grid utilizing 225 kW wind generation and 85 kW solar generation combined with battery and hydrogen storage to eliminate the need for installation of an undersea power supply cable.
- Big Hit Orkney Islands, Scotland – 900 kW tidal turbine generators supplying a green hydrogen generation system employed to provide fuel for marine vessels and automobiles, as well as energy and heat to two buildings and feedstock to local industry.
- Bright Green Levenmouth, Scotland – 760 kW wind turbine and 180 kW solar array used to provide power and heat to an 8 building microgrid and 350 bar refueling station for 17 vehicle automobile fleet.

The following section takes information from the international review and digests the lessons learned in the contexts of the isolated grids in Chile, reviewed in detail in Section 1.6.

1.5 Main Findings

The lessons learned from the projects analysed include:

1. System design, including technologies suitable for microgrid applications, is critical
2. Hydrogen storage systems can compete with fossil fuels in remote locations with renewable electricity generation capacity
3. Stakeholders who are focused on maximizing near term profit are not ideal project partners

1.5.1 System Design

Based on this review, it was found that intelligent process design was integral to the technical and commercial success of each project. The projects all demonstrated the utilization of hydrogen storage systems consisting of PEM electrolyzer systems, PEM fuel cell systems and aboveground gaseous hydrogen storage. PEM electrolyzers and fuel cells provided flexibility to operate in the highly variable conditions. PEM electrolyzers operate under pressure and are capable of self-compressing hydrogen products to an operating pressure suitable for use in a PEM fuel cell, so external compression infrastructure and associated costs can be avoided.

See Section 3 for a more detailed description of the system that was replicated based on the findings of this review of projects internationally.

1.5.2 Cost Competitiveness of Hydrogen

In each of the projects, it was found that hydrogen was adequate for supporting grid applications in conjunction with short term storage and by utilizing excess renewable energy. In projects like Raglan Mine, operations benefitted from the deployment of hydrogen and did not have to significantly change behaviors. In projects where the impact of producing and utilizing green hydrogen involved a wide range of end uses, issues with funding were observed. Specifically, difficulty in coordinating and implementing offtake agreements and incentives resulted in delays and operating losses. Where there is not yet a diverse hydrogen economy, by implementing well-structured policy initiatives and revenue recycle, hydrogen can be used to support deployment of renewables and decarbonization of the grid in a way that will not negatively impact consumers.

1.5.3 Project Partnerships

Financial support through strategic grant funds from governments was employed in all of the studied projects. Electrolyzer manufacturers, notably whose interests are aligned with the success of the projects, were key project partners in each project. Involvement of academia and other research institutions was important for conducting experiments and publishing findings. These project partners were integral in maximizing the co-benefits of green hydrogen pilot projects regardless of ownership.

1.6 International Grid Analysis

1.6.1 Raglan Mine, Canada

This project aimed to set a new landmark in renewable energy penetration of diesel autonomous grids, by coupling leading-edge storage technologies and an advanced controller to an Arctic-grade wind turbine, at a Canadian Arctic mine location (Figure 6). The project was successful in demonstrating a high-impact pathway towards full energy diversification north of the 60th parallel. [4]

The system used an integrated multi-modal storage system to provide variable response time power. A flywheel was used for quick response and to smooth the power from the

4 https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662

wind turbine. A lithium-ion battery system was used for intermediate response when the load exceeded the generating capacity of the wind turbine for short periods. The hydrogen system was used to provide longer term response. Finally, diesel was used when other power was not available.

Conversely, excess power from the turbine was first used to power the flywheel, followed by charging the lithium-ion batteries. After the batteries were fully charged, power was sent to the electrolyzers and stored as hydrogen.

The project used an Arctic-rated 3 MW ENERCON E-82 E4 wind turbine generator, coupled to leading-edge storage technologies configured in a three-tiered smart grid:

- A 200 kilowatt (kW) 1.5 kilowatt-hour (kWh) KTSI GTR-200 flywheel for fast transients,
- A 200 kW / 250 kWh Electrovaya SuperPolymer 2.0™ Li-Ion battery for transition backup, and
- A HYDROGENICS 200 kW / 1 MWh (HySTAT 60™ Electrolyser 315 kW coupled to HyPM-XR.TM 198 kW PEM fuel cell).

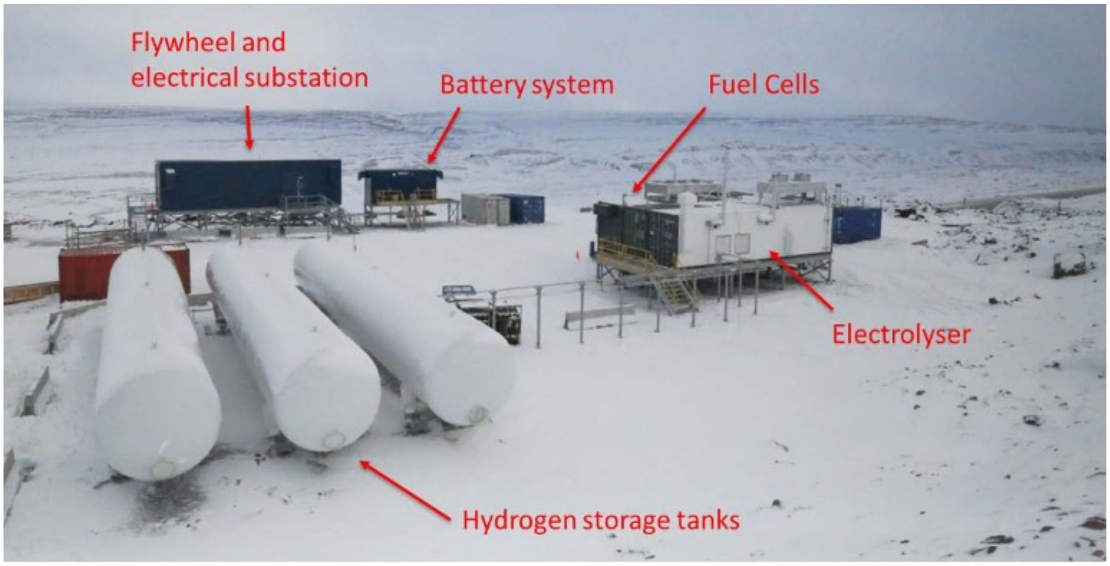
The project successfully deployed and operated a wind turbine, achieving 97.3% availability during the inaugural period and displacing 3.4 million litres of diesel and 9,110 tons of greenhouse gas (GHG) (equivalent to removing 2,400 cars from Canadian roads). Each storage technology has been commissioned and activated, with positive control from Hatch's HμGRID controller. Experimental optimization has been successful in achieving higher than 40% renewables penetration, contained to the subset island of Mine 2 and 3 within RAGLAN's broader micro-grid. This project costed approximately $20 million CAD with $7.8 million provided by the Canadian government and start-up in Dec 2015. [5]

Lessons learned from the Raglan Mine system are:

- Multi-tiered storage architecture, advanced controllers, and predictive generation models can enhance the operability of the system and smooth the perturbations associated with wind dip and wind drop, especially significant in one-turbine systems.
- Power storage systems and hydrogen fuel cells can facilitate variable loads from industrial processes.
- Levelized cost of power from renewable energy can be lower than diesel generated for systems in this size range (2-3 MW) and can stabilize cost vulnerability to fuel commodity costs. Note: the LCOE of the system was held in confidence by the facility owner.
- Replication of existing control systems can reduce the design and start-up costs.

5 https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662

Figure 6:
Layout of Renewable Energy Storage at RAGLAN Mine [6]



- Hybrid renewable storage systems are important for reliable operation of micro-grids with high renewable penetration. Hydrogen can make up a portion of a storage system but should be considered as part of a larger network of interconnected parts that include batteries and smart grids to automate and regulate the system.
- A big takeaway is that in remote applications with high fuel and transportation costs as well as high potential to generate renewables, in some cases it is currently economical to incorporate renewable storage in these systems and can provide considerable cost savings when implemented and funded properly.
- When projects are innovative and utilize data-driven problem solving for planning, there is greater potential for success both from a profitability and operational point of view.

1.6.2 Froan Island, Norway

The Froan Islands are located off the west coast of Norway. The islands are currently interconnected by a medium-scale electric grid with one connection to the mainland through a sea cable. Since the cable is outdated, there is urgency to replace it or consider alternatives. Because the cost of replacing the cable is very high, an effort is being made to find renewable alternatives, including the use of hydrogen as a storage medium.

The exploitation of local renewable energy sources, i.e., solar and wind, together with a H2-battery storage system has been chosen as a potential solution. Main drivers to consider this alternative were:

6 https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662

1) Avoiding the high-priced and invasive replacement of the sea cable,

2) Avoiding the use of diesel power generation because of security, cost, and emissions, and

3) Testing hydrogen-based system operation in Nordic climates and evaluating applicability for use in other remote areas. [7]

The objective of the project was to demonstrate the technical and economic feasibility of two fuel cells-based H2 energy storage solutions: one integrated P2P (power-to-power) system, and one non-integrated P2G+G2P (power-to-gas and gas-to-power) system based on renewably generated electricity.

The renewable energy sources were based on a hybrid system with solar (PV) and wind generators. On the island, there are residential loads and fish industry.

The system was supplied by:

- 225 kW wind turbine
- 85 kW PV power plant

The energy storage was provided by a non-integrated P2P solution by:

- 55 kW air-fed PEM electrolyzer
- 100 kW PEM fuel cell
- Hydrogen storage tank (~ 100 kg capacity)
- 5 racks of 110 kWh Li-ion batteries

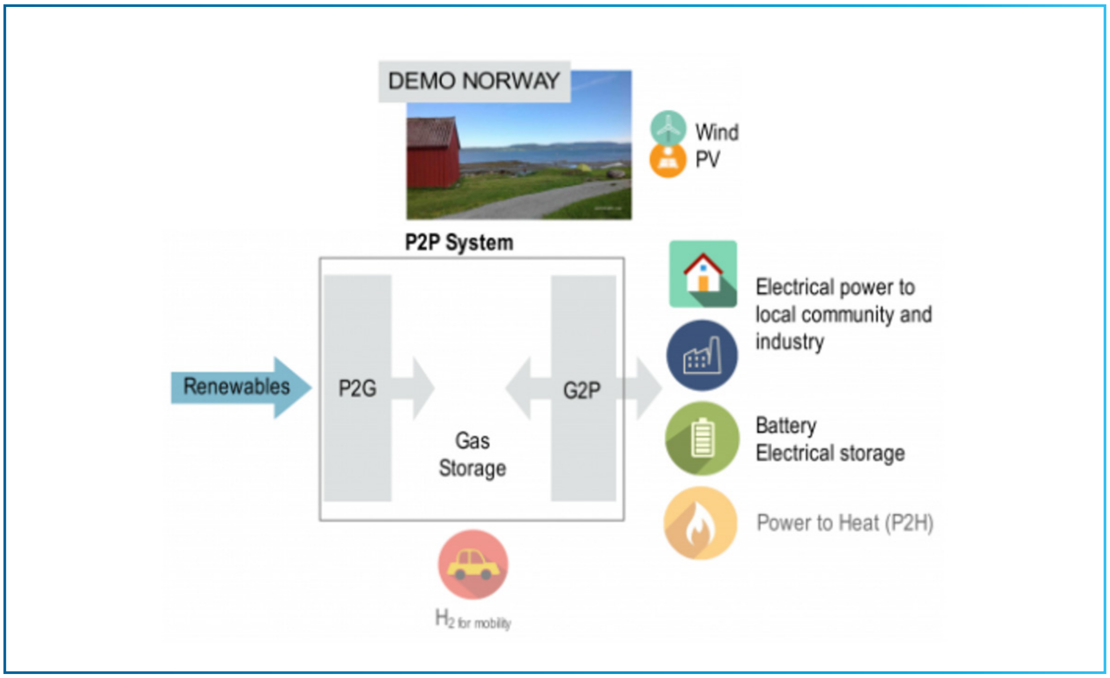
The project demonstrates that the use of a fuel cell-based H2 energy storage system could obviate the costs for a new sub-marine power line and provide almost complete substitution of fossil fuels with renewable energy penetration of 95%.

Lessons learned from the Demo 4 project are:

- Combined renewable generation and hydrogen storage is effective in replacing hydrocarbon generation in small grids when designed to balance renewable generating capacity and storage capacity.
- Flexibility of the renewable grid is enhanced by the use of multi-tiered energy storage systems to service demand response.
- Implementation of renewable energy storage systems can be cost effective compared to hydrocarbon generation and/or distribution connection either in near term or long term.

7 https://energyandmines.com/wp-content/uploads/2014/08/Raglan.pdf

Figure 7.
Layout of the DEMO Froan Island project in Norway [8]



- Having a project team consisting of experts from industry, academia, equipment manufacturers, government (Ministry of Energy), local utilities and finance that understand hydrogen systems, infrastructure and best practices is key for the development and execution of pilot projects as well as for conducting useful experimentation and analysis that can be used to develop best practice and identify important contextual nuances that matter for the Chilean context and within that the Chilean isolated grid community context.
- The integration of electrolyzer and fuel cells systems is a key element for increasing storage system efficiency and reducing costs.

1.6.3 BIG HIT Orkney Islands Project, Scotland

BIG HIT builds on foundations laid by the Orkney Surf 'n' Turf initiative, and will see production of hydrogen on the islands of Eday and Shapinsay using wind and tidal energy (Figure 8). Orkney is a community of about 300 people.

The project uses curtailed electricity from the Eday and Shapinsay wind turbines (900 kW each) owned by the local power cooperative for each community. Additionally, the tidal turbines being tested at the European Marine Energy Center at Eday generate electricity for the Eday electrolyzer.

Two proton exchange membrane (PEM) electrolyzers are used. The Shapinsay electrolyzer is 1 MW capacity and Eday electrolyzer is 0.5 MW capacity, both located close to their respective renewable generation assets. The hydrogen is stored as high-pressure gas in tube trailers, which can be transported to Kirkwall on mainland Orkney via ferries.

8 https://energyandmines.com/wp-content/uploads/2014/08/Raglan.pdf

In Kirkwall a 75 kW hydrogen fuel cell supplies heat and power for several harbor buildings, a marina and 3 ferries (when docked). Additionally, the hydrogen supplies a new hydrogen refuelling station in Kirkwall that serves the 5 Symbio hydrogen fuel cell road vehicles for Orkney Islands Council.

The two PEM electrolyzers produce about 50 tons of hydrogen each year from constrained renewables. And finally, the new hydrogen refuelling station in Kirkwall fuels the 5 Symbio hydrogen fuel cell road vehicles for Orkney Islands Council. [9]

The Project demonstrates the use of hydrogen as a flexible local energy store and vector. The hydrogen is used to demonstrate end-use applications for hydrogen including heat and auxiliary power for ferries in Kirkwall harbor, fuelling a fleet of hydrogen range-extended light vehicles, and heating for buildings in the Kirkwall area. [10]

Lessons learned from the BIG HIT project are:

- Storing curtailed energy from multiple sources in the form of hydrogen and gathering by small-scale shipment to power dedicated resources can be used to decarbonize focused assets or to incubate new fuel sources.
- Curtailed renewable energy can be used to manage intermittent or peak loads such as maritime or airport auxiliary power.

Figure 8
Layout of the Microgrid system at Orkney Island

9 Kalantari H, Ghoreishi-Madiseh SA, Sasmito AP. Hybrid Renewable Hydrogen Energy Solution for Application in Remote Mines. Energies. 2020; 13(23):6365. https://doi.org/10.3390/en13236365

10 https://tugliq.com/wp-content/uploads/2019/01/1901-project-sheet-raglan-i-eng-1.pdf

- This project is highly relevant to Isla de Pascua, and although this analysis was focused on wind and solar assets for renewable generation, it is recommended that a similar analysis be done to incorporate the findings of the tidal power study done for Isla de Pascua to understand feasibility and hydrogen export potential. Additionally, this project highlights the complexity associated with the construction of projects in remote island locations.
- Given that the system integrated maritime transportation, compression infrastructure may not be required unless space constraints exist for the grid storage project footprint. However, there are considerable costs associated with storing highly pressurized hydrogen, typically only feasible for long-distance transportation.
- This project involved many stakeholders and complex coordination without the development of a hydrogen market, which caused many unexpected delays and funding issues.

1.6.4 Bright Green Levenmouth, Scotland

In partnership with Bright Green Hydrogen, Toshiba, Fife Council and Hydrogenics, the facility at the Levenmouth Community Energy Project was constructed between 2011 and 2014 to demonstrate green hydrogen as a viable medium for energy storage, grid balancing, electricity generation and transport fuel (Figure 9).

The intent of the project was to provide power for the Methil Docks Business Park, comprising 8 buildings and a renewable power innovation center. Additionally, a market for hydrogen vehicles was established in and around the park. Bright Green Hydrogen has a fleet of 10 Renault HyKangoo vans for lease which are electric with hydrogen range extenders. Fife Council operates 5 Ford Transit vans which run on a diesel/hydrogen mix, and 2 refuse collection vehicles which also run on diesel/hydrogen. All vehicles can be refuelled at the demonstration site in the Methil Docks Business Park, with council vehicles able to refuel at the Bankhead Depot.

The facility produces compressed hydrogen through electrolysis from surplus electricity generated by a 750 kW wind turbine and 160 kW solar photovoltaics. A 270 kW PEM electrolyzer produces approximately 100 kg of hydrogen per day for the onsite energy storage requirements, which is then used in a 100 kW PEM fuel cell to generate electricity for the micro-grid at times when demand is higher than the renewable energy supply. Two further electrolyzers, a 60 kW PEM electrolyser and a 60 kW alkaline electrolyzer, each generate around 24 kg of hydrogen for the vehicle refuelling system. This hydrogen is stored at 450 bar and used to fuel the local fleet of hydrogen-powered vehicles. [11]

The system provides 100% renewable penetration for the Methil Docks Business Park.

The Toshiba hydrogen energy management system allows 8 buildings in the Methil Docks Business Park to be actively managed as part of a renewable energy micro-grid. The main office in the facility employs a 5 kW hydrogen-powered boiler to provide space heating in the innovation center. When the hydrogen storage is full, excess electricity is exported to the National Grid.

11 https://tugliq.com/wp-content/uploads/2019/01/1901-project-sheet-raglan-ii-eng-1.pdf

Lessons learned from the BIG HIT project are:

- Properly balanced systems can provide 100% renewable penetration and facilitate additional hydrogen related markets.
- Co-development of hydrogen markets enhances the commercial feasibility of small grids.
- Advanced controls are required to maximize the value of multi-modal renewable storage systems.

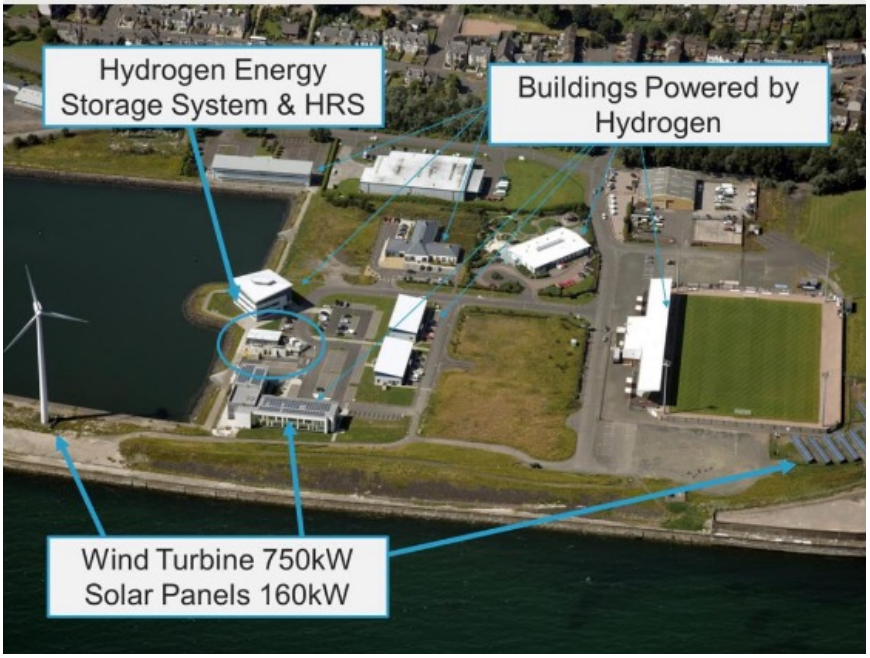


Figure 9.

Layout of the Microgrid system at Levenmouth [12]

Failed projects like the Bright Green Levenmouth project are extremely relevant to Chile. Critical lessons learned unique to this project are:

- Having flexible and adequate financial support and carefully selected stakeholders is key to project success. Even as mishaps and mistakes are discovered that have impacts of project profitability, the greatest value derived from pilot projects is through the opportunity to build hydrogen expertise in the Chilean workforce and determine contextual best practices in design, installation and operation.
- Modelling that accurately reflects the design and operation of green hydrogen storage systems is important for design and finance planning. This often requires more detailed analysis that considers unit operations, thermodynamic behavior and a different sequence of operation to determine indicative project costs.
- Timing and momentum are just as important as good design. This project took advantage of a political moment that was not sustained long enough for continued support of the project.

12 https://tugliq.com/wp-content/uploads/2019/09/2016-11-11-tugliq-raglan-public-report-en.pdf

1.7 Project Overview

This analysis includes testimony from project participants from BIG HIT and Bright Green Levenmouth. See appendices for a compilation of online resources and additional information on each project. The following is an overview of each project based on the following aspects:

- Lessons learned
- Best practices
- Public/private partnership
- Business model employed
- Funding scheme
- Technologies employed
- Challenges and barriers
- Costs
- Results

Table 5: Isolated Grid Analysis

Project	Raglan Mine Microgrid Project, Canada (Source 1-6)	Remote Demo Froan Island Project, Norway (Source 8-13)	Big HIT Orkney Island Project, Scotland (Source 7)	Bright Green Levenmouth Energy Project, Scotland (Source 7)
Lesson Learned	Use a scaled approach when transitioning to renewable energy and storage on grid systems, starting with a pilot plant demonstration for training of personnel and understanding project risks. Permitting is key for the project management timetable. Due to volatility of mining industry, soliciting investment is challenging due to higher costs. Procurement of government grants is key for reducing financial risks.	Innovative projects can be successfully delivered in remote locations and can successfully leverage collaboration between international and local support. The findings from pilot projects can be more valuable than the cost savings demonstrated by renewable energy and hydrogen storage system projects. Develop analysis for unlocking potential cost savings of hydrogen-battery storage systems by doing thorough analysis of all aspects of the energy system	Ensure the project has sufficient project management resource to support. Environmental conditions and locations must be considered in the project plan and program. Long timescales of two years or more are likely to be required to establish operational hydrogen projects.	Need to account for all system loads when conducting modelling to determine feasibility Ensure the project has sufficient project management resource to support Understand how local support might change when they realize that the project is public funded
Best Practices	The project demonstrated renewable penetration surpassing 40% is achievable at the largest micro-grid and largest emission source in the Arctic. Grid reliability is enhanced through utilization of hydrogen storage system. Understanding and planning for long lead times associated with all equipment in procurement process for timely project delivery.	The project demonstrated renewable penetration surpassing 95% is achievable for an island micro-grid application The stakeholders were able to adequately design a system and perform the analysis that proved cost savings of high renewable penetration and auxiliary storage systems compared to conventional and well understood methods.	BIG HIT demonstrated the Orkney Islands of Scotland as a replicable Hydrogen Territory, using curtailed renewable energy generated locally to produce hydrogen which can then be used as a clean energy vector to store and use valuable energy for local applications. Hydrogen storage systems should be developed alongside hydrogen markets to maximize the value of curtailed power. Tube trailers are an effective distribution method for small scale storage and distribution operations in local proximity.	Maintaining a strong team throughout the process - Levenmouth was made to publicly procure things, which annoyed several of the early stage partners. Utilize an alkaline system if reliability is key, utilize a PEM system is fluctuating input is key. Having refueling close to production results in a much lower hydrogen price than if the hydrogen needs transported.

Public / Private Participation	Glencore's RAGLAN Mine Other strategic partners: Hatch Ltd., BBA Inc., Enercon G.m.b.H., Hydrogenics Corp., KTSI Kinetics Traction Systems Inc., Groupe Ohmega Inc., Gas Metro Renewable Energies, Morneau Construction Inc., NEAS Shipping Co., Katinniq Transport Ltd., and a range of other suppliers and partners involved TUGLIQ Energie Co. conducted technoeconomic modeling, engineering design services and construction and monitoring services	Key project partners were the EU, Trønder Energi, Engine, Grupo Capisa, ITC Canarias (The Canary Island Institute of Technology), Inycom, Ballard Power Systems Europe, Hydrogenics, PowiDian, Politecnico di Torino, The Italian Department of Energy, STEPS – Synergies of Thermo-chemical and Electro-chemical Power Systems (research group)	BIG HIT consortium includes a planning authority: OIC (Orkney Islands Council), the research community: DTU and FHA (Technical University of Denmark; The Foundation for the Development of New Hydrogen Technologies,), local charities and SMEs (Small and Medium Enterprises) from the UK: SDT, SHFCA, CES, ITM, and EMEC (Shapinsay Development Trust, Scottish Hydrogen and Fuel Cell Association, Community Energy Scotland, ITM power, and European Marine Energy centre), and industrial companies and SMEs from other EU countries.	Key project partners were Toshiba and Fife Council (public). Other partners included Scottish Hydrogen and Fuel Cell Association, Fife College, Leven Valley Development Trust, Community Energy Scotland and Green Business Fife. The system was designed and installed by Logan Energy and utilized Hydrogenics electrolyzers.
Business model Employed	Wind energy is the lowest source of energy available to the site locally, increased penetration through the grid operation and storage system reduced operating costs of isolated grid and thus mining operation significantly.	Cost savings were observed through on site, island production of hydrogen compared to an underwater power line and decreased reliance on fossil fuels	The company, Orkney Hydrogen Trading (OHT) was formed in relation to the BIG HIT project. The responsibility of OHT is to make sure that the project would be generating, compressing, and transporting hydrogen by some partners, while other partners are responsible for the offtake hydrogen to replace fossil fuel. This organization allows anyone interested in implementing hydrogen applications to acquire hydrogen. Without high capital investment or production cost risk. This encourages the rollout of hydrogen technologies on the islands.	Business model was that the extra revenue from microgrid electricity sales would subsidize the sale of hydrogen to the vehicles. Ultimately, the project failed to break-even due to issues surrounding the OPEX of the electrolyzers.
Market Participation	TUGLIQ Energy is the owner and operator of the asset and has signed a 20-year Power Purchase agreement with Glencore RAGLAN Mine.	Electricity to Trønder Energi, the utility provider for the island.	The project provides hydrogen to the local economy via offtake agreements. The project does not participate in the electric energy marketplace beyond receiving curtailed power from the existing wind turbines.	Electricity sales to microgrid Electricity sale to grid Hydrogen sales to Fife Council Hydrogen sales via onsite refueller
Funding Scheme	The FEED study was funded $7.8M CAD from the Canadian government's innovation fund within the clean energy sector. Project was financed by TD Bank in partnership with TUGLIQ. Minimized economic impact of Cap and Trade and Carbon pricing mandated by Canadian government.	Part of EU REMOTE program looking at integration of hydrogen systems in micro-grid applications in the EU with the aim at developing best practices and conducting studies through public/ private/academic partnership	The project is funded by European Commission's Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) under the EU Horizon 2020 program. The total funding is around £10.9 million.	£4.7M from Scottish Government through the Local Energy Challenge fund administered by Local Energy Scotland ~ £1.9M from private sources including project partners
Technologies Employed	2x 3MW Wind turbines (1 per Phase) 200KW/250KWh Li-ion battery (Phase I) 3MW/1MWh Li-ion battery (Phase II) 200kW Flywheel (Phase I) 315kW Electrolyzer (Phase I) 198kW PEM fuel cell (Phase I) Hatch Microgrid Controller (HμGrid) (Phase I)	55kW PEM electrolyzer 85kW solar PV 225kW wind turbine 100kW PEM fuel cell 5x 110 kWh Li-ion battery racks Master Controller technology from Powidian Electrolyzer and fuel cell system are integrated into a single system called Smart Autonomous Green Energy Station (SAGES)	Wind turbine (900kW) Tidal turbines A 500kW electrolyzer and a 1MW electrolyzer High pressure gas stored in 5 tube trailers 75kW hydrogen fuel cell supplying heat and power to several harbor buildings, a marina and 3 ferries Hydrogen refueling station 5 Symbio hydrogen fuel cell road vehicles	750kW wind turbine 160kW solar PV 8 building microgrid with seamless switching H2EMS Smart Grid management system including both generation and demand forecasting 250kW PEM electrolyzer 100kW PEM fuel cell 5kW hydrogen boiler 60kW PEM electrolyzer integrated with a 350bar refueller 60kW Alkaline electrolyzer integrated with a 350bar refueller 17 vehicle hydrogen fleet - 10 fuel cell range extended Renault Kangoo vans, 5 H2ICED Ford Transits, 2 H2ICED Refuse Collection Vehicles

Challenges and Barriers	Difficulty operating/installing rotating machines in northern climate. Grid reliability difficult to maintain with high variable renewable penetration, which is crucial in industrial/mining operations to maintain worker safety. Historically, similar projects have been abandoned due to high O&M and installation costs.	First of kind project Power management is challenging, bespoke algorithms were developed to adequately manage system	Lack of planning for environmental conditions and issues associated with remote location of site. Delays in project program. Insufficient project resource.	Significant delays to equipment delivery resulted in 18 month delay to system completion TRL of 60kW PEM system supplied by Hydrogenics was lower than we were led to believe and was ultimately a test unit in a demonstration project Local support evaporated when the public funding was announced as they all wanted a piece of that money without realizing that it was already allocated.
Costs	Total estimated costs of $20M CAD. $41M CAD projected in fuel and O&M cost savings are projected over the 20 year lifespan of the turbine.	50M NOK allocated for three projects	Total estimated costs of €10.9 million. €5 million of this was received as funding from FCH 2 JU.	~ £6.6M total project cost ~£1.2M for Energy Storage system (250kW electrolyzer + 100kW fuel cell) ~ £1.1M for two refuellers
Results	Project demonstrated successful incorporation of hydrogen storage systems for mining/industrial, off-grid operation and operation in extremely low temperatures. Offset of 4.4 million liters of diesel fuel and 12,000 tons of CO2 emissions. The renewable energy production and storage system set contribute to 10% of the mine's total energy. Phase I of the project was so successful that an expansion of the renewable generation and storage system was repeated in a continuation project (Phase II)	Demonstrating grid storage projects in remote, micro-grid locations where fossil fuel costs are already very high is the first step in integrating energy storage and renewables in larger scale systems. The success of the project resulted in avoiding the installation of an underwater power transmission line. Several important studies have been published on the project, which demonstrate how Renewable-based solutions are cheaper than current diesel based systems.	This project demonstrated a fully integrated model of hydrogen production, storage, transportation and utilization for low carbon heat, power, and transport. The projects address several operational and development challenges including the logistical and regulatory aspects for transport of hydrogen fuel between islands, and the orientation and familiarization with new hydrogen building and transport technologies.	Project was a technical success with approximately 1 month of system running. Unfortunately, the system running costs were around £50k a year more than had been budgeted (~ £125k total). This was not sustainable for the very small not-for-profit who were leading the scheme. This lead the site to be mothballed.

1 https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662
2 https://energyandmines.com/wp-content/uploads/2014/08/Raglan.pdf
3 Kalantari H, Ghoreishi-Madiseh SA, Sasmito AP. Hybrid Renewable Hydrogen Energy Solution for Application in Remote Mines. Energies. 2020; 13(23):6365. https://doi.org/10.3390/en13236365
4 https://tugliq.com/wp-content/uploads/2019/01/1901-project-sheet-raglan-i-eng-1.pdf
5 https://tugliq.com/wp-content/uploads/2019/01/1901-project-sheet-raglan-ii-eng-1.pdf
6 https://tugliq.com/wp-content/uploads/2019/09/2016-11-11-tugliq-raglan-public-report-en.pdf
7 Arup source, past project participant
8 https://www.sciencedirect.com/science/article/pii/S019689042100323X?via%3Dihub
9 https://www.remote-euproject.eu/partners/
10 https://www.remote-euproject.eu/remote18/rem18-cont/uploads/2019/03/REMOTE-D2.1.pdf
11 https://www.remote-euproject.eu/remote18/rem18-cont/uploads/2019/03/REMOTE-D2.2.pdf
12 https://www.remote-euproject.eu/remote18/rem18-cont/uploads/2019/03/REMOTE-D2.5.pdf
13 https://www.remote-euproject.eu/remote18/rem18-cont/uploads/2019/03/REMOTE-D2.5.pdf

2 Analysis and Recommendations for the Potential Incorporation of Hydrogen Storage Systems in Isolated Grids in Chile

This analysis was performed to understand the opportunities and barriers associated with the incorporation of green hydrogen and other storage technologies in five isolated grids in Chile including those serving:

- Punta Arenas
- Puerto Natales
- San Pedro de Atacama
- Aysen
- Isla de Pascua

In general, the scenarios and analysis are based on price, performance and demand projections that are in line with current available literature. The results of this analysis are to be considered indicative and variations in modeling assumptions are impacted by dynamics that cannot be adequately modeled. Therefore, this study is meant to be qualitative and identify opportunities and barriers for each of the five grids analyzed at a high level. See the Appendix for detailed modeling assumptions.

In the cases of isolated grids in Chile, where renewable energy generation potential was high, fossil fuel import costs were high and energy security related to fossil fuel availability was an issue. The increased incorporation and utilization of renewables for electricity generation and storage presented many advantages in terms of costs, increased energy independence, reduced GHG emissions and increased reliability when compared with current demand and infrastructure capacity projections.

2.1 Discussion of the Analysis and Results

This section begins with a discussion of overall structure, themes, and findings of the analysis in the following areas:

- Methodology
- Scenarios
- Primary Findings

This is then followed by a characterization of each grid, the nuances of the analysis, and the pertaining results, which are broken down into the following categories for each grid:

- Description
- System Capacity
- Power Generation
- Emissions Reduction
- Jobs Creation Potential
- Levelized Cost of Energy
- Other Project Scope

In addition to the above mentioned for each grid, commentary and analysis is provided on the benefits of hydrogen storage systems in isolated grids through the lens of Isla de Pascua and San Pedro de Atacama.

2.1.1 Approach

Technoeconomic models were created for each grid to estimate the opportunities for incorporation of green hydrogen. In this section, the aspects of the analysis that were consistent across each grid are discussed.

Methodology

Arup used Calliope, a Python-based linear optimization tool to optimally size electrical generation technology for cost minimization in the year 2030. The tool modeled multiple energy streams (hydrogen, electricity, solar energy, hydro-electric and wind energy) at an 8760 hour/year resolution on the grid level to find optimal outcomes based on localized metrics. This provides advantages in the modelling of future national scale grids, such as that of Switzerland, the UK and Europe, where it has been used to provide detailed insights into lowest cost combinations of zero carbon technologies, including batteries, solar, wind, nuclear and hydro power alongside all conventional fossil fuel plants. Arup is experienced with this approach, having applied it effectively for multiple projects around the world.

The Calliope software, while used by Arup, was developed by others. See the following link for more details – www.callio.pe

The information that was used to characterize and constrain each model is represented in Figure 10. The infrastructure currently installed at each site was investigated to determine the possible technology pathways for 2030. If evidence of the current deployment of a hydrocarbon-based generating technology on a specific grid was not found, it was not included as a possible technology pathway for future generation. This was done to prevent the models from proposing unfeasible solutions.

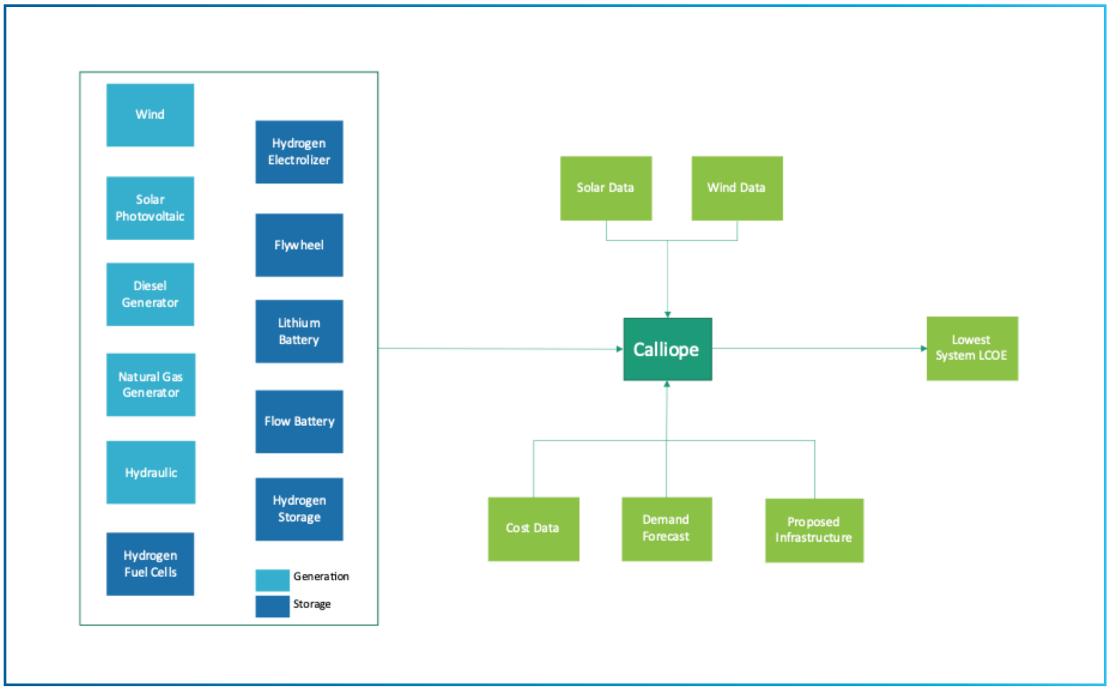


Figure 10.
Visual Representation of the Cost Optimization Model Developed for this Study

Certain characteristics of each technology were not modeled in order to maintain consistency when weighing technology options against each other. This included parasitic and minimum operating thresholds, performance derates over time, installation timelines including project planning and phasing, embodied emissions and indirect land use changes. A breakdown of assumptions for each technology can be found in the Appendix. These factors should be included in future detailed grid implementation planning.

Detailed renewable site assessment was not included as a part of this scope. A formal site assessment for wind and solar projects should be performed as a part of any detailed grid implementation planning to understand the land requirements associated with the renewable energy generation. Sites that were selected were not necessarily feasible for project implementation and were included only to be indicative of the conditions that have historically been seen at a single point.

Storage was incorporated into the grid when cost effective according to the grid specifics, including renewable generation potential, non-fuel variable costs, demand profile, and installed infrastructure capacity and type. To understand how variable renewable generation assets could be incorporated cost-effectively, storage solutions were included as an option in each grid in every scenario. Storage infrastructure solutions assessed for in this study were:

- Hydrogen storage systems found suitable for grid application based on the international grid review (PEM electrolyzer system, PEM fuel cell system and aboveground storage at 20 bar. The fuel cell system and the electrolyzer system were assumed to be consolidated to remove unnecessary redundancy in equipment and costs.)

- Lithium-ion batteries

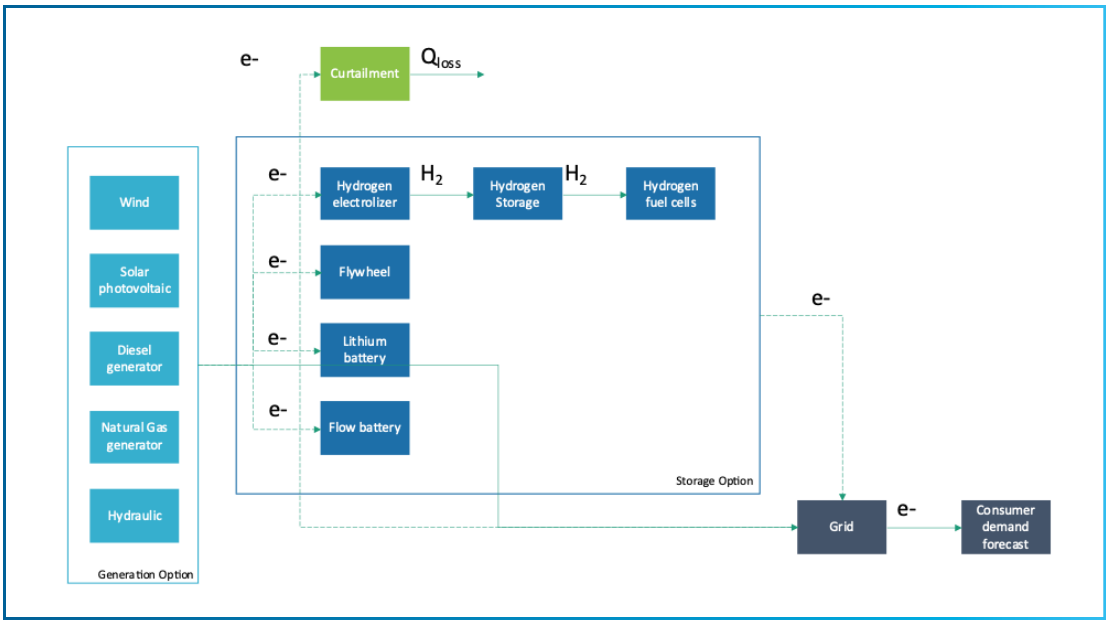
- Flywheels (note that, because of the time resolution of the simulations, flywheel deployment was never selected. However, this technology should be considered in more detailed future analysis to provide grid stability when switching between generation and storage modes.)

- Vanadium flow batteries

A detailed comparison of the storage technologies evaluated for this study is included in the Appendix.

The models determined the cost optimal systems and generating profiles to meet the demands of the grids. See Figure 11 depicting possible supply and demand pathways that were used for modeling.

Figure 11.
Supply and demand system pathways



As discussed in the international isolated grid review, control system upgrades and additional infrastructure to complement hydrogen storage systems is recommended and generally good practice for all modern grid systems utilizing naturally variable generation infrastructure. Auxiliary system costs and infrastructure associated with grid operations was not modeled.

Transmission & distribution upgrades necessary for the grid system were not included in the analysis and were assumed to be at parity between scenarios. Storage infrastructure was assumed to be at the site of renewable electricity generation, thus reducing reliance on the existing transmission system. Reported levelized costs were limited to electricity production and storage only. The modeled system capacities and utilization of each technology were representative of the technology mix that was conducive for lowest cost of electricity for each scenario.

Scenarios

To understand the technology makeup of cost-optimized Chilean isolated grid operation under different circumstances, a model was developed to estimate emission and cost reductions that are achieved by deploying renewables and storage solutions based on certain assumptions.

The model was run under four scenarios to provide an understanding of sensitivities that affect the results. Each scenario builds off a set of assumptions that are used to draw a comparison from a baseline model.

In each scenario, the base price of fossil fuels in 2030 was derived from the current price of fuel in each grid location, as supplied by the Ministry of Energy. Fuel prices were then subjected to a growth rate that is consistent with the reference case growth trajectory employed by the Ministry of Energy in its long-term energy planning process before applying a carbon tax. Detailed calculations and assumptions for fuel and technology prices for each grid can be found in the Appendix.

The scenarios are as follows:

- Baseline Scenario 1 was employed to establish a baseline for the analysis and understand the sensitivity of a low carbon price of USD $35 / ton CO2 based on the Chilean Updated National Energy Policy[13] and IRENA projected conservative 2030 renewable technology costs on the technology mix and grid composition that provides the lowest cost of electricity. This scenario demonstrates how a low carbon price can remove economic barriers related to the deployment of renewables and green hydrogen for each grid.

- Scenario 2 was employed to understand the sensitivity of a high carbon price of USD $80 / ton CO2 on the cost-optimal technology mix and grid composition. This scenario demonstrates how a high carbon price can remove economic barriers related to the deployment of renewables and green hydrogen for each grid.

- Scenario 3 was employed to understand the effect of optimistic capital costs for wind and solar technology (based on the IRENA "2030-low" forecast), in addition to the assumptions in Scenario 2, on the cost-optimal technology mix and grid composition. This scenario demonstrates how reduced generating technology costs can remove economic barriers related to the deployment of renewables and green hydrogen for each grid compared to a carbon pricing alone.

- Scenario 4 was employed to understand the sensitivity that optimistic costs for electrolyzer and fuel cell technologies (based on the IRENA "2030-low" forecast), in addition to the assumptions for Scenario 3, had on the cost-optimal technology mix and grid. This scenario demonstrates how reduced hydrogen technology costs can remove economic barriers related to the deployment of renewables and green hydrogen for each grid compared to a high carbon price and low renewable generation costs alone.

13 Gobierno de Chile, Ministerio de Energía, 2022: « https://energia.gob.cl/sites/default/files/documentos/actualizacion_politica_energetica_nacional.pdf »

Primary Findings

This section discusses common findings that are true for all grids studied in this analysis. The information in this section is general in nature and covers high level relationships observed through the lens of isolated grids in Chile as well as more broadly across all contexts.

The most basic takeaway from this analysis is that the supply and demand dynamics of each grid drove vastly different solutions for the technology mix and deployment for the lowest cost of electricity. In all scenarios analyzed, renewable infrastructure was added to achieve the cost-optimized solution. Additionally, renewables with a total installed capacity higher than the peak demand complemented with storage was observed. This is due to the naturally variable generation profile of renewables and cost and performance limitations of storage technology.

This is consistent with a broader observation of the utilization of renewable energy: meeting demand with renewable energy requires installation of excess capacity that is greater than what is conventionally provided for infrastructure that uses fossil fuels for power generation. To achieve higher renewable penetration on grids, planning around capacity factor, storage and total system capacity must differ from the methods used to plan grids that are comprised of non-renewable generation technologies.

Storage was an aspect of all cost optimal systems. However, only two types of storage were observed in the scenarios for each grid: lithium-ion batteries and hydrogen storage systems. Generally, batteries were utilized for short term, lower capacity storage and hydrogen storage was utilized for longer term and larger capacity storage.

Carbon taxes alone in Scenarios 1 and 2 drove renewable generation and storage and lowered emissions but did not necessarily drive the lowest cost of energy to the consumer. This was particularly true of grids operating with gas turbine generation that was cost competitive with hydrogen storage even after the application of the carbon tax.

An optimistic forecast for cost associated with renewable generation increased the deployment of renewable assets and associated storage and lowered the LCOE and emissions for all grids.

An optimistic forecast for the capital cost of hydrogen storage systems increased renewable generation asset deployment and maximized the use of hydrogen, thereby minimizing the LCOE and emissions in grids with highly variable renewable generation. Hydrogen deployment in grids with low-variability renewable generation was not significantly affected by low cost hydrogen storage.

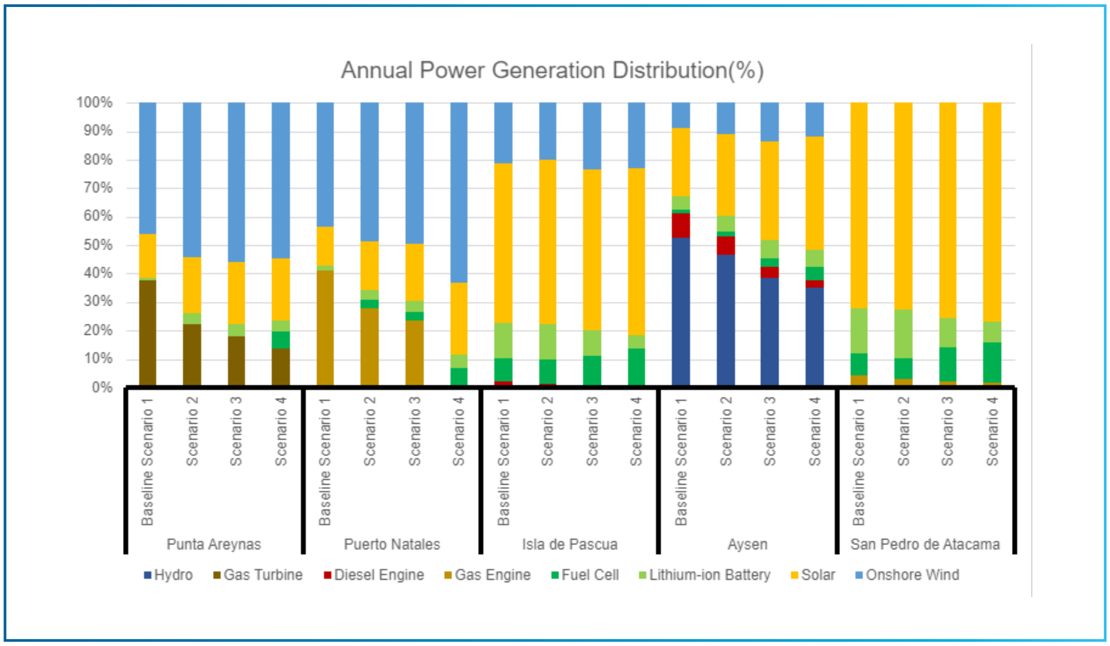


Figure 12:
2030 Punta Arenas, Puerto Natales, Isla de Pascua, Aysen and San Pedro de Atacama cost optimized technology contribution per scenario

As depicted in Figure 12, the deployment of renewables and storage on each grid varies given the contextual nuances of each grid, including:

- Renewable generation potential (including wind, solar and hydroelectric power)
- Demand profile
- Cost of diesel and gas fuels

Because the cost of solar is lower than that of wind, the deployment of solar was observed at a high rate even in places where the solar potential is not optimal. Because the cost of fossil fuels on the isolated grids is high, it was observed that renewable electricity was more cost effective than the utilization of fossil fuel-derived electricity, even when the total installed capacity of renewable generation infrastructure was in excess of the total peak demand. This was facilitated by utilization of storage to reduce curtailment.

In the case of Punta Arenas, fuel cell generation was only included in the most optimistic scenario. This was due to the balance of wind and solar generation coupled with low-cost gas turbine generation. The combination of low-variability and low-cost generation allowed lithium-ion batteries to maximize the penetration of renewable energy. Hydrogen became cost effective under the most optimistic cost assumptions in Scenario 4 and facilitated the greatest reduction in hydrocarbon generation and, therefore, the highest emissions reduction.

Puerto Natales, similarly to Punta Arenas, has well balanced renewable resources combined with natural gas generation. Therefore, there was little need for hydrogen fuel cell generation in the cost-optimized system. However, because of the lower efficiency of gas engines compared to gas turbines, combined lithium-ion battery and hydrogen storage could be used to efficiently displace hydrocarbon generation in Scenarios 2, 3, and 4 with an almost complete elimination of hydrocarbons in Scenario 4.

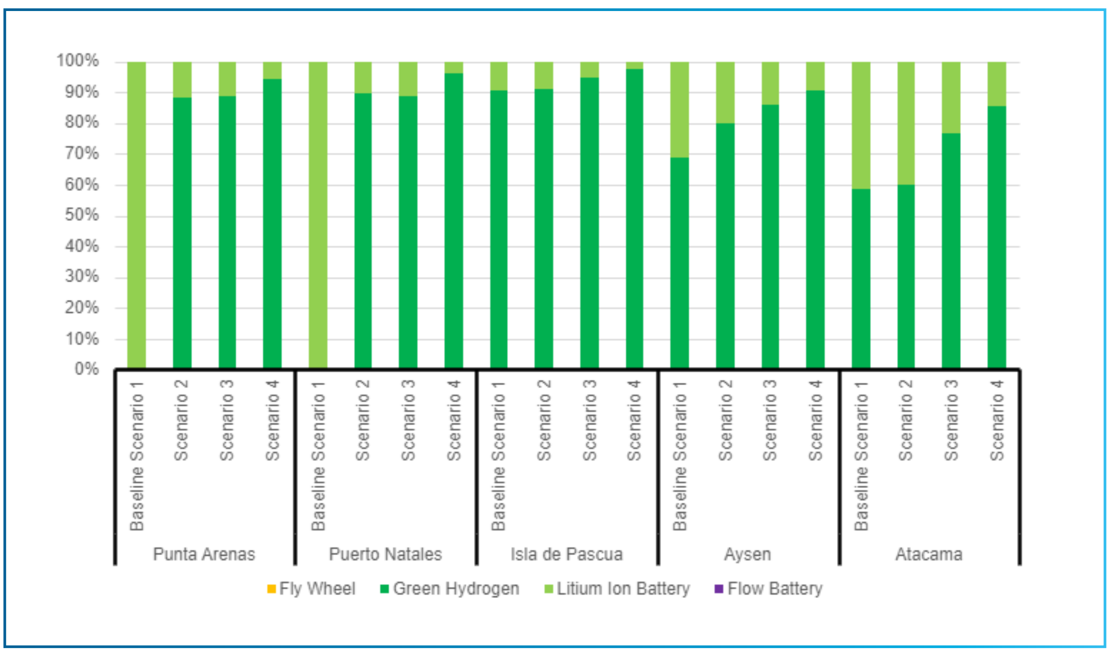
Isla de Pascua is an example of a grid that heavily favors the use of hydrogen for energy storage due to the reliance on solar and the high cost of imported diesel fuel. In all scenarios the reliance of diesel generation could be substantially eliminated by renewable generation and storage.

Aysen illustrates the potential for renewables and storage to complement hydropower in the cost-optimized grid. Combined battery and hydrogen storage can allow renewables to compete with hydropower while also lowering the need for diesel back-up generation.

Finally, the Atacama grid, which has extremely high solar resources, could employ those resources combined with battery and hydrogen storage to virtually eliminate the need for hydrocarbon generation in all scenarios. While solar provided direct supply of the grid needs during the day, battery and fuel cell generation met the lower demand levels at night. Gas engine generation provided peaking generation only when demand exceeded the capacity of the storage system. Due to the strong solar resources, solar and storage was more cost effective than hydrocarbon generation in all scenarios. The increase in hydrogen storage compared to battery storage in Scenarios 2-4 was due to the optimistic cost reduction of hydrogen systems assumed in those scenarios.

Lithium batteries have a valuable short-duration storage role to play in optimizing grid operation. It was found that deployment of batteries was cost effective in every grid and scenario to complement cost-effective renewable generation, as seen in Figure 13:

Figure 13:
2030 Punta Arenas, Puerto Natales, Isla de Pascua, Aysen and San Pedro de Atacama Proportion of Cost Optimized Storage Technology per scenario



Green Hydrogen Generation as % of total Power Supply				
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Punta Arenas	0%	0%	0%	6%
Puerto Natales	0%	3%	3%	7%
Isla de Pascua	8%	9%	10%	13%
Aysen	1%	2%	3%	5%
San Pedro de Atacama	8%	8%	12%	14%

Table 6:
Green Hydrogen Generation as a % of Total Power Supply

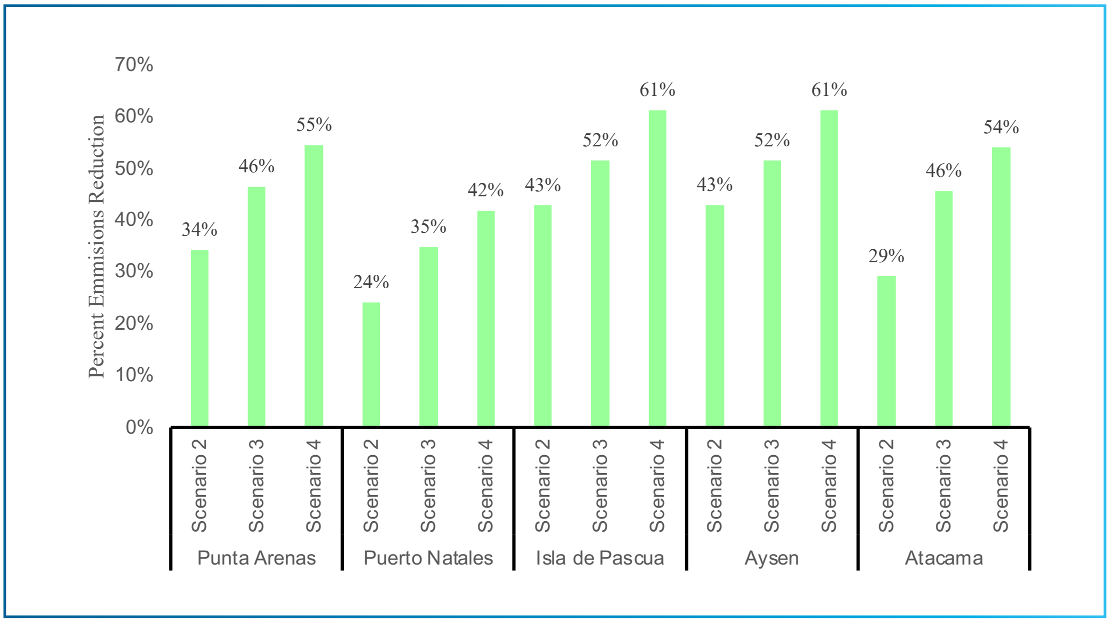
The utilization of hydrogen as a percentage of the total grid generation is included in Table 6. Generally, hydrogen storage was observed as more cost effective for a greater portion of stored energy than batteries, with the exception of the Baseline Scenarios of both Punta Arenas and Puerto Natales. This aligns well with expectations given that batteries are ideal for relatively lower-capacity, shorter-duration storage, whereas hydrogen is suited to longer durations. This is compounded by the following:

- Wind and solar generation are highly variable hourly and seasonally yet generally more cost effective than fossil fuel-derived dispatchable power in this context.
- Independent shifts in energy demand are observed on a daily and seasonal basis where applicable.

This is because despite the higher CAPEX per kW and lower single-pass round-trip efficiencies, it provides a lower cost for energy storage at scale for prolonged periods. research currently being performed to increase the efficiency of electrolyzer and fuel cell systems and associated cost reductions was modeled in Scenario 4.

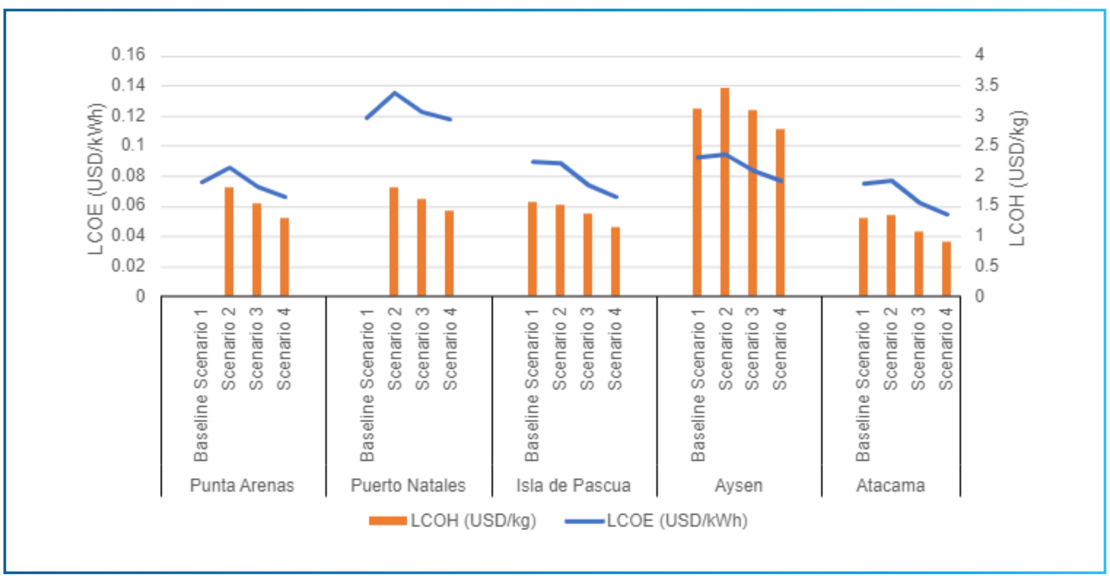
Each scenario observed significant carbon savings, as shown in Figure 14. This represents a step change in the carbon intensity of the Chile electricity market and if implemented would assist Chile in becoming a world leader in grid decarbonization.

Figure 14:
Estimated 2030 Carbon Emissions Reduction compared to the Baseline Scenario



Based on the modelling done for this study, reduced costs of renewable infrastructure and increased costs of fossil fuels resulted in increased renewables, increased storage capacity and reduced carbon emissions associated with the lowest cost grid operation, as shown in Figure 15.

Figure 15:
Levelized Cost of Hydrogen (orange bars & right axis) & Levelized Cost of Electricity (blue lines and left axis) for each Grid and Scenario



The levelized cost of energy rose, as expected, in Scenario 1 where the carbon tax alone was employed. The exception was Isla de Pascua, which did not observe significant change in levelized cost of electricity. In the case of Isla de Pascua, the high cost of diesel fuel facilitated the competitive replacement of hydrocarbon generation with renewable energy, thereby offsetting the higher carbon tax. This was also seen to a lesser degree in Aysen. However, the lower cost of renewables and hydrogen storage was required to provide an overall lower cost of electricity in the other grids for both Scenario 3 and Scenario 4. This demonstrates the sensitivity of all the grids to the cost of renewable generation and hydrogen storage facilities. Note that the cost discrepancies between grids were caused by different grid sizes and fuel costs.

Additional options for dispatching stored power in hydrogen are possible by utilizing different methods for storing and generating electricity using hydrogen. Different hydrogen storage systems may be more ideal than the one modeled in this study depending on context found to be not within the scope of this investigation.

While these models are computationally sophisticated, they are only an abstraction of each grid system, and their results are limited in terms of representation of the system. The results are useful for identifying creative arrangements that might not have been possible without the models. The analysis and results are qualitative even though quantitative and discrete outputs are presented. While the results can be compared to current tariffication rates to understand how they might be modified, additional, more in-depth methods for quantifying exact configurations is required.

This study was limited to focusing on the cost optimization of each grid for one year (2030). System sizing and technology utilization was modeled in such a way that all storage capacity is utilized within the defined timeframe without consideration for multi-year variability and resiliency. A study to understand resiliency requirements for the grid should be performed in conjunction with any project planning activities. Future projection and planning studies could be performed in conjunction with an additional iteration of this study to portray a cost optimal system that span a greater timescale and is inclusive of certain constraints not in the scope of this assessment.

All values in this report show significant figures needed to illustrate the relationship between the different scenarios and are not meant to convey the certainty or accuracy of the results.

2.1.2 Punta Arenas

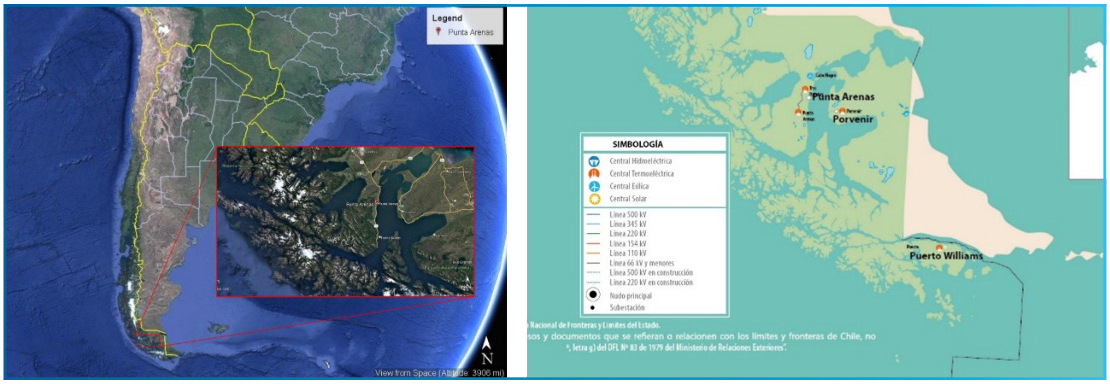


Figure 16.
Geographical location of the grid of Punta Arenas.

The following section documents information and results that are specific to the grid serving the area Punta Arenas.

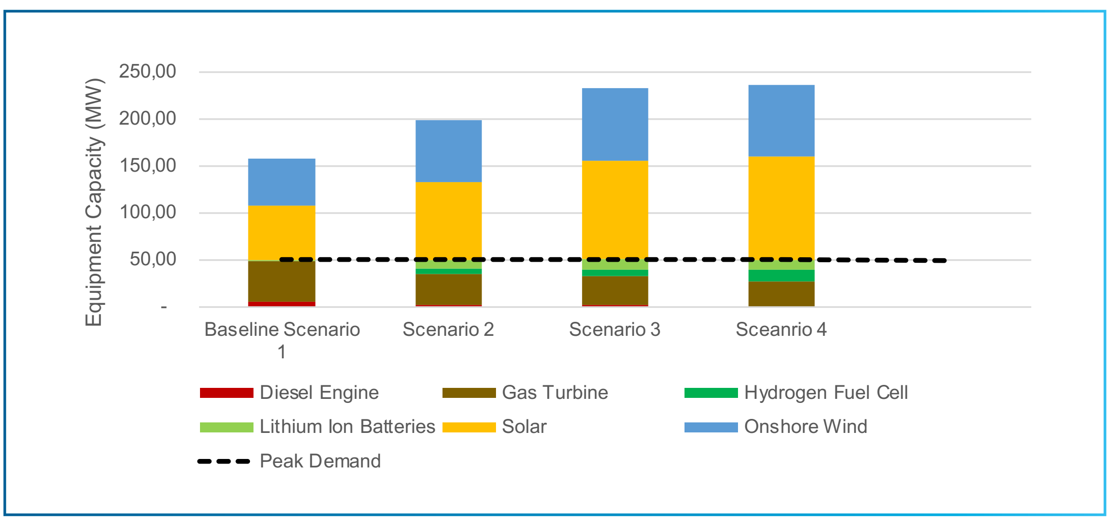
Description

Punta Arenas is the capital of the southern region of Chile called Magallanes. It has a median temperature of 6,3°C but in summer it can experience temperatures up to 25°C. or even 30°C. The local economy is mixed but the principal activities according to the GDP are manufacturing, mining and tourism . Oil reserves and refining infrastructure are located in the area, and fossil fuel prices in Punta Arenas are of the lowest of the isolated grids that were the focus of this study. Because midstream oil and gas infrastructure are present in the region at a once-major port, Punta Arenas can support the utilization of gas fuel, which is comparatively cheaper than diesel fuel. The area has significant wind energy generation potential and limited solar energy generation potential; overall, Punta Arenas is wind-dominant. Currently, the Punta Arenas grid is supported primarily by gas turbines with diesel engines used for peaking and spare generation capacity. The grid itself is medium-sized. Peak demand is projected to be just under 51 MW in 2030.

Cost-optimal technology mix for 2030

Figure 17 and Table 7 detail the final technology mix identified to provide the lowest cost of electricity production, meeting demand growth for each scenario. The results are direct outputs of the cost optimization model. Note that the capacity shown in Figure 17 illustrates the equipment capacity related to the supply of electricity. Table 7 shows such equipment capacity and Table 8 shows storage capacity.

Figure 17:
System capacities of each technology per scenario for Punta Arenas (2030)



Peak Capacities (MW)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Peak Demand	50.93	50.93	50.93	50.93
Diesel Engine	6	3	3	0
Gas Turbine	43	32	30	27
Hydrogen Electrolyzer	0	8	9	17
Hydrogen Fuel Cell	0	5	7	12
Lithium-Ion Batteries	1	9	11	10
Solar	58	82	104	109
Onshore Wind	50	66	78	76

Table 7:
Peak Equipment Capacities (MW) of each technology per scenario for Punta Arenas (2030)

Hydrogen was not found to be cost effective for the Baseline Scenario. In each scenario where hydrogen was found to be cost effective, the storage system was limited by the size of the hydrogen fuel cell because the peak deployment of power to the grid using the fuel cell exceeds the curtailed power. The storage system is demand-driven rather than supply-driven.

Storage Capacities (MWh)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Hydrogen Storage	0	300	354	674
Lithium-ion Battery	5	39	45	42

Table 8:
Capacities of each storage technology per scenario

As seen in Figure 22, when hydrogen becomes cost effective for storage, the effect on decarbonization is quite significant. The need for long-term and large-capacity storage to support renewable penetration is apparent when comparing the scenarios. Because Punta Arenas is wind-dominant, the cost of building excess capacity for production of hydrogen is higher than on the other grids where the hydrogen storage systems are limited by the electrolyzer.

It should also be noted that there is a decrease in lithium-ion battery storage capacity and onshore wind capacity when comparing Scenario 3 and Scenario 4. Additionally, the storage capacity of the hydrogen system increases. Given that the cost of solar PV infrastructure is lower than that of wind and the minimum time required to store solar energy is longer, it is more effective to store solar energy with hydrogen. Therefore, when the electrolyzer system cost is reduced, greater deployment of solar is enabled. Most importantly, the utilization of hydrogen allows for increased utilization of wind assets. See the following section for discussion around increased technology utilization associated with the deployment of hydrogen systems.

Figure 18:
2030 Punta Arenas Scenario 2
system storage profile

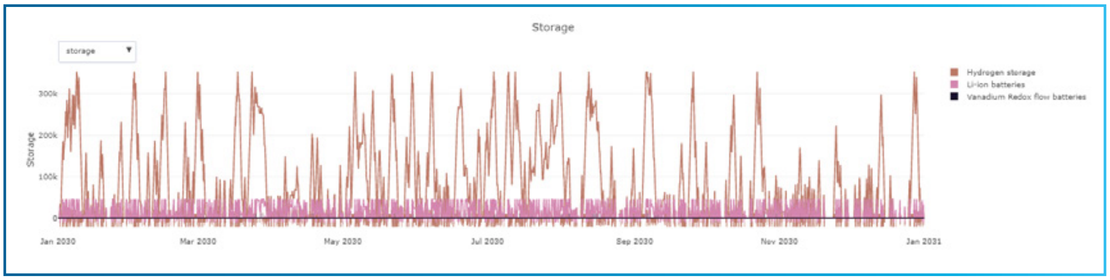
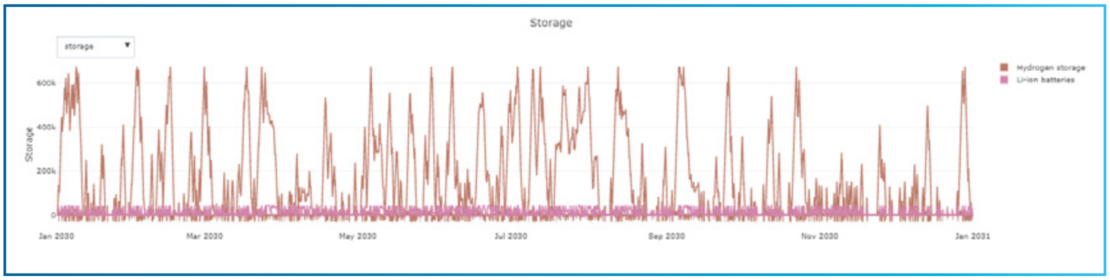


Figure 19:
2030 Punta Arenas Scenario 4
system storage profile

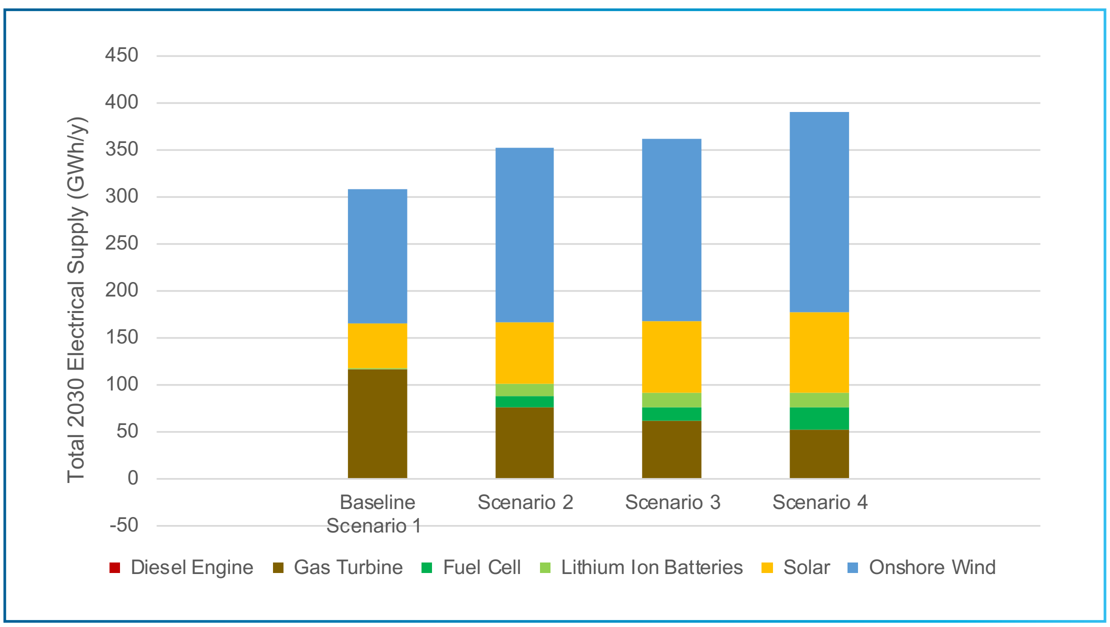


Notice that the storage profile between Scenario 3 and Scenario 4 in Figure 18 and Figure 19 does not change significantly; however, the quantity of hydrogen storage increases. This also aligns with an increased reliance on solar energy.

Power Generation

Yearly power supply from each technology for Punta Arenas per scenario can be found below in Figure 20, which includes both stored and dispatched power.

Figure 20:
Electrical Supply (GWh/year) per
technology in 2030



Even though Punta Arenas does not have significant solar generation potential relative to other locations, solar was deployed in lieu of wind, storage, or fossil fuel infrastructure. The lower capacity factor did not disincentivize utilization of solar based on the cost optimization. Solar energy projects are viable to support the Punta Arenas grid and contribute to low cost of electricity despite the great wind energy potential in the region.

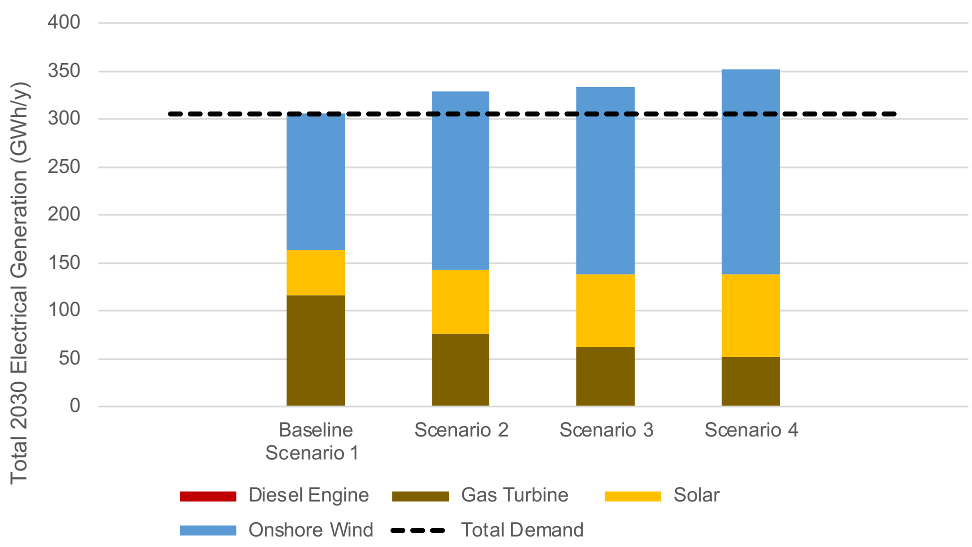


Figure 21:
Punta Arenas grid system electrical generation technology utilization per scenario

The required generation by the technologies employed for generation excluding power supplied from storage is depicted in Figure 21 to show the relative losses due to storage efficiency. The increased utilization of hydrogen storage resulted in increased losses due to roundtrip efficiencies. Even though additional increased capacity for renewables was required (see Table 7), the cost of energy was lowered under the conditions of Scenario 3 and 4 (see Table 11).

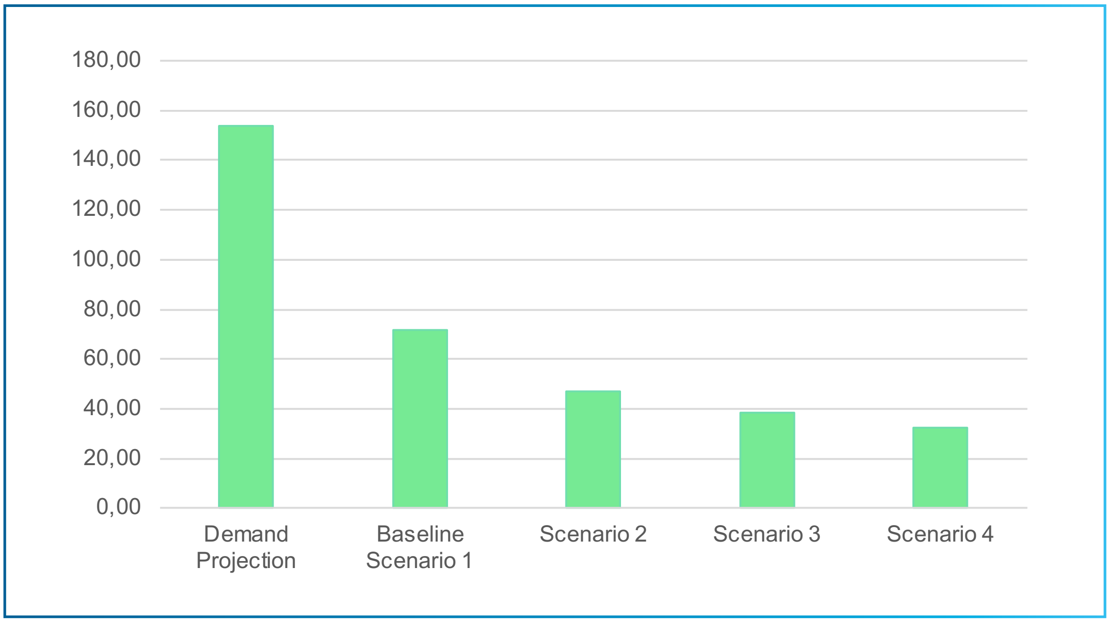
Table 9:
Punta Arenas grid system 2030 power supply (GWh/year) per scenario

Annual Power Supply in 2030 (GWh/year)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	0.237	0.085	0.076	0
Gas Turbine	116	76	62	52
Hydrogen Fuel Cell	0	11	13	23
Lithium-Ion Batteries	2	13	16	15
Solar	47	66	76	86
Onshore Wind	142	185	195	213

Emission reductions

As shown in Figure 22, there is significant potential for decarbonization against the current projected infrastructure planned for Punta Arenas. Increased emissions savings related to an increased carbon tax can be witnessed for Punta Arenas by comparing Scenarios 1 and 2. Although all of the scenarios provided reductions, the greatest amount of emission reduction was associated with Scenario 1. It can also be stated that increasing utilization of hydrogen storage across scenarios was related to a decrease in emissions.

Figure 22:
2030 Punta Arenas 2030 carbon emissions (kt CO2/year) per scenario



Job creation potential

Job creation potential for each scenario for Punta Arenas is shown below.

Table 10:
Estimated green job creation per scenario

Scenario	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
	MCI	O&M	MCI	O&M
Baseline Scenario 1	0	0	1465.3	27.4
Scenario 2	50	5.75	2057.1	44.6
Scenario 3	50	5.75	2606.3	53.8
Scenario 4	50	5.75	2667.7	49.2

Levelized costs of electricity production

The levelized cost of electricity and hydrogen production based on each scenario are shown in Table 11 below, followed by a qualitative discussion of the results and trends that were observed.

Table 11:
Punta Arenas estimated levelized cost for 2030

Levelized Cost (Production)	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Electricity (USD/kWh)	0.076	0.086	0.073	0.066
Hydrogen (USD/kg)	N/A	1.80	1.54	1.29

As expected, an increase in the cost of electricity was observed when comparing Scenarios 1 and 2. There was a roughly 12% increase in electricity costs upon the implementation of a high carbon tax. If adequate revenue recycle is not implemented, it could be cost-prohibitive for low-income consumers in cost of living; however, when a higher carbon tax is complemented with the optimistic cost of renewable energy, as seen in the Scenario 3, electricity costs fall lower than the baseline. CAPEX reduction of both renewable generation and hydrogen storage systems can lead to a LCOE reduction of 13%.

Other Project Scope

The following table provides estimates of the total capital costs of renewable infrastructure, the yearly O&M costs, and the market size of hydrogen associated with each scenario. These figures do not account for the capital costs of wind and solar infrastructure already installed or under construction. The hydrogen storage market size is defined as the simulated quantity of hydrogen produced by the electrolyzer system.

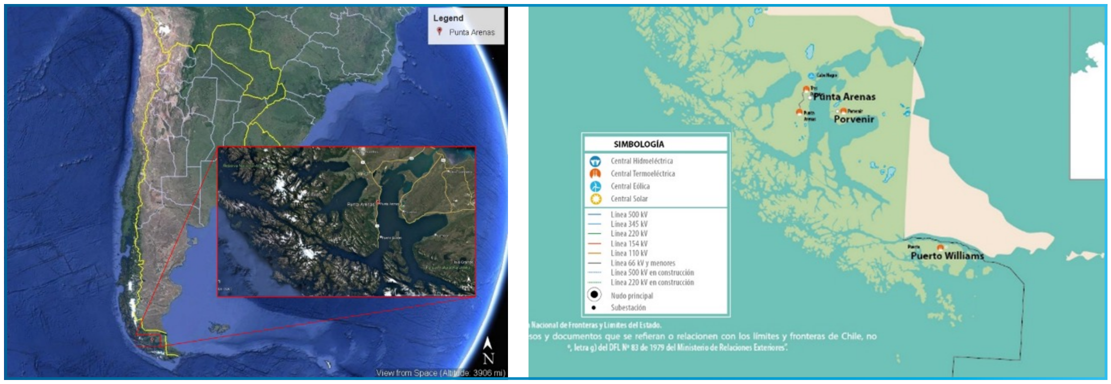
Table 12:
Estimates of other project attributes

Variable	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX total (MMUSD)	90	150	135	145
O&M (MMUSD/year)	1.3	1.9	1.8	1.6
Storage Market Size (tons H2/yr)	-	620	750	1,300

The estimated infrastructure and O&M costs account for the wind, solar, hydrogen electrolyzer system, hydrogen storage, fuel cell system and lithium-ion battery system. O&M costs include both fixed and variable costs. Detailed cost assumptions can be found in the Appendix.

2.1.3 Puerto Natales

Figure 23.
Geographical location of the grid of Puerto Natales.



The following section documents information and results specific to the grid serving the area Puerto Natales.[14]

Description

Puerto Natales is located in the southern region of Chile called Magallanes. It is roughly 150 miles northwest of Punta Arenas and is similar climactically. Rainfall throughout the year is common making its solar energy potential reduced. The region also experiences extreme shifts in daylight throughout the year. There is significant potential in Puerto Natales for generation of wind energy. The local economy has recently grown in tourism and has other principal activities like agriculture and stockbreeding.[15] Currently, the Punta Arenas grid is supported by gas engines with diesel engines for peaking and spare generation capacity. The grid is medium-sized with peak demand at around 23 MW.

Cost-optimal technology mix for 2030

Figure 24 and Table 13 detail the installed equipment required for the lowest cost of electricity production to meet demand for each scenario.

14 Coordinador Eléctrico Nacional de Chile. (n.d.). Sistemas eléctricos de Chile 2017 [Map]. Https://Www.Coordinador.Cl/#. https://sic.coordinador.cl/wp-content/uploads/2013/06/Mapa-Coordinador-Electrico-01.jpg

15 Ilustre Municipalidad de Natales. (2020). Plan regulador comuna de Natales. Informe de revisión ambiental complementario. Municipalidad de Natales.

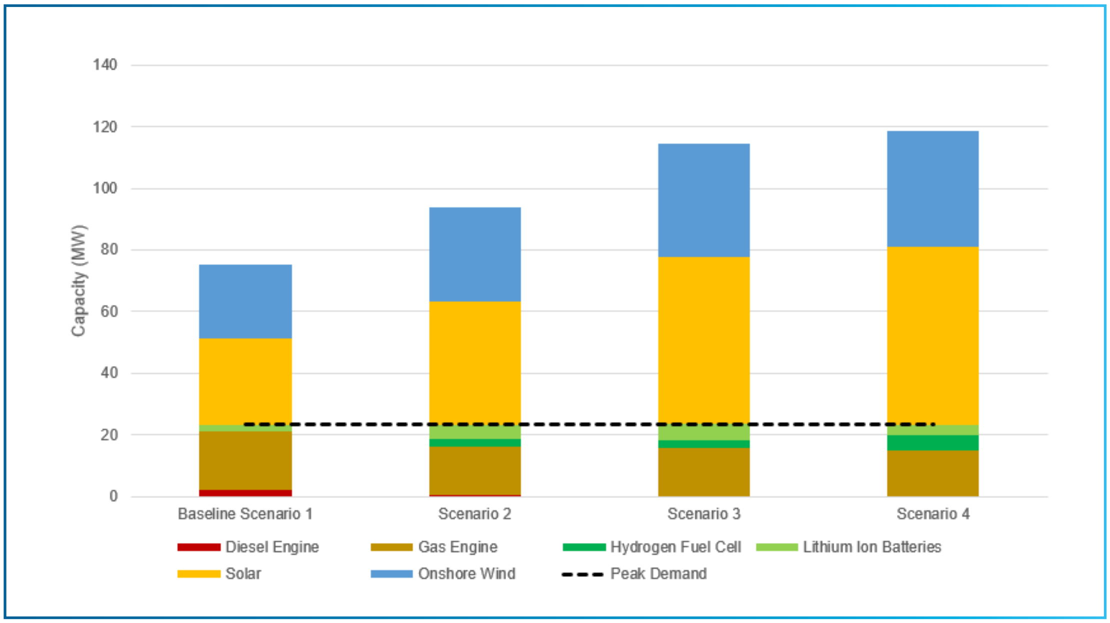


Figure 24:
System capacities of each technology per scenario for Puerto Natales (2030)

Given the dynamics of the cost optimization, hydrogen was not found to be cost effective for the baseline scenario. Because Puerto Natales is wind-dominant, the cost of building excess renewable generating capacity for production of hydrogen was higher than in the other grids where low-cost solar electricity was more readily available.

Table 13:
Peak Capacities (MW) of each technology per scenario for Puerto Natales (2030)

Peak Capacities (MW)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	2.04	0.38	0.19	0.25
Flywheel	-	-	-	-
Gas Engine	18.91	16.00	15.54	14.54
Hydrogen Electrolyzer	-	3.37	3.87	9.24
Hydrogen Fuel Cell	-	2.43	2.66	5.00
Hydrogen Storage	-	4.04	4.43	9.24
Lithium-Ion Batteries	2.28	4.44	5.06	3.45
Solar	28.14	40.10	54.45	57.80
Onshore Wind	24.03	30.49	36.74	37.70

Table 14:
Calculated peak storage capacities per scenario

Storage Capacities (MWh)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Hydrogen Storage	0	155	160	342
Lithium-ion Battery	9	18	20	14

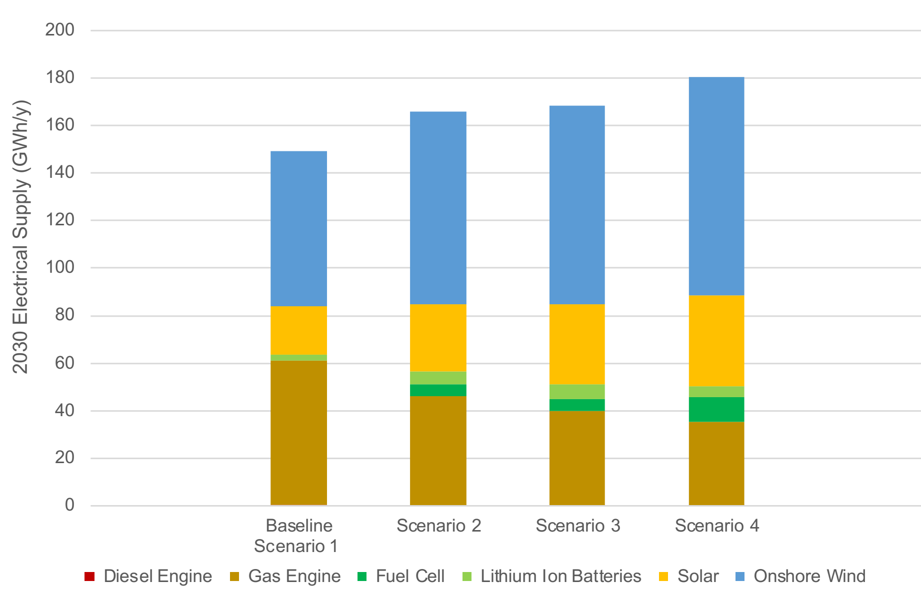
As shown in Table 14, potential hydrogen storage is considerable in Scenarios 2 through 4. When costs of hydrogen infrastructure fall to become more competitive with batteries, a greater proportion of stored electricity can be cost-effectively stored as hydrogen, as indicated in the difference between Scenarios 3 and 4.

Power Generation

As is true with Punta Arenas, even though Puerto Natales does not have significant solar generation potential relative to other locations, solar was deployed in lieu of wind or fossil fuel infrastructure. The relatively low capacity factor did not disincentivize utilization of solar. It should be noted that solar energy projects are viable to support the Puerto Natales grid and contribute to low cost of electricity despite the relatively higher wind energy potential in the region.

Yearly power supply to the grid from each technology for Puerto Natales can be found below in Figure 25, which includes both stored and dispatched power sources:

Figure 25:
Puerto Natales Grid System Annual Power Supply (GWh/year) Technology Utilization per scenario



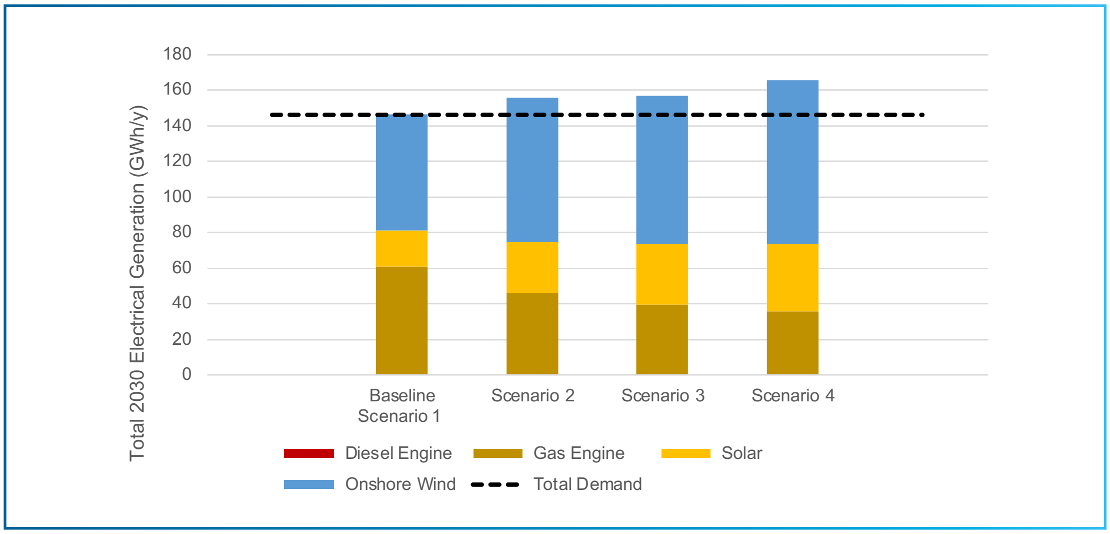


Figure 26:
Puerto Natales Grid System Annual Power Generation (GWh/year) Technology Utilization per scenario

The total demand is depicted against technologies employed for generation (excluding power returned from storage) in Figure 26 and Table 15 to show the relative loss in efficiency that is observed across each scenario. Given that the baseline scenario did not employ hydrogen, the storage efficiency losses were virtually eliminated. The increased utilization of hydrogen storage resulted in increased losses due to roundtrip efficiencies. In this instance, generation overcapacity is needed for systems functioning with higher renewable penetration as discussed in the previous section of this report.

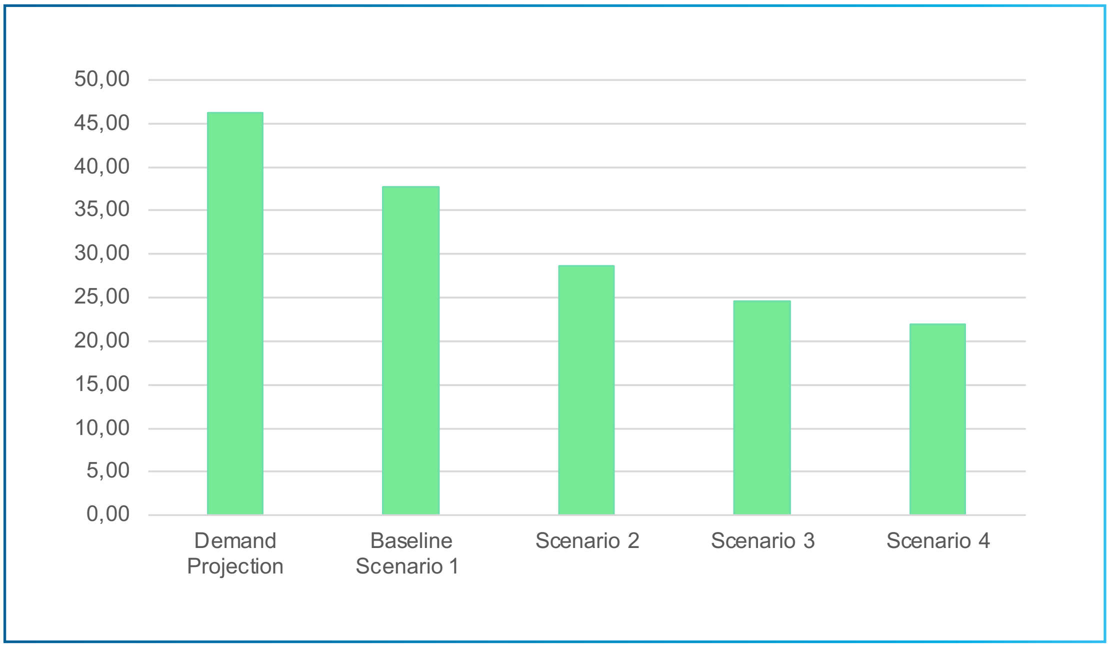
Table 15:
Punta Natales Grid System Electrical Generation in 2030 per scenario

Electricity Generation in 2030 (GWh/year)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	0.13	0.05	0.03	0.04
Gas Engine	60.88	46.21	39.65	35.39
Fuel Cell	-	4.72	5.21	10.31
Lithium-Ion Batteries	2.68	5.59	6.30	4.55
Solar	20.29	28.27	33.64	38.10
Onshore Wind	65.28	81.21	83.46	92.32

Emission reductions

As observed in Figure 27, there is significant potential for decarbonization against the current projected infrastructure planned for Puerto Natales. Increased emissions savings related to an increased carbon tax can be witnessed for Puerto Natales by comparing Scenarios 1 and 2. The proportional reduction in emissions for Puerto Natales was lower than other grids because of the relative cost-competitiveness of gas turbine generation, which was not displaced significantly by renewables in the cost optimization; however, a 50% reduction could be realized.

Figure 27:
2030 Puerto Natales Carbon Emissions (ktCO2/year) per scenario



Job creation potential

Job creation potential for each scenario for Puerto Natales is shown below in Table 16. A significant increase in permanent green job creation is observed upon the implementation of a high carbon tax by comparing Scenarios 1 and 2.

Table 16:
Green Job Creation per scenario

Scenario	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
	MCI	O&M	MCI	O&M
Baseline Scenario 1	0	0	710.4	13.2
Scenario 2	50	5.75	1030.0	23.9
Scenario 3	50	5.75	1340.6	29.4
Scenario 4	50	5.75	1408.8	30.6

Levelized costs of electricity production

The levelized cost of electricity and hydrogen production based on each scenario are shown in Table 17 below followed by a qualitative discussion of the results and trends that were observed.

Table 17:
Puerto Natales Estimated Levelized Cost of Electricity And Hydrogen in 2030

Levelized Cost (Production)	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Electricity (USD/kWh)	0.119	0.136	0.123	0.118
Hydrogen (USD/kg)	N/A	1.80	1.61	1.42

As expected, an increase in the cost of electricity was observed when comparing Scenarios 1 and 2. There was an approximately 13% increase in estimated electricity costs upon the implementation of a high carbon tax. If adequate revenue recycle is not implemented, it might be cost-prohibitive for low-income consumers in cost of living; however, when a higher carbon tax is associated with optimistic cost reduction of renewable energy, as seen in Scenario 2, electricity costs fall lower than the baseline. Lower costs of both renewable generation and hydrogen storage systems leads to an estimated savings of roughly 1% when comparing Scenarios 1 and 4.

Low-cost hydrogen production infrastructure (or other energy storage technology) is key for enabling low electricity costs in Puerto Natales.

Other Project Scope

The following table discloses estimates of the total capital costs of renewable infrastructure, the yearly O&M costs and the market size of hydrogen storage associated with each scenario. These figures do not account for the capital costs of wind and solar infrastructure already installed or under construction. The market size is defined as the amount of hydrogen produced by the electrolyzer system as nominally defined in the year 2030.

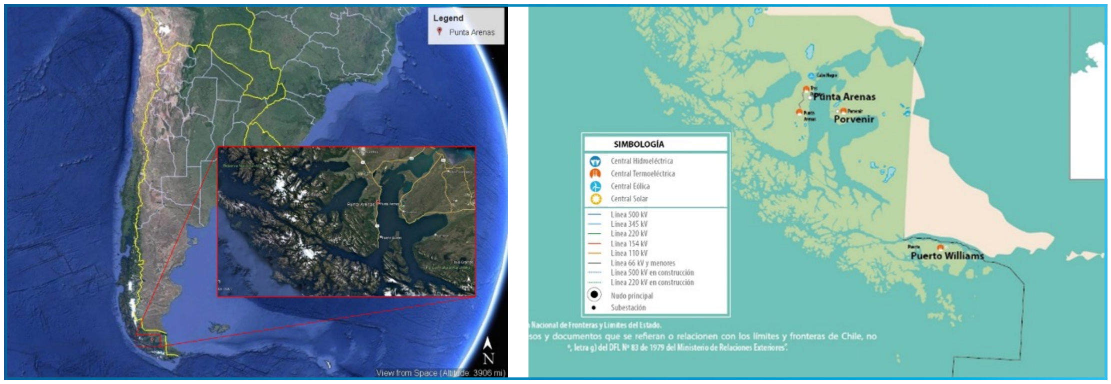
Table 18:
Estimates of Other Project Attributes

Project Variable	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX total (MMUSD)	50	70	65	70
O&M (MMUSD/year)	0.6	1.4	1.3	1.8
Storage Market Size (tons H2/yr)	0	260	270	570

The estimated infrastructure and O&M costs account for the wind, solar, hydrogen electrolyzer system, hydrogen storage, fuel cell system and lithium-ion battery system. O&M costs include both fixed and variable costs. Detailed cost assumptions can be found in the Appendix.

2.1.4 Isla de Pascua

Figure 28.
Geographical Location of the Grid of Isla de Pascua.[16]



The following section documents information and results that are specific to the grid serving the area Isla de Pascua.

A "No H2" scenario was added to demonstrate the differential value of a hydrogen storage system for Isla de Pascua's grid system.

Note that construction costs for infrastructure are not specific to Isla de Pascua and do not reflect increased costs that could be associated with the remote nature of the island.

Capital cost is applied consistently across all grids to maintain a direct comparison. Therefore, further analysis is needed to understand the implications for Isla de Pascua.

Description

Isla de Pascua is a volcanic island that is 2300 miles off the coast of mainland Chile. The island does not experience significant seasonal shifts and has reduced daily temperature shifts. The island does not experience extreme temperatures. There are significant shifts in the amount of daylight that is experienced in a day: half of the year has especially low solar energy potential. Given its geographical location, Isla de Pascua does have high wind and tidal energy potential. The local economy is primarily based on tourism. Imported goods are expensive and the island has experienced significant deforestation.[17] Currently, diesel generators are used almost exclusively for power generation. The grid itself is small. Peak demand was estimated to be just under 3.8 MW.

Cost Optimal Technology Mix for 2030

Figure 29 and Table 19 detail the installed equipment required for the lowest cost of electricity production to meet demand for each scenario. Note that the capacity shown in Figure 29 is meant to portray the equipment capacity that is utilized in the production of electricity. Table 19 shows the equipment capacity of all equipment. Table 20 shows storage capacity.

16 Coordinador Eléctrico Nacional de Chile. (n.d.). Sistemas eléctricos de Chile 2017 [Map]. Https://Www.Coordinador.Cl/#. https://sic.coordinador.cl/wp-content/uploads/2013/06/Mapa-Coordinador-Electrico-01.jpg

17 Gobierno regional de Valparaíso. (2016). PLAN REGIONAL DE ORDENAMIENTO TERRITORIAL INSULAR ISLA DE PASCUA. Isla de Pascua.

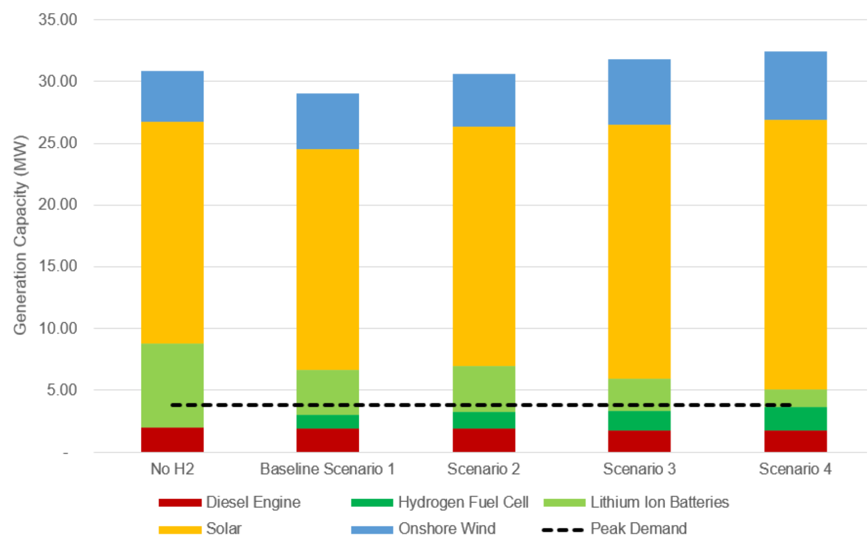


Figure 29:
System Capacities of Each Technology per Scenario for Isla de Pascua (2030)

Increased utilization of hydrogen is associated with a higher total system capacity with respect to the baseline scenarios due to efficiency losses associated with the storage and utilization of hydrogen. However, as seen in the No H2 scenario, utilizing batteries for high capacity and long-term storage does result in reduced storage efficiency. The No H2 scenario resulted in capacities that are more in line with the high-fossil fuel price scenarios. The implications of this in terms of cost, equipment utilization and carbon emissions are discussed in the following sections.

Note that no constraints were placed on the relative size of generation capacity other than with respect to lowest cost. The analysis did not consider land area and environmental sensitivity when sizing renewable resources.

Peak Capacities (MW)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Peak Demand	3.80	3.80	3.80	3.80	3.80
Diesel Engine	1.96	1.90	1.94	1.77	1.73
Hydrogen Electrolyzer	-	3.25	3.60	3.83	5.54
Hydrogen Fuel Cell	-	1.09	1.27	1.53	1.94
Lithium-Ion Batteries	6.80	3.63	3.78	2.65	1.40
Solar	18.0	17.9	19.3	20.5	21.8
Onshore Wind	4.11	4.52	4.26	5.29	5.54

Table 19:
Peak Capacities (MW) of each technology per scenario for Isla de Pascua (2030)

The peak storage capacities are reported below in Table 20:

Table 20:
Capacities of each storage technology per scenario

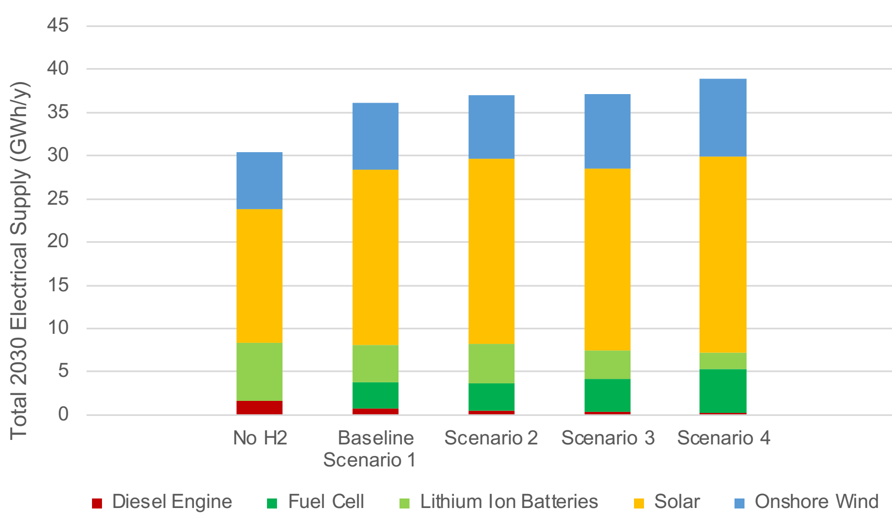
Storage Capacities (MWh)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Hydrogen Storage	0	142	151	191	214
Lithium-ion Battery	27	14	15	11	6

As shown in Table 20, hydrogen was found to be cost effective under the baseline scenario conditions. Hydrogen storage significantly increased the grid's resiliency in the case of Isla de Pascua. When factoring in efficiencies of end use, the No H2 scenario had the capacity to store only 25% of the electricity of the Baseline Scenario. In the Baseline Scenario, the peak storage capacity could support the grid operating at 50% of the peak load for over 50 hours. Under the same conditions, the peak storage capacity of the No H2 scenario would support the grid for less than 14 hours (excluding self-discharge).

Power Generation

A very small proportion of electricity generation is derived from consumption of fossil fuels in the cost-optimal system through utilization of hydrogen storage, as seen in Figure 30.

Figure 30:
Isla de Pascua Grid System Electrical Supply (GWh/year) per scenario



The total demand was utilized to show the relative loss in efficiency that was observed across each scenario in Figure 31. The increased utilization of hydrogen storage resulted in increased losses due to roundtrip efficiencies. Additional over-capacity was needed for systems functioning with higher renewable penetration as discussed in the previous section of this report. Additional generation was needed when hydrogen was utilized for cost-optimal storage due to the energy efficiency of the storage system.

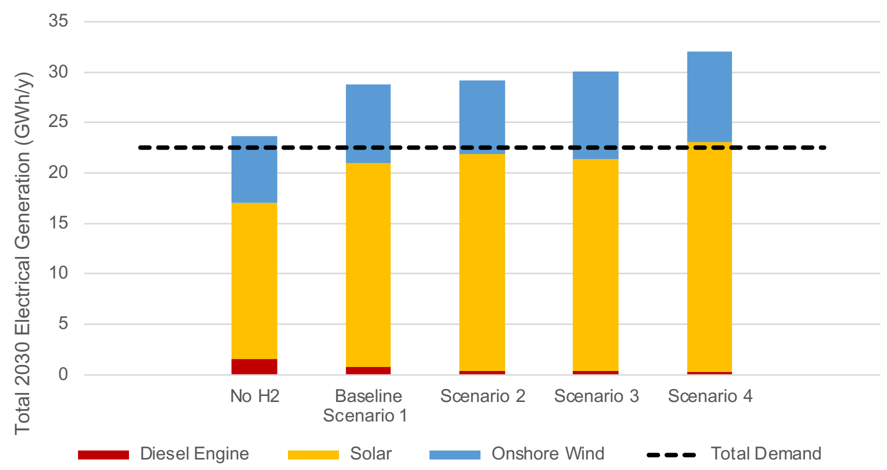


Figure 31:
Isla de Pascua Grid System Electrical Generation Assets (GWh/year) vs the total demand

Table 21:
Isla de Pascua grid system 2030 power generation (GWh/year) per scenario

Annual Generation 2030 (GWh/year)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	1.59	0.75	0.43	0.36	0.29
Hydrogen Fuel Cell	0	3.0	3.2	3.8	5.0
Lithium-Ion Battery	6.7	4.4	4.6	3.3	1.9
Solar	15.5	20.2	21.4	21.0	22.7
Onshore Wind	6.5	7.8	7.3	8.7	9.0

Emission reductions

The introduction of renewable generation with or without storage has the potential to virtually eliminate emissions from the Isla de Pascua grid. The use of hydrogen storage can reduce the emissions an additional 50% as shown in Figure 32 and Figure 33 below.

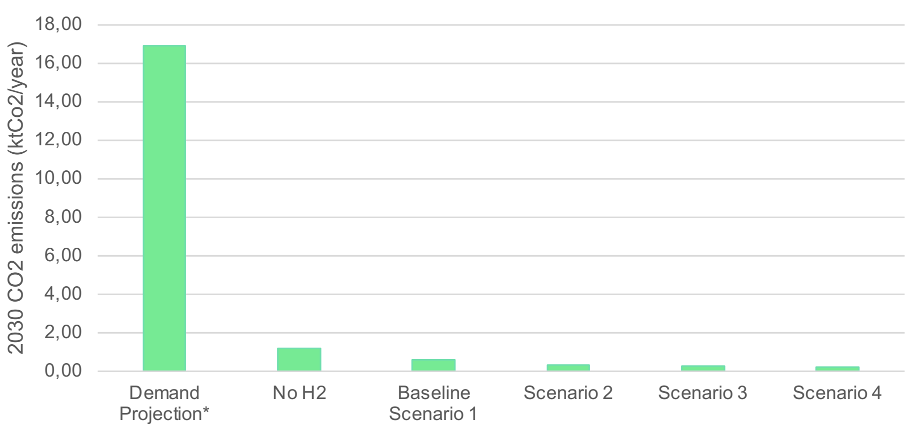


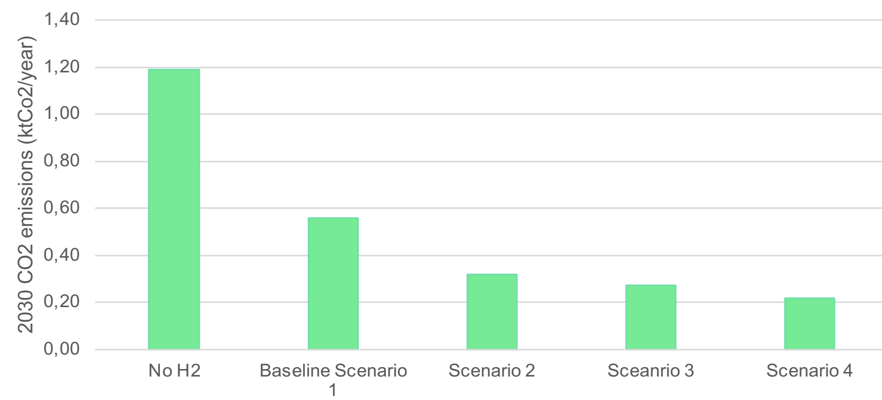
Figure 32:
2030 Isla de Pascua carbon emissions (ktCO2/year) per scenario *(demand projection figure assumes 2020 infrastructure makeup based on Formularios para Isla de Pasua in 2020)

Prices of fossil fuels are extremely high in Isla de Pascua given the remote nature of the island, thereby enabling a highly cost-competitive deployment of renewable generation. Long-term hydrogen storage capacity would facilitate the ability to eliminate reliance on fossil fuel imports.

All resulting carbon emissions savings from each scenario were underpinned by a reduction in reliance on fossil fuel consumption. The assumption used to estimate the emissions for the demand projection was based on the same grid composition that was installed in 2020, which is wholly nonrenewable energy. A fundamental rethinking of the Isla de Pascua grid to take advantage of its renewable generation potential will result in significant cost and carbon savings in this context.

For a better comparison of the emissions savings across modeled scenarios, Figure 33 excludes estimated demand projections.

Figure 33:
2030 Isla de Pascua carbon emissions (ktCO2/year) per scenario



When comparing the No H2 scenario to Scenario 1, it is clear that hydrogen has an important role in reducing carbon emissions in a cost-optimal grid. Given that Isla de Pascua is subjected to greater seasonal shifts and has a greater proportion of wind energy contributing to the grid, the performance characteristics of hydrogen storage systems are better suited for storage than batteries in this context. This contrasts with the decarbonization potential in a solar-dominated grid, as illustrated for San Pedro de Atacama in Figure 45.

Job creation potential

The remote nature of Isla de Pascua and the skilled labor availability will affect the viability of employment, indicated in Table 22 below. Skills development programs will likely be required to realize the benefits of these jobs to the local community.

Table 22:
Green job creation per scenario

	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
Scenario	MCI	O&M	MCI	O&M
Baseline Scenario 1	50	5.75	416.3	12.4
Scenario 2	50	5.75	439.4	12.8
Scenario 3	50	5.75	1617.3	13.2
Scenario 4	50	5.75	1712.5	13.6

Levelized costs of electricity production

The levelized cost information shown in Table 23 does not represent the costs that consumers will pay and is not representative of the costs that are associated with the construction of projects resembling this study on Isla de Pascua.

Levelized Cost (Production)	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Electricity (USD/kWh)	0.111	0.090	0.090	0.075	0.067
Hydrogen (USD/kg)	N/A	1.57	1.52	1.37	1.14

Table 23
Isla de Pascua levelized cost for energy production per carrier per scenario

In Isla de Pascua, hydrogen is a major contributor to delivering cost-optimal energy. Fossil fuel costs are prohibitive in Isla de Pascua and dispatchable power can be cost-effectively provided using hydrogen storage systems. Hydrogen is effective in Isla de Pascua due to the combination of solar and wind renewable generation potential and the small size of the grid. Though there are additional complexities and costs beyond the scope of this study associated with the development of projects on Isla de Pascua, the case for hydrogen is strong based on the modeling assumptions. Additional analysis of this context is recommended for more detailed understanding of the opportunities.

Other Project Attributes

The following table provides estimates of the total capital costs of renewable infrastructure, the yearly O&M costs and the market size of hydrogen associated with each scenario. These figures do not account for the capital costs of wind and solar infrastructure already installed or under construction.

The market size is defined as the amount of hydrogen produced by the electrolyzer system as nominally estimated in the year 2030. It should be noted that the reduction in capital cost estimated in Scenarios 3 and 4 is driven by the optimistic lower cost of hydrogen facilities included in the scenarios.

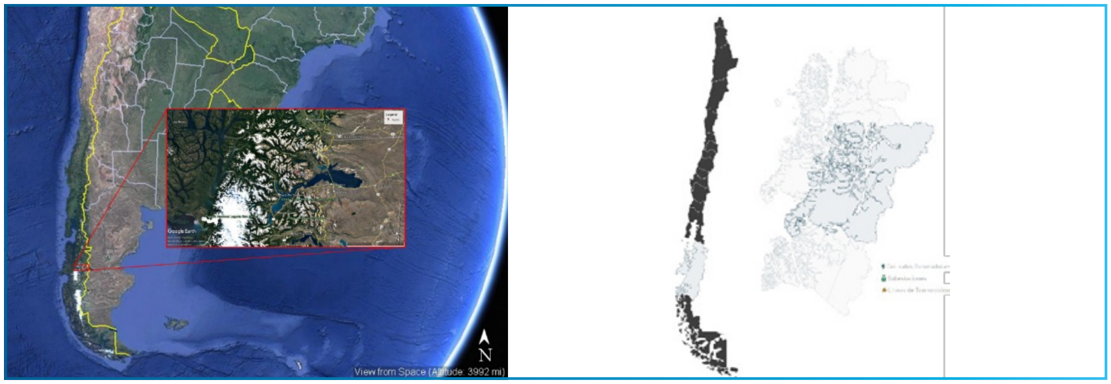
2030 Estimate	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX total (MMUSD)	24.4	25.4	26.6	21.8	20.8
O&M (MMUSD/year)	0.170	0.385	0.395	0.370	0.420
Market Size (tons H2)	N/A	165	180	210	280

Table 24:
Estimates of other project attributes

The estimated infrastructure and O&M costs account for the wind, solar, hydrogen electrolyzer system, hydrogen storage, fuel cell system and lithium-ion battery system. O&M costs include both fixed and variable costs. Detailed cost assumptions can be found in the Appendix.

2.1.5 Aysen

Figure 34. Geographical location of the grid of Aysen.[18]



The following section documents information and results that are specific to the grid serving the area Aysen.

Description

Aysen is located in the Aysen region of Chile. The main centre of population is in the town Coyhaique. The area experiences narrow seasonal shifts and extreme temperatures are uncommon. Unlike the other southern areas (Punta Arenas and Puerto Natales), Aysen has more potential for solar energy generation. Coyhaique has very poor air quality due to residents using wood as a primary source of heating and due to geographical and climactic conditions. Aysen has diverse industrial activities that support the local economy. The main industries are fishing, agriculture and tourism.[19] The Aysen power grid is supported by a high proportion of renewables currently with most of the power demand being met by hydroelectric power generation. Droughts have caused significant reduction in the reliability of the electricity system. Additionally, wind and solar assets as well as diesel generators support the grid and provide power generation. The grid is medium-sized and nearly 26 MW peak demand is projected for the year 2030.

Cost-optimal technology mix for 2030

The system capacities associated with a cost-optimized Aysen grid for each scenario are shown below in Figure 35 and Table 25. The sum of the total installed capacity of infrastructure associated with meeting the demand based on the cost optimization increases for each scenario. As the cost of renewables decreases, a certain amount of storage becomes cost effective, which drives the amount of overcapacity in the system that is allowed.

Although Aysen does currently have high renewable penetration through utilization of hydroelectric power infrastructure, this has presented issues, as droughts in the region have historically caused serious challenges associated with energy security. Over-reliance on the current hydro resources in Aysen puts local communities at higher risk than that of regions that are dependent on fossil fuels as climate change and droughts worsen.

18 Coordinador Eléctrico Nacional de Chile. (n.d.). Sistemas eléctricos de Chile 2017 [Map]. Https://Www.Coordinador.Cl/#. https://sic.coordinador.cl/wp-content/uploads/2013/06/Mapa-Coordinador-Electrico-01.jpg

19 Ilustre Municipalidad de Aysén. (2016). Plan de desarrollo comunal de Aysén (PLADECO). Ilustre Municipalidad de Aysén.

This analysis poses an alternative option for the region as seen in Figure 35.

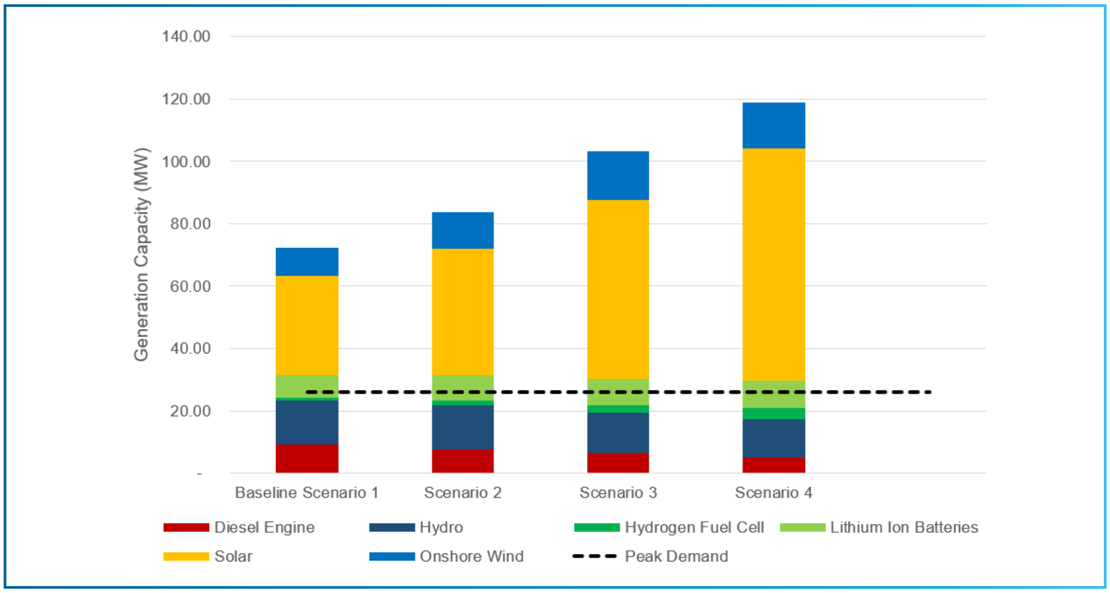


Figure 35:
System capacities of each technology per scenario for Aysen (2030)

Incentivizing renewables not only results in decreased reliance on fossil fuels in the region but also on the hydroelectric resources. Increased incorporation of diversified renewable resources complemented with hydrogen and batteries is both cost-optimal and contributes to a more secure energy future for Aysen.

Equipment Capacities (MW)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Peak Demand	25.90	25.90	25.90	25.90
Diesel Engine	9.19	7.70	6.47	5.02
Hydro	14.28	14.27	13.02	12.37
Hydrogen Electrolyzer	2.39	5.30	9.35	17.28
Hydrogen Fuel Cell	0.75	1.23	2.21	3.68
Lithium-Ion Batteries	7.33	8.33	8.61	8.56
Solar	31.83	40.61	57.18	74.56
Onshore Wind	8.80	11.50	15.81	14.73

Table 25:
Peak Capacities (MW) of each technology per scenario for Aysen (2030)

Based on a comparison of the sum of the electrolyzer and lithium-ion battery capacity, it is clear that there is significantly more overcapacity than there is storage. This relates to the capacity factor of the wind and solar assets. Solar assets, which have a significantly lower cost than wind assets, have a lower capacity factor than the wind assets as well.

The need for long-term and large-capacity storage for renewable penetration is apparent when comparing the scenarios. Because Aysen is wind-dominant, the cost of building excess capacity for hydrogen production is higher than on the other grids where the hydrogen storage systems are limited by the electrolyzer.

Table 26:
Capacities of each storage technology per scenario

Storage Capacities (MWh)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Hydrogen Storage	64	130	213	322
Lithium-ion Battery	29.3	33.3	34.4	34.2

Because the current cost of solar PV infrastructure is lower than that of wind, it becomes more cost effective to store solar energy with hydrogen when the electrolyzer costs are reduced in Scenario 4. The optimistic cost projections will enable greater deployment of solar generation.

Figure 36
2030 Aysen Scenario 3 system storage profile

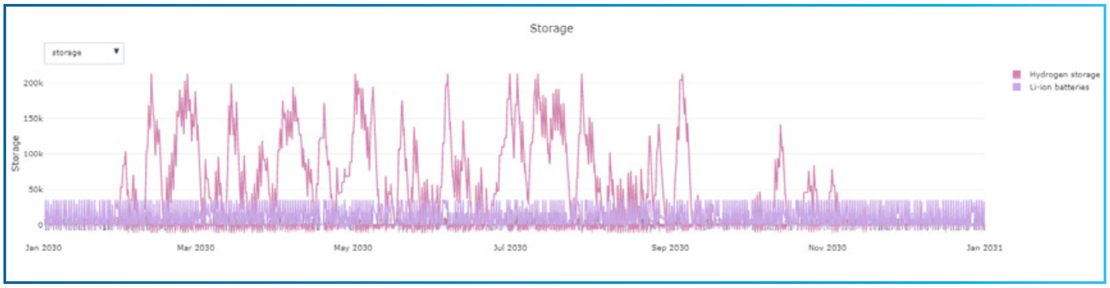
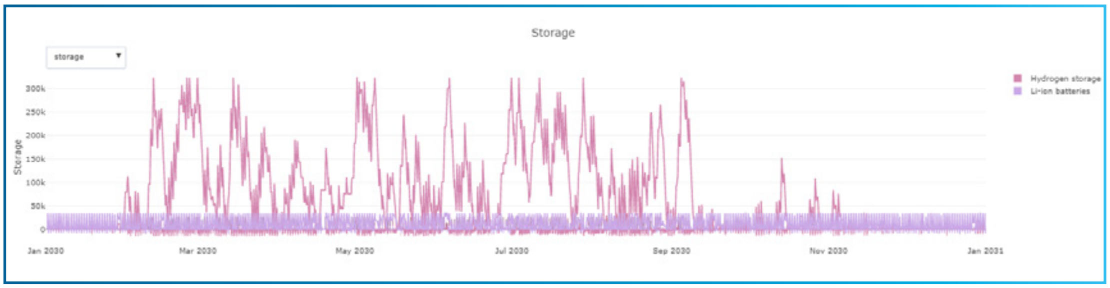


Figure 37:
2030 Aysen Scenario 4 system storage profile



The storage profiles between Scenarios 3 and 4, as shown in Figure 36 and Figure 37, do not change significantly, however, the quantity of hydrogen storage increases dramatically. This also aligns with an increased reliance on solar energy.

Power Generation

As shown below, for Aysen, which is reported to have problems with underutilization of hydro assets due to droughts, there is an opportunity to cost-effectively offset some of the load that is projected for the hydro resources with solar generation complemented by hydrogen and battery storage. Pursuing a scheme that reflects the results of this modeling exercise, for the Aysen grid in particular, could increase the reliability of the grid and reduce the fuel related cost burden associated with drought conditions.

Although Aysen has lower solar generation potential relative to other locations, solar is deployed in lieu of wind under the conditions specified in the analysis. The value of solar generation to the system is driven by the relative variability, the stability of the hydropower component, and ability to utilize a balanced battery and hydrogen storage system. Therefore, it can be concluded that solar energy projects are viable to support the Aysen grid and contribute to low cost of electricity despite the greater wind energy potential in the region.

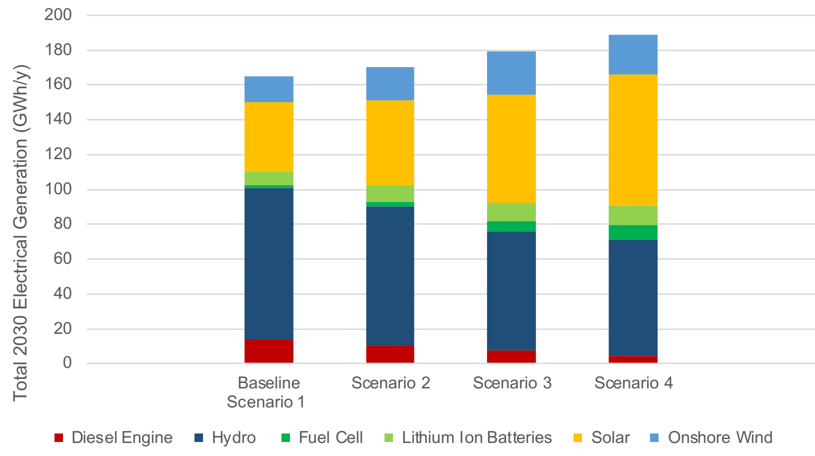


Figure 38
Aysen grid system 2030 grid system electrical generation (GWh/year) per scenario

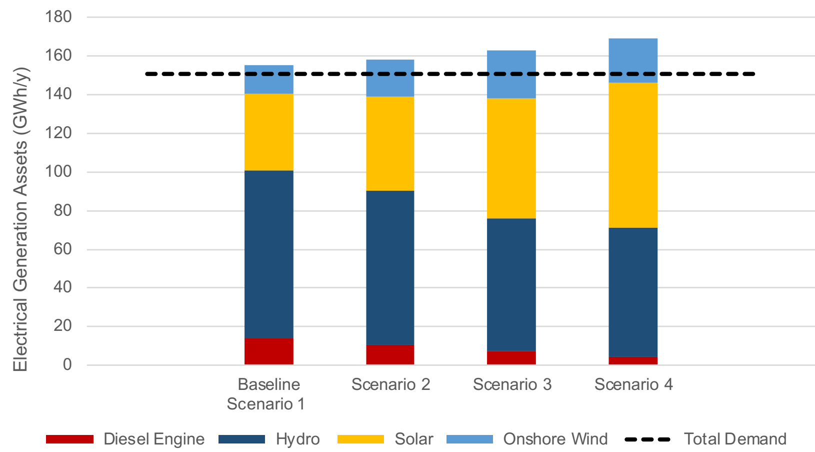


Figure 39:
Aysen grid system 2030 grid system electrical generation (GWh/year) per scenario

When comparing wind and solar in Scenarios 3 and 4, it was observed that solar complemented with hydrogen infrastructure was cost effective compared to wind assets. The overall loss of efficiency across the scenarios was lower than in other scenarios because the systems do not rely as much on hydrogen storage due to the stability of the hydropower contribution.

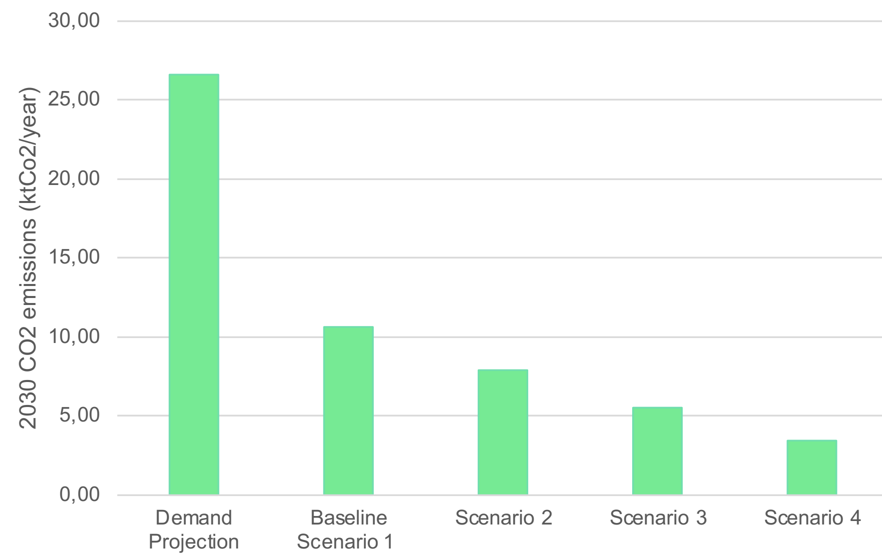
2030 Power Generation (GWh/year)				
Technologies	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	14	10	7	5
Hydro	87	80	69	66
Hydrogen Fuel Cell	2	3	5	9
Lithium-Ion Batteries	7.8	9.4	11	11.2
Solar	40	49	62	75
Onshore Wind	15	19	25	23

Table 27:
Aysen grid system electricity generation (GWh/year) per scenario

Emission reductions

As illustrated in Figure 40, there is potential for decarbonization compared to the current projected infrastructure planned for Aysen. Although the absolute magnitude of the carbon reduction, which was greater than 15 kt CO2/year, was not as large as that predicted for other grids, it does represent a comparative reduction of greater than 60%. The conditions in Scenarios 2-4 could represent an additional 60% reduction.

Figure 40:
2030 Aysen carbon emissions (ktCO2/year) per scenario



Job creation potential

Job creation potential for each scenario for Aysen is shown below.

Table 28:
Green job creation potential per scenario

Scenario	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
	MCI	O&M	MCI	O&M
Baseline Scenario 1	50	5.75	707.9	17.8
Scenario 2	50	5.75	890.1	21.1
Scenario 3	50	5.75	1224.0	26.9
Scenario 4	50	5.75	1525.9	31.9

It should be noted that job creation or loss attributed to hydroelectric resources were excluded from this analysis. Any jobs already existing for the support of wind and solar resources are included in the results reported in Table 28.

Levelized costs of electricity production

The levelized cost of electricity and hydrogen production based on each scenario are shown in Table 29 below and are followed by a qualitative discussion of the results and trends that were observed.

Levelized Cost (Production)	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Electricity (USD/kWh)	0.092	0.095	0.084	0.078
Hydrogen (USD/kg)	3.11	3.45	3.09	2.78

Table 29:
Aysen 2030 levelized cost per scenario

Comparing Scenarios 1 and 2, the increase in electricity price from an increased carbon tax at just over 3% is the lowest of the medium-sized grids, which rely more heavily on fossil fuels and therefore experience a greater increase in the cost of electricity production.

Scenarios 3 and 4 indicate a cost savings of 9% and 15% respectively, compared to the Baseline, demonstrating how deployment of renewables can lead to cost optimal electricity.

Other Project Scope

The following table provides estimates of the total capital costs of renewable infrastructure, the yearly O&M costs and the market size of hydrogen associated with each scenario. These figures do not account for the capital costs of wind and solar infrastructure already installed or under construction. Also, CAPEX and OPEX costs for hydroelectric infrastructure are excluded, as well.

The market size is defined as the amount of hydrogen produced by the electrolyzer system as nominally estimated in the year 2030. It should be noted that the reduction in capital cost estimated in Scenarios 3 and 4 is driven by the optimistic lower cost of hydrogen facilities included in these scenarios.

Estimate	Scenarios			
	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX total (MMUSD)	45	55	60	65
O&M (MMUSD/year)	0.56	0.85	1.08	1.51
Market Size (tons H2)	95	165	305	490

Table 30:
Estimates of other project attributes

The estimated infrastructure and O&M costs account for the wind, solar, hydrogen electrolyzer system, hydrogen storage, fuel cell system and lithium-ion battery system. O&M costs include both fixed and variable costs. Detailed cost assumptions can be found in the Appendix.

2.1.6 San Pedro de Atacama

Figure 41:
Geographical location of the grid of San Pedro de Atacama

The following section documents information and results that are specific to the grid serving the area San Pedro de Atacama.

In order to understand the importance of hydrogen as a storage medium for solar energy generated to support San Pedro de Atacama, a counterfactual case study was run against the Baseline Scenario, excluding hydrogen from the possible technology pathways.

Description

San Pedro de Atacama is located in the northern part of Chile in the Atacama Desert. The region has high solar energy potential, and there is significant investment in large-scale solar projects to supply the global renewable energy demand. This is projected to result in increased population growth in the region due to increased job opportunity. Currently, the San Pedro de Atacama grid is supported by diesel engines and gas engines for power generation. The grid itself is relatively small in size and peak demand is estimated to be just under 3.1 MW in 2030.

Cost-optimal technology mix for 2030

Of all the grids, San Pedro de Atacama is the most promising in terms of cost-effective utilization of hydrogen given the high potential for solar energy. As seen in Figure 42 and Table 31, wind infrastructure in this region is not cost competitive with solar under any scenario.

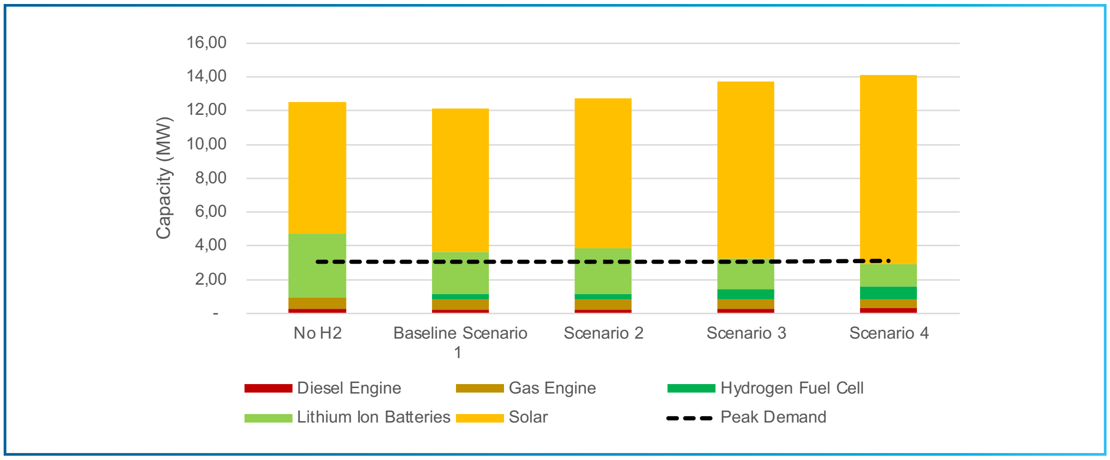


Figure 42:
System capacities of each technology per scenario for San Pedro de Atacama (2030)

As seen in Table 31 when comparing the diesel engine peak across the scenarios, the capacity increases. Intuitively, one may think that as the price of diesel goes up, the diesel engine capacity would reduce. However, this is not the case in this instance. Two different phenomena are observed in the cost optimization.

When comparing Scenario 1 and Scenario 2 in terms of both peak capacity (Table 31) and annual power generation (Table 33), the peak capacity of the diesel engine increases and the annual diesel engine power generation decreases. While the overall consumption does decrease as expected, the peak load that is cost-optimally met with the diesel engines increases. The utilization of the diesel engine is reduced because the costs of fuel has increased. The load that was met with the diesel engine in the baseline scenario is distributed across other resources – this redistribution of resources results in a single timestep where more diesel is deployed fewer times throughout the year. Due to the supply and demand dynamics and the limitations of the other equipment, it was found to be more cost effective to deploy and operate the diesel engine in this way rather than to increase the system capacities of other technologies. It is noted that the total power supplied by the diesel generators is very low compared to the gas engines and renewables.

When comparing Scenarios 2 and 3 as well as Scenarios 3 and 4, again, the peak capacity of the diesel engine does increase, however, the annual power generation of the diesel engine increases as well. This is attributed to an overall reduction in fossil fuel consumption when comparing both the diesel and gas utilization for power generation. Since gas engines have a higher capital cost per capacity than diesel engines, it was found that some of the reduced gas engine load was cost-optimally distributed to the diesel engine rather than increasing the capacity of the other resources to meet the entire peak coincident and annual generation load that was no longer cost-optimally met by the gas engine. Significant reduction in the gas engine utilization is predicted for Scenarios 3 and 4.

Table 31:
Peak Capacities (MW) of each technology per scenario for San Pedro de Atacama (2030)

Peak Capacities (MW)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Peak Demand	3.09	3.09	3.09	3.09	3.09
Diesel Engine	0.29	0.21	0.22	0.28	0.31
Gas Engine	0.62	0.61	0.59	0.52	0.49
Hydrogen Electrolyzer	-	1.16	1.23	2.09	2.74
Hydrogen Fuel Cell	-	0.33	0.36	0.63	0.81
Lithium-Ion Batteries	3.81	2.49	2.67	1.79	1.29
Solar	7.80	8.47	8.93	10.50	11.21
Onshore Wind	-	-	-	-	-

Of all the grids, San Pedro de Atacama has the greatest potential for hydrogen in terms of low-cost production because of the abundance of solar generation capacity. In each scenario where hydrogen was allowed, the proportion of storage capacity that is stored in batteries decreases as hydrogen becomes more cost competitive.

Table 32:
Capacities of each storage technology per scenario

Storage Capacities (MWh)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Hydrogen Storage	-	14	16	24	30
Lithium-ion Battery	15	10	11	7	5

Power Generation

Utilization of fossil fuels was negligible in the cost optimization under all scenarios in San Pedro de Atacama. Considerable solar generation potential in the Atacama Desert region drove the cost optimization in the San Pedro de Atacama grid. It was found that hydrogen can enable increased deployment of solar infrastructure. The total utilization of storage across each scenario is nearly equal even though the total storage capacity increases in each scenario, as seen in Figure 43.

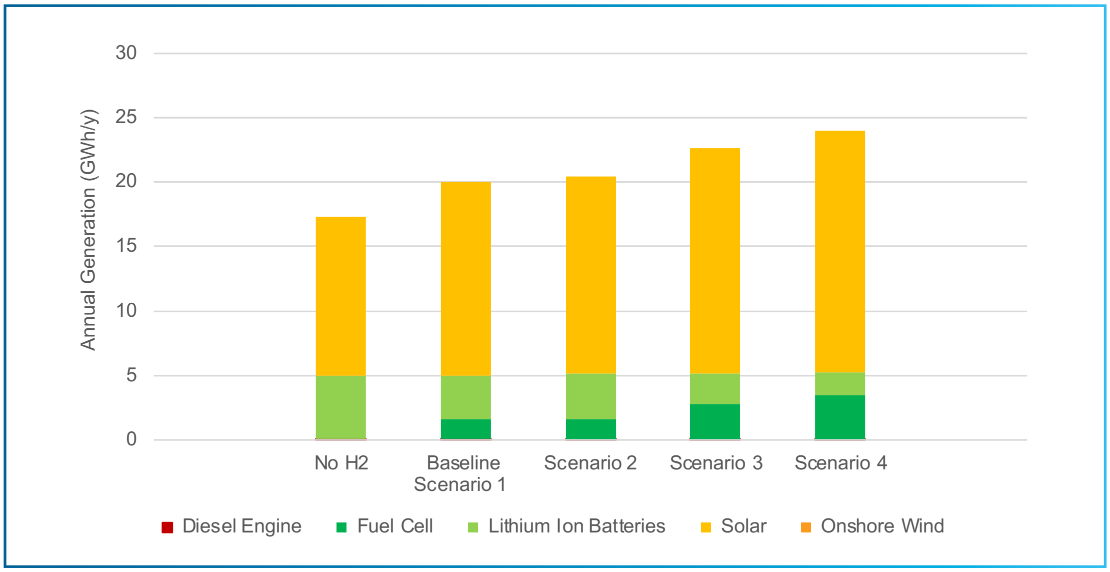


Figure 43:
San Pedro de Atacama grid system electrical generation in 2030 per scenario (GWh/year)

Figure 43 illustrates the potential of incorporating solar into grid operations. By combining solar and storage, the need for hydrocarbon generation can be practically eliminated. The analysis also demonstrated the effect of the relative cost competitiveness of battery storage systems and hydrogen storage systems; as hydrogen becomes cost effective against batteries, additional solar generating assets are needed to compensate for the energy losses experienced during electrolysis, storage, and fuel cell operations.

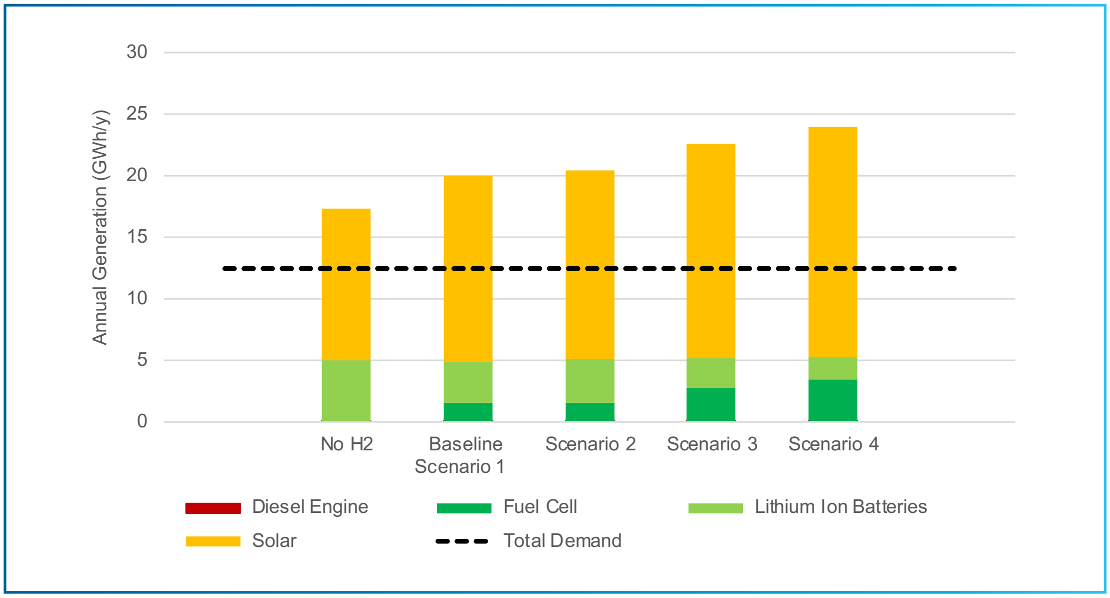


Figure 44:
San Pedro de Atacama grid system 2030 generation (GWh/year) per scenario

As shown in Figure 44, all scenarios required solar generating capacity above the demand load. The solar capacity increases as the amount of hydrogen storage in the system is increases. The increase is driven by the efficiency losses in the hydrogen storage system. In this scenario and as shown in Table 35, Scenario 4 provides the lowest LCOE. This result is driven by the optimistic cost of hydrogen production, which was an assumption of the study. The same result could be driven by an increase in the efficiency of hydrogen production which would also result in a lower required solar generating capacity, thereby compounding the cost reduction impact.

Table 33:
San Pedro de Atacama grid system 2030 power generation (GWh/year) per scenario

2030 Generation (GWh/year)					
Technologies	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Diesel Engine	0.053	0.038	0.023	0.024	0.026
Gas Engine	0.92	0.87	0.62	0.47	0.39
Hydrogen Fuel Cell	-	1.57	1.55	2.74	3.45
Lithium-Ion Batteries	4.94	3.33	3.56	2.42	1.77
Solar	12.35	15.05	15.31	17.45	18.75
Onshore Wind	-	-	-	-	-

Table 33 provides the generating load of each of the components of the grid. As can be seen, increasing contribution of storage drives lower LCOE despite the need for more renewable generating assets.

Emission reductions

Figure 45 illustrates the predicted carbon emissions compared to the current demand projection. The decarbonization potential of the San Pedro de Atacama grid is significant compared to current (2020) grid infrastructure despite the significant growth in population in the region expected by 2030. This is because the 2020 grid composition had no renewables supporting the grid for power generation. Even in the Baseline Scenario, nearly all of the power generation comes from solar energy with storage. Inexpensive solar supported by storage infrastructure drives a lower cost of electricity generation than is currently being seen in the region.

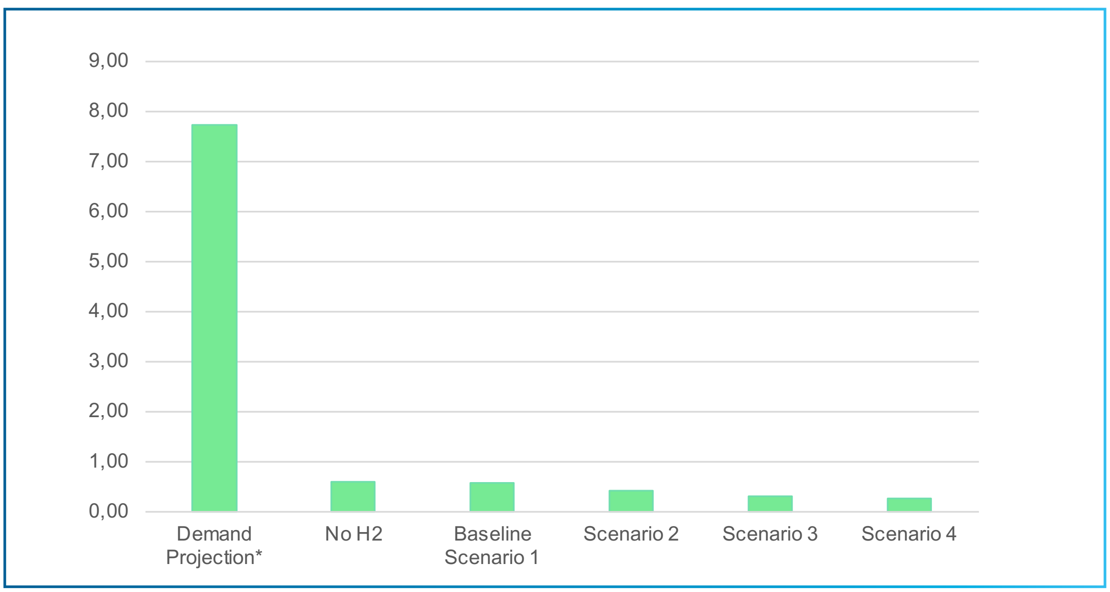


Figure 45:
Estimated San Pedro de Atacama 2030 grid carbon emissions (ktCO2/year) per scenario *(demand projection figure assumes 2018 infrastructure makeup based on Formularios para San Pedro de Atacama in 2018)

All resulting carbon emissions savings from each scenario are underpinned by a reduction in reliance on fossil fuel consumption.

The assumption used to estimate the emissions for the demand projection is based on the same grid composition that was installed in 2018, which is wholly hydrocarbon-derived energy. A transition of the Atacama grid to take advantage of prevalent, relatively low-cost solar generation will result in significant cost and carbon savings.

For better comparison of the emissions savings across modeled scenarios, Figure 46 excludes estimated demand projections.

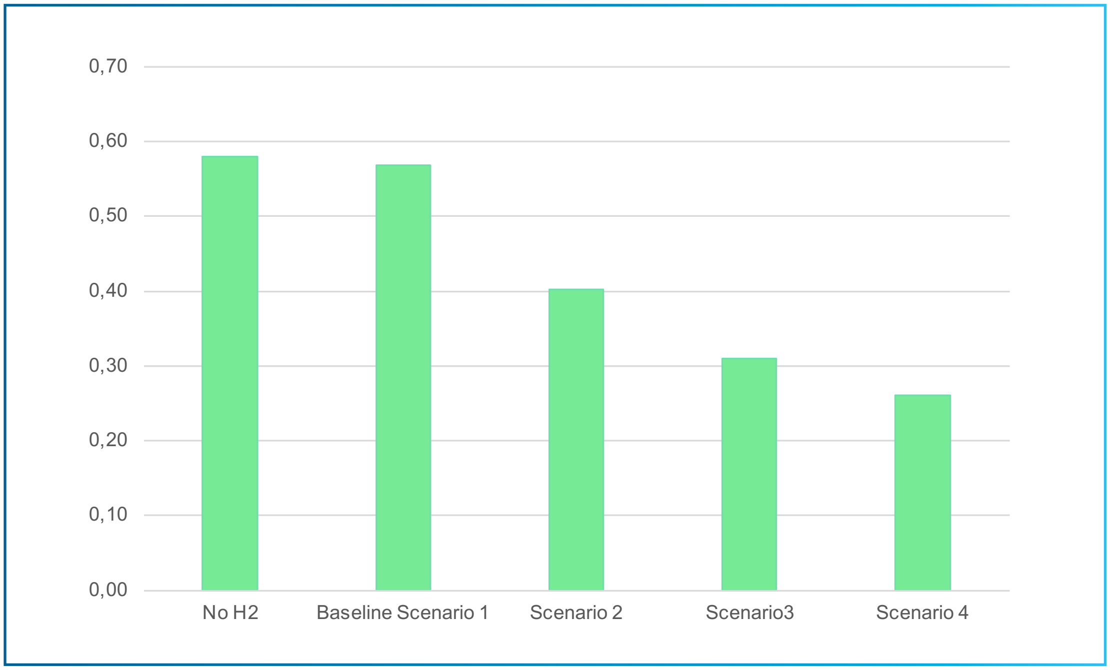


Figure 46:
Estimated 2030 San Pedro de Atacama grid carbon emissions (ktCO2/year) per scenario

As seen in Figure 46, there are no significant carbon emission savings through the use of hydrogen storage over battery storage. The increased use of hydrogen as a storage medium in Scenarios 3 and 4 is driven by the relative cost competitiveness of hydrogen in the scenario assumptions. This result is typical of that expected for short-term variability of solar-dominated grids.

Job creation potential

The job creation potential associated with the scenario analysis is shown below for San Pedro de Atacama.

Scenario	Hydrogen Jobs (FTE)		Total Green Jobs (FTE)	
	MCI	O&M	MCI	O&M
Baseline Scenario 1	50	5.75	205.8	8.5
Scenario 2	50	5.75	214.4	8.7
Scenario 3	50	5.75	241.0	9.1
Scenario 4	50	5.75	252.9	9.2

Table 34:
Estimated green job creation per scenario

Levelized costs of electricity production

The virtue of hydrogen was not observed in terms of carbon emissions. However, savings in cost through utilization of hydrogen for electricity production are discussed in this section. See the below levelized costs of electricity production in Table 35.

Table 35: Estimated San Pedro de Atacama levelized cost of electricity and hydrogen

Levelized Cost (Production)	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
Electricity (USD/kWh)	0.086	0.076	0.077	0.063	0.055
Hydrogen (USD/kg)	N/A	1.286	1.351	1.084	0.906

The benefits of hydrogen storage for San Pedro de Atacama are in the resulting cost of electricity, which was almost 12% lower when comparing the No H2 and Baseline scenarios. As discussed, cheap and abundant solar energy drives the deployment of renewable energy over the utilization of fossil fuels. While there are no significant savings in emissions, this grid is an excellent representation of how hydrogen can be a cost-effective storage medium to support grid operations with renewables.

Increasing carbon price resulted in an almost 2% increase in cost of electricity when comparing Scenarios 1 and 2. However, the conditions in Scenarios 3 and 4 could provide a savings of over 17% and 27%, respectively, compared to the baseline.

Other Project Scope

The following table provides estimates of the total capital costs of renewable infrastructure, the yearly O&M costs and the market size of hydrogen associated with each scenario. These figures do not account for the capital costs of wind and solar infrastructure already installed or under construction.

The market size is defined as the amount of hydrogen produced by the electrolyzer system as nominally estimated in the year 2030. It should be noted that the reduction of capital cost estimated in Scenarios 3 and 4 was driven by the optimistic lower cost of hydrogen facilities included in the scenarios.

Table 36: Estimates of other project attributes for 2030

Variable	Scenarios				
	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX total (MMUSD)	10.5	10.2	10.8	9.2	8.5
O&M (MMUSD/year)	0.045	0.140	0.145	0.170	0.190
Market Size (tons H2)	N/A	87	86	150	190

The estimated infrastructure and O&M costs account for the solar, hydrogen electrolyzer system, hydrogen storage, fuel cell system and lithium-ion battery system. O&M costs include both fixed and variable costs. Detailed cost assumptions can be found in the Appendix.

General Regulatory & Social Consideration

2.2 Regulatory Review

The regulatory review is limited to those concepts and elements related specifically to the implementation of hydrogen in small and medium grids, together referred to as "isolated grids" in the context of the Chilean infrastructure.

A robust National Energy strategy is being developed in Chile to develop market conditions conducive to the development of renewable energy generation and battery storage assets. It is beyond the scope of this study to contribute to that strategy development beyond the contribution of elements that relate specifically to green hydrogen implementation. The implementation of the reforms must be made in a thoughtful manner, and potentially with specific considerations for each isolated grid, in order to provide the cost and reliability benefits to the rate payers.

The implementation of green hydrogen in isolated grids requires a system that is intricately linked between generation, storage, and offtake. The planning and design of the grids will take on new attributes that have not been previously considered and are not compatible with current laws and regulations. Among the non-compatible attributes are planned over-generation, redundant transmission, and storage capacity fees, all of which are discussed below. While these are true of all renewable generation and storage schemes, they are amplified by the nature of isolated grids, the long-term nature of hydrogen storage, and the low round-trip energy efficiency (and consequent process losses) of hydrogen storage.

2.2.1 Small and Medium Grid Attributes

The isolated grids studied are currently dominated by hydrocarbon generation complemented by hydropower and with a small renewable component. The grids have been planned and designed using a system generally oriented toward hydrocarbon-generating assets. This has resulted in generally reliable grid operations providing energy at reasonable prices. However, to achieve this level of service both high carbon emissions and subsidized fuels are required.

The grids typically have a small number of generation stations with limited interconnectivity of the transmission lines resulting in single feed service to most users. Furthermore, the grids tend to have highly variable diurnal loading and seasonal demand profile associated with industrial demand and seasonal weather patterns.

While base-load hydrocarbon generation is primarily provided by efficient reciprocating engines and turbines, peaking power during high-demand periods is primarily provided by high-emission diesel reciprocating engines, often at or near the end of life. Additionally, because of the remote nature of isolated grids, the distance to market and supply quantity of the imported diesel results in very high-cost hydrocarbon fuel. To provide a reasonable cost to energy consumers, the diesel is subsidized by the federal government in a grid-specific scheme.

Furthermore, the Chilean isolated grids tend to be located in areas that have high potential for wind generation, solar generation, or both. As has been demonstrated in Section 2 above, the attributes of the specific Chilean isolated grids studied provide an opportunity for implementation of renewable generation and storage, and in particular, for long-term hydrogen storage.

2.2.2 Green Hydrogen System Attributes

The cost of green hydrogen energy storage is closely related to the rate of utilization of the electrolyzers, known as the capacity factor. The higher the capacity factor, the more the cost is driven by the cost of power, while systems with lower capacity factor are driven by the capital cost of the electrolyzer and storage systems, resulting in a higher cost of storage. Therefore, in order to optimize the value of the hydrogen storage systems, the renewable generating assets must be sized to provide an over-supply of power that can be redirected to storage. Because renewable generating assets are designed using probabilistic forecasting of generation and demand, over-supply occurs on peak generating days. In the absence of storage, the over-supply is often curtailed. Hydrogen storage can utilize the curtailed over-supply but also requires dedicated generation to optimize the cost. Therefore, renewable generation capacity must be planned, designed, and financed as a system with the storage considered: storage cannot be commercially viable without generation, and over-supply of generation cannot be commercially feasible without storage.

Hydrogen storage is differentiated from battery storage by the ability to cost-effectively store large amounts of power over long durations (Hydrogen is also differentiated by the low energy efficiency of less than 50% for hydrogen compared to 90% for short-term battery storage, which is discussed below). Battery storage is typically used frequently or daily to provide capacity during peak loads, during intermittent outages, and to other ancillary grid services. Therefore, while battery storage systems can generate revenue on a consistent basis, hydrogen storage systems are better suited for long-term, low-frequency storage, which is often a need of small, isolated grids. The simulations of the isolated grids performed in this study indicated that hydrogen storage would be utilized primarily in very limited instances spanning multiple days when weather patterns are not conducive to renewable generation. Therefore, hydrogen storage systems could be producing and storing hydrogen for months or years without returning energy to the grid. This usage pattern causes a large separation between system cost and revenue. Thus, the ability to provide revenue to hydrogen storage systems based on the capacity of the storage, rather than or in addition to actual power provided, will be required in order to make these investments economically feasible.

Hydrogen storage is an effective means of providing long-term storage of energy. However, the fact that the energy efficiency of hydrogen production, storage and generation is less than 50% represents a challenge. This is significant because more than half of the power generated and stored in hydrogen will be lost and not delivered to an end user, an important consideration when calculating generation and transmission capacity and fees, as well as the revenue streams required by these systems.

2.2.3 Recommendations for Grid Design Consideration

Because of the specific attributes of green hydrogen storage systems, special consideration should be given to the design of the grid to enable incorporation. The consideration should be focused on three areas that have been indicated in the grid modelling and evaluation effort, which include hydrogen generation and storage assets, renewable generation coupled with green hydrogen systems, and transmission. Finally, the market design to provide compensation for grid services supplied by long-term, low-frequency hydrogen storage systems must be considered.

Considerations for Hydrogen Generation and Storage

Hydrogen is best suited for long-term low-frequency storage. Hydrogen storage systems may be operating for months converting excess power to hydrogen before any energy is discharged to the grid. The timing or frequency of discharge to the grid will not be controlled by the storage facility and can only be forecasted on a probabilistic basis. Therefore, the revenue streams required to support this investment must be different than those typically associated with hydrocarbon generation and short-term battery storage.

Consistent revenue to the hydrogen storage system will be required to underpin the capital investment and operating expenses (inclusive of both the generating and storage assets). Development of hydrogen storage systems, including coupled wind and solar generation, require long-term purchase agreements to facilitate financing. Typical agreements for renewable power storage projects are 15-30 years. The revenue models can be structured to provide flexibility in pricing based on variable costs but must be firm enough to satisfy financial institution requirements.

Considerations for renewable generation associated with green hydrogen

In small and medium grids, green hydrogen storage must be developed in conjunction with renewable generation. It is unlikely that merchant green hydrogen facilities based on curtailed renewable generation or pricing arbitrage will be financially viable in small and medium grids due to the close planning between generation and loading. With the primary purpose of long-term hydrogen storage being energy supply during low wind / solar generation periods, generation over-capacity will be required during normal wind / solar generation periods to provide energy to hydrogen production. The generation over-capacity is the result of several factors, including capacity of variable renewable generation (derated by the capacity factor), energy losses associated with round-trip hydrogen production, and the inclusion of hydrogen fuel-cell generation capacity. This phenomenon can be seen in Figure 20, Figure 25, Figure 31, and Figure 38, where the incorporation of long-term storage results in significant generation over-capacity in the grid system while also lowering average energy costs. The generation over-capacity factor for the green hydrogen system will be at least 50% and potentially higher depending on the variability and intermittency of the generation and discharge. It should be noted, however, that the total installed generation capacity could, in some instances of high demand or low production, be used to support the grid instead of being stored. In this sense, the over-capacity provides energy security benefits to the grid under multiple scenarios.

The planification process must provide mechanisms to assess the benefits of over-capacity to enable green hydrogen storage. Additionally, the tariffication process must provide mechanisms for compensation for generation deferred while in storage and for power lost in the hydrogen storage process.

Considerations for Transmission Assets

Hydrogen storage systems can be co-located and directly coupled with renewable generation assets. In this case the over-generation will be stored as hydrogen prior to ever entering the grid transmission system. Co-location and electric coupling is the most efficient method of producing hydrogen. In this case, the transmission system will not see any additional utilization beyond the power dispatched from the facility to meet the current demand, whether from ongoing generation or from storage.

Nonetheless, there is the potential that hydrogen storage will provide the highest value to the grid when placed centrally between several generating sites or behind points of potential transmission congestion. In these cases, power will be transmitted through the infrastructure between generation and storage systems prior to conversion to hydrogen. When the energy is finally dispatched to the end-user it will be at least 50% less than the originally transmitted amount because of the energy losses associated with green hydrogen production. Properly designed, the use of green hydrogen storage will alleviate over-all grid congestion and defer capital expenditures associated with the transmission system. However, the planification process should consider upgrades to the system needed to enable hydrogen storage that produces net higher benefits.

2.2.4 Considerations for Market Competitiveness

The construction of the grid planning process must include an openness to innovative developments that provide benefits to the grid. This openness must be able to accommodate the consideration of novel designs and asset configurations, not only of hydrogen-based solutions but of other storage systems as well. As demonstrated clearly in the grid analysis performed as part of this report, optimal power cost will likely be achieved by a mix of short term and long-term storage.

The market design will need the ability to provide long-term storage capacity purchase agreements. The agreements will be related to the services that the storage system is ready and able to provide, rather than (or in addition to) the actual services performed. This will provide cash flow needed to service debt on a consistent basis even in times when long term storage is not needed to maintain grid reliability. This is critical for hydrogen storage systems but could also apply to other forms of long-term or short-term storage depending on the services being provided.

The ability to provide long-term purchase agreements is needed to underpin investments because of the need to finance and recover the cost of the storage systems over a long period. The purchase agreement structure should be flexible in order to incorporate the capital and operations costs for generation and storage assets combined. Typical international agreement terms range from 7 to 15 years depending on the nature of the grid and the assets.[20] Additionally, the use of private-public partnerships (PPPs) can also enhance the value of power projects. [21]

Market design should provide support for transmission of renewable power bound for hydrogen storage. Pricing should consider the benefits that storage can bring to the grid by relieving congestion and lowering peak pricing and emissions. This could be accomplished by subsidizing, reducing, or eliminating the cost of transmission used for long-term storage.

Finally, financial and regulatory support should be provided for demonstration projects that may not be otherwise financially viable. Demonstration projects are useful to fully understand the application and benefit of long-term storage in a specific grid. This can be especially beneficial when applied to facilities that can be expanded after the demonstration period and incorporated into a fully functional facility.

2.2.5 Pathways for Implementation

The implementation of green hydrogen storage into isolated grids will require modifications of the planification and tariffication processes to consider the specific attributes of electricity storage using green hydrogen. To inform this process, the International Renewable energy Agency, IRENA, published the Electricity Storage Valuation Framework in 2020 which provides general guidelines for evaluating and planning renewable energy storage systems. Although the IRENA report does not address hydrogen systems specifically, the framework can be adapted and applied. The IRENA framework includes a 6-phase evaluation process as shown in Figure 47. This framework will require augmentation to address hydrogen by evaluating some elements in parallel.

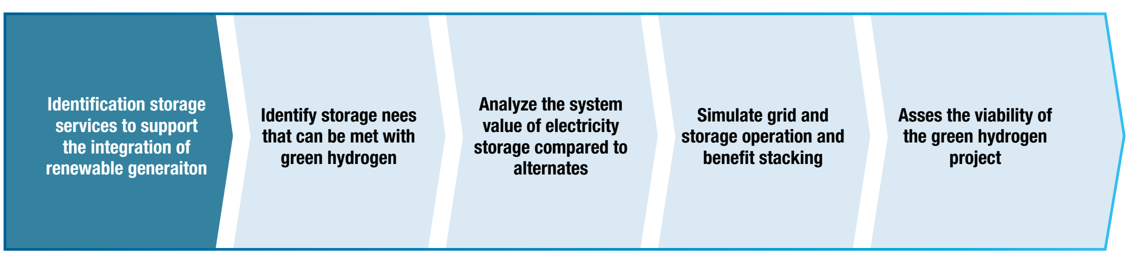


Figure 47:
Green Hydrogen Valuation Process. (Adapted from IRENA Electricity Storage Valuation Framework 2020)

Specifically, the green hydrogen planning framework will need to begin with a focus on the supply of long duration storage to enable integration of renewable generation (steps 1 and 2). The first steps should promote the concept of maximizing penetration of renewable energy in the grid. Long-term storage then becomes the enabler for the renewable generation.

The framework will then need to allow a comparison to other storage technologies (Step 3). This step would employ analysis techniques similar to those employed in this report to balance the variability of the renewable generation with the most appropriate storage technology. This step would consider ancillary services that could be supplied by other storage technologies as well as the location of storage to best utilize transmission and distribution assets.

20 For more information on power purchase agreements see https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements

21 For more information see https://ppp.worldbank.org/public-private-partnership/sector/energy

The next phase of the analysis would be to simulate the grid operations with the renewable generation and storage to determine the benefits. The benefits of the storage may include emissions reduction, energy security, deferred investment in transmission infrastructure, and reduction in subsidies.

The final step would be to assess the financial viability of the project including the market mechanisms to support the investment. The financial viability and market mechanisms will be closely interlocked and include balancing the capital and operational costs with the revenue generated by capacity supply and generation provided.

3 Recommendations for Follow Up Studies

A degree of renewable curtailment was observed across all scenarios. There is an opportunity for project owners to deploy hydrogen storage systems to produce hydrogen that has the potential to be exported or used for export, or sold as a commodity domestically. These hydrogen storage systems that are deployed with the sole purpose of export are external to the grid storage system. Allowing project owners to capitalize on any additional excess in the system may increase the attractiveness of projects in isolated locations that support grid storage and operation. It is important to note that while the potential for penetration into an export market is attractive, it is important that resource consumption is also optimized and where there are opportunities to decarbonize locally, domestic use of green hydrogen or renewable energy could potentially have a larger impact in terms of reducing emissions. Though system consolidation could lead to improved economics, there are certain regulatory considerations that are critical to protect Chilean consumers and maintain energy security on isolated grids. This is not covered in the scope of this analysis, but this analysis is highly recommended as a future study.

An investigation of options for best deploying renewable technology to satisfy resilience, cost and decarbonization for each grid is recommended as a continuation of this study and modelling effort. System requirements for isolated grids should be determined in nationwide specifications but allow for system size and contextual constraints to drive the requirements.

Additionally, certain equipment can accept a blend of hydrogen and fossil fuels to a varying degree. This could be an avenue for maximizing installed assets without a fuel cell or other hydrogen-dedicated power generation infrastructure. As typical blending targets are less than 15%, blending hydrogen with fossil fuels for power generation does not significantly reduce the resulting carbon emissions. Studies have been and are currently being performed globally to assess the viability and nuances of blending for power generation. However, this was not a feature of the projects investigated for this study. For these reasons, the option for blending hydrogen with fossil fuels in existing infrastructure was excluded as an option for this study. It is recommended that a more detailed infrastructure assessment follow this study to better understand opportunities for integration of hydrogen in isolated grid applications, including opportunities for blending of hydrogen with natural gas in existing infrastructure.

Appendix

Grid Storage Analysis

Technology	Description	Advantages/Disadvantages	Applications
Flow Battery	Flow batteries are a rechargeable battery using two liquid electrolytes, one positively charged and one negative, as the energy carriers. The electrolytes are separated using an ion-selective membrane, which under charging and discharging conditions allows selected ions to pass and complete chemical reactions. The electrolyte is stored in separate tanks and is pumped into the battery when required. The storage capacity of flow batteries can be increased by simply utilizing larger storage tanks for the electrolyte. Several chemistries are possible for the battery.	- Less sensitive to higher depths of discharge - Able to tolerate a large number of charge/discharge cycles - Reduced likelihood of the cells output being reduced to that of the lowest performing cell - Virtually unlimited capacity - Low energy density - Not commercially mature	-Flow batteries can be used for many grid applications such as: load balancing, standby power and the integration of renewable energy sources. -In Dalian, China, there is a 200MW/800MWh capacity vanadium redox flow battery facility. The facility will provide power at peak times, grid stabilization and provide back-up supply.
Lithium-ion Battery	Lithium ion (Li-ion) batteries are a type of rechargeable battery in which lithium ions move from the negative electrode to the positive electrode during discharge and back when charging. They are commonly used in consumer electronic products, where a high energy density is required. The technology can be scaled up to distribution scale size and is commonly used in electric vehicles. The deployment of which is expected to drive down cost and improve performance. Research and development is on-going in various other chemistries of the battery type with a view to improving performance and reducing the cost.	- Li-ion batteries have an extremely high energy density, in the order of 400 Wh/l - Li-ion batteries can tolerate more discharge cycles than other technologies - High efficiency - Li-ion batteries have a higher cost than other technologies - Negative effects of overcharging/ over discharging - Potential for issues associated with overheating	Lithium-ion batteries can be used for many grid applications such as: frequency regulation, voltage regulation and the integration of renewable energy sources. In 2017, US utility company San Diego Gas and Electric opened a 30 MW battery facility based on Li-Ion batteries with 120 MWh of storage capacity. Similarly, in 2017, Tesla constructed the Hornsdale Power Reserve on the site of the Hornsdale Wind Farm in south Australia. It has a capacity of 100 MW/129 MWh, providing grid stability services and load shifting.
Flywheel	Flywheel energy storage makes use of the mechanical inertia contained within a rotating flywheel in order to store energy. Flywheels store electrical energy by using the electrical energy to spin a flywheel (usually by means of a reversible motor/generator). To retrieve the stored energy, the process is reversed with the motor that accelerated the flywheel acting as a brake extracting energy from the rotating flywheel. To reduce friction losses, it is common to place the flywheels inside a vacuum with the actual flywheel magnetically levitated instead of using conventional bearings.	- Rapid response times - Low maintenance requirements - Effective way of maintaining power quality - Virtually unlimited number of charge/discharge cycles - Must be housed in robust containers, in order to contain fragments if the flywheel fails - Variable speed rotation as energy is extracted - Requirement for precision engineered components - High price	Flywheels as energy storage devices are more suited to improving power quality by smoothing fluctuations in generation, as opposed to having long output durations. This is because of the ability of flywheels to rapidly charge and discharge. Controlling grid frequency is an important feature and the need for this service will increase as the penetration of intermittent generating units increase. There are limited grid scale installations to date, an example being an installation in New York state, USA. The plant operates continuously, storing and returning energy to the grid to provide approximately 10% of the local state's overall frequency regulation needs
Hydrogen	"Green gaseous hydrogen can be produced using renewable electricity and an electrolyzer. The electrolyzer splits water into its constituent elements, hydrogen and water. Hydrogen can then be stored for long periods of time and transported to different regions to balance renewable energy supply and demand. Electricity produced from hydrogen is well understood and can be achieved using a variety of equipment including (fuel cells, turbines and generators) Intermittency of renewable electricity along with variability of energy demand creates a growing demand for energy storage. "	- Emissions at the point of use are water vapors, NOx emissions are lower in hydrogen consumption than fossil fuel consumption if equipment is designed appropriately - Can be transported from the point of production to the point of demand if required - Can be used to power vehicles and as a feedstock in industrial applications in addition to grid storage - Stored hydrogen can be used any time without self-discharge - Low round trip efficiencies (~40%) - Low volumetric energy density - There are potential safety concerns over the storage of hydrogen - Fuel cell and hydrogen production technologies are currently expensive but costs are expected to fall with economies of scale	See Section 2

Detailed Key Assumptions

Solar and wind data & site selection criteria are discussed below:

Solar and wind infrastructure performance is based on datasets generated using the Ministerio de Energia renewables web tool, which is derived from a single location adjacent to each grid and normalized as a timeseries capacity factor (kWh/kW).

- The single location was determined by selecting the intermediate of three different locations 3 km from a central grid location with respect to capacity factor. In general, each site was selected to maximize distance from each other while avoiding visible conflicts.

- Where multiple generation sites exist, a location with connection to large fossil fuel generation infrastructure that would be potentially replaced by renewables was selected to look at opportunities where existing transmission infrastructure can be leveraged.

- A site assessment was not in the scope of this work. In general, the selected sites for this modelling exercise may be inadequate locations for the cost optimal system for each scenario. This modelling exercise could be enhanced alongside a site assessment to produce more granular results.

- For each solar site, angles were optimized at each site to generate solar data.

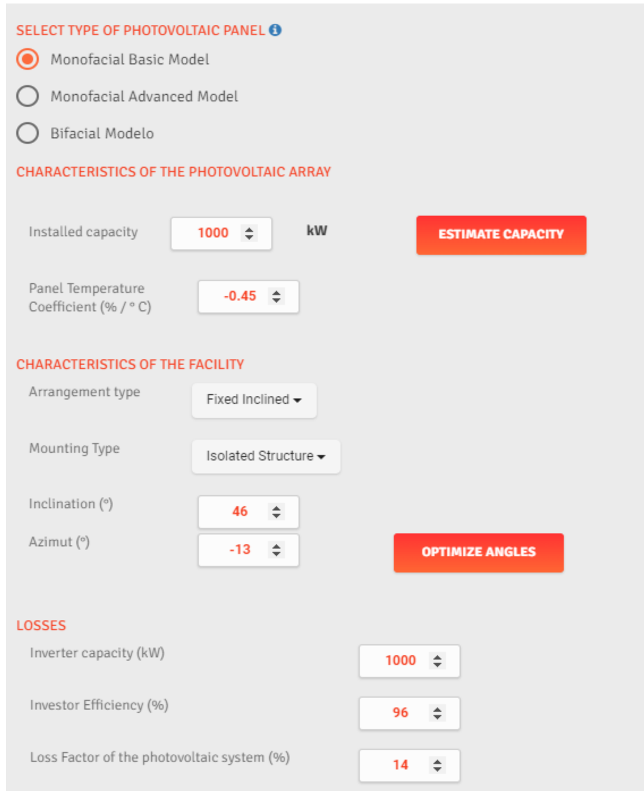
- Detailed information pertaining to the site selection criteria can be found in the detailed breakdown of each grid in Sections 3.1.2-3.1.6.

Each wind generation profile was generated using the following settings:

Figure 48:
Screenshot of assumptions used to generate wind generation profiles (Source: Ministerio de Energia)

Each solar PV generation profile was generated using the following settings:

Figure 49:
Screenshot of assumptions used to generate solar PV generation profiles (Source: Ministerio de Energia)



Scenario development for modeling is discussed below:

In each scenario, the base price of fossil fuels in 2030 is derived from the price of fuel in each grid location, as supplied by the Ministry of Energy. Fuel prices were then subjected to a growth rate that is consistent with the reference case growth trajectory that is proportional to that employed by the Ministry of Energy in its Long Term Energy Planning process before applying a carbon tax as discussed in the Section 2.2.1. Detailed calculations and assumptions for fuel prices for each grid can be found in the Appendix.

Following the discussion of the scenarios in Section 2.1, the baseline scenario considers a carbon price that is on the low end of International carbon pricing systems. A carbon price of 35 USD/ton CO2 emissions is applied to each technology based on emissions factors for power generation consistent with the Low Carbon Fuel Standard (LCFS). Renewable technologies do not fall more than what is conservatively projected for 2030. This rate was determined by comparing current wind and solar costs in Chile to equivalent prices used by IRENA. Based on the comparison a factor was applied to determine the high cost of wind and solar technology for Chile in 2030 as shown in Table 38.

Table 38:
Renewable technology cost assumptions

CAPEX Assumptions (USD/kW)			
Technology	Current	2030 Low	2030 High
IRENA			
Wind	1497	800	1350
Solar	1210	340	834
Chile			
Wind	1497	800	1350
Solar	1210	340	834

Scenario 2 represents a scenario where the price of fossil fuel is subjected to the same growth rate as the baseline scenario up to 2030, however, the good scenario considers a carbon price that is on the high end of International carbon pricing systems. A carbon price of 80USD/tonCO2 emissions is applied to each technology based on emissions factors for power generation consistent with the Low Carbon Fuel Standard (LCFS). Like the Baseline scenario, the costs of renewable technologies do not fall more than what is conservatively projected as average for 2030.

Scenario 3 represents a scenario with fossil fuels emissions are subjected to a carbon price of 80USD/tonCO2 emissions and the cost of solar and wind technology falls to an optimistic level as projected by IRENA for 2030. All other technology costs remain the same. This scenario is employed to understand the sensitivity of a high carbon price on the technology mix and grid composition that satisfies the lowest cost of electricity related to each of the five grids.

Scenario 4 represents a scenario with fossil fuels emissions are subjected to a carbon price of 80USD/tonCO2 emissions and the cost of solar, wind and electrolyzer technology falls to an optimistic level as projected by IRENA for 2030. Fuel cell technology falls to a technology cost goal projected by NREL for 2030. All other technology costs remain the same.

The key assumptions specific to Punta Arenas are discussed below:

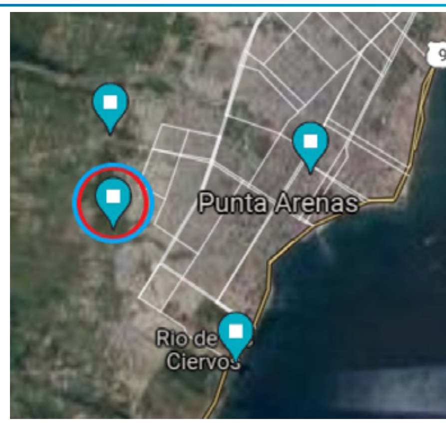
- Overall hourly electricity demand was based on projections for 2030 by the Ministerio de Energia
- Fuel prices were taken from Estudio de Planificación y Tarificación de los Sistemas Medianos de Punta Arenas, Puerto Natales, Porvenir y Puerto Williams, Tabla 134, which were converted to 2016 USD and then 2020 USD using information from Banco Central de Chile and US Bureau of Labor Statistics, respectively. A growth rate from 2016 to 2030 based on fuel prices provided by the Ministerio de Energia
- Technology included for modelling included gas turbine, diesel engine, solar PV, onshore wind, fuel cell for power generation; lithium-ion battery, vanadium redox flow battery, aboveground hydrogen storage, fuel cell, flywheel for storage; and hydrogen electrolyzer for hydrogen generation

Renewable Site Selection:

Table 39:
Renewable site selection exercise for Punta Arenas

Site	Type	Latitude	Longitude	Annual Generation Potential (kWh)	Capacity Factor (%)
1	Solar	-53.18	-70.92	1,104,741	13
2		-53.15	-70.96	1,124,802	13
3		-53.16	-70.95	1,120,666	13
1	Wind	-53.18	-70.92	6,648,991	38
2		-53.15	-70.96	7,827,164	44.7
3		-53.16	-70.95	7,432,503	42.4

Figure 41:
Screenshot of renewable sites evaluated for model, sites circled in blue indicate the point where the wind data was taken and sites circled in red indicate the point where the solar data was taken for modelling



A characterization of the variables and their values used for the scenario analysis can be found in Table 40 below:

Table 40:
Variables per scenario for Punta Arenas

Technology	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Fuel Cost USD/kW			
Diesel	0.103	0.137	0.137	0.137
Gas	0.051	0.079	0.079	0.079

The key assumptions specific to Puerto Natales are discussed below:

- Overall hourly electricity demand was based on projections for 2030 by the Ministerio de Energia

- Fuel prices were taken from Estudio de Planificación y Tarificación de los Sistemas Medianos de Punta Arenas, Puerto Natales, Porvenir y Puerto Williams, Tabla 134, which were converted to 2016 USD and then 2020 USD using information from Banco Central de Chile and US Bureau of Labor Statistics, respectively. A growth rate from 2016 to 2030 based on fuel prices provided by the Ministerio de Energia

- Technology included for modelling included gas engine, diesel engine, solar PV, onshore wind, fuel cell for power generation; lithium-ion battery, vanadium redox flow battery, aboveground hydrogen storage, fuel cell, flywheel for storage; and hydrogen electrolyzer for hydrogen generation

Renewable Site Selection:

Site	Type	Latitude	Longitude	Annual Generation Potential (kWh)	Capacity Factor (%)
1	Solar	-51.71	-72.5	1,043,131	12
2		-51.73	-72.44	1,077,428	12
3		-51.75	-72.45	1,076,416	12
1	Wind	-51.71	-72.5	6,937,207	39.6
2		-51.73	-72.44	6,880,088	39.3
3		-51.75	-72.45	6,536,693	37.3

Table 41:
Renewable site selection exercise for Puerto Natales

Figure 50:
Screenshot of renewable sites evaluated for model, sites circled in blue indicate the point where the wind data was taken and sites circled in red indicate the point where the solar data was taken for modelling

A characterization of the variables and their values used for the scenario analysis can be found in Table 40 below:

Technology	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Fuel Cost USD/kW			
Diesel	0.104	0.138	0.138	0.138
Gas	0.050	0.077	0.077	0.077

Table 42:
Variables per scenario for Puerto Natales

The key assumptions specific to Isla de Pascua are discussed below:

- For Isla de Pascua, 2018 historical data was scaled based on a projected, increased consumption rate for 2030 taken from Figure 17 in report "Estrategia Energetica para el Desarrollo de la Energia Marina en Comunidades Costeras de la Region de Valparaiso"

- Fuel prices were taken from Expenses incurred between July 2019 and June 2020 are considered, provided by the Ministerio de Energia, which were converted to 2020 USD using information from Banco Central de Chile. A growth rate from 2020 to 2030 based on fuel prices provided by the Ministerio de Energia

- Technology included for modelling included diesel engine, solar PV, onshore wind, fuel cell for power generation; lithium-ion battery, vanadium redox flow battery, aboveground hydrogen storage, fuel cell, flywheel for storage; and hydrogen electrolyzer for hydrogen generation

- In the Baseline – H2 scenario, technologies options included the above mentioned minus and electrolyzer, aboveground hydrogen storage and fuel cell

Tidal power was not included in this study, however, it is recommended that a future study of this nature include tidal energy as a possible pathway in the analysis to determine its viability as a method for producing the lowest cost electricity for Isla de Pascua.

See the overall methodology for site selection criteria. The following information pertains to the wind and solar generation site selection process for the Isla de Pascua grid model:

Table 43:
Renewable site selection exercise for Isla de Pascua

Site	Type	Latitude	Longitude	Annual Generation Potential (kWh)	Capacity Factor (%)
1	Solar	-109.45	-27.18	6,001,251	34.3
2		-109.41	-27.17	3,459,266	19.7
3		-109.43	-27.13	3,790,274	21.6
1	Wind	-109.45	-27.18	1,219,742	14
2		-109.41	-27.17	1,292,844	15
3		-109.43	-27.13	1,297,380	14.8

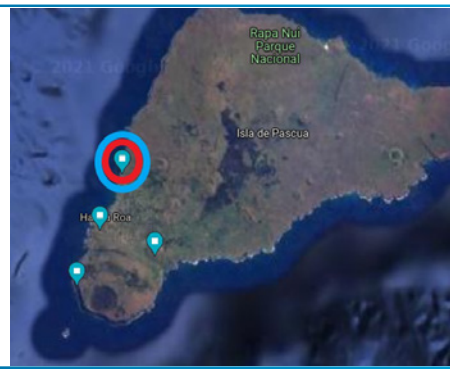


Figure 51:
Wind (blue) and solar (red) locations used for site selection for Isla de Pascua

A characterization of the variables and their values used for the scenario analysis can be found in Table 44 below:

Table 44:
Variables per scenario for Isla de Pascua

Technology	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
	CAPEX (USD/kW)				
Fuel Cell	N/A	1000	1000	1000	800
Electrolyzer	N/A	700	700	700	450
Wind	1140	1140	1140	800	800
Solar	540	540	540	340	340
	Fuel Cost USD/kW				
Diesel	0.143	0.143	0.177	0.177	0.177

The key assumptions specific to Aysen are discussed below:

- Overall hourly electricity demand was based on projections for 2030 by the Ministerio de Energia

- Fuel prices were taken Estudio de Planificación y Tarificación de los Sistemas Medianos de Aysén, Palena, General Carrera, Cochamó y Hornopiré, which were converted to 2016 USD and then 2020 USD using information from Banco Central de Chile and US Bureau of Labor Statistics, respectively. A growth rate from 2016 to 2030 based on fuel prices provided by the Ministerio de Energia

- Technology included for modelling included hydro-electric power, diesel engine, solar PV, onshore wind, fuel cell for power generation; lithium-ion battery, vanadium redox flow battery, aboveground hydrogen storage, fuel cell, flywheel for storage; and hydrogen electrolyzer for hydrogen generation

- Hydro infrastructure performance was set based on 2030 demand projections provided by the Ministerio de Energia – additional hydro resources were not assessed as an option for the cost optimization due to both the contextual complexity and the decreasing utilization of hydro infrastructure due to droughts

Renewable Site Selection:

Site	Type	Latitude	Longitude	Annual Generation Potential (kWh)	Capacity Factor (%)
1	Solar	-45.6	-72.13	1,267,477	14
2		-45.64	-72.13	1,258,264	14
3		-45.62	-72.1	1,260,774	14
1	Wind	-45.6	-72.13	3,513,067	20.1
2		-45.64	-72.13	3,271,396	18.7
3		-45.62	-72.1	3,375,193	19.3

Table 45:
Renewable site selection exercise for Aysen

Figure 52:
Wind (blue) and solar (red) locations used for site selection for Aysen

A characterization of the variables and their values used for the scenario analysis can be found in Table 46 below:

Technology	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Fuel Cost USD/kW			
Diesel	0.101	0.135	0.135	0.135

Table 46:
Variables per scenario for Aysen

The key assumptions specific to San Pedro de Atacama are discussed below:

- A bespoke demand profile was developed based on information provided by Ministerio de Energía and energy modelling expertise; see Appendix for detailed calculations

- Fuel prices were taken from Formulario 1 – Anos 2020 provided by the Ministerio de Energia, which were converted to 2020 USD using information from Banco Central de Chile. A growth rate from 2020 to 2030 based on fuel prices provided by the Ministerio de Energia

- Technology included for modelling included gas engine, diesel engine, solar PV, onshore wind, fuel cell for power generation; lithium-ion battery, vanadium redox flow battery, aboveground hydrogen storage, fuel cell, flywheel for storage; and hydrogen electrolyzer for hydrogen generation

Renewable Site Selection:

Table 47:
Renewable site selection exercise for San Pedro de Atacama

Site	Type	Latitude	Longitude	Annual Generation Potential (kWh)	Capacity Factor (%)
1	Solar	-68.16	-22.98	1951014	22
2		-68.18	-22.95	1948166	22
3		-68.13	-22.98	1947385	22
1	Wind	-68.16	-22.98	1202205	6.9
2		-68.18	-22.95	1253231	7.2
3		-68.13	-22.98	992484	5.7

Figure 53:
Wind (blue) and solar (red) locations used for site selection for San Pedro de Atacama

The scenarios for San Pedro de Atacama are shown in Table 48 below:

Table 48:
Variables per scenario for San Pedro de Atacama

Technology	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Fuel Cost USD/kW			
Diesel	0.123	0.157	0.157	0.157
Gas	0.084	0.112	0.112	0.112

Assumptions used to create the demand profile for San Pedro de Atacama are shown below:

Month	Total Consumption (Kwh/Month)	Days per Month	Number Of Weekends	Weekdays	Weekend Hours	Weekday Hours
Jan	911,970.41	31	8.00	23.00	192.00	552.00
Feb	1,091,131.75	28	8.00	20.00	192.00	480.00
Mar	820,858.34	31	10.00	21.00	240.00	504.00
Apr	974,171.69	30	8.00	22.00	192.00	528.00
May	754,095.64	31	8.00	23.00	192.00	552.00
Jun	911,898.00	30	10.00	20.00	240.00	480.00
Jul	811,303.83	31	8.00	23.00	192.00	552.00
Aug	872,078.91	31	9.00	22.00	216.00	528.00
Sept	804,523.87	30	9.00	21.00	216.00	504.00
Oct	796,390.11	31	8.00	23.00	192.00	552.00
Nov	797,914.68	30	9.00	21.00	216.00	504.00
Dec	801,089.50	31	9.00	22.00	216.00	528.00

Weekend Hour Total

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Residential	2	1	1	1	1	2	3	6	6	3	3	3	3	3	3	3	6	8	10	10	8	8	6	4
School	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mail	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Church	1	1	1	1	2	3	4	8	8	10	10	10	8	4	3	4	10	10	10	10	6	4	1	1
Commercial	2	2	1	1	4	5	5	4	4	4	4	8	8	10	9	9	10	6	6	6	6	4	2	1
Lighting	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10
Museum	2	2	2	2	2	2	2	4	6	6	8	8	8	8	8	8	8	6	4	1	1	1	1	1

Weekday Hourly Load Profile

	kWh/month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Residential	496,998.27	2	1	1	1	1	2	3	6	6	3	3	3		3	3	3	6	8	10	10	8	8	6	4
School	6,882.41	1	1	1	1	2	2	3	6	9	9	8	10	10	8	8	8	6	5	4	1	1	1	1	1
Mail	1,685.77	1	1	1	1	2	2	6	6	6	10	10	10	10	10	10	8	4	2	1	1	1	1	1	1
Church	486.33	1	1	1	1	1	1	1	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
Commercial	298,550.32	1	1	1	1	1	2	2	4	6	6	8	8	8	8	6	4	4	6	8	8	6	1	1	1
Lighting	55,805.20	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10
Museum	186,222.71	2	2	2	2	2	2	2	4	6	6	8	8	8	8	8	8	8	6	4	1	1	1	1	1
2020 hourly Subsidized Loads (kwh)	1,046,631.02																								
2020 Total Yearly Demand	10,347,426.72																								

Table 49:
San Pedro de Atacama load profile assumptions

Detailed Results

Estimated emission Reduction data is shown below for each grid:

2030 CO2 emissions (ktCo2/year) per scenario					
Demand Projection*	No H2	Baseline Scenario 1	Scenario 2	Scenario 3	Scenario 4
16.91	1.1	0.56	0.32	0.27	0.22

Table 50:
2030 Isla de Pascua 2030 carbon emissions (ktCO2/year) per scenario *(demand projection figure assumes 2020 infrastructure makeup based on Formularios para Isla de Pascua in 2020)

Annual Profiles:

In each scenario, a yearly cost optimized technology mix and generation profile was determined through modeling. See below for Calliope outputs depicting the cost optimal grid system behavior in each scenario:

Figure 54: 2030 Punta Arenas Baseline Scenario 1 system generation profile

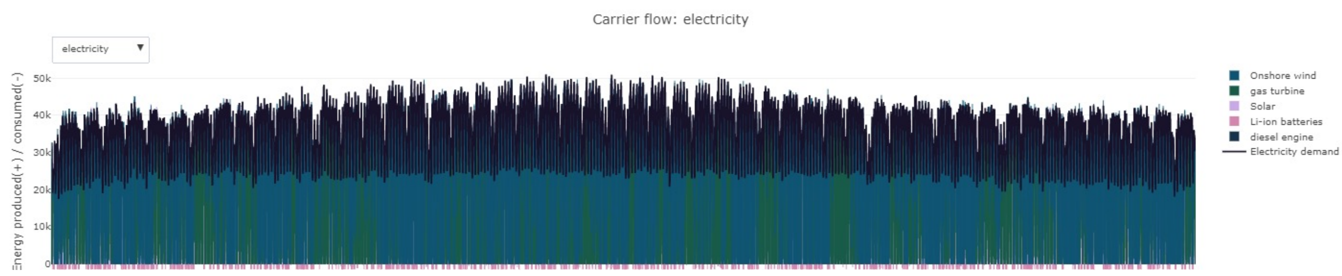


Figure 55: 2030 Punta Arenas Baseline Scenario 1 system storage profile

Figure 56: 2030 Punta Arenas Scenario 2 system generation profile

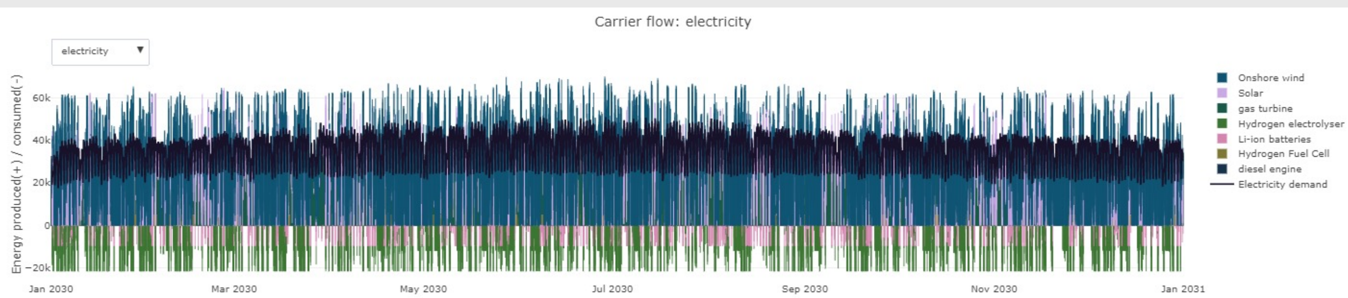


Figure 57: 2030 Punta Arenas Scenario 2 system storage profile

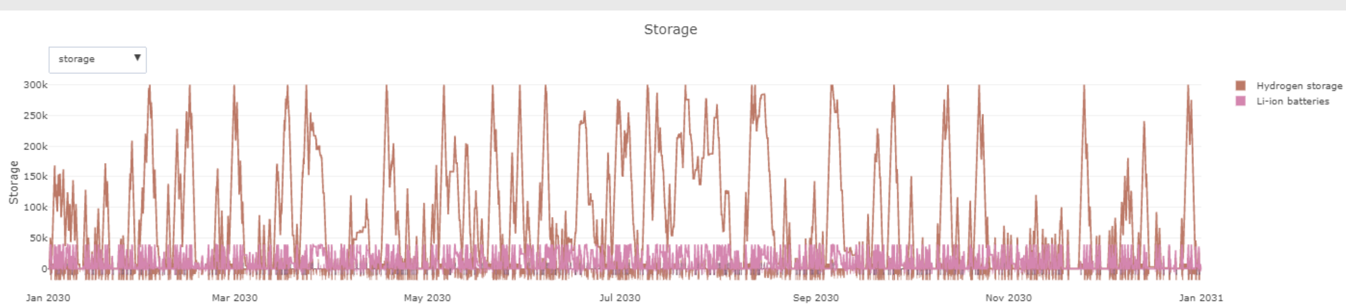


Figure 54: 2030 Punta Arenas Baseline Scenario 1 system generation profile

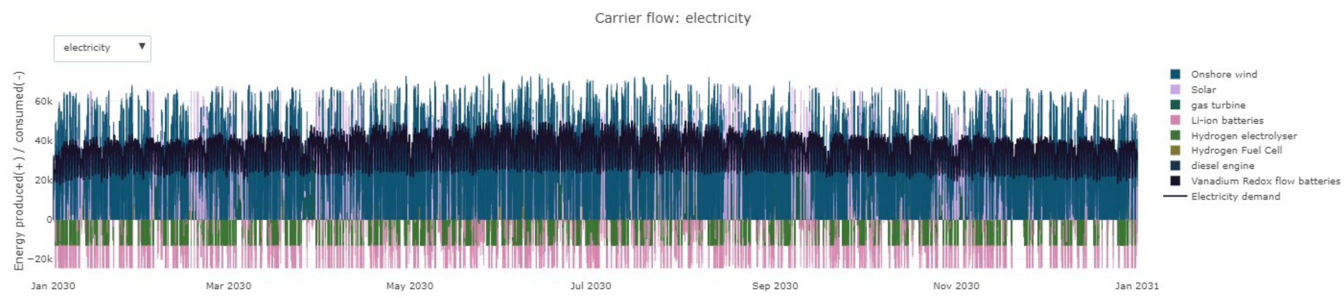


Figure 58: 2030 Punta Arenas Scenario 3 system generation profile

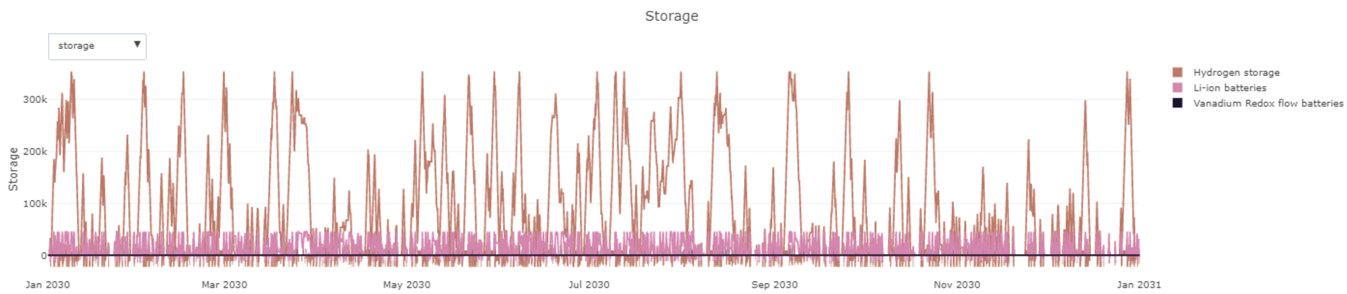


Figure 60: 2030 Punta Arenas Scenario 4 system generation profile

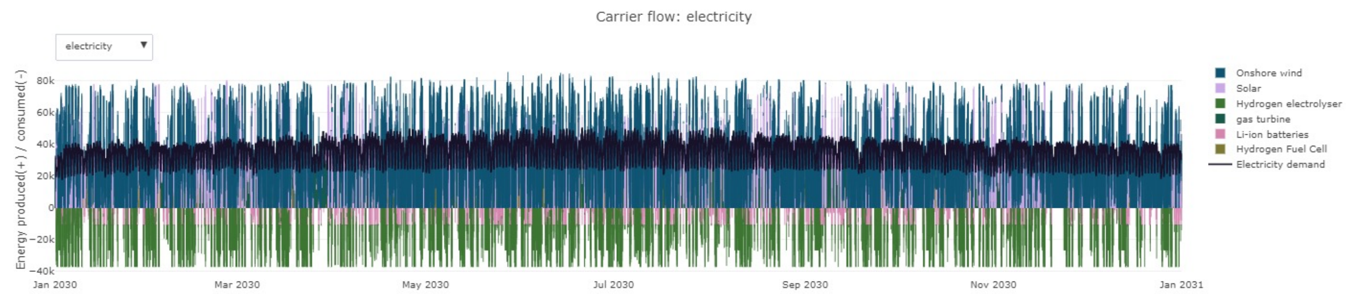


Figure 61: 2030 Punta Arenas Scenario 4 system storage profile

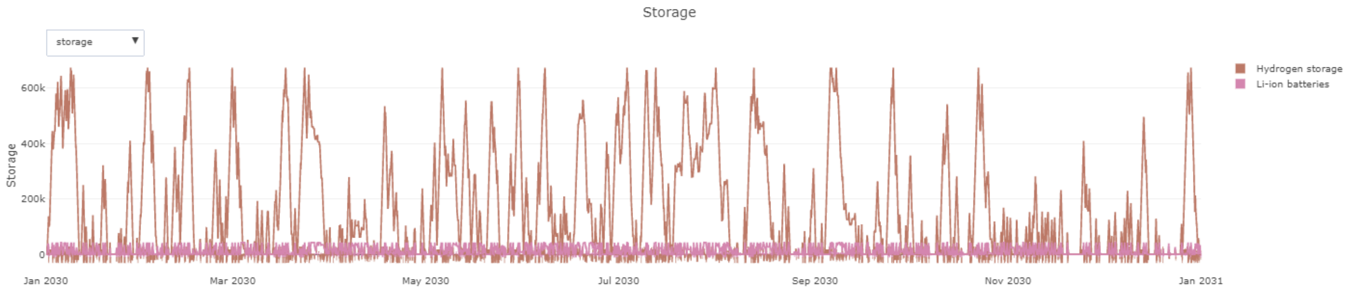


Figure 62: 2030 Puerto Natales Baseline Scenario 1 system generation profile

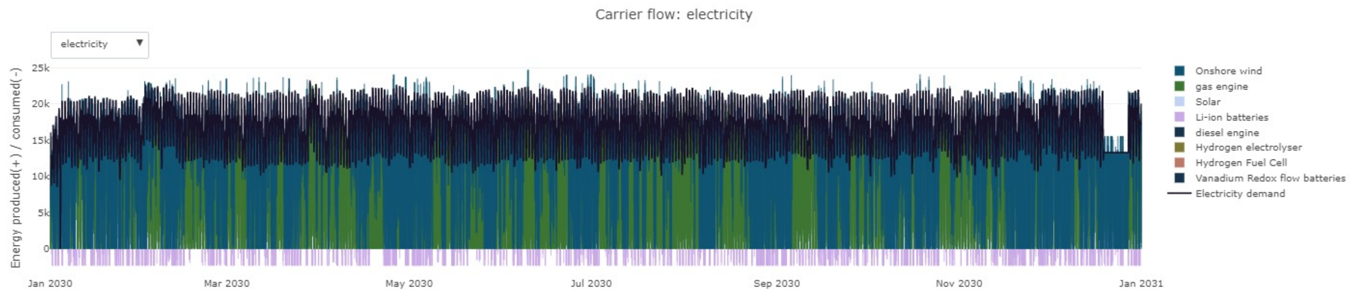


Figure 63: 2030 Puerto Natales Baseline Scenario 1 system storage profile

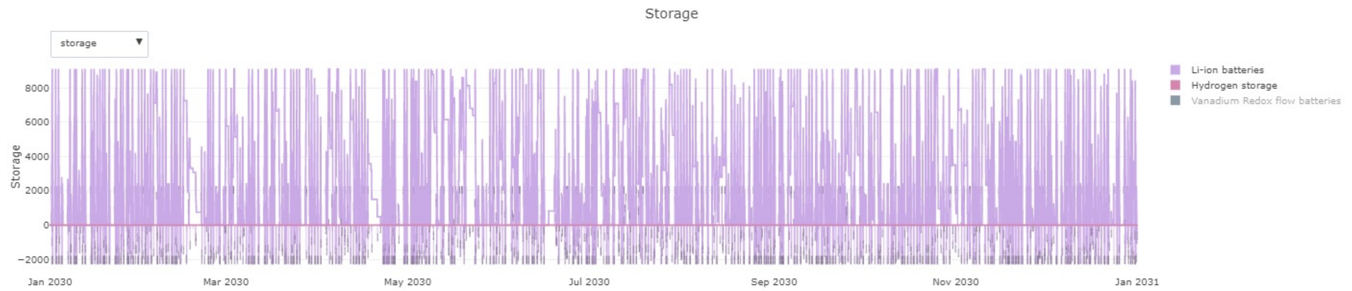


Figure 64: 2030 Puerto Natales Scenario 2 system generation profile

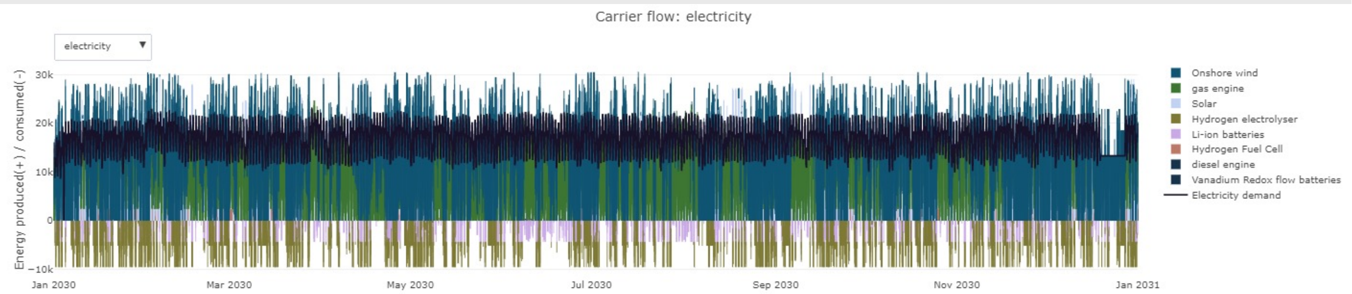


Figure 65: 2030 Puerto Natales Scenario 2 system storage profile

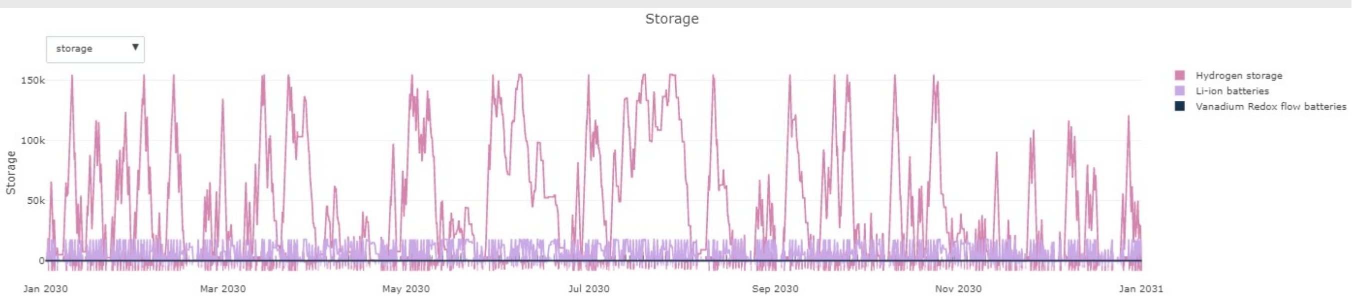


Figure 66: 2030 Puerto Natales Scenario 3 system generation profile

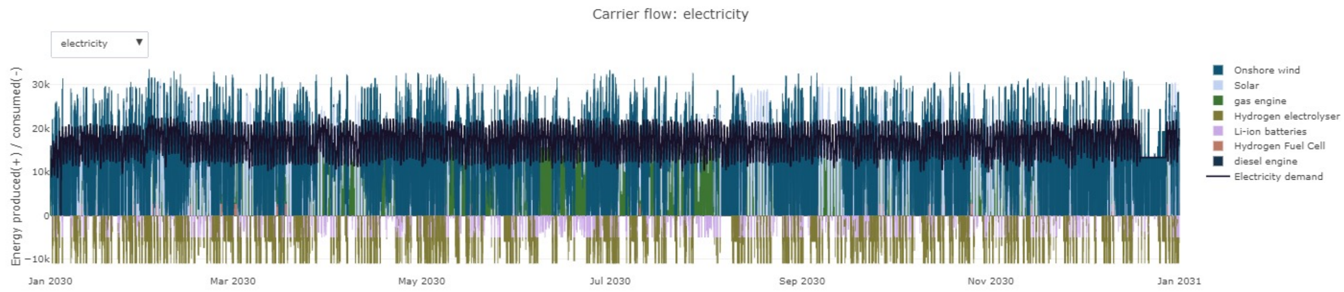


Figure 67: 2030 Puerto Natales Scenario 3 system storage profile

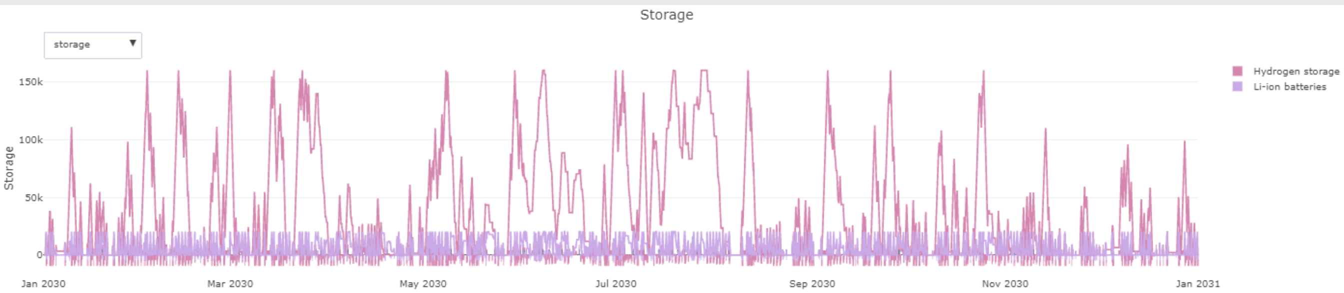


Figure 68: 2030 Puerto Natales Scenario 4 system generation profile

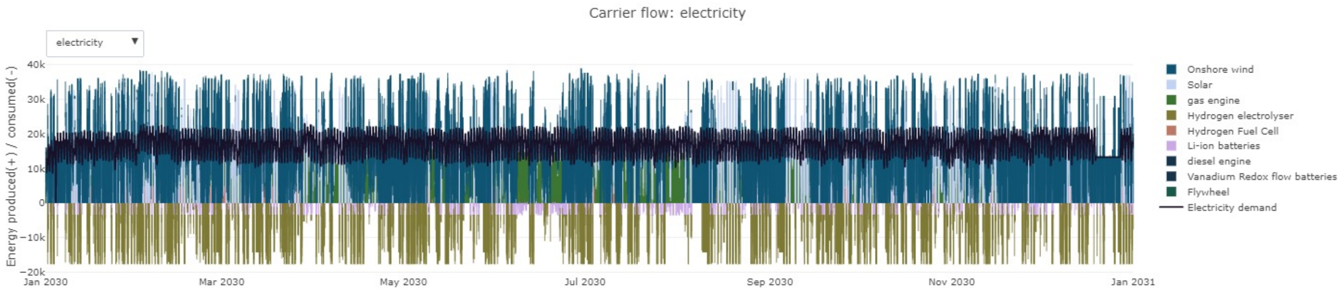


Figure 69: 2030 Puerto Natales Scenario 4 system storage profile

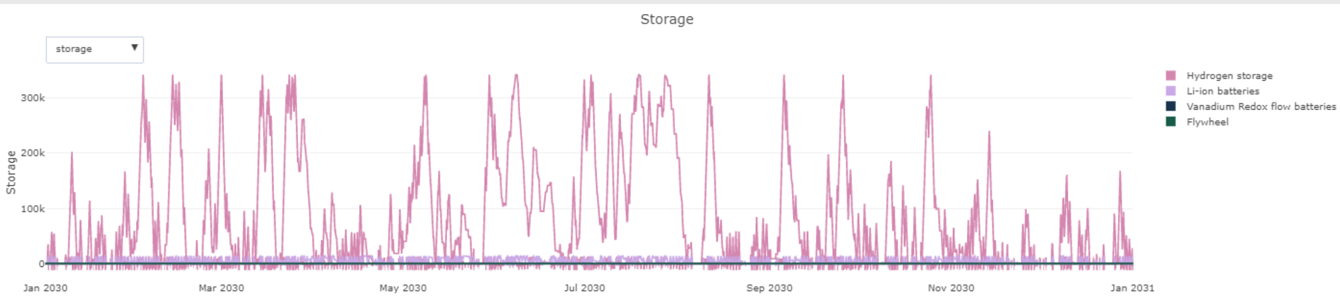


Figure 70: 2030 Isla de Pascua Baseline Scenario 1 system generation profile

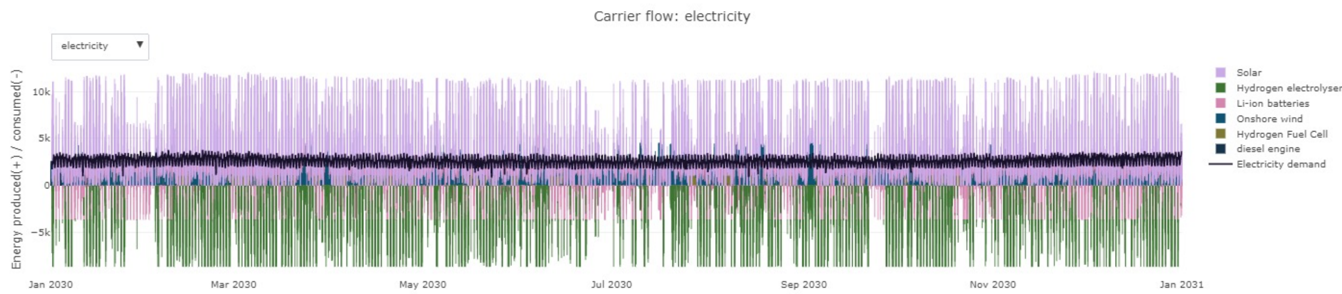


Figure 71: 2030 Isla de Pascua Baseline Scenario 1 system storage profile

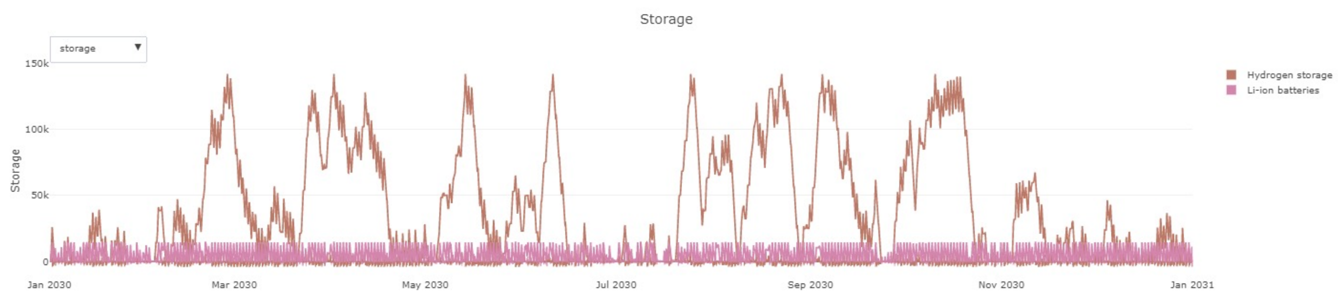


Figure 72: 2030 Isla de Pascua Scenario 2 system generation profile

Figure 73: 2030 Isla de Pascua Scenario 2 system storage profile

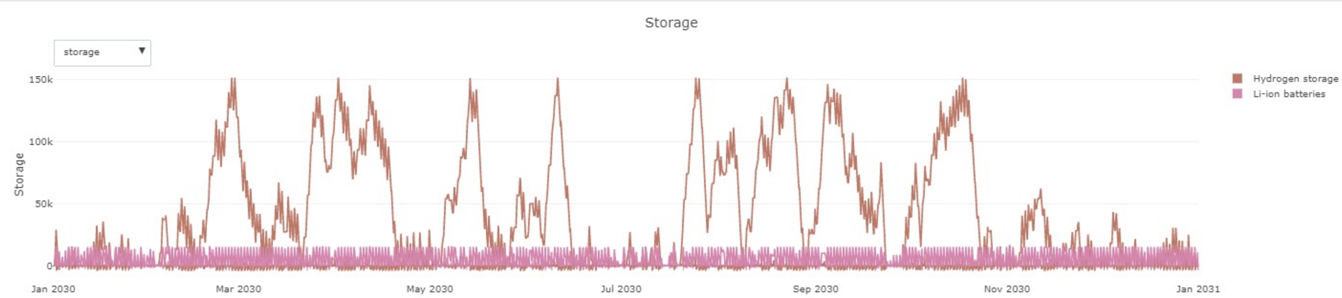


Figure 74: 2030 Isla de Pascua Scenario 3 system generation profile

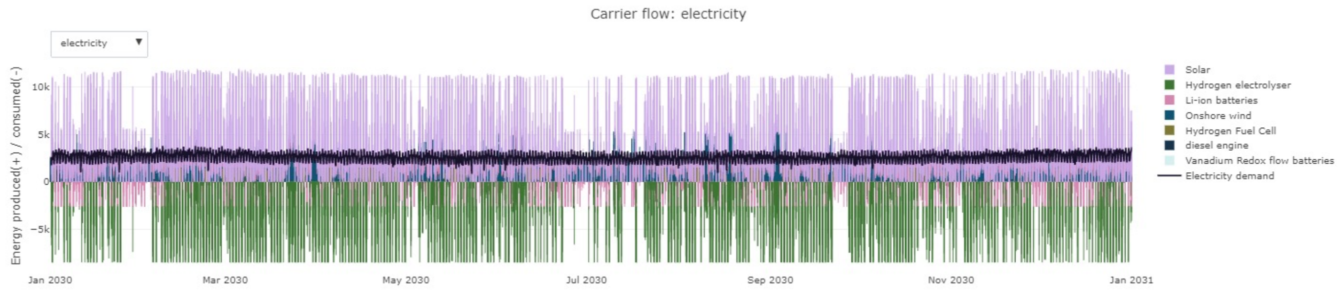


Figure 75: 2030 Isla de Pascua Scenario 3 system storage profile

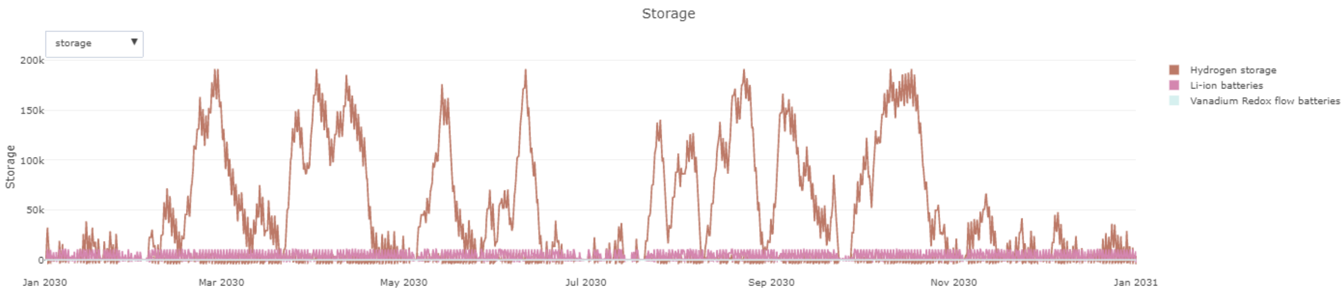


Figure 76: 2030 Isla de Pascua Scenario 4 system generation profile

Figure 77: 2030 Isla de Pascua Scenario 4 system storage profile

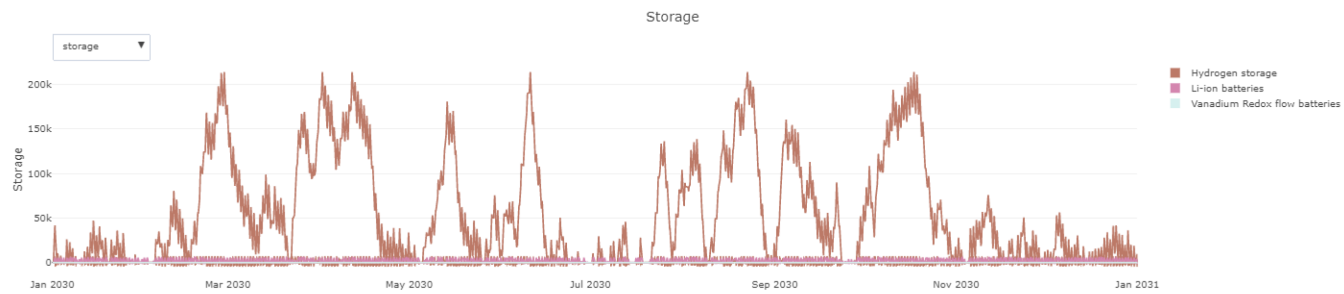


Figure 78: 2030 Aysen Baseline Scenario 1 system generation profile

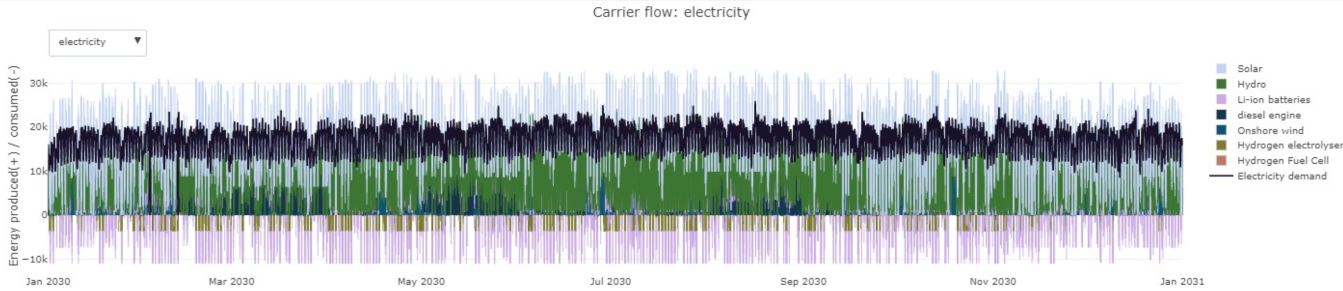


Figure 79: 2030 Aysen Baseline Scenario 1 system storage profile

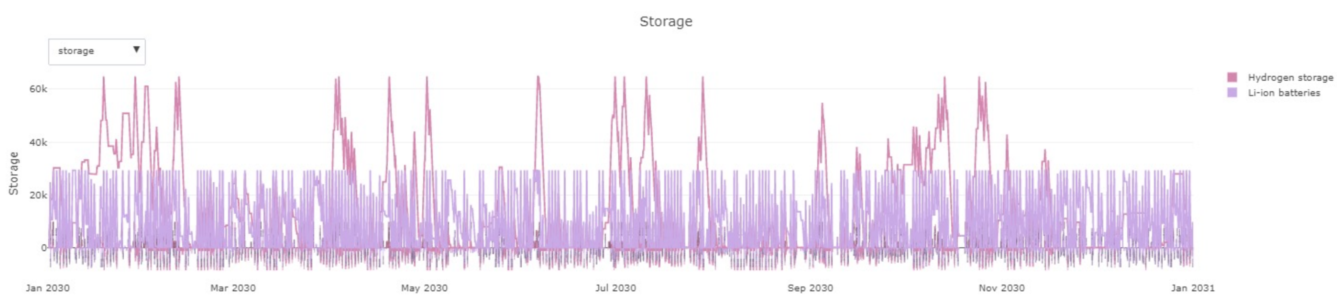


Figure 80: 2030 Aysen Scenario 2 system generation profile

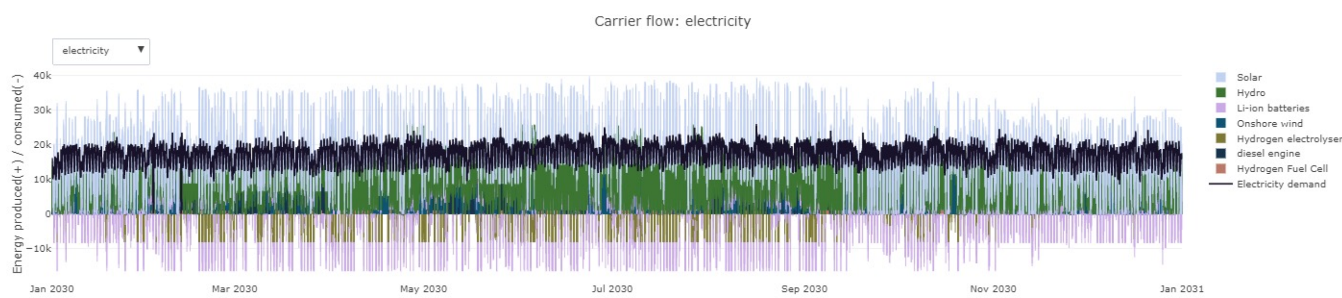


Figure 81: 2030 Aysen Scenario 2 system storage profile

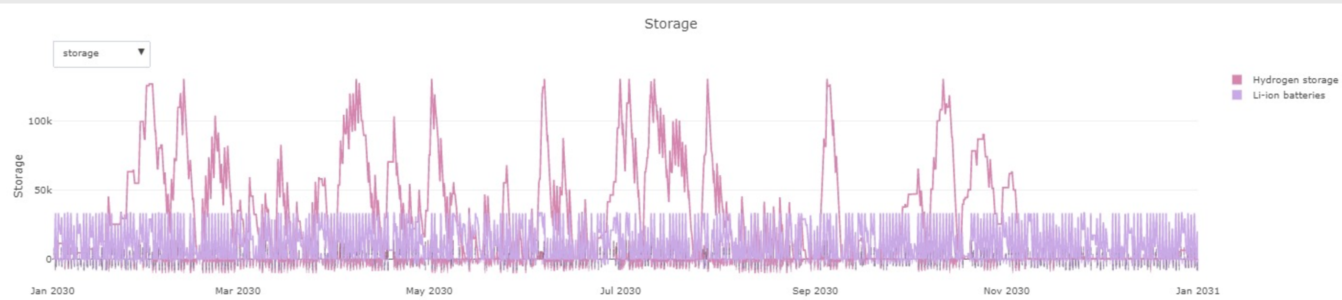


Figure 82: 2030 Aysen Scenario 3 system generation profile

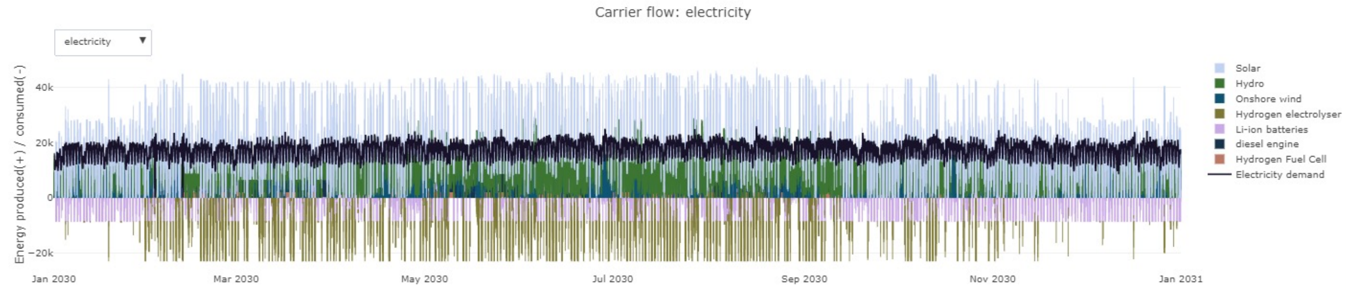


Figure 83: 2030 Aysen Scenario 3 system storage profile

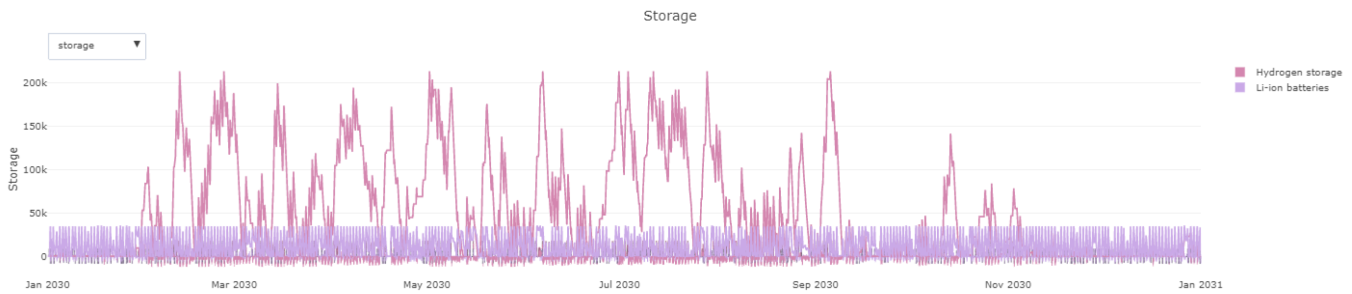


Figure 84: 2030 Aysen Scenario 4 system generation profile

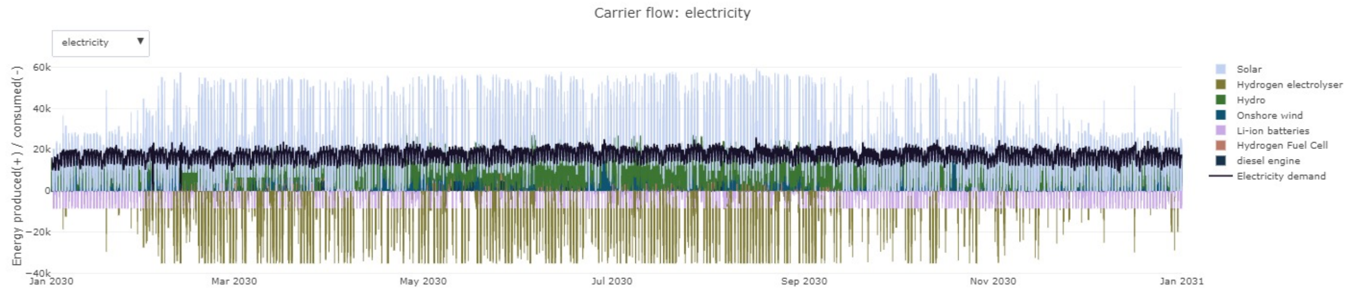


Figure 85: 2030 Aysen Scenario 4 system storage profile

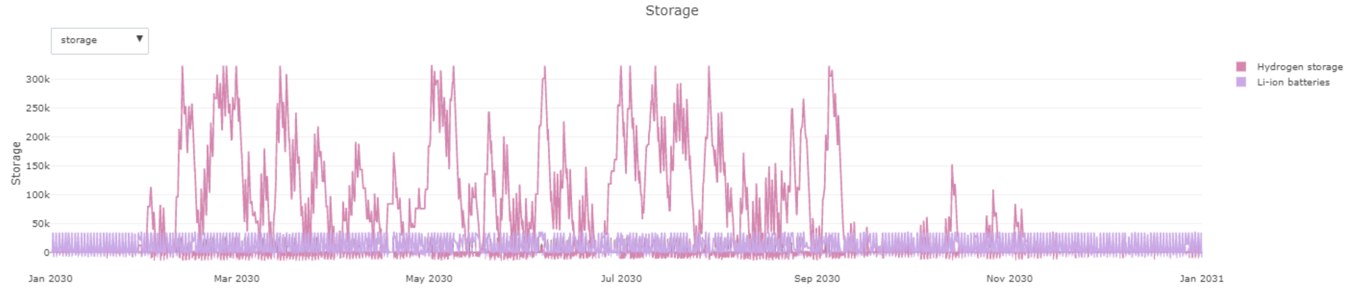


Figure 86: 2030 San Pedro de Atacama Baseline Scenario 1 system generation profile

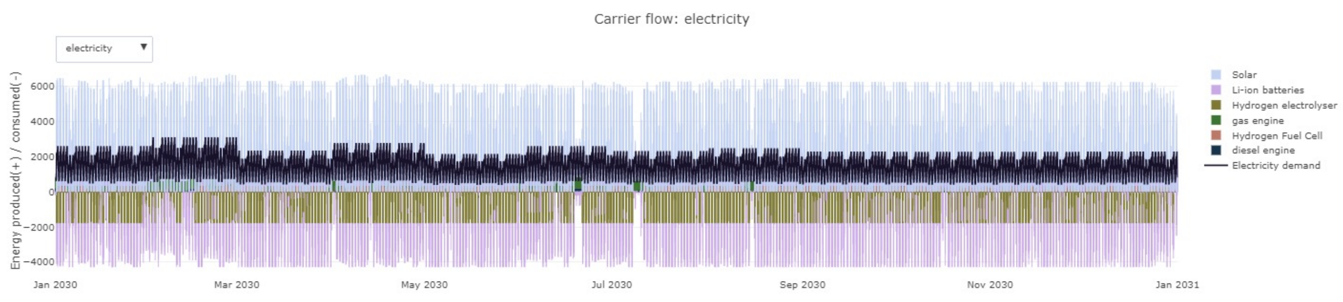


Figure 87: 2030 San Pedro de Atacama Baseline Scenario 1 system storage profile

Figure 88: 2030 San Pedro de Atacama Scenario 2 system generation profile

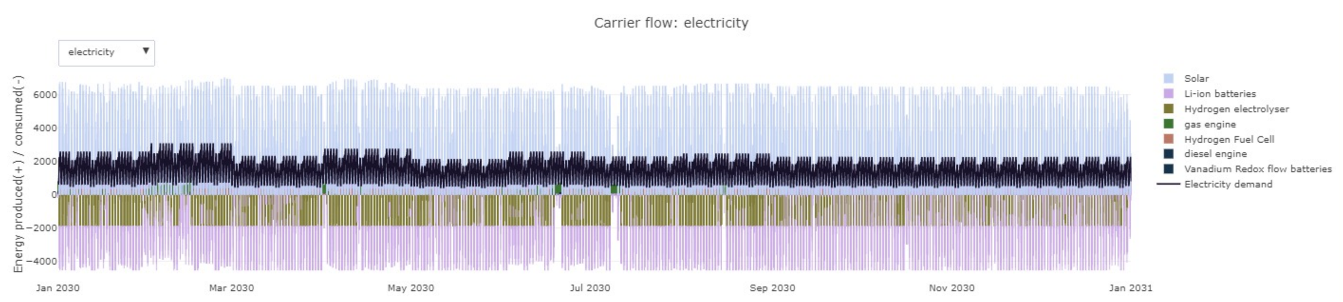


Figure 89: 2030 San Pedro de Atacama Scenario 2 system storage profile

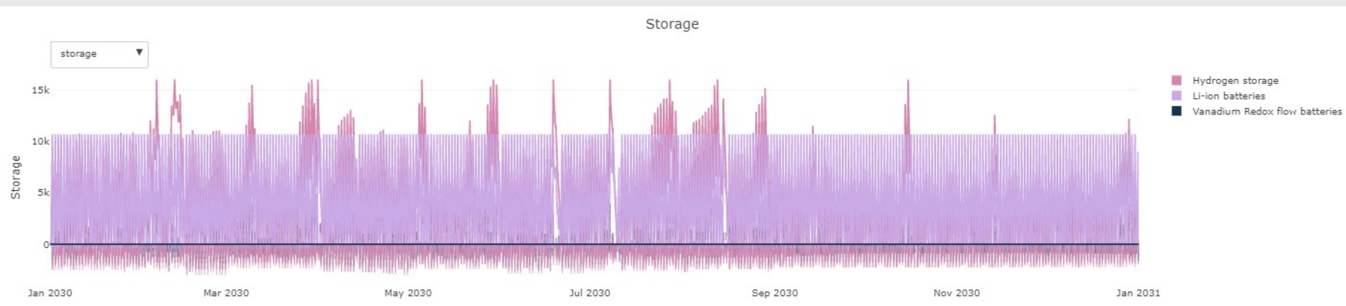


Figure 90: 2030 San Pedro de Atacama Scenario 3 system generation profile

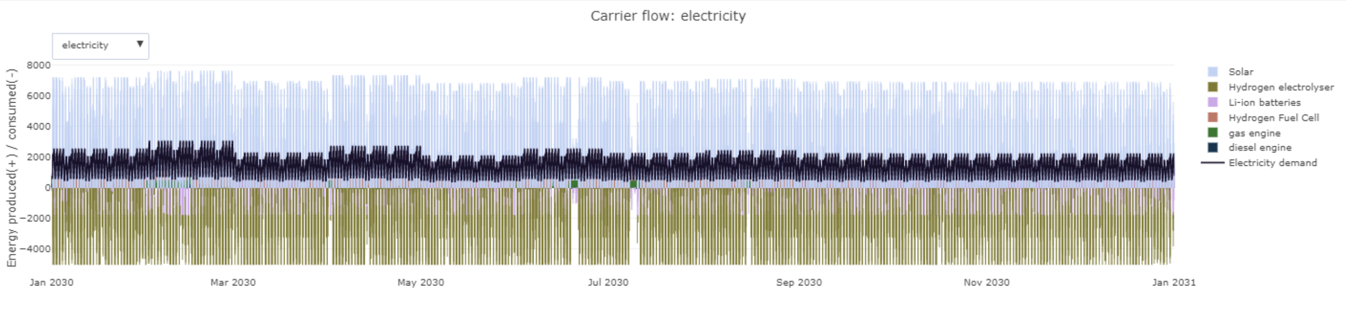


Figure 91: 2030 San Pedro de Atacama Scenario 3 system storage profile

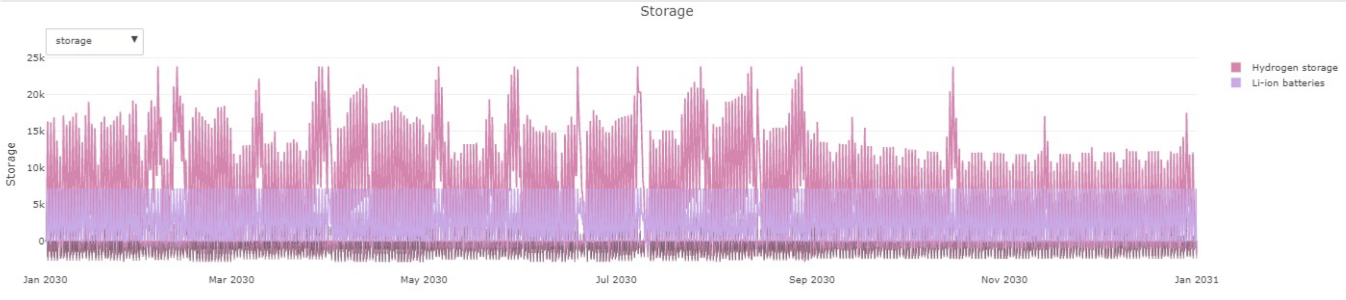


Figure 92: 2030 San Pedro de Atacama Scenario 4 system generation profile

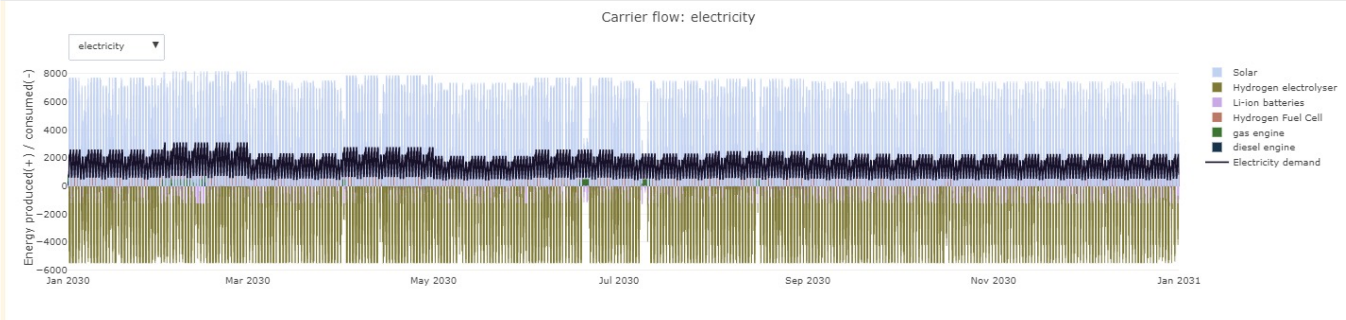


Figure 93: 2030 San Pedro de Atacama Scenario 4 system storage profile

Detailed Modelling Assumptions – Technologies

Table 51: Detailed assumptions

Variable (2030)	Value	Unit	Source
Fuel Cell Technology			
Energy Efficiency	60	%	https://www.energy.gov/eere/fuelcells/comparison-fuel-cell-technologies
Lifespan	10000	hours	https://www.energy.gov/eere/fuelcells/fuel-cells
CAPEX	1000	USD/kw	https://www.hydrogen.energy.gov/pdfs/review20/fc332_wei_2020_o.pdf
Fixed OPEX	3.5	%	https://www.hydrogen.energy.gov/pdfs/20001-reversible-fuel-cell-targets.pdf
Onshore Wind Technology			
Lifespan	25	Años (years)	MoE
CAPEX	1140	USD/kW	MoE + adjusted for 2030, https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf
Non fuel variable OPEX	0	USD/MWh	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 14
Fixed OPEX	1.5	%	Arup, past projects
Turbine Performance/Capacity Factor	data/2MW	KWh/KW	http://eolico.minenergia.cl/potencia
Gas Turbine Technology			
Energy Efficiency	0.38	fraction	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 13
Lifespan	20	years	site info tab, MoE
Non fuel variable OPEX	0.004	USD/kWh	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 14
CAPEX	668	USD/kW	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 12
Fixed OPEX	0.03	fraction	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 15
Diesel Engine Technology			
Energy Efficiency	30	%	Arup estimate, past projects
Lifespan	20	years	site info tab, MoE
Non fuel variable OPEX	0.01	USD/kWh	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 14
CAPEX	448	USD/kW	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 12
Fixed OPEX	0.047	USD/kW	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 15
Flywheel Technology			
Energy Efficiency	85	%	https://www.arup.com/perspectives/publications/research/section/five-minute-guide-to-electricity-storage
Lifespan	40	years	https://doi.org/10.1016/j.joule.2018.12.009
Minimum Charge Capacity requirement	0.5		Arup estimate, past projects
Loss per storage	10	%/day	Arup estimate, past projects
CAPEX	600	USD/kW	https://doi.org/10.1016/j.joule.2018.12.008
Storage Operating Cost	3000	USD/kWh	https://doi.org/10.1016/j.joule.2018.12.009
Lithium Ion Battery Technology			
Energy Efficiency	0.927	fraction	Arup estimate, past projects
Lifespan	10	Años (years)	Arup estimate, past projects
C factor (discharge/storage capacity)	0.25		Arup estimate, past projects
Minimum Charge Capacity requirement	0.2	fraction	Arup estimate, past projects
Storage Cost	366.96	USD/kWh	Arup estimate, past projects
Hydrogen Electrolyzer Technology			
Energy Efficiency	65	%	Arup estimate, past projects
Lifespan	25	years	Arup estimate, past projects
Non fuel variable OPEX	0.003	USD/kW	Arup estimate, past projects
CAPEX	700	USD/kW	https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf
Fixed OPEX	1.5	%	IEA

Variable (2030)	Value	Unit	Source
Technology			
Lifespan	30	years	MoE
CAPEX	540	USD/kW	MoE, adjusted to 2030 https://irena.org/-/media/Files/IRENA/Agency/Publication/2019/Nov/IRENA_Future_of_Solar_PV_2019.pdf
Non fuel variable OPEX	0	USD/kWh	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 14
Fixed OPEX	0.01		Arup estimate, past projects
Solar Panel Performance	TMY data	kWh/kW	http://solar.minenergia.cl/fotovoltaico
Vanadium Flow Battery Technology			
Energy Efficiency	0.822		Arup estimate, past projects
Lifespan	15	years	Arup estimate, past projects
C Factor	0.25		Arup estimate, past projects
Minimum Charge Capacity requirement	0.1		Arup estimate, past projects
Storage Cost	754.3	USD/kW	Arup estimate, past projects
Hydrogen Storage Technology			
Lifespan	20	years	IEA
CAPEX	12.78	USD/kWh	Past projects, above ground storage at 20barg
Energy Efficiency	95	%	Arup estimate given storage system
Hydro Technology			
Energy Efficiency	n/a	fraction	Arup estimate, past projects
Lifespan	40	years	Arup estimate
Non fuel variable OPEX	0.031	USD/kWh	MoE, CVNC hidro, Aysen avg
CAPEX	4022	USD/kW	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 12
Fixed OPEX	0.03	fraction	MoE, Informe Costos Tecnologias de Generacion ICTG Junio 2021, Table 15
Installed Capacity	2030 projections	MW/hr	MoE (demand projections), hydro load

Job Creation Assumptions

Table 52: Job creation assumptions

Technology	MCI (Jobs per newly installed MW)	O&M (Jobs per MW)	Region	Year of estimation	Year of estimation
Wind, onshore	8.6	0.2	OECD countries (Average values)	Various (2006-2011)	Source 1
	27	0.72	South Africa	2007	Source 2
	6	0.5	South Africa	NA	Source 3
	12.1	0.1	United States	2010	Source 4
	8.8	0.4	Greece	2011	Source 5
Wind, offshore	18.1	0.2	OECD countries (Average values)	2010	Source 1
Solar PV	17.9	0.3	OECD countries (Average values)	Various (2007-2011)	Source 1
	69.1	0.73	South Africa	2007	Source 2
	25.8	0.7	South Africa	NA	Source 3
	20	0.2	United States	2011	Source 4
CSP	18	1.33	South Africa	2007	Source 2
	36	0.54	South Africa	NA	Source 3
	7	0.6	Spain	2010	Source 6
	19	0.9	Spain	2010	Source 7
Hydro, large	7.5	0.3	OECD countries (Average values)	Various	Source 1
Hydro, small	20.5	2.4	OECD countries (Average values)	Various	Source 1
	20.3	0.04	South Africa	2009	Source 2
Geothermal	10.7	0.4	OECD countries (Average values)	Various (2009-2012)	Source 1
	5.9	1.33	South Africa	2004	Source 2
BESS	1.7	0.1	USA	2021	Source 9
Biomass	7.7	5.51	South Africa	2000	Source 2
Hydrogen storage system	50	5.75	UK	2021	Source 8

Sources: 1) Rutovitz and Harris (2012); 2) Rutovitz (2010); 3) Maia et al. (2011); 4) National Renewable Energy Laboratory NREL (2010); 5) Tourkolias and Mirasgedis (2011); 6) NREL (2013); and 7) NREL (2012) 8) Arup estimate, past projects 9) ACP-Labor Supply Report

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