NET ZERO WORLD INITIATIVE

Accelerating Global Energy System Decarbonization

Tierra del Fuego Case Study Capacity Expansion Analysis

Net Zero World: Tom Harris, Sarah Turner, James Morris, Anastasiia Sakharova, Omar Guerra, Juan Pablo Carvallo, Daniella Rough

Government of Argentina: Subsecretariat of Energy Planning of the National Energy Secretariat, Ministry of Economy, highlighting the contributions Ezequiel Perez Vazquez, Joaquin Alfredo Perez Torres, and Ana Belen Ferrera

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List of Acronyms

ATB	Annual Technology Baseline
BAU	business-as-usual
CAMMESA	Compañía Administradora del Mercado Mayorista Eléctrico S.A.
CO_2	carbon dioxide
LCOE	levelized cost of electricity
USD	United States dollars

Executive Summary

This case study, developed by Net Zero World Initiative and the Government of Argentina, examines least-cost decarbonization pathways for Tierra del Fuego, Argentina, utilizing renewable energy, lithium-ion battery and hydrogen energy storage, and other decarbonization technologies. Being the second-largest natural gas-producing province in Argentina, Tierra del Fuego has historically relied on natural gas for its energy sector needs. As Tierra del Fuego looks at possible decarbonization pathways, it faces challenges due to extreme weather conditions, isolation from the mainland, and low population density.

This study utilizes the Engage web application for capacity expansion modeling, addressing both business-as-usual (BAU) and accelerated decarbonization scenarios, with varying degrees of electrification and carbon emission constraints. Under the assumption that end uses would be electrified through technologies such as heat pumps and electric vehicles, our analysis revealed that an interconnection with the mainland and a high contribution of wind energy development on Tierra del Fuego emerge as the most cost-effective solutions for decarbonization. The combined deployment of these technologies was found to significantly reduce carbon emissions and electric system energy costs per unit of energy delivered. The study explores self-generation and interconnection alternatives, demonstrating the economic advantage of an interconnection of Tierra del Fuego with the mainland, as an alternative to 100% local generation. Sensitivity analyses on wind data sources and temporal resolutions, as well as projected natural gas prices, highlight the influence of external factors on the feasibility of decarbonization pathways. Potential challenges identified include the practicability of phasing out natural gas, economic uncertainty, cost implications of long-term storage technologies as the contribution of wind energy increases and geographical limitations on siting of wind generation. In addition, the study looked only at the high-level capital costs to construct transmission, and these costs can be affected by terrain type, siting and permitting cost uncertainties as well.

The case study concludes that, while substantial emissions reductions can be achieved by 2050 and can be competitive with conventional pathways, achieving a full 100% decarbonization by 2050 would entail higher costs, particularly due to the significant reliance on storage solutions with higher contributions of wind energy.[1] This analysis offers valuable insights for policymakers and stakeholders in Argentina's energy sector, emphasizing the importance of strategic planning, investment in renewable energy and storage technologies, and careful consideration of local conditions in the transition toward net-zero targets.

[1] It is important to note that this work only focused on the costs associated with the supply side of a net zero transition. Demand-specific costs such as installing heat pumps or building up electric vehicle charging infrastructure were not studied and would need to be considered in future research to capture the full cost of decarbonization.

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1 Introduction

The Net Zero World Initiative is a collaborative effort involving various U.S. government agencies, including the U.S. Department of Energy, U.S. national laboratories, and international partners. The primary goal of the initiative is to accelerate the decarbonization of energy systems and ensure a smooth energy transition, helping countries enhance their climate goals by developing technical and investment strategies for achieving net-zero emissions. The Net Zero World Initiative joins forces with international partners to accelerate the transition to a clean and secure energy system in a worldwide effort to build a net-zero world.

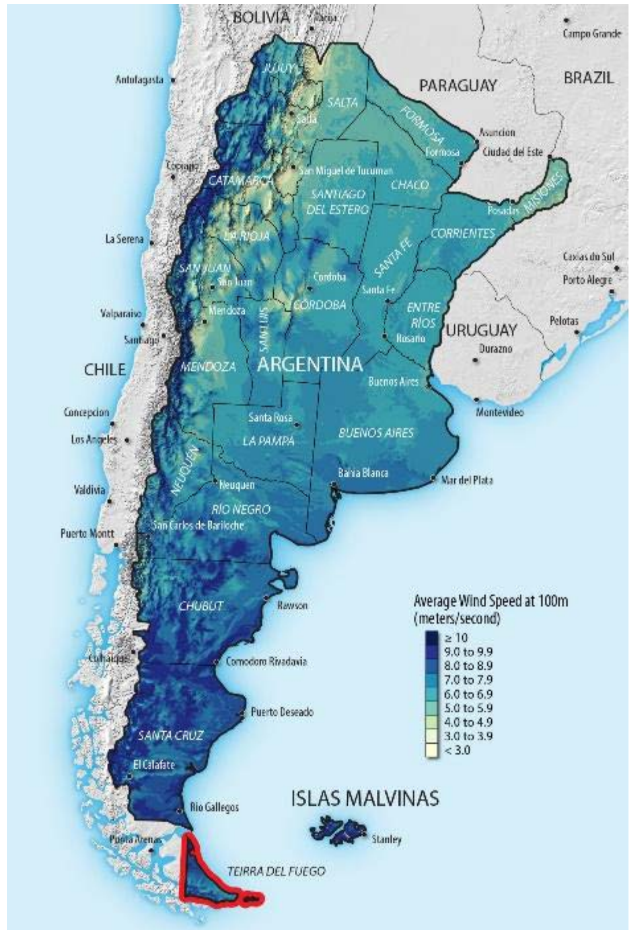

Figure 1. Average wind speeds for Argentina at 100 m (m/s)

Source: NREL, Global Wind Atlas (n.d.)

In collaboration with the National Energy Secretariat and with input from other local partners, Net Zero World investigated exploratory decarbonization scenarios for the Argentinean province of Tierra del Fuego, Antártida e Islas del Atlántico Sur, through integration of renewable energy and energy storage solutions. The culmination of the effort is presented in this case study, which outlines specific decarbonization pathways for the Tierra del Fuego province. In turn, these pathways may provide a reference for pursuing decarbonization goals nationally and replicating the analytical approaches on a country-wide scale. The study concludes with a discussion of the existing challenges to decarbonization in Tierra del Fuego and ways the island might tackle them in the future.

2 Background

The Province of Tierra del Fuego, Antártida e Islas del Atlántico Sur, includes the Argentinian portion of Isla Grande de Tierra del Fuego, territories in the Antarctic, and islands in the Atlantic Ocean. It is the biggest and least-populated province of Argentina, with only 190,641 inhabitants. The population density of the Isla Grande de Tierra del Fuego alone is 9.21 people per km^2 (Republic of Argentina n.d.). The province's population resides mostly in the cities of Rio Grande, Ushuaia, and Tolhuin. Tierra del Fuego is also the coldest region in Argentina, where the weather is characterized by freezing temperatures, strong winds, and little direct solar radiation and an average temperature of roughly 10°C (50°F) in January and 2°C (35°F) in July for Ushuaia (National Meteorological Service of Argentina n.d.)[2].

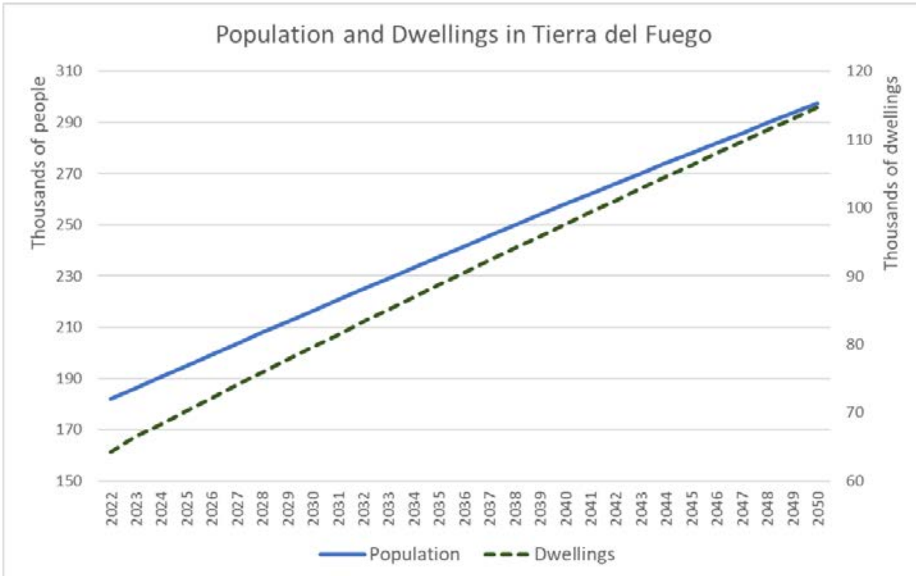

Figure 2. Population and dwellings in Isla Grande de Tierra del Fuego, based on data from the National Institute of Statistics and Consensus Argentina

This extreme climate increases Tierra del Fuego's energy use, both electricity and natural gas, during the winter. The average annual residential electricity consumption is 2,995 kWh per household, peaking in August during the winter and falling to its lowest in February during the summer. The average annual natural gas consumption per household in Tierra del Fuego is 8,300 m^3.[3] According to the National Institute of Statistics and Consensus in Argentina, it is projected that by 2050 the population of Isla Grande de Tierra del Fuego will reach 300,000 inhabitants with almost 115,000 dwellings (Figure 2). Currently, 94% of households have access to electricity in Tierra del Fuego, and residential consumption of electricity will likely increase, as will the consumption of fuel.

For Tierra del Fuego to fully decarbonize its energy sector, the province must transform its historically fossil-fuel-reliant end uses (such as heating, cooking, and transportation) to a reliance on electric power. This transition will substantially increase the demand and strain on Tierra del Fuego's generation capacity, particularly during the winter months when electricity will replace natural gas for heating. As such, this case study assesses approaches for Tierra del Fuego to meet the energy demands of its growing population while investing in clean energy solutions that will reduce the province's emissions without increasing its overall energy costs.

[2] National Meteorological Service of Argentina, https://www.smn.gob.ar/clima/vigilancia

[3] Equivalent to 6.9 tons of oil equivalent per household per year, calculated using Argentina's conversion factor.

3 Methodology

3.1 Modeling Approach

The modeling for Tierra del Fuego's decarbonization pathways was conducted using Engage. Engage is a free and publicly available capacity expansion web application capable of modeling energy systems, including those with high shares of variable generation and storage. Engage is useful for planning generation and transmission assets, analyzing the infrastructure implications of energy decisions, and outlining the least-cost path through a clean energy transition (Beshilas 2021). Engage optimizes a model's generation and transmission capacities and dispatch, adhering to constraints set by the modeler, to identify the most cost-effective portfolio of technologies to meet demand. These features make Engage an ideal modeling tool for policymakers to analyze the costs of different clean energy solutions.

Figure 3. Engage is a capacity expansion modeling tool supported by the National Renewable Energy Laboratory

3.2 Modeling Scenarios

Net Zero World developed two main modeling scenarios to analyze the emissions and costs associated with decarbonizing Tierra del Fuego's energy system. While these modeling scenarios will be explained in more detail during the subsequent sections, the core differences between the scenarios are as follows:

- **Business as Usual (BAU)**, in which no emissions constraints were enforced in the model so that Engage would only build and dispatch the least-cost generation to meet demand from the perspective of the electric utility owning and leasing generation assets and paying for fuel. This demand assumed minimal electrification would occur and residents would continue to burn fossil fuel in non-electrified end uses like heating, cooking, and transportation.
- **Decarbonization**, in which generation was similarly cost-optimized to meet demand, but with emissions constraints enforced to achieve inter-year decarbonization targets out to 2050. In addition to carbon dioxide (CO_2) emissions constraints, the Decarbonization scenario assumed an aggressive electrification rate whereby most end uses would either be electrified or met through zero-emissions fuels by 2050.

The case study also explored how costs and emissions would change for each of the scenarios if a transmission line was built to connect Tierra del Fuego to the mainland by 2035. Interconnecting the province to the continent has long been an interest to local stakeholders because Tierra del Fuego is only separated from the mainland by a narrow strait. Figure 4 provides summary descriptions of each of these scenarios and how they were compared across several metrics.

	Business as Usual (BAU)	Decarbonization
Electricity Generation	• Least-cost build out of generation with no constraints for emissions	• Emissions reductions by year relative to the 2023 baseline scenario, in line with Argentina's *Guidelines and Scenarios for Argentina's Energy Transition through 2050* 2025 – 12%; 2030 – 41%; 2035 – 72%; 2040 – 91%; 2045 – 92%; 2050 – 93%
Electricity Demand	• Minimal end-user electrification • Electricity demand grows only with changes in population and gross domestic product (GDP)	• Aggressive electrification of residential and commercial end uses, including heating, cooking, and transportation
Technologies Explored	• Both scenarios model the same existing resources and new technologies as well as timeframes for deployment	Existing Resources (2023 – 2030): Legacy Natural Gas New Resources (2025 – 2050): Photovoltaic Cells*, Lithium-Ion Batteries, Compressed Hydrogen, New Natural Gas, Wind Turbines, Interconnection (from 2035)
Electricity Generation Alternatives	• Both BAU and Decarbonization scenarios model two electricity generation alternatives	1 Self-Generation: All generation is built on Tierra del Fuego and there is no interconnection to the mainland 2 Interconnected: Tierra del Fuego is connected to the mainland by 2035 to allow for imported electricity
Key Metrics	• Key metrics for comparison include: CO_2-equivalent (CO_{2e}) emissions reductions, levelized cost of electricity, electricity emissions, cost of avoided carbon, wind capacity, curtailed wind, wind's share of production, and total energy costs (from both electricity and non-electrified end uses)**	

* Solar technologies were initially modeled in the decarbonization analysis but were later dropped as they were found to not be as cost-effective.

** The cost of electricity included both the variable and capital costs of constructing generators, but only the fuel costs were considered for non-electrified end uses. In other words, the fixed costs for purchasing and installing heat pumps, electric stoves, electric vehicles, and electric vehicle charging infrastructure were not modeled in Engage and were not explicitly explored in this case study.

Figure 4. Engage modeling pathways for different energy system transitions on Tierra del Fuego

Solar photovoltaic was also modeled in various scenarios but was found not to be cost-competitive with other technologies. This can be attributed to the wind resource in Tierra del Fuego being very robust, with average annual capacity factors potentially in excess of 60%, depending upon turbine choice and location, resulting in a levelized cost of electricity (LCOE) for wind of $0.03 per kWh.[4] Solar, on the other hand, averaged an annual capacity factor for 11% in Ushuaia and 12% in Rio Grande, resulting in an LCOE of roughly $0.15 per kWh.[5] Other technologies that, combined, fully meet demand had combined LCOEs across all scenarios ranging from $0.05 to $0.07 per kWh. Because solar photovoltaics were not cost-competitive with other tech portfolios that fully met demand they were not deployed by the model.

[4] Assuming no curtailment and wind turbine capital cost of $1250/kW financed over a 30-year lifetime at 10% per annum interest rate and annual fixed operations and maintenance cost of $37.60/kW.

[5] Assuming no curtailment and photovoltaic capital cost of $1331.35/kW financed over a 30-year lifetime at 10% per annum interest rate and annual fixed operations and maintenance cost of $21.50/kW.

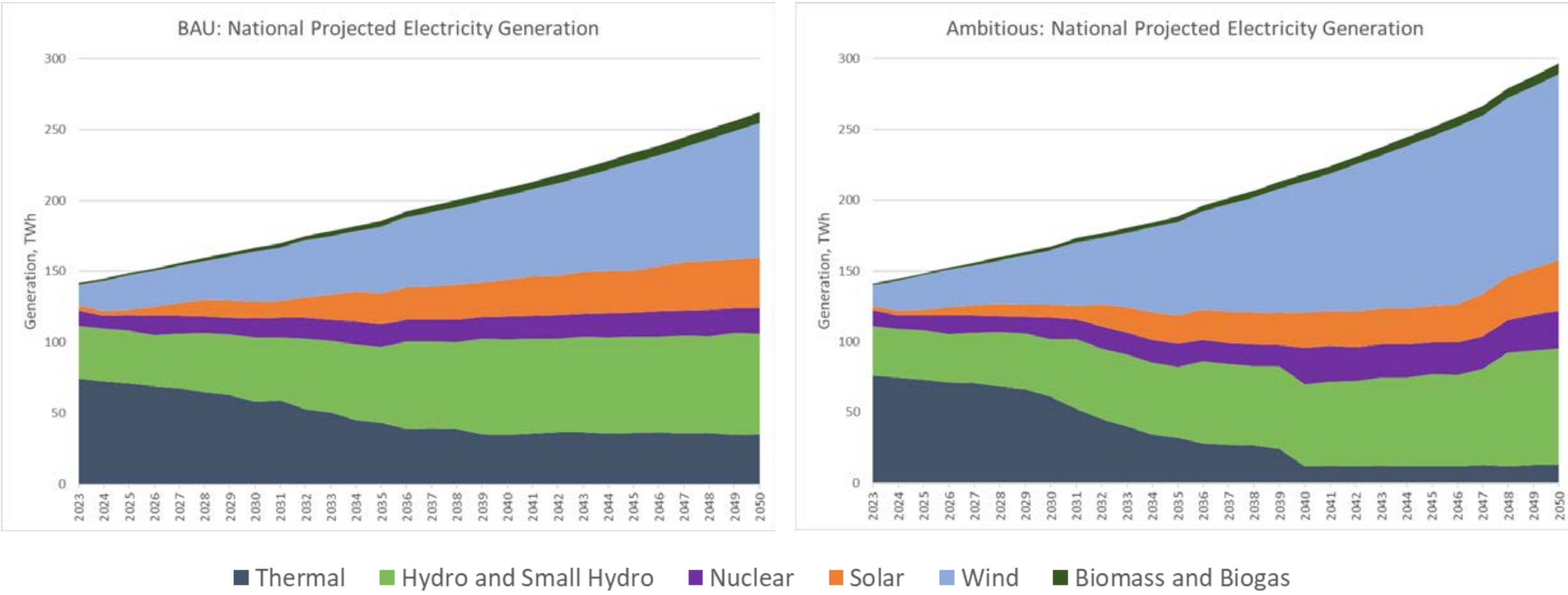

Figure 5. National projected electricity generation under BAU (left) and Ambitious (Decarbonization) scenarios (right), per Guidelines and Scenarios for the Energy Transition to 2050, resolution 518/2023

Source: Data obtained from the Energy Secretariat of Argentina's Ministry of Economy.

The Decarbonization scenario focused on how energy supply costs and emissions would change in Tierra del Fuego if the province developed decarbonization goals that aligned with the national ones outlined in Argentina's *Guidelines and Scenarios for Argentina's Energy Transition through 2050*. These guidelines, with inter-year carbon reduction benchmarks, project an aggressive reduction in national emissions from a present-day baseline through 2050. Figure 5 illustrates how national electricity generation mixes are forecasted to evolve for Argentina nationwide under the Office of the Energy Secretariat's version of the BAU and Ambitious (Decarbonization) scenarios.

While national clean energy generation under Argentina's Ambitious scenario stopped short of 100% decarbonization, national plans would put Argentina on course to achieving a 93% emissions reduction relative to a 2023 baseline by 2050. As such, Engage decarbonization models for Tierra del Fuego for both interconnection and self-generation scenarios capped emissions at 93% below emissions for 2023 (per MWh generated), to make national and Tierra del Fuego pathways comparable. The carbon emissions constraints placed on the model only dealt with emissions resulting from the electricity coming from the electrical grid and did not cap emissions from the entire energy sector. Energy costs and emissions outside of the grid, such as for transportation, cooking, and heating, were calculated outside the Engage model and were incorporated later into the scenario analysis to get a final representation of the energy sector.[6]

[6] Emissions in Engage from the grid were calculated in CO_2 while emissions from non-electrified end uses were calculated in CO_{2e}.

To assess changes in the power sector based on both BAU and high electrification of currently non-electric end uses, Engage used energy demand projections provided by the Energy Secretariat of Argentina. These demand projections incorporated current electricity demand data for Rio Grande and Ushuaia and projected their evolution over time, which varied depending on the rate of electrification. As shown in Figure 6, the BAU scenario assumed that minimal electrification would occur and that electricity demand would only grow according to changes in population and gross domestic product. The Decarbonization scenario (referred to as Ambitious in Argentina's *Guidelines and Scenarios for the Energy Transition to 2050*), however, considered how electricity demand would grow if the majority of end uses for natural gas, diesel, gasoline, and liquid petroleum gas were electrified by 2050 (high electrification).[7] These assumptions resulted in total electrical demand increasing by a factor of five during the summer and a factor of six during the winter by 2050.

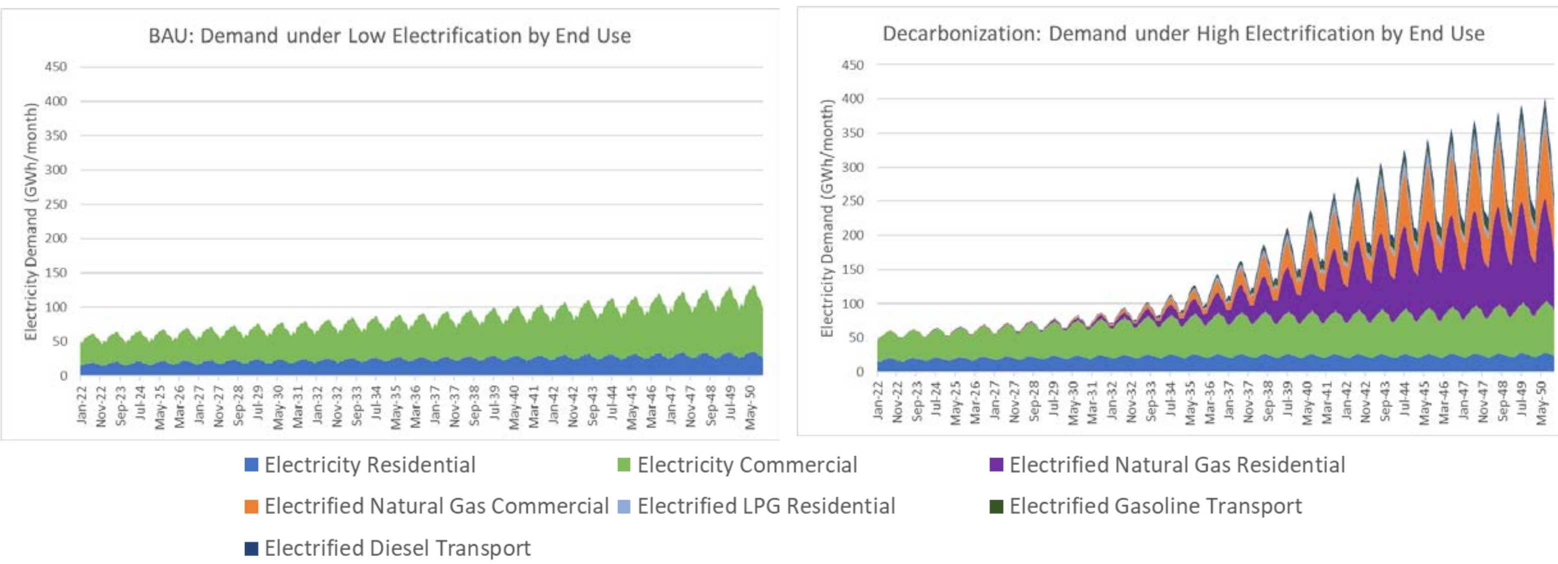

Figure 6. Projected monthly electricity demand totals for Tierra del Fuego under BAU with low electrification (left) and decarbonization with high electrification (right), broken down by end use

Source: Data obtained from the Office of the Energy Secretariat of Argentina.

Figure 7, in comparison, illustrates the evolution of Tierra del Fuego's projected energy demand by fuel type and sector for the BAU and Decarbonization scenarios, respectively. While BAU demand was projected to steadily grow with the province's population, under the Decarbonization scenario, electrification of residential and commercial end uses was aggressively escalated, along with imports for biofuels and sustainable aviation fuel. It is important to note that high electrification under decarbonization assumed that heat pumps would be used to replace most natural gas heating, while electric vehicles and electric stoves would replace most internal combustion engine vehicles and gas stoves, respectively. For this reason, even though electricity usage significantly increased under decarbonization, overall energy

[7] Energy demand projections assumed 20% efficiency in end uses and did not include electrified end uses for aviation fuel under the assumption that biofuels and sustainable aviation fuel would better serve this demand. Certain transportation end uses like marine transportation were also non-electrified and instead included as demand for biofuels.

demand for the province decreased due to improvements in energy efficiency associated with substitution of electric devices, which are far more energy efficient than legacy technologies.

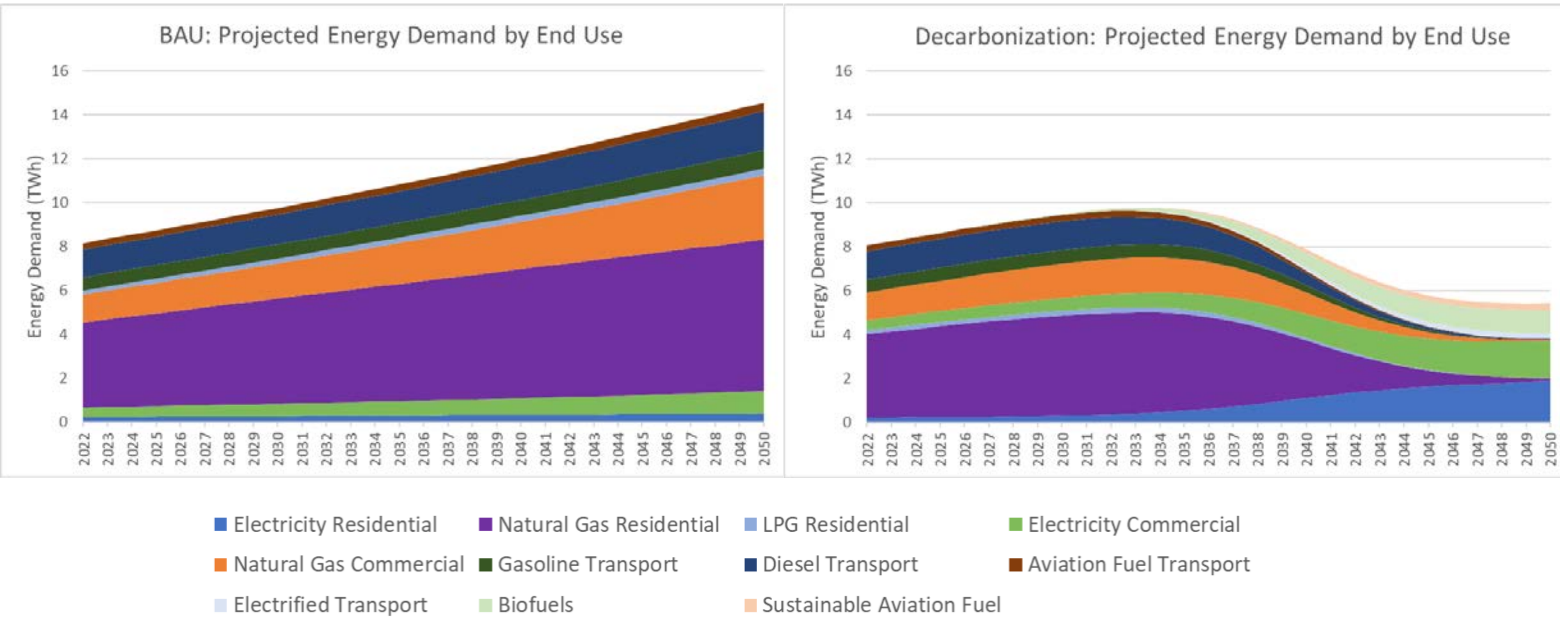

Figure 7. Projected energy demand for Tierra del Fuego by the end use for BAU (left) and Decarbonization (right) scenarios

Source: Data obtained from the Office of the Energy Secretariat of Argentina.

3.3 Integrating Grid Technologies

Tierra del Fuego represents an interesting case study for assessing decarbonization scenarios because it is the second-largest natural gas-producing province in Argentina, producing around 20–25 million m^3/day of natural gas (Energy Secretariat, Ministry of Economy n.d.). This makes natural gas both a common and competitive electricity generation resource in Tierra del Fuego. The province, however, also has rich wind resources.[8] Harnessing wind power has the greatest potential to replace Tierra del Fuego's current natural gas thermal generation and diversify the province's clean energy portfolio to meet demand, under both low and high electrification scenarios.[9] To determine how cost-competitive wind would be against natural gas generation, the case study relied on simulated data for a Goldwind GW140 3.4-MW wind turbine to generate production profiles for wind farms in Rio Grande and Ushuaia.[10] These wind turbines had average capacity factors of 63% for Ushuaia and 68% for Rio Grande, respectively. Figure 8 details an hourly profile of the wind capacity factor in Ushuaia. The simulated capacity factors are more optimistic than prior feasibility studies performed in the region, including one that determined Tierra del Fuego's wind resources had an average capacity factor of 56% at a hub

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[8] Average wind speeds range from 9 to 10 meters per second. More information can be found at https://www.argentina.gob.ar/ciencia/cofecyt/proyectos-cofecyt/potencial-eolico-tierradelfuego.

[9] Early iterations of the model included solar resource technologies, but they were later dropped by modelers because Engage never built these technologies to meet demand.

[10] Additional information about this wind turbine can be found at https://www.goldwindamericas.com/sites/default/files/GW%20140-3.4%20MW_EN.pdf.

height of 69 meters.[11] While the simulated Goldwind turbine hub height stands at 100 meters, it is important to acknowledge that these simulated wind capacity factor profiles are likely to be lower in practice, because they assume optimum conditions. Nevertheless, they provided a valuable starting point for developing a wind generation portfolio in Engage.

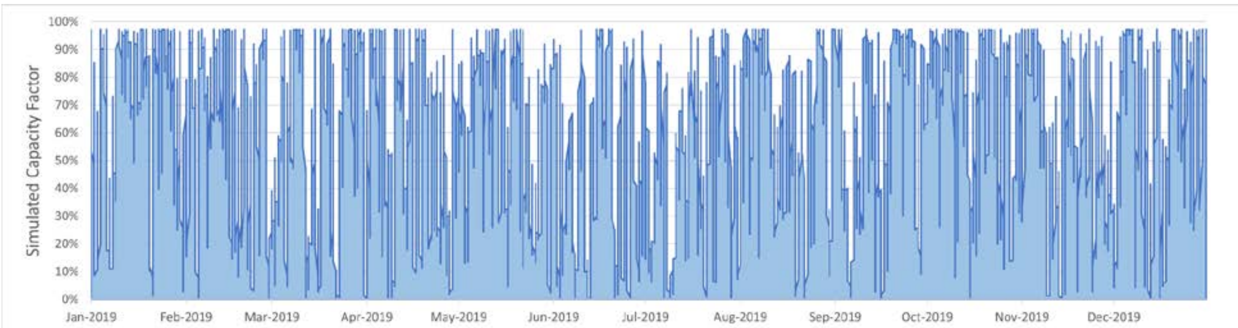

Figure 8. Simulated Goldwind wind turbine (3.4-MW) hourly capacity factor profile for Ushuaia

Source: Data obtained from Renewables.ninja[12]

Engage also accounted for the cost and energy capacities of lithium-ion batteries and compressed hydrogen storage technologies, which became particularly relevant in the self-generation case.[13] The capacities of the individual components of the electrolytic hydrogen generation, compressed hydrogen storage, and hydrogen combustion turbine system were cost-optimized, while capacities of each duration of fixed-duration lithium-ion batteries were cost-optimized.[14] For most of its technology data, Engage relied on cost inputs obtained from the National Renewable Energy Laboratory's Annual Technology Baseline (ATB), which assumed a 4.3% inflation rate.[15] Information for thermal generators, including new natural gas-fueled electric generation facilities in Tierra del Fuego and existing natural gas thermal electric generation, were provided by Compañía Administradora del Mercado Mayorista Eléctrico (CAMMESA), the country's wholesale energy market operator.[16] Based on stakeholder feedback, the case study assumed that natural gas fuel prices would not increase or decline, but stay constant over time.

The case study employed an approach in which most of the existing generation facilities like wind farms were assumed to stay in operation until they reached their end of life and were then retired. For the baseline, accounting for present-day costs and emissions, Engage modeled Tierra

[11] This feasibility study was performed by the Asian Infrastructure Investment Bank, which can be found at https://www.aiib.org/en/projects/details/2023/_download/Argentina/AIIB-P000654-Tierra-del-Fuego-Energy-Transition-Support-Project-APD-for-disclosure.pdf.

[12] This source was used due to the limited data availability for Tierra del Fuego, especially for the hourly granularity needed to populate the model. Data from Renewables.ninja relies on National Aeronautics and Space Administration MERRA reanalysis and CM-SAF's SARAH dataset. For further information on data sources, visit www.renewables.ninja.

[13] The compressed hydrogen storage systems include a hydrogen electrolyzer, a hydrogen compressor, steel hydrogen storage tanks, and a hydrogen combustion turbine.

[14] These fixed durations were 2-hour, 4-hour, 6-hour, 8-hour, and 10-hour batteries.

[15] For full technology cost estimates, visit the ATB at https://atb.nrel.gov/. Given stakeholder feedback, cost projections from the ATB were not adjusted to reflect the present-day economic conditions in Latin America under the assumption that the technology costs will more closely reflect the U.S. costs by 2030.

[16] All costs used in the model were represented using real dollars.

del Fuego's existing and less-efficient legacy natural gas generators to exclusively meet demand until 2025, at which point Engage allowed for the option to build new generation based on wind and/or more-efficient natural gas generation or lithium-ion or hydrogen storage systems. In the 2030 model year, the legacy natural gas generation units were forced to retire due to their age. New natural gas generator costs were represented as operating contracts with a minimum 9-year capital recovery period term to model actual contract costs based on information provided by CAMMESA. Engage could either renew the contracts at a reduced annual contract cost or retire and replace the gas generation contracts with other technologies.

Figure 9. Transmission points, as shown in Engage

Source: Engage Interface. The first 500-kV transmission line ran from Esperanza to Rio Grande, while the second 345-kV line ran from Rio Grande to Ushuaia. It should be noted that this is how Engage presents transmission technologies and that these lines would not necessarily follow the path shown in the figure.

Finally, the analysis used Engage to study the potential for a transmission line to be built between Tierra del Fuego and Santa Cruz, where Esperanza would act as the interconnection point for the mainland grid power supply (Figure 9). While there were a number of technical approaches to interconnection, from running underground sea cables to building overhead transmission lines across the narrowest part of the Strait of Magellan in Chile, the Engage model priced transmission using cost estimates for overhead high-voltage transmission lines. The interconnection technology incorporated local construction and projected grid power supply costs from the Office of the Energy Secretariat to analyze the competitiveness of continental power against self-generation for the province.[17] Unlike some modeled technologies that were configured in Engage to size optimally, the interconnection was designed to be a fixed asset with its initial operation date in 2035. This was based on prior analysis demonstrating that the transmission line was highly competitive with local generation, and the year was chosen to account for the timeline for permitting, procurement, design, and construction of high-voltage electric transmission projects. Furthermore, exporting energy from Tierra del Fuego to the mainland was disallowed in the capacity expansion model as a conservative assumption about likely congestion on the mainland transmission network. However, as described in subsequent sections, a post-model study of possible economic benefit of limited export was conducted.

In this way, Engage modeled a total system cost-optimized portfolio combining energy storage, wind, and natural gas thermal generation to satisfy energy demand. Though the long-term load forecasts[18] upon which the model's solutions relied are subject to uncertainty, the solutions nevertheless provide useful insights into possible energy supply mixes for decarbonization through 2050.

4 Results

At a high level, Table 1 demonstrates the comparison between the BAU and Decarbonization scenarios. Each of these comparisons is discussed in the following subsections.

[17] This analysis only considered the direct costs of what Tierra del Fuego would need to invest in to meet demand. As such, even though there would likely be increased generation costs on the mainland to meet Tierra del Fuego's load if the province were interconnected, these costs would be indirect and were not considered relevant to the case study. For a complete description of how the transmission line was priced in the model, see Table A- 3.

[18] For the analysis period (2023–2050), Engage ran simulations every 5 years, which was post-processed using a linear extrapolation approach to gauge what the energy costs and emissions would be during inter-year periods.

Table 1. Energy Metrics Comparison by Scenario

Year	Scenario	Mainland Connection	Emission Changes		Cost of Avoided Carbon ($/ton)	Energy Sector Costs ($ in Millions)				Wind Generation**		
			From 2023 Baseline	From BAU		Power Sector Costs	End-Use Costs*		LCOE ($/kWh)			
							Upfront	Fuel		Capacity	Curtailed	Share
2025	BAU	No	-11%		-	$36	?	$246	$0.04	93 MW	6%	71%
	Decarb	No	-11%	-0.4%	-$200	$36	?	$244	$0.05	95 MW	6%	71%
2030	BAU	No	-3%		-	$54	?	$259	$0.07	94 MW	6%	65%
	Decarb	No	-5%	-2%	-$66	$58	?	$252	$0.07	97 MW	1%	63%
2035	BAU	No	7%	-	-	$62	?	$288	$0.07	108 MW	1%	65%
	Decarb	No	-10%	-16%	-$37	$88	?	$248	$0.07	189 WM	9%	76%
	BAU	Yes	7%	-	-	$137	?	$288	$0.14	108 MW	0%	66%
	Decarb	Yes	-10%	-16%	-$68	$151	?	$248	$0.11	107 MW	6%	75%
2040	BAU	No	18%	-	-	$52	?	$321	$0.05	127 MW	2%	67%
	Decarb	No	-50%	-57%	-$6	$198	?	$166	$0.07	669 MW	32%	96%
	BAU	Yes	15%	-	-	$121	?	$321	$0.11	134 MW	3%	70%
	Decarb	Yes	-50%	-56%	-$74	$173	?	$166	$0.07	341 MW	6 %	77%
2045	BAU	No	29%	-	-	$59	?	$354	$0.05	149 MW	2%	68%
	Decarb	No	-85%	-88%	-$21	$292	?	$71	$0.07	1.01 GW	36%	98%
	BAU	Yes	26%	-	-	$125	?	$354	$0.10	158 MW	4%	72%
	Decarb	Yes	-85%	-88%	-$85	$207	?	$71	$0.06	492 MW	13%	77%
2050	BAU	No	41%	-	-	$66	?	$399	$0.05	174 MW	3%	70%
	Decarb	No	-96%	-97%	-$23	$350	?	$47	$0.07	1.25 GW	39%	98%
	BAU	Yes	37%	-	-	$130	?	$399	$0.09	187 MW	6%	73%
	Decarb	Yes	-96%	-97%	-$89	$229	?	$47	$0.06	599 MW	16%	78%
	100% Decarb		100%	98%	$16	$467	?	$47	$0.10	1.58 GW	50%	100%

* Upfront costs represent expenses to transition residents to electric end uses, including heat pumps, electric vehicles, electric vehicle charging infrastructure, and more. Such costs were not explored in this case study and require further analysis. All costs represent real 2023 dollars.
** Share under wind generation represents wind's share of the annual production.

4.1 BAU vs. Decarbonization

Under the BAU scenario, the model built a significant amount of wind capacity early on, a strong indication of wind's economic viability in Tierra del Fuego. In 2025, Engage initially built 93 MW of wind capacity, increasing its wind generation capacity to 174 MW by 2050 under the BAU self-generation scenario (Figure 10). Wind performed well even against Tierra del Fuego's legacy thermal units, which made up most of the natural gas generation in 2025 due to low contract costs.[19]

The model relied on legacy natural gas generation until the units were forcibly retired in 2030 at the end of their useful life, which partially explains the jump in the BAU and Decarbonization's LCOE in that year. The model quickly built new natural gas generation, which was more expensive but also more efficient, to make up for lost capacity of the retiring legacy units. The model built a small amount of storage in 2030 as well under both scenarios, favoring short duration (2- to 4-hour) lithium-ion batteries for dispatch in the summer when demand was low and prioritizing natural gas generation during the peak in winter. The relative proportions of natural gas generation, wind, and storage to meet demand remained relatively constant as the cost-optimal approach to meet demand throughout the planning horizon, as seen in Figure 10. After increasing in 2030, the BAU cost of electricity returned to 2025 levels by 2040 with the declining costs of wind in later years.

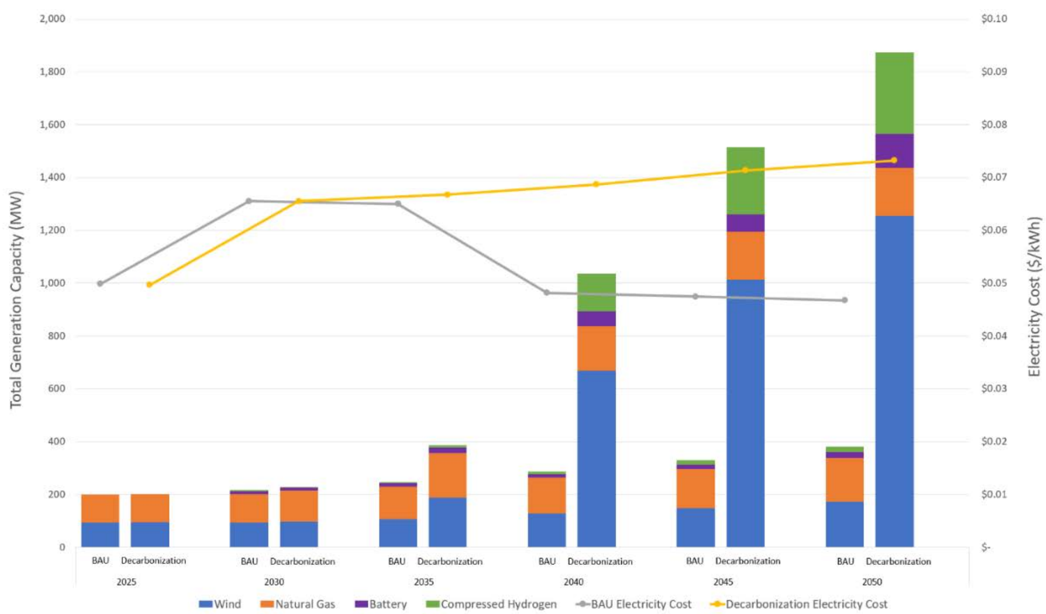

Figure 10. Total generation capacity and LCOE for BAU (left) and decarbonization (right) under self-generation scenarios. Battery and compressed hydrogen are represented by their dispatch capacities[20]

[19] For full details on contract costs, see Table A- 2.

[20] Dispatch capacity for compressed hydrogen is measured by the size of the hydrogen combustion turbine.

Under the Decarbonization scenario, Engage built a similar generation mix to that built in the BAU—over 95 MW of wind capacity in 2025. Wind generation after 2035, however, was significantly greater in the Decarbonization scenario vs. the BAU scenario, with 1.25 GW of wind capacity by 2050. This massive difference is seen for three reasons:

1. To meet the fivefold increase in demand due to high electrification
2. To satisfy the model's carbon reduction requirements, which start to significantly cap carbon emissions after 2030.

In this scenario, wind's share of annual production grew from 71% in 2025 to over 98% in 2050, leaving the remaining 2% of annual generation served by natural gas generation. While the model did not eliminate natural gas generation, it became more selective, burning natural gas in the winter to generate electricity when demand is at its highest. Before 2035, the emission reductions for the BAU and Decarbonization scenarios exceeded reductions required by the caps set for the model. The emission reductions were also similar since wind was highly cost competitive and the model built similar generation capacities for wind in both scenarios, with a small difference due to the escalation of electrification under Decarbonization. After 2035, however, the carbon caps were active constraints, pushing the model to build more wind generation than it would have under a carbon-unconstrained scenario. By 2050, Engage still built natural gas generators only to meet the peak demand in winter. To satisfy the remaining demand in winter when wind generation was low, Engage chose to invest in long-duration storage technologies, particularly compressed hydrogen (Figure 11), as well as 4- and 8-hour batteries through the analysis period (2023–2050). Even though the high demand under electrification and carbon caps justified these investments, the scale of the investments relative to the amount of energy produced also progressively increased the LCOE to 7.322 U.S. dollars (USD) cents per kWh by 2050, despite the declining cost of generation capacity.

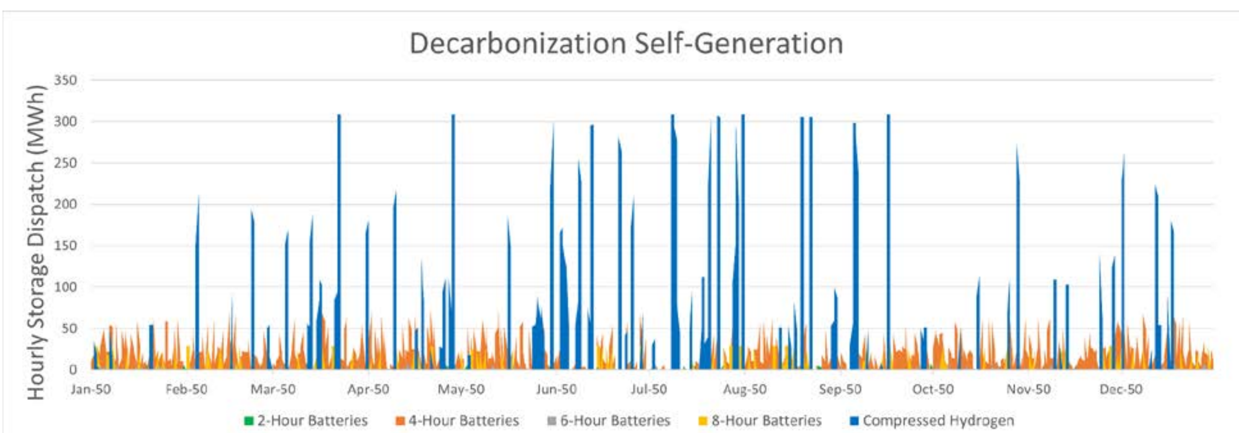

Figure 11. Hourly storage dispatch profile for Decarbonization scenario, assuming self-generation for the whole province

Overall, the decarbonization self-generation pathway in 2050 achieved a 97% emission reduction when compared to total energy sector emissions under BAU, which includes non-electrified end uses. Decarbonization, despite its increase in electricity cost, was also able to achieve a 41% reduction in total energy costs, owing to a great reduction in total energy consumption on account of the province's improved energy efficiency through electrification technologies like heat pumps and electric vehicles. Importantly, the costs for purchasing and installing heat pumps, electric stoves, and incorporating electric vehicles and electric vehicle charging infrastructure were not accounted for in this case study. These likely significant costs will be a societal component borne by the consumer or the government of the total cost of the energy transition, which warrants further analysis.[21] Engage's early buildout of wind generation additionally suggests that wind is a resource cost-competitive with natural gas generation until reaching 70% of generation and could be the province's best primary energy source for decarbonization, provided that capital costs in Argentina stabilize. However, policy support, such as a renewable portfolio standard, could be required to push wind generation beyond 70% of the annual share of production. This is especially true if the simulated wind capacity factors prove to be overly optimistic and more wind capacity is needed.

The rising cost of electricity under the Decarbonization scenario pointed to another opportunity for further exploration: the nature and cost of long-term storage. Given the model's significant reliance on long-term storage to meet demand in the winter and the large cost of long-term storage as a proportion of overall costs, less-costly long-term storage for Tierra del Fuego could help keep the price of energy competitively low. Even though this case study primarily focused on compressed hydrogen and lithium-ion batteries, future iterations could involve other technologies such as pumped hydro storage.

4.2 Self-Generation vs. Interconnection

In the interconnected generation pathway, all aspects of the model, including technology configurations, electricity demand, and carbon caps were the same as in the self-generation pathway. The only change within the interconnected pathways was the establishment of an interconnection point between Tierra del Fuego and the mainland in 2035. Engage explored interconnection to see if transmission was cost-competitive with self-generation and could reduce the burden of massively scaling Tierra del Fuego's generation system under high electrification.

The analysis showed that, when interconnection was built in 2035, LCOE spiked for both the BAU and Decarbonization scenarios, as seen in Figure 12. This increase is partially explained by the capital costs of building the transmission line, which in 2035 saw its first year of payment since Engage annualized the total capital cost of the project over its projected 50-year lifespan. Even though the transmission line was built, electricity imports from the mainland were minimal, accounting in both cases for less than 2% of the annual share of production in 2035. This changed, however, by 2040, when Engage began to increase its imports from the mainland, reaching 9% of the annual production for BAU and 20% for decarbonization, respectively. This development revealed another reason electricity costs initially spiked in 2035 but went down after 2040, as the model was given the option to either retire or renew its natural gas generation contracts.

[21] It should be noted that the Engage model analyzed and cost optimized the financial perspective of the generation and transmission system, both on an operational and investment basis. This is often the perspective of the electric utility when deciding when to retire or build new assets. While Engage has the capabilities to integrate electric tariffs and consider behind-the-meter costs, this was not the focus of this report.

This was an option the model did not have in 2035 since the contracts with the new, more efficient natural gas generators started in 2030 when the legacy units retired. The length of these contracts last nine years the first time they are used by the model and can then be retired any time after that. Consequently, even though the mainland's grid power emerged as a supply option in 2035, because the model entered into nine-year natural gas contracts in 2030, Engage had to use the natural gas generators even though payments started for the interconnection in 2035.
In other words, this indicates that it may be more economically efficient to retire and replace the legacy natural gas generators earlier than 2030 as was modeled so that the expiration of the capital recovery period on the new natural gas generators occurs in or soon after 2035, and some of that capacity may be retired when or soon after the transmission line begins operation.

For both the BAU and Decarbonization scenarios, natural gas generation capacity was reduced and replaced with imports from the grid power supply after 2035, although Decarbonization experienced the greatest reduction, going from 117 MW to 16 MW in 2040. By 2050, natural gas generation represented the smallest share of annual production in the model, becoming almost zero under the Decarbonization scenario.

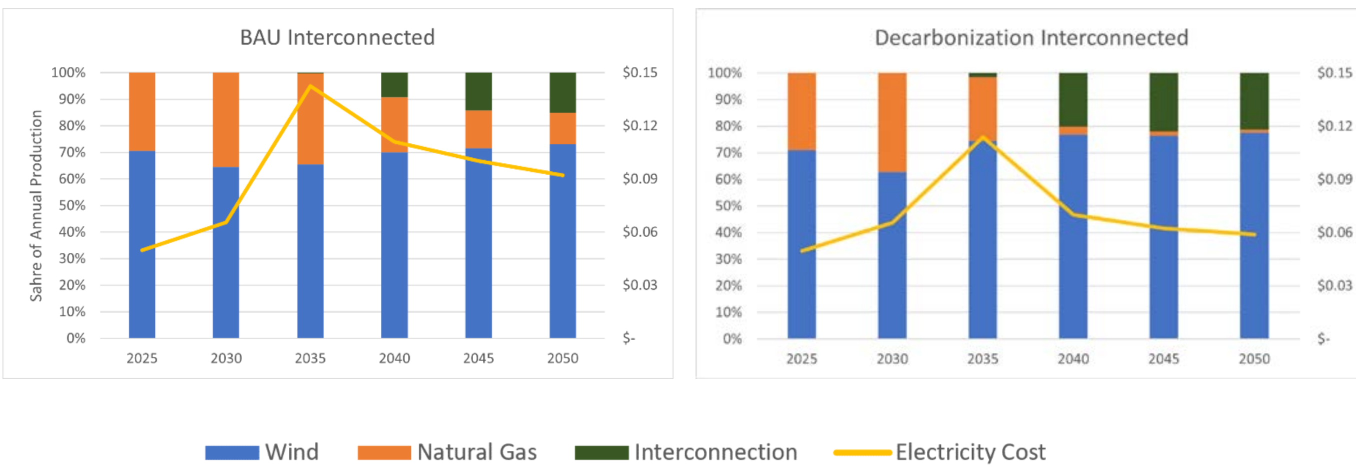

Figure 12. Share of annual production and LCOE for BAU (left) and Decarbonization (right) scenarios, assuming interconnection with the mainland

As grid power supply prices on the mainland continued to decline, the model's generation mix of wind and imports eventually brought down the LCOE in both scenarios to a cost comparable to the cost in the self-generation pathway. It was only in the Decarbonization scenario, however, that interconnection became more cost-effective than self-generation, leading to a lower LCOE in 2045 than the cost of electricity in self-generation. This development can be attributed to eliminating the need to build storage. Figure 13 shows that, for both BAU and Decarbonization, after the transmission line was constructed in 2035, the model stopped building new storage and completely retired the storage assets it built prior to 2035 in 2050. Interconnection in this way substituted for long-term storage capacity and became the model's primary method for meeting demand when wind production was low.

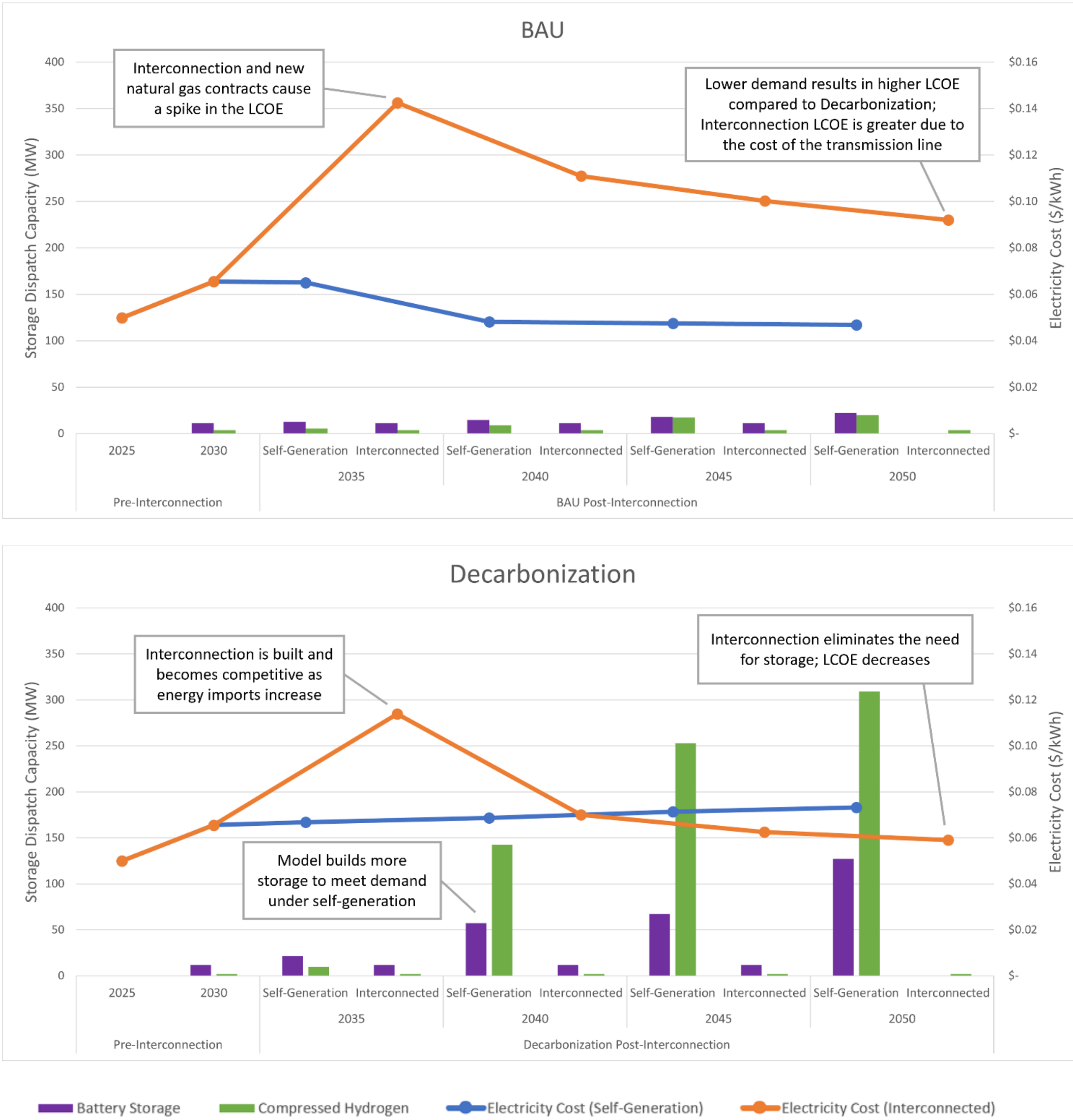

Figure 13. Total storage dispatch capacity under BAU scenarios (top) and Decarbonization scenarios (bottom) for self-generation versus interconnection

These savings are seen through the model's total energy sector costs (less, as discussed earlier, investment costs for electrification of end uses), represented in Figure 14, which charts the total investment and operating costs of Tierra del Fuego's generation in addition to fuel for non-electrified end uses. Prior to 2030, the BAU and Decarbonization pathways had comparable annual costs until interconnection, after which costs significantly increased in the interconnected pathways. For the BAU interconnected pathway, costs continue to grow until 2050, when it becomes the most expensive of the pathways, highlighting interconnection's struggle to be cost-competitive if natural gas generation is an alternative for meeting energy demand. In the BAU scenario, the interconnection was built and not fully utilized since the cost of local generation, including natural gas, was cheaper than the mainland's power. Costs in the Decarbonization scenario with interconnection, however, significantly decreased after 2035, becoming cost-effective by 2040 and the least-expensive option by 2045. This turning point, while significant in demonstrating interconnection's cost-competitiveness as a storage alternative by 2050, should be prefaced by the limitations of the modeling approach. The model runs were annual runs without foresight to subsequent years. Because transmission was modeled as a fixed asset coming online in 2035, but the model does not have foresight about this in the 2030 model year, it built a notable amount of wind generation and new natural gas generation contracts prior to 2035, which became excess capacity in 2035.

On the other hand, the capacity built prior to 2035 was needed to serve load. Future scenarios can be modeled to determine the optimal timing of interconnection (possibly after 2035) and the most cost-effective type of generation to build before 2035 in anticipation of the interconnection. Because the model was constrained not to export power to the mainland, future research could adjust this approach so that at least some of the excess Tierra del Fuego capacity could export power and support the mainland with low-cost generation from the island's cost-effective renewable energy resources while generating revenue and mitigating/resolving the "stranded assets" issue that results when transmission is built and some generating capacity on Tierra del Fuego is no longer needed.

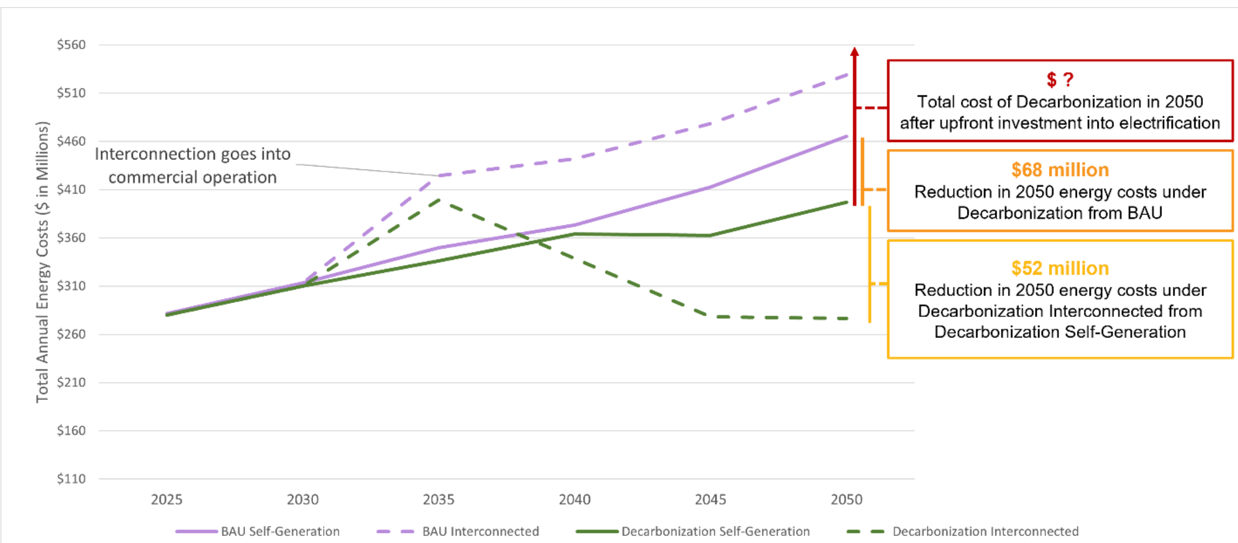

Figure 14. Total annual energy costs, including electricity and non-electrified end uses, under BAU scenarios (purple) and Decarbonization scenarios (green) for self-generation versus interconnection.[22] Costs are represented in terms of their future value in 2050

[22] For the analysis period (2023–2050), Engage ran simulations every 5 years, which were post-processed using a linear interpolation approach to approximate energy costs and emissions during inter-simulation years. As such, even though interconnection did not come online until 2035, the linear inter-year interpolation raised the cost of both interconnection pathways significantly between 2030 and 2035 compared to self-generation.

Reduced need for storage was not the only reason decarbonization under the interconnected pathway was more cost-effective than under self-generation. By eliminating the need for storage, the interconnection also eliminated the need to build as much wind. Under the decarbonization interconnected pathway, as shown in Table 1, Engage built only half the wind capacity it built under the self-generation pathway. As shown in Figure 15, lower curtailment numbers under interconnection also speak to the improved capital efficiency of the system, in which wind generation is only 15% curtailed, compared to self-generation's 39%.

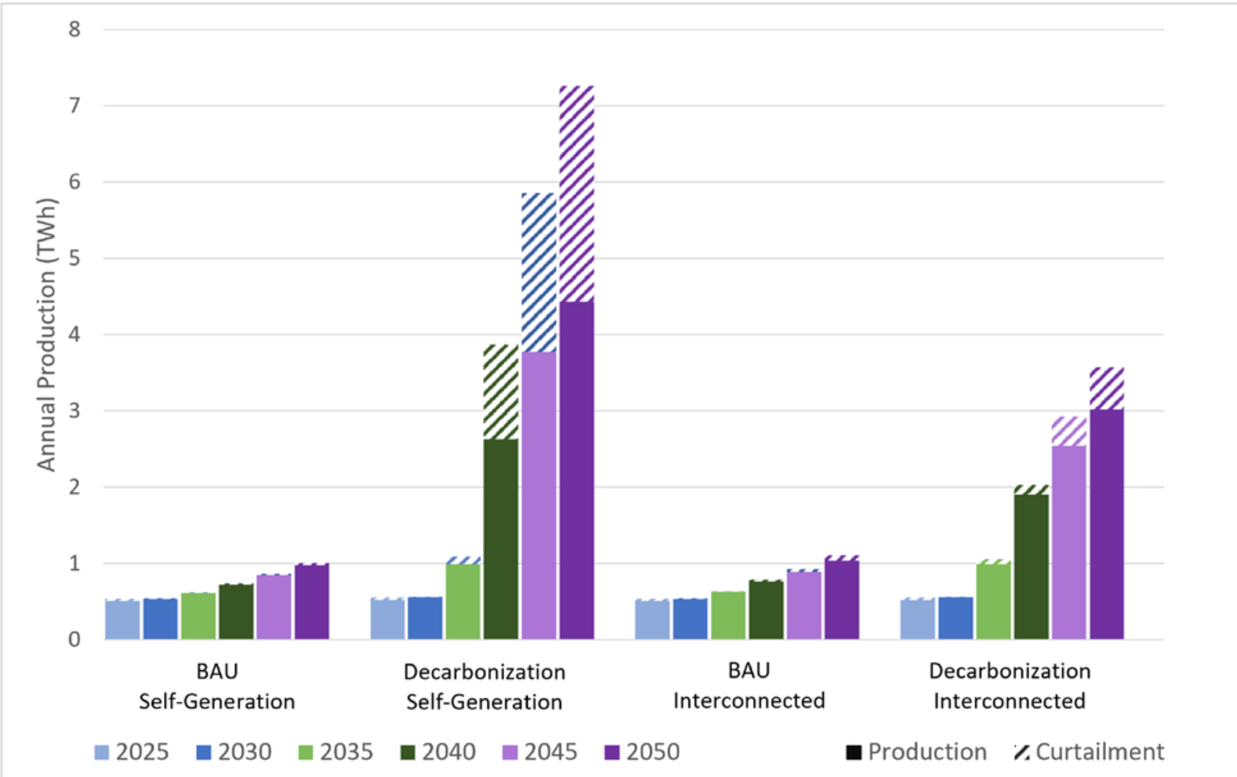

Figure 15. Annual wind production and curtailment by modeled scenario

The interconnected pathways evaluated the impact of energy imports on some of the model's build decisions, assuming a continuously decreasing carbon emissions profile of the imported power in line with Argentina's current energy transition policy scenarios through 2050. Yet another valuable point of insight would be to see how the model behaves when export is also allowed. One conservative approach to evaluating this potential would be to calculate the additional revenue Tierra del Fuego could collect if the province was able to export its curtailed generation. This approach does not allow the model to cost-optimize by building more wind capacity for the purpose export but does evaluate the potential for revenue if export is allowed with the capacities built in the subject scenarios. Using interconnected wind capacity figures, the export potential for BAU was $3,301,868 and for decarbonization was $36,623,162.[23] While Tierra del Fuego could potentially export even more energy from wind generation, this initial estimate offers a glimpse into how transmission costs could be offset so that the interconnected scenarios are more cost-effective in comparison with self-generation. Additional analysis would

[23] These values were converted to present-day dollars, utilizing a 10% discount rate. Export potential was determined by multiplying the curtailed wind generation against the mainland energy prices for that year.

be required to gauge this potential because uncertainties remain about mainland developments and congestion risks.

4.3 100% Decarbonization

As a final point of analysis, Net Zero World ran a decarbonization scenario through Engage that looked at what the total operation and investment costs would be if Tierra del Fuego reached 100% decarbonization of its grid by 2050. This pathway only involved self-generation because 100% decarbonization of the Tierra del Fuego electric grid is not possible with interconnection when complete decarbonization of the power sector on a country-level is not planned. The scenario followed similar inter-year carbon reduction caps, except for the 2050 model year in which the permissible emissions from the grid were constrained to zero.[24] As shown in Figure 16, the cost of electricity was 32% higher than in the 93% grid Decarbonization scenario relative to the 2023 baseline, reaching 9.682 USD cents per kWh in 2050. This higher cost can be partially explained by the model's additional wind capacity—it built 1.5 GW of wind capacity in the 100% Decarbonization scenario compared to 1.25 GW of wind capacity under the 93% Decarbonization scenario. This combined with the and the high cost of additional required storage in the 100% Decarbonization scenario account for the difference in cost.

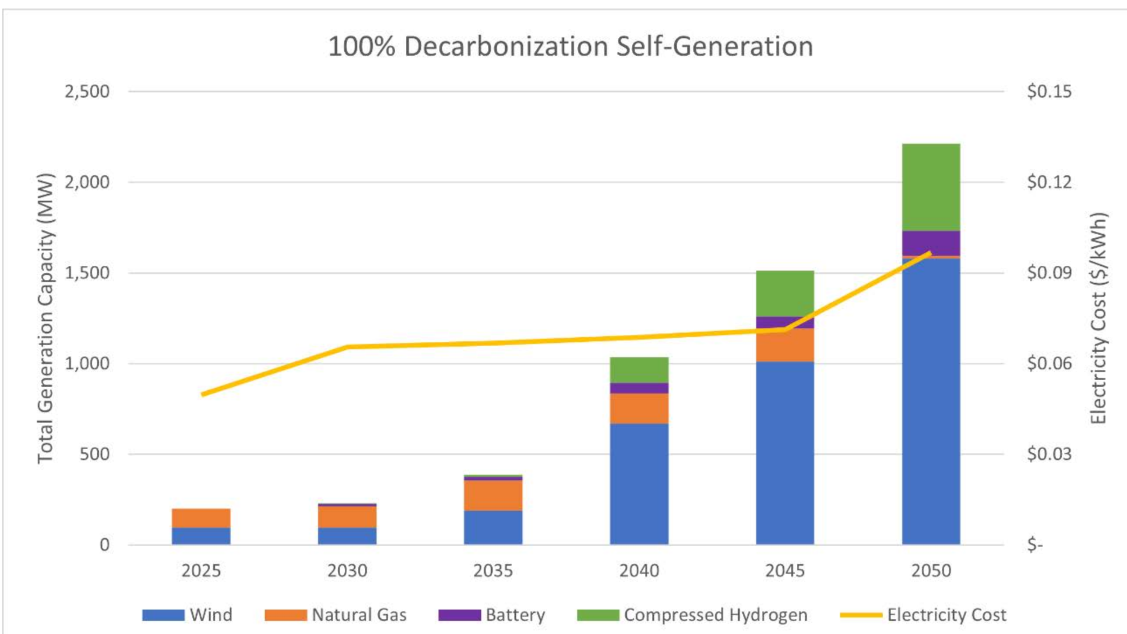

Figure 16. Total generation capacity and LCOE for 100% decarbonization under self-generation

Storage technologies like lithium-ion batteries and compressed hydrogen storage also grew under 100% decarbonization, but to different degrees. Battery storage only grew 8% between the two decarbonization scenarios, while the dispatch capacity of compressed hydrogen storage grew 55%. Compressed hydrogen storage experienced the largest percentage increase in dispatch

[24] While the grid had zero emissions, there were still 55,13 metric tons of CO_{2e} from non-electrified end uses. These emissions stemmed from areas of industry identified to be the most difficult to decarbonize, such as marine and aviation transport.

capacity among all technologies between the scenarios.[25] This dramatic difference in the capacities of compressed hydrogen storage between the scenarios likely accounts for a large portion of the increase in the cost of electricity under the 100% Decarbonization scenario. The hierarchical pie charts in Figure 17 contain the total investment and operating costs, including fuel, and illustrate the relative shares of those costs by scenario and technology type in 2050. In each decarbonization scenario, compressed hydrogen made up a significant portion of the total investment and operating costs compared to the BAU scenario, where compressed hydrogen amounted to less than 7% of the total costs.

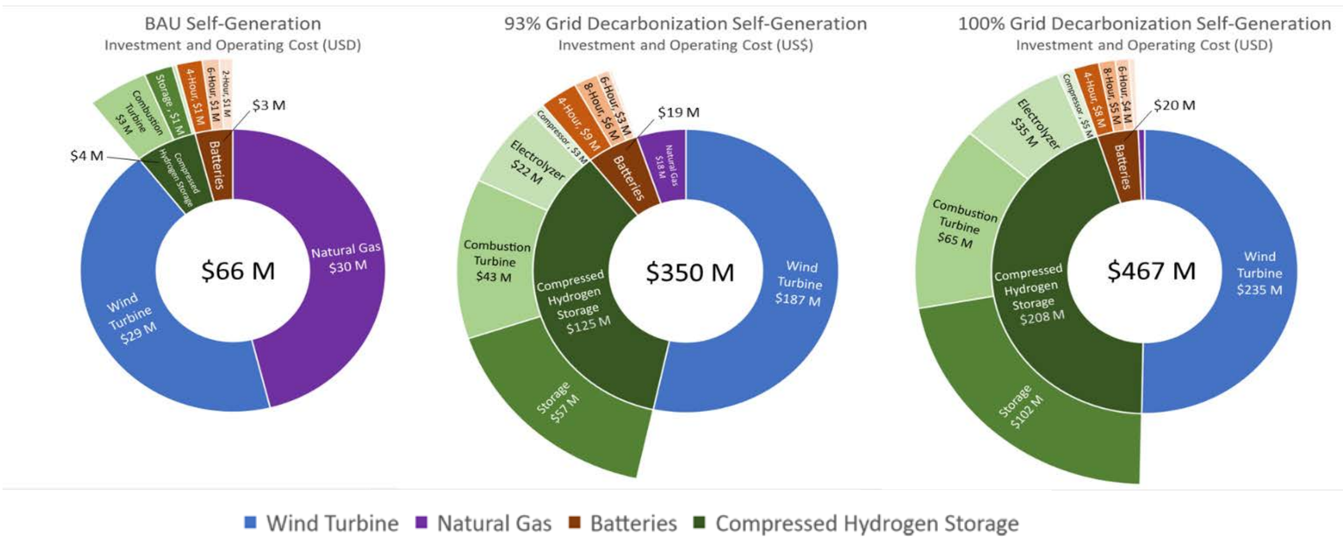

Figure 17. Share of 2050 total investment and operating costs for self-generation and magnitude of cost by technology type for BAU (left), Decarbonization (middle), and 100% Decarbonization (right) scenarios, represented in millions[26]

Hydrogen storage and the combustion turbine were the costliest components of the hydrogen storage stack in every scenario. Yet as the scale of the compressed hydrogen storage system increased between scenarios, the storage of compressed hydrogen grew to be the largest expense of the system, accounting for 22% of the total costs under 100% decarbonization. It is important to note that this case study incorporated cost data from resources that assumed compressed hydrogen would be stored in metal tanks because there have been limited studies to determine Tierra del Fuego's potential for geological storage. If a geological analysis reveals that compressed hydrogen storage would be competitive given the province's terrain, then this may be a promising area in which Tierra del Fuego can decrease its long-term storage costs.

This case study demonstrates that wind is a competitive resource that Tierra del Fuego should consider in its decarbonization plans, as it can cost-effectively replace a large portion of the generation fueled by natural gas. Even under BAU scenarios, the Engage model built large wind capacities as soon as it was allowed, highlighting a path to emissions savings likely to result in monetary savings.

[25] This percentage of increase comes from the sizing of the combustion hydrogen turbine between scenarios, because it represents the dispatch capacity of the storage technology.

[26] A breakdown of the total investment and operating costs in 2050 can be found in Table A- 4.

Figure 18 shows that, over the analysis period, decarbonization could save Tierra del Fuego $80 million in energy costs if we convert back to present value while also mitigating nearly 30 million metric tons of CO_2 emissions. This breaks down to $2.65 saved by power system operators per avoided metric ton of CO_{2e} under the Self-Generation scenario and $13.11 saved under the Interconnected scenario (Figure 18). To reiterate, however, the stated savings are energy cost savings and do not account for the costs of electrification, such as the labor and capital costs of installing heat pumps, replacing internal combustion engine vehicles, transitioning to electric vehicles and building electric vehicle charging infrastructure. If these costs are accounted for, projected monetary savings on an energy system level[27] may be notably diminished, potentially to the point of becoming neutral or more expensive than BAU. That said, the modeled scenarios' projected energy cost savings might be used to guide policymakers to set the maximum investment or subsidy to transition residents to electrification to keep decarbonization competitive with BAU. Such a subsidy—together with the costs citizens and businesses would have encountered to replace aging legacy equipment—might be sufficient for substantial progress toward electrification.

Table 2. Comparison of the energy sector costs and emissions across modeling scenarios.

Period Analysis* (2023–2050)		BAU		Decarbonization	
		Self-Generation	Interconnected	Self-Generation	Interconnected
Total Energy Sector Costs		$3.30 billion	$3.55 billion	$3.22 billion	$3.16 billion
Cost Share From Electricity		15%	25%	47%	42%
Cost Share From Non-Electric End Uses	Fossil Fuels	85%	75%	47%	51%
	Biofuels and E-Fuels	0%	0%	6%	6%
Total Cost Savings From BAU				$80 million	$385 million
Energy Sector Emissions (metric tons)		67.17 million	66.27 million	36.93 million	36.93 million
Emission Share From Electricity		2%	2%	2%	2%
Emission Share From Fossil Fuels in Non-Electric End Uses		98%	98%	98%	98%
Total Emissions Savings From BAU				30.24 million	29.34 million
Cost Savings for Avoided Carbon ($/ metric ton)				$2.65	$13.11

* Total energy sector costs from electricity and non-electrified end uses were discounted to present-day dollars using a 10% interest rate. Emissions are represented in CO_2 equivalent metric tons. Electricity costs represent total investment and operating costs, while non-electric costs only represent fuel costs and not the costs of switching to electrification.

[27] The model only cost-optimized from the power system operator perspective.

Overall, these results provide actionable insights into the decarbonization cost curve in Tierra del Fuego and how energy costs may see significant escalation to reach full carbon abatement. This is reflected in the net cost of avoided carbon under the 100% Decarbonization scenario, which, unlike the initial modeled Decarbonization scenario became positive at $16.37 per metric ton. Under the first Decarbonization scenario, which did not model 100% decarbonization, once end use fuel costs were factored back into the model, the cost of avoided carbon was always negative, meaning the new energy portfolio could save emissions while reducing costs. The positive cost of avoided carbon, however, indicates that a 100% Decarbonization scenario could cost more than the BAU, even with fuel costs incorporated, and that to reach zero emissions, there would be an additional cost of $16.27 for every avoided metric ton of CO_2 emissions. Although more research is ultimately needed to determine the true costs of decarbonization, this analysis can provide guidance on how and where to minimize their inflection point.

5 Challenges

Several factors significantly influence the cost and feasibility of decarbonization scenarios. Such factors include the availability and time resolution of wind data from distinct geographic locations, as well as disparities when comparing wind data sources for the same location, both of which can impact modeling outcomes. Fluctuations in gas prices over time, and assumptions used for future pricing of natural gas, can significantly impact a model's capacity results and final costs. The cost of transmission can likewise affect cost results. Transmission costs, if higher than the ones used in this study, could undermine the interconnected pathway's cost-effectiveness over self-generation under the Decarbonization scenario.

The potential high cost of achieving a 100% reduction in emissions might require some external financial support. Notably, there were energy technologies that were not studied, such as combined heat and power technologies and fuel cells, that may offer further efficiencies and cost savings in small and district energy applications to make hydrogen more cost-effective. Therefore, a recommendation of this case study is to conduct additional sensitivity analyses to achieve results that consider these important factors. Lastly, phasing out the use of natural gas may be challenging, considering the importance of this energy source for the region as a natural gas exporter province and for residents as a long and well-known source for heating energy.

5.1 Study Considerations

Capacity expansion modeling for electric grids necessarily makes many rough approximations and cost projections; as a "desktop" study, this type of modeling typically does not include in-depth evaluation of terrain and geology or local market conditions—for example, to estimate site- and country-specific technology implementation costs. Furthermore, technological advances, economic conditions, and trade factors will necessarily render cost projections in the analysis out of date. Assuming future rates of inflation and other economic indicators significantly influences the outcomes of the modeled results, so sensitivity analyses are key for understanding the possible ranges of modeled outcomes, especially for longer-term projections.

Likewise, due to the computational intensity of models that consider hourly load and variable renewable energy profiles but look out over a 25-year planning horizon, it is not currently computationally feasible to account for grid operational details such as day-ahead unit commitment or voltage regulation in such models. Thus, the results of the Engage analysis may be refinable with the benefit of production cost modeling, power flow modeling, system stability modeling, etc.

Moreover, simplifications were made to modeling constraints to rapidly generate high-level lessons about the high-level technologies and costs likely in the energy transition. No planning or operating reserve margins were applied in the modeling, and conservative assumptions were made about electric transmission congestion on the continental grid disallowing export of wind from Tierra del Fuego.

Further evaluation is needed to determine what additional economic costs will be required to meet resource adequacy for system reliability and what additional economic benefits might be gained through fuller exploitation of Tierra del Fuego's world-class wind resources. Additional modeling of the integrated continental and Tierra del Fuego grids may indicate whether building wind for export and putting operational coordination and/or more continental transmission capacity in place to accommodate new hydroelectric power resources on the continent and wind export from Tierra del Fuego would be cost-effective, or whether Tierra del Fuego wind is most economically used primarily as a local resource.

6 Key Findings and Conclusions

As a result of this study, several key findings were identified, as summarized below:

- Wind power emerges as the most cost-competitive resource for Tierra del Fuego's decarbonization efforts, offering an economic alternative to natural gas generation.
- Initial model results indicate short-duration storage competitiveness during the summer, but long-duration storage is essential for decarbonization to meet the high winter demand.
- Scaling batteries and compressed hydrogen storage systems may lead to higher, less-competitive electricity prices. Elevated compressed hydrogen costs can be reduced if the province has a terrain for underground hydrogen storage that could be utilized in lieu of more costly aboveground storage tanks.
- Affordable long-term storage options could be vital for the decarbonization of Tierra del Fuego, particularly if the province is responsible for self-generation, and likely other provinces looking to decarbonize their energy sectors.
- Interconnection emerges as a potential competitive alternative to storage under decarbonization, particularly if wind export has potential, but can spike costs if implemented without regard to opportunities to economically retire other capacity.
- Further analysis is required to understand the full costs of decarbonization, considering wind resource limitations and geographical constraints. Practical restrictions to wind generation include steep terrain and possible turbulence considerations due to the surrounding mountainous terrain, particularly in Ushuaia.
- A full 100% carbon reduction could entail significantly more cost differential than projected in the case study, particularly if natural gas prices become more competitive or if interest rates increase over time.

The path to decarbonization is a complex one that can take many turns, relying on a combination of different clean energy technologies and solutions for achieving zero emissions. The costs and cumulative emissions of these strategies can change significantly, depending on when they are implemented and how they complement one another. Using the Engage tool, this case study explored four different pathways that addressed how a province like Tierra del Fuego could decarbonize its energy system and chart a path forward. These pathways considered both a diversity of energy technologies as well as growing electricity demand because electrification will be vital to decarbonizing the region's fossil fuel-based energy end uses.

The study also reveals a crucial turning point for the role of both interconnection and storage technologies in decarbonization. Early iterations of the model for BAU showed that minimal short-duration storage is only competitive when dispatched in the summer to meet demand. Yet if Tierra del Fuego plans to decarbonize its grid beyond BAU, which will be necessary to meet Argentina's ambitious Decarbonization scenario, long-duration storage will be required to meet demand when wind generation is limited, particularly in the winter when demand is at its peak. The massive scaling of battery and compressed hydrogen storage systems likely creates higher and less cost-effective prices for electricity, demonstrating a need that Tierra del Fuego and other provinces will have for affordable long-term storage options. The study explored interconnection as a potential alternative to storage technologies in the province, and it appears to be cost-effective under the Decarbonization scenario. Yet mainland transmission interconnection, as a large project representing a step-change and temporary overcapacity for the Tierra del Fuego grid with commensurate cost, without a corresponding opportunity to economically retire generation capacity or a very rapidly growing load, like any large-scale generation project, can result in energy cost increases.

More analysis and higher-quality resource data are needed to better understand the costs of decarbonization in Tierra del Fuego. High-quality wind resource data will be valuable for refining models' optimizations of wind capacities. This may be particularly important, given the promise wind shows for playing such a large role in Tierra del Fuego's clean energy future.

In conclusion, this case study explored different decarbonization pathways for Tierra del Fuego, emphasizing and optimizing the role of wind generation, interconnection with mainland Argentina, and energy storage technologies in reducing emissions and managing costs within the energy sector. It highlighted potential solutions and confronted the significant challenges of decarbonizing the energy grid within Argentina's economic, social, and regulatory contexts. One key outcome to highlight is that the Decarbonization scenario was more economic than the BAU scenario, achieving up to 97% carbon reduction, but as decarbonization reached 100%, the high costs of storage became more relevant and less competitive. These early modeling results, aimed at supporting the clean energy transition in Argentina, offer promising insights that Tierra del Fuego can consider when decarbonizing their energy sector.

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Appendix

Table A- 1. Costs of Production Capacity and Operations and Maintenance for Clean Energy Technologies

Technology*	Efficiency	Year	Cost of Production Capacity (US$/kW)	Fixed Operations and Maintenance Costs (US$/kW/yr)
Hydrogen Combustion Turbine	35%	2025	1,299	24
		2030	1,246	23
		2035	1,194	22
		2040	1,141	22
		2045	1,089	21
		2050	1,036	20
Hydrogen Electrolyzer	90%	2025	878	70
		2030	511	46
		2035	444	40
		2040	400	36
		2045	367	33
		2050	344	31
Hydrogen Compressor	100%	2025	100	-
		2030	100	-
		2035	100	-
		2040	100	-
		2045	100	-
		2050	100	-
2-Hour Battery	92.2% (one-way)	2025	862	22
		2030	748	19
		2035	697	17
		2040	646	16
		2045	594	15
		2050	541	14
4-Hour Battery	92.2% (one-way)	2025	1,436	36
		2030	1,204	30
		2035	1,111	28
		2040	1,018	25
		2045	925	23
		2050	833	21
6-Hour Battery	92.2% (one-way)	2025	2,010	50
		2030	1,659	41
		2035	1,525	38
		2040	1,391	35
		2045	1,257	31
		2050	1,124	28
8-Hour Battery	92.2% (one-way)	2025	2,584	65
		2030	2,114	53

		2035	1,938	48
		2040	1,763	44
		2045	1,589	40
		2050	1,415	35
10-Hour Battery	92.2% (one-way)	2025	3,158	79
		2030	2,569	64
		2035	2,352	59
		2040	2,136	53
		2045	1,920	48
		2050	1,706	43
Hydrogen Storage, Cost of Storage Capacity	100%	2025	15	-
		2030	14	-
		2035	12	-
		2040	11	-
		2045	10	-
		2050	10	-
Goldwind GW 140 – 3.4 MW	68%: Rio Grande Capacity Factor 63%: Ushuaia Capacity Factor	2025	1,348	37
		2030	1,263	35
		2035	1,203	34
		2040	1,143	32
		2045	1,084	31
		2050	1,024	30

* All lithium-ion batteries and wind turbine costs were pulled from the ATB. Engage consulted the moderate projections for utility-scale battery storage and the moderate projections for a Class 9 Technology 3 land-based wind turbine. Cost projections for a natural gas combustion turbine (F-Frame) were also used from the ATB to project costs for a hydrogen combustion turbine, considering the similarities between the two technologies. This table includes the fixed costs of all the zero-emission technologies, but it does not include costs for the formal logistics of establishing a wind farm, for example, such as the labor and cost of equipment for scoping sites and constructing roads to get to the sites.

Table A- 2. Costs of Production Capacity and Operations and Maintenance for Thermal Technologies

Technology	Efficiency	Cost of Power Purchase Agreement With CAMMESA (US$/kW/yr)	Cost of Natural Gas (US$/kWh)
Existing Generation (Legacy Units)	24%: Rio Grande 31%: Ushuaia	72	0.015 ($4.26 per MMBtu)
New Generation	45.6%: Rio Grande 45.2%: Ushuaia	240	0.015 ($4.2601 per MMBtu)

Table A- 3. Cost of Carrying Capacity for Interconnection

Interconnection	Cost of Carrying Capacity (USD/kW/km)*	Carrying Capacity (MW)	Carrying Efficiency	Voltage (kV)	Distance (km)
Esperanza to Rio Grande	454.18	1,233	98%	500	370
Rio Grande to Ushuaia	317.12	700	98%	345	212

* Cost of carrying capacity for the transmission line from Esperanza to Rio Grande was calculated by dividing $560,000,000 by the carrying capacity of the line. $560,000,000 was the cost projection of a proposed transmission line (Office of the Energy Secretariat n.d.). Cost of carrying capacity for Rio Grande to Ushuaia was pulled from an American Electric Power transmission study that projected overhead transmission construction costs over rural terrain with rolling hills would be $1.1-$2 per mile (American Electric Power n.d.). These projections include siting and right-of-way costs but exclude station costs. The final cost of carrying capacity relied on a $1,300,000 transmission cost multiplied against the line's distance and divided by the line's carrying capacity. For the prices of electricity imports on the mainland, Engage incorporated yearly prices from the Office of the Energy Secretariat. Using projections on the generation profile under BAU and Ambitious scenarios, the Office could model and estimate what electricity prices could be.

Table A- 4. Breakdown of Total Investment and Operating Cost for Scenarios in 2050

Technology	BAU		93% Decarbonization		100% Decarbonization	
	Cost ($M/Yr)	Share	Cost ($M/Yr)	Share	Cost ($M/Yr)	Share
Wind Turbines	$28.71	43.4%	$186.95	53.4%	$234.82	50.3%
Natural Gas Combustion Turbine	$30.46	46.1%	$18.35	5.2%	$3.18	0.7%
Batteries	$2.64	4.0%	$19.24	5.5%	$20.33	4.4%
2-Hour	$0.64	1.0%	$0.74	0.2%	$1.98	0.4%
4-Hour	$1.22	1.8%	$9.47	2.7%	$8.50	1.8%
6-Hour	$0.78	1.2%	$3.17	0.9%	$4.48	1.0%
8-Hour	-	-	$5.87	1.7%	$5.38	1.2%
Compressed Hydrogen Storage	$4.34	6.6%	$125.33	35.8%	$208.30	44.6%
Compressor	$0.02	<0%	$3.35	1.0%	$5.46	1.2%
Electrolyzer	$0.16	0.2%	$22.03	6.3%	$35.28	7.6%
Combustion Turbine	$2.80	4.2%	$42.53	12.2%	$65.45	14.0%
Storage Tank	$1.34	2.0%	$57.43	16.4%	$102.11	21.9%
Total 2050 Costs*	$66.14		$349.87		$466.64	

* Costs are represented in the millions.

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