Territorial Viability of Photovoltaic, Battery Storage, and Hybrid Systems: Profitability Thresholds in Chile's National Electric System

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Abstract

The growing penetration of variable renewable energy in Chile has been modifying the temporal structure of prices, generating frequent daytime depressions and potential opportunities for energy arbitrage through storage. This phenomenon, combined with the marked gradient of solar irradiation that decreases towards the south of the country, raises questions about the economic viability of these technologies outside the desert areas where these projects are traditionally located. This study comparatively evaluates the economic viability of photovoltaic (PV) systems, battery storage (BESS), and hybrid configurations (PV+BESS) in eight utility grids of the National Electric System, using hourly data on marginal prices and solar generation. A low computational load model based on reference capacities and hourly valuation is adopted, appropriate as a first geographic filter. The results show differentiated viability according to technology and location: PV is attractive where the average solar price is high; BESS requires significant night-day differentials; while PV+BESS presents more homogeneous profitability across territories. Indicative viability thresholds are proposed, noting that, in daytime saturation scenarios, the price structure predominates over the solar capacity factor as a determinant of profitability. These conclusions are framed within the model's assumptions and motivate extensions that incorporate degradation and variable storage efficiency, as well as multi-year analyses.

Keywords: photovoltaic systems; battery energy storage; PV-BESS hybrid systems; energy arbitrage; price-resource decoupling; profitability thresholds; Chilean National Electric System.

1. Introduction

In Chile, the deployment of renewable energies, including solar photovoltaics, has been favored, in part, by the availability of solar resources, which is greater in the north of the country, and by decarbonization commitments (Ministry of Energy, 2025). This dynamism may be accompanied by certain operational and market challenges, such as potential discharges, daytime prices that tend to approach zero, and greater intraday variability (M. Pavlík, et al. 2025). International literature suggests that, in contexts of greater solar penetration, volatility could increase, opening up space for storage solutions that help shift energy over time and mitigate constraints. In Chile's National Electricity System (SEN), marginal costs tend to align with this dynamic, since in general, more marked daytime minimums and day-night differentials are observed, being more visible in areas with a greater photovoltaic presence (X. Kan et al. 2021).

In this context, photovoltaic (PV) systems, battery storage (BESS), and hybrid PV+BESS configurations are presented as complementary options. On the one hand, PV energy alone offers limited operational flexibility; its main contribution is to deliver energy when the resource is available and capture the associated price. BESS, on the other hand, allows for arbitration between time slots and the provision of flexibility services, while the hybrid scheme integrates both mechanisms and can shift part of the production to periods of higher value (A. Bâra, S.-V. Oprea, 2025). The economic viability of these alternatives depends on the temporal structure of local prices, the available resources, and technological costs. In contexts of high renewable penetration, there may be some decoupling between the resource and demand, so that the price signal and intraday differentials (spreads) tend to gain relevance (J. Lima, 2022).

Based on this, this study develops and applies a simplified techno-economic evaluation framework to compare the performance of standalone PV, standalone BESS, and hybrid PV+BESS systems at eight representative utility grids in the SEN. The approach uses uniform reference capacities, valuation through hourly marginal costs, and public solar generation data, prioritizing territorial comparability over site-specific optimization. The results quantify economic viability through financial indicators (NPV, IRR, payback) and establish a ranking of optimal configurations by location, aimed at site preselection and support for investment decisions. The analysis is interpreted under conservative assumptions that do not incorporate complementary services, equipment degradation, or advanced operational optimization, constituting an initial geographic filter for subsequent, more detailed evaluations.

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The article is structured as follows: Section 2 presents the system framework, describes the busbars studied, and details the economic valuation methodology for each technology; Section 3 presents comparative results by busbar and configuration; and Section 4 presents the main conclusions and implications for investment and planning.

2. Systemic Context and Methodological Framework

To examine how this new pricing regime translates into realizable value, the study limits its analysis to eight 220 kV SEN busbars distributed throughout Chile (north, center, and south), selected for their contrasts in solar resources and intraday price structures. This sample allows for the observation of differential value creation mechanisms for photovoltaic, storage, and hybrid technologies. The Table 1 summarizes the main characteristics of these busbars in the reference year.

Table 1 Analyzed bars and their operating characteristics for the year 2023.

Zone	Bus	Location of the main node	Characteristics (Coordinador Eléctrico Nacional; Generadoras de Chile, 2025; World Bank Group et al., 2019)
North	Crucero	Antofagasta	GHI 2300–2500 kWh/m² year. Renewable 60% / Thermal 40%; renewable energy is led by PV with a high density of parks.
	Diego de Almagro	Atacama	GHI 2200–2500 kWh/m² year. Renewable 72% / Thermal 28%; PV predominance and increasing hybridization with BESS. Strong daytime injection.
	Cardones		
Central	Quillota	Valparaíso	GHI 1600–1800 kWh/m² year. Renewable 77% / Thermal 23%; PV predominates (mostly PMGD) supplemented by hydro.
	Polpaico	Metropolitana De Santiago	GHI 1600–1800 kWh/m² year. Renewable 80% / Thermal 20%; new injections, mostly PV, with support from other technologies.
	Rapel	O'Higgins	GHI 1550–1800 kWh/m² year. Renewable 87% / Thermal 13%; historical presence of hydro, PV accounts for the majority of new additions.
	Charrúa	BioBío	GHI 1200–1750 kWh/m² year. Renewable 76% / Thermal 24%; diversified matrix (hydro and wind significant), growing PV.
South	Puerto Montt	Los Lagos	GHI 1000–1300 kWh/m² year. Renewable 70% / Thermal 30%; mainly hydropower, with PV being a minority due to a smaller solar resource.

For each bar, hourly series from 2023 are used, matching:

- Marginal costs (CMg_h, USD/MWh): published by the National Electricity Coordinator of Chile.
- Photovoltaic generation ($E_{PV,h}$, kWh): published on the website of the Ministry of Energy's Solar Explorer.

Generation is normalized to installed power by:

$$E_{PV,h}^{norm} = \frac{E_{PV,h}}{P_{instalada}}, \qquad (Eq. 1)$$

where $P_{instalada}$ is defined in the following section for all bars. This standardization allows the effect of local conditions (irradiation and prices) on economic viability to be isolated, without variations due to site-specific design. The following sections characterize the energy performance of the photovoltaic plant and the marginal cost structure that determines the arbitrage potential at each location.

2.1. Energy Generation System

The power generation system defines a reference photovoltaic plant of 100 MW for all busbars: a monofacial system in a fixed array (30°/0°), inverter efficiency of 96%, and total losses of 14%. The 2023 hourly generation profiles come from the Ministry of Energy's Solar Explorer, normalized to installed capacity to ensure comparability between locations. The summarized data are shown in Table 2.

Table 2 Technical parameters of the reference photovoltaic configuration.

Category	Parameter	Value
PV System	Technology	Monofacial silicon
	Installed Capacity	100 MW
Configuration	Arrangement	Fixed-tilt (no tracking)
	Inclination/Azimuth	30° / 0° (Norte)
	Temperature Coeff.	-0.45 %/°C
Inverter and Losses	Rated Power	100 MW
	Efficiency	96%
	Total Loss Factor	14%

From hourly generation data, two key metrics are calculated. Total annual energy (GWh/year) is obtained by:

$$E_{total} = \sum_{h=1}^{8760} E_h \times 10^{-6}, \qquad (Eq. 2)$$

where E_h is the energy generated per hour (kWh). The Capacity Factor (CF) represents the relationship between actual and potential generation:

$$CF = \frac{E_{total}}{P_{instalada} \times 8760} \times 100, \qquad (Eq. 3)$$

where $P_{instalada}$= 100 MW and 8760 are the hours per year. Figure 1 presents these indicators for the eight busbars, highlighting the system's north-south productivity gradient:

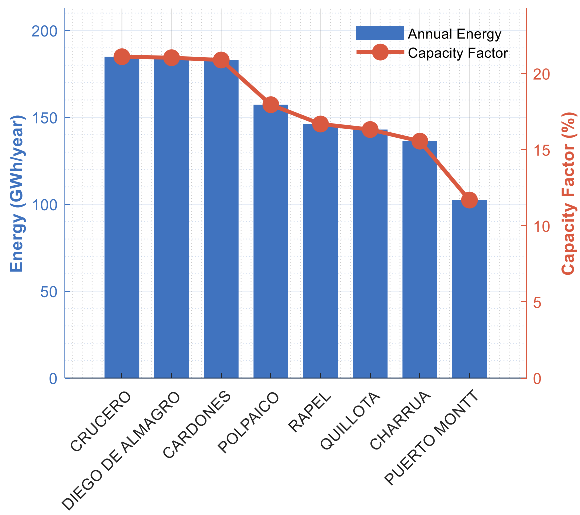

Figure 1 Annual generation and capacity factor per bus.

The results for a 100 MW PV plant confirm the north–south gradient in the resource and its reflection in production: the northern bars (Crucero, Diego de Almagro and Cardones) converge to very similar values (~183–185 GWh/year, CF ~20.9–21.1%), suggesting comparable irradiance conditions and low sensitivity to small site differences. In the central zone, an intermediate dispersion is observed: Polpaico reaches 157 GWh (CF 17.95%), above Quillota and Rapel (~143–146 GWh; CF ~16.3–16.7%), reflecting local variations in climate and seasonal shading. Towards the south, Charrúa reduces to 136 GWh (CF 15.56%) and Puerto Montt marks the minimum with 102 GWh (CF 11.7%), consistent with the sustained drop in irradiance.

Maintaining the same technical configuration, the CF varies by almost 10 percentage points between extremes (21.1% to 11.7%). This difference establishes an objective basis for evaluating the energy capture of standalone PV systems and the potential value of supplementing with BESS storage in locations with lower CF or greater intraday variability.

2.2. Marginal Costs

The economic viability of storage is largely explained by valuation differentials over time—intraday, daily, or even seasonal—and, in some cases, between locations. These spreads open up arbitrage opportunities: charging when energy is cheap and discharging when it is expensive. Effective utilization depends on the magnitude of the differential, as well as its frequency and duration, cycle efficiency, equipment degradation, and market costs and restrictions.

To characterize it in each bar, two continuous 4-hour time windows are identified: the one with the lowest average CMg (buy, $\overline{CMg_{min}}$) and the one with the highest CMg (sell, $\overline{CMg_{max}}$).

The arbitrage spread is calculated as:

$$\Delta CMg = \overline{CMg_{max}} - \overline{CMg_{min}}, \qquad (Eq.4)$$

where:

$$\overline{CMg_{min}} = \frac{1}{4} \sum_{h \in V_{min}} CMg_h, \qquad (Eq.5)$$

$$\overline{CMg_{max}} = \frac{1}{4} \sum_{h \in V_{max}} CMg_h, \qquad (Eq.6)$$

where V_{min} and V_{max} are the consecutive 4-hour windows that minimize and maximize the average CMg, respectively. The values and spreads for each bar are shown in Figure .

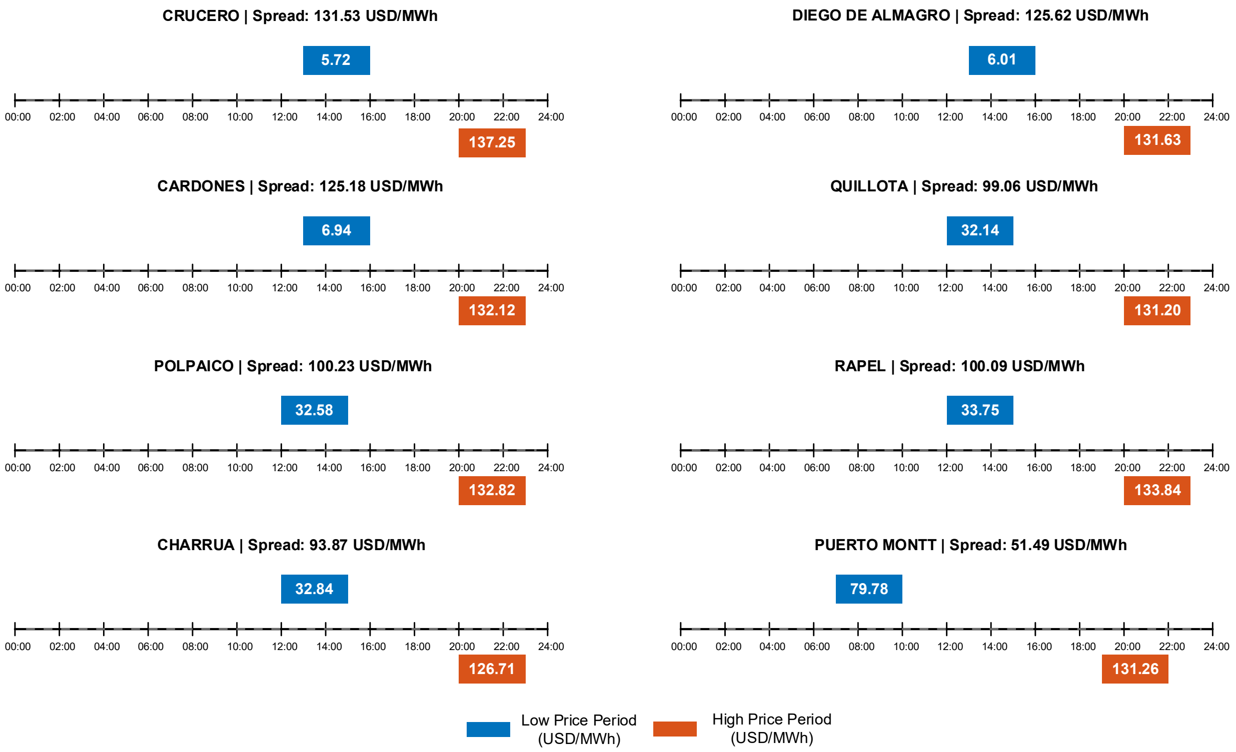

Figure Each bar represents a continuous 4-hour time window. Blue indicates the low valuation period (lower average CMg) and brown the high valuation period (higher average CMg), expressed in USD/MWh.

The results reveal marked heterogeneity: the northern bars exhibit the highest spreads (Crucero 131.53 USD/MWh, Diego de Almagro 125.62 USD/MWh, Cardones 125.18 USD/MWh), driven by high solar penetration that depresses daytime prices. The central bars present intermediate spreads (~100 USD/MWh in Polpaico, Quillota, Rapel), while the transition (Charrúa 93.87 USD/MWh) and southern (Puerto Montt 51.49 USD/MWh) zones register progressively narrower spreads, reflecting lower variable renewable penetration and distinct demand profiles.

This spread quantifies both the gross potential for temporary arbitrage for storage and the economic penalty of concentrating PV generation during low CMg hours.

2.3. Economic valuation

The economic evaluation compares the three technologies using a simplified model that captures the essential value creation mechanisms, under conservative operating assumptions. Within this framework, a standalone photovoltaic system obtains its annual revenue from the direct sale of energy at market prices.

$$I_{PV} = E_{PV} \cdot \bar{p}_{PV}, \qquad \text{(Eq.7)}$$

where E_{PV} is the annual energy generated (MWh) and $\bar{p}_{PV}$ is the weighted average price per hourly generation (USD/MWh), calculated as:

$$\bar{p}_{PV} = \frac{\sum_{h=1}^{8760} E_{PV,h} \cdot CMg_h}{E_{PV}}, \qquad \text{(Eq.8)}$$

This average, weighted by the energy contribution of each hour, captures the effective value of photovoltaic generation. The initial investment is modeled as CAPEX_PV. A standalone BESS operates through intraday arbitrage: charging during off-peak hours and discharging when prices are high. Assuming a full daily cycle, the annual energy mobilized is:

$$E_{BESS} = 365 \cdot E_{nominal} \cdot \eta_{RT}, \qquad \text{(Eq.9)}$$

where $E_{nominal}$ is the energy capacity (MWh) and $\eta_{RT} = 85\%$ is the round-trip efficiency that reflects conversion losses. The annual margin considers both the selling price and the efficiency-adjusted purchase cost:

$$I_{BESS} = E_{BESS} \cdot \left(\bar{p}_{max} - \frac{\bar{p}_{min}}{\eta_{RT}}\right), \qquad \text{(Eq.10)}$$

The prices $\bar{p}_{max}$ and $\bar{p}_{min}$ correspond to the averages in the 4-hour windows of highest and lowest valuation identified in section 2.2 by equations (5) and (6) and where the initial investment is $CAPEX_{BESS}$.

Finally, the hybrid system represents the complete integration of both technologies. Under the assumption of full time-shifting, all photovoltaic generation is stored during the day and sold during the peak value period identified for each busbar. This configuration maximizes value capture by avoiding the overlap between peak solar supply and price lows.

$$I_{híbrido} = E_{PV} \cdot \eta_{RT} \cdot \bar{p}_{max}, \qquad \text{(Eq.11)}$$

where $\bar{p}_{max}$ is the average price in the window of maximum appreciation (Eq. 6). The investment combines both components:

$$CAPEX_{híbrido} = CAPEX_{PV} + CAPEX_{BESS}, \qquad \text{(Eq.12)}$$

This formulation establishes an upper limit of profitability under optimal utilization, useful as a comparative reference between locations.

Based on this, viability is assessed using three complementary indicators. The Simple Payback Period (SPP), or in Figure 3 simply called Payback, quantifies the time required to recover the investment through undiscounted cash flows:

$$PBP = \min\left\{n: \sum_{t=1}^{n} F_t \geq |F_0|\right\}, \qquad (Eq. 13)$$

where F_0 represents the initial investment (negative value) and F_t the annual cash flows. Lower values indicate faster capital recovery.

Net Present Value (NPV) incorporates the time value of money by updating future cash flows:

$$NPV = \sum_{t=0}^{25} \frac{F_t}{(1+r)^t}, \qquad (Eq. 14)$$

where r is the real discount rate (8% per year) and a useful life of 25 years is considered. A positive NPV indicates that the project generates economic value above the opportunity cost of capital.

The Internal Rate of Return (IRR) is defined as the discount rate at which the present value of cash flows equals the initial investment, and its formula is as follows:

$$0 = \sum_{t=0}^{25} \frac{F_t}{(1+IRR)^t} = 0\ , \qquad (Eq. 15)$$

The IRR is obtained through iterative numerical methods and represents the intrinsic profitability of the project. It is considered attractive when IRR > r, where r is the discount rate or cost of capital.

2.4. Simulation Framework Parameters and Outputs

To ensure comparability between busbars and isolate specific design effects, uniform technical and economic parameters are adopted across all locations. Table 3 summarizes these reference values, representative of 2023-2024 market conditions for utility-scale projects.

Table 3 Economic and sizing parameters.

Category	Item	Value	Unit
PV Standalone	Capacity	100	MW
	Specific CAPEX	800	USD/kW
	Total CAPEX	80	MUSD
BESS Standalone	Power	100	MW
	Energy capacity	400	MWh
	Duration	4	hours
	Round-trip efficiency	85	%
	Specific CAPEX	300	USD/kWh
	Total CAPEX	120	MUSD
PV+BESS	Total CAPEX	200	MUSD
Financial parameters	Real discount rate	8	%
	Service life	25	years

With these fixed parameters, the differences in profitability between bars reflect exclusively variations in solar resource, price structure and their correlation, eliminating site-specific optimization effects that would hinder territorial comparison.

Regarding standardized outputs, a bar-by-bar analysis is performed, generating standardized economic indicators that allow for systematic inter-regional comparison and the identification of optimal configurations based on nodal characteristics. These are:

- Initial Investment (CAPEX, MUSD): Capital required per configuration.
- Net Present Value (NPV, MUSD): Absolute return adjusted for cost of capital.
- Internal Rate of Return (IRR, %): Percentage return on investment.
- Payback Period (Years): Investment recovery speed.

These indicators allow us to: (i) quantify the decoupling between physical availability of resources and economic valuation, (ii) establish a ranking of viability by technology and location, and (iii) identify areas where storage or hybridization maximize value capture in the face of solar saturation or price volatility.

3. Results

The economic evaluation of the eight busbars reveals distinct territorial patterns that confirm the study's central hypothesis: the viability of renewable energy projects depends not only on the available solar resource, but also on the interaction between generation, marginal price structure, and the temporal correlation between the two. This section presents the comparative results of the three technological configurations (standalone PV, standalone BESS, and hybrid PV+BESS system), demonstrating how nodal conditions determine effective value capture.

Figure 2 summarizes the four main economic indicators for the eight bars studied, allowing an integrated reading of the relative viability of each technology according to its geographical location.

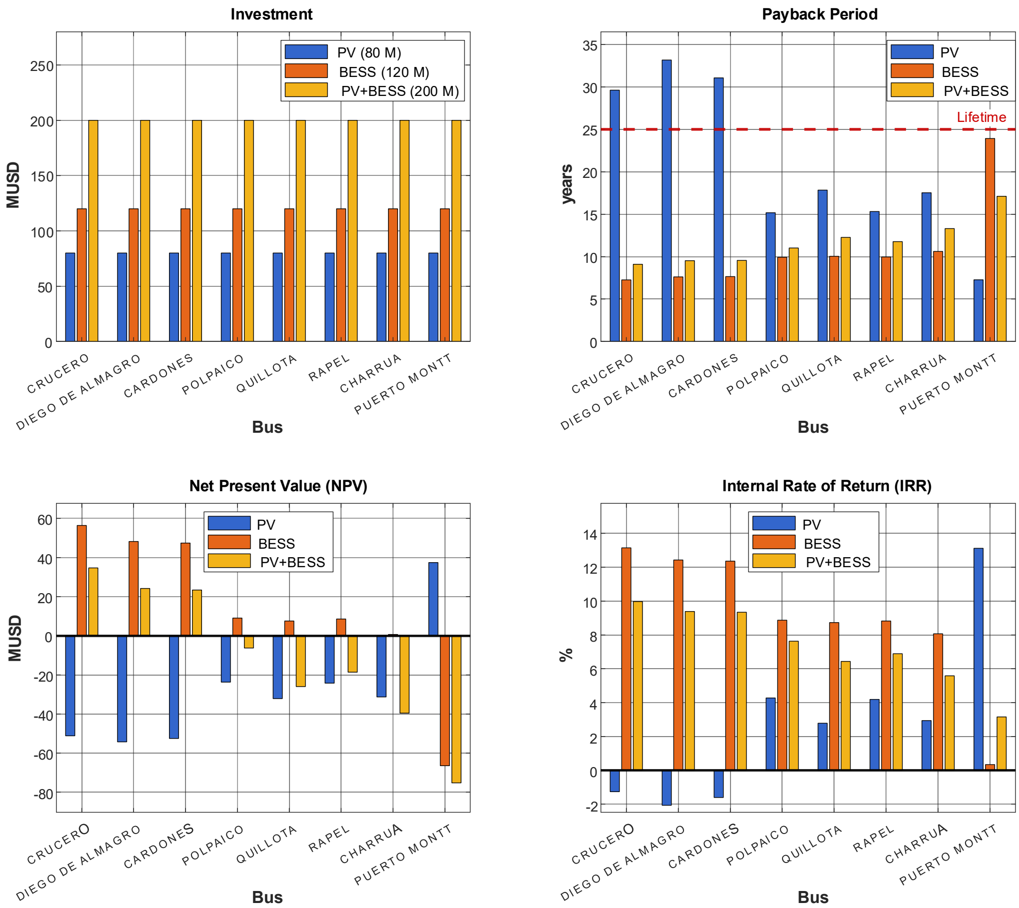

Figure 2 Comparative Economic Assessment: Investment, Payback, NPV and IRR

The investment chart confirms the methodological premise: all bars face identical capital requirements (80 MUSD for PV, 120 MUSD for BESS, 200 MUSD for the hybrid system), so the differences in profitability are attributed to operational and local market factors, not to design variations.

The payback period exhibits territorial divergence. The northern bars show prolonged paybacks for standalone PV projects (e.g., in the range of ~30 years), exceeding the project's useful life (25 years). In contrast, Puerto Montt has the most favorable payback for PV projects (≈7.4 years), followed by Polpaico (≈15.3 years). For standalone BESS projects, the pattern is reversed: the northern bars show faster paybacks (≈7-8 years), while Puerto Montt reaches ≈24 years.

This divergence is reflected in the NPV (8% annual discount). Standalone PV systems show negative NPV in seven of the eight busbars, indicating destruction of economic value despite higher capacity factors in the north; only Puerto Montt achieves a positive NPV. Standalone storage, on the other hand, exhibits positive NPV in seven of the eight busbars, with the lowest values in Puerto Montt (negative value). The hybrid system shows positive profitability in four of the eight busbars, with the highest values in the north and a specific central zone, and negative results in Charrúa and Puerto Montt.

The IRR confirms these findings. PV standalone shows a negative or lower IRR (cost of capital) in most of the busbars, while Puerto Montt exceeds that threshold (≈13.2%). BESS standalone maintains an IRR above 8% in almost the entire territory, becoming marginal or negative in Puerto Montt. The hybrid system ranges between ~10% (north) and ~3% (south), with intermediate values in the central zone (≈6-9%).

3.1. North versus South

In the north (Crucero, Diego de Almagro, Cardones), the high penetration of photovoltaics has generated a price regime characterized by severe daytime depression: marginal costs during peak irradiation hours are very low, while nighttime prices remain high (often >100 USD/MWh). This phenomenon (price cannibalization or duck curve) results in high arbitrage spreads (> ~125 USD/MWh) that favor storage but penalize direct photovoltaic generation (low $\bar{p}_{PV}$).

In contrast, Puerto Montt exhibits low solar penetration (CF ≈ 11.7%) and a more homogeneous price structure, with narrow spreads (~51.5 USD/MWh). This context favors direct photovoltaic generation, which captures higher average prices, but reduces the value that can be captured through arbitrage, discouraging standalone storage and hybridization under current assumptions.

The busbars in the central zone (Polpaico, Quillota, Rapel, Charrúa) occupy intermediate positions: moderate spreads (~88–100 USD/MWh) and $\bar{p}_{PV}$ between 50–70 USD/MWh. This transition zone presents marginal viability for hybrid configurations, where storage mitigates the negative correlation between generation and price without reaching the margins of pure arbitrage observed in the north.

3.2. Decoupling between Physical Resource and Economic Value

There is no positive correlation between capacity factor and profitability. Crucero, Diego de Almagro, and Cardones lead in production (≈183–185 GWh/year; capacity factor ≈ 21%), but exhibit the worst financial indicators for standalone PV (negative NPV). Conversely, Puerto Montt generates ≈102 GWh/year (capacity factor ≈ 11.7%) and achieves the highest photovoltaic profitability in the system. In contexts of high variable renewable penetration, the time-based price structure predominates over the solar capacity factor as a determinant of viability.

3.3. Robustness of Storage versus Photovoltaics

Standalone storage emerges as the technology with the greatest territorial robustness: it presents a positive NPV and IRR > 8% in seven out of eight busbars, capitalizing on intraday differentials in the SEN. Only in Puerto Montt, where the energy mix is predominantly hydroelectric with low solar participation, is the spread insufficient. Conversely, standalone photovoltaics exhibits high territorial specificity, viable mainly where daytime prices are not depressed. The hybrid PV+BESS system offers an intermediate option: positive profitability in four out of eight busbars, with the advantage of shifting solar energy to more valuable periods, but with a relatively lower return than pure BESS due to higher capital commitment.

3.4. Viability ranking by technology

The profitability hierarchy among technologies and locations reflects the interaction between available solar resources, the time-based price structure, and the degree of correlation between photovoltaic generation and hourly valuation. While in the north, high solar penetration compresses daytime prices and penalizes direct PV generation, in the south, the limited renewable supply maintains high valuations even during daylight hours. Storage captures value through the time-shifting of energy, proving more profitable where day-night differentials are pronounced. Hybrid systems face doubling of CAPEX, which erodes their competitiveness compared to standalone configurations when a single technology efficiently captures the available value. To summarize the economic hierarchy of the evaluated configurations, Table 4 presents the ranking of bars ordered by decreasing NPV for each technology. The eight bars are ordered from highest to lowest profitability for each technology and present three complementary indicators: NPV, IRR and simple payback period.

Table 4 Ranking of economic viability by technology.

Rank	PV Standalone		BESS Standalone		Hybrid PV+BESS	
	Bus	NPV / IRR / PBP	Bus	NPV / IRR / PBP	Bus	NPV / IRR / PBP
1st	Puerto Montt	38.2 / 13.2% / 7.4	Crucero	55.9 / 13.2% / 7.4	Crucero	35.9 / 10.0% / 9.2
2nd	Polpaico	-18.9 / 4.3% / 15.3	Diego de Almagro	47.8 / 12.5% / 7.8	Diego de Almagro	25.4 / 9.4% / 9.6
3rd	Rapel	-19.1 / 4.2% / 15.5	Cardones	46.2 / 12.4% / 7.9	Cardones	23.6 / 9.3% / 9.7
4th	Charrúa	-24.1 / 3.0% / 17.7	Polpaico	9.3 / 8.8% / 10.2	Polpaico	1.8 / 7.6% / 11.8
5th	Quillota	-28.1 / 2.8% / 18.5	Quillota	9.0 / 8.8% / 10.3	Rapel	-0.3 / 6.9% / 12.9
6th	Cardones	-49.7 / -1.4% / 30.9	Rapel	8.9 / 8.8% / 10.3	Quillota	-6.0 / 6.4% / 14.0
7th	Diego de Almagro	-52.8 / -1.8% / 32.6	Charrúa	8.0 / 8.0% / 11.2	Charrúa	-35.8 / 5.6% / 13.3
8th	Crucero	-53.3 / -1.0% / 29.9	Puerto Montt	-67.8 / 0.4% / 24.1	Puerto Montt	-76.2 / 3.2% / 17.3

The results vary by technology: photovoltaic systems only show positive profitability in Puerto Montt (NPV 38.2 million USD; IRR 13.2%), while the other seven busbars register negative NPV, with the north being the least favorable segment (NPV between -49 and -53 million USD). Energy storage (BESS) exhibits the most consistent performance: 7 out of 8 busbars are profitable, led by the north (NPV +46 to +56 million USD, IRR >12%, payback <8 years). In the central zone, profitability is maintained, although more limited (NPV +8 to +9 million USD; IRR ~8.8%). Only Puerto Montt shows a negative NPV in BESS (-67.8 million USD). Hybrid PV+BESS systems replicate the storage pattern, but with lower returns, maintaining positive NPV in four busbars in the north and central zone.

These findings are corroborated by the project pipeline under construction reported by Generadoras de Chile (Boletín Generadoras de Chile, 2025), where 55.3% of the storage capacity under development (5,408 MW) corresponds to standalone BESS systems, concentrated mainly in the northern regions—Atacama (68%), Antofagasta (72%), and Tarapacá (54%)—where the proposed model predicts the highest returns (IRR 12–13%). Conversely, hybrid PV+BESS systems represent only 5.0% of the pipeline (490 MW), with a marginal presence in the transitional north-central zone (e.g., Tarapacá 13% and Valparaíso with less than 15% of regional capacity), consistent with the borderline viability identified in the analysis. This alignment between economic projections and real investment decisions is consistent with the predictive capacity of the model under the adopted assumptions, and reflects the prevalence of pure arbitrage strategies in the current context of daytime solar saturation of the SEN.

The comparison between indicators confirms the hierarchy: where the NPV is higher, the IRR is also high and the return period shorter, indicating robustness against the evaluation criterion. Even so, configurations with marginal NPV but an IRR higher than the cost of capital (8%) can be attractive to investors with capital constraints or specific risk profiles, especially in the central region, where several technologies operate near the viability threshold.

As a visual summary, Figure 3 relates the Global Horizontal Irradiance (GHI) to the location of the SEN bars (from Tarapacá to Los Lagos), providing the territorial context to compare energy capture and guide the optimal configuration per node.

The boxes distinguish three economic zones:

- **North:** Crucero (CF 21.33%), Diego de Almagro (CF 21.04%) and Cardones (CF 20.49%) have the highest FC; the optimal configuration is BESS standalone and PV+BESS is also viable (moderate profitability).
- **Central:** Intermediate CF (15.56–17.93%): Polpaico favors BESS standalone (optimal) and accepts PV+BESS as a marginal option; in Quillota, Rapel and Charrúa only BESS standalone is viable.
- **South:** Puerto Montt (CF 11.7%) is the exception: optimal PV standalone; BESS and PV+BESS are not viable.

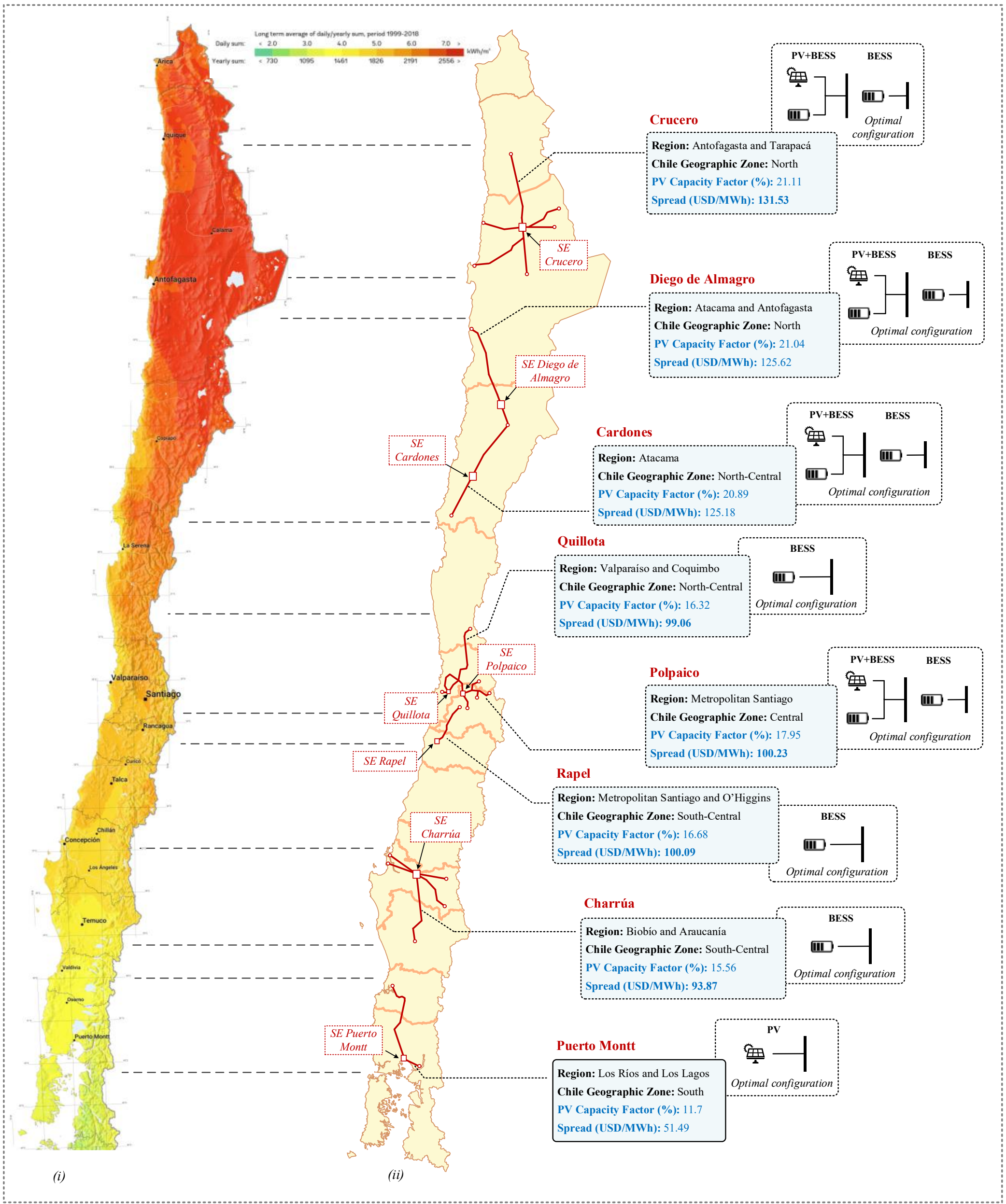

Figure 3 Geographic map of Chile. *(i)* Distribution of Global Horizontal irradiance and *(ii)* Spatial location of the study bars.

In summary, the overlap of irradiance and nodes suggests that profitability depends not only on the resource itself, but also on the nodal signal and grid conditions. Based on this, in the following sections we quantify PV generation per bus and characterize the spreads that determine the BESS and PV+BESS values.

3.5. Discussion

The results indicate marked territorial differentiation, reflecting the interaction between resource and local prices. In the north, high solar penetration leads to daytime price depressions and high spreads (>125 USD/MWh). Under these conditions, standalone PV faces compromised profitability by valuing its production during off-peak hours; standalone storage, on the other hand, presents significant opportunities. In the south, low solar penetration and the hydroelectric matrix maintain narrow spreads (~51 USD/MWh), which favors direct PV but limits the value that can be captured by BESS (Bulk Energy Storage System). The central region constitutes a transitional space with marginal viability for multiple technologies, sensitive to more sophisticated operational strategies (optimized dispatch, ancillary services, long-term contracts).

A key finding is the lack of a direct correlation between solar capacity factor and economic profitability. In contexts of high renewable energy penetration, intraday price formation dominates viability. This observation is relevant for land-use planning: the optimal location based on solar resources does not necessarily coincide with the most economically attractive location under market signals.

The results reveal a relative performance of hybridization, as the PV+BESS configuration does not always maximize value compared to a standalone BESS, especially in the north where spreads exceed $125 USD/MWh. This counterintuitive result is explained by an imbalance between generation and storage capacity: the 100 MW PV system generates approximately 500 MWh/day on average, while the BESS, sized for 4 hours of operation (400 MWh), can only store about 80% of the daily production. The surplus photovoltaic energy must be sold at depressed daytime prices ($30-40 USD/MWh), capturing only a fraction of the value that could be obtained through pure arbitrage. Although PV+BESS increases absolute revenues compared to standalone BESS (approximately $17 million USD vs. approximately $15 million USD annually), the increased capital required ($200 million USD vs. $120 million USD) dilutes normalized profitability, resulting in lower NPVs ($24–36 million USD vs. $46–56 million USD). This finding suggests that in contexts of severe solar saturation, the relative sizing between generation and storage emerges as a critical design variable, and that configurations with longer storage durations (>4 hours) or a lower PV/BESS ratio could improve the value capture of the hybrid system.

The results should be interpreted considering the model's assumptions: simplified strip-based operation, no OPEX, no degradation or ancillary services, and fixed sizing (100 MW PV, 400 MWh BESS) without site-specific optimization. Future extensions will incorporate storage degradation and variable efficiency, operation and maintenance costs, PV/BESS ratio optimization and storage duration, time-of-use dispatch and multi-year scenarios for renewable energy prices and penetration, as well as grid constraints and contractual revenue combinations.

4. Conclusion

This study proposes a computationally low-load analytical framework to evaluate the economic viability of PV, BESS, and hybrid PV+BESS systems at eight busbars of the Chilean National Electric System. The results show that, in markets with high renewable energy penetration, the time-series price structure predominates over the solar capacity factor as a determinant of profitability.

The analysis identifies three distinct economic zones. In the north (Crucero, Diego de Almagro, Cardones), photovoltaic saturation generates spreads exceeding USD 125/MWh, favoring standalone storage but penalizing direct PV generation. The central zone (Polpaico, Quillota, Rapel, Charrúa) registers intermediate spreads (approximately USD 88–100/MWh) with marginal viability for multiple technologies, creating a transitional space where operational refinements can influence profitability. In the south (Puerto Montt), low solar penetration maintains high valuations that make PV viable, but the narrow spread (approximately USD 51/MWh) is insufficient to make storage profitable.

The identified thresholds provide quantitative criteria for territorial characterization: standalone BESS achieves robust profitability with spreads above USD 100/MWh (north: USD 125-131/MWh) and marginal viability with spreads of USD 88-100/MWh (central zone); standalone PV is viable only in Puerto Montt, where low solar penetration maintains high valuations during generation hours; while hybrid systems offer greater geographical robustness by combining both value capture mechanisms. However, hybridization is not always synergistic: in the north, standalone BESS achieves NPVs of USD 46-56 million versus USD 24-36 million in a PV+BESS configuration, demonstrating that in contexts of extreme spreads (>USD 125/MWh), fixed sizing (PV/BESS ratio of 1:4h) limits value capture by generating surpluses that must be sold at depressed daytime prices.

The model's simplifications—constant hourly operation, absence of degradation and OPEX, and valuation by time slots—allow for a replicable and computationally efficient initial territorial filter. This approach facilitates the early identification of opportunities, establishing an analytical foundation that future extensions can refine through optimized dispatch, multi-year analysis, and modeling of complementary services.

In summary, this work demonstrates, through quantitative analysis, that the optimal location of renewable assets transcends the availability of the primary resource. In an electrical system in transition, nodal price signals emerge as the critical factor determining the optimal location and technological configuration to realize the value of investments in generation and storage. This analytical framework is particularly urgent given the expansion of energy storage in Chile, where, according to data from the National Energy Commission, 52 BESS projects are under construction as of September 2025, totaling approximately 6,000 MW and 26,179 MWh. The study's results suggest that the differentiated territorial viability of these investments requires incorporating busbar price signals from the initial planning stages.

5. References

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