UNIVERSIDAD ADOLFO IBÁÑEZ

CENTRA

CENTER FOR ENERGY TRANSITION

VPP Roadmap for Chile

Virtual Power Plants for Sustainable and Resilient Energy Systems in Chile

Project Team

Project Title: Virtual Power Plants (VPPs) for Sustainable and Resilient Energy Systems in Chile

Report Title: Final Report – Industrial Research Chair

Authors:

- **Lester Marrero, PhD** – Postdoctoral Fellow, CENTRA
- **Daniel Olivares, PhD** – Former Chair
- **Juan Pablo Torres, PhD** – Chair
- **Luis Gutiérrez, PhD** – Co-Chair
- **Bernardo Severino** – Head of Studies, CENTRA
- **José María Cruz** – Head of Center, CENTRA

Research Assistants:

- **Vicente Guzmán**
- **Ignacio Pérez**
- **Valentina Arias**
- **Vicente Martínez**
- **Valentina Navarro**

Institution: Center for Energy Transition (CENTRA), Faculty of Engineering and Sciences, Universidad Adolfo Ibáñez

Partner Institution:

- **SAESA** (Pilot Project Partner)

Date: November 2025

Executive Summary

Chile is undergoing a decisive energy transformation, marked by high renewable penetration and growing challenges in grid stability and supply interruption risks. This report confirms that Virtual Power Plants (VPPs) are not just a theoretical aspiration, but a **technically and economically viable solution today** to provide flexibility and resilience to the national electric system.

Below are the five key takeaways derived from the study:

1. A National Potential of 8 GW by 2035

The most compelling finding of the report is the magnitude of the available resource. It is estimated that the national potential for VPPs in Chile reaches **8 GW**, combining "behind-the-meter" (BTM) batteries, electric vehicles, and electric climatization.

- This figure represents more than half of Chile’s current peak demand (~12 GW) and approximately one-quarter of the total installed capacity of the system.
- This deployment would allow avoiding costly investments in generation and transmission infrastructure by leveraging existing or projected distributed resources.

2. Immediate Economic Viability in the Current Market

Contrary to the belief that massive subsidies are required, the analysis of business models in representative zones (Lampa and Osorno) demonstrates that VPPs are profitable under current regulations or with minimal adjustments.

- **Profitability Threshold:** A VPP is financially viable starting from an aggregated capacity of **1 MW**.
- **Return on Investment:** Dynamic models show that, after an initial amortization period for implementation and marketing costs, operating margins become positive starting from the third year, recovering the initial investment in less than 4 years.
- **Diversified Revenues:** Profitability is sustained through "value stacking": primary frequency control, peak demand reduction, and local resilience services.

3. Resilience as a Critical Value-Add

Given Chile’s geographical and climatic vulnerability, evidenced by recent weather events and massive outages, VPPs offer unique value that traditional plants cannot match: local resilience.

- VPPs can be designed to operate in "island mode," maintaining power supply in communities during external contingencies.
- The technical study confirms that coordinating residential batteries to sustain critical services is feasible, reducing interruption indices (SAIDI/SAIFI) and avoiding penalties for distribution companies.

4. Overcomable Technical and Regulatory Challenges

Despite the potential, massive deployment faces "bottlenecks" requiring immediate political action:

- **Metering Infrastructure:** The lack of smart meters is a critical barrier. Without granular data, dynamic demand management is not feasible.
- **Grid Constraints:** Technical analysis (AC OPF) reveals that current distribution grids reach operational limits. In the studied networks, the maximum technical power export capacity is reached under the participation of approximately 21-25% of customers with batteries before violating voltage or thermal limits in LV networks.
- **Regulatory Gap:** The figure of the "independent aggregator" does not explicitly exist in Chilean regulation, limiting competition and participation in the wholesale market.

5. Roadmap and Pilot Project

To unlock this potential, the report proposes a clear roadmap and the design of a real-world pilot.

- **Immediate Action (Sandbox):** The creation of "regulatory sandboxes" is recommended to test VPPs without immediately modifying the entire electricity law.
- **Pilot Project with SAESA:** A specific pilot has been designed in southern Chile to validate ancillary service provision and island operation in the field, serving as a case study for future national regulation.
- **Long Term:** The final reform should aim to separate distribution from commercialization, allowing retail competition and dynamic tariffs that incentivize the end-user.

Contents

1 Introduction

The evolution of the electric power system has been characterized by a significant transition from centralized to decentralized generation paradigms. This shift is primarily driven by the increasing integration of distributed energy resources (DERs) (Shaviv, 2025). This decentralization needs innovative approaches to managing, controlling, and participating in electricity markets. Virtual Power Plants (VPPs) have emerged as a promising solution to these challenges, based on their potential to optimize the operational efficiency of distributed resources, enhance grid stability, and support the adoption of renewable energy technologies (Wang, 2025; Kaiss, 2025). These systems enable distributed resources to participate in ancillary services, demand response, and energy trading, providing grid operators with additional flexibility (Zhu, 2025; Pang, 2024; Wei, 2024).

In this global context, the Chilean electric power system is undergoing a significant transformation. Driven by the rapid integration of renewable energy sources, the electrification of energy services, and the growing impacts of climate-related events, one of the critical challenges Chile faces is the heightened risk of energy interruptions.

The contribution of non-conventional renewable energies to national generation by August 2025 is approximately 49.5 % (ACERA, n.d.). However, the effective integration of renewable energy sources, especially photovoltaic (PV), remains problematic and entails operational challenges at power system-level: transmission lines are congested in hours of high generation, there is dumping of surplus renewable energy due to this transmission grid congestion and the lack of flexible demand, and the electric system requires higher flexibility to balance the variable nature of renewable sources. For example, the total dumped of renewable energy as of June 2025 reached 2,421 GWh, representing an increase of 18.3 % compared to the same period in 2024. It is important to note that these challenges are not unique to Chile; similar situations can be found in other countries or regions with comparable scenarios, such as Brazil and Uruguay in Latin America (OLADE, 2025).

Furthermore, the electrification of industries and services such as heating, cooling, and transportation significantly increases total and peak electricity demand while raising expectations for uninterrupted service. For example, the electricity consumption of commercial and residential customers and services in 2023 increased by 5.9 % compared to 2022 and 10.2 % compared to 2021 (CNE, n.d.). Simultaneously, increasingly frequent and severe extreme weather events, including wildfires, storms, ice events, and landslides, pose growing threats to electricity infrastructure. Although the probability of individual events may be low, their consequences are becoming increasingly catastrophic.

Recent significant interruptions in electricity service have highlighted the vulnerability of Chile's predominantly centralized power grid, with limited real-time visibility, control, and flexibility. For example, a windstorm in August 2024 left six million people without electricity, and a nationwide blackout in February 2025 affected 98.5 % of the population. Similar events internationally, such as the winter storm in Texas in 2022, which resulted in hundreds of deaths and economic losses exceeding USD 190 billion, and the recent blackout in the Iberian

Peninsula in April 2025, demonstrate a limited response capacity of traditionally managed power systems to cope with these adverse events.

Along with these extreme events, service interruptions occur daily, affecting local communities by interfering with essential services. For instance, Fig. 1 illustrates the number of customers without electricity, as reported by the Superintendency of Electricity and Fuels (SEC, n.d. a), for days without any particular system-level fault or climate-related event. The chart indicates that over 30,000 customers may experience power outages on a common day. This scenario highlights the need to improve resiliency in distribution networks, where the increasing DERs can play a crucial role, if they can operate autonomously during contingency situations.

In the short term, the Chilean electric system will rely on ancillary services from non-synchronous DERs, especially during periods of high renewable generation. These ancillary services include mainly frequency control. The growing share of renewable energy sources poses significant challenges to the system supply-demand balance due to their variable nature and specific limitations. As a result, severe contingencies can occur more frequently.

VPPs are emerging as a transformative solution. By aggregating DERs, including residential PV panels, batteries, electric vehicles (EVs), and smart appliances, VPPs can deliver flexibility, resilience, and efficiency. Functioning as a coordinated network of small-scale energy assets, VPPs emulate the operations of a centralized power plant while offering additional benefits, including local back-up, demand response, and frequency control. While individual DERs may struggle to provide these services consistently, a sufficiently heterogeneous group of DERs can achieve this effectively.

During prolonged power outages, VPPs can leverage available energy resources in neighborhoods and communities to enhance local resilience. VPPs provide resilience benefits that traditional generation assets cannot, at a lower cost than alternatives. VPPs that include solar and storage at a household or commercial site provide power with far fewer potential points of failure than power supplied from a distant traditional power plant. VPPs also have the potential to help utilities restore power to impacted areas more quickly, reducing the length of outages for customers affected by severe weather events (DOE, 2025).

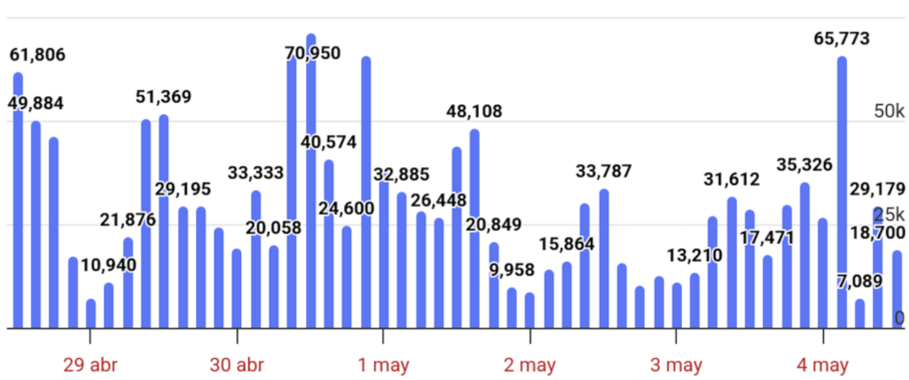

Fig. 1. Customers with electricity supply interruptions from noon on April 28 to noon on May 4, 2025 (SEC, n.d. a).

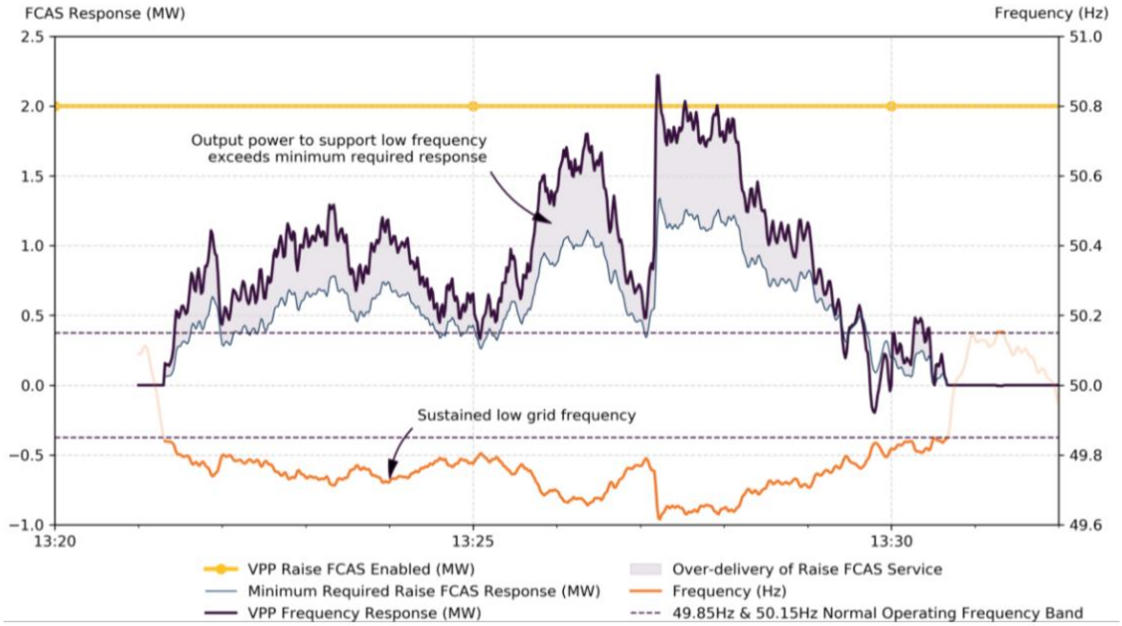

Fig. 2. Response of Energy Locals VPP to a frequency deviation below the normal operating range, March 2, 2020 (AEMO, 2020).

International experiences have also demonstrated the potential of VPPs in addressing severe frequency deviations. For example, Fig. 2 illustrates the actual aggregated response of Energy Locals VPP in Australia during an event that occurred on March 2, 2020. In this event, the system frequency decreased below 49.85 Hz, the lower limit for normal operation in Australia, and remained below this value for approximately 10 minutes.

The current inability to leverage and dispatch local DERs highlights the urgent need for a more decentralized and resilient grid architecture. The growth of DERs, combined with the revealed vulnerabilities, indicates both a necessity within the power system and a strategic opportunity: by aggregating and intelligently coordinating thousands of DERs, VPPs can provide essential grid services and enhance resilience across Chile's electric system.

1.1 Project Objectives

The general objective of the project **VPPs for Sustainable and Resilient Energy Systems in Chile** is to enhance the understanding and foster the implementation of Virtual Power Plants in Chile, enhancing grid resilience and sustainability while enabling equitable access to renewable energy for local communities, contributing to the country's carbon neutrality goals by 2050.

The project's Industrial Research Chair aims to enhance the understanding and foster the implementation of VPPs in Chile through the following short-term objectives:

- Inform Policy and Regulatory Frameworks for VPPs: To provide international evidence-based insights to key local stakeholders, including government agencies and regulatory bodies, to inform and foster the development of policies and regulations that enable the effective deployment of VPPs in Chile.
- Establish Technical Performance for VPPs in Chile: To assess the technical performance of VPPs in Chile for modeling the operation of local distributed energy resources.
- Identify High-Potential Areas for VPP Integration: To evaluate overall Chile's VPP potential based on the technical performance assessment and the expected development of renewable energy resources and grid infrastructure.
- Develop Viable Market Models for VPPs: To create and validate prototypical business models for VPPs that align with current market conditions or feasible market evolution.
- Lay the Foundation for Practical Implementation: To design a pilot project and regulatory sandbox to validate the real-world application of VPPs, bridging the gap between theory and practice.

1.2 Purpose and Scope of the Final Report

This report focuses on estimating the national potential for VPPs in Chile, analyzing viable market models for VPPs within the Chilean context, and implementing the modeling and simulation of their technical performance across representative regions.

The report defines five specific objectives:

- To summarize the key barriers currently limiting the VPP implementation in Chile, including regulatory, technical, and institutional barriers, and unique opportunities that could accelerate adoption. Additionally, the policy roadmap, structured into short-, medium-, and long-term recommendations, is presented to address the barriers and leverage the opportunities.
- To analyze the economic viability of VPPs in Chile based on the existing regulatory framework related to systemic-level and local grid services, including frequency control, peak demand reduction, and energy resilience.
- To assess the technical feasibility and performance of VPPs through mathematical modeling and simulation of low-voltage (LV) distribution networks in Chile.
- To estimate the national potential of VPPs in Chile by considering both the economic and technical viability in representative regions, along with the grid services that VPPs can provide.
- To design a framework for implementing a VPP pilot project in partnership with the SAESA distribution company that enhances the understanding of the economic and technical impacts of this technology in Chile.

1.3 Report Organization

The organization of this report is as follows: Section 2 presents key concepts and provides a brief overview of international experiences with VPPs. Section 3 summarizes the main barriers and opportunities for VPP implementation in the Chilean context. Section 4 describes the roadmap of policy recommendations. Section 5 presents the proposed general methodology. Section 6 examines the VPP business models through both static and dynamic analyses, considering the current regulatory framework in Chile. Section 7 presents the details of the technical assessment methodology for quantifying the VPP potential and applies it on two LV networks. Section 8 presents the estimation of national potential. Section 9 outlines the bases for the proposed pilot project to enhance the understanding and foster the implementation of VPPs in Chile. Finally, section 10 concludes the report.

2 Definition and International Context of VPPs

This section provides definitions, principles of operation for VPPs, together with a review on international experiences and lessons that could be applied to the Chilean case.

2.1 Definition and Operating Principles

Achieving energy transition goals will require new solutions that bring flexibility to the system. In this context, VPPs emerge as an innovative solution for a more resilient, efficient, and participatory electricity system. VPPs offer a new paradigm: instead of relying solely on large-scale power plants and hardened grids, the pooling of heterogeneous distributed resources (including residential and commercial solar panels and batteries, electric vehicles, and controllable loads) in an aggregation is possible, functioning together as a single resource (IEA, 2022). Thus, VPPs can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant (DOE, 2023). Fig. 3 illustrates how VPPs, through the aggregation and coordination of DERs, enable the control of these DERs.

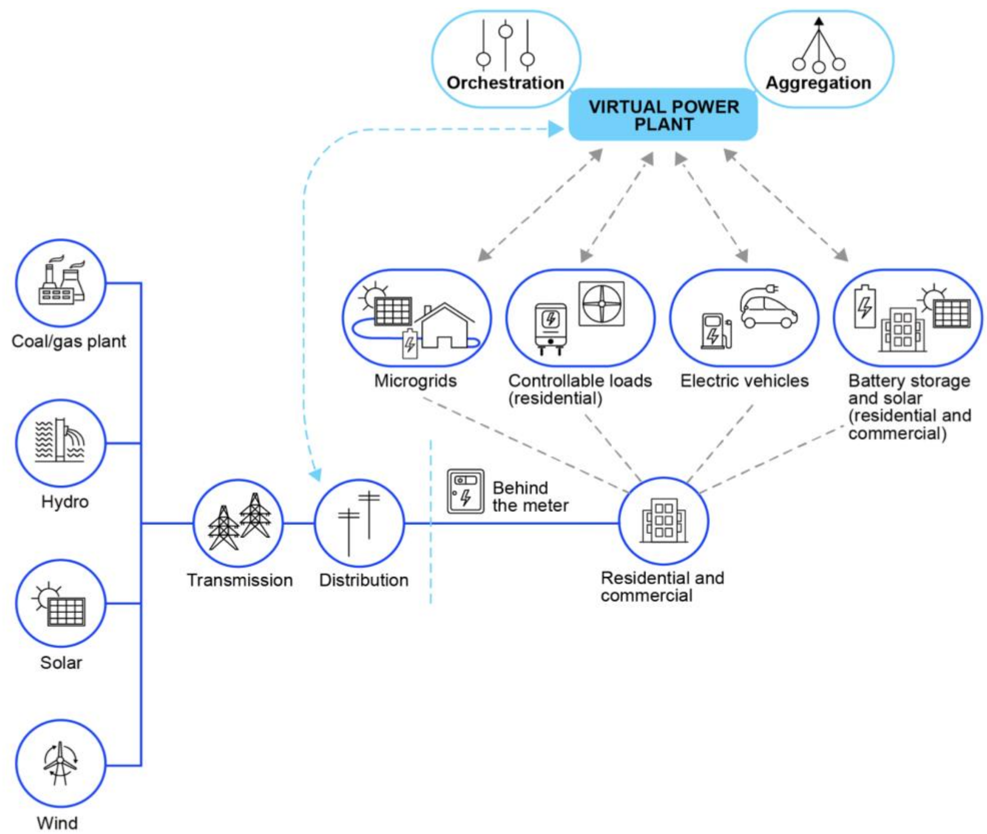

Fig. 3. Schematic diagram of a VPP (IEA, 2022).

In practice, a VPP dispatches power from multiple small sources. For example, it can instruct a hundred or so residential batteries to inject stored power in the evening, emulating the response of a traditional generation plant. Additionally, it can reduce aggregated consumption by slightly adjusting thermostats in many homes or temporarily reducing industrial loads during the peak of the system's electrical demand. These modifications occur automatically and almost instantly, responding to signals from the electricity market or directives from the system operator.

In other words, the VPP acts as an intelligent intermediary between the electric grid and the distributed resources: it knows how much energy they can deliver or stop consuming at any given moment and manages them collectively to provide services to the electric system (frequency control, voltage control, congestion relief, among others). It is important to note that VPPs do not require additional large-scale physical infrastructure. Instead, they utilize devices already installed in the community (behind the meter) and connect them through software. This approach makes VPPs a fast and cost-effective solution for increasing the capacity and flexibility of the electric system without the need to construct new power plants or power lines. However, some VPPs may also incorporate their own assets to enhance technical offerings and performance.

2.2 International Experience

Several leading jurisdictions already recognize VPPs as mainstream resources. Below are three key examples, highlighting the positive impact of changes in their policy regulations:

- Australia's progress relies on flexible and experimental regulatory frameworks. The electricity market operator (AEMO) led the nationwide VPP Demonstrations program (2019-2021), inviting aggregators to test involvement in multiple services (ARENA, n.d.a). The results of these pilots prompted the AEMO to update ancillary services specifications by introducing more granular metering protocols (AEMO, 2021). Additionally, regulatory sandboxes accelerate scale-up: the Energy Commission's 2020 framework grants temporary regulation exemptions for novel projects (AEMC, n.d.), and a policy-led sandbox from the energy regulator (AER) targets large-scale DER integration (AER, 2025).
- Federal regulatory actions support the adoption in the United States. A key milestone in the process is the Federal Energy Regulatory Commission (FERC) Order 2222 (2020), which obliges all RTO/ISO wholesale markets to admit the participation of aggregated DERs on equal footing with large power plants (FERC, 2020). In response to this order, each regional market has been adjusting rules to incorporate VPPs, triggering a wave of state pilots focused on defining how to register these resources, calculate their effective contribution, and coordinate them with the local utility. At the state level, the Department of Energy's report "Pathways to Commercial Liftoff: Virtual Power Plants" (DOE, 2023) framed the value proposition of VPPs, and its 2025 update calls for 80-160 GW of VPP capacity by 2030 to address near-term grid challenges of reliability, affordability, and extreme-weather resilience (DOE, 2025). Dedicated federal funding

now supports VPP demonstration projects focused on vulnerable communities more susceptible to power outages.

- The political and regulatory policy of the European Union centers on decentralization. The 2019 Clean Energy Package established a common legal framework to integrate demand aggregators into European electricity markets. Directive 2019/944 requires the removal of barriers and a level playing field for VPPs to participate in energy, ancillary service, and capacity markets (European Parliament & Council 2019). Simultaneously, European regulations on system operation (Network Codes) reinforce non-discrimination, obliging grid operators to accept services from all resources, including DERs, that meet technical criteria (CEDEC et al. 2019). Complementary initiatives seek to reinforce the transition; for example, in 2022, the European Commission launched a Digitization Plan for the energy sector (European Commission, 2022) that promotes real-time data exchange platforms between transmission and distribution operators, facilitating the harmonious management of distributed resources.

2.3 Lessons Learned for Chile

These experiences demonstrate the enabling policies for the VPP development, providing valuable lessons to accelerate adoption in Chile. Australia demonstrates that combining pilot projects with dynamic regulatory measures results in commercially viable VPPs, improving the grid resilience and providing ancillary services. Europe represents an example of a coordinated effort, including legal changes, investment in digitalization, and the emergence of innovative private actors, thus enabling the transition of VPPs to integral components of the dynamic electricity markets. The experience of the United States provides two key lessons. First, enabling regulatory changes (such as Order 2222) can significantly stimulate the development of VPP business models. Second, the success of VPPs also requires local policy and coordination actions, such as standardizing interfaces between transmission and distribution operators, ensuring the cybersecurity of numerous distributed connections, and educating or incentivizing consumers for participation.

3 Barriers and Opportunities

In a first outcome of this project, a Policy Brief (CENTRA, 2025) has been developed to outline the main barriers to address and the opportunities to leverage for VPP adoption in Chile. This section summarizes the main insights from this result.

3.1 Regulatory and Market Barriers

The electric system in Chile is regulated by the General Law of Electrical Services (LGSE, 2007), which establishes the fundamental legal framework governing the country's generation, transmission, and distribution of electric energy. Chilean current regulations do not explicitly recognize the role of the independent aggregator, posing barriers to its participation in energy markets and inhibiting its formalization. Specifically, Article 149 of the LGSE states that energy (and power) transfers occur between electric companies that own generation facilities, storage systems, or other facilities with the capacity to inject energy into the electric system. This limitation restricts the possibility of direct participation of demand in the energy market. Additionally, while Article 148 of the law allows generators to negotiate with both free and regulated customers, either directly or through distribution companies, on reductions or increases in demand imputed to their committed supplies, the Article only refers to generators and customers, with the first establishing all the conditions of the offer.

Likewise, market procedures, including the rules of the National Electric Coordinator (CEN) in Chile, have not been adapted to allow aggregated distributed resources to offer energy services to the system. While the regulation governing ancillary services, especially the Decree 113 (2019), permits the aggregation of resources at the level of free customers, it leaves the responsibility for complying with all service requirements and demands to the end-users themselves, which also implies a barrier to the implementation of aggregators.

Another challenge is the monopolized nature of retail electricity commercialization. Distribution companies are legally granted exclusivity in selling electricity to smaller customers (with a connected power of less than 300 kW) within their concessions. This exclusivity makes it difficult for new players, including aggregators, to compete by offering innovative services.

Furthermore, Law 20.571 (2014) and its amendment Law 21.118 (2018) allow end-users to install small renewable generation systems (Net billing). However, they strictly limit activities to self-consumption and restrict any potential participation in ancillary services or energy markets as part of a third-party technical or commercial aggregation. Similarly, the Decree 88 (2019) from the Ministry of Energy allows small resources for distributed generation (PMGDs) to be connected to a distribution company's grid. While this Decree facilitates the connection of these plants up to 9 MW, it remains restrictive regarding their aggregation and coordinated operation through VPPs.

3.2 Technological and Operational Barriers

The current infrastructure of distribution grids in Chile has significant shortcomings that hinder the implementation of VPPs. One major issue is the lack of smart meters in most households and small businesses. Although Chile initiated a replacement plan in 2019, it was suspended due to public opposition, leading to very low penetration rates until at least 2025. Without smart metering, it becomes challenging to implement dynamic hourly tariffs or interval settlement systems, which are crucial for rewarding the flexibility provided by VPPs.

Another concern is the lack of consistent standardization for the underlying technologies of VPPs. Currently, various distributed devices, such as solar inverters, electric vehicle chargers, batteries, and smart appliances, may use proprietary or incompatible communication protocols, making it difficult to connect them to a unified control platform. Furthermore, the proliferation of different interconnection standards leads to complexity for some DER technologies, while other technologies lack established standards altogether. This issue is technology-specific; for example, it is not an issue for most flexible-demand DERs but is a challenge for distributed PV generation and some electric vehicle chargers (DOE, 2023).

Chile lacks robust data platforms to facilitate real-time information exchange between the system operator, distribution companies, and potential aggregators. Such platforms are necessary for the secure coordination of the distributed resources. In this context, the content and format of electricity data can vary among grid actors. Therefore, standard data formats for sharing across these organizational platforms are needed.

Concerning the operational challenges, the increasing number of DERs adds complexity to their integration and dispatch. For a VPP, it is essential to understand the capabilities for frequency and voltage control, including the transient response at the connection point (Xie, 2024). Likewise, when the number of connected DERs increases, implying the processing of significant volumes of information, significant challenges for real-time communication within the VPP can arise. The differentiated communication modes and multiformat information collection also involve a heterogeneous communication network (Gao, 2024).

Additionally, cybersecurity can represent an important barrier. VPPs can be vulnerable to many types of cybersecurity threats that use the communication technologies and their distributed architecture, including: 1) false-data-injection attacks into sensors and control systems, potentially leading to blackouts; 2) malware attacks, which can compromise the integrity of VPPs; and 3) denial-of-service attacks, which aim to inundate VPP networks with excessive traffic (Alajlan, 2024). Finally, grid-edge optimization represents the primary challenge in algorithmic programming, involving the real-time control and coordination of numerous DERs. The non-convex nature, heterogeneity, and diversity of control modes of the problem require the development of computationally tractable models for large-scale optimization under uncertainty (Srivastava, 2025).

3.3 Institutional and Cultural Barriers

In addition to regulatory and technical issues, Chile faces an institutional and cultural challenge in adopting the VPP model. For decades, the electric scheme has revolved around large generation companies selling energy through distribution companies to passive customers. This highly centralized framework has influenced the planning and regulation of the electric system, with top-down solutions being the norm, and the integration of distributed actors being a relatively new concept. As a result, some stakeholders have distrust or a lack of knowledge about the reliability of distributed resources, or resistance from others who see their traditional business models threatened.

Likewise, Chilean end-users are typically unfamiliar with managing demand or participating in electricity programs beyond self-consumption via Net billing. To successfully implement VPPs, it is essential to invest in education and outreach programs. This effort will help citizens understand the opportunities and benefits of involvement, such as cost savings, compensation, and enhanced community resilience, thereby increasing engagement. International experience shows that without sufficient end-users willing to participate, VPPs do not achieve critical mass (Brehm, 2023). Overcoming this cultural inertia requires leadership from the authorities and demonstration projects that make the benefits visible.

3.4 Opportunities for Chile

Despite the above challenges, Chile exhibits unique conditions that favor the implementation of VPPs:

- The high current and projected renewable penetration highlight the real and immediate need for flexibility within the electric system. This scenario represents a clear case of systemic business for VPPs that economically justify the required reforms, as they can help avoid dumping renewables, manage variability, and defer grid investments.
- Chile already has a growing base of distributed resources on which to build VPPs: more than 37,000 installations under the Net billing scheme (up to 300 kW), 99.9 % of which are solar PV systems (SEC, n.d. b), a growing rate of electric vehicle sales (ANAC, 2025), and a rising trend in community self-generation projects. This distributed infrastructure can scale rapidly with the right incentives, forming the technological backbone of future VPPs. Looking forward, national targets and market trends indicate an increase in DERs. By 2035, the projected residential Net billing is approximately 700 MW. In the same year, EVs and air conditioning units are expected to account for about 23.2 % and 14.5 %, respectively, of the electric demand of the commercial, public, and residential sector (Moreno, 2024; E2BIZ, 2021).
- The country has local capabilities in innovation. Energy technology startups, research centers, and pioneering companies are already exploring digitization and energy management solutions. With the appropriate framework, these national actors could design VPP platforms, tailored to the specific context of Chile.

- Load flexibility benefit can be unlocked through effective planning and policies: Recent studies in Chile (CENTRA, 2023) indicate that, under existing market conditions, the country has the potential to integrate nearly 6 GW of residential distributed generation. This amount represents about 50 % of Chile's 2025 hourly maximum demand.
- At the political level, there is a strong national commitment to climate action and the modernization of the electricity sector. The Energy Planning 2023-2027 of the Ministry of Energy recognizes the importance of distributed generation and flexibility in achieving the goals set for 2050 (Ministry of Energy, 2025 a). This scenario creates a favorable environment for promoting structural reforms that support energy transition.

These factors suggest that while Chile faces regulatory, technical, and institutional challenges, it is well-positioned to pioneer VPPs in Latin America if appropriate reforms are implemented.

4 Policy Roadmap

This section presents the proposed policy roadmap for implementing VPPs in Chile, structured into short-, medium-, and long-term actions. By following these policies, Chile could effectively harness the potential of VPPs to safely integrate more renewable energy, enhance the resilience of the electricity system, and place end-users at the forefront of the energy transition.

4.1 Short-Term Priorities

1. Launch regulatory sandboxes and pilots

Initiate the development of VPPs through regulated experimentation frameworks. For example, implement one or several sandboxes that authorize VPP pilot projects under special conditions. In these pilots, the CEN could grant temporary exemptions to specific rules that currently prevent or limit the participation of aggregated distributed resources (for instance, exempting a group of customers from the requirement to be served only by the distribution company or allowing an aggregator to operate in a specific zone). Such projects would operate in supervised test environments, with limited duration and controlled scope. The objective is to gather technical, economic, and operational evidence based on actual results in the Chilean context before making permanent changes. Pilot selection criteria can include factors such as the diversity of participants, geographical uniqueness, and current grid capacity. Areas with higher renewable integration, detailed load data, or specific consumption patterns may be prioritized.

Experiences abroad demonstrate that these sandbox spaces facilitate regulatory adjustments. Australia and the United Kingdom launched regulated pilots, resulting in successful modifications in their markets.

In Chile, it is crucial to clearly define roles and governance responsibilities within sandboxes, along with establishing specific goals. One main objective is to foster collaboration among key entities in the energy sector. For instance, a pilot could be led by the CNE and the SEC, in coordination with the CEN. While these entities would not participate directly, they would provide supervision, technical feedback, and regulatory guidance. Instead, the distribution company should assume the technical responsibility, as it owns the distribution grid and has the relevant operational experience. Moreover, specific services to test and key performance indicators should be defined to ensure effective monitoring and evaluation, including flexibility provided, consumer savings, and effects on the grid. For Chile, it is particularly significant to assess the capacity of the VPP to enhance system resilience, which involves testing whether the VPP can maintain power supply while operating in island mode and coordinating the distributed resources.

2. Accelerate smart metering and digital infrastructure

Accelerate the modernization of distribution grids by launching a comprehensive program for the widespread installation of smart meters and robust communication systems. Globally, the lack of smart metering has proven to be a significant barrier to integrating small, distributed resources into flexibility schemes and VPPs. Without granular data, VPPs cannot operate effectively, limiting the participation of residential and small commercial customers. Chile must urgently relaunch its smart meter replacement plan, ensuring this initiative is supported by a clear and transparent communication strategy. This campaign should emphasize the tangible benefits to end-users, such as more accurate billing, enhanced service quality, greater control over energy usage, and expanded opportunities for savings. Building public trust and support is essential for the plan's success, as previous attempts have faced resistance due to limited information and misunderstandings about the technology.

Furthermore, it is crucial to deploy advanced telemetry and remote-control infrastructure. These technologies will allow real-time communication between distribution companies, aggregators, and end-user equipment, facilitating monitoring, management, and coordination of grid-edge resources and platforms for secure financial transactions. Priority should be given to completing meter and infrastructure upgrades within two years in regions with high DER penetration and a large share of residential customers. This foundational work will pave the way for implementing advanced tariff structures, such as hourly or even sub-hourly rates, and enable dynamic price signals that better reflect grid conditions. With interval-based net metering, utilities can record how much energy each customer injects into or draws from the grid, thus opening participation in automated demand response programs and new business models for flexibility services.

4.2 Medium-Term Measures

3. Standardize interoperability protocols

In parallel with the progress in smart metering, Chile must advance in interoperability standards for VPP systems. This standardization process implies that the CNE, the CEN, and the SEC must work together, with the support of the Ministry of Energy and distribution companies, to define a set of open communication and control protocols that must be complied with by the equipment and platforms participating in aggregation. International references for DER integration such as IEEE 2030.5 (2023) or OpenADR (n.d.) can serve as a basis. The idea is to avoid technological fragmentation and facilitate the easy integration of DERs into the VPP management system.

Currently, the lack of guidelines in this field can lead to incompatible proprietary solutions, which make scalability more expensive and complex. Similarly, data formats, cybersecurity, and performance criteria for VPPs need standardization. For example, to establish how VPPs report their data to the CEN, including maximum latency and communication security measures, or set quality of service requirements (for instance, minimum committed power delivery reliability). These technical standards will provide certainty to both developers and authorities about the operation of VPPs. A recommended approach is to form a multi-sectoral technical committee (government, regulators, industry, academia) for their development, drawing on the experience of organizations such as NIST and IEEE already working on VPP protocols (Alajlan, 2024). Adopting international standardization early will facilitate the VPP integration, open the market to global technology providers, and reduce costs due to economies of scale.

4. Update market regulation for aggregated resources

While obtaining pilot results and better infrastructure are in place, it is necessary to undertake formal regulatory reforms to incorporate VPPs into the permanent regime of electricity markets. Several specific actions become effective here. First, formalize the figure of the aggregator. This recognition involves appropriate modifications to the LGSE or associated regulations, including defining its rights and responsibilities. Additionally, it is necessary to clarify the mechanisms for the participation of VPPs in the different markets, allowing them to offer energy in the spot market or in contracts, to provide ancillary services to the CEN, and even to contribute to the peak supply capacity (to be considered in the planning as a firm power resource).

One important technical and regulatory component is establishing measurement and verification methods to quantify the contribution of aggregate resources. Within this context, concepts such as baseline methodologies are key to estimating what energy a customer would have consumed or injected without the action of the VPP and then calculating the effective contribution after modulating its behavior. Incorporating these methodologies into settlement procedures can ensure that aggregators and their customers are paid fairly for the service provided, while protecting distribution companies from potential disadvantages caused by the reduced demand that they cannot sell. The European experience suggests introducing compensation schemes. For example, if an aggregator reduces the consumption of customers, a compensatory payment could be defined for the distribution company due to the unrealized sales, but only the avoided costs, without diminishing the incentive for savings (European Parliament and Council, Article 17). These adjustments aim to align incentives so that each actor (aggregator, distribution company, customer) can obtain gains from VPPs.

Another regulatory front is adjusting price signals in the market. Specifically, moving to a wholesale market based on competitive bids (reform underway in Chile) will help reveal the unique value of flexibility, allowing VPPs to compete by bidding for demand reductions or injections at critical times. Likewise, revising electricity tariffs to introduce more marked hourly components or differentiated prices according to local congestion could incentivize more customers to adopt technologies and join VPPs (Fitch, 2024).

4.3 Long-Term Reforms

5. Open retail market to competition

Chile must evaluate more in-depth transformations of its electric model to allow the full maturity of VPPs and customer-centered innovation. To materialize the widely studied and discussed introduction of competition in supplying electricity to end-users. This reform would imply separating functions: on the one hand, distribution companies would continue to oversee the physical grid (cables, quality of service, meters), but on the other hand, different retailers could offer energy and services to the customers, competing on price and quality. A context of free retail competition would allow, for example, companies specialized in aggregation or local communities to form marketing companies that offer supply plans to neighbors based on a community VPP, with customized tariffs and profit sharing. Technology companies could also enter through "VPP as a service" models, installing equipment in homes in exchange for managing them in aggregation and sharing savings. In countries with open markets, including many in Europe, there are already commercial offers where customers subscribe to a "Virtual Plant in your Home" program and obtain reduced bills in exchange for some flexibility in their equipment.

Although the opening of electricity retailing in Chile would require legal changes and delicate regulation to protect consumers, its long-term benefits could be significant: higher innovation in energy products, a boost to digitalization (since each competitor will want to take advantage of the flexibility of its customers), lower prices due to competition, and diverse options that empower the end-user (for example, choosing a green plan, a community plan, or one with intelligent consumption management). This fifth measure is envisioned in a 5-year horizon, given the political complexity it has shown in past attempts (for instance, the Electric Portability Bill in 2020). Ultimately, an open and dynamic retail market is the ideal environment where VPPs can deploy their maximum potential to benefit the consumers, competing to offer them better tariffs, resilience, and customized services.

5 General Methodology

This section proposes a methodology to estimate the potential for VPPs in Chile considering two main aspects. First, the installed capacity from which a VPP is economically feasible and, secondly, the maximum capacity that can be technically connected to LV distribution grids without leading to voltage or thermal issues.

To achieve this objective, the study examines two representative areas, each characterized by different customer densities on the distribution network: one with a medium density and the other with a low density. This approach recognizes that regions with high customer density typically contain a higher number of buildings of apartments, which can limit the expansion of DERs such as solar PV and BTM batteries. Conversely, regions with very low customer densities often provide fewer opportunities to scale VPP business models effectively.

The adopted methodology is illustrated in Fig. 4. For each selected region, two evaluation processes are used. On the one hand, an economic analysis aims to determine the minimum volume of DERs that makes the VPP economically viable. This can be aligned with the expected DER adoption levels in Chile, helping to assess how far the country is from having viable VPPs. On the other hand, a technical assessment aims to determine the maximum feasible VPP capacity, considering distribution grid constraints, including nodal voltages and current flows in distribution lines and transformers. Based on these findings, a feasibility analysis is conducted to outline the necessary conditions for implementing VPPs. Ultimately, by scaling the grid services that VPPs can provide, an estimate of their potential contribution to Chile's energy landscape can be derived. Lastly, the report focuses on three types of DERs: BTM batteries, EVs, and electric climatization units. The focus on these resources responds to their expected penetration in Chilean distribution grids, as stated in Section 3.

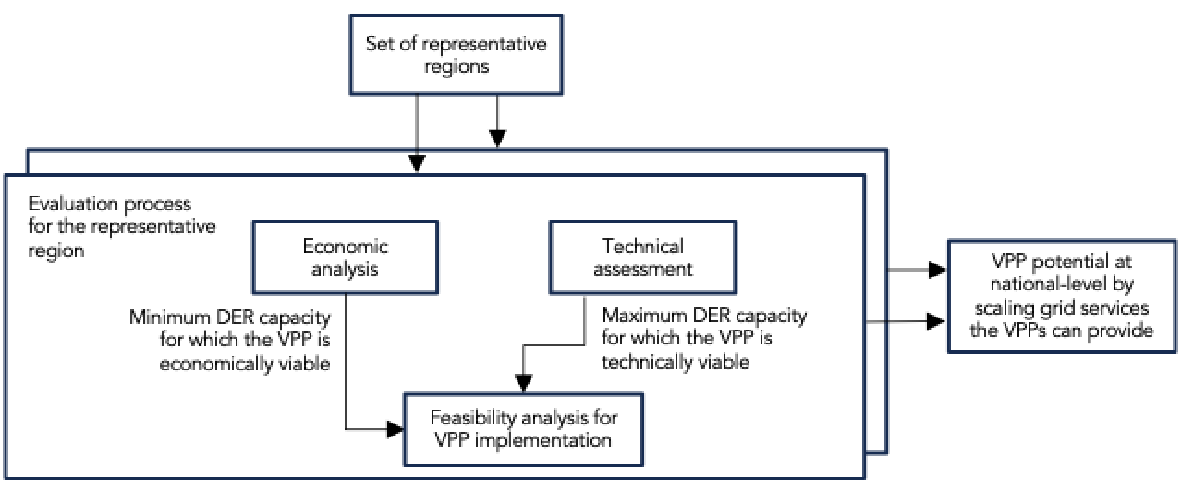

Fig. 4. Overview of the proposed general methodology.

In the upcoming sections, the methodology is applied to two LV networks where VPPs are assessed. These correspond to Lampa and Osorno, which represent regions of low and medium customer densities, respectively. The selection of these regions is intentional to ensure comprehensive representation; Lampa is situated in the Metropolitan Region, while Osorno is in the southern part of the country, in the Los Lagos Region. Additionally, Lampa is supplied by Enel Company, and Osorno is supplied by SAESA Company, both of which are among the largest distribution companies in Chile and are members of the industry association Empresas Eléctricas (EE) AG.

6 Business Models

This section presents the methodology and analysis of VPP business models tailored to the Chilean context. It focuses on evaluating the economic viability of VPPs by examining cost and revenue drivers associated with DERs in two representative regions with differing customer densities: Lampa and Osorno. The section integrates static economic analyses with dynamic simulations to assess the potential growth of DER adoption and the financial performance of VPPs under current regulatory frameworks and market conditions. This comprehensive approach aims to identify feasible business models that can support the deployment and scalability of VPPs in Chile, providing insights into the economic incentives and operational strategies necessary for their success.

6.1 VPP Business Models Economics

The reviewed international context demonstrates that VPPs are economically viable today in regions where local and wholesale market participation is feasible. This section aims to demonstrate the financial viability of VPP business models in Chile based on a static analysis. The analysis considers both the short-term expected DER penetration and current compensations for market participation, representing a realistic scenario achievable through minimal regulatory changes. A key finding illustrates the fundamental costs and revenues from the perspective of the VPP operator managing DERs to maximize earnings in Chilean markets.

6.1.1 Methodology

The proposed methodology for this economic analysis comprises the two selected examples: Lampa and Osorno. For simplicity, the case of Lampa is presented in detail. Additionally, the methodology involves realistic international costs to assess the VPP's financial viability and the grid services the VPP can provide within the Chilean market context from which receives revenue. Specifically, the following cost and revenue drivers are analyzed for the proposed first study, although the specific economics of future VPPs can vary according to DER composition and the operational model used:

Cost:

- Project implementation and administrative costs: DER management system and associated information technology (IT) and personnel costs; ongoing administrative costs.
- Participant acquisition costs: Marketing and customer recruitment.
- Participant incentives: Energy payments to participant customers.

Revenue:

- Ancillary services: Payment for ancillary services; specifically, frequency control.
- Local capacity: Payment per MW of energy option procured.
- Local resilience: Payment for enhancing grid resilience.

To facilitate the analysis, all customers are assumed to be enrolled and participating with full availability. This economic analysis outcome relates to the annual revenue, costs, and profit for both VPPs, including the minimum capacity to achieve financial viability.

6.1.2 Results and analysis

The VPP creates value for the power grid by providing a stack of valuable services from its set of DERs across different time scales, paying participants ongoing performance incentives. These interactions are represented in Fig. 5. Ancillary services are provided to the bulk power system, while peak reduction and grid resilience are provided locally to the distribution company. The VPP also coordinates and orchestrates the dispatch of DERs. Furthermore, Table 1 lists these services, the type of resource and capacity to provide them, and the periods within which they are delivered throughout the day or year. The list includes the services that may be applicable in the bulk power system and the distribution system. The study also includes the following additional assumptions: 1) customers with solar PV and BTM batteries: 50 % of the total population. Each BTM battery has an active power of 5 kW and a capacity of 13.5 kWh. 2) Customers with electric climatization units (for example, heat pumps, HPs) and EVs: 11.5 % and 17.8 %, respectively. These values are obtained based on daily demand profiles of Chilean customers. Specifically, by integrating typical load profiles of HPs and EVs from Navarro (2015), the total customer consumption is expanded to meet their expected projections (14.5 % and 23.2 %, respectively). Thus, from the resulting number of HP and EV profiles, the corresponding percentage of customers with these resources can be derived. The active power for both is 4.5 kW and 7.0 kW, respectively.

Before analyzing the economic performance of the VPP, it is necessary to define how the available DER capacity is allocated across the different services that the VPP can provide. The allocation used in this study should be viewed as a preliminary but practical assumption, grounded in international experience with operational VPPs. Under this framework, 50 % of the battery storage capacity is assigned to primary frequency control, while 30 % is allocated to local peak demand reduction. The remaining 20 % is reserved for providing backup power to customers during grid outages, consistent with practices commonly observed in the United States (DOE, 2023). In this context, grid resilience is prioritized because the ability to deliver frequency control and peak reduction can be affected during power interruptions.

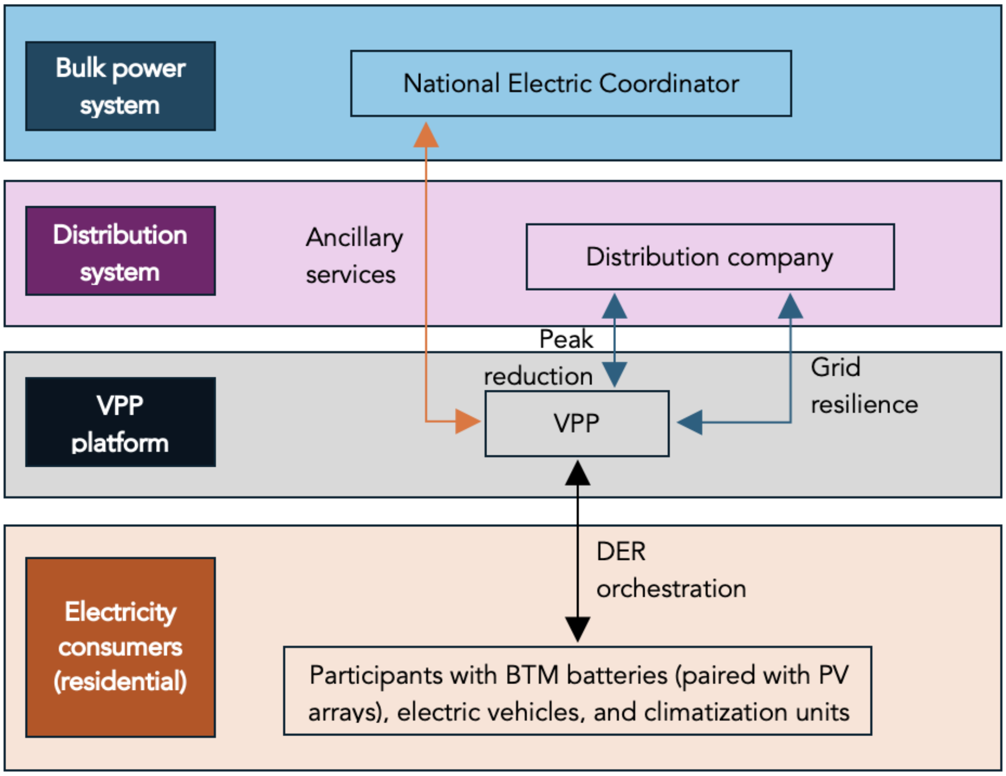

Fig. 5. Illustrative operations of the analyzed Lampa VPP.

Table 1. Grid services provided, type of DER involved, and corresponding period of operation.

Grid service	DER participation	Period of operation
Bulk power system		
Primary frequency control: over-frequency	BTM batteries	6:01 AM - 10:00 AM, per year
Primary frequency control: under-frequency	BTM batteries (50 % of capacity)	5:01 PM - 9:00 PM, per year
Interruptible loads	EVs and HPs	6:00 PM - 10:00 PM, working days, May to August, per event in the year
Distribution system		
Peak demand reduction	BTM batteries (30 % of capacity)	8:00 PM - 10:00 PM, April to September, per event in the year
Grid resilience	BTM batteries (maximum: 80 % of capacity)	Per event in the year Conditioned by the weather, technological, and grid infrastructure conditions

However, it is significant to establish that the availability of this service is strongly dependent on local weather conditions, which may limit its feasibility. Additionally, technological factors are essential, particularly considering the state of charge of batteries. For instance, it becomes challenging to provide grid resilience when an interruption occurs after the batteries have already been dispatched for the other services. Lastly, infrastructure conditions, including the integrity of the distribution network, also impact the delivery of this service.

In Chile, ancillary services for frequency control involve a set of actions to maintain the operating frequency within a predefined range around the reference frequency of 50 Hz. As frequency is the result of power balance in the electric system, these actions help correct any immediate imbalances between the power generated and the power demanded. Frequency control encompasses five basic categories that are interrelated: fast frequency control (CRF), primary frequency control (CPF), secondary frequency control (CSF), tertiary frequency control (CTF), and interruptible loads (CI). Fig. 6 illustrates the connections among these different categories.

According to international experience, BTM batteries have proven to be highly effective when coordinated by VPPs to provide fast frequency and primary frequency services. Examples such as the VPPs operated by Green Mountain Power and Rocky Mountain Power in the United States (DOE, 2025), as well as the Energy Locals VPP in Australia (AEMO, 2020), illustrate the established business model for enrolling BTM batteries in these ancillary services. However, Chile's system-level needs differ from those in these jurisdictions. The CEN conducts annual planning studies to determine the ancillary services required for secure and cost-effective system operation, and fast frequency response (CRF) is not always necessary. For instance, the CEN decided not to procure CRF for the upcoming year (CEN, 2025a). Given this context, primary frequency control (CPF) emerges as the most relevant and realistic service for VPP participation in Chile.

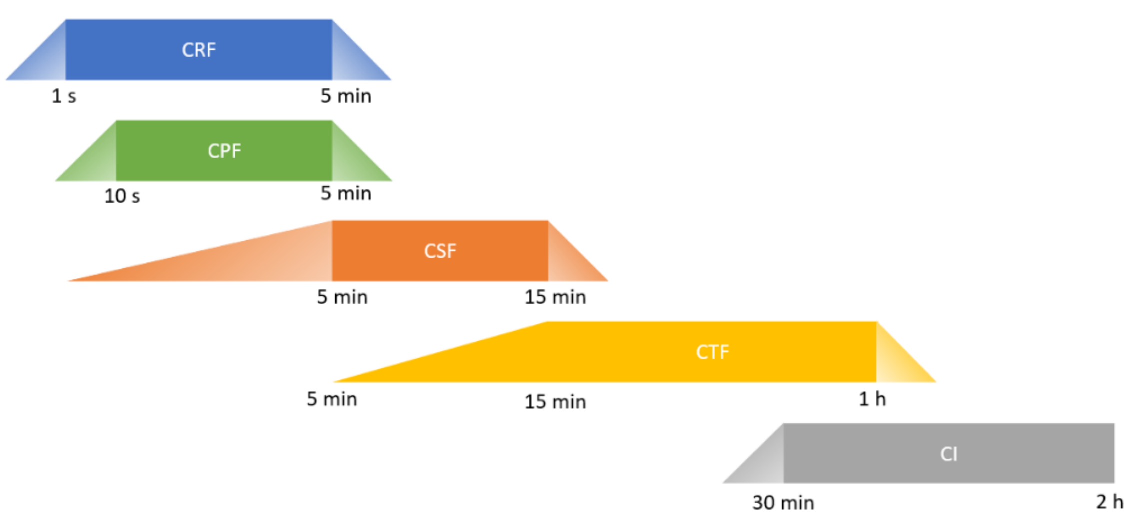

Fig. 6. Frequency control reserves in Chile (CEN, 2025 a).

For this reason, the economic analysis in this report focuses on evaluating VPP participation in CPF using BTM batteries. CPF has a total activation time of 10 seconds and a minimum delivery duration of five minutes, and it comprises two subcategories: primary frequency control by under-frequency (CPF+) and primary frequency control by over-frequency (CPF–). These characteristics make CPF technically compatible with the operational capabilities of BTM batteries and economically meaningful under the current regulatory framework. By centering the analysis on CPF, the study aligns international evidence with the specific ancillary service needs identified in Chile.

During normal operating conditions, active power reserves are necessary for managing variations in demand and renewable generation relative to scheduled dispatch values. In Chile, frequency deviations within the ± 0.2 Hz band are considered normal variations. The frequency control intended for normal operation passively responds according to droop-based and inertia-based characteristics to attenuate frequency deviations locally. However, when supply unexpectedly drops significantly below demand, the system frequency declines, leading to a contingency situation. A similar issue arises, for example, with the disconnection of a large load in the system, causing the frequency to increase. The CPF is activated during these severe load-generation imbalances or when faults occur, where set-points of different resources are actively adjusted to prevent the frequency from falling or rising excessively. DERs contribute to contingency frequency services through the VPP.

Likewise, CI represents the last category within frequency control. Due to its particular features, including a net demand reduction under the direct instruction requirement from the CEN, a total activation time of 30 minutes, and a delivery time of two hours, this service can be effectively provided by disconnecting EVs and HPs. Moreover, the objective of the CI category, as defined by the CEN, also comprises reducing demand during periods of high consumption and low generation, managing congestion, and responding to systemic emergencies (CEN, 2025 a). Consequently, CI functions as a demand response at the system level and may be requested outside of contingency situations.

Currently, CPF- is provided through auctions, where participating agents are required to bid based on their direct costs of service provision for a specific forward day. The Administrative Bases for auctions define the following five time blocks within the day for which bids can be submitted: 12:01 AM – 6:00 AM, 6:01 AM – 10:00 AM, 10:01 AM – 5:00 PM, 5:01 PM – 9:00 PM, and 9:01 PM – 12:00 AM. In general, participants can bid prices for one or more blocks as they deem appropriate; however, it is significant to note that the final adjudication will be subject to the CEN's operation schedule (CEN, 2024 a).

The selection of the second block to provide CPF- (6:01 AM – 10:00 AM) is derived based on the expected occurrence of over-frequency events throughout the year. Figs. 7 and 8 illustrate the percentage of system frequency deviations at the hourly level for 2024 and 2023, respectively, including the compliance with the corresponding regulatory standard. As can be observed, the most significant deviations are due to over-frequencies, which predominantly happen in the morning hours and result in violations of the regulatory standard. This pattern is largely influenced by the entry of high-power blocks from solar PV generation and the subsequent retirement of thermal production. Therefore, the electric system needs power retirements during this period, representing a business opportunity for VPPs. The regulatory standard is set in both cases at 97 % because the energy contribution from hydroelectric plants during these years did not exceed 60 % of total generation. If the contribution from hydroelectric plants surpasses 60 %, the standard increases to 99 %.

In compliance with the current Regulation on Ancillary Services, energy and reserves are co-optimized daily to determine the award of the corresponding ancillary services, taking into account all available generating units authorized to provide frequency control (CEN, 2025 c). Currently, CPF+ is a service assigned by direct instruction.

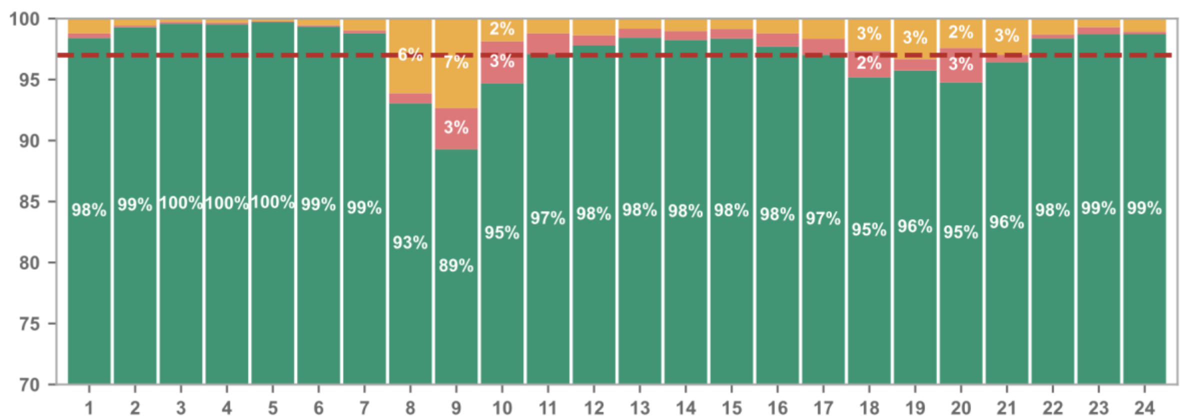

Fig. 7. Percentage of deviation for system frequency at the hourly level and compliance with the regulatory annual standard (in dashed line) during 2024 (CEN, 2025 b).

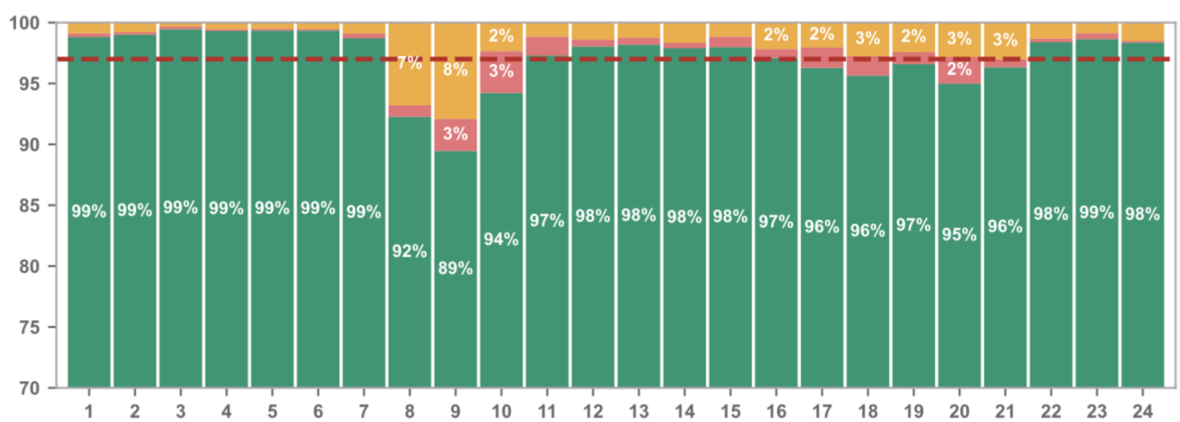

Fig. 8. Percentage of deviation for system frequency at the hourly level and compliance with the regulatory annual standard (in dashed line) during 2023 (CEN, 2024 b).

The present economic analysis is also built based on the assumption that the VPP provides this service in the block of 5:01 PM to 9:00 PM, when BTM batteries are expected to be fully charged. As depicted in Figs. 8 and 9, this period experiences significant under-frequency events, coinciding with the typical increase in system demand and the retirement of solar PV generation. This assumption contrasts with other periods when batteries are expected to be charged and can export power, particularly in the afternoon, for two key reasons: 1) In the afternoon, the power that the VPP can export from batteries may be limited by both distribution lines and transformers, and the capacity of hybrid inverters. With high levels of PV penetration, part of this generation is already present in the distribution grid, thus reducing the power that can be delivered due to these constraints, as demonstrated by (Gutiérrez-Lagos, 2021); and 2) although the afternoon period coincides with higher system-level PV generation, it also sees increased instances of curtailment. As a result, PV plants are offering large blocks of available reserves at minimal costs, making it difficult for the VPP to compete with them.

Lastly, the CI service is responsible for reducing net demand after direct instructions from the CEN. The most critical period for the system's facilities studied by the CEN, in terms of peak demand conditions, occurs between 6:00 PM and 10:00 PM on working days from May to August. Specifically, the CEN establishes a maximum of 15 events for this service during these critical months. Likewise, the Ministry of Energy defines peak hours as this period, adding the months of April and September (Ministry of Energy, 2025 b). In this analysis, the peak demand reduction service offered to the distribution company also comprises 15 events within the two hours indicated in Table 1.

On the other hand, considering a realistic cost for the VPP is fundamental for conducting the economic analysis. Table 2 outlines an estimated annual cost for a VPP in Chile, where the VPP operator is also the BTM battery manufacturer, benefiting from existing access to the battery software. However, as mentioned above, this cost can vary depending on the specific DER composition and operational model. The amounts referenced in Table 2 are derived from a real VPP in the United States (DOE, 2023). Specifically, this example VPP describes a market participant VPP with 10,000 BTM batteries, collectively representing 35 MW of capacity used for demand reduction during critical peak events. The total cost involves both operational costs, including implementation and marketing, and participant incentives. Implementation costs consist of annualized payments over five years for 50,000 USD (fixed annual costs) and administrative annual costs, assumed to be proportional to the number of BTM batteries (variable costs). Likewise, marketing and recruitment payments are also annualized at 50 USD per participant, based on the VPP example. Regarding participant incentives, the VPP offers 0.90 USD per kWh to customers for dispatching stored energy during both system-level and local-level contingencies, as well as local high-demand periods. Furthermore, the VPP provides participants with 0.50 USD per kWh for disconnecting their EVs and turning down their HPs for approximately two hours when instructed directly by the CEN.

Table 2. VPP cost.

VPP operations	Implementation costs	USD		
	One-time payment (annualized over five years)	50,000		
	Administrative (per year, per BTM battery)	5		
	Marketing and recruitment costs			
	Per participant (annualized over five years)	10		
Participant incentives	Primary frequency control, peak demand reduction, and grid resilience	USD/kWh		
	Energy credit	0.90		
	Interruptible loads	USD/kWh	Annual hours	Annual USD/MW
	Energy credit	0.50	30	15,000

Table 3 shows the projected revenue for the VPP based on current electricity markets in Chile and specific data concerning Lampa. The total revenue includes compensation for providing the selected three services through the three types of DERs. First, the CPF- in the country is currently remunerated for the effective provision of the service, particularly for activation, at the price awarded by the auction (CNE, 2025 a). This analysis considers the events of over-frequency deviations within the selected time block during 2024, estimated in 427 events based on data from (CEN, 2025 b) regarding total activations during this period and the generation units most frequently called upon to provide the service. Additionally, the average daily cost per MW for the VPP is 2.74 USD, accounting for both the annual administrative cost per battery and the considered active power (5 kW). On average, the VPP expects one activation per day for most of the year. Thus, it is assumed that the VPP bids into the auction using its average daily cost (without considering the CPF+ service, with a lower probability of activation). Consequently, the annual compensation from CPF- can amount to 1,169.9 USD/MW. While this final amount may be low, a main benefit of this service is the retirement of energy from the grid, which end-users can utilize for self-consumption.

The components currently considered for the remuneration of the CPF+ service include both availability and activation. The availability component, associated with the remuneration for maintaining the reserve available during the required period, corresponds to the under-frequency band interval for the awarded value. Similarly, the activation component, associated with the payment for the effective provision of the service, corresponds to the injection of energy valued at the marginal cost of the injection node (CNE, 2025 a).

Table 3. VPP revenue.

Primary frequency control: over-frequency	USD/MW per event	Annual events	Annual USD/MW			
Activation	2.74	427	1,169.9			
Primary frequency control: under-frequency		USD/MWh				
	USD/MW	5 - 6 PM	6 - 7 PM	7 - 8 PM	8 - 9 PM	Annual USD/MW
Availability	2.74	92.4	98.1	97.0	94.8	47,179.2
	Annual hours					
	5 - 6 PM	6 - 7 PM	7 - 8 PM	8 - 9 PM		
	7.7	3.3	10.2	2.9		
	Annual hours affected by the frequency change					
	5 - 6 PM	6 - 7 PM	7 - 8 PM	8 - 9 PM	Annual USD/MW	
Activation	5.3	2.3	7.0	2.0	1,576.5	
Interruptible loads	USD/MWh	Annual hours	Annual USD/MW			
Availability	5.5	328.0	1,804			
Activation (maximum: 15 events of ~2 hours)	550	30.0	16,500			
Peak demand reduction	USD/kW per month	Events	Annual USD/MW			
Availability (maximum: 15 events per year)	8.46	15	41,099.3			
Grid resilience enhancement	USD/kWh	Events	USD/MW			
Maximum: 80 % of VPP capacity	0.93	3	6,054.8			

Regarding the availability component for the VPP, the awarded cost comprises the sum of the real opportunity cost, calculated ex post by the CEN, and the direct costs for providing the service (2.74 USD/MW). The real opportunity cost is defined as the cost incurred by an awarded facility due to the loss of energy sales in the spot market resulting from limited or null use of the facility's capacity in providing the ancillary service (CEN, 2025 a). To estimate this opportunity cost, this study considers the average marginal cost at Lampa's 23 kV node from April to September 2025. These average marginal costs are detailed in Table 3 for the time block of reserve. Assuming that the VPP can offer this service 98 % of the time throughout the year (or 358 days), the amount of energy maintained as reserve (50 % of battery capacity) valued at the marginal cost, combined with the direct cost of service provision, results in a total of 47,179.2 USD/MW. The 2 % of unavailability includes the provision of the grid resilience service. The total value represents the highest remuneration among all the payments the VPP receives.

For the activation component of the CPF+, this analysis considers the annual hours in 2024 during which under-frequency events occur. These values can be estimated for each service hour based on Fig. 7, resulting in 7.7, 3.3, 10.2, and 2.9 hours, respectively. However, it is important to underline that the VPP (assuming it operates all these hours) does not export energy at full active power. Instead, the output energy profile depends on the frequency behavior in each deviation. Due to the difficulty of obtaining specific data on these frequency deviations, a piecewise linearization approach is used for simplicity. Specifically, the study considers that the following frequency values: 49.7 Hz, 49.6 Hz, 49.5 Hz, and 49.4 Hz are present during the following percentages of time: 20, 30, 30, and 20 %. In addition, the selected value for the BTM batteries' droop is set to 0.7 %, based on the international experience in Australia (AEMO, 2019). This droop value enables power regulation in inverter-based DERs as a function of system frequency, based on frequency deviations regarding a reference value. As a result, the above annual hours are affected by a factor that reflects variations in frequency, leading to the following values: 5.3, 2.3, 7.0, and 2.0 hours. When these new hours are valued at the average marginal costs in Lampa's 23 kV node, the result is 1,576.5 USD/MW.

As detailed in Table 3, the components of the CI service that are subject to remuneration include availability and activation. The CNE (CNE, 2023) currently establishes the maximum payments for these components at 5.5 USD/MWh and 550 USD/MWh, respectively. These amounts are used as the awarded values in this economic study. The availability component for remuneration takes into account maintaining reserve capacity available during the required period, that is, four hours for all working days in Chile from May to August, for example, 82 days in 2025. This results in a total of 1,804 USD/MW for availability. Likewise, assuming direct instructions from the CEN for the established maximum of 15 events during the year, each of two hours, the annual payment can be 16,500 USD/MW for activation.

Concerning the peak demand reduction service provided to the local distribution company, this economic study considers a maximum of 15 events per year, similar to the case with CI. In Chile, distribution companies typically face maximum demand during peak hours and select between two billing systems for maximum demand, supplied by generation companies: 1) maximum demand read, and 2) contracted power. In the first case, distribution companies have a charge based on the average of historic maximum demands recorded during peak hours over the past 12 months. Additionally, distribution companies need to agree on a maximum connected power. In the second case, distribution companies must arrange bilateral contracts for peak power for a minimum duration of one year (Ministry of Energy, 2025 b). In both situations (contracted peak power or maximum demand read), the active power value is billed monthly at the peak power node price at the point of delivery. This peak power node price is calculated in Chile twice a year.

However, it is significant to understand that if the maximum demand of a distribution company exceeds the contracted (or connected) power, each kW of excess usage will be charged at double the established price. Additionally, if the contracted (or connected) power is exceeded for more than two days within one year, the generation company can require the distribution company to redefine the value of this power. As a result, the distribution company has a strong incentive to maintain demand during expected peak events below the contracted (or connected) power limit. In this economic study, the distribution company contracts directly with the VPP to ensure an available reserve capacity (30 % of battery capacity) for use during these expected peak events. The payment for this service, detailed in Table 3, corresponds to the peak power node price from April to September 2025, at the Lampa 220 kV substation. This amount is billed monthly by the VPP, similar to the generation companies. Furthermore, through negotiations with the VPP, there may be opportunities to offer incentives that increase the VPP's capacity by adding more customers. Therefore, this could lead to improved service from the VPP during resilience events.

The utilization of the VPP reserve capacity depends on the contracted active power by the distribution company and the demand behavior during the peak event. For example, if the distribution company contracts the maximum active power from a 1 MW VPP, then 30 % of capacity corresponds to 0.81 MWh. This result implies exporting energy at maximum active power for nearly 50 minutes.

The final service provided is grid resilience, also available to the distribution company. In Chile, distribution companies can face penalties from the SEC due to power interruptions in their concessioned areas. These penalties are determined based on reliability indices such as the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), which characterize supply interruptions in distribution systems under normal conditions (CNE, 2024). SAIDI measures the average duration of interruptions experienced by customers, expressed in hours per year. In contrast, SAIFI is calculated by dividing the number of customers who experienced interruption by the total number of customers in a specific area. Both indicators consider all supply interruptions caused by failures or disconnections in the distribution company's facilities that last longer than three minutes. In Lampa, the SAIDI and SAIFI values for 2024 were 17.03 hours and 8.5 interruptions, respectively, exceeding the defined average limits for the region: nine hours and seven interruptions (Enel, 2024). These values were significantly affected by the windstorm in August, which left thousands of residents without power for several days.

For failures in the distribution system (more frequent compared to the transmission system) affecting regulated customers, Law 18.410 (1985) and its amendment Law 19.613 (1999) define in Article 16 B the corresponding compensations, charged to the distribution company, as double the value of the energy not supplied during the interruption or suspension of service, valued at the rationing cost, which represents the cost per MWh that end-users would incur on average if they did not have energy available in a rationing scenario. The rationing cost is also calculated twice a year by the CNE. Thus, the compensation value for regulated customers due to distribution-level failures is currently 934.4 USD/MWh (CNE, 2025 b).

While this service may not always be available due to the conditions outlined above (see Table 1), it is significant for the distribution company to maintain low values for the SAIDI and SAIFI indices. Maintaining both indices low will avoid not only potential penalties but also defer investments in grid infrastructure. This study assumes one-third of the annual events (three in this case), with the option to provide grid resilience service using the total 80 % of the battery reserved. In practice, the VPP schedules the dispatch of reserve in advance and decides whether to provide this service based on factors such as forecasted local weather or information regarding planned outages. This assumption implies an annual revenue of just over 6,000 USD per MW.

Finally, Table 4 presents the annual revenue, cost, and profit for the VPP in Lampa, considering three different installed capacities, starting from 1 MW. The results indicate that, based on the stated assumptions, the VPP with a minimum capacity of 1 MW is financially viable. As this capacity increases, the VPP has the potential to grow by generating more income, demonstrating the feasibility of this business model.

On the other hand, Table 5 presents the result of annual revenue, cost, and profit for the VPP in Osorno, using region-specific data while maintaining the same cost assumptions. However, for Osorno, the key difference regarding Lampa is the exclusion of the category of CI in the frequency control service based on the expectation of a lower adoption rate of EVs and HPs in Chilean regions with smaller populations, influenced by economic and cultural factors. As can be observed, a BTM battery VPP in Osorno can also be economically sustainable.

In particular, the average marginal costs at Osorno’s 23 kV node for the corresponding time block of reserve are 88.3 USD/MWh, 93.1 USD/MWh, 88.4 USD/MWh, and 84.3 USD/MWh. Additionally, the payment for peak reduction results in 8.37 USD/kW per month. This value corresponds to the peak power node price from April to September 2025 at the Rahue 220 kV substation.

Table 4. Annual revenue, cost, and profit for the Lampa VPP based on installed capacity.

	Active power (MW)	Annual revenue (USD)	Annual cost (USD)	Annual profit (USD)
BTM batteries	1	97,079.6	80,989	16,090.6
EVs & HPs	0.7	12,886	10,560	2,326
Total	1.7	109,965.6	91,549	18,416,7
BTM batteries	3	291,238.9	142,966.9	148,271.9
EVs & HPs	2.1	38,786.2	31,785	7,001.2
Total	5.1	330,025	174,751.9	155,273.1
BTM batteries	5	485,398.1	204,944.9	280,453.2
EVs & HPs	3.5	64,558.2	52,905	11,653.2
Total	8.5	549,956.3	257,849.9	292,106.4

Table 5. Annual revenue, cost, and profit for the Osorno VPP based on installed capacity.

	Active power (MW)	Annual revenue (USD)	Annual cost (USD)	Annual profit (USD)
BTM batteries	1	93,158.6	80,989	12,169.6
BTM batteries	3	279,475.7	142,966.9	136,508.8
BTM batteries	5	465,792.9	204,944.9	260,848

6.2 VPP Business Models Simulation

This section presents dynamic simulations for the VPP business models in Chile over a ten-year horizon with annual time steps to evaluate their economic performance in representative rural contexts. It incorporates the previously defined revenue and cost structures, applying them to various customer adaptation and technology scenarios to quantify the evolution of the project's profitability over time.

The model simulates the expansion of the VPP as a function of population growth, housing stock development, and the progressive adaptation of batteries and other distributed resources, capturing how these factors influence the annual cash flow. From these flows, the study derives time series for revenues, costs, and margins, enabling an assessment of the VPP's economic viability and a comparison of the performance of the considered business model throughout the period.

6.2.1 Methodology

This methodology uses Vensim (Vensim, n.d.), a visual modeling tool that enables the conceptualization, simulation, and optimization of dynamic system models. In Vensim, regulatory and economic parameters are explicitly introduced as revenue flows related to the business models under study, including: 1) frequency control revenues, linked to the available aggregated DER capacity and the activation and availability payments defined in current ancillary service regulations; 2) peak demand reduction revenues from providing a local service; and 3) grid resilience revenues for backup energy during outages. Consequently, the time evolution of the “Margin VPP” stock endogenously reflects the same cost and income structure outlined in Tables 2 to 5 but projected over ten years under different adoption trajectories.

A basic example illustrates the transition from the causal map to the stock–flow diagram in Fig. 9 and its numerical formulation. A single Stock level is modeled with two rates:

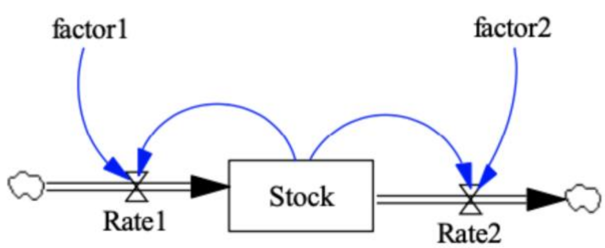

Fig. 9. Minimum stock–flow diagram with one level and two rates; the arrows from factor1 and factor2 indicate proportional relationships.

where Rate1 (inflow) and Rate2 (outflow), both proportional to the previous state, are defined as follows:

$$Rate\ 1(t) = factor\ 1 \cdot Stock(t-1),\ Rate\ 2(t) = factor\ 2 \cdot Stock\ (t-1) \qquad (1)$$

The continuous dynamics of the level are given by:

$$Stock(t) = \int Rate\ \ 1(t) \cdot Rate\ 2(t)\ dt \qquad (2)$$

and its explicit temporal evolution (discretization for simulation) by:

$$Stock(t) = Stock\,(t-1) + \Delta t \cdot (Rate\,1 - Rate\,2) \qquad (3)$$

6.2.1.1 Calibration of the rural case

The “typical rural” scenario used in this dynamic model is calibrated to be consistent with the economic analysis and network characteristics previously developed for Lampa and Osorno, while excluding their specific network topologies. The demand levels, battery power capabilities (assumed to be 5 kW at peak hours and 2 kW during solar hours), and the considered share of households with PV and storage are aligned with the penetration levels and DER configurations discussed earlier. As a result, the simulated VPP size and annual energy volumes are comparable to the 1–5 MW ranges analyzed for both regions.

To represent resilience services, the frequency and severity of local outages in the rural prototype are parameterized within the same order of magnitude as the SAIDI and SAIFI values observed in Lampa and Osorno, and the corresponding regulatory compensation framework based on the rationing cost for energy not served. Nodal marginal prices at the 23 kV distribution nodes and peak power node prices at the 220 kV substations, as used in the stacked-services revenue calculation, are adopted as reference price signals in the simulation, ensuring consistency between the dynamic model and the static annual revenue estimates.

6.2.1.2 Stocks

The system is based on five key stocks: Population, VPP Clients, Battery Structures, Inverter Structures, and Housing Structures.

The "Population" stock represents the total inhabitants in the modeled community. Its dynamics are determined based on four fundamental flows. The inflows correspond to births and immigration, which increase the population size in each annual period. Conversely, the outflows consist of deaths and emigrations, which decrease the number of inhabitants. Thus, the population evolves throughout the simulation according to the demographic pattern’s characteristic of rural areas in Chile, capturing both the growth and transformation of the local community.

The "VPP Clients" stock accounts for the active customers participating in the VPP, who adopt distributed energy solutions and benefit from the services offered. The inflow, termed "Customer entry," represents the increase in clients driven by the adoption of new technologies, economic incentives, and the effectiveness of the incentive strategies. The model assumes that the entry rate is influenced by the system's attractiveness, population density, and several social or economic factors encouraging adoption. As a result, this stock enables the assessment of expansion capacity and potential saturation of the rural market over the considered scenario.

The "Battery Structures" stock records the total number of BTM batteries available in the community. Its primary inflow, "Battery acquisition," responds directly to customer demand for technology, the growing adoption of solar solutions, and the economic incentives provided by the VPP. The outflow, "Battery demolition," reflects the withdrawal or replacement of batteries due to factors such as obsolescence, failures, or technological upgrades. Through this dynamic, the model enables simulation of the storage fleet evolution and its capacity to provide frequency and resiliency services within the territory.

The "Inverter Structures" stock represents the total installed inverters in the grid, which are essential for the proper functioning of batteries and distributed solar generation. The entry of new inverters is regulated by the "Inverter acquisition" flow, typically associated with the simultaneous adoption of batteries and solar panels. The outflow, "Inverter demolition," corresponds to the removal or replacement of obsolete or malfunctioning inverters, in line with maintenance and technological update strategies. This dynamic ensures correct technical operation and efficient support of VPP services provided in the community.

The "Housing Structures" stock encompasses the total number of habitable dwellings existing in the simulated area. Its development is influenced by the inflow "Housing construction," which considers the building of new housing units in response to population growth and land availability. The outflow, "Housing demolition," refers to the removal of dwellings due to obsolescence, deterioration, or demographic changes. The interaction between construction and demolition enables the assessment of the physical infrastructure's impact on energy demand, the potential customer base, and the specific constraints of rural land in Chile.

6.2.1.3 Subsystems

The system is modeled using stock-and-flow structures in Vensim, integrating the following subsystems:

- Housing and Territory: Articulated through the "Housing Structures" stock, this subsystem encompasses the construction and demolition of dwellings, as well as land use and density. Elements such as "Area," "Housing density construction multiplier," and "Land fraction occupied" determine both the capacity for expansion and the territorial limitations for new housing and potential solar adopters. This territorial logic establishes the physical, social, and regulatory boundaries inherent to the Chilean rural environment.
- Solar Technology and Battery: This subsystem integrates two stocks: "Battery Structures" and "Inverter Structures." Moreover, it manages the acquisition, removal, and saturation of energy storage and conversion systems, as well as the adoption of solar panels ("Solar Panel Adopters," "Potential Solar Adopters multiplier"). Variables such as "Battery acquisition," "Battery demolition," and technological incentives ("Attractiveness of solar neighborhoods") define the penetration of clean technologies and their linkage with the provision of VPP services during frequency events and contingencies.

- VPP Clients and Adoption: This subsystem, reflected in the "VPP Clients" stock, controls the entry of new clients into the distributed system, related to both social dynamics ("Interested People," "Immigration fraction," "Adapters to Population ratio") and economic and technological incentives. It governs market expansion, potential saturation, and the evolution of the VPP user base.

- VPP Economic and Margin: This subsystem is represented by "Margin VPP," whose dynamics depend on revenue flows ("Revenues EVs & HPF," "Revenues BTM Batteries," "Participant incentives CPF") and costs (implementation, operation, marketing). It also integrates critical business variables, including participation in frequency control and resiliency markets, thus providing a framework for evaluating the financial model's viability across different scenarios and tariff strategies.

6.2.1.4 Interactions and feedback loops

The implemented VPP model integrates a complex systemic structure where four main feedback loops, along with multiple secondary interactions, determine the emergent behavior of the energy community over the ten-year simulation. In system dynamics, these loops can be classified into two broad categories: reinforcing loops and balancing loops, each modulating different facets of growth, technology adoption, and land use.

Reinforcing loops are mechanisms that amplify growth within the system. A key example in the context of the VPP is the population-housing demand growth loop, in which a larger population leads to an increased demand for housing, which, in turn, enables the community to receive and accommodate more inhabitants, creating a cycle of exponential growth. Another reinforcing loop is the technological adoption loop, where a growing number of VPP clients and solar technology enhance the system’s attractiveness and motivate more people to participate as VPP prosumers, thereby accelerating the penetration of distributed energy solutions.

Conversely, balancing loops serve to regulate and limit excessive growth, establishing boundaries, and promoting system stability. In the VPP model, territorial limitation is the principal balancing loop. As residential construction consumes available space, expansion becomes constrained, and the system gradually approaches its maximum capacity. Likewise, competition for land use between housing and solar generation is a balancing loop that necessitates the strategic distribution of physical resources, moderating both housing density and the possibility of installing new technologies.

- Population Growth and Housing Demand Loop (Reinforcing): In this loop, the interaction between the Population and Housing stocks is fundamental. An increase in population generates demand for new housing, which leads to increased residential construction. As more homes are built, the community’s capacity to accommodate people expands, enabling higher immigration rates and reducing emigration, which further reinforces population growth. This positive cycle stimulates the simultaneous expansion of both the community and its residential infrastructure, enlarging the potential market for VPP services. However, in the absence of clear limits on land or resource availability, this loop can result in rapid territorial saturation and increased energy demands, underscoring the importance of complementary balancing loops.

- Solar Adoption and Technological Attractiveness Loop (Reinforcing): The dynamics of technology adoption are influenced by the social perception of the neighborhood and the economic incentives of the VPP. As more residents install solar panels and batteries, the attractiveness of the area increases, motivating others to participate as VPP clients. This process accelerates the diffusion of clean energy technology, multiplying the critical mass of active users. Moreover, growth in technology adoption can drive the implementation of incentive policies and community projects, further expediting the local energy transition. This loop supports the progressive integration of storage and distributed generation technologies, enhancing resilience and response capabilities during grid events.
- Territorial Resource Limitation Loop (Balancing): In contrast to the reinforcing loops, this loop introduces constraints on growth. As more homes are constructed and more batteries and inverters are installed, the amount of available land diminishes. This progressive depletion of spatial resources limits future expansion, necessitating adjustments in housing densities, restrictions on new development, and optimization of space for energy infrastructure. In high-demand scenarios, the territorial limitation loop drives efficient land use, maintaining a balance between growth and sustainability. This loop is essential to prevent overload scenarios and to ensure that VPP services and technology adoption remain viable in the medium and long term.
- Land Use Competition Loop between Housing and Solar Generation (Balancing): One of the most significant mechanisms in the model is the direct competition for land use between housing expansion and the installation of distributed solar generation infrastructure. As more territory is allocated to new homes, space available for community-level solar panels and batteries diminishes, potentially limiting the maximum capacity for energy generation and storage. This balance necessitates creative solutions, such as homes with integrated systems, increased vertical density, or multi-functional optimization of spaces. Territorial prioritization decisions have a direct impact on the technical and economic viability of the VPP: an excess of housing can create bottlenecks for technology adoption, while equitable planning can achieve greater resilience and flexibility in the system.

6.2.2 Results and analysis

This section presents dynamic simulations of VPP business models in Chile over a ten-year period with annual steps. It evaluates the economic performance of VPPs in rural contexts by incorporating revenue and cost structures and modeling customer adoption and technology scenarios. The simulations track annual cash flows, revenues, costs, and margins, offering insights into VPP financial viability and scalability under current market and regulatory conditions. Using system dynamics modeling, it represents demographic growth, housing development, and technology adoption to comprehensively assess VPP expansion and profitability over time.

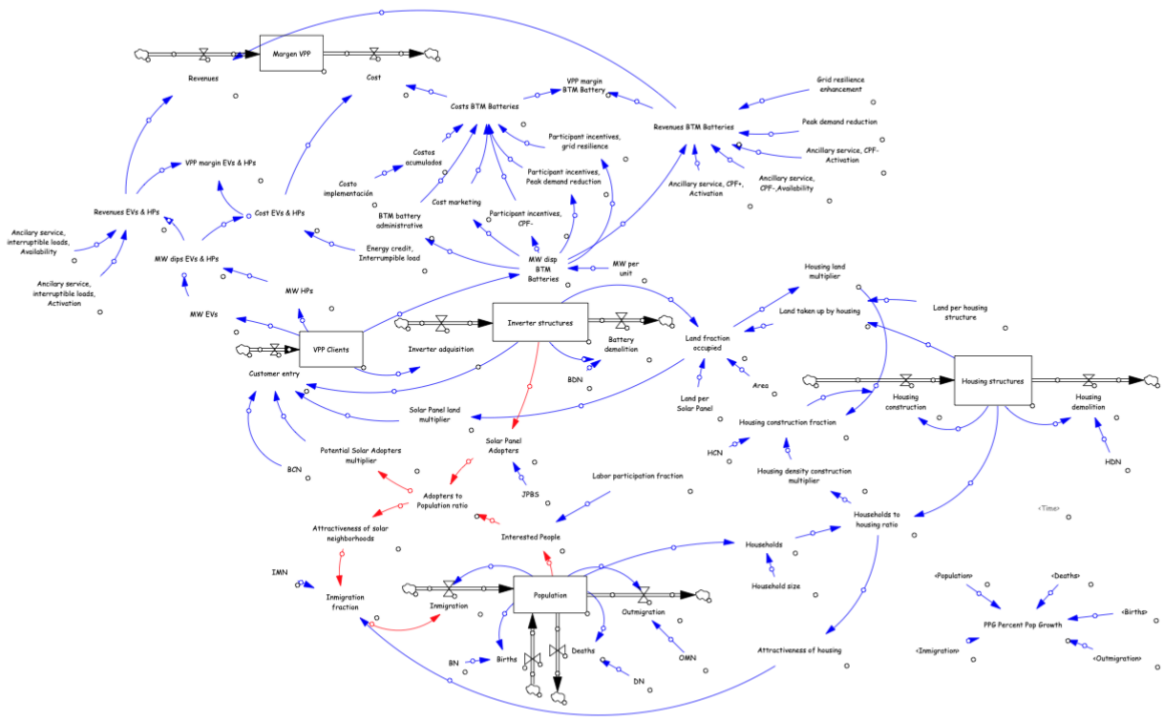

Fig. 10. Stock and flow model based on system dynamics modeling.

6.2.2.1 Model structure

The final model, illustrated in Fig. 10, shows the five defined stocks, each of which plays an essential role in the dynamics of the VPP and is interconnected through specific flows, thus enabling a comprehensive simulation of energy and demographic evolution in rural areas of Chile.

6.2.2.2 Model simulation results

In the VPP business model, population evolution is incorporated as a central axis of the analysis using key demographic variables such as the birth rate (0.011), the mortality rate (0.065), the immigration rate (0.1), and the emigration rate (0.07). The simulation begins with an initial population of 60,000 people and models its evolution over ten years, reaching 57,569 people that result from the dynamic interaction between births, deaths, and migratory flows.

The dynamics of housing structures are addressed using variables such as the construction and demolition rates. The initial modeling assumes a house construction rate of 0.07, while the demolition rate is set at 0.015. The simulation begins with a base of 14,000 housing structures, representing the available residential stock for the integration of VPP technologies.

The evolution of VPP clients in the model is described through an adoption curve over the simulation period, reflecting the progressive increase of end-users integrating distributed energy technologies. Initially, the model starts with two base groups of customers: one more conservative, consisting of 150 customers, and another with accelerated adoption, comprising 210 customers. As the years advance and depending on the selected growth scenario, the number of clients can approach 800, demonstrating the model's scalability potential according to market conditions and applied incentives.

6.2.2.3 Revenue and cost results

The analysis of the revenue and cost in Fig. 11 reveals the financial evolution of the VPP under the two customer adoption scenarios. The revenue graph indicates a consistent growth trend in both scenarios, with the accelerated growth scenario yielding higher revenues. This increase is attributed to a rising number of customers, which boosts the services provided and increases the project's profitability. The upward curve of the graph illustrates the gradual integration of households and batteries, along with the strengthening of the business model within the Chilean market.

On the other hand, the cost graph shows an upward trend during the first five years, followed by a substantial drop starting in the sixth year. This abrupt decline is due to the completion of payments for capital and marketing costs, distributed over the first five years of operation. From that point on, operating costs decrease significantly, contributing to improving the VPP net margin. This cost trend allows for visualization of how the initial financial structure impacts economic performance and how, after the amortization period, the project becomes notably more profitable due to a better balance between revenues and expenses.

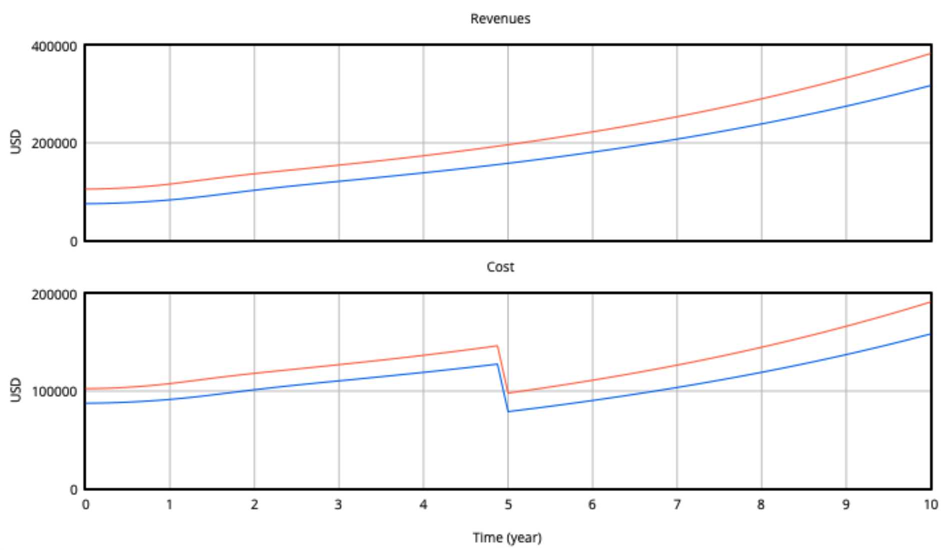

Fig. 11. Revenue and cost evolution of the VPP under conservative and more accelerated client growth scenarios.

Both graphs highlight the importance of financial planning, the design of adoption strategies, and the amortization of initial costs for the viability of the VPP model, supporting the idea that incentive policies and proper deployment can ensure the project's sustainability and long-term economic success.

In the dynamic model, total revenues are explicitly decomposed into contributions from CPF, peak demand reduction, CI, and grid resilience services, reflecting the stacked-services structure introduced earlier. For a reference case with 1.8 MW of aggregated capacity and 210 prosumers, the static revenue analysis yields approximately 112,000 USD per year in gross revenues, 94,000 USD in annualized costs, and around 18,000 USD in net profit, with the dedicated resilience product contributing on the order of 6,000 USD per MW and accounting for roughly ten percent of total revenues. In the time-dependent simulations, these unit prices are applied to the evolving VPP capacity and service volume so that the annual income series used to construct the revenues graph distinguishes between payments related to these services. This structure allows the share of the economic margin attributable to each service category to be tracked over time and across adoption scenarios, while remaining directly consistent with the stacked-services economics already developed.

6.2.2.4 Margin VPP results

The analysis of the VPP's economic margin considers the interaction of demographic parameters, the growth of the housing stock, and the progressive adoption of customers during the simulation period. Fig. 12 depicts the margin curves, which reflect how revenues and costs evolve, distinguishing between the two client growth scenarios: the conservative (150 initial customers) and the more accelerated (210 initial customers).

In the first years, both scenarios exhibit negative margins, mainly due to initial implementation costs, adoption of incentives, and administrative expenses. However, as the number of customers increases and benefits accumulate, the margins become positive after approximately the third year. The trajectory is upward and exponential, showing that, especially in the more dynamic scenario, the margin exceeds 800,000 USD by the tenth year. This positive dynamic is sustained by population growth, the increase in the number of homes eligible to participate, and the VPP client adoption, enabling the leverage of economies of scale and higher revenues from services provided. The economic margin obtained supports the viability of the VPP model in the Chilean markets, suggesting that, with favorable adoption conditions and incentive policies, the project can generate significant net benefits within competitive timeframes.

For this study, economic viability is defined using standard financial indicators applied to the simulated "Margin VPP" cash flows. First, a minimum viability condition is that the cumulative margin becomes positive within the ten-year horizon and remains positive thereafter in both client-adoption scenarios, which is satisfied as the conservative case crosses zero slightly after 3.5 years, while the accelerated case does so between years 2 and 3. Second, the simple payback time is identified as the year in which the accumulated net margin equals the initial capital and marketing expenditures; in the model, this occurs at roughly 3.7 years for the conservative scenario and earlier for the accelerated scenario, confirming that the upfront investment can be recovered in less than half of the simulation period.

Beyond the two illustrative adoption trajectories (150 and 210 initial customers), the simulation outputs allow the identification of approximate thresholds for economic viability in rural areas. Under the assumed prices and costs, both adoption cases lead to clearly positive annual margins by mid-horizon and to values between roughly 0.16–0.59 million USD and 0.27–0.80 million USD per year for the conservative and accelerated scenarios, respectively, over the 6.5–10 year interval, indicating that VPPs with several hundred PV-battery clients and 1.8 MW of aggregated capacity can sustain a robust business case.

6.2.3 Discussion of implications for Chile

Under the simulated assumptions on demographic evolution, housing growth, cost structure, and stacked revenues for frequency control, peak reduction, and resilience, both client adoption scenarios lead to negative margins in the early years but turn positive after approximately the third year of operation. In the accelerated adoption case, with an initial base of 210 prosumers and subsequent growth toward nearly 800 VPP participants, the cumulative economic margin exceeds 800,000 USD by year ten, indicating that a rural VPP can become financially attractive within a decade if minimum thresholds of enrolled customers and DER capacity are reached.

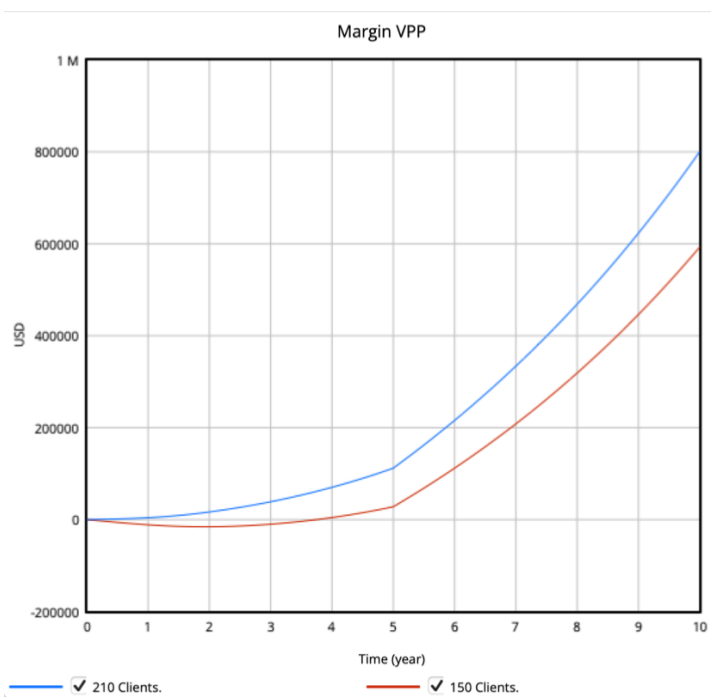

Fig. 12. Economic margin of the VPP under conservative and more accelerated client growth scenarios.

These results suggest that primary frequency control, peak reduction, and resilience services, when remunerated according to the current Chilean ancillary services and reliability compensation schemes, can support viable VPP business models in rural areas, particularly where outage indices are above regional averages, and the value of avoided interruptions is high. Therefore, the dynamic simulations provide a bridge between the network-level economics in Lampa and Osorno and the national-scale assessment, informing how many rural communities with similar characteristics could host profitable VPPs and under what adoption conditions.

Finally, the ten-year results for population, housing structures, VPP clients, and economic margin offer practical guidance for the pilot project design in Section 8, especially for a sandbox with SAESA in low-density networks. They indicate that pilot areas with a sufficient initial base of PV-battery households and above-average SAIDI/SAIFI values are likely to deliver not only measurable technical benefits but also a credible path to economic sustainability for VPP operators, supporting the case for targeted regulatory experimentation in rural Chile.

7 Technical Assessment

This section aims to assess the technical feasibility of implementing VPPs in typical distribution grids across Chile. This assessment focuses on two representative distribution grids located in Lampa and Osorno, corresponding to medium- and low-density, respectively. In Chile, distribution networks are formally classified according to electrical density, which directly conditions the feasible adoption of DERs. High-density grids, typically associated with multi-story buildings, offer limited rooftop areas per household, and empirical evidence shows that the adoption of BTM PV systems and battery storage in these environments has been marginal. Conversely, low- and medium-density grids, generally characterized by single-family dwellings and greater rooftop availability, concentrate the highest technical and economic potential for DER expansion. For this reason, the selected distribution grids provide a representative basis for analyzing the technical feasibility of VPPs in the segments of the distribution system where DER-based flexibility can realistically scale. Insights from these two networks allow for extrapolation of results to estimate a robust, policy-relevant national potential.

For the technical assessment, DER operation is modeled as being centrally coordinated by the VPP. In line with the stacked-service framework introduced in Section 5, the VPP dispatches customers' resources to meet specific operational objectives, allocating portions of their capacity to primary frequency control, peak reduction, and resilience according to predefined reserve shares. Likewise, when considering grid constraints, the available capacity to provide grid services varies throughout the day due to changes in demand and local PV generation. Thus, the technical assessment focuses on identifying the maximum DER capacity that each network can host while allowing the VPP to operate effectively.

For simplicity, the technical assessment considers a 30-minute service period during which the VPP operates at a high-power level (for example, exporting energy at maximum power). According to the services detailed in Table 1 in Section 5, and the time blocks assigned to each of them, this operating condition corresponds primarily to the peak demand reduction service, and in some cases may also coincide with CPF+. It is important to note that peak reduction does not always require exporting energy to the grid. In the context of this assessment, peak reduction is assumed to be delivered primarily through battery discharge, which results in local net injections within the network and, when capacity allows, exports to adjacent areas of the distribution system. This approach aligns with the stacked-service framework introduced earlier, where 30 % of battery capacity is allocated to peak demand reduction.

The selected service period for assessment is 8:00 PM. Therefore, simulations are conducted by considering the extreme case of batteries exporting at maximum power. This focus is essential to ensure that exporting energy to the grid does not result in grid issues, particularly regarding nodal voltages and current flows in lines and transformers. Ultimately, the technical analysis for each distribution network allows for an assessment of the impacts and potential benefits of VPP coordination.

In contrast, the service of CI, operated occasionally, reduces active power locally, both at the prosumer level and the network level, by disconnecting EVs and climatization units. As a result, this service does not compromise the system operation due to its minimal impact on the distribution network parameters. Concerning CPF-, although this service can imply a significant energy import during the defined morning block, the maximum power level is only maintained briefly. Similarly, the primary characteristic of grid resilience is maintaining power balance within the network operating in island mode, with the expectation of reduced demand from consumers in case of a contingency.

To help the VPP understand the impacts of network constraints, a programming method based on AC optimal power flow has been introduced. This approach quantifies how three-phase LV grid constraints affect the power imported or delivered by the VPP. Based on a convex multi-period formulation, the method aims to maximize DER exports during the service-related period while also enhancing household self-consumption during other periods. Furthermore, for comparison purposes and to assess the VPP's technical performance, the analysis includes the baseline self-consumption operation, currently in place in Chile under the Net billing regimen. Under this operational setting, each prosumer optimizes its battery charge and discharge setup to maximize self-consumption.

7.1 Problem Formulation

This section outlines the problem formulation of the VPP. The corresponding household constraints (power and energy balances, including DERs) are presented first, followed by the three-phase AC OPF formulation (grid model). Lastly, the section introduces the proposed objective functions. The formulation consists of the multi-period AC OPF proposed in (Gutierrez-Lagos, 2019), which enables scalability and speed in solving large, unbalanced distribution networks.

7.1.1 Theoretical models for households and BTM batteries

The active power balance of each managed household at time t, $P_{s,t}$, is given by (4), where $P_{s,t}^{d}$ and $P_{s,t}^{g}$ represent the household non-controllable demand and PV generation, respectively, and $P_{s,t}^{b}$ denotes the total power of each battery. To facilitate the formulation of the objective functions, $P_{s,t}$, which can take positive or negative values, is split into imports ($P_{s,t}^{+}$) and exports ($P_{s,t}^{-}$) in (5). Similarly, $P_{s,t}^{b}$ is split in (6) into charging ($P_{s,t}^{b,+}$) and discharging ($P_{s,t}^{b,-}$) non-negative variables. Equation (7) constrains the non-negative variables above. Based on the injecting power case, (8) ensures that every managed household participates in providing services; that is, all households will either discharge their batteries or stay idle during the service period.

$$P_{s,t} = P^{d}_{s,t} - P^{g}_{s,t} + P^{b}_{s,t} \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{4}$$

$$P_{s,t} = P^{+}_{s,t} - P^{-}_{s,t} \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{5}$$

$$P^{b}_{s,t} = P^{b,+}_{s,t} - P^{b,-}_{s,t} \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{6}$$

$$P^{+}_{s,t}, P^{-}_{s,t}, P^{b,+}_{s,t}, P^{b,-}_{s,t} \geq 0 \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{7}$$

$$P^{b}_{s,t} \leq 0 \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T}^{s} \tag{8}$$

where $\boldsymbol{T}$ is the set time points within the day, $\boldsymbol{T}^{s} \subseteq \boldsymbol{T}$ is the pre-defined service period and set $\boldsymbol{S} \subseteq \boldsymbol{H}$ is the households managed by the VPP, being $\boldsymbol{H}$ the set of all households.

The inter-temporal constraints for the calculation of the energy stored in batteries, $E^{b}_{s,t}$, which depends on previous charging/discharging active powers as in (9), consider charging and discharging efficiencies, $\eta^{b,+}_{s}$ and $\eta^{b,-}_{s}$, respectively. Here, $E^{b}_{s,0}$ is the energy stored at the beginning of the day (a parameter), and Δt is the time step, which enables converting power into energy. Moreover, the energy stored in the battery is limited by its energy rating, $\bar{E}^{b}_{s}$, as given in (10).

$$E^{b}_{s,t} = E^{b}_{s,0} + \sum_{i \in [1,t]} \left(\eta^{b,+}_{s} P^{b,+}_{s,i} - \frac{P^{b,-}_{s,i}}{\eta^{b,-}_{s}} \right) \Delta t \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{9}$$

$$E^{b}_{s,t} \leq \bar{E}^{b}_{s} \qquad s \in \boldsymbol{S}, t \in \boldsymbol{T} \tag{10}$$

7.1.2 Three-phase AC OPF formulation

The AC OPF formulation to model the effect of grid constraints in the VPP problem includes the linear constraints and convex approximations for shunt currents and minimum voltage limits. For simplicity, the time-dependent subscripts, which apply to currents, powers, and voltages, are omitted.

Constraints (11) and (12) correspond to the phase-to-ground voltage drop equation given by Kirchhoff's Voltage Law in a three-phase line $l \in \boldsymbol{L}$ with starting and ending nodes $\beta^{1}_{l}, \beta^{2}_{l} \in \boldsymbol{N}$, with $\boldsymbol{N}$ being the set of nodes. Here, $V^{re}_{n,\varphi}$ and $V^{im}_{n,\varphi}$ are the real and imaginary parts of the voltage at node n and phase φ, respectively, $R^{\varphi,\vartheta}_{l}$ and $X^{\varphi,\vartheta}_{l}$ are the resistance and reactance of the line between phases $\varphi, \vartheta \in \Phi$, and $I^{re}_{l,\varphi}$ and $I^{im}_{l,\varphi}$ are the phase current components in lines. Shunt admittances have been neglected due to their typically negligible values in distribution lines.

$$V^{re}_{\beta^1_l,\varphi} - V^{re}_{\beta^2_l,\varphi} = \sum_{\vartheta\in\Phi} \left(R^{\varphi,\vartheta}_l I^{re}_{l,\vartheta} - X^{\varphi,\vartheta}_l I^{im}_{l,\vartheta}\right) \quad l \in \boldsymbol{L}, \varphi \in \Phi \tag{11}$$

$$V^{im}_{\beta^1_l,\varphi} - V^{im}_{\beta^2_l,\varphi} = \sum_{\vartheta\in\Phi} \left(R^{\varphi,\vartheta}_l I^{im}_{l,\vartheta} - X^{\varphi,\vartheta}_l I^{re}_{l,\vartheta}\right) \quad l \in \boldsymbol{L}, \varphi \in \Phi \tag{12}$$

The current balance at each node $n \in \boldsymbol{N}$ and phase $\varphi \in \Phi$, given by Kirchhoff's Current Law, is shown in (13) and (14) for real and imaginary parts, respectively. These linear equations consider shunt and series elements connected, where indexes b and d denote the batteries and loads. Here, battery currents take positive and negative values when charging and discharging, respectively.

$$\sum_{l\in\boldsymbol{L}|\beta^1_l=n} I^{re}_{l,\beta^1_l,\varphi} - \sum_{l\in\boldsymbol{L}|\beta^2_l=n} I^{re}_{l,\beta^2_l,\varphi} + I_{d,n,\varphi} + I_{b,n,\varphi} = 0 \quad n \in \boldsymbol{N}, \varphi \in \Phi \tag{13}$$

$$\sum_{l\in\boldsymbol{L}|\beta^1_l=n} I^{im}_{l,\beta^1_l,\varphi} - \sum_{l\in\boldsymbol{L}|\beta^2_l=n} I^{im}_{l,\beta^2_l,\varphi} + I_{d,n,\varphi} + I_{b,n,\varphi} = 0 \quad n \in \boldsymbol{N}, \varphi \in \Phi \tag{14}$$

The real and imaginary parts of the current demanded by a single-phase household load $d \in \boldsymbol{D}$ at household $h \in \boldsymbol{H}$ (managed by the VPP or not), connected at node n and phase φ, are represented in pu by (15) and (16).

$$I^{re}_{d,n,\varphi} = \frac{\left(P^d_h V^{re}_{n,\varphi} + Q^d_h V^{im}_{n,\varphi}\right)}{\left({V^{re}_{n,\varphi}}^2 + {V^{im}_{n,\varphi}}^2\right)} \quad h \in \boldsymbol{H} \tag{15}$$

$$I^{im}_{d,n,\varphi} = \frac{\left(P^d_h V^{im}_{n,\varphi} - Q^d_h V^{re}_{n,\varphi}\right)}{\left({V^{re}_{n,\varphi}}^2 + {V^{im}_{n,\varphi}}^2\right)} \quad h \in \boldsymbol{H} \tag{16}$$

These current equations can be linearized using a first-order Taylor expansion around estimated voltages ${V^{re}_{n,\varphi}}^*, {V^{im}_{n,\varphi}}^*$, as shown in (17).

$$I^{re,im}_{d,n,\varphi} \approx I^{re,im}_{d,n,\varphi}|^* + \frac{\partial I^{re,im}_{d,n,\varphi}}{\partial V^{re}_{n,\varphi}}|^*\left(V^{re}_{n,\varphi} - {V^{re}_{n,\varphi}}^*\right) + \frac{\partial I^{re,im}_{d,n,\varphi}}{\partial V^{im}_{n,\varphi}}|^*\left(V^{im}_{n,\varphi} - {V^{im}_{n,\varphi}}^*\right) \quad d \in \boldsymbol{D} \tag{17}$$

In the study, single-phase PV systems are assumed to operate at unity power factor, without curtailment. Time-varying active powers of PV systems are known (for example, based on forecasts), and their currents can be approximated with a similar set of linearized equations. Thus, the active power of these non-controllable elements (loads and PV) can be aggregated to obtain their corresponding currents.

On the other hand, batteries are assumed to be directly managed by the VPP. The active and reactive powers for a battery connected at node n and phase φ are approximated using (18) and (19), respectively.

$$P_s^b \approx {V_{n,\varphi}^{re}}^* I_{s,n,\varphi}^{re} + {V_{n,\varphi}^{im}}^* I_{s,n,\varphi}^{im} \quad s \in \boldsymbol{S} \tag{18}$$

$$Q_s^b \approx -{V_{n,\varphi}^{re}}^* I_{s,n,\varphi}^{im} + {V_{n,\varphi}^{im}}^* I_{s,n,\varphi}^{re} \quad s \in \boldsymbol{S} \tag{19}$$

Finally, the magnitude of phase currents in each line $l \in \boldsymbol{L}$ is constrained by their capacity $\bar{I}_l$. These constraints can be expressed in a quadratic and convex form by relating their square magnitudes as shown in (20).

$${I_{l,\beta_l,\varphi}^{re}}^2 + {I_{l,\beta_l,\varphi}^{im}}^2 \leq \bar{I}_l^2 \quad l \in \boldsymbol{L}, \varphi \in \Phi, \beta_l \in \{\beta_l^1, \beta_l^2\} \tag{20}$$

The constraints for the maximum voltage limit $\bar{V}_n$ at node n and phase φ are represented by (21). However, the analogous constraints for the minimum voltage limit $\underline{V}_n$ are non-convex. Here, the voltage magnitude squared ${V_{n,\varphi}^{re}}^2 + {V_{n,\varphi}^{im}}^2$ is linearized using a first-order Taylor expansion around ${V_{n,\varphi}^{re}}^*, {V_{n,\varphi}^{im}}^*$, resulting in the linear constraint shown in (22).

$${V_{n,\varphi}^{re}}^2 + {V_{n,\varphi}^{im}}^2 \leq \bar{V}_n^2 \quad n \in \boldsymbol{N}, \varphi \in \Phi \tag{21}$$

$${V_{n,\varphi}^{re}}^{*2} + {V_{n,\varphi}^{im}}^{*2} + 2{V_{n,\varphi}^{re}}^*\left(V_{n,\varphi}^{re} - {V_{n,\varphi}^{re}}^*\right) + 2{V_{n,\varphi}^{im}}^*\left(V_{n,\varphi}^{im} - {V_{n,\varphi}^{im}}^*\right) \geq \underline{V}_n^2 \quad n \in \boldsymbol{N}, \varphi \in \Phi \tag{22}$$

7.1.3 Objective functions

The self-consumption scenario represents the current situation in Chile. In this case, each prosumer optimizes its battery charge and discharge to maximize self-consumption. Equation (23) outlines the proposed objective function, which comprises two terms. The first term is implemented by minimizing active power imports $P_{s,t}^+$ and exports $P_{s,t}^-$ across all households throughout the day, resulting in a minimization of grid dependency for the prosumers. The second term is intended to prevent solutions where batteries are simultaneously charging and discharging. For more details, please refer to (Gutierrez-Lagos, 2021).

$$\min \sum_{s \in \boldsymbol{S}} \left[\sum_{t \in \boldsymbol{T}} \left(P_{s,t}^{+} + P_{s,t}^{-} \right) + \mu \sum_{t \in \boldsymbol{T}} \left(P_{s,t}^{b,+} + P_{s,t}^{b,-} \right) \right] \tag{23}$$

$$\text{s.t.}$$

$$(4) - (7), (9) - (22)$$

To find the largest aggregated exported power for a predefined service period $\boldsymbol{T}^{S}$, the following objective function (24) can be defined:

$$\min \sum_{s \in \boldsymbol{S}} \left[\omega_t^{s} \sum_{t \in \boldsymbol{T}^{S}} P_{s,t} + \omega_t^{sc} \sum_{t \in \boldsymbol{T}-\boldsymbol{T}^{S}} \left(P_{s,t}^{+} + P_{s,t}^{-} \right) + \mu \sum_{t \in \boldsymbol{T}} \left(P_{s,t}^{b,+} + P_{s,t}^{b,-} \right) \right] \tag{24}$$

$$\text{s.t.}$$

$$(4) - (22)$$

The first term is implemented by minimizing the net household power consumption over all households managed by the VPP during the service period. The other terms are similar to those in (23), which means that part of the batteries' energy is supplied to the individual loads for the remainder of the day.

Specifically, two weighting factors ω_t^{s} and ω_t^{sc} are introduced for service and no service, respectively. These factors help determine priorities, allowing either a focus on service during the specific period (when $\omega_t^{s} > \omega_t^{sc}$) or an emphasis on minimizing household power imports for the remainder of the day (when $\omega_t^{s} < \omega_t^{sc}$). Additionally, these weighting factors can vary over time, prioritizing specific service periods while also reflecting the minimization of grid imports outside them.

7.2 Data and Assumptions

The AC OPF-based methodology presented in this report is applied to the two selected LV networks representing the regions of Lampa and Osorno. The distribution network in Lampa comprises 251 customers, while the network located in Osorno involves 275. The DERs considered in the technical analysis include the BTM batteries and distributed PV arrays. The report utilizes real-world demand profiles of residential end-users from smart meter measurements recorded at 30-minute intervals. This electricity data has been anonymized to preserve privacy. The calculation of reactive power profiles assumes an inductive power factor of 0.98. Likewise, the voltage at the head of both distribution grids is fixed at 1.0 pu per phase, while voltage limits, enforced across all periods, are defined between 0.9 and 1.1 pu on a 220 V line-to-neutral base. These grid heads consist of 300 kVA, 12-0.4 kV and 200 kVA, 23-0.4 kV delta-wye secondary transformers for Lampa and Osorno, respectively.

Furthermore, the sizes of PV systems are determined based on typical installed capacities in Chile (ACESOL, 2022), with an average of 2.5 kW-peak per end-user. This study also employs a real-world single irradiance profile, applied for simplicity to all prosumers. The conventional data for BTM batteries, as defined in Section 5, is used, including an assumption of 95 % round-trip efficiency.

Concerning the weighting factors of problem formulation, $\omega_t^s = 1.0$ for all $t \in \boldsymbol{T}^s$, while ω_t^{sc} varies with time following the equation $2 - 0.01(t-1)$ for all $t \in \boldsymbol{T} - \boldsymbol{T}^s$. Additionally, $\mu = 0.1$. These considerations indicate the prioritization of grid services. In the algorithmic implementation, the software AIMMS (Bisschop, 2006) is utilized in combination with the Gurobi 12.0 (Gurobi Optimization LLC, 2025) optimization solver.

7.3 Results and Analysis

One of the main objectives of this report is to determine the maximum DER capacity that enables the effective technical operation of the VPP for the two selected distribution networks. The analysis involves a 30-minute service period at 8:00 PM, during which the VPP exports energy to the distribution system at maximum active power to reduce peak demand. Moreover, this analysis quantifies the service provided under the following two conditions: 1) without considering grid constraints (labeled as “no GC”), and 2) with grid constraints (labeled as “GC”). For comparison, the self-consumption operation (labeled as “SC”) is also included in the analysis.

From the initial set of customers, the study randomly selects a group of prosumers, who make up nearly 50 % of the total. The prosumers are equipped with solar PV systems and BTM batteries. This PV penetration does not cause thermal or voltage issues, which implies that reverse power flows can be managed without the need for specific operational strategies. However, challenges may arise in the distribution grid if VPP batteries discharge during periods of PV generation or even when there is no generation present.

Figs. 13 and 14 depict the aggregated net active power provided by the VPP during the analyzed peak demand period for Lampa and Osorno, respectively. In the figures, positive values indicate imports, while negative values indicate exports. As shown in both graphs, the ideal condition without grid constraints results in a higher net active power (about 400 kW). In contrast, the realistic condition GC yields lower values, as expected. This decrease occurs because grid limits are reached, indicating that exporting with more power than the presented values implies their violation. Additionally, because batteries need to meet demand during discharge within the period, the exported energy can be limited by the available capacity of battery inverters.

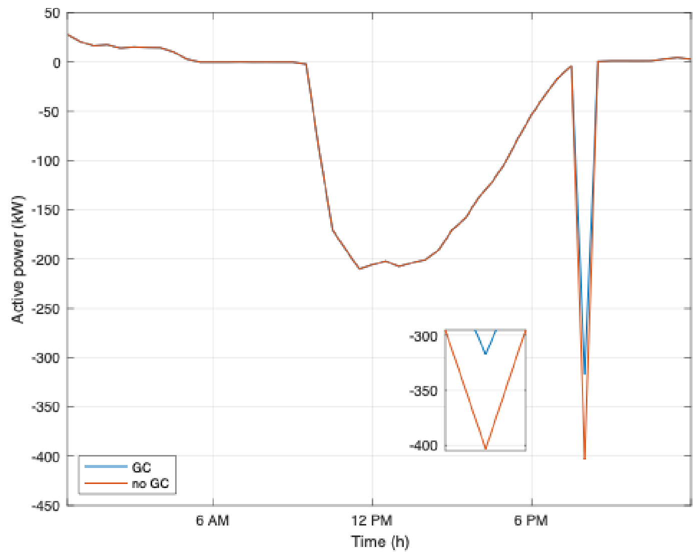

Fig. 13. Aggregated net active power for the Lampa VPP under conditions with and without grid constraints at 8:00 PM.

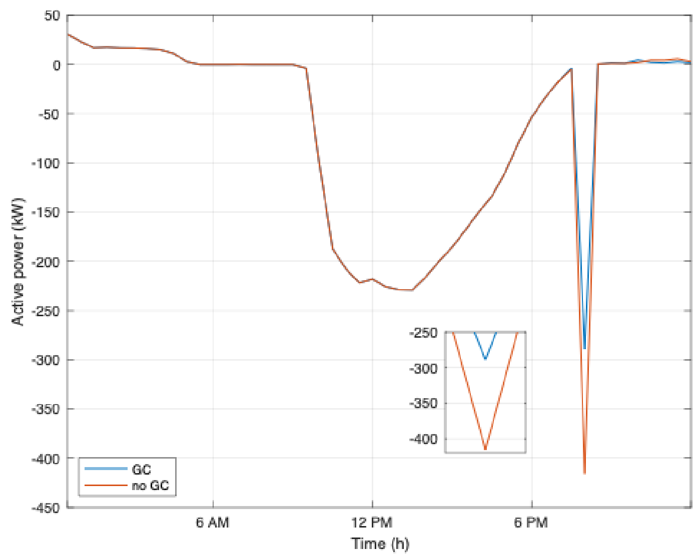

Fig. 14. Aggregated net active power for the Osorno VPP under conditions with and without grid constraints at 8:00 PM.

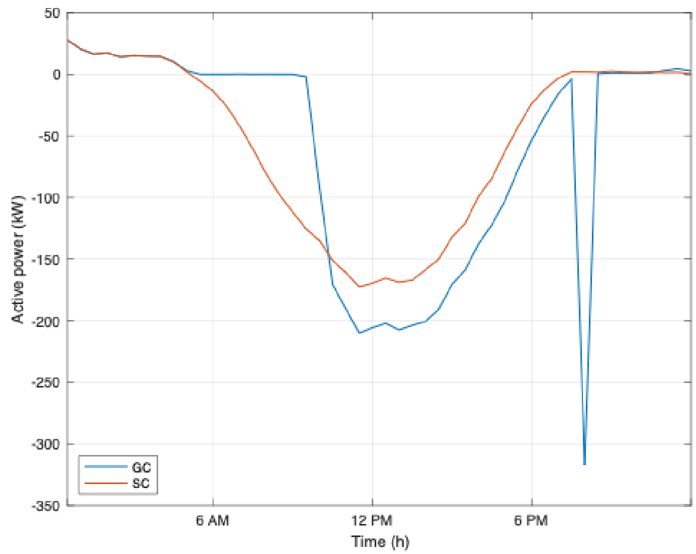

Fig. 15. Aggregated net active power for the Lampa VPP at 8:00 PM and comparison with the self-consumption setting.

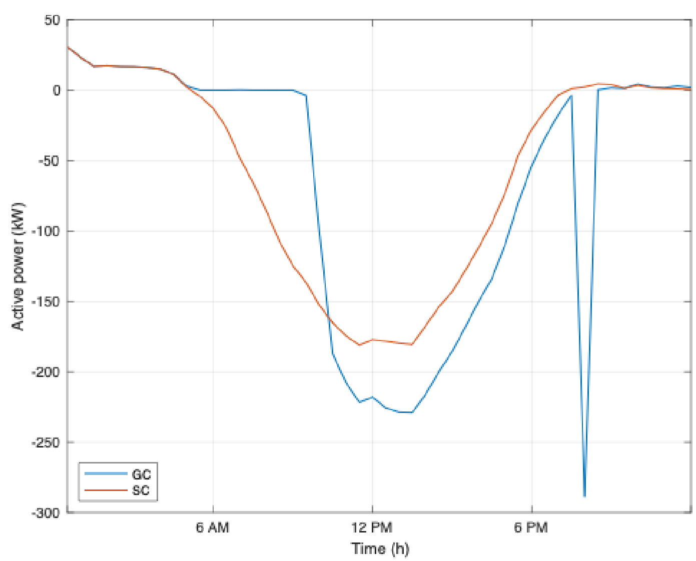

Fig. 16. Aggregated net active power for the Osorno VPP at 8:00 PM and comparison with the self-consumption setting.

However, these realistic results remain significant for the distribution company, as they demonstrate technical performance compared to the self-consumption, in which prosumers essentially manage their batteries to meet their own demand during the peak period. Figs. 15 and 16 illustrate this comparison for both representative networks. These graphs clearly show that a significant amount of energy is consumed by batteries from the onset of available solar generation to deliver maximum power during the service period. As a result, batteries charge rapidly, reaching their full capacity more quickly. Also, due to this effect, PV generation injected into the grid is higher at noon compared to the self-consumption scenario, where the batteries charge more gradually to meet demand at the end of the day.

The difference between the exported values from the VPP and those obtained from self-consumption indicates a more efficient use of the grid infrastructure as a function of the service provided. This concept is illustrated in Figs. 17 and 18. The boxplots in both figures show voltage magnitudes, as well as the utilization of distribution lines and transformers (including the three phases), reflecting the grid constraints throughout the period.

Notably, the operation of VPPs results in many more elements at their limit due to the higher active power exported. It is important to note that, in the case of Lampa, the main limiting factor is the distribution lines. In contrast, in Osorno, both a specific line and the transformer in the three phases are operating at 100 % of utilization.

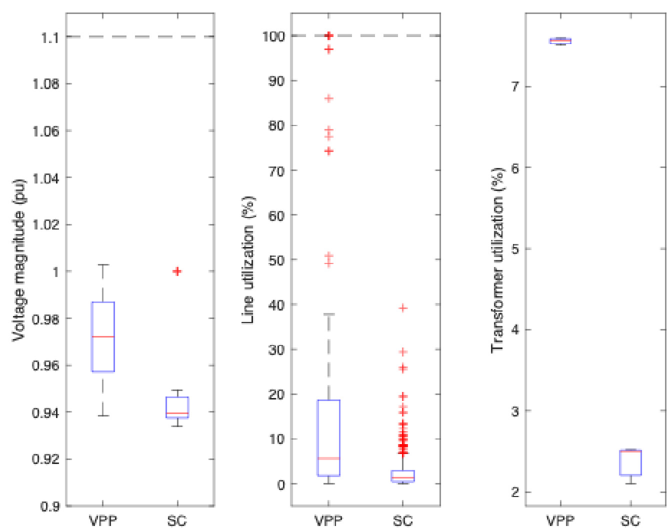

Fig. 17. Voltage magnitudes, and line and transformer utilization levels at 8:00 PM for the Lampa VPP compared to the self-consumption setting.

Finally, to illustrate the technical limitation of exporting energy during periods with high PV generation, Fig. 19 depicts the aggregated net active power for the Osorno VPP at 12:30 PM, both with and without grid constraints. As can be observed, grid constraints significantly limit the available power due to the excess solar generation. Therefore, there is little practical advantage in injecting energy (for example, through the CPF+ service) during these periods of high PV generation.

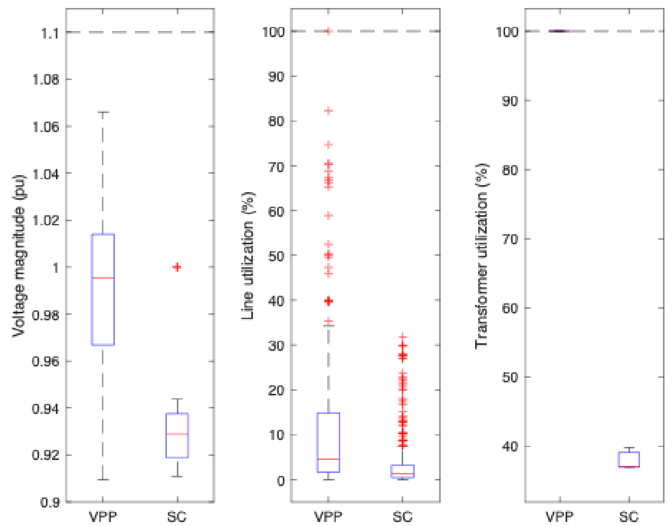

Fig. 18. Voltage magnitudes, and line and transformer utilization levels at 8:00 PM for the Osorno VPP compared to the self-consumption setting.

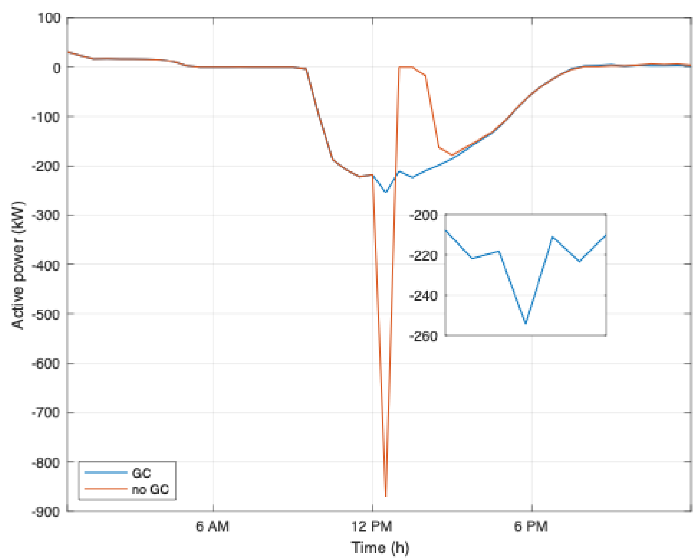

Fig. 19. Aggregated net active power for the Osorno VPP under conditions with and without grid constraints at 12:30 PM.

7.4 Feasibility Analysis

The methodology presented in this report enables the estimation of the maximum power the VPP can technically provide for specific services, primarily focusing on peak demand reduction. The obtained results are valuable for quantifying both exported and imported energy, considering that the VPP knows the distribution grid parameters and its topology.

In addition to these findings, the methodology also allows for calculating the maximum DER capacity for VPP implementation based on the maximum power value and information on the number and active power of battery inverters. Given that each battery is considered to have an active power of 5 kW, this calculation results in 63 batteries for the representative network in Lampa and 58 for the network in Osorno. Consequently, this corresponds to a maximum of 25 % of prosumers among the total number of customers in Lampa and 21 % in Osorno. Furthermore, these percentages are lower than the proportion of single-family dwellings in both regions according to the 2024 census in Chile, which have the potential to incorporate PV panels and batteries. Specifically, Lampa has 95.7 % of its residences classified as single-family dwellings, while Osorno has 88.9 % (INE, n.d.).

It is important to recall that this calculation applies specifically to a continuous service lasting at least 30 minutes. If the VPP offers only a primary frequency control service, for example, these amounts could be slightly higher, as the operation at maximum power is expected to last no more than a minute in each activation. Additionally, if more prosumers with PV and batteries than the results indicate participate in the VPP, not all of them will be able to provide their full power during a single service period.

This technical analysis also suggests that to achieve the minimum of 1 MW proposed in Section 6 for service delivery, as in the international context, such as Australia (AEMO, 2020), the VPP needs to incorporate four distribution grids with a similar structure and number of customers. By implementing this approach, the VPP can achieve both economic and technical viability. Lastly, while this technical analysis does not include EVs and HPs, all customers using these technologies can engage within the VPP, as they directly contribute by reducing demand.

8 VPP National Potential

Historically, demand response in Chile has involved automatic demand reductions through load disconnection schemes, especially during critical moments when the electric system's stability is at risk. Today, the power system has undergone continuous evolution, integrating larger-scale renewable energy sources, modernizing the grid, and rapidly adopting emerging technologies within distribution grids. Given this context, solutions that focus on the demand side have been increasingly proposed.

The electric load, traditionally viewed as a passive component in the initial design of the electric system infrastructure, now acquires value due to the inherent flexibility of these new resources, including the ability to manage them and their contribution to grid services that were traditionally handled by generation sources. However, as stated in Section 1, there are several challenges at both the systemic and distribution levels regarding energy transition. In addressing these challenges, VPPs can play a significant role. This section provides an overview of the value and economic potential of VPPs in Chile's future energy landscape.

8.1 Why a Solution Based on VPPs?

In recent years, projections for electricity demand growth in Chile have risen significantly. For example, the growing interest in artificial intelligence applications powered by energy-intensive data centers will multiply demand by 2030, primarily concentrated in the Metropolitan Region (Systep, 2025). The ongoing electrification of public and private transportation and heating are also contributing to this increase in demand. Likewise, Chile has been developing policies and regulations to establish a sustainable green hydrogen industry for both domestic consumption and export. Local projections indicate that demand for green hydrogen will grow significantly in the coming decade (CEN, 2025 d).

Fig. 20 illustrates the expected electric demand in Chile across three distinct scenarios: low, medium, and high, along with the associated annual growth rate. The difference between these demand scenarios depends on the national economic growth and the expected development of various initiatives, including the above and others linked to copper mining and desalination plants. All scenarios project a sustained increase in electricity consumption, with a more pronounced rise between 2029 and 2035. In the Chilean context, this growth is generally viewed as an opportunity to enable new investment, improve asset utilization, and support the country's broader electrification goals. Rather than representing a source of system stress, rising demand underlines the importance of planning flexible, cost-effective resources to optimize local grid operation. In this regard, VPPs can contribute by coordinating DERs to efficiently meet both consumer needs and system requirements.

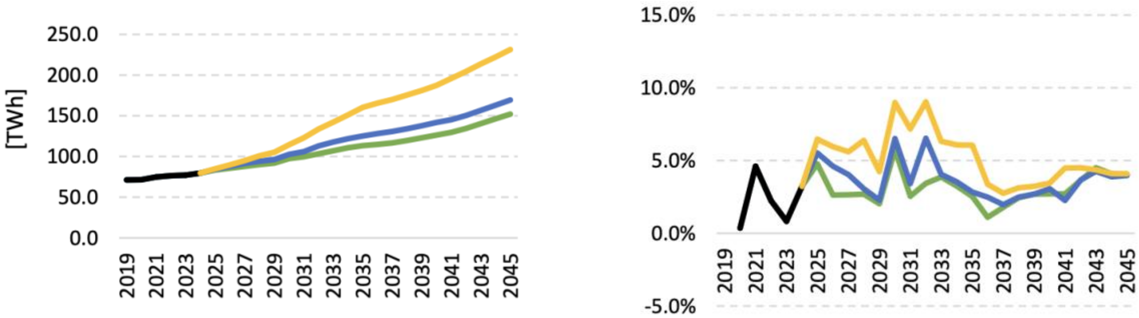

Fig. 20. Expected electric demand in Chile for three distinct scenarios and percentage of demand growth (CEN, 2025 d).

At the same time, recent extreme weather events have highlighted Chile's vulnerable electric system and underscored the necessity for investments in grid resilience. As Fig. 21 depicts, the System Average Interruption Duration Index (SAIDI) is trending upward, potentially exceeding the record set in 2023 and 2024 by July (because of the impact of the strong winds in August 2024). This trend is particularly concerning given Chile's goal for 2035. The target for 2035 is to achieve a national average with a maximum SAIDI of four hours and a maximum System Average Interruption Frequency Index (SAIFI) of five interruptions per customer, while maintaining a low level of dispersion (Ministry of Energy, 2021). However, achieving this goal remains a distant prospect given the current scenario. Furthermore, power interruptions tend to have more severe consequences for non-urban communities. In this context, VPPs can play a significant role in supporting these vulnerable communities.

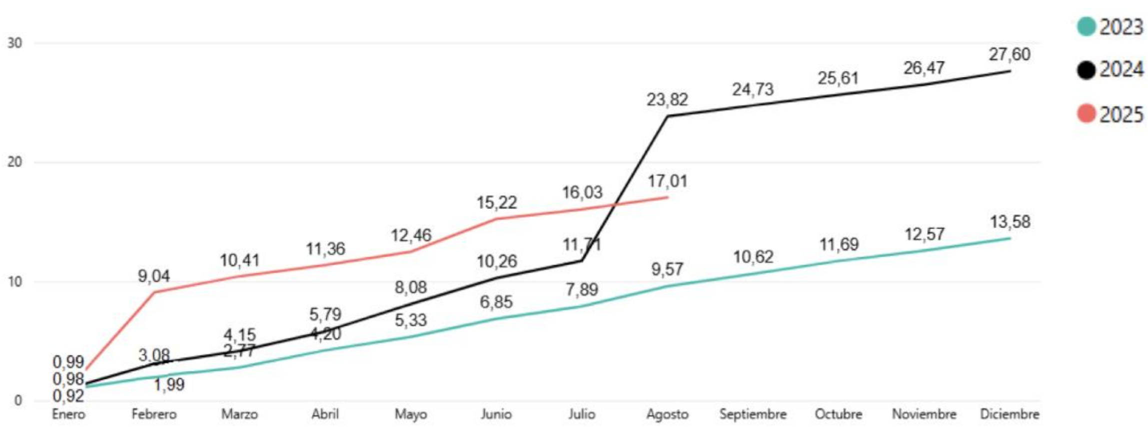

Fig. 21. Monthly evolution of the SAIDI for 2025 and comparison with 2023 and 2024 (SEC, 2025).

Given the value that VPPs can provide under Chile's evolving demand, resilience, and flexibility needs, an important question is whether this solution is feasible at scale. The economic and technical dimensions of VPP operation were addressed in Sections 6 and 7, respectively. What remains to be clarified is at what point VPPs become economically viable, and the extent to which VPPs can deliver services without creating grid issues (technically feasible) within the Chilean context. The latter, quantified in MW, is referred to as the national potential for VPPs. Specifically, this potential relies on two conditions: 1) that distribution grids can technically accommodate the operation of VPP services without violating nodal voltages or thermal constraints; and 2) that VPP deployment is economically viable, meeting a predefined economic performance criterion such as achieving a positive net present value. Only when both criteria are satisfied can aggregate DERs be considered part of the national VPP potential.

8.2 Methodology for Estimating the National Potential

To calculate the national potential of VPPs in Chile, this report uses the following methodology according to the considered DERs:

1. BTM batteries:

First, calculating the national potential for VPPs requires information on both the number of LV distribution networks with low and medium customer densities and the number of dwellings that are potentially available to adopt BTM batteries.

Table 6 summarizes this information, where the number of LV networks (secondary transformers) per municipality was obtained on request from SEC. This totalizes over 220,000 LV networks. Subsequently, this data was mapped to the CNE's customer density classification of municipalities available in the current "Technical standard on service quality for distribution systems" (CNE, 2024). This classification includes five categories of customer density: high, medium, low, very low, and extremely low.

Table 6. Total single-family dwellings and LV distribution networks of medium and low customer density in Chile.

	Single-family dwellings	LV distribution network	Average of dwellings per LV grid
Medium customer density	3,893,059	34,851	118
Low customer density	1,213,660	32,618	37

Similarly, information about the type of dwelling is significant for the final estimation. This data is derived from the 2024 census (INE, n.d.), considering single-family dwellings with direct street access and within condominiums. Each of these houses is classified according to its corresponding municipality. Thus, this information is also mapped with the CNE's classification to determine the total number of dwellings associated with medium and low customer densities. Based on these findings, the national-level average of customers for LV grids of medium and low density is 118 and 37, respectively.

It is important to note, on the one hand, that some LV grids have not been included in the analysis as their classification within the database does not correspond to a combination specified by the CNE. On the other hand, while most municipalities have a single distribution company, some have more, especially those of low customer density. For example, only two of medium customer density have more than one distribution company within their area, two specifically. The first case is a municipality with high and medium customer densities, and the second includes medium and low densities. In both cases, the study assumes half of the dwellings belong to each distribution company. Furthermore, municipalities that exhibit more than one customer density (or more than one distribution company) including low density, tend to have the remaining categorized as extremely low density. In these cases, all dwellings are attributed to the distribution companies of low customer density.

2. EVs and climatization units:

To calculate the national potential of these technologies, the report evaluates their projected penetration for 2035, as outlined in Section 5. By 2035, EVs and electric climatization are expected to account for 23.2 % and 14.5 %, respectively, of the demand in the commercial, public, and residential sector in Chile. By also considering the expected total demand for that year and determining the portion of this sector, an estimation of the potential relative to these resources can be obtained.

Table 7. 2035 expected penetration of EVs and electric climatization, total demand, and percentage of demand of the commercial, public, and residential sector in Chile.

	Expected penetration (%)	Expected total demand (GW)	Commercial, public, and residential sector demand (%)
EVs	23.2	16.8	34.8
Climatization	14.5		

Table 7 presents the relevant data. Initially, the study employs the 2035 hourly maximum demand (16.8 GW), based on a medium demand scenario (CEN, 2025 d). Subsequently, 34.8 % of this value is attributed to the commercial, public, and residential sector. This percentage is derived from the average of the sector's electric demand percentages relative to the total demand over the last three published years (CNE, n.d.). Accordingly, the estimated potential for these resources is 1.36 GW and 0.85 GW, respectively.

It is significant to underline that both EVs and electric climatization (primarily HPs in this study) are considered interruptible loads, consistent with the existing business model in Chile. Consequently, they provide a service for approximately two hours, as defined in Section 5, by interrupting their grid connection. This approach differs from several international examples, such as the Thermostat Program of National Grid's Connected Solutions VPP in the United States (National Grid, n.d.). Through this program, the VPP automatically pre-cools homes during the hottest days of summer and then adjusts temperature by a few degrees during the peak event (three to four hours). Thus, instead of total power, only a portion is managed by the VPP.

8.3 The National Potential of VPPs

To estimate the national potential from BTM batteries, this report applies the average values of 21 % and 25 %, as determined in Section 7 of the technical analysis, to calculate the number of prosumers with 5 kW batteries for each LV grid outlined in Table 6. As a result, the national potential is 4.36 GW for networks of medium density and 1.47 GW for networks of low density. Similarly, based on the results in Table 7, the estimated potential for EVs and electric climatization is 1.36 GW and 0.85 GW, respectively.

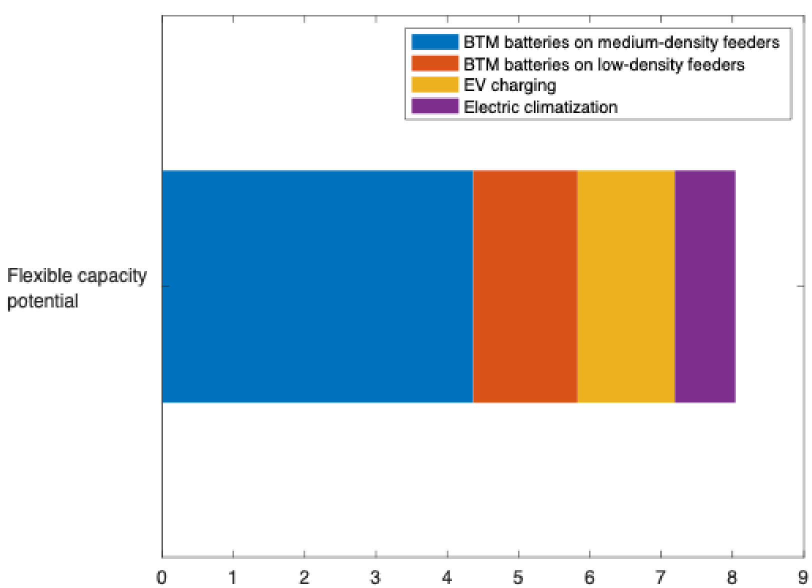

Fig. 22. Estimated national potential for VPPs in Chile (in GW).

Fig. 22 summarizes the cost-effective, flexible capacity of the three studied DERs, with the highest potential achievable from BTM batteries on LV networks in areas of medium customer density. Lastly, the total estimated VPP potential in Chile is 8 GW. This potential indicates that if VPP focuses on the analyzed DERs, as demonstrated in Section 5, where business models based on them achieve economic viability from 1 MW, there is a feasible capacity for VPP implementation in Chile. Deploying the VPP potential by 2035 will help address national capacity needs, as mentioned in Section 1. Furthermore, it could save grid costs for the electric system, mainly by avoiding generation capacity, while also having a positive impact on Chilean life by enhancing energy resilience. However, as discussed in Section 3, the limited regulation for VPP integration into electric system planning, operation, and market participation has hindered their implementation to date.

In summary, given that the minimum economic threshold for a VPP to be viable is 1 MW, and given that the maximum technical threshold is 8 GW, then the VPP potential is exactly 8 GW, which exceeds half of the current maximum demand in Chile, about 12 GW (CEN, 2025 d), while representing approximately over one-quarter of the installed capacity in the electric system, 38.4 GW (ACERA, n.d.).

9 Pilot Project Design

VPPs are emerging as a strategic tool for the future of the Chilean electric system. Their ability to coordinate distributed resources provides multiple benefits that address both the technical needs of the system and the country's priorities. In particular, VPPs enhance local resilience during contingencies and provide ancillary services by optimizing the use of existing infrastructure. Additionally, recent international experience demonstrates that VPPs have become fundamental components of the energy transition.

For Chile, the opportunity to launch a pilot project is twofold:

1. Providing ancillary services to the electric system: In the short term, the Chilean electricity system will rely on ancillary services from non-synchronous DERs, especially during periods of high renewable generation. The growing share of renewable energy sources in the energy mix poses significant challenges for system stability due to their variable nature and specific limitations. By aggregating DERs, VPPs can collectively deliver essential ancillary services, such as frequency control and demand reduction. While individual DERs may struggle to provide these services consistently, a sufficiently heterogeneous group of DERs can achieve this effectively.
2. Boosting resilience in the face of blackouts and grid instability: In a country with significant geographical diversity and exposure to climate and seismic risks, localized power disruptions are a persistent challenge. VPPs can enhance energy resilience by enabling communities, critical infrastructure, and remote areas to maintain power autonomously during grid outages. Battery-backed DERs coordinated through VPPs can form microgrids that operate independently when needed, supporting hospitals, emergency services, and essential facilities.

It is important to note that this strategy focuses on the total community and differs from other international VPP resilience-centered approaches. For example, two of the most successful VPPs in this context involve the following: 1) GMP with its Energy Storage System program in Vermont, United States, by which this utility-led VPP allows customers to lease a Tesla battery for 10 years, based on 5,500 USD as an up-front payment or 55 USD per month. In exchange, GMP owns and operates the battery. Through this program, battery storage is more accessible to customers who cannot afford to purchase a battery on their own (NARUC, 2024). 2) The Community Lighthouse Project in Louisiana, United States, which has been building a local VPP by putting solar and Tesla battery systems, primarily on churches, to transition these buildings into self-sustaining microgrids, and keep the lights on during power outages (Community Lighthouse, n.d.).

Recognizing this opportunity, CENTRA is focusing on implementing a VPP pilot in Chile based on a partnership with the SAESA distribution company and other national stakeholders. This alliance will serve as a multidisciplinary platform to generate knowledge to understand the economic and technical impact of a VPP in Chile.

9.1 Objective and Short-term Objectives

The grant objective maintains concerning the current project, that is: To enhance the understanding and foster the implementation of Virtual Power Plants (VPPs) in Chile, improving grid resilience and sustainability while enabling equitable access to renewable energy for local communities, contributing to the country's carbon neutrality goals by 2050.

Furthermore, CENTRA aims to enhance the understanding and foster the implementation of VPPs in Chile through the following SMART short-term objectives:

- STO0 – To assist the distribution company (the implementation partner) and other collaborating partners in the preparation, procurement, installation, and commissioning of the small-sized VPP control system and associated DERs involved in the pilot project.
- STO1 – To assess the real-time monitoring and coordinated control of the VPP pilot, including distributed photovoltaic generation, utility-scale batteries, behind-the-meter batteries, and flexible demand, using the VPP control system. Based on specific technical tasks, the objective will examine and assess VPP control strategies in response to external signals simulating system-level events. The success of the objective will be measured based on technical and operational metrics, such as activation times, communication delays, and accuracy in tracking power setpoints. The technical findings will be compiled and presented in a comprehensive first report.
- STO2 – To test the capacity of the VPP pilot to provide ancillary services to the centralized system. The objective will include simulating dispatch instructions to provide ancillary services through contributing to reducing system demand during peak consumption periods and to the system frequency control when it deviates from the established normal operating range. The success of the objective will be measured by the effective dispatch of aggregated DERs in response to these simulated instructions. The aim is to test whether the VPP can operate similarly to a conventional power plant when responding to the CEN's directives while complying with technical metrics for service provision. These metrics comprise delivering defined reserves, the total time of activation, and the time-of-service delivery. The technical findings will be compiled and presented in a comprehensive second report.
- STO3 – To test the capacity of the VPP pilot to enhance system resilience through DER configurations. By intentionally disconnecting from the main grid, this objective will test whether the VPP can maintain power supply to a group of customers while operating in island mode and coordinating the distributed resources. The success of the objective will be measured using key technical metrics, which include successful islanding after the intentional disconnection, the operational capacity of the VPP to sustain power supply for a predefined period, maintaining stable frequency and voltage, and the successful reconnection to the main grid. The technical findings will be compiled and presented in a comprehensive third report.

9.2 Action Plan Outline

CENTRA aims to enhance the understanding and foster the implementation of VPPs in Chile through a series of well-defined activities, including VPP technical operation assessment, ancillary services delivery, grid resilience enhancement, and dissemination of results:

A0 – Assist the distribution company in the preparation, procurement, installation, and commissioning: This activity aims to assist the distribution company with preparing, procuring, installing, and commissioning the VPP control system and associated DERs. The process relies on continuous communication and coordination with the distribution company and key stakeholders to align expectations and timelines. In terms of preparation and procurement, specific tasks include: 1) assisting in the definitive technical design of the pilot, which encompasses specifications for the VPP control system and operational definitions for the proposed services, 2) supporting the selection and procurement of technologies, such as solar panels and batteries, and 3) aiding in the preparation and management of contracts with end-users by providing both technical and structural recommendations. Concerning installation and commissioning: 1) ensuring this for the involve technologies, 2) verifying the proper integration of monitoring and control devices, and that communication and telemetry conditions meet the pilot's requirements, and 3) configuring the VPP control system within the distribution company's control room, along with operational coordination of the VPP with the other components.

- A1 – Assess the real-time monitoring and coordinated control of DERs: This activity aims to assess the VPP control system's performance in the real-time monitoring and coordinated control of DERs based on technical and operational indicators such as activation time, communication delay, and accuracy in tracking power setpoints. Specifically, the activity will assess how effectively the VPP responds to these requested power setpoints. Key indicators will include calculations of the error between target signals simulating system-level events and the aggregate response of the VPP. Additionally, the activity will measure the average activation time from when a command is given until the aggregate power reaches the required reserve level, which is significant in ancillary services such as fast and primary frequency control. Corresponding computations will also allow the quantification of communication delays with the different DERs involved in the pilot.
- A2 – Test the capacity of the VPP to provide ancillary services: This activity involves testing the capacity of the VPP to provide ancillary services to the CEN. Specifically, the following two services will be tested: 1) the power reduction (or injection) of the VPP demand during peak consumption periods in the power system, and 2) the contribution to the frequency control when it deviates from the established normal operating range. Key metrics to be calculated within the first include the amount of defined reserve in active power that can be either reduced or injected during these peak periods, and the average activation time when the VPP provides the service. In the second, the activity will measure the contribution to frequency control based on the different technical categories defined by the CEN: primary, secondary, and tertiary control. For each

category, key metrics to be calculated include defined reserves and the times of the VPP for activation and service delivery.

- A3 – Test the capacity of the VPP to enhance system resilience: This activity involves testing the capacity of the VPP to enhance system resilience in the distribution grid by operating in island mode. With the intentional disconnection of the distribution network segment containing the VPP, the first step is to test if the VPP can successfully and securely form an island for autonomous operation. For this task, the presence of an inverter with grid-forming technology and adequate backup resources, such as a utility-scale battery, is required. Additionally, this activity will assess the technical and operational capacity of the VPP in sustaining power supply for a predefined period (several hours) while ensuring that frequency and voltage levels remain stable within established ranges. Finally, the activity will also test the VPP's ability to reconnect the network segment to the rest of the distribution system, considering a suitable synchronization process and the continuity of service. The calculation and documentation of improvements of power supply quality indicators, specifically the duration and frequency of interruptions (SAIDI and SAIFI), will be accomplished.
- A4 – Disseminate the results: Disseminating the results is a crucial activity aimed at communicating the partial and final findings of the pilot project. Meetings will be held with the Advisory Group to discuss key milestones, including the VPP technical and operational performance, the ancillary services provided, and the enhancements to grid resilience. Specifically, four seminars will be organized. The opening seminar will present the pilot objectives and planning, aiming at aligning expectations and gathering feedback for effective implementation. The second seminar will address the procurement and installation process of the pilot technologies, including the VPP control system. The third seminar will discuss the technical results of the VPP control system's performance in the real-time monitoring and coordinated control of DERs, identifying encountered problems and corresponding solutions. The closing seminar will focus on the technical results concerning the ancillary services delivered and grid resilience enhancement, including general insights from the pilot. Additionally, closed meetings with PIE for status updates and feedback suggestions will be held before the above seminar structure.

The following three products will be produced during the project (key deliverables):

- P1) Knowledge Sharing Report 1: Technical evidence and practical experiences of the VPP implementation in Chile.
- P2) Knowledge Sharing Report 2: Results in VPP ancillary services delivery in Chile and relevant recommendations for future integration.
- P3) Knowledge Sharing Report 3: Results in VPP grid resilience enhancement in Chile and relevant recommendations for future integration.

10Conclusion

VPPs are emerging as a strategic tool for the future of the Chilean electric system. Their ability to coordinate distributed resources provides multiple benefits that address both the technical needs of the electric system and the country's priorities. In particular, they enhance local resilience during contingencies and provide ancillary services by optimizing the use of existing infrastructure. This report, as part of the project **VPPs for Sustainable and Resilient Energy Systems in Chile**, aims to enhance understanding and foster the implementation of VPPs in Chile by analyzing economic and technical viability and informing regarding the national potential.

Recent international experience demonstrates that VPPs have become fundamental components of the energy transition. The comparative perspective underscores that Chile's challenges (regulatory gaps, limited digital infrastructure, and cultural inertia) are part of a broader trajectory faced by systems transitioning from centralized to distributed, flexible grids. At the same time, Chile exhibits distinctive features that make the need for flexibility and resilience solutions especially urgent and relevant. The roadmap of policy recommendations offers a feasible pathway: launching sandboxes and pilots, accelerating smart metering, standardizing interoperability, formally recognizing aggregators, and opening retail markets to competition. These actions address Chile's specific barriers while aligning with global best practices.

This report presents evidence of the expected economic and technical viability of VPPs in Chile. It examines two representative regions: Lampa and Osorno, characterized by low and medium customer density, respectively. Some considerations are based on projections of DER penetration in Chile, while others rely on data from international experiences. Based on a detailed analysis of costs and revenues, including payments for services of primary frequency control, local peak demand reduction, and grid resilience, the VPPs are financially viable from 1 MW. Specifically, the analysis provides annual profits of over 18,000 USD for Lampa and 12,000 USD for Osorno, while dynamic simulations demonstrate a positive net margin over 10 years.

Furthermore, the technical analysis, based on an AC OPF-based formulation, allows for quantifying and understanding the effects that three-phase LV grid constraints can have on the service provided by VPPs. This methodology also enables the calculation of the maximum DER capacity for VPP implementation, resulting in a maximum of 25 % of prosumers among the total number of customers in Lampa and 21 % in Osorno. Therefore, to achieve a 1 MW VPP in both regions, it is necessary to incorporate four similar LV distribution networks.

Likewise, based on these representative regions, the VPP national potential in Chile is estimated to be 8 GW. This potential indicates that if VPP focuses on DERs, including BTM batteries, EVs, and climatization units, there is a feasible capacity for VPP implementation in the country. Deploying the VPP potential will help address national capacity needs, could save grid costs, mainly by avoiding generation capacity, while also having a positive impact on Chilean life by enhancing energy resilience. Lastly, the report outlines a VPP pilot project design for implementing a VPP in partnership with the SAESA distribution company. With the same main goal as the current project and composed of four clear short-term objectives and the corresponding action plan, this pilot prioritizes the provision of ancillary services and grid resilience enhancement within the Chilean context.

Ultimately, these findings offer valuable insights for other emerging electricity markets in Latin America that are exploring distributed solutions and facing similar challenges.

11References

ACERA (n.d.). https://www.acera.cl/centro-de-informacion/

ACESOL (2022). https://acesol.cl/info-t%C3%A9cnica/estad%C3%ADsticas-de-mercado-netbilling

AEMC (n.d.). Regulatory Sandboxes. https://www.aemc.gov.au/market-reviews-advice/regulatory-sandboxes

AEMO (2019). https://www.aemo.com.au/-/media/files/electricity/nem/der/2019/vpp-demonstrations/vpp-demonstrations-fcas-specification.pdf

AEMO (2020). AEMO Virtual Power Plant Demonstration: Knowledge Sharing Report #1. https://arena.gov.au/assets/2020/03/aemo-virtual-power-plant-demonstration-knowledge-sharing-report-1.pdf

AEMO (2021). Amendment of the Market Ancillary Service Specification - DER and General Consultation: Final Report and Determination. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/mass/final-determination/final-determination.pdf

AER (2025). Policy-led sandboxing: Accelerating access, deployment and orchestration of distributed energy resources through the regulatory sandbox. Policy brief. https://energyinnovationtoolkit.gov.au/sites/default/files/2025-02/Policy-led%20Sandboxing_%20accelerating%20access_%20deployment%20and%20orchestration%20of%20distributed%20energy%20resources%20through%20the%20regulatory%20sandbox%20-%2013%20February%202025.pdf

Alajlan, R., et al. (2024). A Literature Review on Cybersecurity Risks and Challenges Assessments in Virtual Power Plants: Current Landscape and Future Research Directions. *IEEE Access*, *12*, 188813-188827.

ANAC (2025). https://www.anac.cl/wp-content/uploads/2025/07/06-ANAC-Informe-Cero-y-Bajas-Emisiones-Junio-2025.pdf

ARENA (n.d. a). AEMO Virtual Power Plant Demonstrations. https://arena.gov.au/projects/aemo-virtual-power-plant-demonstrations

Bisschop, J., et al. (2006). Aimms-The User's Guide. Paragon Decision Technology, Haarlem, The Netherlands.

Brehm, K., et al. (2023). *Virtual Power Plants, Real Benefits*. Rocky Mountain Institute. https://rmi.org/insight/virtual-power-plants-real-benefits/

CEDEC, et al. (2019). TSO-DSO Report: An Integrated Approach to Active System Management. https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf

CEN (2024 a). https://www.coordinador.cl/wp-content/uploads/2024/07/Bases-Administrativas-SUBASTAS-SSCC_V6_20240610.pdf

CEN (2024 b). https://www.coordinador.cl/wp-content/uploads/2024/01/2024.01.31-Informe_Factores_Desempeno_2023_CNE.pdf

CEN (2025 a). https://www.coordinador.cl/wp-content/uploads/2025/06/2025.06.30-Informe_SSCC_2026.pdf

CEN (2025 b). https://www.coordinador.cl/wp-content/uploads/2025/01/2025.01.31-Informe_Factores_Desempeno_2024.pdf

CEN (2025 c). https://www.coordinador.cl/wp-content/uploads/2025/04/Informe-Monitoreo-2024.pdf

CEN (2025 d). https://www.coordinador.cl/wp-content/uploads/2025/11/2511-C13-INF-DPR-01-V1-Proy_Dda_25-45.pdf

CENTRA (2023). Analysis and tools for the efficient integration of distributed energy resources in Chile. https://acesol.cl/noticias/resultados-del-estudio-%E2%80%9Can%C3%A1lisis-y-herramientas-para-la-integraci%C3%B3n-eficiente-de-recursos-energ%C3%A9ticos-distribuidos-en-chile%E2%80%9D.html

CENTRA (2025). https://centra.uai.cl/seminario-plantas-virtuales-de-energia-en-chile-rutas-para-un-futuro-sostenible/

CNE (n.d.). http://energiaabierta.cl/visualizaciones/balance-de-energia

CNE (2023). https://www.coordinador.cl/wp-content/uploads/2023/05/Rex.Exta_.Res_.N157_VMax_CI_2104.2023.pdf

CNE (2024). https://www.cne.cl/wp-content/uploads/2024/05/NTCSDx2024-1.pdf

CNE (2025 a). https://www.cne.cl/archivos_bajar/REX%20545-2025.PDF

CNE (2025 b). https://www.cne.cl/tarificacion/electrica/precio-nudo-corto-plazo/

Community Lighthouse (n.d.). https://www.togethernola.org/community-lighthouse

Decree 88 (2019). https://www.bcn.cl/leychile/navegar?idNorma=1150437

Decree 113 (2019). https://www.bcn.cl/leychile/navegar?idNorma=1129970

DOE (2023). Pathways to Commercial Liftoff: Virtual Power Plants. *U.S. Department of Energy Report*.https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

DOE (2025). Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update.

E2BIZ (2021). https://energia.gob.cl/sites/default/files/documentos/e2biz-2021_proyeccion_de_generacion_distribuida.pdf

Enel (2024). https://www.enel.cl/content/dam/enel-cl/inversionistas/enel-distribucion-chile/reportes/memorias/2024/Memoria-Anual-Integrada-Enel-Distribucion-2024.pdf

European Commission (2022). Digitalising the energy system – EU Action Plan. COM (2022) 552.

European Parliament and Council (2019). Directive (EU) 2019/944 on common rules for the internal market for electricity. Official Journal of the European Union L158.

FERC (2020). Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs.

Fitch, T., et al. (2024). Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems. *Rocky Mountain Institute*. https://rmi.org/insight/power-shift/

Gao, H., et al. (2024). Review of virtual power plant operations: Resource coordination and multidimensional interaction. *Applied Energy*, *357*, 122284.

Gurobi Optimization LLC (2025). Gurobi Optimizer Reference Manual. https://www.gurobi.com

Gutierrez-Lagos, L., et al. (2019). Implementable three-phase OPF formulations for MV-LV distribution networks: MILP and MIQCP. In *2019 IEEE PES Innovative Smart Grid Technologies Conference-Latin America (ISGT Latin America)*.

Gutierrez-Lagos, L., et al. (2021). Quantifying the effects of medium-low voltage distribution network constraints and distributed energy resource reactive power capabilities on aggregators. *IET Generation, Transmission & Distribution*, *15*, 2019–2032.

IEA (2022). Unlocking the Potential of Distributed Energy Resources: Power system opportunities and best practices. https://www.iea.org/reports/unlocking-the-potential-of-distributed-energy-resources

IEEE Standard 2030.5 (2023). IEEE Standard for Smart Energy Profile Application Protocol. https://ieeexplore.ieee.org/document/10785536/versions#versions

INE (n. d.). https://censo2024.ine.gob.cl

Kaiss, M., et al. (2025). Review on Virtual Power Plants/Virtual Aggregators: Concepts, applications, prospects and operation strategies. *Renewable and Sustainable Energy Reviews*, *211*, 115242.

Law 18.410 (1985). https://bcn.cl/2fcrz

Law 19613 (1999). https://bcn.cl/2lhas

Law 20.571 (2014). https://www.bcn.cl/leychile/navegar?idNorma=1038211

Law 21.118 (2018). https://www.bcn.cl/leychile/navegar?idNorma=1125560

LGSE (2007). https://bcn.cl/2fdga

Ministry of Energy (2021). https://energia.gob.cl/sites/default/files/documentos/comite_consultivo_-_recomendaciones_para_actualizacion_de_la_pen_vf.pdf

Ministry of Energy (2025 a). Long-term Energy Planning (PELP) 2023-2027. https://energia.gob.cl/sites/default/files/documentos/definitive_report_pelp_2023-2027.pdf

Ministry of Energy (2025 b). Decree 1. https://bcn.cl/RyPI8j

Moreno, R., et al. (2024). https://energia.gob.cl/sites/default/files/documentos/informe_final_der_vf.pdf

NARUC (2024). Aggregated Distributed Energy Resources in 2024: The Fundamentals. https://connectedcommunities.lbl.gov/sites/default/files/2024-07/NARUC_ADER_Fundamentals_Interactive.pdf

National Grid (n.d.). https://www.nationalgridus.com/MA-Home/Energy-Saving-Programs/ConnectedSolutions

Navarro, A., et al. (2015). Dissemination Document "Low Voltage Networks Models and Low Carbon Technology Profiles". https://www.researchgate.net/publication/283569482

OLADE (2025). Renewable Energy Curtailment. https://www.olade.org/wp-content/uploads/2025/06/Vertimientos-de-energia-renovable-OLADE_Jun20.pdf

OpenADR (n.d.). Open Automated Demand Response. https://www.openadr.org

Pang, S., et al. (2024). Robust decomposition and tracking strategy for demand response enhanced virtual power plants. *Applied Energy*, *373*, 123944.

SEC (n.d. a). https://www.sec.cl/interrupciones-en-linea/?view_full_site=true

SEC (n.d. b). https://www.sec.cl/GDA/?view_full_site=true

SEC (2025). https://www.sec.cl/sitio-web/wp-content/uploads/2025/10/Informe-SEC-Septiembre-2025.pdf

Shaviv, E., et al. (2025). A delicate dance: Value-added services and electricity security in decentralized systems. *Energy Policy*, *200*, 114550.

Srivastava, A., et al. (2025). Distribution System Behind-the-Meter DERs: Estimation, Uncertainty Quantification, and Control. *IEEE Transactions on Power Systems*, *40*(1), 1060-1077.

Systep (2025). https://systep.cl/es/data-centers-cuadruplicaran-su-demanda-de-energia-a-2030-alza-presionara-al-sistema-electrico/

Vensim (n.d). https://vensim-com.translate.goog/software/?_x_tr_sl=en&_x_tr_tl=es&_x_tr_hl=es&_x_tr_pto=tc

Wang, G., et al. (2025). Carbon-billed future for virtual power plants: A comprehensive review. *Renewable and Sustainable Energy Reviews*, *217*, 115719.

Wei, X., et al. (2024). Day-ahead optimal dispatch of a virtual power plant in the joint energy-reserve-carbon market. *Applied Energy*, *356*, 122459.

Xie, Y., et al. (2024). Virtual Power Plants for Grid Resilience: A Concise Overview of Research and Applications. *IEEE/CAA Journal of Automatica Sinica*, *11*(2), 329-343.

Zhu, X., et al. (2025). Optimal frequency support from virtual power plants: Minimal reserve and allocation. *Applied Energy*, *392*, 125913.

12Glossary

Note on terminology:
Some terms and definitions provided below for Chilean electric institutions and ancillary services correspond specifically to the official nomenclature, acronyms, and legal definitions used within the Chilean electricity market and its associated regulatory frameworks.

AEMO: Australian Electricity Market Operator.

AER: Australian Energy Regulator.

BTM: Behind-the-meter.

CEN: National Electric Coordinator.

CI: Interruptible load.

CNE: National Energy Commission.

CPF: Primary frequency control.

CPF+: Primary frequency control by under-frequency.

CPF-: Primary frequency control by over-frequency.

CRF: Fast frequency control.

CSF: Secondary frequency control.

CTF: Tertiary frequency control.

DER: Distributed energy resource.

DOE: Department of Energy.

EV: Electric vehicle.

FERC: Federal Energy Regulatory Commission.

HP: Heat pump.

IT: Information Technology.

LGSE: General Law of Electrical Services.

PMGD: Small resources for distributed generation.

SAIDI: System Average Interruption Duration Index.

SAIFI: System Average Interruption Frequency Index.

SEC: Superintendency of Electricity and Fuels.

VPP: Virtual Power Plant.