ECOEMPOWER

ECOsystems EMPOWERing at regional and local scale supporting energy communities

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D2.6 ECOEMPOWER ENERGY-ICT PLATFORM VALIDATION AND ANALYSES OF THE ECOEMPOWER ENERGY COMMUNITIES – FINAL VERSION

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ABBREVIATION LIST

ABBREVIATION	DEFINITION
BCR	Benefit-Cost Ratio
BESS	Battery Energy Storage System
CACER	Configurazioni per l'Autoconsumo Collettivo e le Comunità Energetiche Rinnovabili
CBA	Cost-Benefit Analysis
CHP	Combined Heat and Power
CO2	Carbon Dioxide
CSV	Comma-Separated Values
DSO	Distribution System Operator
EAN	Metering-Point Identification Code (European Article Number)
EC	Energy Community
EnWG	Energiewirtschaftsgesetz (German Energy Industry Act)
EV	Electric Vehicle
GSE	Gestore dei Servizi Energetici
HVAC	Heating, Ventilation and Air Conditioning
ICT	Information and Communication Technology
IRR	Internal Rate of Return
KPI	Key Performance Indicator
LV	Low Voltage
MAE	Mean Absolute Error
MAPE	Mean Absolute Percentage Error
MILP	Mixed-Integer Linear Programming
NPV	Net Present Value

OSS	One-Stop Shop
PPA	Power Purchase Agreement
PV	Photovoltaic
PVGIS	Photovoltaic Geographical Information System (EU Joint Research Centre)
RE	Regional Ecosystem
REC	Renewable Energy Community
RES	Renewable Energy Source
RMSE	Root Mean Square Error
SARIMA	Seasonal Autoregressive Integrated Moving Average
SC	Self-Consumption
SS	Self-Sufficiency
V2G	Vehicle-to-Grid
VDI	Verein Deutscher Ingenieure (Association of German Engineers)
WP	Work Package

DISCLAIMER

Contents

EXECUTIVE SUMMARY

D2.6 is the final output of Work Package 2 and closes Task 2.3. Where D2.4 validated the three analytical tools in isolation and D2.5 documented their redesign into a single, community-centric Platform, D2.6 applies the complete Platform to a dedicated study in each of the five pilot communities and reports the results, the accuracy of the tools, the adoption feedback and the interim arrangements for continued use.

The validation uses a two-tier design on one pilot per Regional Ecosystem (RE): Valle di Fassa in Italy, VercorSoleiL in France, the OAL Energiegemeinschaft in Germany, Vlčnov in the Czech Republic and Domokos in Greece. Each community is run as a real case, reflecting the assets attested on site in the validation Work Package 6, and an expansion case study that models a fuller configuration and appraises candidate investments. Both tiers use the same protocol, giving coherent and reproducible results across community types that range from generation-surplus to strongly demand-dominant.

The tools reach planning-grade accuracy. Across the pilots the 24-hour day-ahead forecasts of demand and generation, validated against the measured representative day, fall between about 0.9 and 5.2 percent Mean Absolute Percentage Error (MAPE) at high confidence, and a monthly validation on the French pilot's twenty-nine installations returns 7.2 percent MAPE on their real, metered generation. The single weak forecast affects only the four-meter Vlčnov case. It reflects the community's very small size rather than a limitation of the tool and is confirmed by the same community's 1.8 percent forecast at extension study scale.

Each study yields a clear operational picture and tailored recommendations. The scheduling tool returns correct and explainable energy balances under all four optimization objectives, and reads each community's position from its own data, showing whether it earns or pays on the day, whether it reaches full self-sufficiency, and where a physical grid limit or the absence of storage bounds what optimization can deliver. Where an investment is appraised, the Cost-Benefit Analysis (CBA) Tool reconciles net present value (NPV), benefit-cost ratio (BCR) and payback under explicit assumptions, and its socio-economic appraisal reflects the local grid's carbon intensity, so the gap between financial and socio-economic value widens or narrows with each community's context.

The final cycle added five new capabilities, namely hydroelectric assets, optional grid connection caps enforced at every timestep, dispatch of combined heat and power units, support for negative day-ahead import prices, and platform-wide multilingual documentation with an in-app Help Centre. Adoption feedback is broadly positive on clarity and usefulness, with the availability of concrete datasets from the pilot partners the main remaining barrier to wider uptake. The local-language need that earlier feedback raised has been met by the multilingual documentation and Help Centre added in this cycle. The Platform is deployed as a centrally hosted instance accessible to all partners, with per-Regional-Ecosystem deployment still being coordinated as no long-term sustainability model has yet been decided, and the interim plan is continued central hosting while a durable solution is agreed. The result is a validated, portable and agnostic Platform that gives five communities reproducible, actionable analysis, with its limits stated openly and a workable path to continued use.

1 Introduction

WP2 of ECOEMPOWER carries the responsibility for the project's Energy and ICT system analysis. Its purpose is to give the five REs and the ECs within them a practical, evidence-based instrument for understanding their own energy capabilities and for planning credible next steps. The work package has followed a three-step approach. T2.1 established the platform requirements and the ECs' Use Cases. T2.2 developed the Platform and its three analytical tools. T2.3, which the present deliverable closes, carries out the validation of the Platform and the dedicated studies for the ECOEMPOWER ECs. This deliverable, D2.6, is the final output of that work package and it is written to be read as the direct successor to D2.4 and D2.5.

The first validation cycle, documented at D2.4, asked whether the analytical methods were valid. The second cycle, documented at D2.5, asked whether the communities could utilize them with their own means and capabilities. This final cycle asks whether the redesigned Platform produces trustworthy results when it is applied to specific pilot communities, and it asks whether those results translate into recommendations that the communities can act on. T2.3 was defined to require both of these outcomes together, and this deliverable is structured to deliver both.

1.1 Scope of the Deliverable

The scope of D2.6 is the final validation of the ECOEMPOWER Energy-ICT Platform and the presentation of a dedicated study for each of five pilot communities. The deliverable reports what the Platform produces when it is run end to end on pilot data, it assesses whether those outputs are accurate and internally consistent, and it draws from each study a set of recommendations addressed to the community concerned. It also records the pilot partners' feedback of the Platform and its functionalities, and it sets out the arrangements for continued use of the tools after the project ends.

To understand the boundaries of this scope, it helps to recall the two deliverables that came before it. D2.4 was the first validation. It examined each of the three tools in isolation, tool by tool, and it confirmed that the analytical methods were coherent, reproducible and portable across pilots. What D2.4 also exposed was that valid results were not enough by themselves. The pilot communities could not operate the tools on their own, because the tools were too technical, they ran as three separate applications, and they did not explain their outputs to a non-technical user. D2.5 responded to that finding, documenting the redesign of the three tools into a single, unified and community-centric Platform, with guided workflows, a five-step setup wizard, an integrated data layer, and explainable before-and-after outputs.

D2.6 therefore applies the complete redesigned Platform to a dedicated study in each pilot community, and it reports the results. The validation operates on two tiers. The first represents each community as it exists today, judged against its real assets and conditions. The second extends the community towards a plausible future, so the Platform's planning value shows even where a community is still at an early stage of development. A distinction within the first tier is that where a pilot could supply continuous measured series these were used directly, but where a site lacked energy bills or the ICT and metering infrastructure to export data from an energy management system, the series were instead constructed from its documented assets and conditions, its installed capacities, asset types and local weather. This follows the approach documented in D2.4 and D2.5, is reconciled with the pilot characterization in D6.3 and is validated on ingestion.

Certain aspects are outside the scope of this deliverable. D2.6 does not repeat the requirements analysis or the development work, which belong to T2.1 and T2.2 and their deliverables. It also does not carry out the project-wide monitoring of the pilot sites, which is the subject of WP6. What D2.6 does is bring the WP2 line of work to its conclusion by demonstrating a validated, usable Platform and a concrete study for every community, together with an honest account of what remains to be done for each of them.

1.2 Structure of the Deliverable

D2.6 is structured in nine sections, moving from the general to the individual pilot studies and back to a synthesis:

- **Executive Summary** – A stand-alone overview of the final validation round and its headline findings.
- **Section 1: Introduction** – The scope, structure, and interdependencies of this deliverable within WP2 and the wider project.
- **Section 2: Final platform enhancements** – The capabilities added since the redesign: hydroelectric modelling, grid connection caps, combined heat and power (CHP) dispatch, negative day-ahead tariffs, and platform-wide multilingual documentation with an in-app Help Centre.
- **Section 3: Validation approach for the final round** – The two-tier data foundation, the three tools and the common run protocol, and the consistency-check framework.
- **Section 4: Cross-pilot dedicated studies** – A dedicated study for one community in each RE (Italy, France, Germany, the Czech Republic, and Greece), each following the same structure: the real case (setup, forecasting and scheduling), an exploration of the expansion options through Long-Term Planning and a CBA where applicable, the resulting study case, and recommendations.
- **Section 5: Cross-pilot synthesis** – A comparison across the five communities, with supporting figures, covering the generation-to-demand balance, tariff regimes, the socio-economic contrast, forecasting accuracy, and what the set demonstrates about the Platform's portability and agnostic design.
- **Section 6: Usability and adoption assessment** – The pilot partners' feedback on clarity and usefulness, the barriers to independent use, and their priorities for improvement.
- **Section 7: Deployment and sustainability** – The current deployment status across the REs, the interim central-hosting arrangement, and the decision pathway toward a long-term model.
- **Section 8: Conclusions and Next Steps** – What the final validation showed, the assessment against the T2.3 success criterion and the remaining steps.

1.3 Interdependencies with other Tasks and Deliverables

D2.6 is the last of the WP2 deliverables, and it is heavily interdependent on the ones that came before it. D2.1 [1] defined the requirements for the Platform and the Use Cases of the ECs, and those Use Cases are the reference against which the analysis objectives in this deliverable are mapped. D2.2 [2] developed the Platform and its three tools, the Energy Forecasting Tool, the Energy Modelling and Scheduling Tool, and the CBA Tool. The analytical engines validated in the present deliverable are those developed under those two deliverables, and the redesign reported in D2.5 [3] reworked them in the unified Platform without changing their analytical behavior. D2.4 [4] was the first validation and D2.5 documented the redesign, and this deliverable completes the sequence by reporting the pilot results that neither of the earlier two could yet provide.

The deliverable also depends on the pilot work carried out in WP6. D6.2 [5] established the baseline situation in the pilot sites, and it provides the starting point against which the studies in this deliverable are framed. D6.3 [6] reports the pilot results and recommendations at M28, and it is the primary source for the real-world descriptions of the communities used in the per-pilot sections.

2 Final platform enhancements

D2.5 delivered the three analytical tools redesigned into a single, community-centric Platform, with guided workflows, a five-step community setup wizard, an integrated data-management layer and explainable outputs, deployed as a central instance accessible to all partners.

Preparing the dedicated studies showed that a small number of capabilities were still needed for the Platform to represent the pilot communities faithfully and to complete the feature set requested for their use cases. Five additions were made in this final cycle, each leaving the underlying forecasting, scheduling and appraisal engines unchanged: hydroelectric modelling, grid connection caps, combined heat and power dispatch, support for negative day-ahead prices, and an in-platform multilingual help centre. The subsections below describe each in turn, setting out what it is and what it lets a community do, along with platform screenshots. The first four are exercised in the dedicated studies of Section 4 and the fifth responds to the local-language priority the pilot partners identified, reported in Section 6.

2.1 Hydroelectric modelling

The Platform now models hydroelectric generation as a community asset. Earlier versions had no native representation of hydro, so a community operating a small hydro plant could only approximate it by declaring its output as a wind turbine, which misrepresented the resource in the setup wizard, the KPI labelling and the planning narrative. Hydroelectric generation is now selectable as a shared community asset, described by its own generation dataset, and carried under its own name from setup through to the final appraisal.

In the Platform's model a hydro plant is dataset-driven, non-dispatchable and curtailable. Its contribution is read from a supplied generation time series at the community's resolution rather than simulated from physical parameters; the optimizer cannot shift its output in time, because the plant's output follows the available water flow; and the optimizer may hold output below the available level when the community can neither use nor export it, for example when an export limit binds. The asset is wired through the optimizer, the energy balance, the self-sufficiency and self-consumption KPIs, the daily-cost accounting and the long-term planning, so that its energy is attributed correctly and it can be reasoned about as a distinct line.

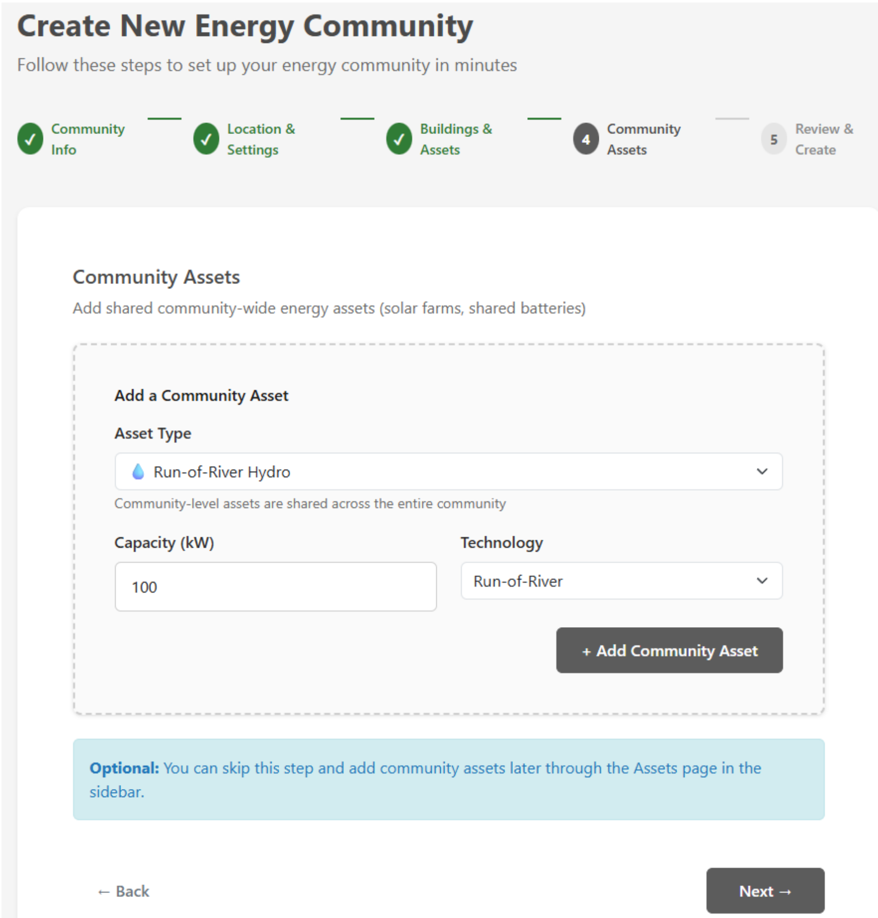

Figure 1 Community Setup Wizard shared-asset step with a hydroelectric plant.

2.2 Grid connection caps

The Platform now allows a community to set optional limits on how much power it may draw from or feed onto the grid. An import cap and an export cap, each expressed in kilowatts, can be entered in the setup wizard alongside the other location and grid settings. Leaving a cap blank keeps that side unconstrained and preserves the behavior of communities that do not need a limit. A community that sets a cap is describing a real physical or contractual boundary at its grid connection point, and the Platform then respects that boundary in everything it schedules.

The caps are enforced by the optimizer at every timestep and on both optimization paths, so that no objective can evade them. When the export cap binds, the surplus that cannot be exported is curtailed and appears in the curtailment KPI; when the import cap binds, the demand that cannot be met within the limit is reported as unserved load. Because the constraint is applied timestep by timestep, the reported daily KPIs already reflect the caps and the before-and-after comparison remains a fair one.

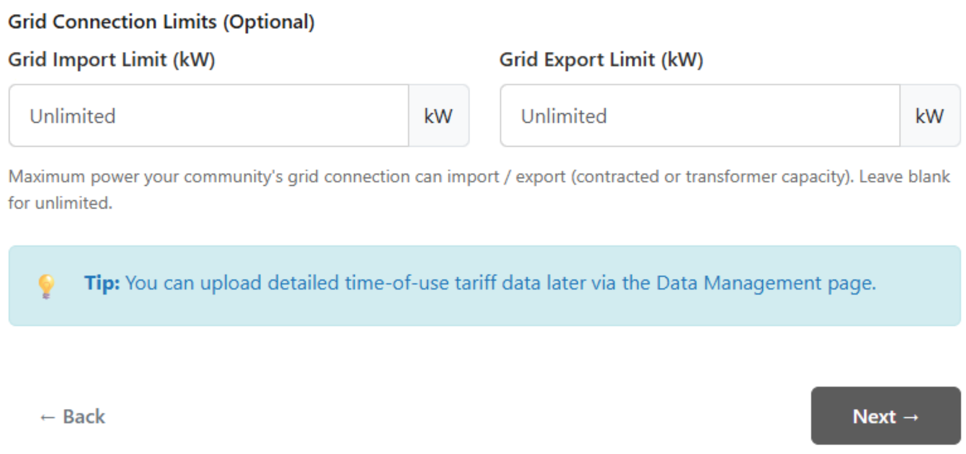

Figure 2 Grid-settings step of the setup wizard with an import cap and an export cap entered in kilowatts.

2.3 Combined heat and power dispatch

The Platform now represents combined heat and power (CHP) as a dispatchable building asset. Unlike photovoltaic (PV) or hydroelectric generation, a CHP unit is a controllable generator whose output the community can raise or hold back, and the scheduler now decides when it should run. A unit is configured in the setup wizard as an asset attached to a building, with the parameters the optimizer needs to reason about its cost of running.

The optimizer switches each unit on or off at every timestep by comparing the cost of running it against the cost of meeting the same demand from the grid: when local generation or cheap grid supply are enough the unit stays off, and when running it is cheaper, or is needed to hold self-sufficiency, it comes on. A unit's generation enters the energy balance and lifts self-sufficiency and self-consumption, its fuel cost enters the daily-cost accounting, and its combustion emissions enter the CO2 figures, so that the emissions-minimizing schedule does not simply run the engine at the expense of emissions. The results view presents each unit's energy, fuel cost and CO2 in a dedicated breakdown.

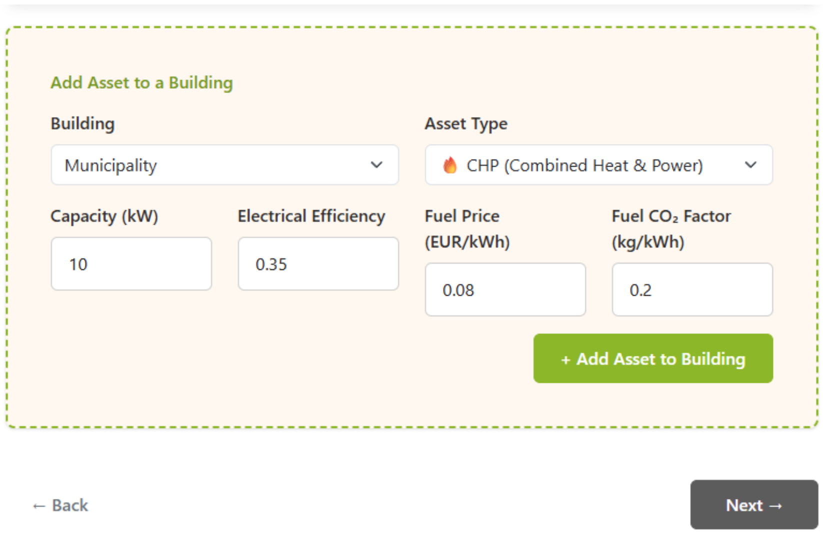

Figure 3 CHP asset breakdown, showing capacity, efficiency, fuel cost and CO2.

2.4 Negative day-ahead tariffs

The Platform now accepts and acts on negative import prices in a day-ahead tariff. Negative prices are a real feature of high-renewables electricity markets [7]: when generation across a market outweighs demand, the day-ahead import price can fall below zero, so a consumer that draws power in that window is effectively paid to consume. Earlier the tariff handling assumed non-negative import prices; a tariff series that dips below zero is now validated on ingestion like any other and exploited in scheduling.

When the import price is negative the optimizer prefers to draw from the grid, charge storage and serve flexible load in those hours, because doing so lowers the community's bill or pays it to consume, which is most valuable for communities with storage or shiftable demand. The behavior is bounded by the grid connection cap described above, so import stays within the community's limit, and a constraint that prevents importing and exporting in the same timestep keeps the schedule physically coherent.

2.5 Multilingual documentation and Help Centre

The final addition is an in-platform Help Centre that makes the Platform's documentation available directly from the top navigation bar, in the languages of the pilot communities. It responds to the clearest priority the pilot partners raised for wider uptake, local-language support, which is reported in Section 6.

The Help Centre organizes the documentation into five categories, getting started, managing a community, forecasting and modelling, CBA, and data inputs, across twenty-four articles. Each article follows a consistent layout of a short introduction, step-by-step guidance, screenshots annotated with where in the Platform each screen is found, and links to the authoritative external sources a community would use for its energy, weather and tariff data, such as the national transmission system and market operators, PVGIS (EU Joint Research Centre’s Photovoltaic Geographical Information System) and public weather services. A full-text search and a language switch are available from every page.

The documentation is provided in English together with Italian, French, German, Czech and Greek, so that each pilot community can read it in its own language. Technical terms and Platform feature names are kept in English for consistency, while the explanatory text, instructions and captions are localized, and the screenshots are kept as a single English reference set.

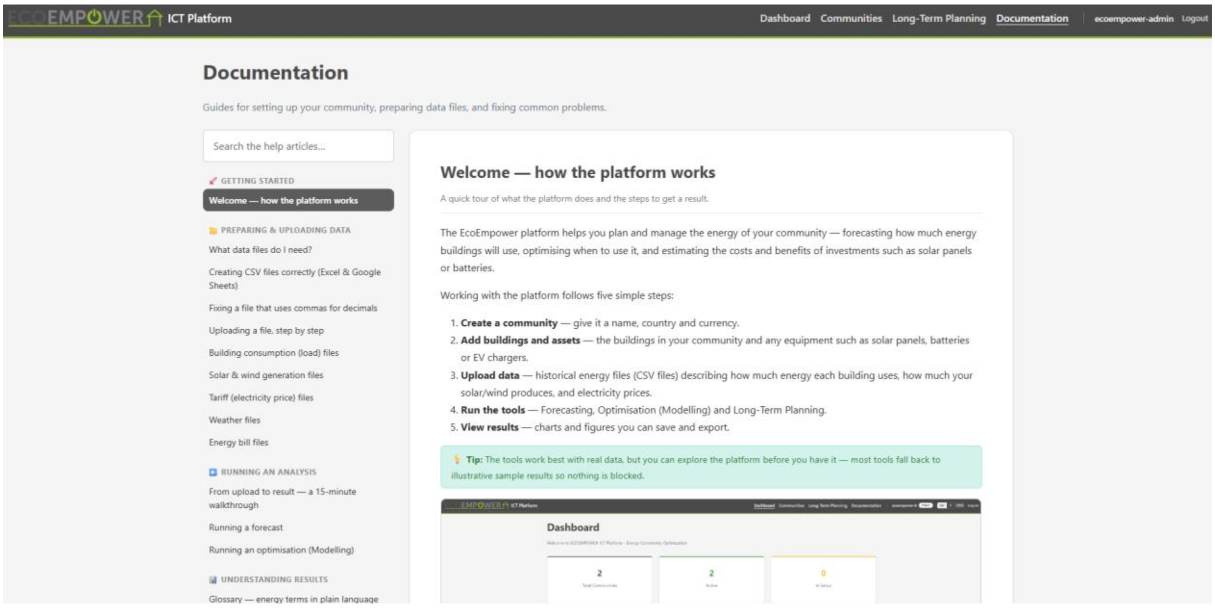

Figure 4 The Help Centre opened from the top navigation bar, showing the documentation categories.

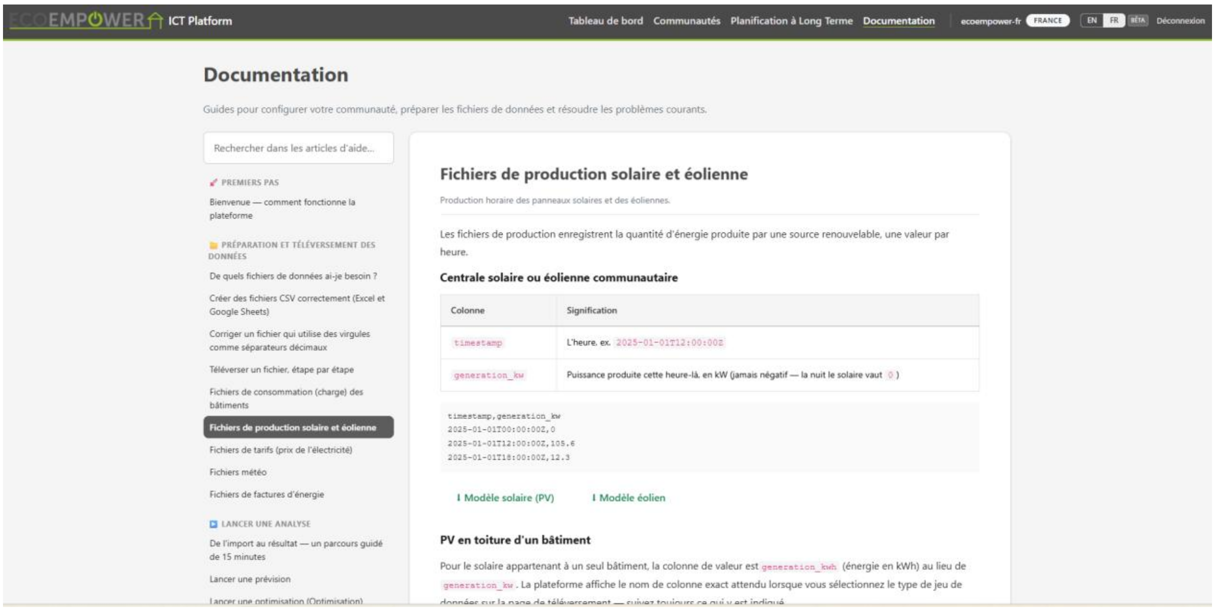

Figure 5 A documentation article shown in French, one of the pilot languages

3 Validation approach for the final round

The final validation round differs in kind from the two that preceded it. D2.4 exercised each of the three tools in isolation, checking that the Energy Forecasting Tool, the Energy Modelling and Scheduling Tool and the CBA Tool each behaved as specified. D2.5 rebuilt those tools into a single, unified, community-centric Platform and documented the redesign, but reported no pilot results. This deliverable closes the loop by applying the complete Platform to a dedicated study in every pilot community. The purpose of this section is to set out how that final round was organized, so that the dedicated studies that follow can be read against a clear and common method.

Three principles shaped the approach. The first is that the evidence must be traceable: every KPI, forecast error and cost figure reported in this deliverable was produced by the Platform from a named dataset under a named configuration and can be reproduced by rerunning the same workflow; where a study additionally draws on an additional analysis, that analysis is documented separately and its role is stated. The second is that a single common method is applied across the pilots, so that the differences visible in the results reflect the communities. The method is followed identically wherever a community's character allows, and any deliberate departure is documented in the study concerned. The clearest such departure is Germany, whose challenge is the offtake of a large, hydro-dominated surplus rather than an investment decision, so its expansion step is a demand-side load-absorption analysis rather than a CBA. The third is that the reporting states its confidence explicitly, indicating where a forecast is strong and where a single input series was too weak to support a planning-grade result. The subsections below describe the two-tier data foundation, the three tools and the common run protocol, and the consistency checks that guarded every run.

3.1 Two-tier data foundation

The validation rests on one pilot community per RE, the Italian, French, German, Czech and Greek ecosystems, each contributing a single site whose data drove the analysis. The pilot communities are at varying stages of formation, and none operate with full metered datasets that could show the full functionality of the ICT Platform today. Every pilot was therefore analyzed on two tiers built to different degrees of measurement. Where assets and measured data are attested, in D6.3 or the pilot leaders' own records, they were used directly. Where they were not yet available, and following the approach already documented in D2.4 and D2.5, indicative datasets and representative configurations were built from the pilots' documented asset descriptions, site and weather conditions, and standard load profiles [8] [9] [10], so that the Platform's full functionality could be validated against realistic community scenarios rather than left untested. Every input stays tied to the real community, and where an input is indicative or representative rather than attested, the relevant tier or study highlights it.

The real tier represents each community as it exists today, with its present buildings, installed generation and storage, and consumption. It draws on attested assets where they exist, on indicative load series where meters do not yet exist. The study tier models an expansion case study, an enlarged or added PV array, a battery energy storage system (BESS), or, where the challenge is demand-side, a set of new loads, and it carries the CBA where one was performed. Reconciliation with D6.3 covered the buildings and shared assets, installed capacities, metering resolution and tariff regime, so that the community described here is the one described by the demonstration work package.

The study-tier configurations follow from the methodology above. For the four investment pilots the extension is the configuration selected by the Long-Term Planning and CBA sweep over candidate PV and storage sizings, and for Germany the demand-absorption loads are those chosen by a load-absorption analysis of the surplus. Table 1 records the resulting configuration for each pilot. How each was derived, and the KPIs and appraisal it produces, are set out in full in the cross-pilot dedicated studies of the following section. Note that in every case the CBA is sized on the study community's demand and run from a no-PV baseline, so it appraises a fresh community-scale PV and storage investment against the grown load rather than an increment on the real community's existing assets. This applies to every pilot CBA reported in the dedicated studies that follow.

Before any analysis, every series passed through the Platform's data management layer, typed as a load, PV generation, tariff or weather series and validated on ingestion for date range, resolution and row count. Table 1 summarizes the two-tier foundation across the five REs.

Table 1 The two-tier data foundation across the five REs. The real tier gives each community's present configuration, combining attested assets with the indicative and representative data used where full metered records do not yet exist. The study (extension) tier gives the configuration detected through the validation methodology, which is derived and explored in the cross-pilot dedicated studies of the following section.

RE	Pilot community	Real tier	Study (extension) tier	CBA performed
RE1 - Italy	Valle di Fassa	3 public buildings; 80 kWp church-roof PV; no storage	10 buildings; ~220 kWp PV (180 kWp distributed + 40 kWp community solar farm); +120 kWh community battery	Yes
RE2 - France	VercorSoleiL	29 distributed rooftops (~474 kWp PV); no storage	29 rooftops + 126 kWp added distributed PV (~700 kWp total); no storage; heat-pump/HVAC flexibility	Yes
RE3 - Germany	OAL Energiegemeinschaft	7 buildings; rooftop PV (~1.08 GWh/yr), hydroelectric asset (~11.2 GWh/yr), 2 CHP units; no storage	Real generation retained + 6 demand-absorption loads (~2,365 MWh, 13 buildings); +200 kWh community battery; EV/V2G, heat-pump/HVAC flexibility; negative overnight tariff	No
RE4 - Czech Republic	Vlčnov	4 municipal/public connection points; 8.9 kWp PV; no storage	13 buildings; 90 kWp PV; +60 kWh building battery; EV charging and heat pumps	Yes

RE5-Greece	Domokos	6 buildings; 90 kWp PV; 100 kWh storage	21 buildings; 150 kWp PV; 100 kWh building battery; EV charging (3 buildings)	Yes

The real-case figures reported for each pilot are values of the WP2 modelling dataset, for the reference period and metered perimeter used in the platform analysis. Where a pilot's final monitored KPIs are reported separately under WP6 (D6.3), those values may differ, because they use a different reference year or a wider pilot asset perimeter. The two are complementary rather than contradictory.

3.2 Tools, Use Cases and the run protocol

The final round exercised all three tools of the Platform, and through them the three Use Cases defined in D2.1. The Energy Forecasting Tool implements UC1 (forecasting of community demand and generation), the Energy Modelling and Scheduling Tool implements UC2 (optimal day-ahead planning and scenario planning), and the CBA Tool implements UC3 (appraisal of an investment).

The forecasting validation step was run in two configurations that together span the horizons a community needs. The short-term configuration produces a day-ahead forecast at a 24-hour horizon, at the native resolution of the measured series, evaluated across a 30-day out-of-sample test window so that the reported error reflects sustained performance rather than a single day. The long-term configuration produces a monthly forecast for planning purposes. The short-term configuration is produced by the gradient-boosting (LightGBM) [11] model and the long-term configuration by a SARIMA-family model [12], with a seasonal fallback where a series is too sparse or irregular to reach high confidence, and each forecast is reported with an explicit HIGH, MEDIUM or LOW confidence rating. The forecasting tool is agnostic in the sense that it works from the historical CSV series alone, without external APIs, DSO integration or real-time data feeds, which is what allows it to run identically on every pilot regardless of local infrastructure.

The optimization validation step was run under all four optimization objectives for every tier of every pilot, so that the four runs form a menu a community can choose from. The four objectives are the minimization of cost, the minimization of CO_2 emissions, the maximization of self-sufficiency and the maximization of self-consumption. Each run is a mixed-integer linear programme (MILP) solved to a proven optimum, and each reports the before-and-after KPIs for the day, namely self-sufficiency, self-consumption, daily cost, curtailed energy and, where grid caps apply, the import and export peaks. A community can see, for example, that the cheapest schedule and the greenest schedule sometimes coincide and sometimes diverge, and it can weigh that against its own priorities. Where a daily cost comes out negative, the community earns money on the day, because its exports and avoided imports outweigh what it pays the grid.

The appraisal validation step was run for the study tier of every pilot that had a defined investment, which is every pilot except the German one, where the final round instead demonstrated the new operational features. The CBA Tool evaluates each investment over a 20-year horizon and reports the Net Present Value (NPV), the benefit-cost ratio (BCR), the discounted payback period, the internal rate of return (IRR) and the CO_2 avoided, together with a socio-economic NPV that adds the wider community benefit to the private return. A range of PV-only and PV-plus-BESS sizings was appraised at each site, so that the marginal value of storage is visible on its own. Table 2 sets out the mapping from tools to Use Cases and to the parts of the run protocol, and it is the template every dedicated study follows.

Table 2 Mapping of the three tools to the D2.1 Use Cases and to the run protocol

Tool	Use Case	Run configuration	Reported outputs
Energy Forecasting Tool	UC1	24-hour day-ahead over a 30-day window, monthly long-term	MAPE, confidence rating
Energy Modelling and Scheduling Tool	UC2	Four objectives per tier (min cost, min CO2, max self-sufficiency, max self-consumption)	Self-sufficiency (SS%), Self-consumption (SC%), daily cost, curtailment, grid peaks
CBA Tool	UC3	20-year appraisal, PV-only and PV-plus-BESS	NPV, BCR, payback, CO2 avoided, socio-economic NPV

3.3 Consistency-check framework

Because the results are meant to be planning-grade and reproducible, every run was guarded by a framework of automatic consistency checks. These checks confirm that a result is internally coherent and physically possible before it is reported, and they catch the class of error that produces a plausible-looking number from a broken input or a mis-specified model. The framework has five categories, and a run had to pass all of them to enter the deliverable.

1. **Energy conservation:** At every timestep the energy balance must close, so that *generation + grid import + storage discharge = load + grid export + storage charge + curtailment*. A balance that fails to close by more than a rounding tolerance indicates a modelling fault. This check is what gives the curtailment figures their meaning, because curtailed energy only appears when generation genuinely exceeds what the community and the grid connection can absorb.

2. **Storage physics:** Every BESS must obey its physical limits across the day, so that *0 ≤ state of charge ≤ rated capacity*, the charge and discharge power stay within their rated limits, the round-trip efficiency is applied on every cycle, and the battery never charges and discharges at once. The scheduling engine enforces these as hard constraints, and the check confirms after the fact that the returned schedule honors them.

3. **KPI ranges:** Self-sufficiency and self-consumption must stay within their definitional bounds, so that 0 ≤ SS ≤ 100% and 0 ≤ SC ≤ 100%. In other words, a community cannot cover more than 100 percent of its demand from its own generation, nor consume more than 100 percent of what it generates. Any value outside that range would signal a definitional error rather than a real result.

4. **Financial identity:** In the CBA outputs the reported quantities must agree with one another, so that *BCR > 1* corresponds to a positive NPV and *BCR < 1* to a negative NPV, the discounted payback is consistent

with the cash-flow profile that produced the NPV, and socio-economic *NPV = private NPV + quantified external benefit*. These identities catch transcription and unit errors that would otherwise pass unnoticed.

5. **Proven optimality:** Every schedule is solved as a MILP and reported only if the solver certifies it as optimal with the optimality gap closed. A schedule that was merely feasible, or that stopped at a time limit, was not treated as a validated optimum.

3.4 Regulatory Context

The platform is built to optimise flexible operation and to place value on a community's surplus, through self-consumption, export or energy sharing. Most of the pilot communities cannot yet use those capabilities in full. Their flexible assets, batteries, EV chargers and heat pumps, are in most cases modelled and not installed, and the frameworks that let a community be paid for exported or shared energy are at different stages of maturity across the five member states. The results in the following sections are therefore reported on a forward-looking basis. Where a figure depends on export remuneration, energy sharing or a flexible asset that is not yet in service, it is presented as a potential value that the framework or the asset unlocks, and each pilot notes where its own community stands. This way, the export earnings, curtailment and flexibility gains reported below measure what each community could capture as its assets and regulation come into place.

The regulatory basis for these capabilities is largely in place or close to it. At EU level, the 2019 Electricity Market Directive [13] introduced the active customer and the citizen energy community, the Renewable Energy Directive [14] and its 2023 revision [15] introduced renewable energy communities and collective self-consumption, and the 2024 electricity market design reform [16] added an explicit right to energy sharing that member states must transpose into national law by 17 July 2026. The five pilot countries implementing these frameworks are at different speeds, as each pilot section records. Since most of the enabling legislation applies by 2026, the period the study cases represent, the export, sharing and flexibility results reported here describe value the communities can realistically expect to capture as these provisions take effect.

4 Cross-pilot dedicated studies

This section presents the dedicated studies carried out for each RE. The aim throughout is to validate the platform and its tools rather than to certify the operational maturity of the communities themselves. The five communities were chosen to present variability, from generation-surplus to demand-dominant and across different tariff regimes and community scales, so that the platform's full set of functionalities is exercised across. Each community is presented first as attested today (the real case) and then in a result-justified expansion (the study case), closing with recommendations. All Platform related KPIs (self-sufficiency, self-consumption, daily cost etc.) are computed on the ECOEMPOWER platform.

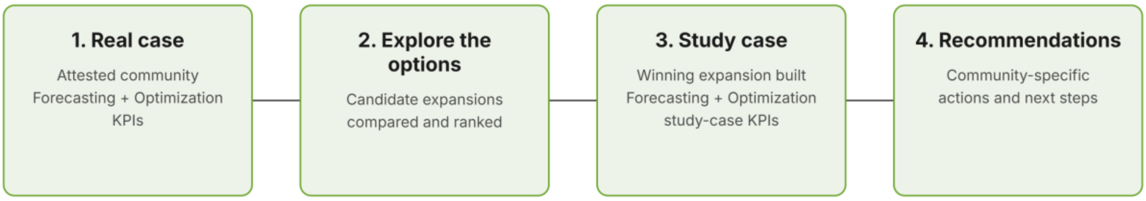

Figure 6 Pilot studies method

The five studies follow one evidence-led method, identical for every pilot except where noted for Germany. First, the real community is set up on the platform from its dataset and run through the Energy Forecasting Tool (30-day training window, 24-hour day-ahead horizon) and the Energy Modelling and Scheduling Tool (all four objectives on a representative day), yielding the real-case KPIs (forecast MAPE, self-sufficiency, self-consumption, daily cost, curtailment). Second, the real KPIs are read for the operational gap they expose. Third, the expansion space is searched as a what-if, in which candidate expansions (PV levels by storage sizes, or demand additions) are scored, and for the four investment pilots the CBA and Long-Term Planning modules rank candidates by NPV, BCR, payback and socio-economic NPV over a 20-year horizon. Fourth, the winning expansion is built and run as the study case, which is a superset of the real tier configured at the result-justified size and run through forecasting and optimization.

Germany is a deliberate exception. The challenge specific to the OAL Community (RE3.3) is offtake of a large, hydro-dominated surplus, so its study is demand-side (local-absorption loads with storage and flexibility) and is not appraised by CBA. The candidate load types were informed by an exploratory analysis rather than a step-by-step platform run, and the German case is built directly on the real 2025 OAL meter used at its measured magnitude. All OAL results assume full community ownership of the hydro plant.

Every case is based in either the pilot-provided datasets or in D6.3, or both. The German case uses the real 2025 OAL meter at measured magnitude, its hydro facility and CHP taken from that provided operational dataset. The German case uses the real 2025 OAL meter at measured magnitude, with its hydro facility and CHP units taken from the provided operational dataset. RE3.3 is officially recorded at an earlier rooftop-PV pooling stage, so the OAL portfolio used here is a capability-demonstrating configuration built on that real operational data, distinct from the final monitored RE3.3 boundary. The rest of the Pilot Cases were built utilizing the assets that were documented in the past deliverables together with some datasets the pilots provided. Load synthesis is used only where no metered data exists and is highlighted in each case.

4.1 Italy (RE1)

The community under study for the Italian RE1 is the EC forming in Valle di Fassa, an alpine valley in the province of Trento at about 1,180 metres of altitude. As recorded in D6.3 (pilot RE1.1), the community's single installed asset today is an 80 kWp rooftop PV system mounted on a local church, serving a Renewable Energy Community (REC) centered on the local school and nursery. The plant is operational and the legal entity has been established, with registration on the GSE portal in progress to make the REC fully operative. No metered consumption data exists yet, so the load profiles used throughout this study are synthesized.

The two tiers reflect the early stage of this community. The real case models the attested site with the church, the school and the nursery, 80 kWp of PV on the church roof, and no storage. The study case grows the same community into the wider community, adding seven further buildings, a small shared community generation asset and a community battery. This expansion is the one the appraisal in this section points to, sized to absorb the local surplus the real case exposes.

The Italian setting exercises the platform's tariff handling. The community operates under the Italian REC and CACER framework [17] that are operational under the 2024 national rules, in which shared and self-consumed energy is made more valuable by a GSE incentive. This is a reward mechanism, not a literal export-above-retail feed-in tariff. The study represents it with an import price of 0.20 EUR per kWh and a higher shared-energy reward of 0.26 EUR per kWh. Because the reward exceeds the import price, the platform raises the expected tariff-inversion flag, which records the incentive working as intended. The consequence, visible in every result below, is that the modelled community earns money, so a negative daily cost is a daily earning.

4.1.1 Real Case Study: Valle di Fassa (RE1.1)

On the platform, the real community is built from its datasets: load series for the three public buildings (the church, the school and the nursery), the generation series for the 80 kWp church-roof PV, and the import and export tariff series, on Europe/Rome time and in euro. No weather series is ingested, as the community is weather-free, and no community-wide assets or grid connection cap are set, the site being storage-free with no generation beyond the church roof. The configured community has a combined annual demand of about 68.1 MWh against about 92.2 MWh of modelled generation, a generation-to-demand ratio of 1.36, so it is generation-first and in surplus for most of the year.

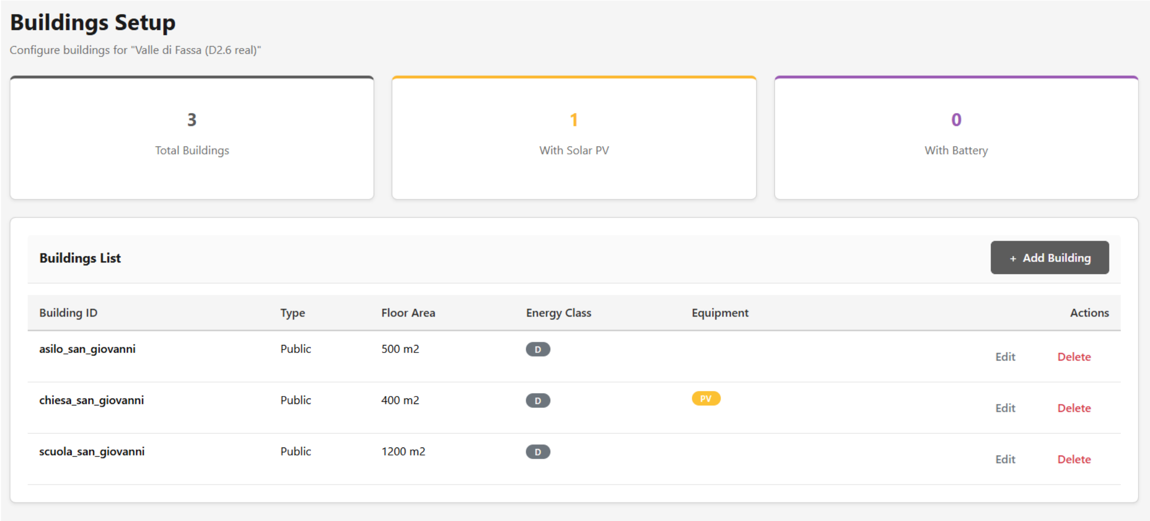

Figure 7 Community configuration for the attested church REC, showing the three public buildings (church, school and nursery), the single 80 kWp church-roof PV system and no battery

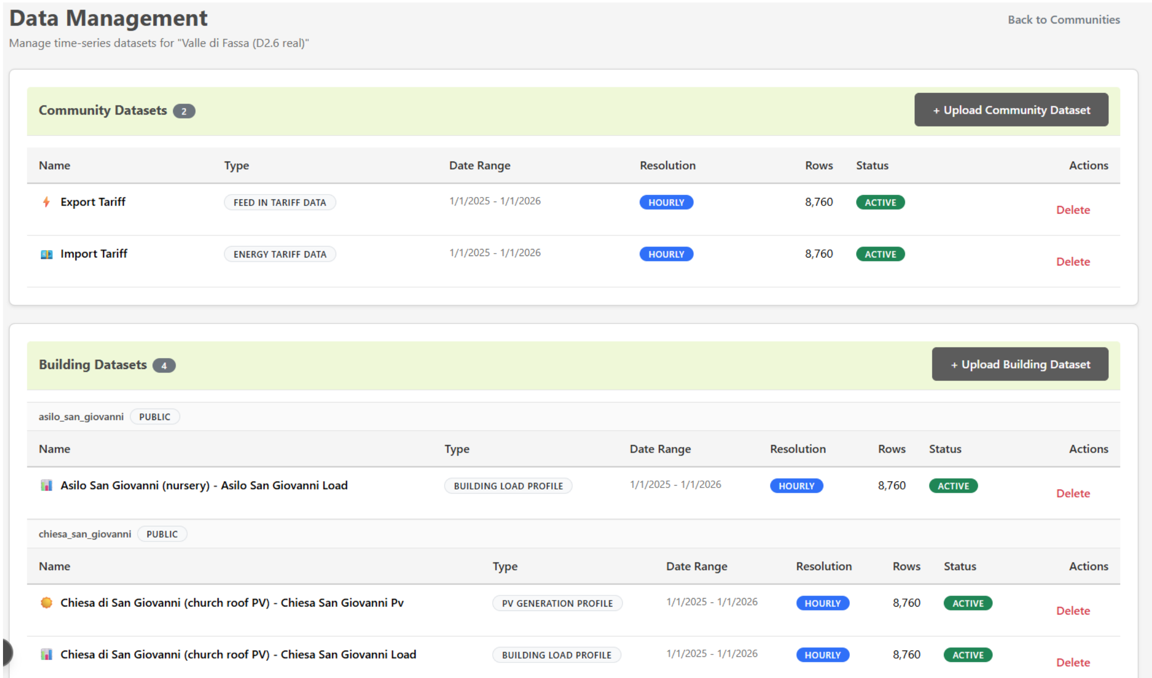

Figure 8 Data management view for the Valle di Fassa real case, showing the ingested community tariff datasets and the per-building load and PV generation series, each validated with its date range, hourly resolution and row count

With the community configured, the platform's Community Dashboard summarizes its starting position over a full year, before any scheduling is applied. Operating as it stands, the church REC covers about 94 percent of its annual demand from its own generation and self-consumes about 35 percent of what it produces, at an average daily cost of about 2 EUR and an annual electricity cost of about 913 EUR. These figures are the reference the forecasting and scheduling results below are read against.

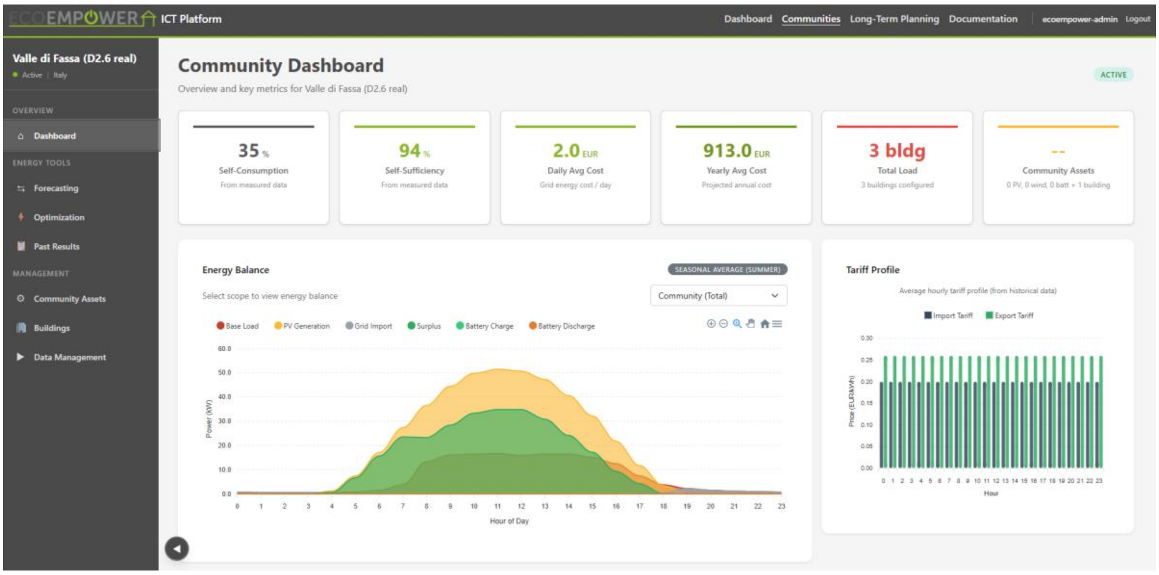

Figure 9 Community Dashboard for the Valle di Fassa real case, consolidating the community's key metrics alongside the representative-day energy balance (base load, PV generation and surplus) and the import and shared-energy tariff profile.

The Energy Forecasting Tool produces the community's day-ahead forecast for 15 June 2025 on a 24-hour horizon. Its accuracy is measured by validating that forecast against the measured series for the day, through the platform's forecast-validation function. On this same-day validation the load forecast returns 3.7 percent MAPE and the generation forecast 5.2 percent, both at high confidence with the LightGBM model.

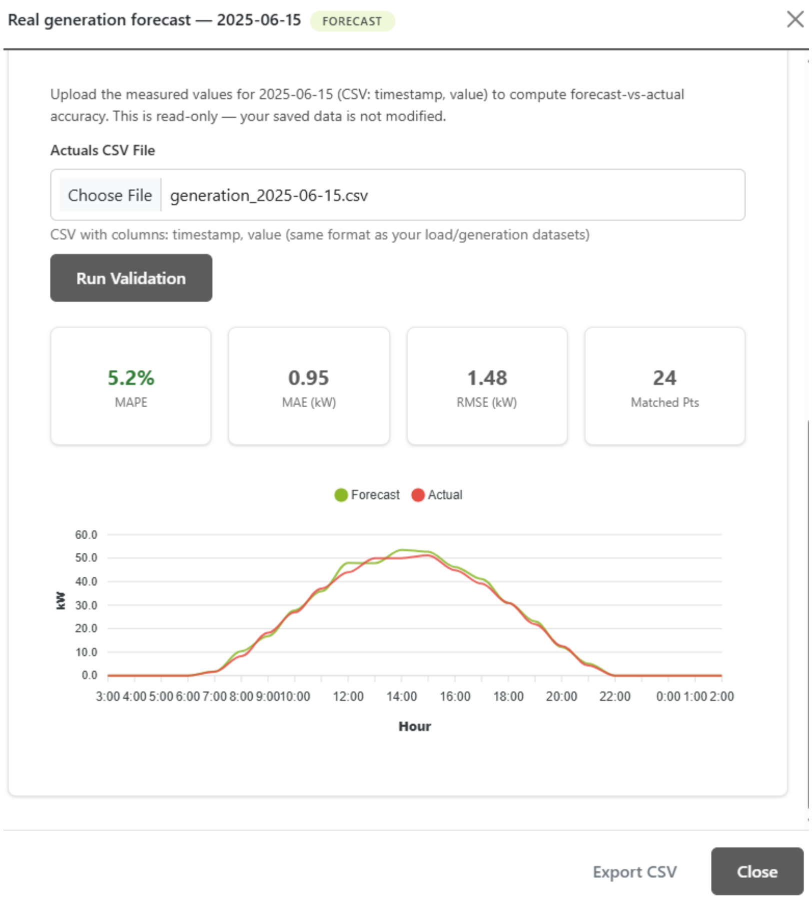

Figure 10 Energy Forecasting Tool day-ahead result for the real case, showing the load forecast at 3.7 percent MAPE and the generation forecast at 5.2 percent MAPE.

Day-ahead scheduling was run under all four objectives. Because the storage-free community has no dispatch to shift, the objectives return the same operating point. On the representative day, 15 June, the community reaches 94.5 percent self-sufficiency and 3.9 percent self-consumption at a daily cost of minus 84.07 EUR, with no curtailment and about 423 kWh shared to the grid.

Table 3 Day-ahead scheduling results by objective, Valle di Fassa real case. Scheduling configuration: 15 June 2025, all four objectives. Tariff: the stylized GSE incentive (import 0.20, shared-energy reward 0.26 EUR per kWh); grid CO2 factor 0.28 kg CO2 per kWh [18]; no grid connection cap. Assets: the church's 80 kWp rooftop PV only, storage-free.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	94.5	3.9	−84.07	0
min_co2	94.5	3.9	−84.07	0
max_self_sufficiency	94.5	3.9	−84.07	0
max_self_consumption	94.5	3.9	−84.07	0

The dashboard baseline and the scheduling result rest on different bases. The dashboard reports the full year, over which self-consumption averages about 35 percent and the community carries a small net annual cost of about 913 EUR. The scheduling KPIs are for a single summer day near the generation peak, when output far exceeds the local load, so self-consumption falls to 3.9 percent and almost all generation can be exported. Rewarded above the import price, that export turns the day into an 84.07 EUR earning, while the annual position stays a modest cost set by the lower-generation months. The gap is one of time window and season, not optimizer action, since the storage-free community has no dispatch to shift. The result confirms a generation asset with little local demand to absorb it, which motivates the expansion: more demand for the surplus and storage to move energy into the hours when demand is present.

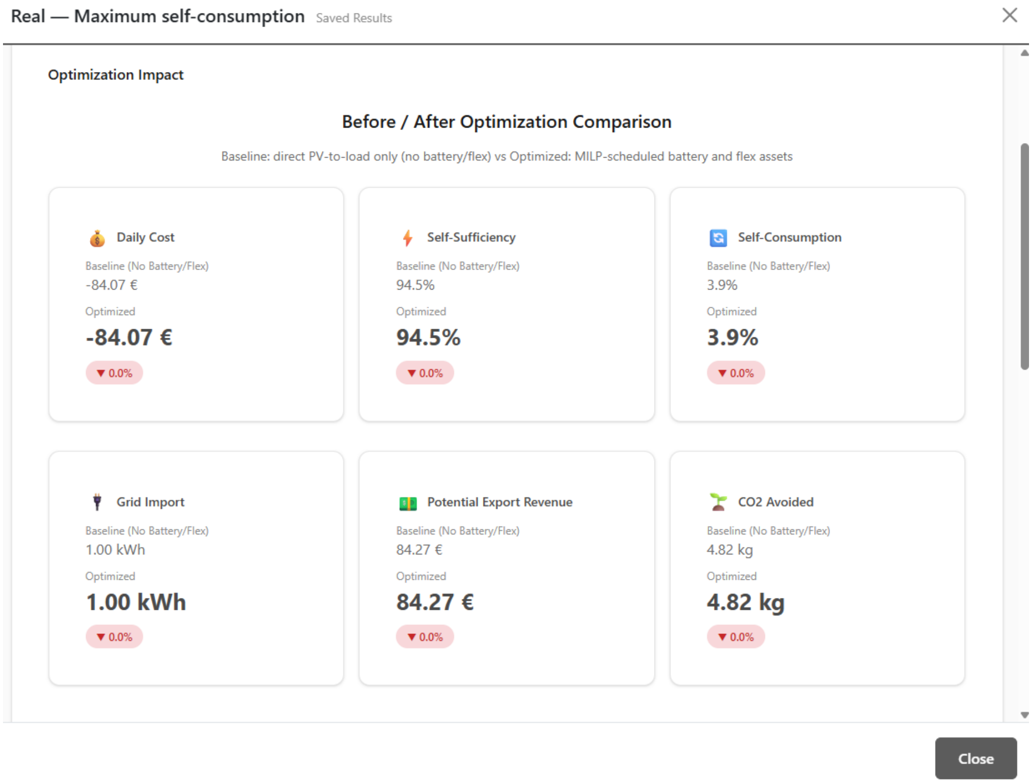

Figure 11 Optimization Result for objective Maximize Self-consumption (15 June 2025)

4.1.2 Exploring the Expansion Options (Long-Term Planning)

The real case shows the church PV is under-used by its small local load, which points to a larger community that can host generation productively. The study therefore begins from the grown demand of a municipal-scale membership, about 260 MWh, roughly 3.8 times the real 68 MWh. Against that grown demand, and from a no-intervention baseline that starts with zero generation and meets the whole load from the grid, the Long-Term Planning module sizes PV and storage with the CBA Tool, so the recommended capacity is an output of the analysis. It varies PV capacity across 180, 220 and 300 kWp and the community battery across 0, 120 and 220 kWh, ranked by NPV in Table 4.

Table 4 CBA what-if ranking for the Valle di Fassa expansion, by NPV. CBA configuration: Twenty-year horizon at an 8 percent financial discount rate, PV capex 1000 EUR per kWp, battery capex 700 EUR per kWh, CO2 valued at 80 EUR per tCO2, electricity-price escalation 3 percent per year, community annual load 260 MWh; candidates are PV-by-battery combinations *scored against a no-intervention baseline. The appraisal follows the cost-benefit methodology of the ENTSO-E CBA guideline [19] and the European Commission Economic Appraisal Vademecum [20].*

Configuration	CAPEX (EUR)	NPV (EUR)	BCR	Payback (yr)	IRR	Socio-econ. NPV (EUR)	CO2 avoided (t/yr)
PV300 + B0	300,000	729,027.99	3.43	3.3	31.4%	817,175.01	100.8
PV300 + B120	384,000	626,459.05	2.63	4.3	24.4%	714,606.07	100.8
PV300 + B220	454,000	540,984.94	2.19	5.1	20.3%	629,131.96	100.8
PV220 + B0	220,000	523,635.47	3.38	3.4	31.0%	588,276.62	73.92
PV180 + B0	180,000	421,656.54	3.34	3.4	30.6%	474,544.76	60.48
PV220 + B120	304,000	421,066.54	2.39	4.7	22.1%	485,707.68	73.92

The ranking follows from the inverted incentive. Because the shared-energy reward (0.26 EUR per kWh) exceeds the import price (0.20 EUR per kWh), exporting is worth more than storing for self-consumption, and two patterns result. More PV raises value. With the battery held at zero, NPV rises from 421.7 thousand euro at 180 kWp to 523.6 thousand at 220 kWp and 729.0 thousand at 300 kWp, while the BCR holds between 3.34 and 3.43 and payback stays near three and a half years. The top candidate is the largest PV-only option, PV300 with no battery, at 729 thousand euro NPV, a BCR of 3.43, a 3.3-year payback (4.0 discounted), a 31.4 percent IRR and an 817.2 thousand euro socio-economic NPV. Storage lowers the headline return at every PV level. At 300 kWp, NPV falls to 626.5 thousand at 120 kWh and 541 thousand at 220 kWh, and the BCR from 3.43 to 2.63 to 2.19, because the battery shifts energy in time and adds no rewarded export.

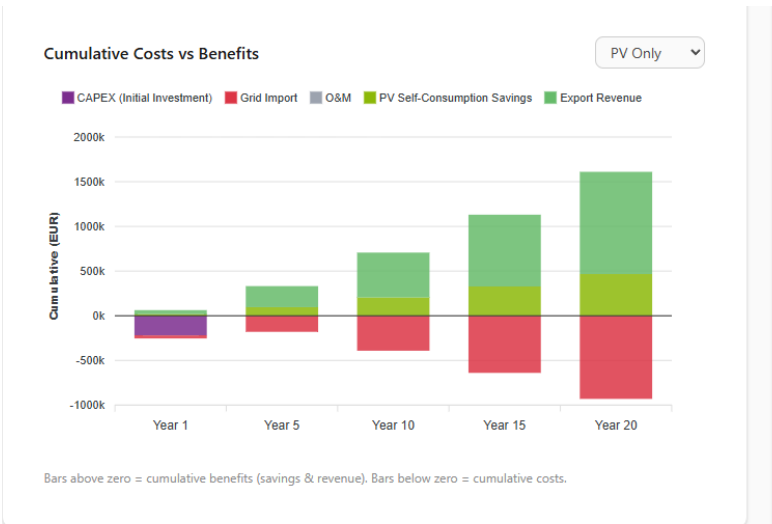

Figure 12 Cumulative Cost vs Benefits and CO2 impact for the winning what-if scenario (PV300+B0)

The study configuration is chosen from this ranking, though not from the top of it. The highest-NPV candidate, PV300 with no battery, is an unconstrained optimum. Because the inverted incentive rewards every added kilowatt of generation, the what-if simply scales PV to the top of the tested range and oversizes the community into a net exporter. The study instead sizes generation to the community's own demand. About 220 kWp yields roughly 254 MWh against the 260 MWh the expanded community consumes, a generation-to-demand ratio of 0.98, so the community covers close to its whole year from its own roofs rather than building capacity to sell. The figure is scaled on the community's real plant, not assumed. The 80 kWp church system attested in D6.3 is modelled at a specific yield near 1,150 kWh per kWp, and the 220 kWp expansion carries that same yield across the ten buildings of the expanded scope. A build of this order matches the community's early ambition, which envisaged a public-roof system of about 130 kWp before the 80 kWp church plant became the one realized. With no battery the PV-only case is strong, its benefit-cost ratio above 3.3 and its net present value rising from 421.7 thousand euro at 180 kWp to 523.6 thousand at 220 kWp. The study still adds a 120 kWh community battery, bringing PV220+B120 to a 421.1 thousand euro net present value at a benefit-cost ratio of 2.39. It sits below the PV-only options and is kept for operational reasons alone. Without storage the study community has no dispatch to optimize and the four scheduling objectives collapse onto a single operating point, as the real case shows, whereas the battery lifts self-sufficiency to 93.5 percent and separates the four objectives into distinct operating points, letting the study additionally demonstrate day-ahead scheduling.

4.1.3 Expansion Case Study: Municipality-Scale Expansion with Storage

The study case builds the configuration selected in 4.1.2. The three public buildings are retained and seven are added, four residential homes, two guesthouses and one municipal building, giving ten in total and raising annual demand from 68.1 to about 260.1 MWh. The sizing places about 220 kWp of PV, roughly 180 kWp of distributed rooftop with a 40 kWp community solar farm, alongside a 120 kWh community battery that is the community's first storage. The farm and the battery are its two community-wide assets, and no grid connection cap is enforced. Table 5 sets the study configuration against the real case.

Table 5 Community setup parameters for the Italian pilot, real and expansion cases. The 92.2 MWh real-case annual generation is the WP2 modelled value for the 80 kWp church-roof array; the final monitored pilot figure reported under WP6 (D6.3) is about 0.08 GWh a year.

Parameter	Real case	Expansion Case Study
Buildings	3 public (church, school, nursery)	10 (3 public, 4 residential, 2 guesthouses, 1 municipal)
Annual demand	68.1 MWh	260.1 MWh
PV capacity	80 kWp (church roof)	~220 kWp (180 kWp distributed rooftop + 40 kWp community solar farm)
Community battery	none	120 kWh
Annual generation	92.2 MWh	253.6 MWh
Generation-to-demand ratio	1.36	0.98

Import price	0.20 EUR/kWh	0.20 EUR/kWh
Shared-energy reward	0.26 EUR/kWh	0.26 EUR/kWh
Grid connection	no binding cap	120 kW contracted (informational)
Weather data	none (weather-free)	none (weather-free)

The expansion moves the community from generation-first surplus to near parity, about 253.6 MWh of generation against 260.1 MWh of demand, so it is almost balanced across the year and leans very slightly demand-dominant. Forecasting stays planning-grade, the load forecast validating at 2.6 percent MAPE and the generation forecast at 3.1 percent, both at HIGH confidence under LightGBM, on the same 15 June 2025 day-ahead setup used for the real case.

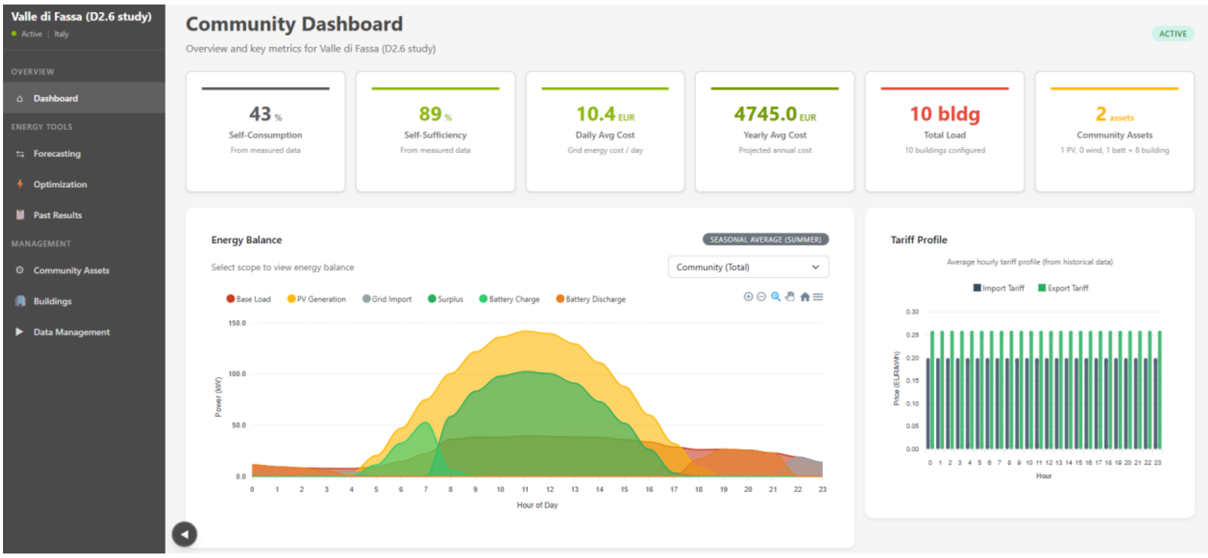

Figure 13 Community Dashboard for the study case, showing the ten buildings, the ~220 kWp of PV and the community-wide assets: the 120 kWh community battery and the 40 kWp community solar farm

Under scheduling the four objectives no longer coincide, because the 120 kWh battery gives the community a dispatch to optimize. Minimum cost reaches 73.5 percent self-sufficiency and 22.4 percent self-consumption at minus 164.37 EUR, the cheapest schedule sharing energy in the hours the incentive rewards most. Minimum CO2 and maximum self-sufficiency settle at the same higher-autonomy point, 93.5 percent self-sufficiency and 30.1 percent self-consumption at minus 163.16 EUR, since a working battery makes the cleanest and most self-sufficient routes coincide. Maximum self-consumption reaches 82.8 percent self-sufficiency and 30.1 percent self-consumption at minus 153.88 EUR. No energy is curtailed on any objective.

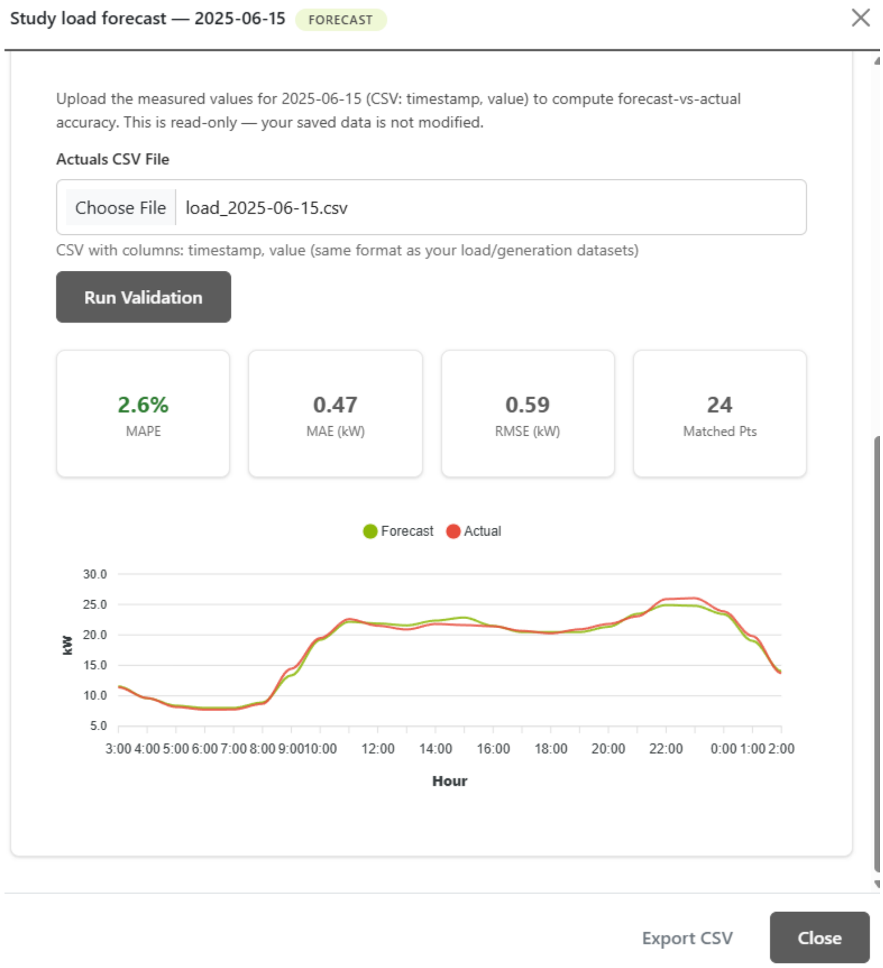

Figure 14 Forecast MAPE for the demand of the Italian study case for 15 June 2025

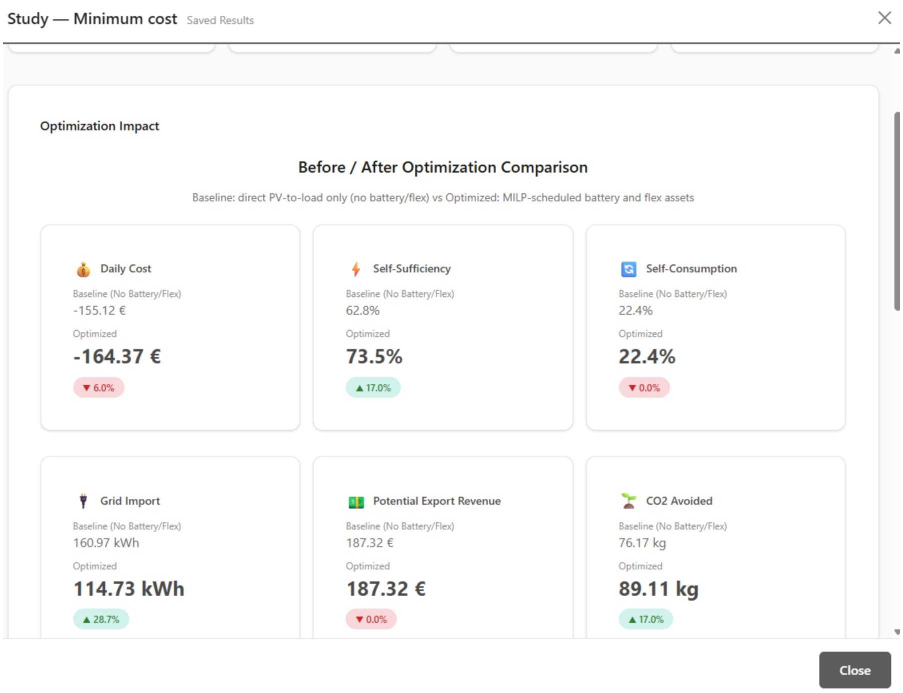

Figure 15 Optimization Result for objective Minimize Cost for the Italian Study Case (15 June 2025)

Table 6 Day-ahead scheduling results by objective, Valle di Fassa study case. Scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, under the same stylized GSE incentive (import 0.20, shared-energy reward 0.26 EUR per kWh) and grid CO2 factor 0.28 kg CO2 per kWh, with no grid connection cap enforced. Assets: 180 kWp of distributed rooftop PV, a 40 kWp community PV farm and a 120 kWh community battery.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	73.5	22.4	−164.37	0
min_co2	93.5	30.1	−163.16	0
max_self_sufficiency	93.5	30.1	−163.16	0
max_self_consumption	82.8	30.1	−153.88	0

Two points stand out. The battery buys autonomy almost for free, lifting self-sufficiency from 73.5 to 93.5 percent between the minimum-cost and maximum-self-sufficiency points while the daily earning falls only about one euro, from minus 164.37 to minus 163.16 EUR. And self-consumption rises from the real case's 3.9 percent to about 30 percent once the added buildings absorb the surplus locally, the direct payoff of expanding the demand base. Most generation is still exported, which under this incentive remains the profitable outcome.

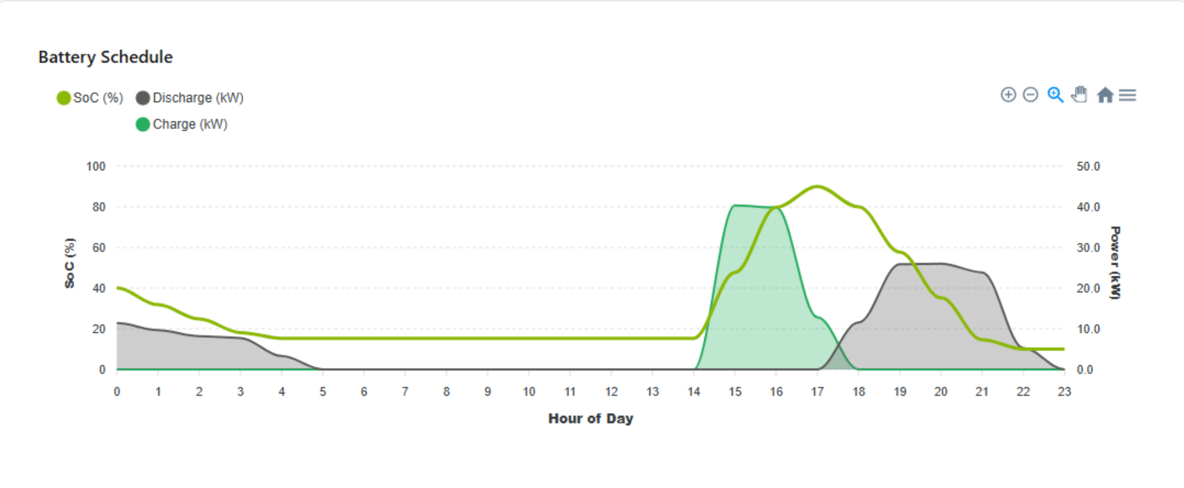

Figure 16 Battery Schedule for the Italian Study Community for the Maximize Self Sufficiency objective (15 June 2025)

4.1.4 Recommendations for the Community

On the community as we have modelled it, Valle di Fassa is a net earner under the Italian REC and CACER incentive on every objective and in both tiers. These recommendations are drawn from a modelled community, since the REC is not yet fully operative and its consumption is synthesized rather than metered, so they are best read as design-stage guidance to test against real data as the community comes online. On these inputs the tariff inversion the platform flags is expected, and it can be documented for operators as the incentive working as designed, so the community can plan on shared and self-consumed energy carrying real value whichever operating objective it chooses.

The real case carries the clearest message, and it depends little on the modelling detail, since it follows from a large rooftop sitting on a small local load. The attested 80 kWp church system is far more than the school and nursery can absorb, so on the modelled day it exports about 96 percent of what it generates and its objectives collapse to a single storage-free point. The asset is sound but under-used locally, which is what motivates the municipality-scale expansion. Adding demand and storage would turn an over-producing rooftop into a functioning community, and the study bears this out, with local self-consumption rising to about 30 percent and self-sufficiency reaching about 93.5 percent at little cost over the cost-minimizing schedule. For day-to-day operation the study points toward that clean, high-autonomy objective, which suits a mountain community that values resilience, with the community battery central to reaching it.

On investment, the modelling supports considering the appraised expansion at about 220 kWp, sized to cover the community's own demand. The PV-only economics come out strong on the assumptions used here, with benefit-cost ratios above 3.3 and paybacks near three and a half years, and the return continues to rise with capacity toward the 300 kWp end of the appraised range. Building beyond parity would improve the financial return further but move the community toward net export, which is a strategic choice for the members rather than a technical one. The battery is best treated as a separate decision. It lowers the headline NPV, so it is better justified for the autonomy and resilience it delivers in operation and appraised on its own rather than bundled with the PV. Because the appraisal assumes an unconstrained connection, the community would be well placed to confirm the export capacity available at its connection point with the distribution operator at detailed design, since a binding limit would reduce the rewarded surplus.

As these figures rest on synthesized consumption, the most useful next step is to revisit with real data as they become available, so to replace the modelled profiles with the community's own measurements and refine both the scheduling and the investment appraisal.

4.2 France (RE2)

The community under study for the French RE2 is VercorSoleiL (pilot RE2.2), a collective self-consumption community forming around Saint-Martin-en-Vercors. As recorded in D6.3, the community rests on a large base of distributed rooftop generation, and a new solar PV project of EUR 20,000 adds to existing installations, together contributing 0.51 GWh of generation in 2024, the historical metered figure adopted from the D6.3/2024 dataset for this analysis, across 29 distributed rooftop installations sited at consumers' premises, with 55 people trained. Its generation is real metered data, drawn from the 29 named installations at monthly resolution over 2017 to 2024, while the building loads are synthesized, sized to a near-balanced collective-self-consumption community. Weather data is available through external services.

The two tiers reflect a mature, near-balanced community. The real case models the 29 attested installations with 474.4 kWp of real distributed rooftop PV and no storage. The study case grows the same community's demand modestly and sizes added generation to it, moving the community into a mild surplus. This expansion is the one the analysis in this section points to, with the sizing deferred to the CBA.

The French setting as we have modelled it, uses a time-of-use tariff with a day and night structure, and a low export price of 0.10 EUR per kWh. The low reward for export shapes the economics that follow, giving stored energy little to arbitrage against and keeping the study deliberately storage-free.

4.2.1 Real Case Study: VercorSoleiL (RE2.2)

On the platform, the real community is built from its datasets: synthesized load series for the 29 buildings, the real generation series for the 474.4 kWp of distributed rooftop PV, the time-of-use import and export tariff series, and the available weather series, on Europe/Paris time and in euro. The 29 buildings comprise 1 municipal, 15 residential, 4 agricultural, 6 public and 3 commercial premises. No community-wide assets are set, the site being storage-free with generation spread across the rooftops. The configured community has a combined annual demand of about 510.1 MWh against about 521.2 MWh of generation, a generation-to-demand ratio of 1.02, so it is near-balanced across the year.

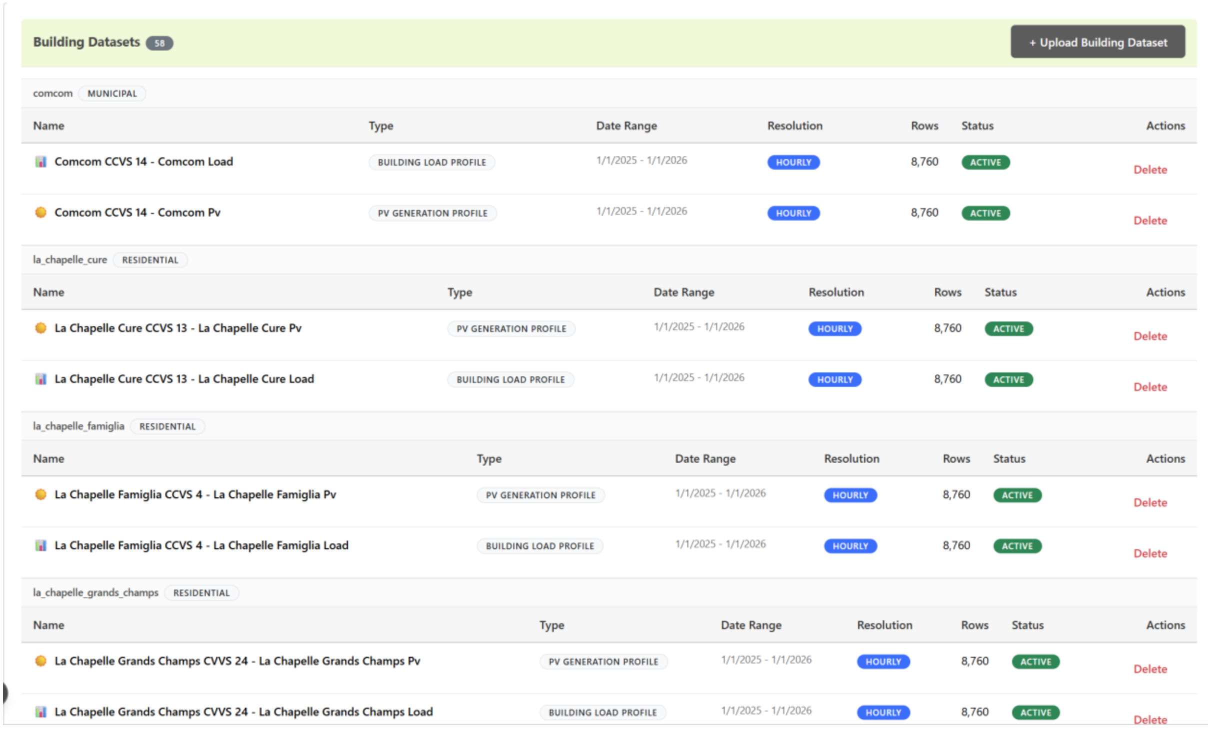

Figure 17 Data management view for the VercorSoleiL real case, showing the ingested community tariff and weather datasets and the per-building load and PV generation series, each validated with its date range, resolution and row count.

The Energy Forecasting Tool produces the community's day-ahead forecast for 15 June 2025 on a 24-hour horizon, validated against the measured series for the day. On this same-day validation the load forecast returns 1.5 percent MAPE and the generation forecast 0.9 percent, both at high confidence with the LightGBM model. Because monthly generation data for the 29 installations is also available, a monthly long-term forecast was also produced, per available installation.

Each installation carries its own SARIMA model trained on all history to October 2023, a six-month forecast is produced per site, and the community total is formed as the aligned sum of the per-site forecasts. Over the November 2023 to April 2024 test window the community forecast returns 7.2 percent MAPE, with a mean absolute error of about 1,616 kWh and a root-mean-square error of about 2,146 kWh.

This community-level monthly forecast was documented in D2.4 at 8.8 percent MAPE. The current 7.2 percent, produced by the same per-site-then-sum procedure, follows a refinement to the monthly model, which now works on the log-transformed output to suit the multiplicative seasonality of PV and rejects numerically divergent fits. The results is comparable and slightly improved, while the month-by-month profile shifts with the corrected model.

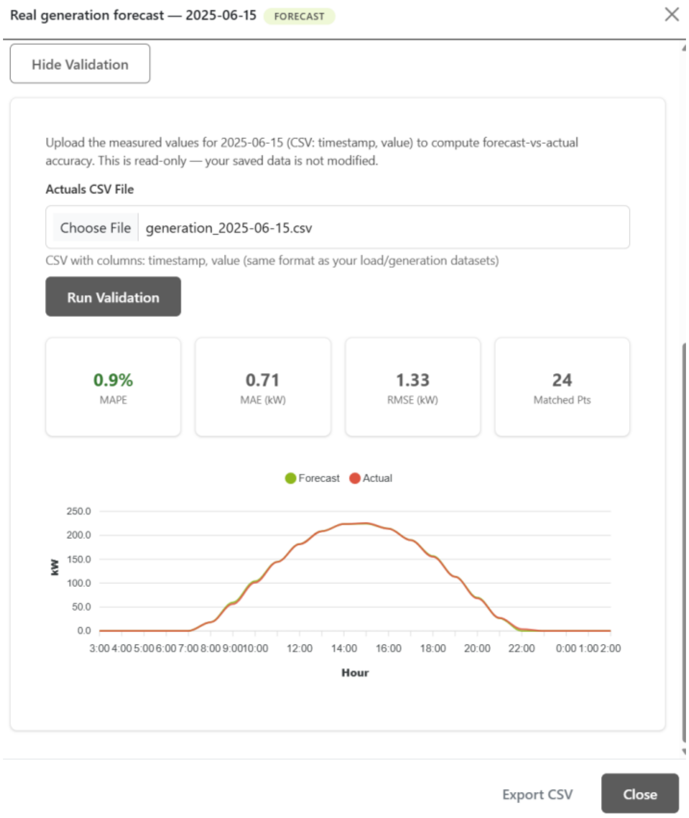

Figure 18 Energy Forecasting Tool, day-ahead result for the real French case the generation forecast at 0.9 percent MAPE

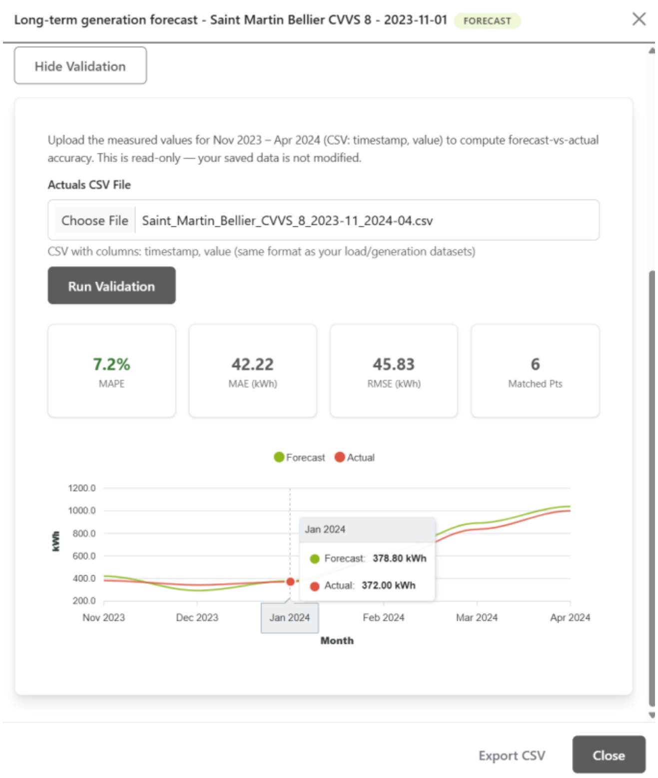

Figure 19 Energy Forecasting Tool monthly result for installation Saint Martin Bellier CVVS 8, showing the generation forecast at 7.2 percent MAPE

Table 7 Monthly long-term generation forecast for the VercorSoleiL community, November 2023 to April 2024, showing forecast, actual and absolute percentage error per month with the community MAPE of 7.16 percent. Per-site SARIMA models are trained on history to October 2023 and the community total is the aligned sum of the per-site forecasts.

Month	Forecast (kWh)	Actual (kWh)	APE (%)
Nov 2023	20,334	21,113	3.7
Dec 2023	14,902	19,354	23.0
Jan 2024	17,797	19,942	10.8
Feb 2024	31,161	30,789	1.2
Mar 2024	45,178	43,675	3.4
Apr 2024	52,882	52,436	0.8
Community MAPE			**7.16**

Day-ahead scheduling was run under all four objectives. Because the storage-free community has no dispatch to shift, the objectives return the same operating point. On the representative day, 15 June, the community reaches 64.0 percent self-sufficiency and 26.0 percent self-consumption at a daily cost of minus 104.55 EUR, with no curtailment and about 1,427 kWh exported to the grid.

Table 8 Day-ahead scheduling results by objective, VercorSoleiL real case. Scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, under the time-of-use day and night tariff with a 0.10 EUR per kWh export price, near-carbon-free grid factor of 0.055 tCO2 per MWh, with no grid connection cap enforced. Assets: 474.4 kWp of real distributed rooftop PV, no storage.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	64.0	26.0	-104.55	0
min_co2	64.0	26.0	-104.55	0
max_self_sufficiency	64.0	26.0	-104.55	0
max_self_consumption	64.0	26.0	-104.55	0

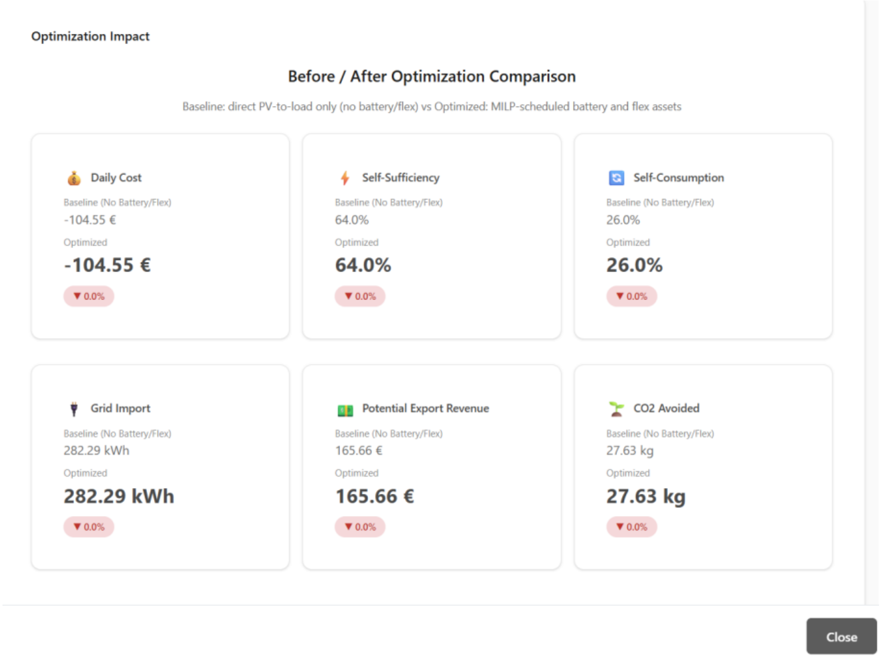

Figure 20 Optimization Result for objective Maximize Self-consumption for the VercorSoleiL real case (15 June 2025).

4.2.2 Exploring the Expansion Options (Long-Term Planning)

The real case shows a near-balanced community that can host a modest amount of added generation productively. The study therefore begins from the grown demand of about 550.1 MWh, roughly 1.1 times the real 510 MWh. Against that grown demand, and from a no-intervention baseline that starts with zero generation and meets the whole load from the grid, the Long-Term Planning module sizes PV and storage with the CBA Tool, so the recommended capacity is an output of the analysis. It varies PV capacity and community storage over a 20-year horizon under standard parameters, ranked by NPV in Table 9.

Table 9 Study-case Cost-Benefit Analysis what-if for VercorSoleiL, twenty-year horizon, ranked by NPV. CBA configuration: 8 percent discount rate, PV capex 1000 EUR per kWp, battery capex 300 EUR per kWh, CO2 valued at 80 EUR per tCO2, electricity-price escalation 2 percent per year, community annual load about 550 MWh, candidates scored against a no-intervention baseline at France's 0.10 EUR per kWh export price and 0.055 tCO2 per MWh grid factor with no grid-connection cap. Annual CO2 avoided is about 39.6 t at the 600 kWp level and about 46.2 t at the adopted 700 kWp level.

Configuration	CAPEX (EUR)	NPV (EUR)	BCR	Payback (yr)	IRR	Socio-econ. NPV (EUR)	CO2 avoided (t/yr)
PV700 + B0	700,000	492,415.20	1.70	6.2	16.0%	532,815.92	46.2
PV700 + B250	775,000	483,246.73	1.62	6.5	15.2%	523,647.45	46.2
PV700 + B500	850,000	474,078.25	1.56	6.7	14.4%	514,478.97	46.2
PV600 + B0	600,000	444,846.48	1.74	6.0	16.4%	479,475.67	39.6
PV600 + B250	675,000	435,678.00	1.65	6.4	15.4%	470,307.19	39.6

PV600 + B500	750,000	426,509.53	1.57	6.7	14.6%	461,138.72	39.6

Three findings shape the choice. First, more PV pays. Even at France's low 0.10 EUR per kWh export price, the 700 kWp candidate carries a higher net present value than the 600 kWp candidate at every battery level, and the highest value in the whole sweep, about 492.4 thousand euro, belongs to PV700 with no battery. Second, the return per euro moves the other way, as the benefit-cost ratio rises from 1.70 at 700 kWp to 1.74 at 600 kWp, with payback and internal rate of return on the same gradient. The two criteria therefore point in opposite directions. Third, a battery does not pay. At each PV level, adding storage lowers the net present value monotonically, from 492.4 to 483.2 to 474.1 thousand euro at 700 kWp as the battery grows from 0 to 250 to 500 kWh, and the same holds at 600 kWp. Every euro of battery capital erodes the financial case under the tariff and cost assumptions used here.

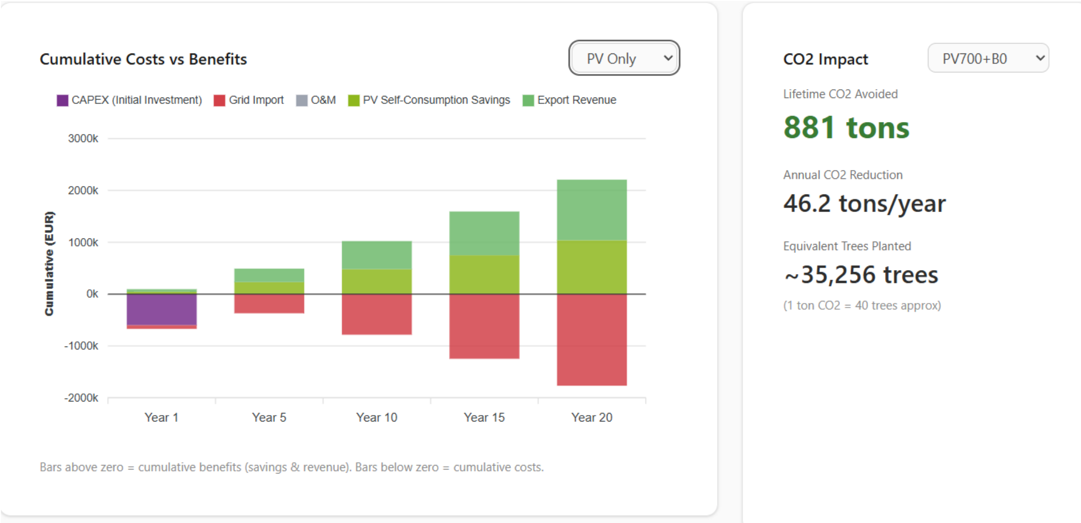

Figure 21 Cumulative Cost vs Benefits and CO2 impact for the selected efficiency-point scenario (PV700+B0).

4.2.3 Expansion Case Study: Aggregated Distributed Expansion, Storage-Free

The study case builds the configuration selected from the CBA. It places about 700 kWp of aggregated distributed PV, the 474.4 kWp of real installations plus a further 226 kWp that represents many small Vercors installations in aggregate and not a single farm, with no storage. It also includes heat-pump and HVAC flexibility as a representative demand-side element to exercise the scheduler. This flexibility is not attested in D6.3 and is included to demonstrate demand-side operation. Annual demand rises from 510.1 to about 550.1 MWh, against about 765 MWh of generation, a generation-to-demand ratio of 1.39. Table 10 sets the study configuration against the real case.

Table 10 Study configuration for VercorSoleiL set against the real case.

Parameter	Real case	Expansion Case Study
Buildings	29	29
Annual demand	510.1 MWh (synthesized)	550.1 MWh
PV capacity	474.4 kWp real distributed rooftop	~700 kWp aggregated distributed

Community battery	none	none
Annual generation	521.2 MWh (Platform modelled annual generation with 1.02 ratio)	~765 MWh
Generation-to-demand ratio	1.02	1.39
Tariff	time-of-use, 0.10 EUR/kWh export	time-of-use, 0.10 EUR/kWh export
Flexibility	none	heat-pump + HVAC
Weather data	available	available

The expansion moves the community from near-balanced to a clear surplus, about 765 MWh of generation against 550.1 MWh of demand. Forecasting stays planning-grade, the load forecast validating at 1.4 percent MAPE and the generation forecast at 2.3 percent, both at HIGH confidence under LightGBM, on the same 15 June 2025 day-ahead setup used for the real case. The generation figure is approximate because the study-generation actual includes the modelled added PV, which carries no meter.

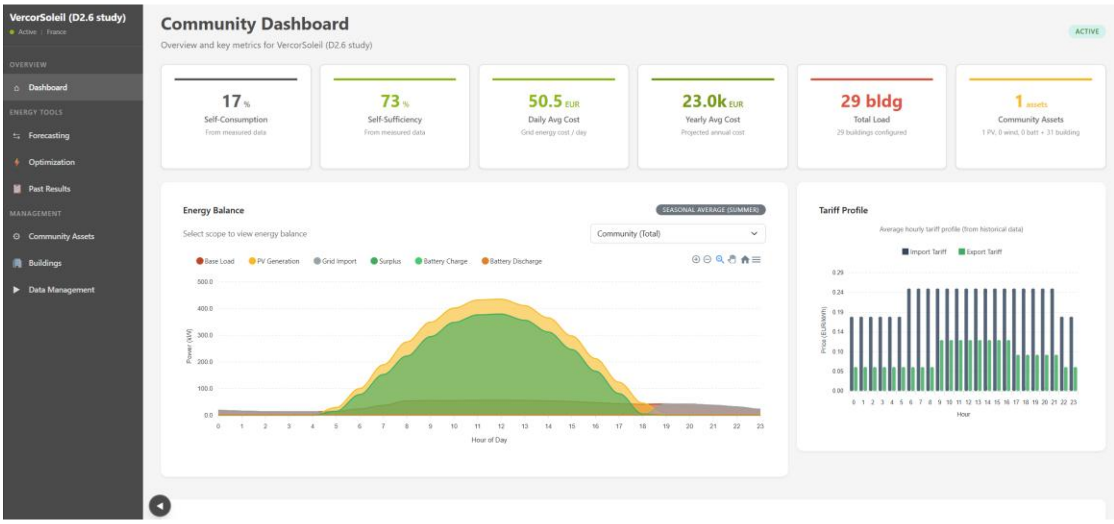

Figure 22 Community Dashboard for the study case, showing the 29 buildings, the ~700 kWp of aggregated distributed PV.

Under scheduling the four objectives stay very close together, because the storage-free community has little dispatch to optimize. No energy is curtailed on any objective, and every objective returns a modest daily earning.

Table 11 Day-ahead scheduling results by objective, VercorSoleiL study case. Scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, storage-free, under the time-of-use day and night tariff with a 0.10 EUR per kWh export price; assets ~700 kWp of aggregated distributed PV with heat-pump and HVAC flexibility.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	69.5	21.5	-218.05	0
min_co2	69.0	21.2	-217.78	0

max_self_sufficiency	71.1	23.2	-212.43	0
max_self_consumption	70	23.9	-203.54	0

Although the community carries no battery, the scheduler still has a store to work against. Two of its schools contribute controllable thermal load whose building fabric holds energy across a few hours. Saint Agnan École runs a 30 kW heat pump with a high thermal mass of about 10 kWh per degree, a heating COP of 3.0 and a 19 to 22 degree comfort band, while Vassieux École runs a 12 kW HVAC unit with a medium thermal mass of about 5 kWh per degree, a cooling EER of 2.1 and a wider 19 to 23 degree band. Within those comfort limits the optimizer can move cooling in time, and this thermal flexibility is what separates the four objectives and lifts self-consumption, even with no battery in the community.

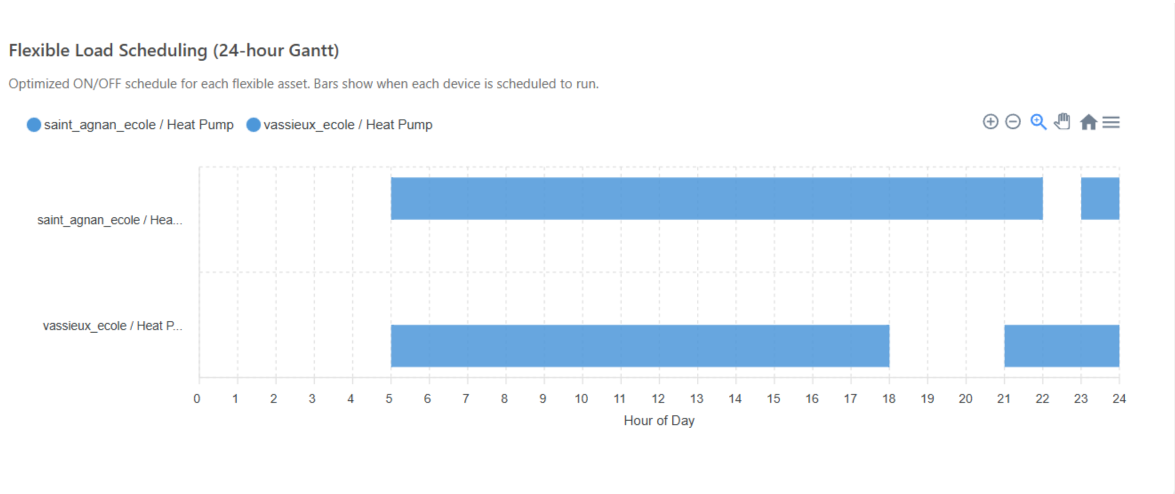

Figure 23 Flexible load scheduling for the two heat pumps in cooling mode for the Max Self-Consumption objective (15 June 2025)

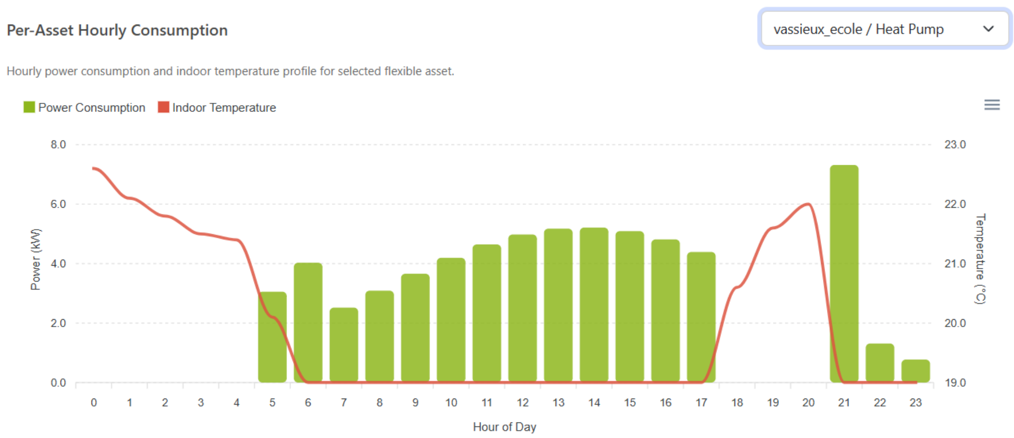

Figure 24 Thermal response of the Vassieux École cooling unit over the representative day, showing cooling power against outdoor temperature with the indoor temperature pinned at the comfort-band floor of 19 degrees while solar is available

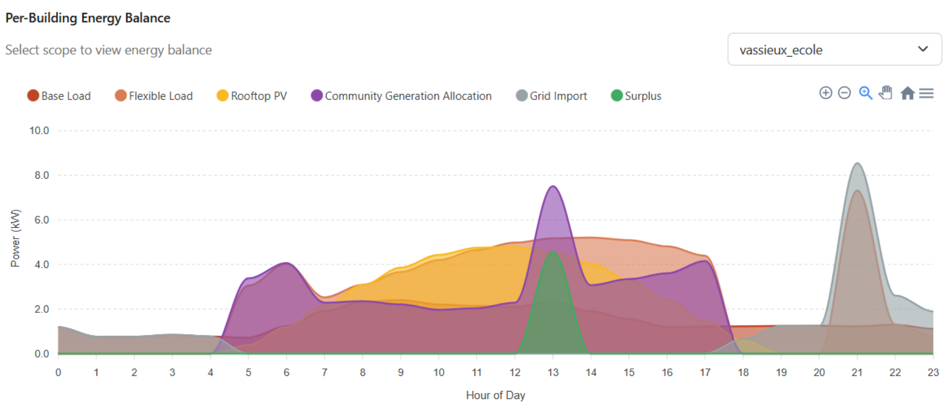

Figure 25 N. Vassieux École energy balance under the maximum self-consumption objective. Daily totals: base load 34.9 kWh, HP cooling 64.3 kWh, own rooftop PV used 40.9 kWh, allocated community generation 42.3 kWh, grid import 20.5 kWh and export 4.6 kWh, for a building self-sufficiency of 79.3 percent at a cost of about 4 EUR. Daytime grid import is held at zero

The maximum self-consumption objective shows most clearly at building level. Under it, Vassieux École meets 79.3 percent of its own demand on the day at a cost of about 4 EUR, and its day falls into three regimes. Overnight the building is idle and drifts down from 22.6 to 21.4 degrees on its own, with a small base load drawn from the grid. From 05:00 the HVAC pulls the indoor temperature to 19.0 degrees, the floor of the comfort band, and holds it there for thirteen hours, over-cooling while free solar is available and turning the building envelope into thermal storage. Cooling power rises from 3.0 kW to 5.2 kW at the 27.8 degree afternoon peak, and across the whole daytime window grid import is zero, the load served entirely by the building's own rooftop PV and its allocated community generation. From 18:00 the HVAC switches off and the indoor temperature coasts back up from 20.6 to 22.0 degrees over three hours on no energy at all, releasing the cooling stored earlier in its fabric.

The study community has no battery, yet its buildings' thermal mass gives the scheduler a real short-horizon store, and a dedicated battery would extend that lever from hours to full days

4.2.4 Recommendations for the Community

On the community as we have modelled it, VercorSoleiL earns on every scheduling objective in both tiers, near-balanced in its real case and export-oriented once the appraised expansion is in place. Generation data across the 29 installations is available, which can support both the same-day forecasting (at 0.9% generation MAPE) and a monthly long-term forecast (at 7.2%). The community could adopt day-ahead forecasting as a routine planning aid, since the historical metered feeds are already collected.

On investment, the cost-benefit analysis supports the adopted 700 kWp build. PV700 with no battery is the top-ranked candidate, with the highest net present value of about 492.4 thousand euro, a benefit-cost ratio of 1.70, a 6.2-year payback and a 16.0 percent internal rate of return, and with no binding site or grid constraint the community can build that winner outright. Storage lowers the net present value at every PV level and does not pay at the low 0.10 EUR per kWh export price, so the study is rightly PV-only. Should the community later add controllable loads of the kind the study models, such as heat-pump and HVAC units on its public buildings, their thermal flexibility would shift load within the day, and a battery would then extend that lever from hours to full days, so storage is best treated as an operational and resilience choice for that stage, as costs fall or price volatility grows. The near-carbon-free grid means the social case adds only about 8% beyond the private return, so the investment stands on its private economics.

As the building loads are synthesized while the generation is collected, this guidance is best read as design-stage. The most useful next step is to bring load measurement online at the consumers' premises, so a future iteration can replace the modelled load profiles with the community's own data and refine both the scheduling and the investment analysis, with the generation forecasting already resting on real measurements.

4.3 Germany (RE3)

The community under study for the German RE3 is the OAL Energiegemeinschaft, formed around the Elektrizitatswerke Reutte and the Ostallgau in the Fussen and Reutte area of the Allgau Alps. It is a mixed-use community that brings together hotels, clinics and an agricultural holding. As recorded in D6.3 (pilot RE3.3), the community is still in formation. An earlier stage pooled existing rooftop PV, and over a 24-hour 15-minute dataset that generation portfolio was shown to fall short of demand, with more than 600 kWp of added capacity needed to close the gap. The real case in this section is built instead on the measured 15-minute OAL operational dataset covering 14 August to 15 September 2025, which includes a hydro plant of about 2,067 kW and two real CHP units. That measured window is tiled to a full year with the correct seasonality, so summer-high PV and snowmelt-high hydro fall in the right months. The hydro and CHP therefore come from the provided operational dataset which makes the German surplus a capability-demonstrating scenario built on provided data. All OAL results assume full community ownership of the hydro plant.

The two tiers reflect this community's distinctive position among the pilots. The real case models the measured OAL portfolio: seven buildings, 394.2 kWp of rooftop PV, the run-of-river hydro plant of about 2,067 kW, two CHP units and no storage. These are the measured values of the OAL operational dataset provided by the German pilot, used as the inputs to the WP2 simulation. They describe the OAL asset boundary and are not the final monitored KPIs of the RE3.3 pilot as reported under WP6 (D6.3), whose pilot perimeter is defined around Füssen. The study case retains that generation and adds new local demand and flexibility, growing the community into thirteen buildings with continuous absorption loads, a community battery, EV and V2G, and heat-pump and HVAC flexibility. Unlike the other pilots, Germany's challenge is the offtake of a large hydro-dominated surplus, so the study is demand-side, adding new local loads together with storage and flexibility, and it is not appraised by a cost-benefit analysis. The lever the analysis sizes is how much well-timed local demand the community can add to absorb a seasonal surplus.

The German setting also exercises the platform's tariff handling. The study community operates under a time-of-use tariff extended with negative overnight day-ahead prices, so on some hours the community is paid to consume. The consequence, visible in the study scheduling section, is that the optimizer charges and consumes when the price turns negative, which lowers the daily cost further into earnings.

4.3.1 Real Case Study: OAL Energiegemeinschaft (RE3.3)

On the platform, the real community is built from the measured OAL datasets: the 15-minute load series for the seven buildings, one agricultural, four commercial and two public, the generation series for the 394.2 kWp of rooftop PV, the run-of-river hydro plant of about 2,067 kW and the two CHP units, together with the tariff and weather series, on Europe/Berlin time and in euro. No storage and no grid connection cap are set for the real tier. The configured community has a combined annual demand of about 1,910.8 MWh against about 12,297.8 MWh of generation, a generation-to-demand ratio of 6.44, so it is strongly generation-first and in surplus across the whole year. The generation is hydro-dominated, and the hydro alone is about six times the community load, so roughly 85 percent of generation is exported. This is a generation-surplus pilot whose defining challenge is offtake of that surplus.

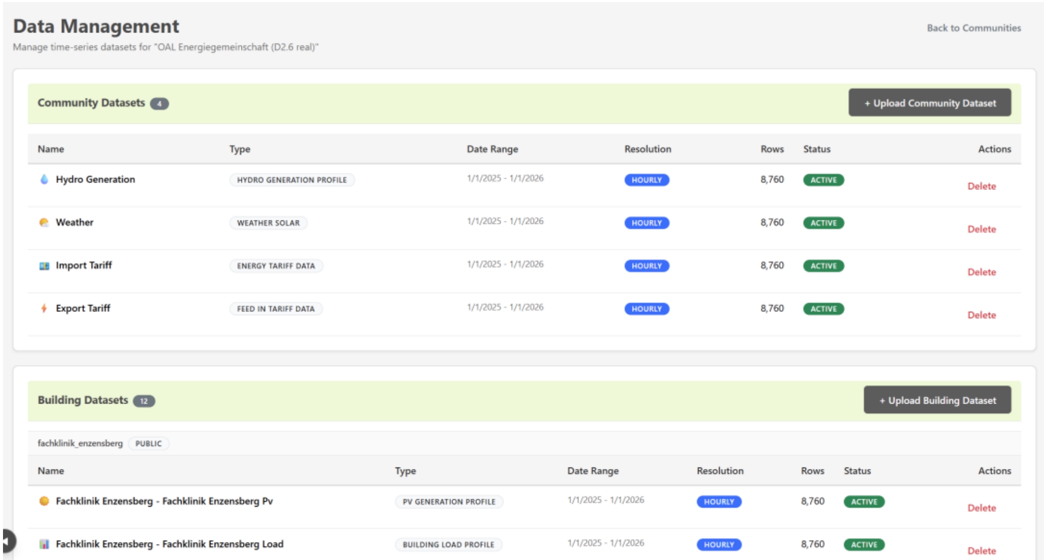

Figure 26 Data management view for the OAL real case, showing the ingested load, generation, hydro, CHP, tariff and weather series, each validated with its date range

The Energy Forecasting Tool produces the community's day-ahead forecast for 15 June 2025 on a 24-hour horizon, and its accuracy is measured by validating that forecast against the measured series for the day. On this same-day validation the load forecast returns 3.7 percent MAPE and the generation forecast 2.8 percent, both at high confidence with the LightGBM model.

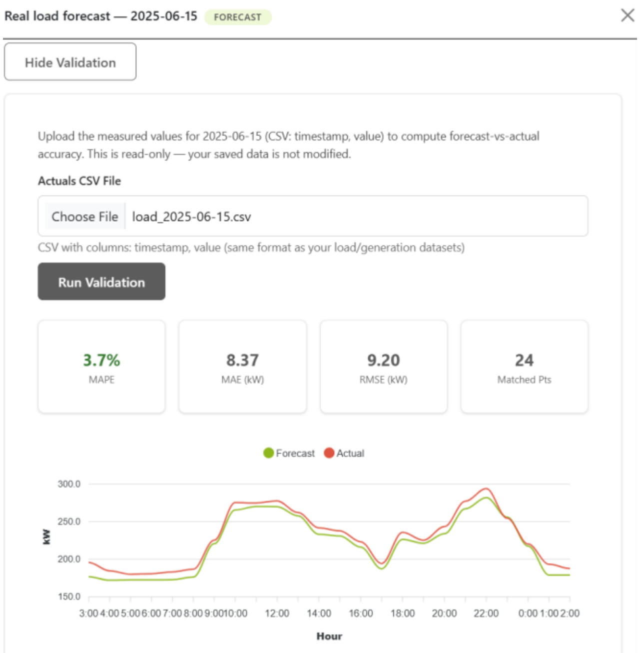

Figure 27 Energy Forecasting Tool day-ahead result for the real German case, showing the load forecast at 3.7 percent MAPE and the generation forecast at 2.8 percent MAPE

Day-ahead scheduling was run under all four objectives, and on every one the community reaches 100 percent self-sufficiency with zero grid import, since the run-of-river hydro alone is about six times the community load. On three of the four objectives, minimum cost, minimum CO2 and maximum self-consumption, the schedule leaves the two CHP units off, sends about 44,465 kWh of surplus to the grid and produces no emissions. Maximum self-sufficiency is the exception. It runs the CHP for 912 kWh, all of it exported, which adds about 145 EUR to the day's cost and 521 kg of CO2, the community's only emissions on any objective, for no gain in a self-sufficiency that was already complete.

Table 12 Day-ahead scheduling results by objective, OAL real case. The community is 100 percent self-sufficient with zero grid import on every objective. Two natural-gas CHP units are registered, Hoteldorf Hartung Hirsch at 17.9 kW and Hotel Eggensberger at 20.1 kW, each at 35 percent electrical efficiency, 0.08 EUR per kWh fuel and a 0.2 kg per kWh fuel CO2 factor. Scheduling configuration: representative day 15 June 2025, all four objectives; assets 394.2 kWp rooftop PV, run-of-river hydro of about 2,067 kW and the two CHP units, no storage.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	100.0	10.9	−3066.63	0
min_co2	100.0	10.9	−3066.63	0
max_self_sufficiency	100.0	10.7	-2921.33	0
max_self_consumption	100.0	10.9	−3066.63	0

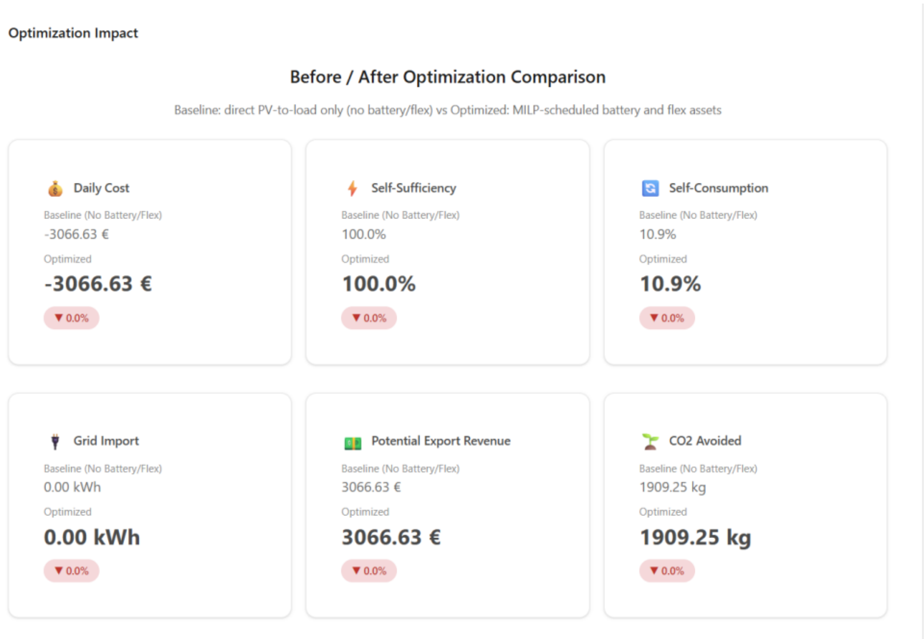

Figure 28 Optimization Result for objective Minimize Cost, OAL real case (15 June 2025).

The daily figures are best read as potential earnings, which is the key point given how the run is set up. The real case sets no grid export cap, so the model treats the entire surplus as exportable and sold at the export price, and that is why no energy is curtailed on any objective and why the day closes at about minus 3,067 EUR. That figure is an upper bound. It assumes an unconstrained connection that accepts up to the roughly 2.6 MW the community produces at peak, together with a market or energy-sharing framework that pays for every exported kilowatt-hour. On a physical connection the export would be limited and the surplus would earn only what such a framework remunerates, so the figures show what the surplus is worth once it can be sold, an opportunity the community has yet to secure.

The small CHP dispatch under maximum self-sufficiency is incorrect behaviour, traced to a platform optimization assumption that prices the CHP as cost-free under the maximizing objectives, so with grid import already at zero the engine runs it for no benefit and books the day's only emissions. This is flagged as a platform refinement, and the correct outcome is the one on the other three objectives, which leave the units off.

With generation more than six times the local load and the hydro plant alone many times larger than demand, the community meets its whole load from its own assets on every objective and could export the great majority of what it produces. The four objectives are nearly identical, since a fully self-sufficient community with no storage gives the scheduler almost nothing to move. The result confirms a generation base with far too little local demand to absorb it, which motivates a demand-side expansion.

4.3.2 Exploring the Expansion Options (Demand-Side Load Absorption)

Because the surplus is so large, the expansion question for Germany is how much local demand can be put to work against the surplus, and in what shape. Answering it starts with the shape of the surplus itself, so the surplus is characterised first.

The measured data covers only 14 August to 15 September 2025. The full-year picture is therefore modelled, built by tiling that window across the calendar under two generation-seasonality assumptions:

1. PV output follows a summer-high irradiance profile for the site.
2. Hydro output follows the Alpine snowmelt regime, which peaks in the summer half-year [21].

Load is held at its measured level all year, because the window contains no winter data from which to derive a heating season.

On this basis the community is in surplus in every hour of the year. The floor holds near 422 kW, the median is about 1,121 kW and the peak about 2,605 kW. The seasonal swing is wide, from a modelled June mean near 1,880 kW to a modelled January mean near 666 kW. Even at the winter low, the floor does not close.

The winter figures are the least certain part of this reading. They rest on the assumed hydro regime with no measured data behind them, so they are stated conservatively. Holding load flat is also the optimistic case for the floor, because a real heating season in the existing buildings would pull it down. The sizing in the rest of this section keeps a margin against that. The finding that carries the section is a surplus present in every hour, winter included.

Table 13 Hourly surplus statistics for the OAL community across the tiled year, showing a firm floor of about 422 kW present in every hour.

Measure	Value
Hours of the year in surplus	100%
Minimum surplus (any hour)	422 kW

Median surplus	1,121 kW
Maximum Surplus	2,605 kW
Monthly minimum (Dec, Jan)	422 to 425 kW

With the shape of the surplus fixed, the operative question is which kinds of added demand absorb it, and how far the addition can grow before absorption falls away. Each of six candidate load shapes was added to the standing surplus on its own, with the annual energy of the addition swept from 400 MWh to 5,000 MWh and no storage layer, and scored by the share of the added demand met directly from would-be-exported surplus. Table 14 reports the result.

Table 14 Share of added demand absorbed locally as the addition grows, by load shape. Continuous baseload is perfectly flat across all 8,760 hours; summer-weighted 24/7 is round-the-clock with May to September at twice the rest of the year; daytime year-round runs 08:00 to 18:00 every day with zero overnight; winter-biased runs November to March at twice and April to October at half; evening household runs 17:00 to 23:00 only; summer-daytime runs June to August, 08:00 to 18:00 only, about 900 hours a year. A continuous or summer-weighted round-the-clock load holds near 100 percent absorption to several gigawatt-hours, while an hour-confined load such as summer-daytime saturates early.

Load shape	400 MWh	2,000 MWh	3,693 MWh	5,000 MWh
Continuous baseload (24/7)	100%	100%	100%	99.5%
Summer-weighted 24/7	100%	100%	100%	100%
Daytime year-round	100%	99.3%	84.3%	73.4%
Winter-biased	100%	100%	92.3%	78.9%
Evening household	100%	95.1%	74.1%	59.2%
Summer-daytime	100%	75.5%	40.9%	30.2%

Absorption depends on the shape of the added load more than on its size across this range. The loads that keep absorbing almost all of the surplus up to several gigawatt-hours are the ones that run at every hour:

- A continuous baseload stays at essentially 100 percent to 3,693 MWh and slips only to 99.5 percent near 5,000 MWh.
- A summer-weighted 24-hour load holds 100 percent across the whole range, because its demand peaks in the months when the surplus is largest.

Loads confined to fewer hours saturate earlier. An evening household load falls to about 74 percent by 3,693 MWh. A summer-daytime load, running only about 900 hours a year, drops to about 41 percent at the same scale, because it runs out of hours that coincide with surplus. For the community, the shape that absorbs the surplus at scale is a load that runs at every hour, anchored by a continuous baseload.

The firm floor also sets a hard ceiling on what the community can absorb without storage. A load that holds the 422 kW floor across all 8,760 hours draws about 3,693 MWh a year. Every kilowatt-hour of it lands on available surplus, with no grid import and no storage. This is the 3,693 MWh column in Table 14, where a continuous baseload still absorbs almost all of the addition. Set against a total annual surplus of about 10,387 MWh, that firm headroom is large, and a continuous baseload is the shape that realises it. Sizing the demand-side additions within this headroom keeps the expansion defensible on the community's own data, because every added kilowatt-hour is then absorbed in every hour of the year. The margin kept below the floor also covers the winter uncertainty noted above. An addition sized at about 358 kW against the modelled 422 kW floor stays fully absorbed even if the existing heating-season load rises by up to roughly 20 percent.

The analysis imposes no grid export limit. A fixed export cap has no meaning against a run-of-river plant of roughly 2 MW that delivers about 11 GWh a year and imposing one would manufacture curtailment as an artefact of the assumption. German regulation is moving the same way. The §42c EnWG energy-sharing provision [22] entered into force in December 2025, with distribution-operator enablement due in June 2026, so the offtake room the community faces is expected to widen. The study therefore models that all surplus is exported, the peak export is about 1,850 kW, and curtailment is zero on every objective.

4.3.3 Expansion Case Study: Demand-Side Absorption with Storage and Flexibility

The study builds the expansion that the sizing analysis points to. It keeps the real generation base unchanged and adds well-shaped demand under the surplus floor, in the form of six absorption archetypes that raise the community from seven to thirteen buildings. No new generation is added and no grid limit is imposed. A 200 kWh community battery is included, along with heat-pump and EV flexibility with vehicle-to-grid, and the study tariff adds negative overnight prices. Table 15 sets the study configuration against the real case.

Table 15 Community setup parameters for the German pilot, real and study cases. Generation is held unchanged; the study adds demand, a 200 kWh community battery and heat-pump and EV flexibility to absorb more of the surplus locally, under a time-of-use tariff that adds negative overnight prices

Parameter	Real case	Expansion Case Study
Buildings	7 (1 agricultural, 4 commercial, 2 public)	13 (7 real plus 6 absorption archetypes)
Annual demand	1,910.8 MWh	4,275.8 MWh
Rooftop PV	394.2 kWp	394.2 kWp (unchanged)
Hydroelectric	2,066.8 kW	2,066.8 kW (unchanged)
CHP	2 units (17.9 and 20.1 kW)	2 units (unchanged)
Community battery	none	200 kWh
Annual generation	12,297.8 MWh	12,297.8 MWh (no new generation)

Generation-to-demand ratio	6.44	2.88
Grid limits	none	none
Tariff	time-of-use	time-of-use with negative overnight prices
Flexibility	none	heat pump, EV charging with V2G
Weather data	available	available

The added demand is assembled from six building archetypes chosen to embody the winning shapes from the absorption analysis, weighted towards continuous and summer-biased loads and anchored by a round-the-clock baseload.

Table 16 The six absorption archetypes added in the study case, with load profile, annual energy, mean and peak demand. The combined addition totals 2,365 MWh at a 358 kW peak, dominated by continuous baseload types.

Archetype	Building type	Profile	Annual MWh	Mean kW	Peak kW
Data centre / compute facility	industrial	flat, round-the-clock	1,050	120	138
Cold storage / logistics facility	commercial	round-the-clock, summer uplift	525	60	81
Dairy / agri-processing facility	agricultural	two-shift 05:00 to 21:00	350	40	76
Wastewater treatment works	municipal	flat, round-the-clock	260	30	33
Thermal / wellness facility	commercial	summer daytime	110	13	28
EV charging hub	public	summer daytime	70	8	25
Combined			2,365	270	358

The combined addition peaks at 358 kW against the firm surplus floor of 422 kW, a margin of about 64 kW. Every added kilowatt-hour therefore lands within each of the 8,760 hours of the year, with zero grid import and without any call on storage. Absorption in this case is a property of how the demand is sized, and the 200 kWh battery and the flexibility assets add value at the margin without being what makes the absorption work.

Five of the buildings are modelled to be equipped with controllable assets, which give the scheduler its only room to shift demand within the day, since the absorption archetypes themselves are fixed in shape. Two real clinics run heat pumps, the real Hotel Hirsch and the study charging hub run EV chargers with vehicle-to-grid, and the study wellness facility adds a further heat pump.

Table 17 Flexibility assets configured in the OAL study case, across two clinics, a hotel and two study archetypes.

Host building	Asset (type)	Rating	Schedule	Comfort / SoC	Efficiency	V2G
Fachklinik Enzensberg	Heat pump (heat_pump)	45 kW	mode auto	20 to 23 °C, init 21 °C, high mass	COP 3.2	n/a
Klinik Alpreflect	HVAC / heat pump (hvac)	20 kW	mode auto	21 to 24 °C, init 23 °C, high mass	COP 2.8 / EER 2.2	n/a
Hotel Hirsch	EV charger (ev_charger)	11 kW	overnight 18:00 to 08:00	3 EVs, 65 kWh each, arrive 0.3 to depart 0.8, 25 kWh/EV/day	n/a	yes
EV charging hub (archetype)	EV charger (ev_charger)	44 kW	daytime 08:00 to 20:00	8 EVs, 24 kWh/EV/day	n/a	yes
Thermal / wellness facility (archetype)	Heat pump (heat_pump)	40 kW	mode heating	26 to 30 °C, init 28 °C, high mass	COP 3.5	n/a

Day-ahead scheduling was run for a representative day under all four objectives (Table 18). Self-sufficiency is 100 percent on every objective, since generation covers demand in every hour and the community never imports to serve load. That leaves self-consumption as the only KPI that separates the objectives, and on the representative day it moves within a narrow band of 23.2 to 24.1 percent. The value in this case comes from how the demand is sized. Dispatch has little left to contribute.

Table 18 Day-ahead scheduling results by objective, OAL study case (representative day). A negative daily cost is a potential daily earning, contingent on the surplus being sold or shared under the framework now emerging in Germany. Self-sufficiency is 100 percent on every objective; self-consumption is the only KPI that separates them.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)

Minimum cost	100.0	23.4	-2,638.08	0
Minimum CO2	100.0	23.4	-2,635.27	0
Maximum self-sufficiency	100.0	23.2	-2,481.02	0
Maximum self-consumption	100.0	24.1	-2,610.53	0

Maximum self-sufficiency is the one outlier. It is the only objective that emits any CO_2, at 521 kg, and the weakest on cost, at a potential earning of about 2,481 EUR against 2,638 EUR for minimum cost. This traces to a known platform issue, in which the optimiser runs one CHP unit for about 912 kWh under this objective even though the community is already fully self-sufficient, so the added generation buys no self-sufficiency and is simply exported. It is a scheduling artefact of the objective's assumptions and carries no physical meaning. Once corrected, this objective matches the minimum-cost result.

The minimum-cost dispatch repays a closer reading, asset by asset, because it shows how the flexible assets and the battery behave when the community never imports and every objective lands on the same near-full-export result. Three platform views make the behavior concrete.

Under the minimum-cost objective the flexible assets are dispatched to satisfy their own thermal and electrical constraints, since the community never imports and faces no time-varying scarcity signal to arbitrage against. The three heat pumps resolve into two operating modes. The two clinic units, at Fachklinik Enzensberg and Klinik Alpreflect, run in cooling mode, because the seasonal automatic setting maps the 15 June representative day to summer. They are active only around the midday temperature peak, drawing up to 6.6 kW and 1.7 kW between roughly 10:00 and 18:00 to hold their zones at the upper comfort bound of 23 and 24 °C. The wellness pool is a year-round heating load. Its heat pump holds the water at the 26 °C comfort floor across all 24 hours, and its power draw rises as the outdoor temperature falls, from near zero at midday, when ambient approaches the setpoint, to about 11 to 12 kW overnight, when heat losses are greatest. The two electric-vehicle chargers show the bidirectional vehicle-to-grid model, in which the same trace reads as a positive load while charging and a negative load while discharging. The Hotel Hirsch fleet charges within its 18:00 to 08:00 overnight plug-in window and returns energy in the evening. The public charging hub charges within its 08:00 to 20:00 daytime window, spread across the morning and late afternoon at up to its 44 kW rating, and likewise feeds energy back in the early evening.

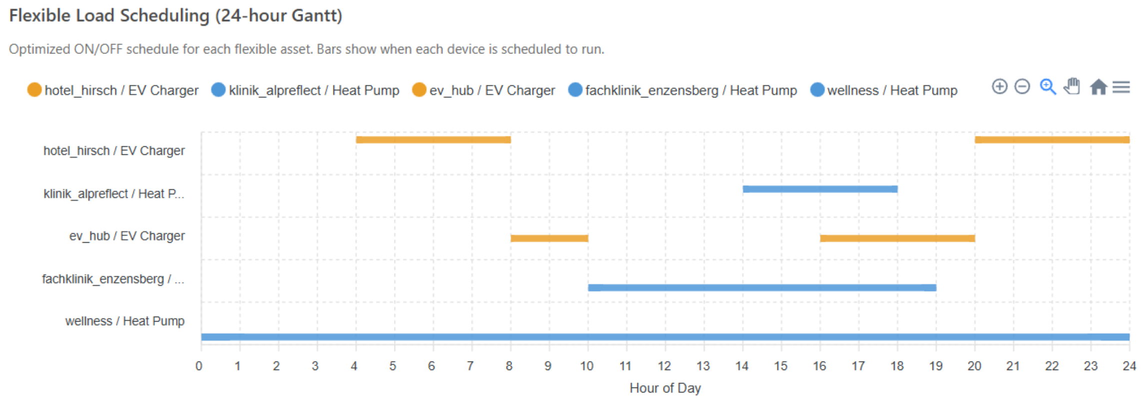

Figure 29 Flexible-asset day-ahead schedule for the OAL study community under the minimum-cost objective, showing the clinic cooling pumps around midday, the wellness heating pump running overnight, and the two vehicle-to-grid chargers charging within their windows and discharging in the evening.

The 200 kWh community battery has almost no role under the minimum-cost objective, and its schedule shows this directly. Because the community never imports and sells its surplus at a flat export price, there is no arbitrage margin to capture by cycling, and at a 93 percent round-trip efficiency, storing free surplus to release it later is a net loss. The battery therefore never charges. It releases its initial reserve once, discharging 86.5 kWh at 10:00 to move from its 50 percent starting state of charge down to the 10 percent operating floor, and then stays idle for the rest of the day. This is consistent with the study's wider finding, that in a community this generation-rich the value lies in demand-side absorption and storage adds little. The heat pumps and the vehicle-to-grid chargers shift energy to good effect, while the battery has nothing worthwhile to do.

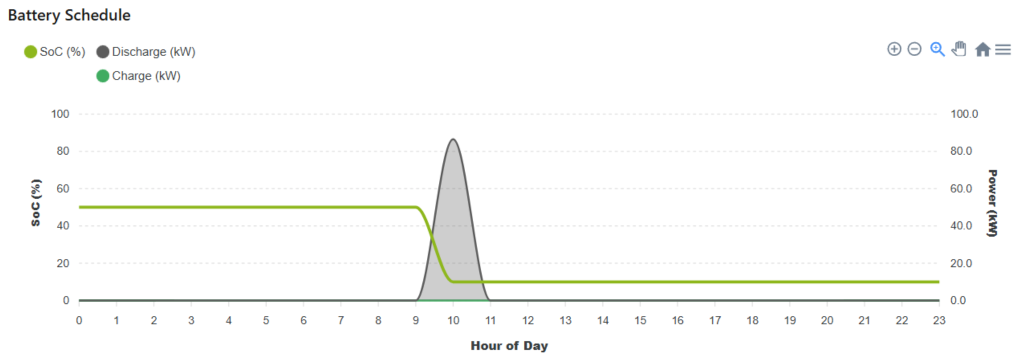

Figure 30 Community battery schedule under the minimum-cost objective, showing a single discharge from the 50 percent starting state of charge to the 10 percent floor and no charging across the rest of the day.

Hotel Hirsch is the clearest illustration of bidirectional flexibility for this study, as its charger is one of the two exercising vehicle-to-grid on this day. The building pairs a small base load, peaking near 8 kWh, with a 29.1 kWp rooftop array. Its three-vehicle fleet charges in the pre-dawn window, drawing up to 33 kW across 04:00 to 06:00, a demand met by early rooftop generation together with run-of-river hydro allocated from the community pool, up to 17.6 kW at 06:00, and never by the grid. That energy is returned through the day, in a brief 7.3 kW discharge at 07:00 and a run of evening discharges between 20:00 and 23:00 that peak at 6.0 kW, covering the building's own load once the PV has faded and only hydro remains on the network. Grid import stays at zero throughout, so the building is 100 percent self-sufficient, while its midday and afternoon PV surplus is shared to the community or exported, up to roughly 20 kW between 11:00 and 17:00. The net outcome for the day is a small revenue of 6.02 EUR.

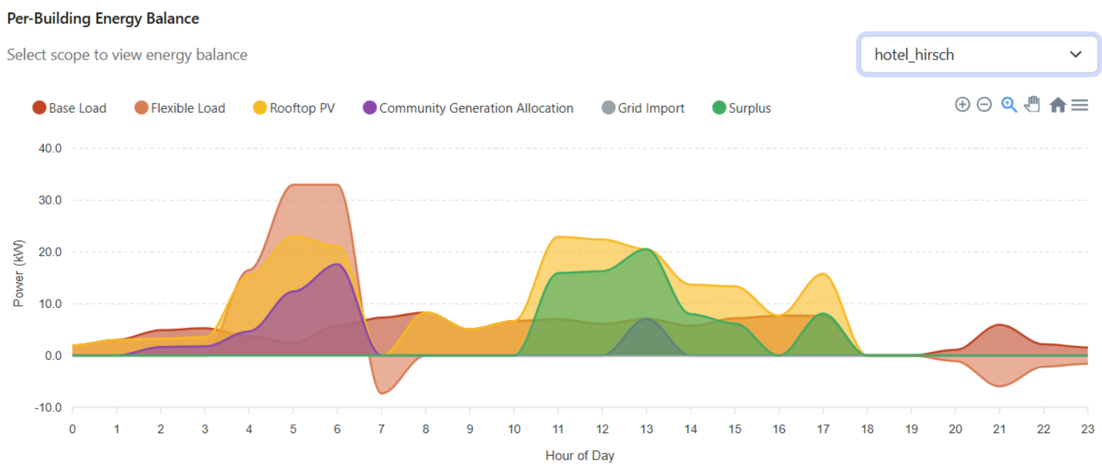

Figure 31 Per-building energy balance for Hotel Hirsch under the minimum-cost objective, showing the vehicle fleet charging in the pre-dawn window and returning energy via vehicle-to-grid in the evening, with zero grid import at every hour

Across the full year the effect of the expansion is clear (Table 19). Self-consumption more than doubles, from 15.5 to 34.8 percent, as 2,365 MWh a year moves from export to local use. Self-sufficiency stays at 100 percent and grid import stays at zero in every hour. Grid export falls from 10,387 to 8,022 MWh, which is the surplus now consumed on site. The whole of this gain is achieved with no new generation and no reliance on storage, purely by placing well-shaped demand under the surplus floor, and every kilowatt-hour of added demand is absorbed across the year.

Table 19 Annual KPIs, OAL real and study cases. Self-consumption more than doubles as 2,365 MWh a year moves from export to local use, with self-sufficiency held at 100 percent and no new generation.

Measure	Real	Study
Annual demand	1,910.8 MWh	4,275.8 MWh
Self-consumption	15.5%	34.8%
Self-sufficiency	100.0%	100.0%
Grid import	0 MWh	0 MWh
Grid export	10,387 MWh	8,022 MWh
Absorption of added demand	—	100.0%

Two limits frame the result. The first is the winter margin, which is the binding uncertainty in the design. With load held at its measured level, the 358 kW addition survives a heating-season rise in the existing buildings of up to about 20 percent, at which point the floor falls to about 376 kW. At a 30 percent rise the floor drops to about 354 kW and the addition would begin to draw imports in the coldest hours. This is why the expansion is sized at 2,365 MWh and not at the full 3,693 MWh envelope, holding a margin below the floor against a winter that the measured window does not observe.

The second limit is structural. Even absorbing the entire firm envelope would lift self-consumption only to about 45 percent, and reaching full self-consumption would require about 12.3 GWh of local demand a year, roughly 6.4 times what the community uses today. Demand-side absorption is materially useful for OAL, moving a large block of energy from export to local value, but it cannot resolve a surplus that is six times demand. The decisive lever for the bulk of the surplus remains offtake, through energy sharing under the section 42c EnWG provision as it comes into force.

4.3.4 Recommendations for the Community

As modelled, the OAL Energiegemeinschaft is defined by the offtake of a hydro-dominated surplus, and this offtake question is its central message, ahead of any investment case. Generation is more than six times local demand in the real tier and nearly three times in the study tier, so the community is 100 percent self-sufficient on every objective and exports the majority of what it produces in both. These recommendations are best read as design-stage guidance, since the community is still in formation and the results assume full community ownership of the hydro plant.

The demand-side study establishes a firm lower bound on what local additions can do. Sized on the community's own data, about 2,365 MWh a year of well-shaped, round-the-clock demand can be placed entirely under the surplus floor, more than doubling self-consumption from 15.5 to 34.8 percent with no new generation, no grid import and no reliance on storage. This is a real and defensible gain, and it raises the community's ability to use energy at the hours when the negative overnight tariff pays it to consume. It remains a partial answer, because as shown in section 4.3.3, demand-side absorption alone cannot resolve a surplus of this magnitude.

The study is also conservative in a second respect, being restricted to the load types the platform can represent today. The candidates best matched to a surplus of this shape, meaning large, firm and seasonally summer-biased loads, are precisely the ones that fall outside the current modelling scope, and they are where the greater opportunity lies:

- **Green hydrogen production.** An electrolyser is a continuous, fully controllable electrical load that scales with available power, matching the firm surplus floor almost exactly. Sized from a few hundred kilowatts upward, it would run as baseload on otherwise-exported energy and yield hydrogen for regional mobility, industrial feedstock or later re-electrification. It is the load best matched to this surplus, and it can scale toward and beyond the firm envelope without the hour-coincidence limits that cap time-confined loads. The platform has no electrolyser or power-to-gas model, so it is not quantified here.
- **Power-to-heat with thermal storage.** Electrode boilers or large heat pumps feeding a local heat network or an industrial host, buffered by a substantial thermal store, would convert summer electrical surplus into heat. A seasonal store is especially relevant here, because it could carry the summer-biased surplus into the winter heating season and so address the one point at which the surplus floor is weakest. The platform models per-building thermal envelopes only, without a district network or a seasonal store, so

this option lies outside the study.

- **Electrification of a co-located industrial or agricultural load.** Contracting the surplus to a nearby continuous process load, such as process heat, cold storage or agri-processing, is represented in the study only as fixed flat archetypes. The real value lies in an interruptible load that responds to price and to the hourly surplus under a bilateral supply arrangement, which needs a demand-contract and tariff model the platform does not yet provide.
- **Long-duration or seasonal storage.** In an Alpine hydro setting, pumped-hydro storage or a utility-scale battery would time-shift the surplus across days or seasons. Where the other options add demand, this shifts energy in time. The platform sizes only the small 200 kWh community battery, so grid-scale and seasonal storage, the storage-side counterpart to this demand-side study, cannot be represented.

Taken together, these point to the same conclusion as the modelled result but at a larger scale. The decisive levers for a surplus six times demand are offtake and conversion, ahead of conventional demand. The most valuable near-term actions for the community are therefore to confirm the export capacity available at the connection point, which this study deliberately leaves uncapped, and to settle how surplus energy is shared or sold, through energy sharing under the section 42c EnWG provision as it enters into force, since these determine the value of every exported kilowatt-hour. In parallel, a single large continuous sink, with green hydrogen the leading candidate, would absorb far more of the surplus than the distributed loads modelled here, and a seasonal store would extend that absorption across the year.

Finally, the study demonstrates several platform capabilities on a real operational dataset, namely hydro modelling, CHP dispatch, negative day-ahead tariffs and EV charging with vehicle-to-grid. As the community moves out of formation, the most useful next steps are to revisit these results with the finalised ownership and grid arrangements, to replace the tiled operational window with a full metered year, and, to assess the options above, to extend the platform with models for electrolysis, district power-to-heat with storage, and grid-scale storage. The present surplus scenario is capability-demonstrating on the provided operational data, and a future iteration can firm up both the offtake framework and the demand-side and conversion additions.

4.4 Czech Republic (RE4)

The community under study for the Czech RE4 is the energy-sharing community forming in the Vlcnov microregion in the Zlin Region, at about 230 metres of altitude. As recorded in D6.3 (pilot RE4.1), the community is built around municipal and public buildings, with the municipality acting as an active customer and the OSS support focused on that active-customer capability and on energy-sharing among the public assets. Households are outside the scope. The Czech energy-sharing and active-customer rules are still being transposed from the EU frameworks, so the sharing values here are contingent on that framework maturing. All figures are in Czech koruna (CZK), and no weather series is available for the site.

The two tiers reflect the small scale of this community today and the municipal-upscale trajectory it is planning toward. The real case models the connected public assets as the smart-meter records describe them, at four connection points, a modest rooftop PV system and no storage. These four metered connection points are the subset selected for the WP2 simulation based on the real metered data provided from the Pilot Site. They do not represent the full RE4.1 municipal pilot, whose asset perimeter under WP6 (D6.3) is wider. The study case grows the same community into a municipal upscale of public buildings and sizes a modest PV and storage build to that trajectory. This expansion is the one the analysis in this section points to, with sizing deferred to the analysis itself.

Two features set the Czech setting apart from the other pilots. It operates under a flat koruna tariff with no intraday variation, so there is no time-of-day arbitrage to exploit. It is also a small, strongly demand-dominant community that imports most of its energy across the year. The study represents the tariff with an import price of 4.8 CZK per kWh and an export price of 1.5 CZK per kWh, held constant across the day. The wide spread between the two, together with the flat profile, shapes every result below and gives storage a distinctive role.

4.4.1 Real Case Study: Vlcnov (RE4.1)

On the platform, the real community is built from its datasets: 15-minute EAN smart-meter load series for the three public buildings and the municipal house across the full year 2023, the rooftop PV generation modelled as a representative full-year Czech profile at about 930 kWh per kWp (only a February to August window was measured on site, too short to tile across the year without over-representing the sunny half), and the flat import and export tariff series, in koruna. No weather series is ingested, as the community is weather-free, and no community-wide assets or grid connection cap are set, the site being storage-free with a single rooftop PV plant. The configured community has a combined annual demand of about 75.2 MWh against about 8.3 MWh of generation, a generation-to-demand ratio of about 0.11, so it is strongly demand-first and imports most of its energy.

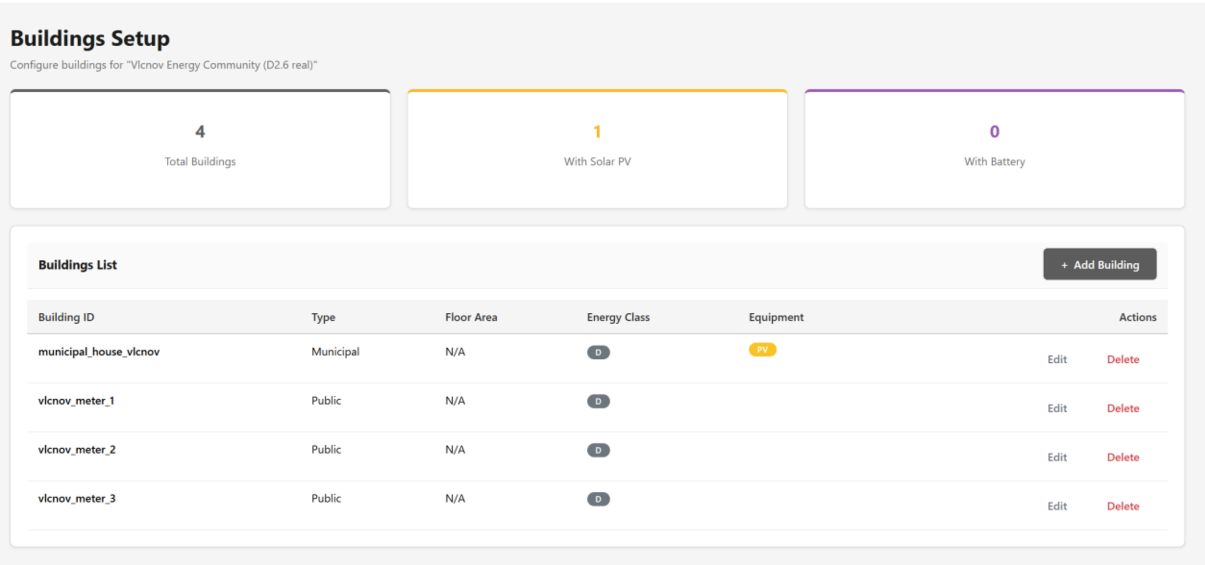

Figure 32 Community configuration for the Vlcnov real case, showing the four connection points (three public buildings and one municipal house)

The Energy Forecasting Tool produces the community's day-ahead forecast for 15 June 2025. On the platform's same-day validation the load forecast returns 18.5 percent MAPE at medium confidence with the Holt-Winters model, and the generation forecast 1.5 percent MAPE at high confidence with the LightGBM model. This is the only non-high load forecast across the whole pilot set, and it follows from the very small four-meter community, whose aggregate load is hard to forecast. The platform flagged the lower confidence directly. At the larger study scale the load forecast becomes 1.8 percent at high confidence, which locates the cause in community size and not in the tool.

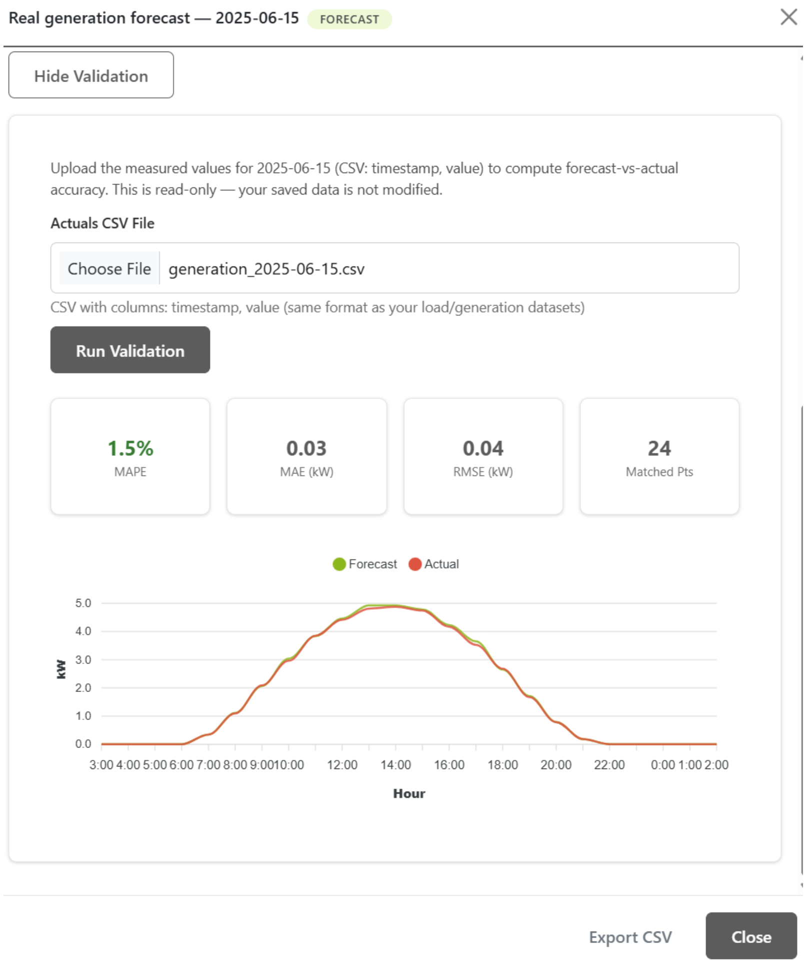

Figure 33 Energy Forecasting Tool day-ahead result for the real Czech case, showing the generation forecast at 1.5 percent MAPE (high confidence)

Day-ahead scheduling was run under all four objectives. Because the community is storage-free and the tariff is flat, there is no dispatch to shift and no arbitrage to capture, so the four objectives return the same operating point. On the representative day the community reaches 8.9 percent self-sufficiency and 100.0 percent self-consumption at a daily cost of 2,064.45 CZK, with no curtailment and no export. Self-consumption is complete because the small PV output is entirely absorbed by the much larger local demand, and self-sufficiency is low for the same reason. Across the full year, self-sufficiency averages about 10 percent and self-consumption about 90 percent, the latter below the representative day because on lower-load days part of the midday generation exceeds instantaneous demand. The community pays a positive daily cost to import the balance.

Table 20 Day-ahead scheduling results by objective, Vlcnov real case; scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, under the flat koruna tariff (import 4.8, export 1.5 CZK per kWh) with no intraday variation and no grid connection cap; assets: 8.9 kWp rooftop PV and no storage.

Objective	SS %	SC %	Daily cost (CZK)	Curtailment (kWh)
min_cost	8.9	100.0	2,064.45	0
min_co2	8.9	100.0	2,064.45	0

max_self_sufficiency	8.9	100.0	2,064.45	0
max_self_consumption	8.9	100.0	2,064.45	0

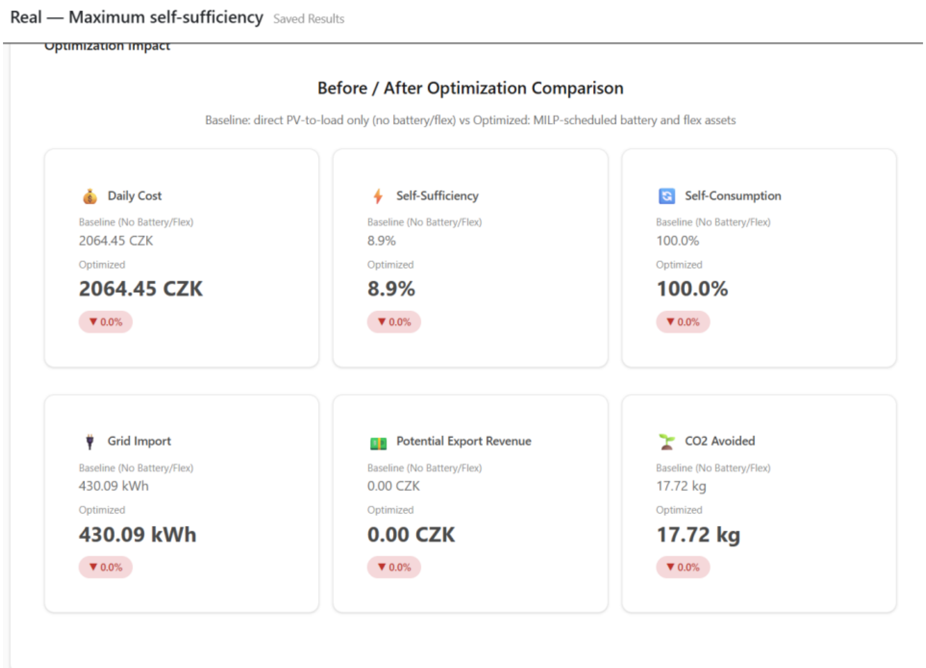

Figure 34 Optimization Result for the Vlcnov real case (15 June 2025), showing the single storage-free operating point shared by all four objectives.

4.4.2 Exploring the Expansion Options (Long-Term Planning)

The real case shows a strongly demand-dominant community whose small rooftop meets only a fraction of its load, which points to a larger public-building membership that can host generation and storage productively. The study therefore begins from the grown demand of a municipal upscale to 13 public buildings, about 299.6 MWh, roughly 4.0 times the real 75.2 MWh, using the real meters as generic public-building templates. Against that grown demand, and from a no-intervention baseline that starts with zero generation and meets the whole load from the grid, the Long-Term Planning module sizes PV and storage with the CBA Tool, so the recommended capacity is an output of the analysis. The monetary figures follow the standard EUR capex basis and are reported in euro. Candidates are ranked by NPV in Table 21.

Table 21 CBA what-if ranking for the Vlcnov expansion, by NPV. CBA configuration: Twenty-year horizon at a 7 percent financial discount rate, PV capex 1000 EUR per kWp, battery capex 300 EUR per kWh, CO2 valued at 80 EUR per tCO2, electricity-price escalation 3 percent per year, community annual load 300 MWh; candidates are PV-by-battery combinations scored against a no-intervention baseline.

Configuration	CAPEX (EUR)	NPV (EUR)	BCR	Payback (yr)	IRR	Socio-econ. NPV (EUR)	CO2 avoided (t/yr)
PV190 + B210	253,000	161,622.39	1.64	7.2	13.7%	252,360.77	95.76

PV150 + B210	213,000	154,628.24	1.73	6.9	14.5%	226,263.81	75.6
PV150 + B60	168,000	136,570.65	1.81	6.6	15.3%	208,206.22	75.6
PV190 + B0	190,000	136,341.75	1.72	6.9	14.4%	227,080.14	95.76
PV150 + B0	150,000	129,347.61	1.86	6.4	15.8%	200,983.18	75.6
PV90 + B60	108,000	120,160.70	2.11	5.7	18.0%	163,142.04	45.36
PV90 + B0	90,000	112,937.66	2.25	5.4	19.2%	155,919.00	45.36

The highest-NPV candidate is PV190+B210, at 161,622 EUR. The Czech ranking is the one case in the pilot set where storage improves the investment. At every PV level, adding the battery raises NPV: PV90+B0 rises from 112,938 EUR to 120,161 EUR at PV90+B60, PV150+B0 from 129,348 EUR to 136,571 EUR at PV150+B60 and 154,628 EUR at PV150+B210, and PV190+B0 from 136,342 EUR to 161,622 EUR at PV190+B210. The reason is the flat tariff with a wide import-to-export spread, 4.8 against 1.5 CZK per kWh. Holding daytime generation in the battery to displace an expensive import is worth more than exporting it at the low export price. This reverses the pattern seen in Italy, France and Greece, where storage lowers the headline return.

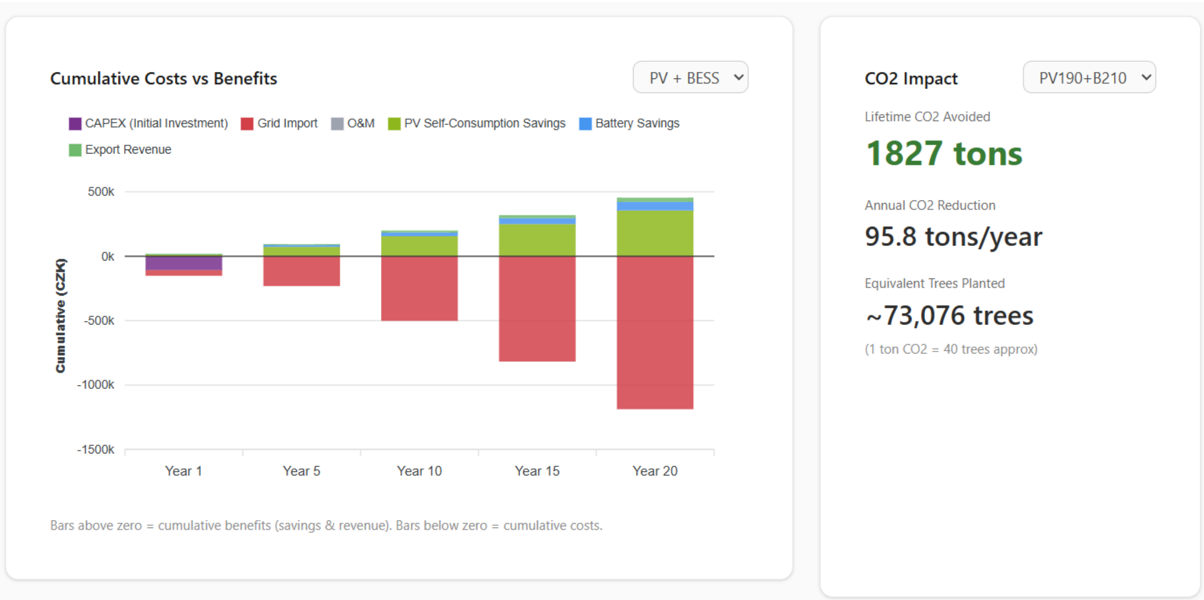

Figure 35 Cumulative Cost vs Benefits and CO2 impact for the highest-NPV candidate (PV190+B210)

The study configuration is chosen from this ranking, though not from the top of it. The highest-NPV candidate scales PV and storage toward the top of the tested range and oversizes the build against the community's own demand. The study instead sizes generation and storage to the municipal-upscale trajectory of 13 public buildings, adopting PV90+B60, a 90 kWp PV system with a 60 kWh building battery. This is a modest build matched to the demand-growth path, and it earns a strong BCR of 2.11, a 5.7-year payback and an 18.0 percent IRR on the assumptions used here, even though the sweep tested larger candidates. The battery is retained on its own merit here, since under the flat koruna tariff it raises NPV at this PV level, so the operational value of higher self-consumption and the financial case point the same way.

4.4.3 Expansion Case Study: Municipal-Upscale Public Buildings with Storage

The study case builds the configuration selected above. The membership grows to 13 municipal and public buildings, raising annual demand from 75.2 to about 299.6 MWh. The sizing places 90 kWp of PV alongside a 60 kWh building battery, the community's first storage, and adds EV charging and heat-pump flexibility. Table 22 sets the study configuration against the real case.

Table 22 Study configuration for the Czech expansion set against the real case.

Parameter	Real case	Expansion Case Study
Connection points / buildings	4	13
Annual demand	75.2 MWh	299.6 MWh
PV capacity	8.9 kWp	90 kWp
Community / building battery	none	60 kWh
Annual generation	8.3 MWh	83.7 MWh
Generation-to-demand ratio	0.11	0.28
Tariff	flat CZK (4.8 import / 1.5 export)	flat CZK
Flexibility	none	EV charging + heat pump
Weather data	none	none

The expansion keeps the community strongly demand-dominant, about 83.7 MWh of generation against 299.6 MWh of demand, a generation-to-demand ratio of 0.28. Forecasting improves markedly at scale. On the same 15 June 2025 day-ahead setup used for the real case, the load forecast validates at 1.8 percent MAPE and the generation forecast at 4.0 percent, both at high confidence. The load forecast moves up from the real case's 18.5 percent MAPE at medium confidence to 1.8 percent at high confidence once the community is at 13-building scale, confirming that the earlier error was driven by community size, with the tool unchanged.

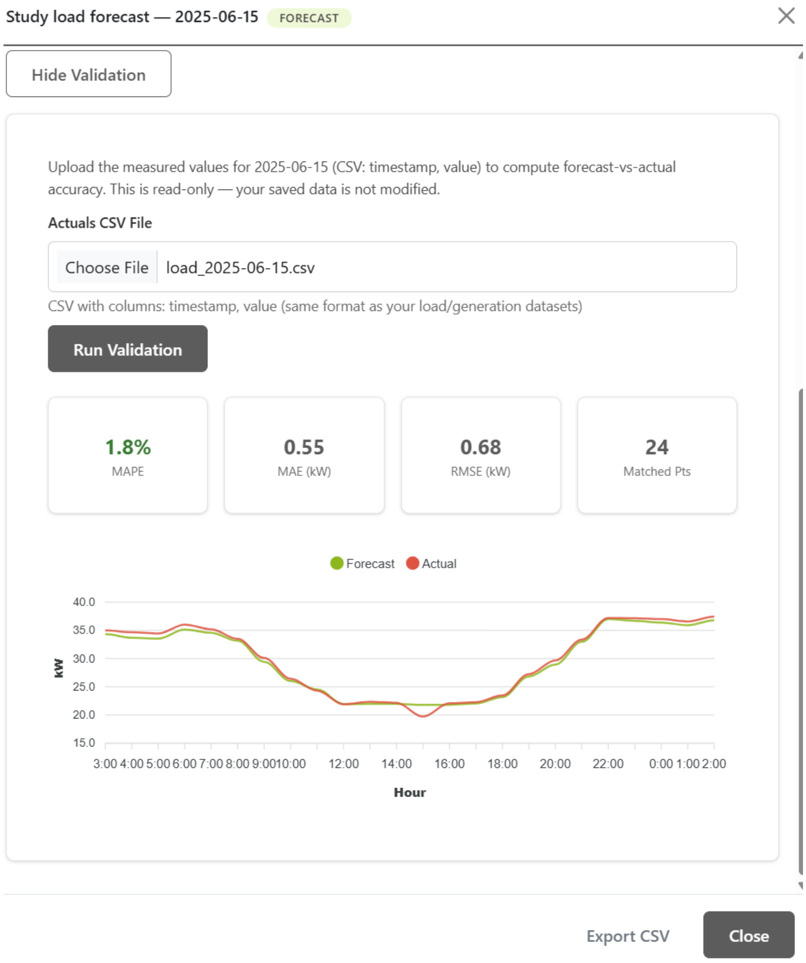

Figure 36 Forecast MAPE for the demand of the Czech study case for 15 June 2025.

Under scheduling the four objectives separate slightly, because the 60 kWh battery gives the community a dispatch to optimize even under a flat tariff. Minimum cost and minimum CO2 land almost together, at 39.3 and 39.1 percent self-sufficiency and 64.1 and 63.7 percent self-consumption, at about 1,974 to 1,975 CZK. Maximum self-sufficiency reaches 39.3 percent self-sufficiency and 67.7 percent self-consumption at 1,996.90 CZK. Maximum self-consumption reaches 39.3 percent self-sufficiency and 70.7 percent self-consumption at 2,039.00 CZK. No energy is curtailed on any objective, and the daily cost stays positive because the community still imports most of its energy.

Table 23 Day-ahead scheduling results by objective, Czech study case; scheduling configuration: representative day 15 June 2025, all four objectives, under the flat koruna tariff with a 90 kWp PV and 60 kWh building battery.

Objective	SS %	SC %	Daily cost (CZK)	Curtailment (kWh)
min_cost	39.3	64.1	1,974.08	0
min_co2	39.1	63.7	1,975.21	0
max_self_sufficiency	39.3	67.7	1,996.90	0
max_self_consumption	39.3	70.7	2,039.00	0

With the battery present the four objectives separate, unlike the flat-tariff real case where they collapsed onto a single point. The separation is modest, since the flat tariff offers no time-of-day arbitrage, and the value of the battery comes instead from raising self-consumption. Self-consumption rises from the real case's complete absorption of a tiny output to about 64 to 71 percent of a much larger generation base, and self-sufficiency rises from 8.9 to about 39 percent as the added buildings and storage keep more generation on site.

Both tiers are scheduled on the same 15 June representative day, for consistency across the pilots. On that day the study's demand is only about 1.5 times the real tier's, well below the roughly fourfold annual ratio, because 15 June is a low-demand summer day for the study's heating-driven public buildings and a high-demand day for the real tier. This is what makes self-sufficiency rise so sharply between the tiers and the study's daily cost land below the real case's despite the larger demand.

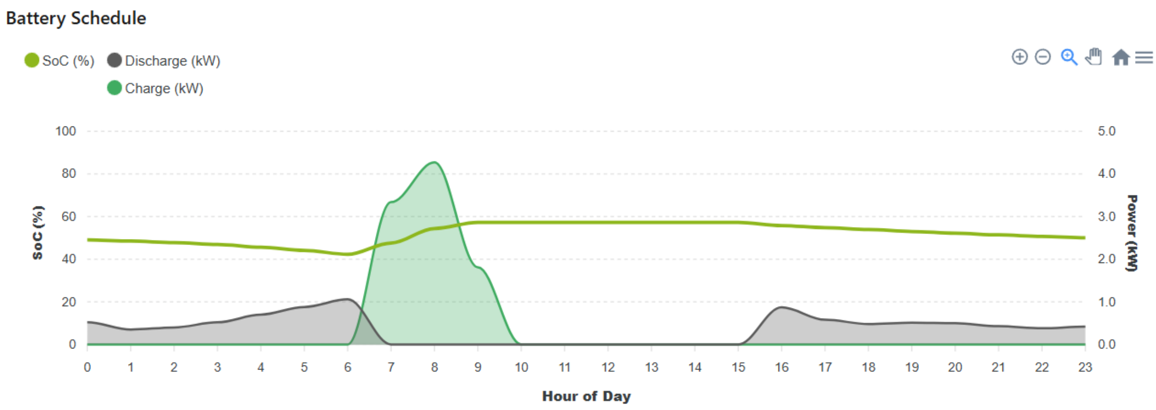

Figure 37 Battery Schedule for Maximize Self-Consumption objective for the Czech Study case (15 June 2025)

4.4.4 Recommendations for the Community

On the community as we have modelled it, Vlcnov is strongly demand-dominant in both tiers and imports most of its energy across the year, so its daily cost stays positive in koruna on every objective. These recommendations are drawn from a design-stage model, with the real case built from metered public-building loads and rooftop generation and the study case grown to a municipal upscale, so they are best read as guidance to test as the community expands.

The clearest message concerns the role of storage under the flat tariff. Because the koruna tariff carries no intraday variation, there is no arbitrage to exploit, and the value of the battery comes from raising self-consumption to displace expensive imports across the wide import-to-export spread. This makes the Czech pilot the one case where the battery earns its keep in the investment case, improving NPV at every PV level. For the study build, PV and storage are sized to the municipal-upscale trajectory of 13 public buildings, adopting a modest 90 kWp PV system with a 60 kWh battery that comes out strong on the assumptions used here, with a benefit-cost ratio above 2 and a payback under six years.

The real-case load forecast carries a second message. It validated at lower confidence because the community today is a very small four-meter system whose aggregate load is hard to forecast, and the platform flagged that confidence directly. At the 13-building study scale the same forecast improves to high confidence, so the community can expect forecasting quality to strengthen as it grows, and the operating cost figures reported here in koruna to firm up alongside it. As the microregion adds public buildings and begins to operate PV and storage, a future iteration would replace the modelled expansion with measured data and refine both the scheduling and the investment case.

4.5 Greece (RE5)

The community under study for the Greek RE5 is Domokos (RE5.1), an early-stage renewable energy community forming in Domokos, in the regional unit of Fthiotida in the Region of Central Greece. As recorded in D6.3, the community brings together about five participating citizens alongside a local farmers' cooperative, and its attested assets today are a single 90 kWp PV installation and one storage system. D6.3 places its footprint at about 0.126 GWh per year of generation, 30.2 tonnes of avoided CO_2 per year and 0.36 million euro invested. Weather series are available for the site, and the community operates under a time-of-use tariff.

The two tiers reflect the early stage of this community and a modest municipal-scale growth path for it. The real case models the attested site with six buildings served by the 90 kWp PV system and one storage system of about 100 kWh. The study case grows the same community into a municipal-scale membership, raising demand along that trajectory and sizing PV and storage to the larger load. This expansion is the one the analysis in this section points to, sized to the community's own demand growth so that the recommended capacity is an output of the study.

The distinguishing feature of the Greek setting is the grid it sits on. The Greek electricity mix is carbon-intensive, at about 0.45 tonnes of CO_2 per MWh, far above the near-carbon-free mixes elsewhere in the pilot set. Every avoided kilowatt-hour therefore displaces a large quantity of grid emissions, and the socio-economic value of the intervention rises accordingly. The consequence, visible throughout the analysis below, is that Greece carries the strongest socio-economic case in the set, with the socio-economic net present value standing well above the financial return at every candidate size.

The community operates under a time-of-use tariff, in which the import price varies with the hour of the day. The platform ingests the community's import and export tariff series and applies them directly, so scheduling can move flexible load and storage toward the cheaper hours. In the real case, where a large PV plant meets a small local load, the community earns a small amount over the day, so a negative daily cost is a daily earning. In the study case, where the grown demand dominates the available generation, the community pays over the day, so the daily cost is positive.

4.5.1 Real Case Study: Domokos (RE5.1)

On the platform, the real community is built from its datasets, the per-building load series for the six buildings, the generation series for the 90 kWp PV system, the storage configuration for the attested battery of about 100 kWh, and the import and export tariff series. The weather series is ingested, the site being weather-available. The configured community has a combined annual demand of about 45.4 MWh against about 113.9 MWh of generation, a generation-to-demand ratio of 2.51, so it is strongly generation-first and in surplus for most of the year. The 113.9 MWh is the platform's modelled output for the 90 kWp system, somewhat below 0.126 GWh.

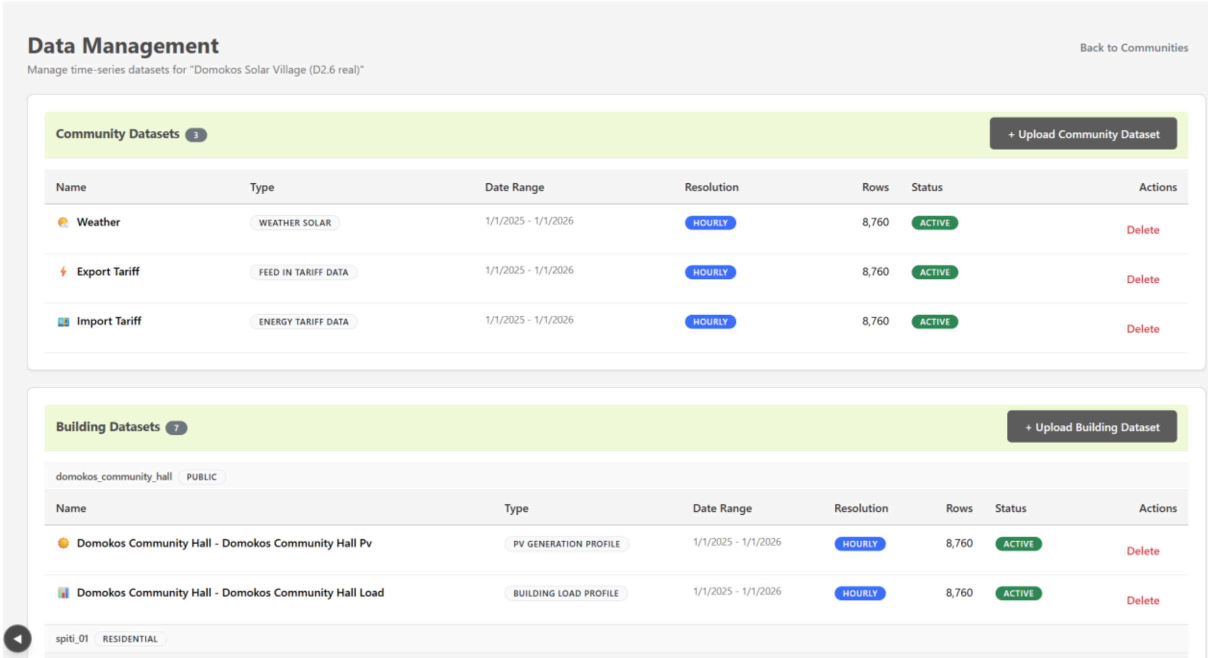

Figure 38 Data management view for the Domokos real case, showing the ingested community tariff datasets and the per-building load and PV generation series, each validated with its date range, hourly resolution and row count

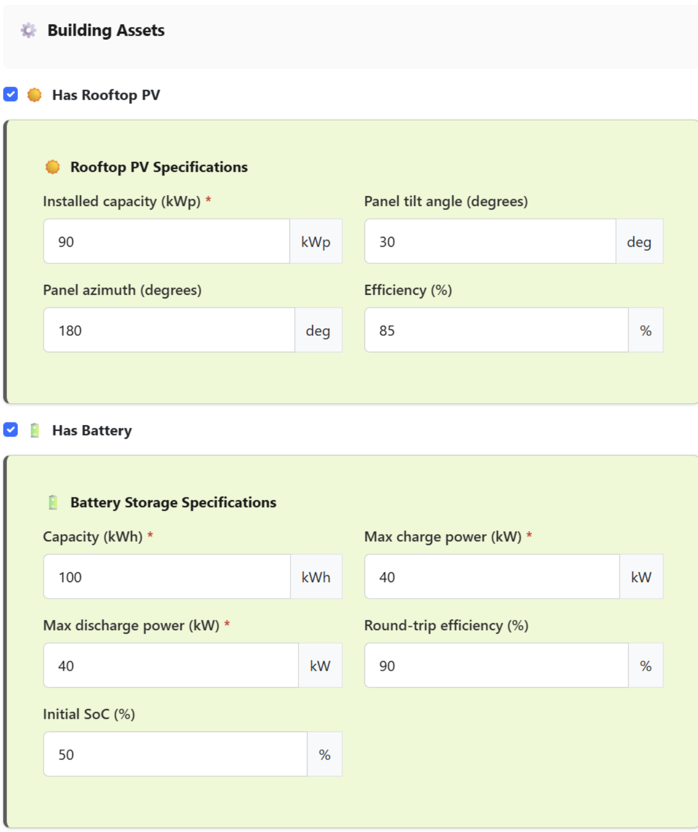

Figure 39 Community configuration for Domokos Municipal Hall showing the PV and battery system

The Energy Forecasting Tool produces the community's day-ahead forecast for 15 June 2025. On the same-day validation, both the load and generation forecast return 3 percent MAPE, at high confidence with the LightGBM model.

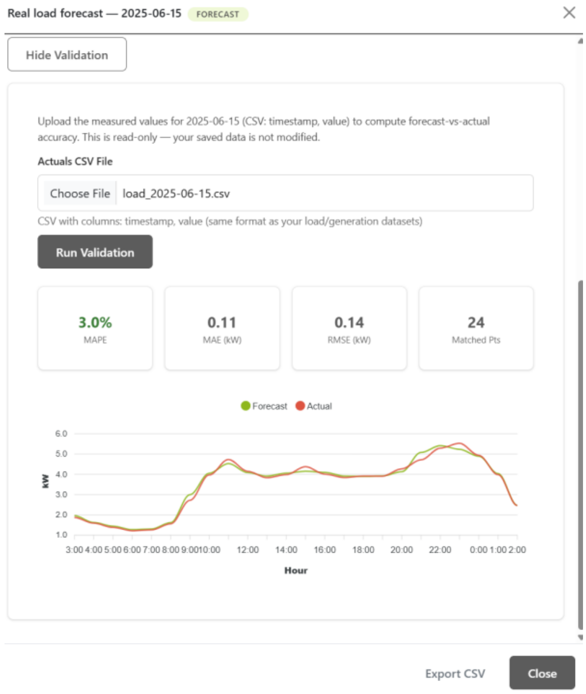

Figure 40 Energy Forecasting Tool day-ahead result for the real case, showing the load forecast at 3 percent MAPE

Day-ahead scheduling was run under all four objectives. Because the attested community has a working storage system, it has a dispatch to optimize, so the four objectives separate into distinct operating points. On the representative day, 15 June, self-sufficiency holds at 60.6 percent across the objectives while self-consumption and daily cost move with the target. Minimum cost reaches 60.6 percent self-sufficiency and 3.6 percent self-consumption at minus 30.93 euro. Minimum CO2 settles at 60.6 percent and 2.7 percent at minus 28.29 euro. Maximum self-sufficiency reaches 60.6 percent and 10.5 percent at minus 26.42 euro, and maximum self-consumption 60.6 percent and 10.7 percent at minus 26.38 euro. No energy is curtailed on any objective.

Table 24 Day-ahead scheduling results by objective, Domokos real case. Scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, under the community time-of-use tariff and a grid CO2 factor of about 0.45 kg CO2 per kWh; assets 90 kWp PV and one storage system of about 100 kWh.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	60.6	3.6	-30.93	0
min_co2	60.6	2.7	-28.29	0
max_self_sufficiency	60.6	10.5	-26.42	0
max_self_consumption	60.6	10.7	-26.38	0

The real case has a distinctive shape. The community is strongly generation-first, at a ratio of 2.51, yet it reaches only 60.6 percent self-sufficiency, because its night demand is imported in the hours when the PV is off and the small storage system can shift only part of the daytime surplus into those hours. Self-consumption stays low, since the large PV plant produces far more than the six buildings absorb and most of it is exported. Under the time-of-use tariff that export leaves the community with a small daily earning across every objective.

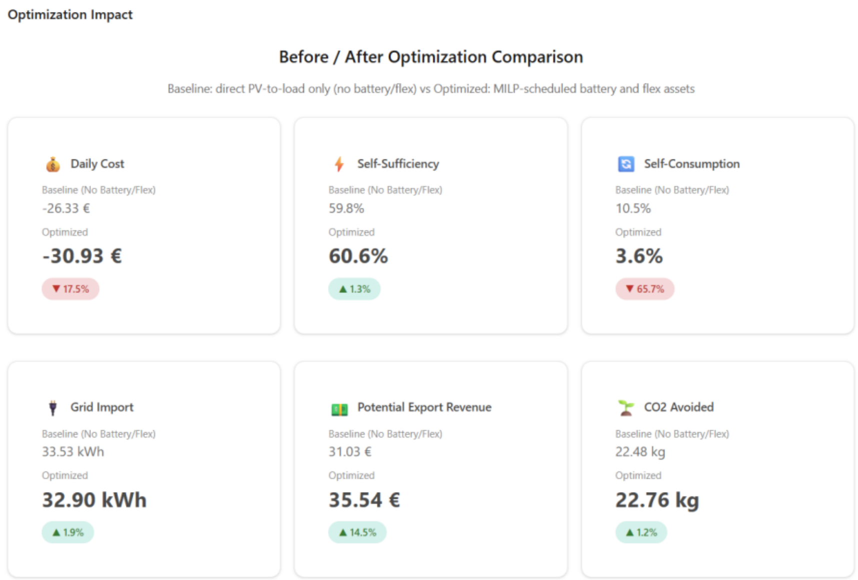

Figure 41 Optimization Result for the Domokos real case under the Minimize Cost objective (15 June 2025)

4.5.2 Exploring the Expansion Options (Long-Term Planning)

The study begins from the grown demand of a municipal-scale membership, about 450 MWh across 21 buildings, roughly 9.9 times the real 45.4 MWh. This is the largest growth factor in the pilot set. Against that grown demand, and from a no-intervention baseline that starts with zero generation and meets the whole load from the grid, the Long-Term Planning module sizes PV and storage with the CBA Tool. It varies PV capacity across 150, 300 and 450 kWp and the community battery across 0 and 250 kWh, ranked by NPV in Table 25.

Table 25 CBA what-if ranking for the Domokos expansion, by NPV. CBA configuration: Twenty-year horizon at an 8 percent financial discount rate, PV capex 1000 EUR per kWp, battery capex 300 EUR per kWh, CO2 valued at 80 EUR per tCO2, electricity-price escalation 2.5 percent per year, community annual load 450 MWh; candidates are PV-by-battery combinations scored against a no-intervention baseline.

Configuration	CAPEX (EUR)	NPV (EUR)	BCR	Payback (yr)	IRR	Socio-econ. NPV (EUR)	CO2 avoided (t/yr)
PV450 + B0	450,000	229,035.38	1.51	7.1	13.8%	476,948.86	283.5
PV450 + B250	525,000	206,199.94	1.39	7.6	12.6%	454,113.43	283.5
PV300 + B0	300,000	184,213.76	1.61	6.6	14.9%	349,489.42	189.0
PV300 + B250	375,000	161,378.32	1.43	7.4	13.0%	326,653.98	189.0
PV150 + B0	150,000	129,748.46	1.86	5.8	17.4%	212,386.29	94.5

PV150 + B250	225,000	106,913.02	1.48	7.2	13.5%	189,550.85	94.5

The highest-NPV candidate is PV450 with no battery, at 229,035 euro of net present value, a benefit-cost ratio of 1.51, a 7.1-year payback, a 13.8 percent IRR and a 476,949 euro socio-economic NPV. The study is not built on it. Because the demand-growth trajectory sets the scale of the community, the study sizes generation to that trajectory and adopts the 150 kWp PV option, PV150 with no battery, which returns the best benefit-cost ratio of the set at 1.86, the shortest payback at 5.8 years and the highest IRR at 17.4 percent. The larger PV450 candidate shows there is headroom in net present value for a community that chose to build toward net export, and the modest 150 kWp build is sized to the demand path the study follows.

The most striking result is the socio-economic uplift. Because the Greek grid is carbon-intensive, at about 0.45 tonnes of CO2 per MWh, the socio-economic net present value stands well above the financial net present value at every candidate. For the adopted PV150 option the socio-economic NPV is about 212.4 thousand euro against a financial 129.7 thousand, roughly 1.6 times as large, and for PV300 it is about 349.5 thousand against 184.2 thousand, roughly 1.9 times. This is the strongest socio-economic uplift in the pilot set, set against the near-carbon-free grids elsewhere that lift the socio-economic return by only about 8 percent. Storage lowers the financial return here, with PV150 plus 250 kWh at 106.9 thousand euro of NPV below the 129.7 thousand of PV150 with no battery. The study still carries a 100 kWh battery, kept for operational reasons and noting that 100 kWh is not one of the battery sizes shown in Table 25, which are 0 and 250 kWh.

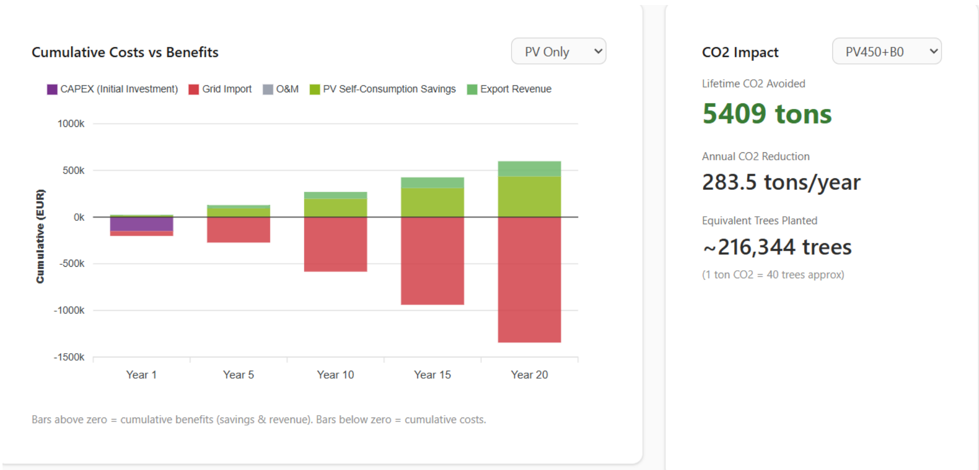

Figure 42 Cumulative Cost vs Benefits and CO2 impact for the highest-NPV what-if scenario (PV450+B0)

4.5.3 Expansion Case Study: Municipal Upscale with Storage and EV Charging

The study case builds the configuration selected from the ranking. The six buildings grow to 21, twenty residential homes and one community hall, raising annual demand from 45.4 to about 450 MWh. The sizing places 150 kWp of distributed rooftop PV alongside 100 kWh of building storage across two units of 60 and 40 kWh, and it adds EV charging on three of the buildings. The EV charging is a study design addition, since the real site reports PV and storage only. The community produces about 189.9 MWh against 450 MWh of demand, a generation-to-demand ratio of 0.42, so the study is demand-dominant. Table 26 sets the study configuration against the real case.

Table 26 Study configuration for Domokos set against the attested real case

Parameter	Real case	Expansion Case Study
Buildings	6 (5 residential, 1 community hall)	21 (20 residential, 1 community hall)
Annual demand	45.4 MWh	450 MWh
PV capacity	90 kWp	150 kWp
Battery	100 kWh	100 kWh
Annual generation	113.9 MWh	189.9 MWh
Generation-to-demand ratio	2.51	0.42
Tariff	time-of-use	time-of-use
EV charging	none	3 buildings
Weather data	available	available

The expansion moves the community from a strong generation surplus to a demand-dominant position, about 189.9 MWh of generation against 450 MWh of demand. Forecasting stays planning-grade, the load forecast validating at 1.8 percent MAPE and the generation forecast at 3.0 percent MAPE, both at high confidence under LightGBM, on the same 15 June 2025 day-ahead setup used for the real case.

Figure 43 Community Dashboard for the Domokos study case, showing the 21 buildings

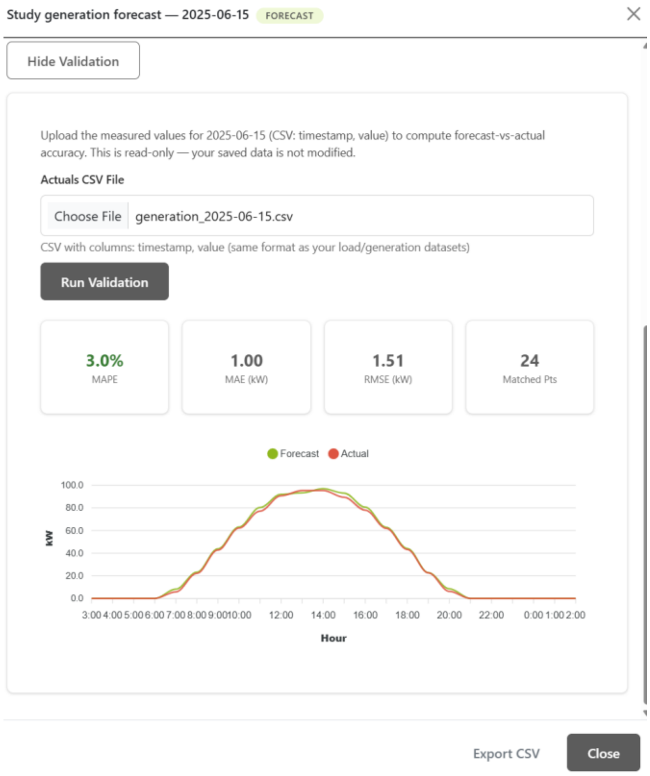

Figure 44 Forecast MAPE for the demand of the Greek study case for 15 June 2025

Under scheduling the four objectives stay close together, because the demand-dominant community imports most of its energy and has limited surplus to redistribute. Minimum cost reaches 53.0 percent self-sufficiency and 79.1 percent self-consumption at plus 69.40 euro. Minimum CO2 and maximum self-sufficiency settle at the same point, 53.0 percent and 79.1 percent at plus 70.00 euro. Maximum self-consumption reaches 52.3 percent self-sufficiency and 83.3 percent self-consumption at plus 73.49 euro. No energy is curtailed on any objective.

Table 27 Day-ahead scheduling results by objective, Domokos study case. Scheduling configuration: Energy Modelling and Scheduling Tool, representative day 15 June 2025, all four objectives, under the community time-of-use tariff and a grid CO2 factor of about 0.45 kg CO2 per kWh; assets 150 kWp distributed rooftop PV, a 100 kWh building battery and EV charging on three buildings.

Objective	SS %	SC %	Daily cost (EUR)	Curtailment (kWh)
min_cost	53.0	79.1	+69.40	0
min_co2	53.0	79.1	+70.00	0
max_self_sufficiency	53.0	79.1	+70.00	0
max_self_consumption	52.3	83.3	+73.49	0

The study case reads the opposite way to the real case. Because the grown demand dominates the available generation, the community imports most of what it uses and the daily cost is positive on every objective, about 69 to 73 euro over the day. Self-sufficiency settles near 53 percent, and self-consumption is high at about 79 to

83 percent, since the community absorbs most of its own generation locally before importing the balance from the grid.

The minimum-cost dispatch is worth reading in detail through three platform views, covering the community storage, the vehicles and a single prosumer home. The study community's storage is two building-sited batteries, spiti_01 at 60 kWh and 25 kW and spiti_05 at 40 kWh and 16 kW, which the dashboard aggregates into a single 100 kWh community battery of about 41 kW, operating between a 10 percent floor and a 90 percent ceiling at 90 percent round-trip efficiency. Under the minimum-cost objective the schedule is a clear price-arbitrage pattern. Overnight the battery trickles out its opening charge, discharging about 1.5 to 3 kW through the first six hours to shave grid imports and drawing its state of charge down from about 48 to 37 percent. As the PV ramps it recharges hard in the late morning, about 7.6 kW at 08:00 and 8.8 kW at 09:00, lifting the state of charge back above 53 percent, then takes a second small top-up from the midday surplus. From mid-afternoon it discharges steadily into the expensive evening peak, reaching about 6 kW around 19:00 and running the pack down to its 10 percent floor by 23:00. Total throughput for the day is 83 kWh, about 0.42 full-equivalent cycles, for a modest 1.25 euro of modelled degradation cost. Emptying the battery by end of day is the correct least-cost behaviour on a single-day horizon, since energy stored past midnight has no value in the model, so the optimiser converts every cheap midday kilowatt-hour into an avoided peak-price import.

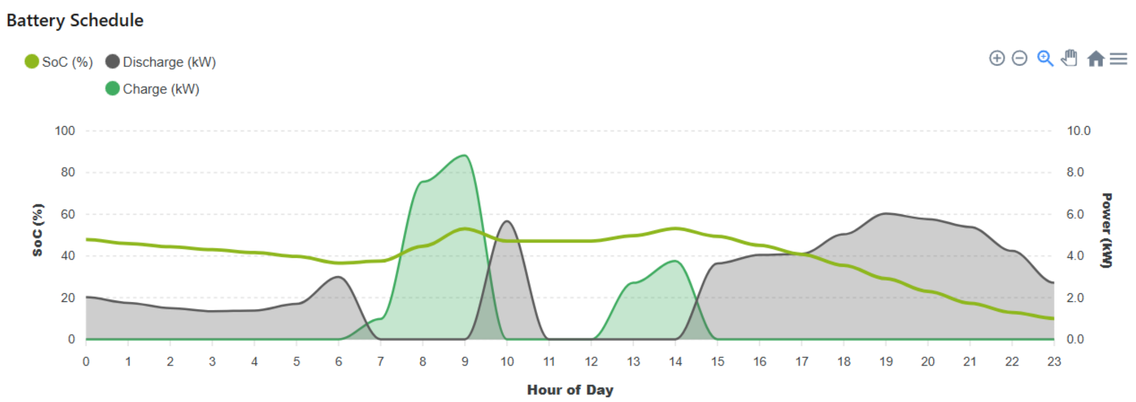

Figure 45 Aggregated community battery schedule for the Domokos study case under the minimum-cost objective, showing overnight discharge, late-morning recharge from PV and a steady discharge into the evening peak down to the 10 percent floor.

The study community carries three identical residential EV chargers, on spiti_03, spiti_10 and spiti_17, each a 7.4 kW single-phase wallbox serving a 60 kWh vehicle with no vehicle-to-grid capability. Each car is available from 18:00 to 08:00, arrives at about 30 percent charge and must reach 80 percent by departure, needing about 14 kWh a day. The minimum-cost optimiser does not charge on plug-in. It defers each vehicle into the cheapest hours inside the window, the small hours before dawn, pulling close to the full 7.4 kW rating for roughly two hours around 02:00 to 03:00 with a small top-up near 06:00. Each charger draws about 15.4 kWh from the grid to deliver 14 kWh to the vehicle, the difference being charging losses, for a community total of about 46.2 kWh of shiftable load. Because vehicle-to-grid is disabled the chargers only ever absorb energy, so total EV discharge is zero. One consequence of the overnight window is that the cars are never plugged in during solar hours, so they cannot absorb the community's own midday PV and are charged from off-peak grid power instead. The cost objective minimises the price of that energy while leaving its carbon content untouched, so routing solar into the vehicles would need a daytime charging window or added storage.

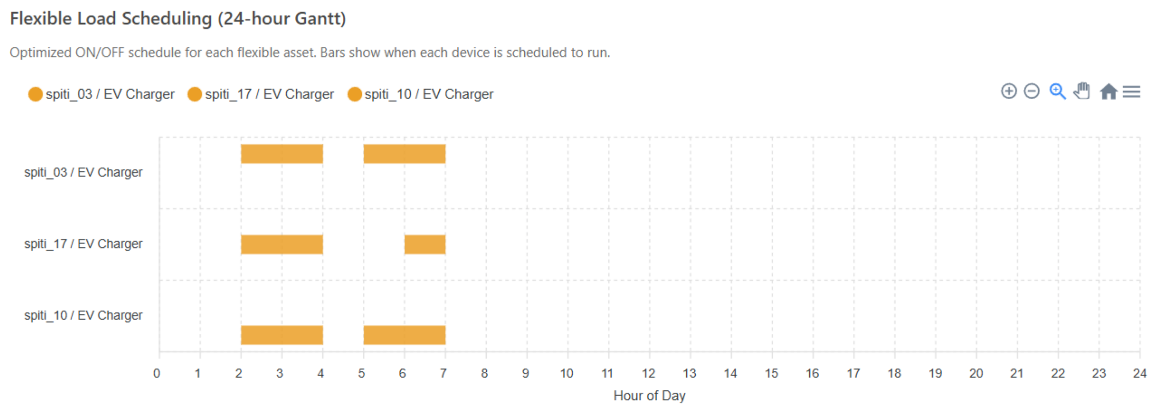

Figure 46 EV charger schedule for the three study chargers under the minimum-cost objective, showing charging deferred to the cheapest pre-dawn hours within the 18:00 to 08:00 plug-in window.

A prosumer household with a rooftop PV array and one EV charger and no battery of its own produces the Energy Balance showed below. Over the day its PV generates 30.3 kWh against a base household load of 41.7 kWh plus 15.4 kWh of EV charging, a total demand of 57.1 kWh. The balance splits by time of day. During daylight the rooftop PV covers the household load and runs a surplus, which is first shared into the community pool for neighbouring buildings and then exported to the grid, in three export peaks around 09:00, 12:00 and 13:00 totalling about 7 kWh. After sunset and overnight the house falls back on the grid, and the two tall imports of about 8 kW at 02:00 to 03:00 are the EV charging on top of the ordinary evening and morning household draw. The building imports 33.9 kWh and self-consumes 23.2 kWh of its own solar, a self-sufficiency of 40.7 percent at a daily cost of 4.26 euro. That ceiling is structural. With the EV plugged in only overnight and no home battery to bridge the gap, the household's own midday solar is exported and the car is charged from the night grid, so a substantial part of the day's demand is met by imports despite a healthy solar yield. It shows where a home battery, or a daytime charging option, would move a single prosumer home further toward self-supply.

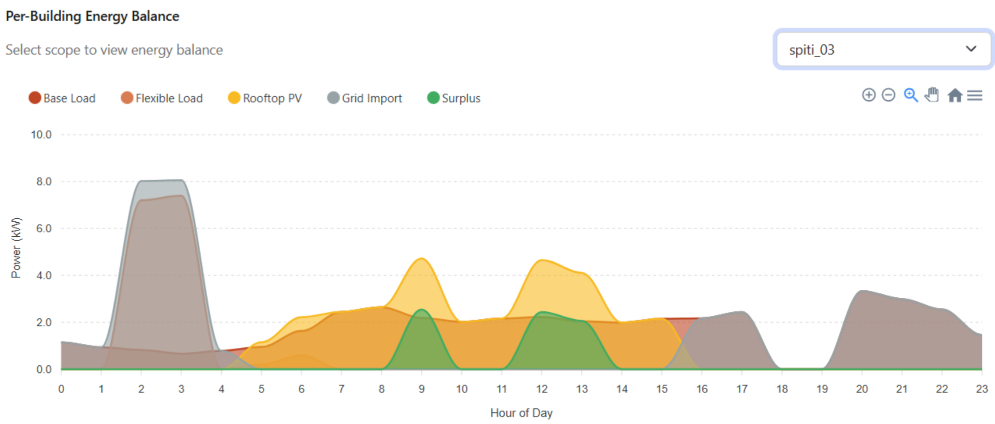

Figure 47 Per-building energy balance for spiti_03 under the minimum-cost objective, showing daytime PV surplus shared and exported and overnight grid import dominated by EV charging.

4.5.4 Recommendations for the Community

The clearest message for Domokos comes from the grid it sits on. Because the Greek electricity mix is carbon-intensive, at about 0.45 tonnes of CO2 per MWh, the socio-economic value of the intervention runs well ahead of its financial return, at about 1.6 to 1.9 times the financial net present value across the candidate sizes. This is the strongest socio-economic case in the pilot set, and it is the argument best suited to public support for the community, since much of the value the investment creates is the avoided grid emission that the community shares with wider society.

On investment, the modelling supports the 150 kWp PV build the study adopts, which returns the best benefit-cost ratio at 1.86, the shortest payback at 5.8 years and the highest IRR at 17.4 percent. The PV is sized to the demand-growth trajectory of a municipal-scale membership. The larger PV450 candidate holds the highest net present value and shows there is headroom for a community that chose to build toward net export, which is a strategic choice for the members. The battery is best treated as a separate decision. It lowers the financial return here, so the 100 kWh of storage is best justified for the operational value it delivers, and the community may wish to note that this size falls between the battery sizes shown in Table 25, 0 and 250 kWh.

The study is a demand-dominant municipal upscale that imports most of its energy, so its daily operation carries a positive cost and its priority is to lift local self-consumption and manage the flexible load, including the EV charging added on three buildings, toward the cheaper hours of the time-of-use tariff. The real site's 90 kWp PV and its storage system are attested in D6.3, and the larger study is a representative upscale of that early-stage community. As the community grows and begins to collect operational data, a future iteration can replace the modelled study profiles with the community's own measurements and refine both the scheduling and the investment analysis.

5 Cross-pilot synthesis

The five dedicated studies were run on the ICT Platform, using the run protocol defined at Section 3 and the same four optimization objectives, across five different Pilot Cases. This section compares the five results, covering the balance between generation and demand, the tariff regimes represented, the socio-economic contrast between cases, the forecasting accuracy achieved, and what the combined set indicates about the platform's portability and technology-agnostic design.

Each of the five is a real pilot community, modelled for fidelity to its own situation first. The real cases follow the assets and conditions of the ECs, with representative data being used where continuous measurements are not yet available. The study cases grow each community along a plausible, demand-sized path. Each community is modelled based on a real pilot site, and the five were chosen to span a wide range, from a demand-dominant municipal cluster to a hydro-led export community. Because each is an archetype grounded in a real community, the results the platform produces for one pilot could carry over to other communities of the same kind.

5.1 Generation-to-demand balance and optimization outcomes

The pilots differ most in the balance between what a community generates and what it consumes. As they have been modelled, at the demand-dominant end, Vlcnov in its real case meets only about a tenth of its demand from a single 8.9 kWp array, a generation-to-demand ratio of about 0.11, and the Greek study case reaches 53.0 percent self-sufficiency against a 450 MWh municipal load, a ratio of 0.42. At the generation-surplus end, the German OAL group is fully self-sufficient once its full asset base is counted, at a generation-to-demand ratio of about 6.44, a hydro-dominated surplus of which it exports roughly 85 percent, and the Greek real case runs a ratio near 2.51 and can export most of what it makes. Between these poles sit the near-balanced communities, with France at 1.02 in the real case and 1.39 in the study, about 765 MWh of generation against a 550 MWh load, and Valle di Fassa's study at 0.98, while Valle di Fassa's real 80 kWp church array over-produces for its small school-and-nursery load, a ratio of 1.36 with roughly 96 percent exported, which places the real tier on the generation-first side. The ICT Platform produced a coherent reading across all three regimes and, in each, identified the lever that actually moves the community's position, whether more generation, more storage, better placement of an existing surplus, or securing offtake for it.

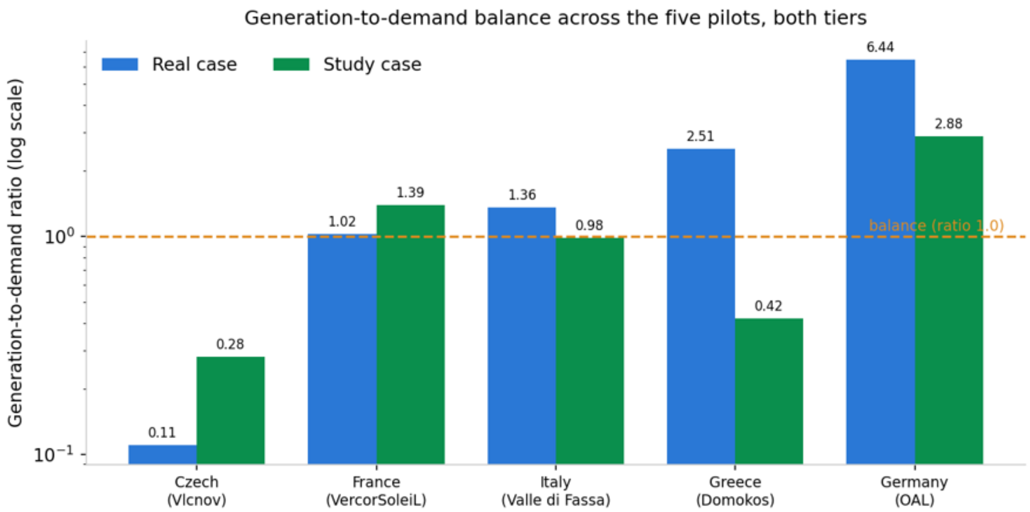

Figure 48 Generation-to-demand ratio across the five pilots and both tiers, on a logarithmic scale, sorted from the most demand-dominant to the most generation-surplus community, with the balance point at a ratio of 1.0

The scheduling results follow directly from this balance. Self-sufficiency cannot exceed what a community generates, so it tracks the generation-to-demand ratio. The German surplus community reaches 100 percent on every objective, the near-balanced and generation-first communities sit in the middle, and the demand-dominant Czech community settles near 39 percent. Self-consumption follows a similar pattern. A demand-dominant community uses almost all of its own generation on site, so the Czech and Greek study cases self-consume between about 64 and 83 percent, while a surplus community exports most of what it makes and self-consumes little, around 23 to 30 percent in Germany and Italy. Figures 49 to 52 show the study-case self-sufficiency and self-consumption for the five pilots under each of the four objectives. Where a community has storage or flexibility to dispatch, the objectives separate, trading a few points of self-sufficiency for self-consumption or cost. Where it is storage-free or already fully self-sufficient, as in the German case, the four objectives nearly coincide, since the scheduler has little left to move. Across every case the platform read the community's operating position from its own data, showing on the day whether it earns or pays, whether it reaches full self-sufficiency, and how much of its own generation it keeps.

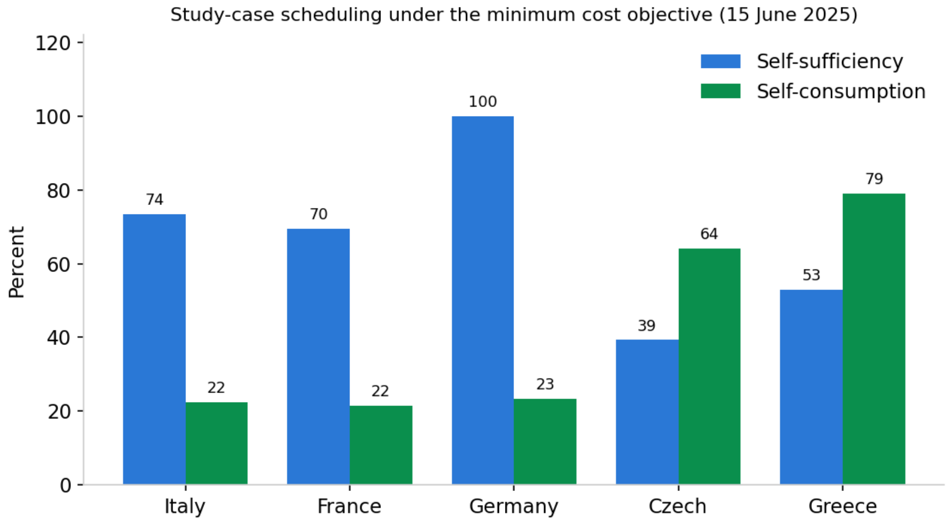

Figure 49 Study-case self-sufficiency and self-consumption for the five pilots under the minimum-cost objective

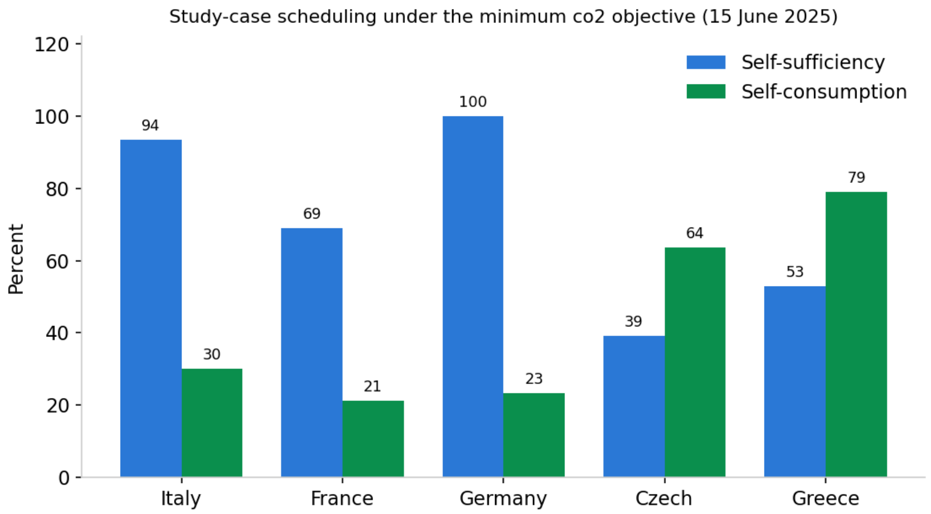

Figure 50 Study-case self-sufficiency and self-consumption for the five pilots under the minimum-CO2 objective

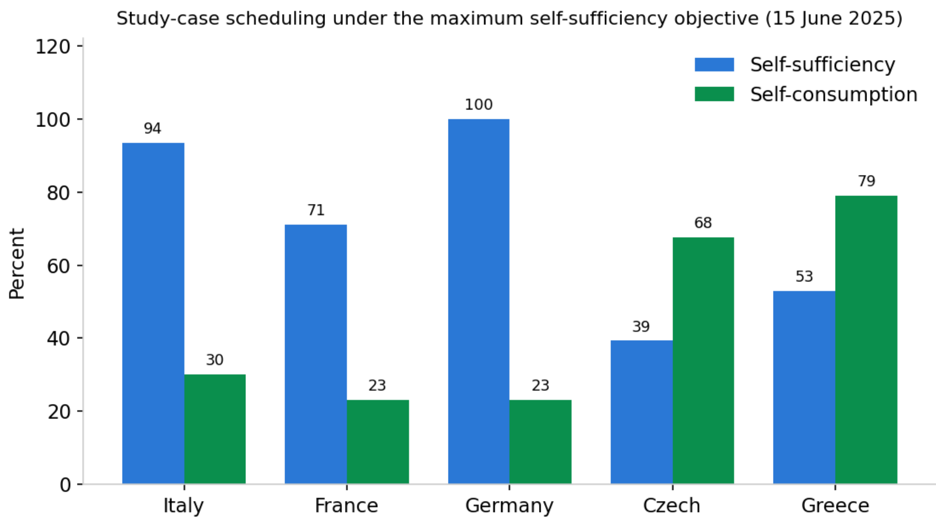

Figure 51 Study-case self-sufficiency and self-consumption for the five pilots under the maximum-self-sufficiency objective

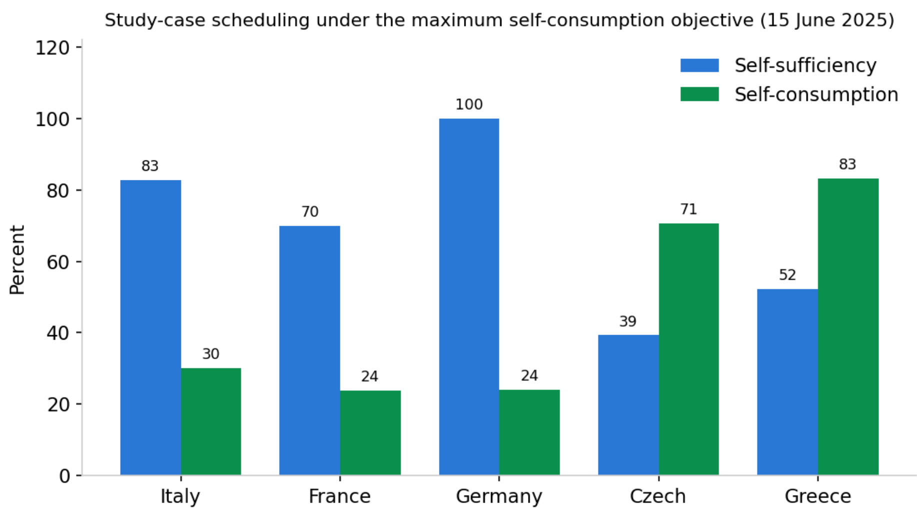

Figure 52 Study-case self-sufficiency and self-consumption for the five pilots under the maximum-self-consumption objective

5.2 Tariff regimes and their representation

The five pilots as we have modelled them, also span five distinct ways of valuing energy. Vlcnov operates under a flat koruna tariff with no intraday variation, so storage earns its value purely through self-consumption, by holding daytime generation to displace an expensive import, which is exactly why it is the one pilot where a battery improves the investment case. France and Greece use time-of-use day and night tariffs, which let the objectives separate once storage is present. Germany's study tariff includes negative overnight prices, where the community is paid to consume, and the optimiser exploits them by scheduling flexible demand and charging into those hours. Italy is a reward mechanism, the REC and CACER incentive, under which the shared-energy reward of 0.26 EUR per kWh can exceed the import price of 0.20 EUR per kWh, and the platform correctly flags the tariff inversion. These regimes are also the regulatory instruments through which each community is paid, and most are already in force or newly introduced, so the platform's what-if scenarios are grounded in a current, realistic setting. The platform represented all of them through the same general tariff handling, with no pilot-specific configuration, and the consistency checks held throughout, which is direct evidence that the scheduling and cost logic are agnostic to the tariff structure they are given.

5.3 Investment economics and socio-economics

Four of the five pilots carried a cost-benefit analysis, every one except Germany, whose expansion is demand-side and is not appraised by a CBA. Each was sized on the study community's demand and run from a no-generation baseline, so the analysis reflects a fresh community-scale investment on a common basis. Table 28 sets the adopted build of the four side by side.

Table 28 Cost-benefit results for the adopted build of the four investment pilots, on the common 20-year, 8 percent-discount-rate basis, with the exception of Czech Pilot Site at 7 percent. Germany is excluded, its expansion being demand-side rather than an investment

Pilot	Adopted build	NPV (k EUR)	BCR	Payback (yr)	IRR	Socio-economic NPV (k EUR)
Italy (RE1.1)	PV220 + 120 kWh	421.1	2.39	4.7	22.1%	485.7
France (RE2.2)	PV700, no battery	492.4	1.70	6.2	16.0%	532.8
Czech Republic (RE4.1)	PV90 + 60 kWh	120.2	2.11	5.7	18.0%	163.1
Greece (RE5.1)	PV150, no battery	129.7	1.86	5.8	17.4%	212.4

All four adopted builds return a positive net present value and a benefit-cost ratio above one, with paybacks between about five and six years and internal rates of return between 16 and 22 percent. The two larger, near-balanced communities, Italy and France, carry the highest absolute net present value, while the smaller demand-dominant communities, the Czech Republic and Greece, show the strongest benefit-cost ratios and returns on a modest, demand-sized build. In every case the adopted build is sized to the community's own demand growth, below the top-NPV candidate the sweep found, which would oversize the community toward net export. The clearest structural difference is in storage. It lowers the return in Italy, France and Greece and is kept for its operational value, while in the Czech Republic, under a flat tariff with a wide import-to-export spread, it raises the net present value and is adopted on its own merit.

Every investment the CBA scores carries two values. The financial NPV is the return to the community itself, the money it saves on its bills and earns from its surplus. The socio-economic NPV takes that same return and adds a value the community does not capture directly, the avoided cost of the carbon emissions its solar keeps out of the grid. The distance between the two is the worth of that avoided carbon.

How wide that distance opens depends almost entirely on the grid the community sits on, because solar mainly displaces electricity that would otherwise be drawn from the grid. On a grid that is already close to carbon-free, as in France at about 0.055 tonnes of CO2 per MWh, each kilowatt of solar avoids little emission, and the two values sit close together. On a carbon-intensive grid, as in Greece at about 0.45 tonnes per MWh, roughly eight times higher, the same solar avoids far more emission, and the socio-economic value stands well above the financial one. Figure 53 shows the two cases side by side, and in Greece the gap widens further as the community builds more solar, since every added kilowatt displaces more of a carbon-heavy grid.

What matters is how that gap behaves across the two grids. The same tool and method, given only each community's own grid data, produce a small social premium in one country and a large one in the other. This shows how much the socio-economic case, the argument a community makes for public funding on grounds of wider benefit, adds to its investment. On a near-carbon-free grid the project rests mainly on its private economics. On a carbon-intensive grid the social value can match or exceed the private return, which is where the socio-economic case carries the most weight.

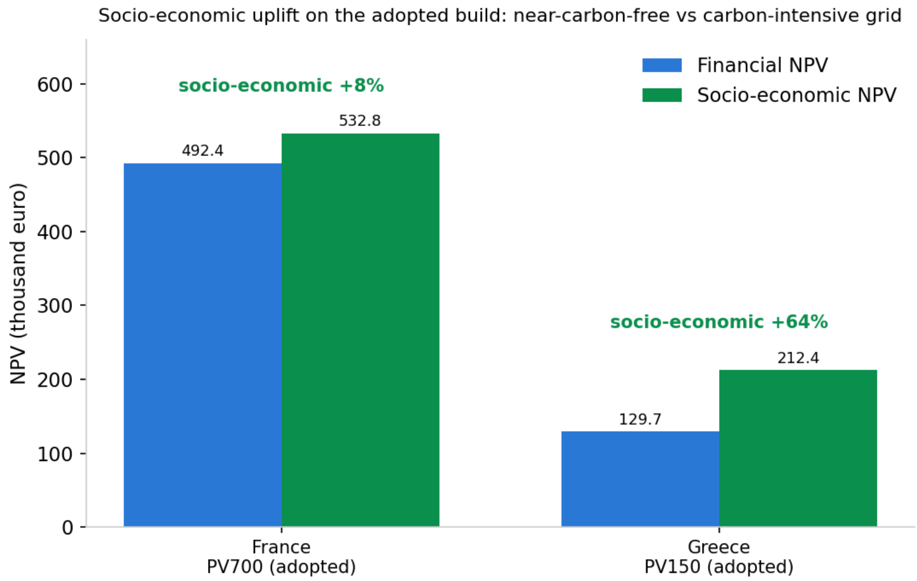

Figure 53 Financial and socio-economic NPV for the adopted PV candidate in France and in Greece. The socio-economic uplift is marginal on the near-carbon-free French grid and on the carbon-intensive Greek grid it is significantly bigger

5.4 Forecasting accuracy across the pilots

Across every pilot and tier the day-ahead forecasts, validated against the measured representative day of 15 June 2025, fall between about 0.9 and 5.2 percent MAPE at high confidence, which is planning-grade for scheduling. In addition, the French pilot's monthly validation over its twenty-nine real installations returned 7.2 percent MAPE with a SARIMA-family model, obtained directly on the community's generation. The one exception is the Czech real case, where the four-meter Vlcnov load forecast is flagged below high confidence, validating at about 18.5 percent against the measured representative day. The same community at thirteen-building study scale reaches 1.8 percent at high confidence, which locates the cause in community size and not in the tool, and the platform flagged the weaker forecast instead of presenting a spurious result. The per-pilot figures are reported in the dedicated studies.

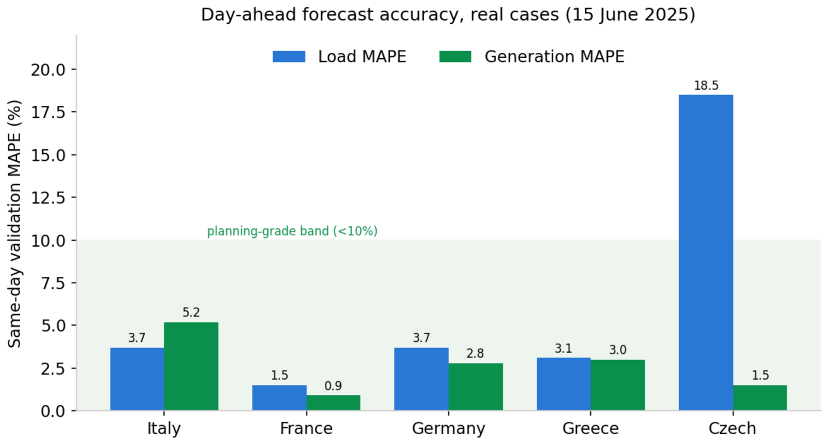

Figure 54 Day-ahead load and generation MAPE for the five real cases, validated against 15 June 2025, with the planning-grade band below 10 percent shaded. The Czech four-meter load forecast is the single case below high confidence, at 18.5 percent

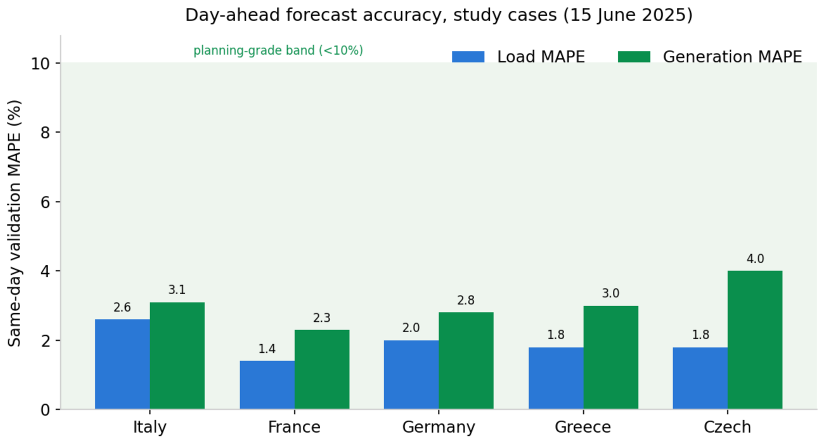

Figure 55 Day-ahead load and generation MAPE for the five study cases, validated against 15 June 2025. Every study-case forecast is high confidence and within the planning-grade band, including the Czech community once it reaches thirteen-building scale.

5.5 Platform portability and technology-agnostic design

Across the five studies the platform is portable between communities that differ in almost every dimension, and agnostic to the specifics of any one, which is what makes the reading it produced for each archetype a useful reference for communities of the same kind elsewhere.

The same setup, three tools and run protocol produced coherent, reproducible results in every setting without bespoke adaptation, and the consistency checks held across all of them, with a live re-run reproducing the stored cost-optimal scheduling KPIs, self-sufficiency, self-consumption and daily cost, to the decimal across all ten cases. In each pilot the platform surfaced the lever that governs that community's outcome, and it was different every time, the incentive inversion in Italy, the offtake of the hydro surplus in Germany, the low export price that leaves storage uneconomic in France, the grid carbon intensity in Greece, and the wide import-to-export price gap that makes storage pay in the Czech Republic. Each community was represented from the best evidence available for it, combining the datasets the pilots could supply with assets, conditions and settings attested through D6.3, the pilot leaders' records and the supporting literature, and with representative profiles built where measured data did not yet exist. Working from those inputs and each community's own regulatory setting, the ICT Platform produced results in every case, which is the practical meaning of portability and agnosticism.

6 Usability and adoption assessment

Validation shows the Platform produces coherent, reproducible results, but T2.3 also measures whether the communities can operate it themselves and derive actionable insight. This section reports the adoption and usability evidence gathered from the pilot partners, read honestly, including where it points to work that remains.

6.1 Method

The evidence was collected through a structured questionnaire circulated to the pilot partners after the final version of the ICT Platform was released, with eight responses returned from the ECOEMPOWER Consortium. The questionnaire combined five-point rated items, on the overall impression and the clarity of setup, scenario creation and the before-and-after view, with open questions on barriers, improvement priorities, objective preferences and hosting. The sample is small (eight responses), so the figures are indicative rather than statistically robust, but they come directly from the intended users and are consistent across communities.

6.2 Overall impression and clarity

The overall impression of the Platform was positive, at 4.1 out of five. The clarity ratings for individual workflow steps were lower and tell a coherent story: pilot setup 3.7, long-term what-if scenarios 3.8, and the before-and-after optimization view 3.5. The friction sits in getting a community started rather than in interpreting results once it is running, and the before-and-after view, where much of the community value is made visible, is the clearest candidate for improved presentation. The ratings are summarized in Table 29.

Table 29 Partner ratings of the third version of the Platform and of the clarity of the main workflow steps

Rated item	Mean (5-point scale)	Responses
Overall impression of the third version	4.1	8
Clarity of the pilot setup process	3.7	7
Clarity of creating long-term what-if scenarios	3.8	6
Clarity of the before-and-after optimization view	3.5	6

6.3 Barriers to independent use

The strongest and most consistent barrier, by some distance, is the absence of concrete datasets from the pilot partners themselves. Energy data often exist but are sporadic, aggregated, held in different formats and rarely continuous, and several partners were unsure they could supply even the six continuous months of measured data the Energy Forecasting Tool needs. One response stated directly that “we are just starting, and we don't get monthly bills.” This is the constraint that shaped the two-tier design and the use of indicative datasets, and it is the single most important adoption finding. A related gap is that the flexible assets the scheduling tool is built to dispatch, batteries, electric-vehicle chargers and heat pumps, are for most communities planned rather than active, so in several pilots the optimization currently operates over PV and load alone. Beyond data, partners named data-privacy constraints, the difficulty of extracting data from existing meters, the absence of standard formats, and a shortage of staff time, with municipal operators noting that Platform work competes with other duties.

6.4 Priorities for improvement

The improvement partners asked for most was local-language support, an interface and materials in their own languages rather than English only. That priority has since been met: the multilingual Help Centre described in Section 2 delivers the documentation in the five pilot languages alongside English, so the top request from this exercise is already addressed in the current Platform. The remaining priorities are documentation and training, meaning structured guidance on running the workflow from setup through to reading the CBA results, and hands-on support with onboarding and data acquisition, which follows directly from the data barrier above. As one response stated, “this software is super useful but still an EC needs somebody to take time and train themselves for using it properly.” Two concrete feature requests are worth recording: staged data submission, letting a community start a setup, save it and complete it later, and an indicator counting the quarter-hour periods in which self-sufficiency exceeds fifty, eighty and one hundred percent. On the optimization objectives, partners rated minimizing cost and maximizing self-consumption most important, consistent with the studies.

7 Deployment and sustainability

The validation was carried out on a working, deployed instance of the ICT Platform. This section sets out how the Platform is deployed today, how the REs reach it, and what arrangements are in place to keep it available after the project. Currently, there is a working central deployment every partner can use, an interim plan to keep it running, and a long-term sustainability decision that is still pending. When partners were asked how they would prefer the Platform to be hosted after the project, a plurality preferred continued central hosting through the ECOEMPOWER website and a smaller number preferred hosting by their own regional structures or OSSs, and that preference is the starting point for the arrangement below.

The Platform is deployed and operational as a single centrally hosted instance accessible to all partners at https://ecoempower-ict.euprojects.net. The Platform is not open to the general public. Access is managed through the regional leaders of each community, who can grant access to interested members on request. This keeps community energy and metering data restricted to the partners and members entitled to see it. In this instance every community setup, forecast, schedule and CBA in this deliverable was produced, so its readiness has been demonstrated by use rather than asserted. Reaching the Platform and operating it independently are different things, however, and how ready each RE is to drive it themselves tracks the data and capacity barriers of Section 6 far more than any technical limit of the deployment.

The existing central instance will keep running for a limited period of time beyond the end of the project until the final evaluation has been completed. The main limit is that extended central hosting carries a continuing responsibility to maintain, secure and fund the instance. The sustainability issue was largely debated during the project lifetime, but in the end regional ecosystems are not going to host locally the tools, as it would be a cost and it requires some level of technical commitment from the host organization, and also considering that the tool will not be updated after the project conclusions. The consortium is seeking new funding sources to support future adoption of the tool.

8 Conclusions and Next Steps

This deliverable closes WP2. Where D2.4 validated the three tools in isolation and D2.5 documented their redesign into a single, community-centric Platform, D2.6 applied the complete Platform end to end, to a real case and an expansion case study for each of the five pilot communities, under the consistency-check framework, and reported the results, the adoption feedback and the path to continued use. The outcome is a coherent and reproducible body of evidence: the tools reach planning-grade forecasting accuracy across the set, with a single, clearly bounded exception that the validation was designed to surface. The scheduling engines behave correctly across the full spread of community types, from generation-surplus to strongly demand-dominant. Each study yields a defensible investment case and specific, actionable recommendations, as T2.3 requires. The per-pilot figures behind these findings are given in the dedicated studies and the cross-pilot synthesis and are not restated here.

Against the T2.3 success criterion, the assessment is positive and appropriately qualified. Operability and actionable insight are met across all five pilots, including for communities that are not yet operative or are too small for dependable short-term load forecasting at their present size, where the two-tier design still allowed a full study to be produced. The criterion not yet settled is continuity: every community has an interim path through the shared central instance, but a confirmed per-Regional-Ecosystem hosting arrangement and a consortium-wide sustainability decision remain open. Continuity is therefore assessed as met on an interim basis, pending those decisions.

Looking ahead, the work list is partner-driven and follows from the adoption evidence. The most-requested improvement, local-language support, has already been delivered through the multilingual Help Centre added in this final cycle. In parallel, the consortium needs to turn the interim central-hosting arrangement into a settled model by taking the per-Regional-Ecosystem hosting and long-term sustainability decisions.

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LIST OF FIGURES

LIST OF TABLES