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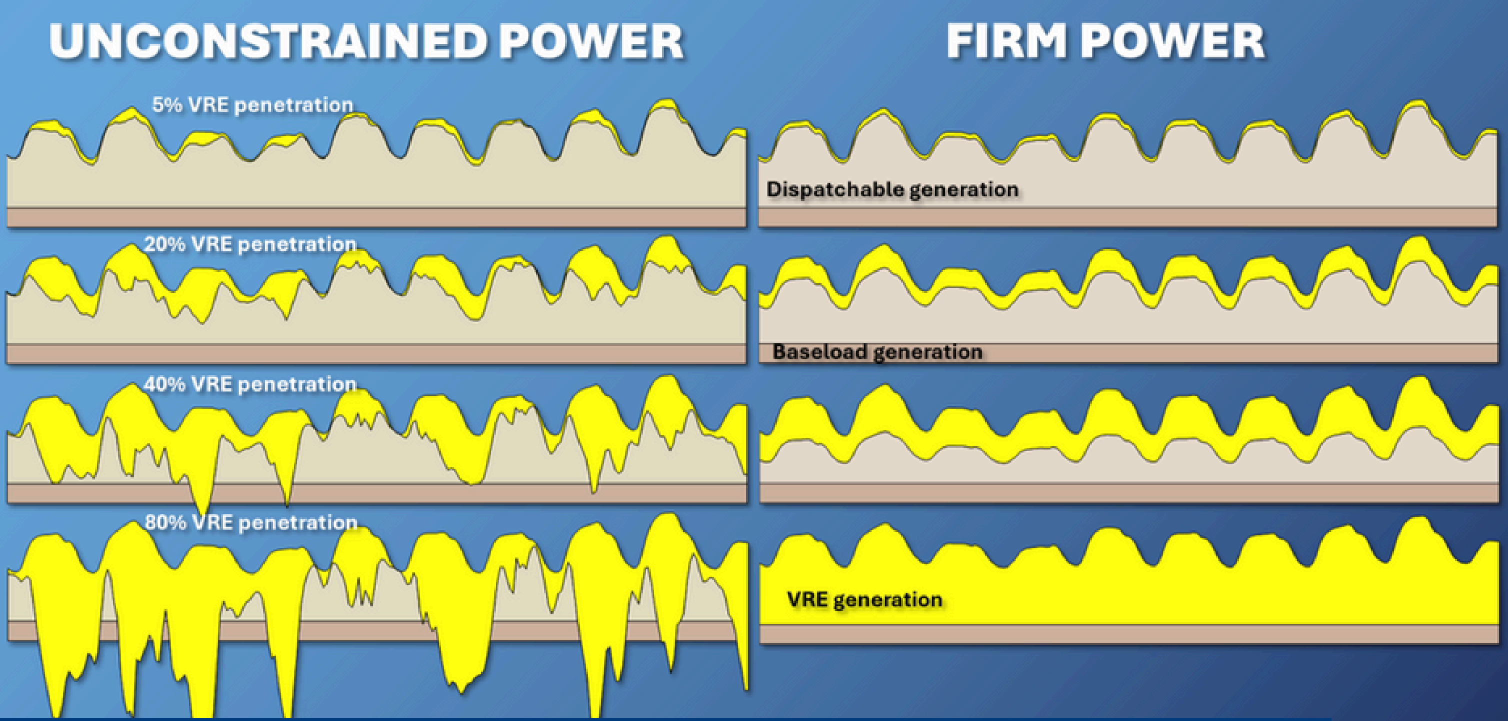
Photovoltaic Power Systems Programme



Task 16 Solar Resource for High Penetration and Large Scale Applications

PVPS

Firm Power Generation

2026

Report IEA-PVPS T16-07:2026

What is IEA PVPS TCP?

The International Energy Agency (IEA), founded in 1974, is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD). The Technology Collaboration Programme (TCP) was created with a belief that the future of energy security and sustainability starts with global collaboration. The programme is made up of 6.000 experts across government, academia, and industry dedicated to advancing common research and the application of specific energy technologies.

The IEA Photovoltaic Power Systems Programme (IEA PVPS) is one of the TCP's within the IEA and was established in 1993. The mission of the programme is to "enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems." In order to achieve this, the Programme's participants have undertaken a variety of joint research projects in PV power systems applications. The overall programme is headed by an Executive Committee, comprised of one delegate from each country or organisation member, which designates distinct 'Tasks,' that may be research projects or activity areas.

The IEA PVPS participating countries are Australia, Austria, Belgium, Canada, China, Denmark, Finland, France, Germany, India, Israel, Italy, Japan, Korea, Lithuania, Malaysia, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Turkey, the United Kingdom and the United States of America. The European Commission, Solar Power Europe and the Solar Energy Research Institute of Singapore are also members.

Visit us at: www.iea-pvps.org

What is IEA PVPS Task 16?

Task 16 provides access to comprehensive international studies and experiences with solar resources and forecasts. It supports different stakeholders from research, instrument manufacturers as well as private data providers and utilities.

Task 16 is a joint Task with the TCP Solar PACES (Task V). It collaborates also with the Solar Heating and Cooling (SHC) and with Wind Task 51.

The main goals of Task 16 are to lower barriers and costs of grid integration of PV and to lower planning and investment costs for PV by enhancing the quality of the forecasts and the resources assessments. Solar resources are introducing the highest share of uncertainty in yield assessments.

The work programme of Task 16 addresses from scientific meteorological and climatological issues to high penetration and large scale PV in electricity networks, and also includes a strong focus on user needs. Dissemination and user interaction is foreseen in many different ways from workshops and webinars to paper and reports and online code archives or Wikipedia.

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COVER PICTURE

Diagram of unconstrained vs firm power from Figure C1 of this report.

INTERNATIONAL ENERGY AGENCY

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

IEA PVPS Task 16
Solar Resource for High Penetration and Large Scale Applications

Firm Power Generation

Report IEA-PVPS T16-07:2026
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LIST OF ABBREVIATIONS

ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
BMS	Battery Management System
BU	Bottom-Up
CCS	Carbon Capture and Storage
CMM	satellite Cloud Motion Model
CONUS	Continental United States
DAFM	Day-Ahead Firm Market
DPV	Distributed Photovoltaic
DSM	Demand-Side Management
DSO	Distributed System Operator
EU	European Union
EV	Electric Vehicle
GHG	Greenhouse Gas
HRRR	High Resolution Rapid Refresh
IEA	International Energy Agency
IEA PVPS	IEA Power Systems Programme
IRES	International Renewable Energy Agency
JRA	Joint Research Activity
LCOE	Levelized Cost of Energy
LV	Low Voltage
MISO	Midcontinent Independent System Operator
NEM	National Electricity Market
NPE	Dutch National Energy System Plan
NPV	Net Present Value
NWP	Numerical Weather Prediction
OECD	Organization for Economic Cooperation and Development
OVS	Oversizing
PEIROCOM	Pan-European Intermittent Renewable Overbuilding & Curtailment Optimization Model
PER	Lazio Regional Energy Plan
PFM	Perfect Forecast Metric
PHS	Pumped Hydro Storage
PNRR	EU National Recovery and Resilience Plan
PV	Photovoltaic
REC	Residential Energy Communities
RES	Renewable Energy Sources
SA	SolarAnywhere
SP	Self-Production
SPIES	Smart Power & Internet Energy Systems
TCP	Technology Collaboration Programme

TMY	Typical Meteorological Year
TSO	Transmission System Operator
US	United States
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRM	Variable Renewable Market

EXECUTIVE SUMMARY

This report builds on the foundational *Firm Power Report* published in January 2023, presenting a consolidated overview of expert insights and technical progress in firm power generation—the capability of energy systems to reliably meet electricity demand 24/7, year-round.

Key Concepts and Strategies

Firm Power from Variable Renewable Energy (VRE): Wind and solar, despite their variability, can be engineered into firm power sources through strategic system design. The most cost-effective strategies include:

- **Optimal VRE Blending:** Combining wind and solar to better align with demand profiles.
- **Physical Storage:** Utilizing batteries, pumped hydro, or other technologies to store surplus energy for later use.
- **Overbuilding with Curtailment (i.e., Implicit Storage):** Installing excess VRE capacity and selectively curtailing output to reduce reliance on physical storage.
- **System Flexibility:** Adjusting demand or supplementing VREs with dispatchable generation (e.g., gas turbines operating on 100% renewable fuels).

Additional strategies include:

- **Geographic Dispersion:** Spreading VRE resources to mitigate weather and seasonal variability—balanced against transmission infrastructure needs and local resilience.
- **Hydrogen Integration:** Using curtailed energy for hydrogen production, which can be reinjected into the grid via, e.g., fuel cells.
- **VRE-Coincident Loads:** Developing new loads that match VRE output to consume otherwise curtailed energy.

Key Takeaways

This updated report incorporates over 25 expert contributions and reinforces the 2023 findings:

- Analyses of hourly supply–demand balancing across diverse regions find that fully renewable VRE systems can economically provide year-round electricity..
- VRE Overbuilding and curtailment are essential key drivers, showing that firm power can be supplied at low cost, even without seasonal storage or large cross-continental grid expansion
- Limited dispatchable thermal generation using e-fuels can lower overall system costs.
- Market reforms are crucial to unlocking the least-cost firm power configurations.

Expert Contributions

The report categorizes contributions into two main areas:

1. **Comprehensive Solutions:** Modeling fully renewable, economically optimized power systems at national, regional, and local scales. Case studies from China, Australia, Italy, Switzerland, Canada, and the EU demonstrate the reliability and viability of firm VRE-based grids.
2. **Transition Strategies & VRE Fundamentals:** Analyzing VRE variability and exploring interim solutions that leverage current market structures—such as enhancing forecast accuracy or introducing innovative market mechanisms compatible with existing regulations.

Conclusion

Firm renewable power is not only technically achievable but also economically competitive. Realizing this vision requires advanced modeling, strategic system design, and—most importantly—market reforms to support new configurations. These findings affirm the 2023 report and offer a clear roadmap for transitioning to resilient, fully renewable energy systems.

Optimal firm power configurations ─ particularly the amount of VRE overbuilding ─ depend on local resources, strategic assumptions, and system capabilities—such as access to low-cost supply-side flexibility or sector coupling. The studies presented span a range of scenarios, from *'tabula rasa'* models with VRE-only generation and new e-fuel flexibility, to configurations integrated into regional systems with existing flexible renewable generation or mature sector coupling options.

1 CENTRAL REPORT – FIRM POWER GENERATION

1.1 Firm Power Generation

The term refers to the ability of an energy source—or a combination of sources—to match supply and demand continuously and reliably, 24 hours a day, 365 days a year with a high degree of confidence. Wind and solar, as variable renewable energy (VRE) resources driven by weather conditions, are not firm by default. As their penetration grows, they present increasing challenges to grid reliability (see fig. C1 below). However, through targeted technologies and strategies, VREs can be effectively transformed into firm power sources and mitigate associated reliability concerns.

Firm power is defined in relation to meeting specific load requirements. These requirements may span a wide range, including the entire load of a regional grid, the variable part of the load above baseload (as illustrated in figure C1 below), substation-level loads, preset loads (e.g., constant baseload), etc. Firm power may also be defined in relation to the forecasted VRE output for specific time horizons (e.g., day-ahead forecasts), with the objective of effectively delivering perfect power forecasts.

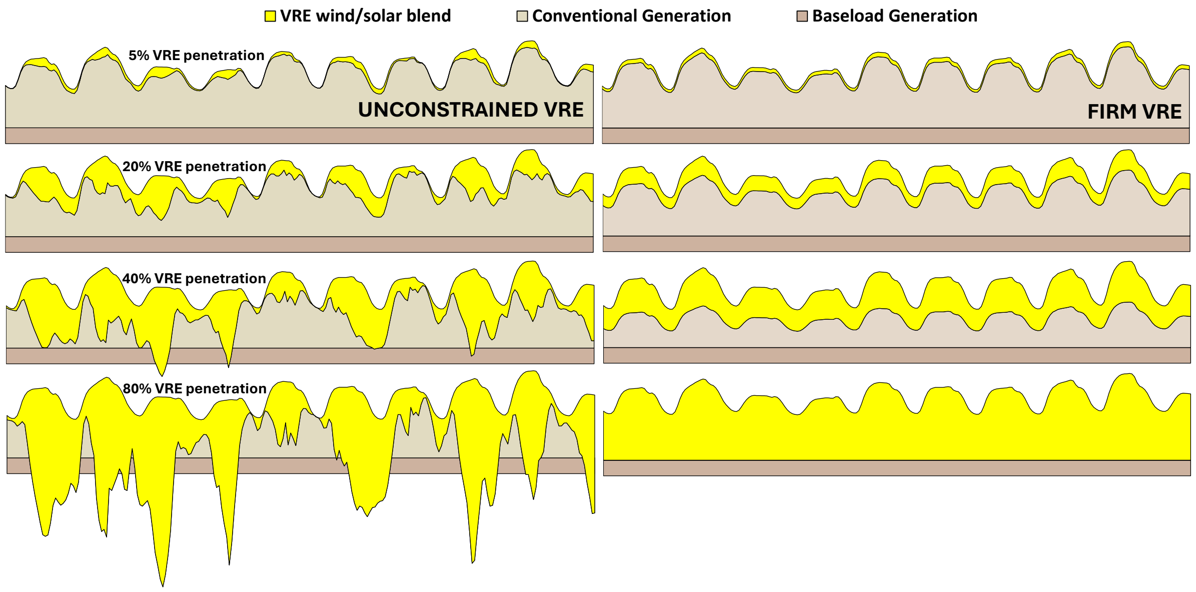


Figure C1: This figure compares the effects of unconstrained (i.e., "business-as-usual" deployment without additional strategies) versus firm variable renewable energy (VRE) generation on a given power grid's operation across several days. It assumes a grid with 20% baseload and 80% dispatchable generation with an equal mix of wind and solar (PV) gradually displacing conventional dispatchable generation.

Achieving firm power from variable resources in a cost-optimized manner involves key **core firm power strategies**:

- Optimal VRE Blending: Wind and solar can complement each other across seasonal and daily patterns, improving load matching when strategically combined.
- Physical Energy Storage: Technologies such as battery energy storage systems (BESS), or regionally available options like pumped hydro, store excess VRE and release it when output is low.
- Implicit Storage (Overbuilding + Curtailment): Overbuilding wind/solar capacity and allowing dynamic curtailment can substantially reduce the size of costly physical storage.
- System Flexibility: re-shaping the load seen by the VREs to reduce imbalances. This can be achieved on the demand side, with *demand-side management (DSM)* or on the supply side with *dispatchable generation* by adding adjustable sources like gas turbines, which could eventually operate on 100% renewable, zero-emission fuels such as e-fuels.

Other strategies such as the utilization of curtailed power (from implicit storage) to generate hydrogen and reinjecting it into the grid as a flexible resource (e.g., via fuel cells of via transformation into e-fuels), or geographic dispersion to reduce VREs' inherent meteorological and astronomical variability could also be considered.

For any given firm VRE power objective, an optimal blend of the above strategies ─ yielding the lowest possible levelized cost of firm electricity generation (Firm LCOE) ─ can be determined. This optimum configuration depends on the temporal characteristics of the load and the VREs, and on the specs, capital and operating expenses (CapEx and OpEx) of the considered VREs, storage, dispatchable generation and demand side flexibility strategies. Several models capable of scanning the solution space to converge on the lowest cost solution have been developed and implemented by the contributors of this report.

1.2 Takeaways from the 2023 Report

The investigations undertaken in our initial phase [1] suggested the following assertions:

- 100% RE power grids should be economically viable almost anywhere on the planet.
- Overbuilding and curtailing VREs (aka implicit storage) is critical in achieving this objective.
- Seasonal storage and large-scale grid build-up are not indispensable.
- A small amount of e-fuel-powered thermal generation, albeit inherently very expensive, is an effective catalyst to achieving the lowest overall firm power LCOE.
- Most importantly, new market rules facilitating the deployment and operation of least-cost firm power configurations must be crafted and implemented, because the current rules (e.g., power purchase agreements, merit order markets) cannot foster these solutions.

This initial work was also influential in shaping some of the objectives of a new IEA PVPS Task, Task 19, in particular its Joint Research Activity (JRA) #24 titled *Understanding Firm Power in a National Level* (https://iea-pvps.org/research-tasks/pv-integration/).

1.3 Experts' contributions

Contributions are regrouped in two broad categories:

- Contributions focusing on firm power generation to meet [multi] national, regional local loads, or predefined loads such as baseloads. These studies identify "endgame" configurations showing what fully renewable and economically optimized energy systems could look like going forward.
- Studies addressing other aspects of firm power, in particular: (1) studies focused on the transition evolving from the current paradigm with its existing market rules/regulations towards larger scale applicability, (2) studies addressing firm power forecasts as an entry step to large scale firm power, (3) studies focusing on distribution systems, and (4) studies addressing fundamentals of VRE intermittency and their impact on firm power generation.

These new contributions confirm/reinforce the assertions from the 2023 report through comprehensive case studies. They are listed in table C-1 below, including their main focus, regional context, considered time frame and technologies, and briefly outlined thereafter.

Table C-1 – Experts' contributions to the report

Contribution	Focus	Geographic Region	Time period	Technologies
Firm PV Power Gen: Overview and Economic Outlook	Firm Power Generation	Multiple	Current and Future (2050)	PV, wind, BESS, Hydro, e-fuel, import/exports
Firm Wind & Solar Power in Nova Scotia with Fully Electrified Grid	Firm Power Generation	Nova Scotia, Canada	Future (2050)	PV, wind, BESS, Hydro, e-fuel, import/exports
Flexible PV for Renewable Integration in Lazio, Italy	Firm Power Generation	Lazio Region, Italy	Future (2050)	PV, BESS
PV/BESS Strategy for Rome Technopole	Firm Power Generation	Single site in Rome, Italy	Current and Future	PV, BESS
Infinity: A Small-Scale Prototype for Firm PV Generation	Firm Power Generation Demo	Single site in Rome, Italy	current	PV, BESS
Firm PV in Switzerland: 2023 Updates & Strategic Implications	Firm Power Generation	Switzerland	Current and Future (2050)	PV, wind, BESS, Hydro, e-fuel, import/exports, nuclear
Firming 100% VREs — Costs & Opportunities in Australia's Grid	Firm Power Generation	Australia	Current and Future (2030)	PV, wind, BESS, Hydro
Localized, Cost-Effective Firm Power w/o Major Grid Expansion	Firm Power Generation	Continental USA	Future (2050)	PV, wind, BESS, e-fuel
Impact of Price Trends & Resource Uncertainty on Firm Solar Delivery	Firm Power Generation	Northern China	Current & Future	PV, BESS
PV Overbuilding and Curtailment for Cost Reduction	Firm Power Generation	Northern China	Current & Future	PV, BESS
Hydrogen Production from Curtailed Firm PV Electricity	Firm Power Generation	Northern China	Current	PV, BESS, Hydrogen
Optimized Hydrogen Production Using Curtailed Firm VRE	Firm Power Generation	Northern China	Current	PV, BESS, Hydrogen
PV Overbuilding with Pumped Hydro Storage in Northern China	Firm Power Generation	Northern China	Current	PV, BESS, PHS

Firm Power Modeling for the Iberian Peninsula	Firm Power Generation	Portugal, Spain	Future (2050)	PV, Wind, BESS, Hydro, PHS, Biomass, H2, CCGT
Electricity Mix & Market Dynamics in 2035 CO2-free Electricity System	Firm Power Generation	The Netherlands	Future (2035)	PV, wind, BESS, H2 export & storage, demand response
Firm wind and PV with proactive curtailment: A European analysis	Firm Power Generation	Europe	Current	PV, Wind, BESS, H2, Demand Response
Using PV Forecasts to Lower Firm Gen Costs & Improve Supply Certainty	Forecast & firm power	Italy	Current	PV, wind BESS
Ancillary Services from Flexible PV/Wind Systems and Implicit Storage	Forecast, Ancil. Services	Italy	Future (2030/40)	PV, wind, dispatchable gen
Enabling Fully Solar Renewable Energy Communities	Partially firm power gen	Northern Italian Communities	Current	PV, BESS
Feasibility of Fully Solar Residential Energy Communities (REC) in Italy	Local self-sufficiency	Italy	Current	PV, BESS
Firm & dispatchable PV/Wind through generation and markets splitting	Firm Power transition	Italy	Current to future (2050)	PPV, Wind, BESS
Reducing Grid Impact of Distributed Solar via VPP-Based Firm PV Strategy	Distribution level Firm Power	Italy	Current	PV, BESS
Maximizing DPV Hosting Capacity with Regional Firm VRE Generation	Distribution level Firm Power	Louisiana, Iowa, USA	Future (2050)	PV, Wind, BESS, e-fuel gen
Complementary Variability of Solar and Wind Resources	VRE resource Fundamentals	USA	N/A	PV, Wind
Dispatchable Solar Power via Hierarchical Forecast Reconciliation	Firm Power Forecasts	China	Current	PV, BESS
Firm Solar Forecasting with PV Overbuilding and Battery Storage	Firm Power Forecasts	China	Current	PV, BESS
The Perfect Forecast Metric (PFM)	Firm Power Forecasts	Arbitrary	User-selectable	PV, BESS
Dark Doldrums: Estimating Successive Days of Low VRE Output	VRE resource Fundamentals	Australia, Denmark	N/A	PV, Wind

Contributions from the first category (firm power generation) include:

- **Firm Photovoltaic Power Generation: Overview and Economic Outlook**
  Remund et al., 2023
  Presents a structured economic interpretation of key findings from the 2023 report, identifying shortcomings in current market rules and proposing alternative frameworks.
- **Firm Wind & Solar Power in Nova Scotia with Fully Electrified Building & Transportation Sectors**
  Perez et al., 2025
  A two-phase analysis of Nova Scotia's grid shows that a mix of 67% wind, 23% solar PV, 5% e-fuels, and 5% existing hydro can deliver 100% renewable electricity at $45/MWh in 2050 —even with an 80% increase in demand from full electrification of buildings and transport.
- **Flexible PV Systems for Renewable Integration in Lazio, Italy**
  Bovesecchi et al., 2025
  Evaluates firm PV with battery storage across Lazio's 17,000 km² region, demonstrating

a reliable supply of 90% of electricity demand at $91/MWh using just 13% of suitable solar land.

- **PV/BESS Strategy for Rome Technopole**
  Andreozzi et al., 2024
  Assesses the feasibility of a localized firm PV/BESS system for the Rome Technopole. Under 2024 cost assumptions, an optimized setup could profitably meet 65% of energy demand. The analysis also explores land use and future cost trends.
- **Infinity: A Small-Scale Prototype for Firm PV Generation**
  Andreozzi et al., 2025
  Prototypes and tests firm solar generation using overbuilding and minimal storage. The system dynamically manages power flows and simulates curtailment, with early results confirming reliable performance under variable weather—supporting future scalability.
- **Firm PV in Switzerland: 2023 Updates and Strategic Implications**
  Remund et al., 2024
  Updates the 2022 Swiss firm power study detailed in the 2023 firm power report, validating high-renewable viability for 2050 net-zero goals. Across nine scenarios, LCOE remains stable (6.8–8.6 ¢/kWh). Key strategies include PV overbuilding with 10–30% curtailment and ~5% firm sources to reduce winter costs. Policy reform is identified as the main barrier.
- **Firming 100% Renewable Power: Costs and Opportunities in Australia's National Electricity Market**
  Rey Costa et al., 2023
  Analyzes 11 years of time-synchronized load and resource data, showing that oversized wind/solar with hydro or battery storage can reliably supply Australia's electricity at competitive costs. Regional curtailment mapping highlights optimal zones for new development.
- **Localized, Cost-Effective Firm Renewable Power Without Major Grid Expansion**
  Perez et al., 2025
  Applies high-resolution U.S. data to model firm PV/wind systems (including limited clean thermoelectric backup) as a function of the VRE generation footprint. Demonstrates cost-effectiveness within areas under 50,000 km².
- **Impact of Price Trends and Resource Uncertainty on Firm Solar Delivery**
  Yang et al., 2023
  Applies advanced optimization techniques to design cost-effective PV–battery systems. Shows that PV overbuilding reduces costs and battery size, with future cost declines potentially enabling grid parity. The design of the firm system must rely on decade-long data rather than the typical meteorological year data.
- **PV Overbuilding and Curtailment for Cost Reduction**
  Yang et al., 2022
  A simplified companion to the above 2023 study, emphasizing the role of overbuilding in significantly lowering firm power costs.
- **Hydrogen Production from Curtailed Firm PV Electricity**
  Yang et al., 2024
  Integrates curtailed energy use into firm PV/BESS modeling for hydrogen production. Optimized component design reduces overall firm power costs. The additional hydrogen system configuration lowers the curtailment rate and the firm LCOE.

- **Optimized Hydrogen Production Using Curtailed Firm Renewable Energy**
  Yang et al., 2025
  Compares joint vs. separate optimization of firm power and hydrogen production. Joint optimization lowers firm power system costs by 18.4%, with curtailed energy acting as implicit demand-response to enhance flexibility and improve economics.
- **PV Overbuilding with Pumped Hydro Storage in Northern China**
  Gao et al., 2025
  Models a firm PV–Pumped Hydro storage system for city-level demand. Overbuilding reduces firm LCOE by 53.3%, and PHS outperforms batteries with 140% cost advantage.
- **Firm Power Modeling for the Iberian Peninsula**
  Crespo et al., 2025 (work in progress)
  Preliminary modeling under 2050 decarbonization goals finds lowest cost (58 €/MWh) with 156 GW VRE, 6% curtailment, and existing hydro/gas. Without hydro/gas, BESS and curtailment needs rise sharply – importantly hydrogen is found not to be included in the economically optimal firm power configuration..
- **Electricity Mix and Market Dynamics in 2035 CO2-free Electricity System**
  Berkhout et al., 2024
  This study explores a CO_2-free Dutch electricity system by 2035 under the National Energy Plan. Using system optimization and market simulation, it finds that overbuilt renewables can technically deliver firm power with storage and flexibility. However, current market structures fail to support viable business cases for firm capacity. Policy and market reforms are urgently needed to enable investment in renewables, storage, and grid infrastructure.
- **Firm wind and solar photovoltaic power with proactive curtailment: A European analysis**
  van Eldik & van Sark, 2025
  This study evaluates how intermittent renewables can deliver firm power for Europe. Using the PEIROCOM model, we assess cost impacts of overbuilding solar, wind, and integrating storage, hydrogen, and demand response. Results show that strategic overbuilding and green hydrogen for seasonal storage minimize costs and ensure grid stability, enabling near-total reliance on Intermittent Renewable Energy Sources (IRES, aka VREs).

Expert contributions from the second category (other aspects of firm power) include:

- **Using PV Forecasting to Lower Firm Power Costs and Improve Supply Certainty**
  Pierro et al., 2025 (work in progress)
  Explores how accurate forecasting can refine baseload expectations in PV/wind/BESS systems. By aligning firm power commitments with system flexibility, forecasting reduces curtailment, oversizing, and overall costs—while enhancing supply reliability.
- **Ancillary Services from Flexible PV/Wind Systems and Implicit Storage**
  Pierro et al., 2022
  Proposes two alternatives to thermoelectric reserves for balancing Italy's grid: ancillary services from flexible PV/wind fleets and under-forecasting with proactive curtailment. Combined with grid upgrades, these strategies could reduce imbalances by 20–50% zonally and 27–80% nationally by 2030/2040, at costs comparable to thermal solutions.

- **Enabling Fully Solar Renewable Energy Communities**
  Pierro et al., 2024
  Demonstrates that Renewable Energy Communities can be economically powered by flexible PV/battery systems using "generation splitting," where firmed output meets local demand and excess variable energy is sold to the grid.
- **Feasibility of Fully Solar Residential Energy Communities (REC) in Italy**
  Pierro et al., 2025
  Presents a techno-economic analysis of Italy's REC incentive system and proposes a business model to promote residential PV and BESS adoption. By overbuilding PV to roughly three times annual demand and using centralized storage, RECs can achieve up to 98% energy self-sufficiency.
- **Firm and dispatchable solar/wind supply through generation and markets splitting**
  Pierro et al., 2025
  Introduces a dual-market design—Variable Renewable Market (VRM) and Day-Ahead Firm Market (DAFM)—to support dispatchable solar and wind generation. With firm feed-in tariffs below 100 €/MWh, producers are incentivized to prioritize firm output. By 2050, nearly all variable renewable generation could be economically firmed.
- **Reducing Grid Impact of Distributed Solar via VPP-Based Firm PV Strategy**
  Pierro et al., 2025
  Addresses grid congestion from distributed solar by placing batteries with grid-forming inverters at substations, managed by smart controls. Simulations using monitored data from DSO-controlled area in Italy show a 96% reduction in reverse power flows and improved voltage stability, enabling greater local solar use without stressing the transmission grid.
- **Maximizing DPV Hosting Capacity with Regional Firm VRE Generation**
  Perez et al., 2024
  Examines how aligning distributed PV operations with regional firm VRE generation can expand hosting capacity. Using 20 years of hourly data across two Central U.S. case studies, the approach significantly increases DPV hosting potential.
- **Complementary Variability of Solar and Wind Resources**
  Perez et al., 2025
  Analyzes hourly data across the U.S. to compare variability in solar and wind generation. Solar shows greater sub-daily variability, while wind variability dominates at longer timescales. Spatial averaging reduces wind variability more effectively, offering key insights for designing resilient firm renewable systems.
- **Dispatchable Solar Power via Hierarchical Forecast Reconciliation**
  Yang et al., 2024
  Improves PV forecast reliability by combining hierarchical reconciliation across multiple nodes with firm system configurations (PV overbuilding + BESS). Case studies in California show that the firm LCOE at the nodal level is smaller than that at the plant level.
- **Firm Solar Forecasting with PV Overbuilding and Battery Storage**
  Gao & Yang, 2024
  Proposes a forecasting framework using PV overbuilding and battery storage to eliminate errors. In a 1 MW PV plant case study in Hehe, China, a 1.12 oversizing ratio and 2.61 MWh battery achieved firm forecasting—29% lower than a battery-only setup.

- **[The Perfect Forecast Metric (PFM)]**
  Perez et al., 2025
  Introduces PFM as an economically relevant alternative to standard forecast error metrics like MBE and RMSE. It calculates the cost to perfectly match actual output using a firm power gen model and combining optimal costs from storage and overbuilding, then normalizing by expected revenue.
- **[Dark Doldrums: Estimating Successive Days of Low VRE Output]**
  Boland, 2025
  Uses synthetic data to assess risks from extended low-output periods in high-VRE regions like South Australia and Denmark. Findings show these “Dark Doldrums” mostly occur in spring, when demand is low.

2 TECHNICAL REPORT – STUDIES FOCUSING ON FIRM POWER GENERATION FOR NATIONAL REGIONAL OR DEFINED LOADS

2.1 Firm photovoltaic power generation: Overview and economic outlook

Jan Remund, Richard Perez, Marc Perez, Marco Pierro, Dazhi Yang. Solar RRL, September 2023. [2]

https://doi.org/10.1002/solr.202300497

This Solar RRL article offers a structured economic interpretation of key findings from the 2023 IEA PVPS Task 16 report. It explores how variable renewable energy (VRE) sources—primarily solar and wind—can be transformed into firm power: electricity that is reliably available 24 hours a day, 365 days a year.

To achieve this transformation, the authors propose a strategy built on five core pillars:

- Overbuilding VRE capacity
- Proactive curtailment (used as implicit storage)
- Energy storage
- Geographic dispersion
- Load flexibility

The central insight is that curtailment is not a loss, but a strategic and cost-effective tool for enabling firm power. Through detailed case studies—including Minnesota, MISO, Switzerland, Italy, La Réunion, China, and Europe—the article demonstrates that nearly 100% renewable grids could not only be technically feasible but economically viable when VRE systems are optimally configured.

The article also highlights current power market misalignment, and the need for reform.

Indeed, despite the promise of firm VRE systems, current energy markets are poorly suited to support their deployment. Today's market structures:

- Were built around fuel-based generators, where marginal production cost drives dispatch — so they naturally reward energy output rather than firm capacity or reliability.
- Tend to treat PV, wind, storage, and flexible demand as separate resources instead of an integrated reliability system.
- Also discourage curtailment, even though a modest level of curtailment is essential for achieving the lowest-cost renewable mix.
- Together, these features keep renewables in a marginal role and add unnecessary cost and complexity to the energy transition.

To address these challenges, the article introduces a forward-looking market framework centered on capacity-based remuneration and integrated resource valuation. It envisions a system where Virtual Power Plant (VPP) aggregators play a key role in designing and operating optimal firm power configurations.

This framework would enable seamless, scalable, and cost-effective integration of VRE resources—supporting deployment levels approaching 100%.

The key elements of the proposed market design include:

- Remunerate installed capacity that contributes to firm power, rather than energy output alone
- Value resource ensembles (e.g., PV + wind + storage + flexible resources) as coordinated systems
- Empower grid operators to manage curtailment and dispatch signals for optimal system performance
- Establish parallel capacity markets for VREs, distinct from the traditional energy markets where conventional GHG-emitting resources would keep operating until they are fully displaced.

This reimagined market structure aligns economic incentives with the physical realities of renewable energy, paving the way for a resilient, low-cost, and fully renewable power grid.

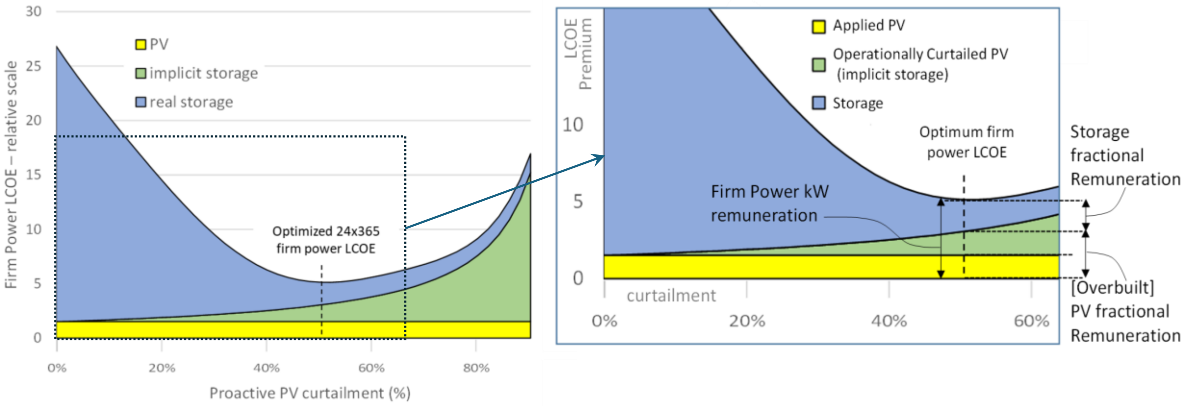


Figure 1: Cost Optimization and Remuneration Strategy for Firm Photovoltaic Power Generation — Left panel shows how proactive curtailment minimizes LCOE; right panel illustrates a possible capacity-based remuneration model for PV and storage [note: a similar proportional revenue distribution strategy could be applied for firm power configurations including wind and flexibility in addition to PV and storage]

2.2 Firm wind & solar power generation in Nova Scotia with fully electrified transportation & building sectors

Marc Perez, Richard Perez, Christopher McNevin, Reda Djebbar, Ryan Kilpatrick, Laura Whelan [3a, 3b]

Final Report, Natural Resources Canada Contract # 300078796 — March 2025

This report examines the feasibility and cost-effectiveness of firm renewable power generation in Nova Scotia under a 100% renewable power generation scenario, considering future (2050) full electrification of buildings and transportation. The analysis builds upon Phase 1 findings and incorporates additional factors such as thermal storage deployment, heat pump penetration ratio, battery cost forecasts, offshore wind viability, inter-provincial power trade, hydrogen generation or EV load management strategies.

Key findings include:

- The electrification of buildings and transportation sectors will increase the 2050 provincial electrical energy demand to 20 TWh/year (+80% relative to 2019), with a peak demand reaching 3.7 GW (+87% relative to 2019).
- Retaining Phase 1 financial and performance specifications for the considered storage and renewable technologies — PV, wind and e-fuel — the optimal power generation mix capable of firmly meeting demand 24/365 at the lowest possible cost consists of 4.23 GW of PV, 5.24 GW of onshore wind, and 2.55 GW of e-fuel thermal generation, supported by 4.65 GW of batteries with 4.75 hours of energy capacity. This optimum configuration results in a firm power levelized cost of electricity (LCOE) of 6.29 C¢/kWh for the province. This compares favorably to the current fuel-based power generation cost on the Nova Scotia power grid at 10+ C¢/kWh.

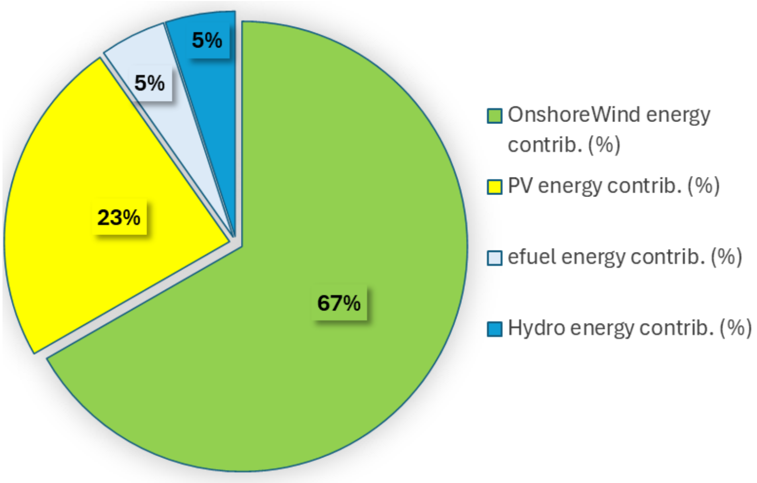


Figure 2: Energy contribution from each generating resource – including a small must-run, i.e., non-firm hydropower component — amounts to respectively 23% for PV, 67% for onshore wind, and 5% each for dispatchable e-fuel generation and must-run hydro.

- Increasing heat pump adoption to 75% of the provincial building stock from a base case assumption of 50% heat pumps and 50% baseboards can reduce winter peak demand by 10%, and annual electrical energy demand by 5% while slightly increasing the optimum proportion of PV (27%) relative to wind (63%).
- Managing intraday electric vehicle (EV) charging fluctuations (amounting to ~ 700 MW daily ramps) from the [firm renewable power] supply-side rather than from the demand side slightly raises the provincial LCOE to 6.44 C¢/kWh without any significant impact on the optimum generation blend. Further considering that some of the generation assets (PVs and batteries) could be deployed on distribution circuits, the case can be made that a regional 100% renewable power generation strategy could also resolve future EV and PV hosting capacity issues on these circuits.
- Allowing interprovincial power trade within existing allowances reduces firm power LCOE to 5.06 C¢/kWh by leveraging cheaper flexible imports (displacing expensive dispatchable e-fuel generation) and monetizing excess variable renewable energy (VRE) output. However, this solution may not be sustainable in the long term if neighboring provinces adopt similar firm VRE power solutions.

- Higher battery storage cost estimates from NREL’s 2023 Annual Technology Baseline (ATB) ─ a ~100% increase over base case assumptions from the 2020 ATB ─ increase LCOE by only 13% as the cost impact can be largely mitigated by increased reliance on implicit storage (i.e., VRE curtailment).
- Thermal storage, while cost-effective for heating loads, only slightly reduces overall firm power LCOE unless battery cost assumptions are sensibly higher (as would be the case for user-sited batteries).
- Offshore wind, even with improved capacity factors from higher (150 meter) turbines, remains costlier than onshore wind, requiring at least a 55% cost reduction to be competitive.
- The utilization of essentially free, but highly variable curtailed VRE electricity to produce hydrogen can only be marginally market competitive if electrolyzer capacity is limited to capture only a third of the available free energy. Increasing implicit storage (VRE curtailments) beyond firm power generation optimum can lower hydrogen costs but slightly raise firm power costs.

2.3 Flexible photovoltaic systems for renewable energy integration in Lazio region, Italy

Gianluigi Bovesecchi, Marco Pierro, Marcello Petitta, Cristina Cornaro, Energy Reports, 2024. [4]

https://doi.org/10.1016/j.egyr.2024.07.029

In line with Italy’s and the European Union's energy transition goals, this study investigates the feasibility and cost-effectiveness of deploying flexible photovoltaic (PV) systems integrated with battery energy storage systems (BESS) in the Lazio region. The aim is to achieve up to 90% self-production of electricity from PV alone, and eventually 100% from renewables by 2050 as set by the Lazio Regional Energy Plan (PER). The concept of "firm PV"—achieving continuous 24/365 operation through optimized overbuilding and proactive curtailment—is central to this strategy.

An optimization model based on brute-force search was used to evaluate combinations of PV oversizing (OVS) and battery capacity (expressed as number of days of autonomy, NDY) needed to meet different levels of self-production (SP), from 50% to 98%. The simulations used real meteorological and demand data from 2017–2019 and included dynamic modeling of system behavior and levelized cost of energy (LCOE) computation. Scenarios considered different cost projections for 2023 to 2050 and included the optional import of wind power from Southern Italy to supplement PV production (Figure 3).

The simulation results demonstrate that achieving 90% electricity self-production in the Lazio region using only photovoltaic and battery systems is technically feasible and economically viable by 2050. This target can be reached by installing approximately 34.73 GW of photovoltaic capacity coupled with 42.34 GWh of battery storage, resulting in a levelized cost of energy (LCOE) of 92.21 €/MWh under future cost projections (Figure 4). The study reveals that increasing photovoltaic capacity beyond demand (i.e., oversizing) significantly reduces the required storage capacity: to reach 98% self-production, the system must be oversized to generate nearly five times the annual demand, which in turn allows storage requirements to be minimized to just one day of autonomy. This strategy proves more cost-effective than relying on seasonal storage, which would otherwise remain largely underutilized.

When evaluating the import of wind energy from Southern Italy as a supplementary resource, the simulations show that integrating 25% to 50% of wind power can reduce both photovoltaic and battery capacity needs by up to 13%, albeit at a slightly higher LCOE due to market purchase prices. Despite the marginal cost increase, these scenarios offer operational flexibility and reduce the infrastructure burden.

Furthermore, the study confirms that the land requirement for such an ambitious energy transition is well within regional availability. For example, by exploiting just 13% of the potential 8000 km² of land suitable for agrivoltaic deployment, the necessary PV capacity could be installed without significant land-use conflict, offering a dual-use model that preserves agricultural productivity.

The study confirms that overbuilt PV combined with daily-scale storage and dynamic curtailment strategies can provide economically viable, firm renewable electricity at the regional scale. The approach also addresses seasonal demand variability without requiring prohibitively large seasonal storage. However, challenges such as BESS cost, network upgrades, and integration of complementary renewables like wind remain. Agrivoltaics and stakeholder engagement are also highlighted as enabling factors for widespread deployment.

Flexible PV systems are a viable pathway for achieving high levels of renewable energy penetration in Lazio, with a clear economic strategy and scalable technical model.

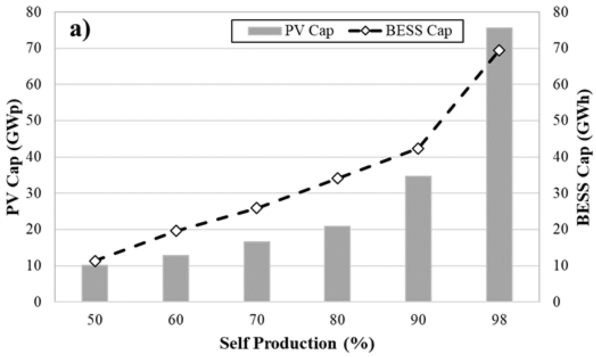


Figure 3 - Simulation results for the PV case as a function of self-production, a) PV and BESS capacity

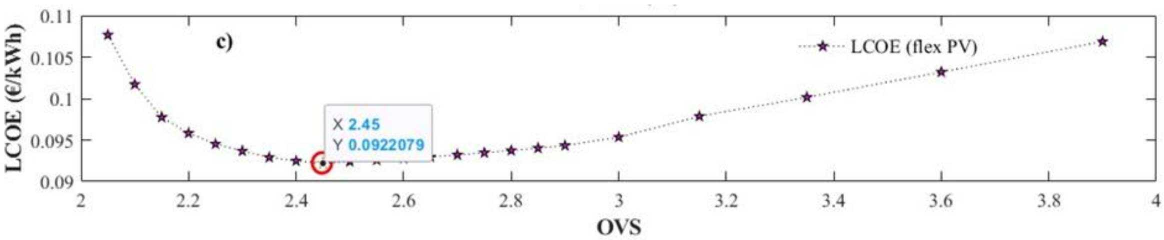


Figure 4 - Simulation results for SP = 90% showing trends of LCOE as a function of oversize.

Reference:

G. Bovesecchi, M. Pierro, M. Petitta, C. Cornaro, (2024), “Flexible Photovoltaic Generation Applied to Lazio Region (Italy), a Case Study”, Energy Reports, https://doi.org/10.1016/j.egyr.2024.07.029

2.4 Flexible photovoltaic generation strategy for Rome Technopole

Gianluigi Bovesecchi, Federico Andreozzi, Marcello Petitta, Marco Pierro, Richard Perez and Cristina Cornaro, 2025 [5]

Energy Conversion and Management: X, 27, art. no. 101204 DOI: 10.1016/j.ecmx.2025.101204

In the framework of the NextGenerationEU initiative and the National Recovery and Resilience Plan (PNRR), the Italian Ministry of University and Research has funded the creation of twelve "Innovation Ecosystems" across the country. One of these is the Rome Technopole, focused on three thematic areas: Energy Transition, Digital Transition, and Health and Bio-Pharma. Among the funded projects is RES4TECH (100% Renewable for Rome Technopole), which aims to develop a strategy to meet the electricity demand of the future Rome Technopole campus using flexible photovoltaic (PV) systems.

Flexible PV systems integrate photovoltaic panels with battery energy storage systems (BESS), smart inverters, and remote-control functionalities that enable proactive curtailment of electricity generation. Remote control allows system output to be adjusted in real time to follow both the expected generation profile (perfect forecast) and the demand profile, enabling reliable 24/365 solar power generation.

Since the Rome Technopole project is scheduled for completion by 2030, the electrical load profile was modeled using historical consumption data from the Faculty of Engineering at the University of Rome Tor Vergata, covering the period 2013–2021. Solar radiation and climate data were provided by EsterLab at the same university. These inputs were used to construct a physical model for simulating PV generation with various tilt angles; a south-facing orientation with a 30° tilt was identified as optimal for the simulations.

An optimization process was developed to match the electric load using flexible PV systems, identifying the optimal trade-off between battery capacity and PV size to minimize production costs. Preliminary results show that, by oversizing the PV system relative to annual electricity demand and incorporating battery storage, up to 100% of the campus electricity demand can be met (corresponding to a configuration of 9.75 MWp PV and 16.48 MWh BESS).

The study also evaluated the discounted payback period (PBP_{disc}) under cost scenarios projected for 2023 and 2050 (see Table 1). The investment analysis indicates that implementing a firm PV system to achieve 65% self-production (with 2.3 MWp PV and 2.62 MWh BESS) is already cost-effective under 2023 conditions, with an LCOE of 112 €/MWh and a PBP_{disc} of 11 years. Achieving 80% self-generation would result in a 28-year payback at current costs, but this could drop to 9 years if the projected 2050 cost reductions are realized as early as 2030.

Moreover, a surface suitability analysis (Figure 5) identifies ample available space for PV panel installation, offering opportunities for further expansion of renewable energy capacity. However, reaching higher self-production levels requires careful assessment of land-use implications and associated investments.

Finally, economic feasibility analyses, including both PBP and Net Present Value (NPV) evaluations, confirm the profitability of firm PV systems up to specific self-production thresholds. While configurations achieving 65% self-sufficiency are already viable, caution is advised when targeting higher self-production levels, as longer payback times and current market uncertainties may impact financial sustainability.

Table 2 – Simulation results and cost analysis.

SP	Installed Capacity		LCOE$_{firm}$		PBP$_{disc}$	
	PV (MWp)	**BESS** (MWh)	**2023** (€/MWh)	**2050** (€/MWh)	**2023** (years)	**2050** (years)
65	2.30	2.62	112	75	11	5
80	3.03	4.63	130	77	28	9
90	4.55	6.42	160	88	-	17
100	9.75	16.48	317	165	-	-

***Figure 5 - Satellite image showing available surfaces in the Engineering Macro-area*.**

Reference:

F. Andreozzi, G. Bovesecchi, M. Petitta, M. Pierro, R. Perez, C. Cornaro, "Flexible photovoltaic generation strategy for Rome Technopole", submitted to Energy Conversion and Management X

2.5 Infinity, a Small-scale Prototype for Firm-PV Generation

Federico Andreozzi, Gianluigi Bovesecchi, Richard Perez, Marco Pierro, Cristina Cornaro (2025) [6]

Oral presentation, EUPVSEC2025 Bilbao, Spain

The "Infinity" (**IN**novative **FI**rm ge**N**eratIon proto**TY**pe) prototype is a small-scale flexible photovoltaic system (f-PV) designed to experimentally validate the concept of firm PV generation—that is, ensuring a stable and dispatchable power output from solar energy.

The idea behind “Infinity” is to use a small-scale flexible photovoltaic system (f-PV) to test the firm PV generation concept—i.e., maintaining a reliable power output from PV systems. This activity is conducted within the framework of the Rome Technopole project, funded by the Italian National Recovery and Resilience Plan (PNRR).

The prototype is based on the principles of PV system overbuilding (also known as implicit storage) and curtailment of excess production. The photovoltaic power must meet the electrical load and recharge the batteries even during winter or prolonged cloudy conditions. This strategy minimizes the size and cost of storage, which is used solely to redistribute solar energy over a 24-hour period.

Technically, the Infinity prototype consists of a 1.815 kWp PV system (three 605 Wp bifacial modules), a 5-kWh lithium battery with BMS, a smart inverter, and a programmable DC load emulator. Power flows are dynamically managed via MATLAB, with the load value updated every minute. When PV production exceeds the energy demand and the battery reaches full charge, the excess energy is fed into the grid to simulate curtailment.

The system’s flexibility enables testing of various load profiles and storage configurations, making it a versatile platform for investigating storage/PV capacity ratios and their impact on firm PV generation.

Infinity represents a significant advancement from previous numerical studies on the feasibility of firm PV generation, previously conducted for the Lazio Region and the Engineering Macro-Area of the University of Rome Tor Vergata. It offers a real-world testbed to validate theoretical findings and assess the effectiveness of different control strategies under actual operating conditions.

Infinity has been fully operational since January 28, 2025, and is currently in the testing phase.

Figure 6 presents the results from one week of operation in March (a), with a focus on a bad weather day (b) and a sunny day (c). The power load currently used is the 2019 electricity demand of the Engineering Macro-Area, scaled down by a factor of 8500.

The plot shows that PV production peaked at around 1.5 kW. Negative battery power values indicate charging, while positive values mean the battery is supplying energy to meet the load. This is particularly evident at night, where the battery and load plots overlap. Curtailment is conventionally shown as negative values.

The PV-to-Load plot illustrates the portion of PV power directly used to satisfy the load. During daylight hours, this plot largely overlaps with the load curve, indicating that PV can generally meet the system’s demand.

Initial results from the first days of operation confirm that the system effectively meets power demands under varying weather conditions. The battery shows satisfactory charge times, and curtailment dynamics largely align with expectations. Further testing will focus on the system’s resilience and optimization strategies for broader applications in sustainable energy integration.

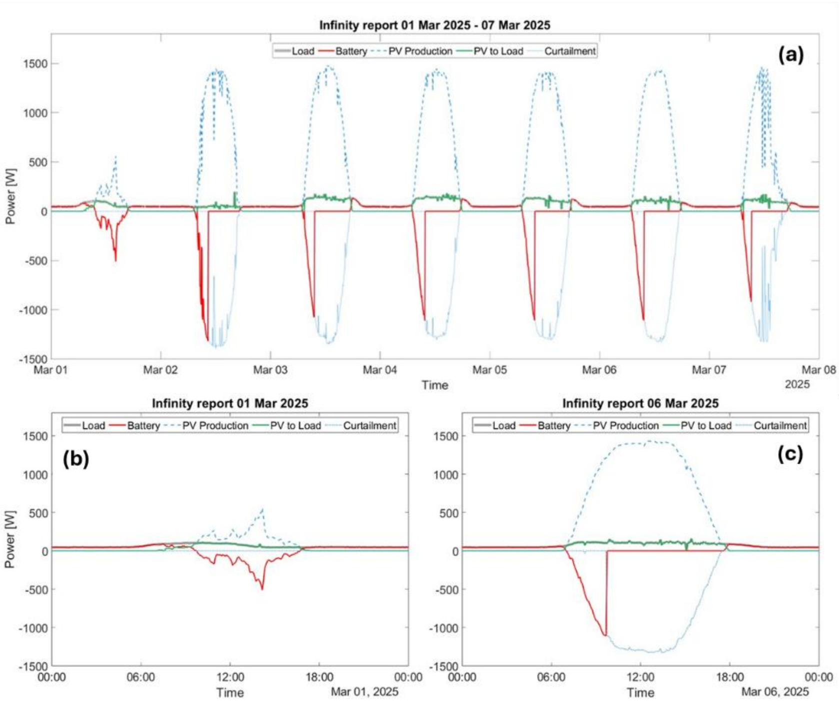


Figure 6 - Results from one week of operation in March (a), with a focus on a bad weather day (b) and a sunny day (c).

Reference:

- Oral presentation at the 3rd Conference of Rete Italiana del Fotovoltaico, Bagnoli (NA) Italia.
- Visual presentation EUPVSEC 2025, Bilbao, Spagna.

2.6 Firm PV Power Generation for Switzerland: 2023 Updates and Strategic Implications

Jan Remund, Marc Perez, & Richard Perez, (2024) [7]

Swiss Federal Energy Office

This report synthesizes the key findings, updated methodology, and strategic implications of the "Firm PV Power Updates 2023 SFOE report" [8], building upon the foundational 2022 study. The analysis confirms the physical and economic viability of high-renewable energy source (RES) solutions for Switzerland's net-zero 2050 goal. A central finding is the consistent Levelized Cost of Energy (LCOE) for electricity production, ranging from 6.8 to 8.6 cts/kWh (Figure 7) across all nine new scenarios and five meteorological years (2018-2022). This range is considered acceptable and robust against year-to-year variations and inherent cost assumption uncertainties.

The study strongly reaffirms the critical role of "implicit storage," achieved through optimally overbuilding photovoltaic (PV) capacity and strategically curtailing excess output. Optimal curtailment levels are consistently found between 10-30%, a strategy that significantly reduces overall system costs by minimizing the need for expensive dedicated battery storage. Without this operationalized overbuilding and curtailment, production costs would escalate dramatically, by 24-80% depending on the scenario (Figure 8).

A non-intuitive but crucial finding is that incorporating low shares (around 5%) of more expensive electricity sources, such as wind and nuclear power, particularly during the winter months, can paradoxically *lower* the overall average production costs. These sources provide critical firm power during periods of lower solar irradiance, thereby reducing the necessity for excessive PV oversizing to meet winter demand. This highlights that an energy source's value extends beyond its isolated LCOE to its systemic contribution and temporal fit within the broader energy system.

All nine new scenarios (Table 2), which explore varying contributions from wind and nuclear power under updated conditions like winter import limitations, are demonstrated to be feasible and yield acceptable cost ranges. This indicates considerable flexibility in Switzerland's pathway choices towards a high-RES future. All cost assumptions for 2050 are based on NREL ATB.

Despite the clear technical and economic feasibility, a significant challenge lies in the current policy and regulatory frameworks. Existing market designs, often based on marginal costs, are ill-suited for a system dominated by marginal cost-free renewables, leading to issues like PV "cannibalization" (zero or negative prices during peak production). Urgent reforms in market design and grid regulations are necessary to properly value and enable firm power, particularly by compensating for or incentivizing strategic curtailment. The study underscores that the bottleneck to energy transition is increasingly political and regulatory, rather than purely technological or economic.

Table 2: Scenario definitions

No.	Scenario definition	No.	Scenario definition
1	97% renewable energy sources (RES) Switzerland including 3 TWh of wind and no nuclear	6	89% renewable energy sources (RES) Switzerland including 3-6 TWh of wind and 1 GW of new nuclear
2	89% renewable energy sources (RES) Switzerland including 3 TWh of wind and 1 GW of lifetime extended nuclear	7	97% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and no nuclear
3	89% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and 1 GW of new nuclear	8	89% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and 1 GW of lifetime extended nuclear
4	97% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and no nuclear	9	89% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and 1 GW of new nuclear
5	89% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and 1 GW of lifetime extended nuclear		

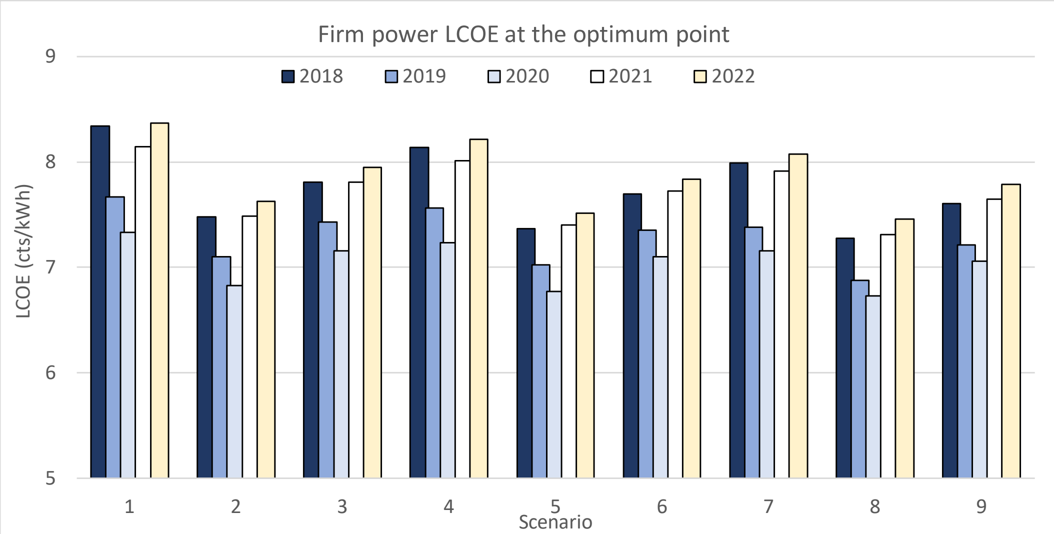


Figure 7: Swiss grid power generation costs for scenarios 1–9

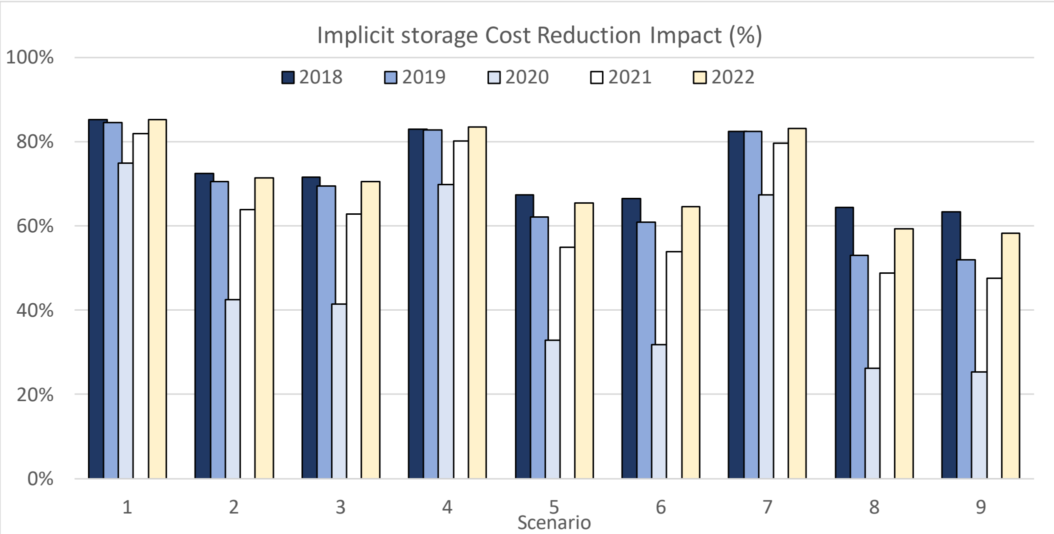


Figure 8: Cost reductions due to implicit storage (overbuilding).

Reference:

Remund, J., Perez, M., & Perez, R. (2024). *Final report Firm PV Power Generation for Switzerland Updates 2023 with scenarios including enhanced wind and nuclear production*. https://www.aramis.admin.ch/Default?DocumentID=71549&Load=true

2.7 Firming 100% renewable power: Costs and opportunities in Australia's National Electricity Market

Elona Rey-Costa, Ben Elliston, Donna Green, Gab Abramowitz, (Renewable Energy, 2023) [9]

https://doi.org/10.1016/j.renene.2023.119416

This study evaluates the feasibility and cost-effectiveness of achieving a 100% renewable electricity system in Australia's National Electricity Market (NEM). It explores scenarios involving strategic oversizing of solar and wind capacity, supported by hydro, battery storage, and gas-fired generation. Using 11 years of historical demand and weather data, the study models system performance and costs under various configurations.

Key Takeaways

- Oversizing solar and wind to generate up to 4× total demand is economically viable and can meet 100% of electricity needs.

- Without battery storage, this approach is 28% cheaper than recent wholesale electricity prices.

- Adding 1–8 hours of battery storage reduces firm power generation costs by 55%, making the system highly competitive.

- Surplus energy ─ 51% to 190% of demand depending on location ─ although could support new industries, especially in rural areas, utilization of surplus energy is not a prerequisite to economically supply the power grid 100% of the time.

- Battery storage tends to reduce reliance on wind vs. solar.

- Existing gas-fired capacity (6.7 GW) can serve as a transitional backup, contributing only 0.2% of total energy.

- Surplus energy is concentrated in Victoria, South Australia, Tasmania, and Queensland.

Methodology Highlights

The study uses the NEMO optimization model with hourly demand and weather data from 2010–2020. It applies cost projections from the CSIRO GenCost 2021–2022 report under four policy scenarios. The model assumes a copper plate grid and prioritizes solar, wind, hydro, and natural gas in dispatch order.

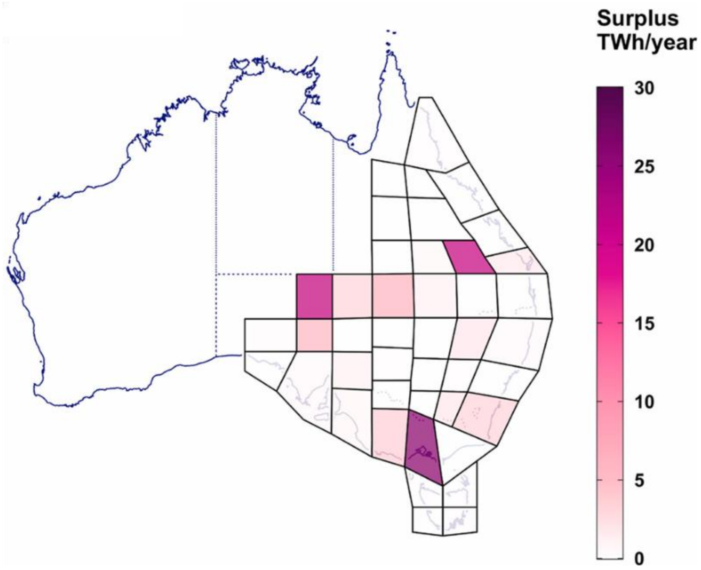


Figure 9: Surplus energy per electrical region in a scenario including 0.2% natural gas

2.8 Localized, cost-effective, 100% renewable firm power generation.

Marc Perez, Richard Perez, James Schlemmer, Marco Pierro & Jan Remund [10]

Oral Presentation [24th Wind & Solar Integration Workshop, Berlin, Germany](),

This study investigates whether firm VRE power generation can be achieved without the need for extensive transmission grid expansion. The research focuses on the continental United States (CONUS) and explores whether localized renewable energy systems can deliver reliable, cost-effective firm power using a mix of photovoltaic (PV), wind, battery energy storage systems (BESS), and minimal dispatchable thermal generation powered by clean e-fuels.

To test this hypothesis, the authors selected 36 geographic centroids across CONUS and simulated renewable generation footprints around these centroids ranging from a single grid cell (~100 km^2) to subcontinental scales (~ 6 million km^2). These footprints were incrementally expanded to assess how the size of the generating area influences the firm system configuration and cost. Hourly wind and solar production data for 2022 were derived from SolarAnywhere irradiance and ERA5 wind datasets, with PV modeled as south-facing arrays and wind turbines placed at 100-meter hub heights, accounting for wake effects.

Using the Clean Power Transformation model, the team optimized configurations of PV, wind, BESS, and curtailment for each footprint to minimize the levelized cost of electricity (LCOE). The analysis assumed a constant baseload demand—akin to a nuclear plant with zero downtime—and allowed 5% of the load to be met by dispatchable e-fuel generation, providing critical (albeit expensive) flexibility and resilience. Capital and operating costs were based on the 2020 NREL Annual Technology Baseline (ATB) projections for 2050.

The results indicate that firm renewable power can be achieved within relatively small geographic areas—less than 50,000 km^2—at competitive costs. LCOEs for these localized systems averaged around 5 ¢/kWh, with a national range of 4–6 ¢/kWh. While larger footprints offer further cost reductions, they come at the expense of local resiliency and would require significant investments in transmission infrastructure. This would finally enhance grid costs. To what extent the grid costs and the gain of LCOE would counteract is yet to be found. Interestingly, despite wind's higher capacity factor, PV tends to dominate the optimal mix in most regions due to its integration advantages and distribution-level hosting capacity benefits. The impacts of footprint on LCOE, optimal PV/wind blend, installed VRE capacity, BESS requirements, implicit storage requirements, and implicit storage effect are summarized in Figure 10.

This study confirms the role of "implicit storage"—the strategic overbuilding and curtailment of VRE output—which significantly reduces the need for physical battery storage and lowers overall system costs. Curtailment levels averaged 25%, and BESS requirements remained relatively stable across regions, typically amounting to 10–15 hours of load coverage.

These findings suggest that a decentralized, resilient, and cost-effective path to 100% renewable energy is not only feasible but also preferable in many cases.

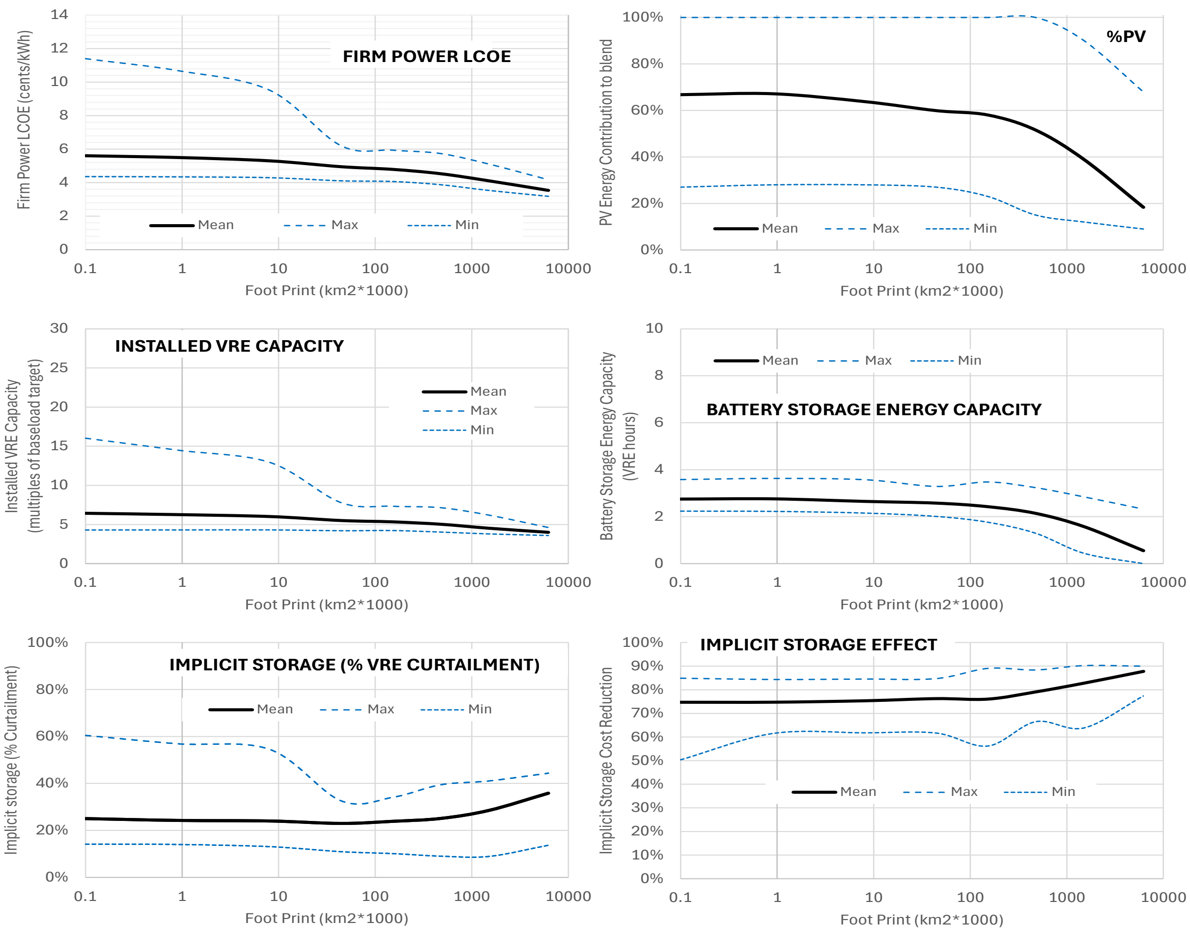


Figure 10: Generation footprint dependence of firm power generation LCOE (top left), optimal proportion of PV in the PV/wind blend (top right), installed VRE capacity in multiples of the selected baseload target (middle left), BESS energy capacity quantified in installed VRE hours (middle right), implicit Storage. i.e., dynamic %VRE curtailment (bottom right), and firm power LCOE reduction enabled by implicit storage (bottom right).

Reference:

- Marc Perez, Richard Perez, Thomas E. Hoff, James Schlemmer, Marco Pierro & Jan Remund, (2025): 100% Renewables without Major Grid Expansion: Unlocking Localized, Cost-Effective Firm Renewable Power Solutions. IEEE PVSC 53 Conference , Montreal Canada. [11]
- Jan Remund, Marc Perez, Richard Perez, James Schlemmer and Marco Pierro, (2025): Localized, cost-effective, 100% renewable firm power generation. 24th Wind & Solar Integration Workshop, Berlin, Germany, 7-10. October 2025. [10]

2.9 Implications of Future Price Trends and Interannual Resource Uncertainty on Firm Solar Power Delivery with Photovoltaic Overbuilding and Battery Storage

G Yang, D Yang, C Lyu, W Wang, N Huang, J Kleissl, M J Perez, R Perez, D Srinivasani, IEEE Transactions on Sustainable Energy 14(4): 2036–2048 (2023) [12]

https://ieeexplore.ieee.org/document/10121691

The authors introduce the concept of optimization modeling for the first time in a journal paper in the field of firm generation and propose two standard mathematical models that simultaneously optimize the rated capacity and operation strategy of each component in a firm PV–battery system. Unlike previous studies, which generally utilize less efficient direct search and bisection methods, this study directly employs the branch-and-bound method embedded in an off-the-shelf solver to solve the proposed mixed-integer linear program (when a generic battery model is applied) or uses a hybrid algorithm that combines the solver with the bisection method to obtain the optimal solution of the proposed bilinear model (when a refined nonlinear battery model is applied). Additionally, this study examines the impact of battery model selection, PV overbuilding ratios, future component costs, and interannual solar resource variability on the firm kWh premium.

This study defines the firm kWh premium as the ratio of the levelized cost of electricity (LCOE) for a firm PV system to that of unconstrained PV (i.e., routine setup without battery storage and PV overcapacity). It is worth noting that the PV overbuilding ratio here refers to the multiplier of the rated power of unconstrained PV, specified in advance, where the annual energy generation is comparable to the annual load demand.

The case studies are based on a virtual firm PV–battery system located in Harbin, China, which delivers a committed supply of 0.17 MW of constant load throughout the year. Assuming the rated power of an unconstrained PV plant is 1 MW, the main findings are as follows:

- Achieving firm PV power generation still faces significant economic challenges under the current cost structure. When a generic battery model is adopted, the optimal premium for the firm PV–battery system is 4.18, which is much higher than the apparent grid parity claimed for unconstrained PV systems (i.e., with a premium of 1).
- PV overbuilding plays an important role as implicit energy storage in reducing the system premium. A reasonable combination of battery storage and PV overbuilding can lower the system premium from 20.19 for a battery-only solution to 4.18, as shown in Figure 11.
- Regardless of the battery model, the state of charge of the battery remains below 0.5 during most periods. On this account, by deploying dispatchable generation units to supply

energy that would otherwise be stored above 50% of battery capacity, the required battery size can be halved, thereby further reducing the premium.

- The modeling complexity of PV and battery storage has no obvious impact on the system premium. For instance, the premium difference between using a generic battery model and a refined battery model is just 0.22.
- To make firm PV power generation cost-competitive with the current electricity price, the unit cost of PV should fall below 250 $/kW, and the unit cost of battery storage should drop below 40 $/kWh, as illustrated in Figure 12.
- Since the typical meteorological year (TMY) data only reflect the median climate conditions and fail to capture periods of prolonged low PV output, the system premium computed in this study based on such data inherently carries a risk of underestimation.

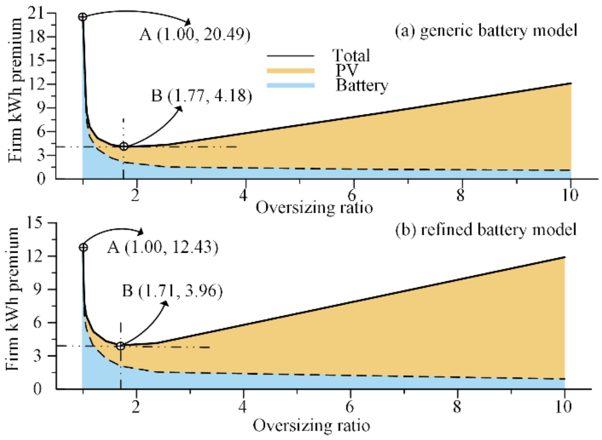


Figure 11: The relationship between system premiums and PV overbuilding ratios when employing either a generic battery model (a) or a refined battery model (b)

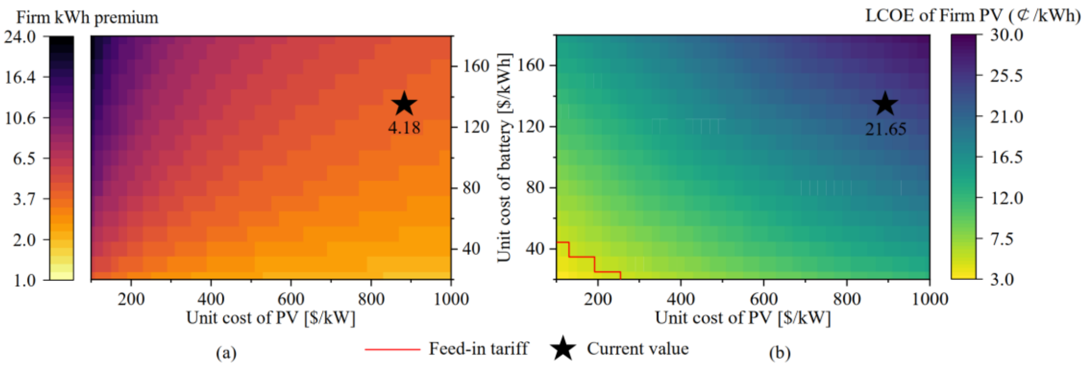


Figure 12: The firm kWh premiums (a) and levelized cost of electricity (b) for a firm PV–battery system under varying unit PV and battery costs

2.10 Firm Photovoltaic Generation through Battery Storage, Overbuilding, and Proactive Curtailment

G Yang, D Yang, C Lyu, W Wang, J Kleissl (2022)

2022 4th International Conference on Smart Power & Internet Energy Systems (SPIES), Beijing, China [13]

Link: https://ieeexplore.ieee.org/abstract/document/10082605

This investigation is a simplified conference version of the above-mentioned work of Yang et al. (2023). The authors develop an optimization model to minimize the firm kWh premium of a firm PV–battery system. The authors also point out that minimizing the system premium is equivalent to minimizing the equivalent annual cost of the system, and it thus serves as the objective function of the optimization model. The model constraints comprise operation constraints of the PV plant, operation constraints of battery storage, and power balance constraints. Since the proposed optimization model is a mixed-integer linear program, the optimal solution can be acquired within minutes through the branch-and-bound method.

The case study compares the daily electricity generation of two PV plants with different power ratings (1 MW and 3 MW) and examines their energy deficits relative to a constant load of 0.17 MW. Concurrently, the battery specifications are optimized to ensure firm solar power delivery across both cases, and the corresponding system premiums are calculated. The results demonstrate that with a PV overbuilding ratio of 3, the system premium is 4.31, which is substantially lower than the value of 18 observed at a PV overbuilding ratio of 1. Furthermore, when the PV overbuilding ratio is treated as a decision variable in the model, the system premium decreases to 3.66, as depicted in Figure 13. It is evident that both PV overbuilding and battery storage are crucial for guaranteeing firm PV power generation at the lowest cost.

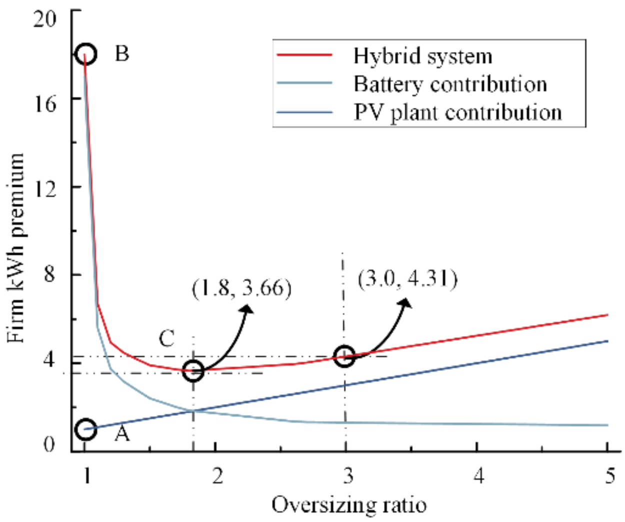


Figure 13: The firm kWh premium of a firm PV–battery system under different PV overbuilding ratios

2.11 Hydrogen production using curtailed electricity of firm photovoltaic plants: Conception, modeling, and optimization

Authors: G Yang, D Yang, M J Perez, R Perez, J Kleissl, J Remund, M Pierro, Y Cheng, Y Wang, X Xia, J Xu, C Lyu, B Liu, H Zhang, 2024 [14]

Journal paper: Energy Conversion and Management 308: 118356

https://www.sciencedirect.com/science/article/pii/S0196890424002978

The authors conduct a thorough analysis of firm solar power generation by incorporating hydrogen production from curtailed energy and refined modeling of system components. It is widely acknowledged that PV overbuilding is considered an implicit energy storage alternative to battery storage; however, its implementation could increase the curtailment ratio of a firm PV–battery system. Therefore, this study quantitatively explores the economic feasibility of utilizing curtailed electricity for hydrogen production and subsequent commercialization.

Moreover, existing research on PV power generation predominantly relies on generic component models with several formulas. Although such generic modeling can intuitively represent the basic working principles of equipment, it exhibits notable limitations in describing the dynamic efficiency characteristics. From this perspective, this study employs both generic component models and refined component models to characterize the operational behaviors of the three key devices (PV, battery, and electrolyzer) in a firm PV–battery–hydrogen system. When generic component models are adopted, the optimization problem on firm system configuration becomes a mixed-integer linear program that can be efficiently solved through the branch-and-bound method. However, with the application of refined component models, the optimization problem emerges as nonconvex and nonlinear, rendering its solution challenging to obtain.

Capitalizing on the modularity of battery storage and piecewise linearization techniques, this study proposes a two-layer iterative algorithm integrating a metaheuristic approach with a branch-and-bound method to derive a solution that meets engineering accuracy requirements. The outer layer of the algorithm employs particle swarm optimization to optimize the selected decision variables that induce model nonconvexity and terminates when the iteration count reaches the predefined threshold. The inner layer invokes a standard solver to solve the mathematical model, which simplifies from the original nonlinear formulation to a mixed-integer linear program when the outer decision variables are fixed. Furthermore, this study examines the implications of different PV overbuilding ratios on system premiums and performs sensitivity analyses of unit costs for PV installations, battery storage, and electrolyzers.

Utilizing a firm PV–battery–hydrogen system virtually located in Winslow, Arizona, United States, as a case study, the following conclusions are drawn.

- The selection of device models significantly impacts the component specifications and economic performance of the system. For instance, the system premium based on the refined component models is 5.78, which represents an 11% reduction compared to the generic component models (6.53).
- Converting curtailed energy into hydrogen for commercial sale in a firm PV–battery system not only mitigates resource waste but also improves the system's economics. In a system comprising only PV plants and battery storage, the premium and PV curtailment ratios are 6.99 and 60%, respectively. Nevertheless, these values decrease to 6.53 and 24% upon hydrogen production system configuration, as shown in Figure 14.

- Consistent with previous studies, moderate PV overbuilding can rapidly reduce system premiums. However, beyond a certain threshold, additional PV overbuilding leads to a quasi-linear increase in system premiums.
- Unit battery costs and unit PV costs are closely linked to optimal system deployment and premiums. It should be noted that the smaller the former relative to the latter, the lower the system premium. Nonetheless, the most significant reduction in the LCOE of firm PV occurs only when both costs simultaneously decline.
- A reduction in unit electrolyzer costs lessens the system premium and shifts electrolyzer operation toward higher-efficiency, lower input power ranges.

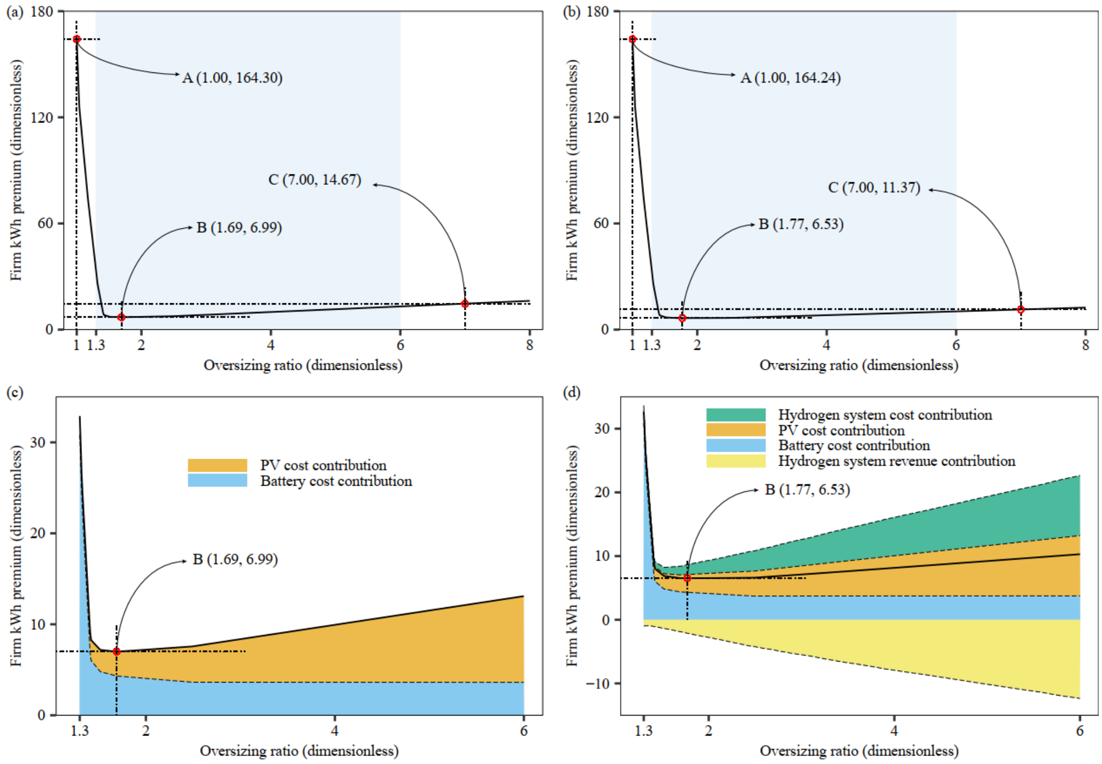


Figure 14: The breakdown of the system premiums under different PV overbuilding ratios. Subplots (a) and (b) respectively correspond to generic component models and refined component models, whereas subplots (c) and (d) provide magnified partial views of subplots (a) and (b), respectively.

2.12 Optimized hydrogen production with proactively curtailed electricity from firm renewable systems

Authors: G Yang, D Yang, B Liu, Y Meng, M J Perez, R Perez, J Remund, X Xia, H Zhang

Solar Energy 297: 113547, (2025) [15]

https://www.sciencedirect.com/science/article/pii/S0038092X2500310X

This study examines the economic feasibility of integrating a hydrogen production system that can utilize curtailed energy to produce hydrogen for commercial sale with a firm wind–PV–battery system. Specifically, for the hydrogen system comprising an electrolyzer, compressor, and hydrogen tank, the authors propose two optimization routines: joint mode and separate mode. The joint mode pertains to the collaborative optimization of the firm wind–PV–battery system and the hydrogen production system, whereas the separate mode first determines the optimal configuration of the firm wind–PV–battery system and acquires the curtailed electricity time series data, followed by optimizing the component sizes of the hydrogen production system based on that data. By comparing these two optimization routines, it can be found that the joint mode can attain a better system design *a priori*; however, its utilization of curtailed energy is limited to hydrogen production only. Although the separate mode is less economical, it offers greater adaptability, allowing for flexible adjustments of curtailed energy usage for applications, such as desalination or irrigation. Additionally, the authors quantify the significant value of energy storage sharing in reducing system premiums, elaborate on the considerable impact of wind–PV blending on enhancing system cost-effectiveness, and conduct a sensitivity analysis of various wind and PV overbuilding ratios.

Through case studies, the authors draw the following conclusions:

- Compared to the separate mode, the joint mode more effectively supports obtaining equipment capacities that align with practical needs, thereby enhancing the overall economics of the system. For instance, the system premium for the joint mode is 1.82, which is dramatically lower than the value of 2.23 for the separate mode, representing a reduction of 18.4%.
- Since hydrogen production using curtailed energy can lessen the system premium, it could be regarded as an "implicit" demand-response resource.
- By implementing the strategy of energy storage sharing, the component sizes of the firm wind–PV–battery–hydrogen system have markedly decreased, resulting in a drop in the premium from 3.30 in the joint mode to 1.82. This highlights the notable advantages of resource synergy, as depicted in Figure 15.
- Another important finding is that wind–PV blending reduces the system premium by leveraging the seasonal complementarity of wind and solar resources. Generally, PV power generation has the highest output in summer, while wind power reaches its peak in winter. As indicated in Fig. 16, the premium for the firm wind-PV–battery–hydrogen system is 27.26% lower than that of the jointly optimized firm wind–PV–battery–hydrogen system.
- Both PV overbuilding and wind overbuilding significantly contribute to improving the cost-effectiveness of the system. Here, when the PV overbuilding ratio reaches 5.0 and the wind overbuilding ratio increases to 4.8, the system premium decreases to its nadir.

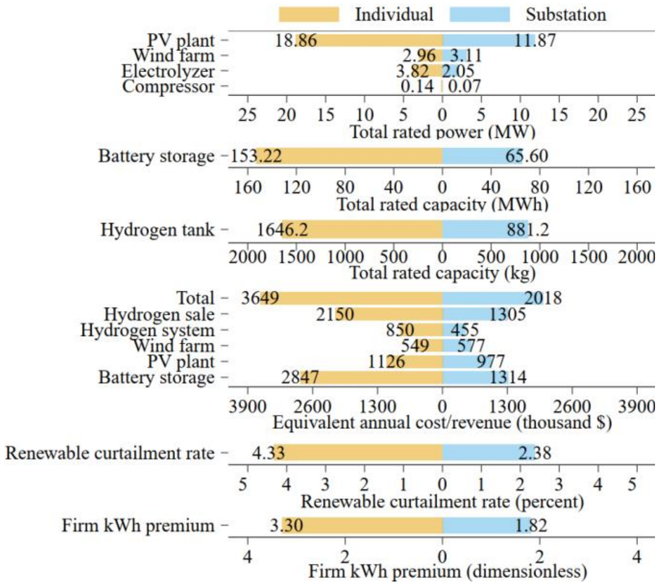


Figure 15: The optimal configuration and economics of the firm energy system, which comprises PV plants, wind farms, battery storage, and hydrogen production devices, under the joint optimization mode at the park level (left) and substation level (right).

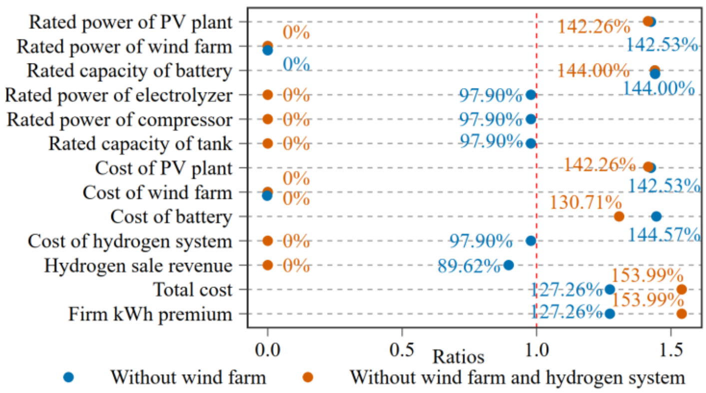


Figure 16: A comparison of equipment specifications and economics across different system configurations. It is noteworthy that the optimized results under the joint optimization mode at the substation level are taken as the benchmark.

2.13 Firm power generation with photovoltaic overbuilding and pumped hydro storage

Authors: Q Gao, Y Chen, D Yang, H Zhang, G Yang, Y Shen, X Xia, B Liu

Energy 324: 135800 (2025) [16]

https://www.sciencedirect.com/science/article/pii/S0360544225014422

This study simulates a firm PV–hydro hybrid system in northern China to meet the electricity demand of a county-level city on a 365/24 basis. For the first time, pumped hydro storage

(PHS), as characterized by its unique long-term storage capacity, is integrated into a firm PV system to replace conventional battery storage. From a mathematical optimization perspective, this study proposes a standard model aimed at minimizing the system premium to determine the optimal ratio of PV overbuilding (implicit storage) and installed capacity of PHS (explicit storage). To demonstrate the validity of the proposed model, several case studies are designed, including a sensitivity analysis of the price trends for PV and PHS on the premium, an investigation into the impact of demand response, and a comparative analysis of the results between PHS and battery storage solutions.

The firm PV–hydro hybrid system is installed in Mudanjiang, China, a region rich in water resources, to meet the hourly load profile, which peaks at over 100 MW. The rated power of the unconstrained PV plant is determined to be 719 MW, ensuring that its annual power generation meets the cumulative load demand for the year. The key takeaways of this study are as follows:

- PV overbuilding can enhance the cost-effectiveness of the firm system by serving as an implicit storage, reducing the premium of the PV–hydro hybrid system at 53.3% compared to the no overbuilding case, as shown in Figure 17.
- Pumped storage offers a cost advantage over battery storage. When firm solar power delivery is achieved, the premium for the battery-only solution exceeds that for the pumped storage-only solution, reaching a threshold of up to 142.92%.
- Utilizing pumped storage as a long-term energy storage alternative helps maintain the optimal configuration of the firm system, even under a demand response strategy or for a prolonged period with low-generation PV output.
- The LCOE of the PV–hydro hybrid system is 10.97 $/MWh. To achieve true grid parity with a feed-in tariff of 5.1 $/MWh, the unit cost of PV must decrease to 466 $/kW, whereas the unit cost of pumped storage needs to decrease slightly by 2% in the future.

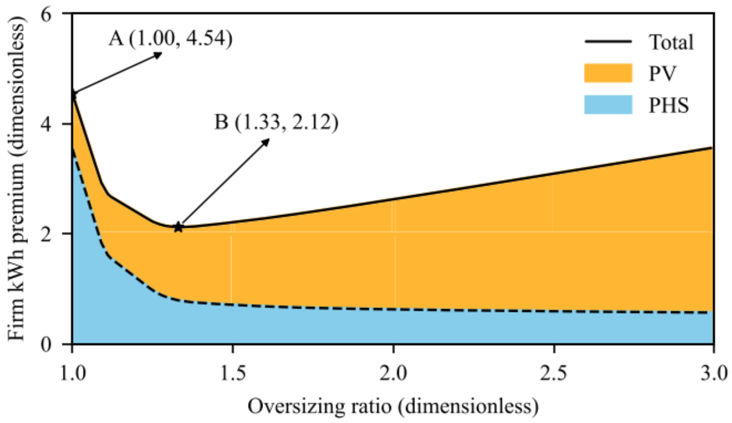


Figure 17: Firm kWh premiums as a function of PV oversizing ratio for a firm PV–hydro hybrid system.

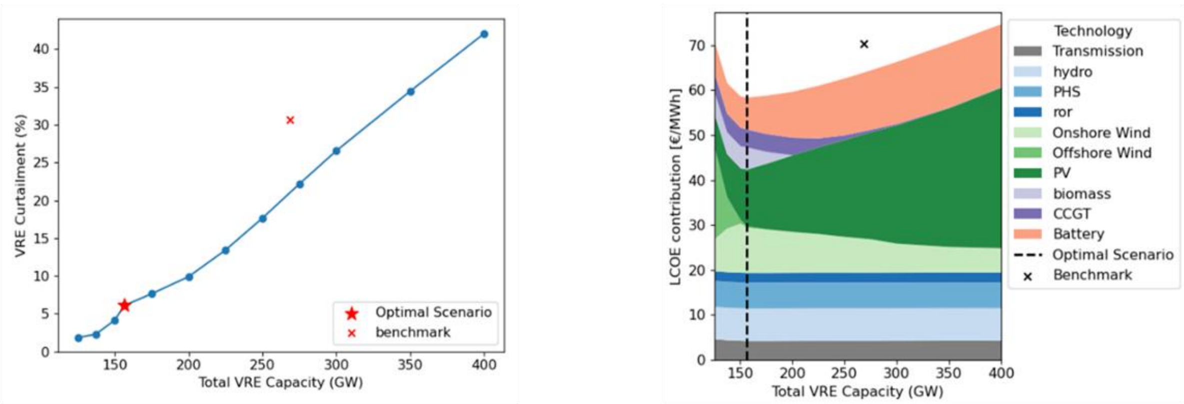
2.14 Firm Power in the Iberian Peninsula

Carolina Crespo, Rodrigo Amaro e Silva, Miguel Centeno Brito (2025)

(work in progress)

This study presents a preliminary firm power analysis for the Iberian Peninsula using energy systems model PyPSAEur [17], and benchmarked against the respective national decarbonization plans of Portugal and Spain for 2050.Iberia has a considerable amount of hydropower generation, as well as pumped hydro storage (PHS), both of which play an important role in system flexibility. Their capacities were fixed at current levels, and the simulations were done using an average precipitation year. Gas supply was limited to 5% of the total energy consumption, and nuclear was excluded to reflect future decommissioning. Various levels of VRE capacity were considered, leaving the share of wind and solar unconstrained to minimize total system costs. In addition, one scenario performed a free optimization without enforcing a fixed VRE capacity, in order to determine the optimal capacity mix.The lowest system cost of 58 e/MWh is achieved with a total VRE capacity of 156 GW, comprising 116 GW of solar PV and 40 GW of wind. This minimum-cost system operates with only 6% curtailment of VRE generation (Figure 18a). Curtailment increases quasi-linearly with increasing VRE capacity.

Furthermore, as evidenced by Figure 18b, which shows a breakdown of contributions to LCOE, an increase in VRE capacity and curtailment is not accompanied by a decrease in energy storage costs — on the contrary, there is an increase. This contrasts with typical firm power literature, where overbuilding and curtailment are seen to reduce storage needs and associated costs. This is likely explained by the gradual substitution of some wind capacity in favor of cheaper PV as the VRE capacity increases, requiring more battery energy storage to cover the day-night cycle — which PHS alone is unable to do, due to insufficient power capacity.Furthermore, as evidenced by Figure 18b, which shows a breakdown of system costs, an increase in VRE capacity and curtailment is not accompanied by a decrease in energy storage costs — on the contrary, there is a slight increase. This is likely explained by the gradual substitution of some wind capacity in favor of cheaper PV as the VRE capacity increases, requiring more battery energy storage to cover the day-night cycle — which PHS alone is unable to do, due to insufficient power capacity.



a Curtailment vs VRE capacity

b LCOE vs. VRE capacity

Figure 18: 5% gas supply scenario

Remarkably, hydrogen is not a part of any of the technology mixes in this scenario. This contrasts with the national decarbonization plans, which set a 11.25 GW total hydrogen capacity between the two countries by 2030. Spain does not yet set a value for 2050, but Portugal's 2030 hydrogen capacity is expected to increase tenfold by 2050.

If gas and biomass are fully excluded from the system (leaving VRE, hydro, and batteries), the optimal VRE capacity increases from 156 to 226 GW, but this does not result in a steep increase in LCOE (7% increase to 62 e/MWh). To achieve this, the curtailment doubles to 12%. At low VRE capacities, offshore wind is favored due to its higher capacity factor. However, low VRE capacities do not lead to a significant increase in battery capacity. This is in large part thanks to hydropower generation and some hydrogen, as these technologies handle energy storage over longer timescales.

This is confirmed by generating an alternate scenario with no hydropower, PHS, gas, biomass or hydrogen — leaving only VRE technologies and batteries (Figure 19). Here, low VRE capacities require significant amounts of battery storage to handle balancing over periods longer than one day, in the absence of more suitable technologies. Battery needs decrease as VRE capacity increases, up to the optimal scenario, which is achieved at a much higher VRE capacity — over twice that of the first scenario. In this configuration, the optimal configuration includes 45% VRE curtailment —– the result of a system relying solely on overbuilt VRE and batteries. Optimal LCOE is 86 e/MWh – 48% higher than the base scenario.

These results highlight the role of Iberia's hydro resources in the flexibility of the electricity grid.

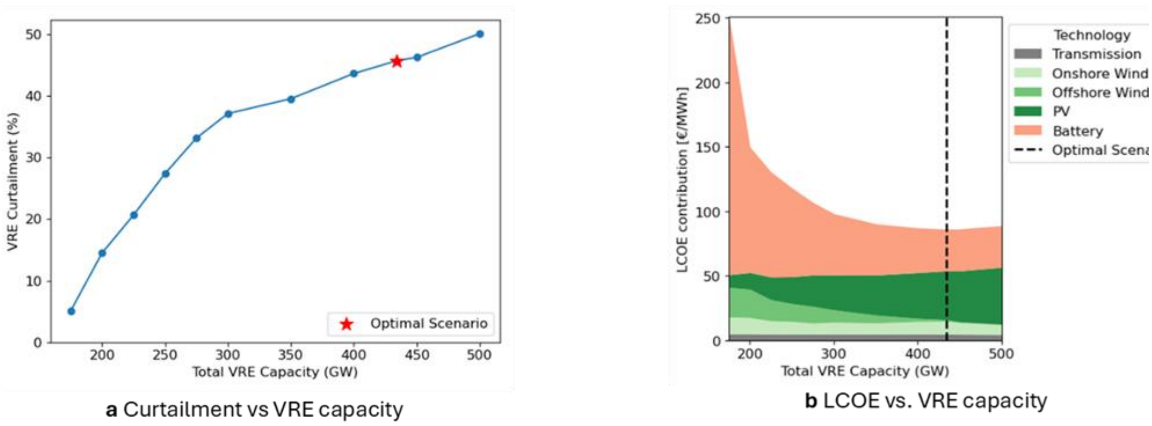


Figure 19: VRE and batteries-only scenario. Hydropower, PHS, biomass, gas and hydrogen are excluded

However, the results are sensitive to hydro availability. While these results used an average year precipitation-wise, future simulations will be extended to both wet and dry years. Future work will also explore the impacts of evolving climate conditions.

Reference:

J. Hoersch, F. Hofmann, D. Schlachtberger, and T. Brown, "Pypsa-eur: An open optimisation model of the European transmission system," Energy Strategy Reviews, vol. 22, pp. 207–215, 2018. eprint: 1806.01613.

2.15 Electricity Mix and Market Dynamics in 2035 CO2-free Electricity System

Casper Berkhout, Niels Janssen, Seth van Wieringen, Lucas van Cappellen, Michiel Bongaerts, Frans Rooijers, Joeri Vendrik (2024) [18]

https://www.rijksoverheid.nl/documenten/rapporten/2024/08/31/elektriciteitsmix-en-marktdynamiek-in-2035-co2-vrij-elektriciteitssysteem

Data viewer https://witteveenbosdatalakeopen.z6.web.core.windows.net/

Objective

The goal of this study is to investigate a CO_2-free electricity system in 2035 within the assumptions of the Dutch National Energy System Plan (NPE) and what market dynamics result from such a system. In line with the NPE, electricity production in this study is CO_2-free without emission compensation. The NPE prescribes ambitious installed capacities for renewable generation: 98 GW solar PV, 47 GW wind (12 GW onshore and 35 GW offshore), and an additional nuclear power plant of 1.6 GW. Importantly, these NPE targets represent a significant overbuilding relative to expected electricity demand. Combined with the variable nature of solar and wind resources, this study provides valuable insights into how VRE-dominated systems can approach firm power generation in the Netherlands.

Methodology

This study models the Northwest-European electricity and hydrogen system in the PyPSA energy system optimization framework. Using system optimization, the optimal capacities of generation, storage, and transmission and the dispatch of generation, storage and demand management were simultaneously determined to meet demand as defined in the TSO's demand scenarios (IP2024 and TYNDP). In the subsequent market simulation and analysis, hourly electricity prices for 2035 were calculated based on current bidding zones and merit-order dispatch principles. This provides an approximation of possible revenues and insight into the business cases for all technologies.

This two-step approach - system optimization followed by market simulation - reveals both the technical feasibility of achieving firm power from a VRE-dominated system and the economic challenges under current market structures. To identify robust developments and key uncertainties, we analyzed 31 variants of the NPE reference scenario, testing different technology costs, demand scenarios, weather years, and policy choices.

Key outcomes

Robust developments: Robust developments observed across all scenarios include major increases in domestic electricity infrastructure and cross border connections, widespread deployment of demand side response, substantial hydrogen production and storage capacity, and a strong need for 24-hour electricity storage. These findings show that although the NPE targets increase nameplate VRE capacity and lead to overproduction of electricity, the effective firm contribution of VRE is much lower, requiring a host of enabling technologies to reliably meet demand. No major tipping points were identified under cost uncertainty, indicating this set of technologies remains dominant under both low and high-cost development. In addition, expanding onshore wind capacity generally reduces overall system costs.

Overproduction and export of green hydrogen: There is more production of electricity than demand in the NPE, which means that a relatively high proportion of Northwest-European hydrogen demand is produced in the Netherlands. Because of the high amount of generation capacity, curtailment and electrolysis play an important role in balancing electricity supply and demand. Northwestern Europe does not import hydrogen at all, partly because of the system-level role of electrolyzers and low electricity prices.

Role of hydrogen-fueled power plants and storage: Hydrogen-fueled power plants play a role in the energy system by supplying electricity during peak demand hours. Security of supply can be achieved with a minimum of 8 GW of hydrogen plants. In addition, there is a need for hydrogen storage of at least 1.2 TWh to balance hydrogen supply and demand throughout the year. These plants use blue hydrogen, as the use of green hydrogen is not cost-effective. Extreme weather conditions or delayed maturation of other technologies can raise the need for additional hydrogen plant capacity as a strategic reserve.

Preference for 24-hour storage: In the scenarios in which there is sufficient availability of 24-hour long-term (mechanical) storage, this is more cost-effective than short-duration batteries for electricity storage. This is partly due to the high availability of electricity at low electricity prices, which means energy storage and conversion with lower efficiency is not a major obstacle. 24-hour storage replaces both short-term storage and partly the need for peak power plants. It does appear that when battery prices are low, some of the capacity of 24-hour storage is being replaced by 4-, 8-, and 12-hour batteries.

Many hours with low prices: Because of large amount of renewable energy production in the NPE reference scenario, the hourly electricity prices are near 0 EUR/MWh for about 35 % of the year when there are large surpluses of energy (see figure 20). Prices are between 5 and 20 EUR/MWh around 40 % of the time, when there is sufficient generation from a combination of renewables, nuclear, and electricity storage to meet demand. About 10 % of the time, demand side response is required in industry and mobility driving the price up further. During the 15 % most expensive hours, the use of hydrogen plants and more expensive sources of stored electricity and demand side response are also required. Three hours a year, there is insufficient production, and part of the industry switches off because of high prices.

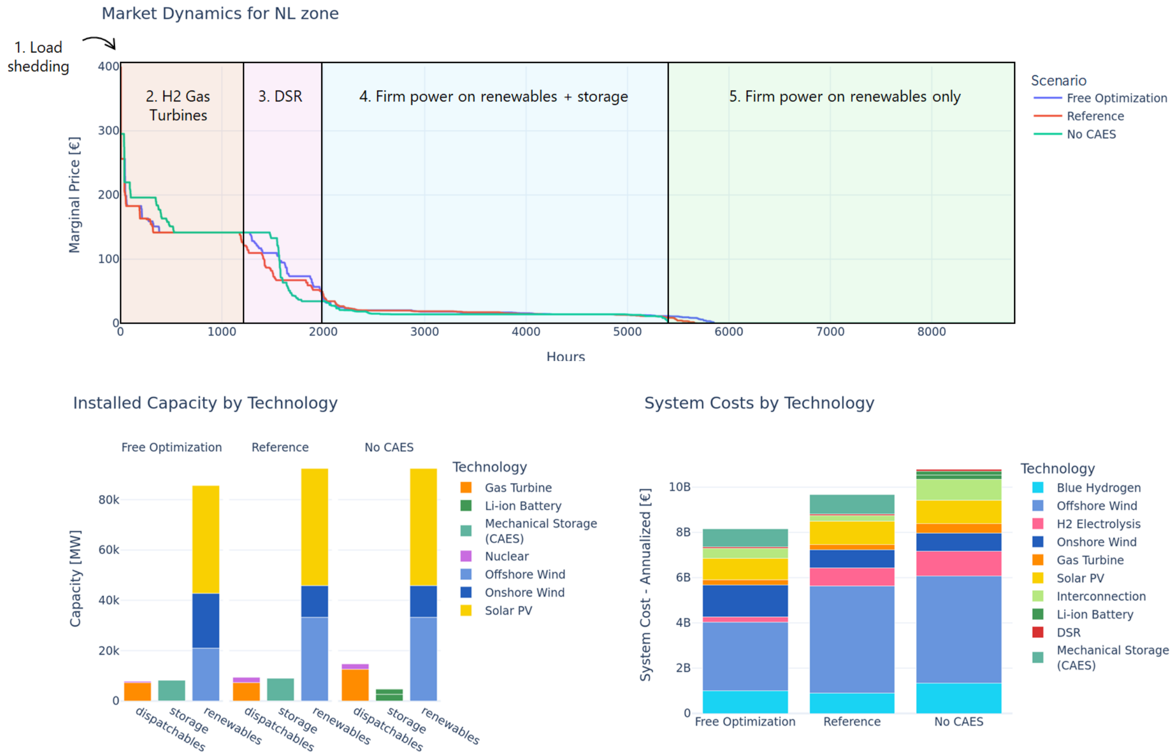


Figure 20: Price-duration curve, installed capacities and system cost (€/MWh) for the Netherlands

Challenges for business cases and market functioning: The surplus of renewable electricity is the result of the assumptions from the NPE, but also the requirement that the electricity system is CO_2-free by 2035. Due to the high amount of solar, wind and nuclear capacity being installed, the electricity price is low for many hours, resulting in unprofitable business cases for these generation sources. In all variants, the current market fails to monetize the value of firm capacity: hourly electricity prices alone are found to be insufficient to realise the required generation and flexibility capacities, with the exception of demand side response. An analysis of the balancing markets has shown that there is still an additional profitable and essential capacity of about 2.2 GW in 2035, for which for instance batteries are currently already being realised.

Free optimization alternative: When NPE targets for renewable generation are abandoned in free optimization, a significantly different energy system is observed. In this scenario, no additional offshore wind capacity beyond existing plans (21 GW) is observed, and no new nuclear energy is realized, leading to almost double the onshore wind but reduced solar PV capacity. Because considerably less electricity is produced, the domestic green hydrogen production is cut drastically from 23 TWh to 7 TWh, relying more on electricity and hydrogen imports from neighbouring countries. Additionally, the reduced domestic renewable generation also decreases the demand for long-term storage and hydrogen infrastructure. This scenario offers a significant reduction in system costs through increased foreign energy production reliance, but at the cost of decreased national self-sufficiency and adequacy.

Conclusion

The overbuilding of renewables as planned in the Dutch National Energy System Plan by 2035, when optimally managed with storage, curtailment strategies and flexible demand, can technically produce an energy system that approaches firm power. However, the current market arrangements make delivery of true firm power practically unachievable: dispatchable resources set prices only in a small number of scarcity hours, whereas extensive VRE overcapacity drives prolonged near-zero prices and leaves capital intensive firm assets without viable revenues. To convert this technical potential into dependable, firm, CO_2-free power, there is an urgent need for renewed policy and market design and regulation. Action is necessary to secure business cases and investment in renewable technologies, long duration storage and system flexibility, including prerequisites such as grid capacity, space and permits.

2.16 Firm wind and solar photovoltaic power with proactive curtailment: A European analysis

Ruben van Eldik & Wilfried van Sark

Energy Conversion & Management, (2026) [19]

doi:10.1016/j.enconman.2025.120399

This study addresses whether intermittent renewable energy sources can provide firm power, the ability to reliably meet electricity demand around the clock and throughout the year, in Europe. Building on the concept of the "firm kWh premium" (the ratio between the levelized cost of firm electricity and unconstrained renewable LCOE), this analysis expands previous work to continental scale, incorporating multiple storage technologies, demand response through hydrogen production, dispatchable generation, and multi-year weather variability to comprehensively assess the technical feasibility and economic implications of firm renewable power across 37 European countries.

Methodology

We developed the Pan-European Intermittent Renewable Overbuilding & Curtailment Optimization Model (PEIROCOM), a linear programming model that simultaneously optimizes installed capacity and dispatch across 50 market nodes and 297 intermittent renewable nodes using 10 climate years with hourly resolution. Six scenarios were analyzed with different technology combinations: Scenario A (baseline) includes only solar PV, wind, and lithium-ion storage; Scenario B adds PEM electrolysis with 20% exogenous hydrogen demand; Scenario C adds existing nuclear capacity; Scenario D adds existing hydropower capacity; Scenario E adds hydrogen gas turbines (CCGT and OCGT) with electrolysis; and Scenario F combines all technologies to explore the benefits of an integrated system approach.

Key Results

Analysis across six scenarios reveals that system architecture fundamentally determines the cost of firm renewable power. A baseline system relying solely on solar PV, wind, and lithium-ion storage requires extensive overbuilding and curtailment, resulting in a firm kWh premium of 3.72. The transformative insight is that adding dispatchable hydrogen gas turbines combined with electrolyzers reduces this premium to just 1.32, meaning firm renewable electricity costs only 32% more than unconstrained generation. This optimal configuration enables intermittent renewables and short-term storage to directly supply over 90% of demand, with hydrogen turbines providing the critical remaining capacity during extended low-generation periods. Notably, existing nuclear and hydropower assets provide limited benefit due to nuclear's high capital costs requiring baseload operation and hydropower's constrained storage capacity. The key enabler is low-capital-cost dispatchable generation that tolerates very low-capacity factors

(1-22%). While we used hydrogen as the fuel source for this low-CAPEX high-OPEX technology, alternative options exist to fill this technology gap, including bio-based fuels and gas turbines with carbon capture and storage (CCS).

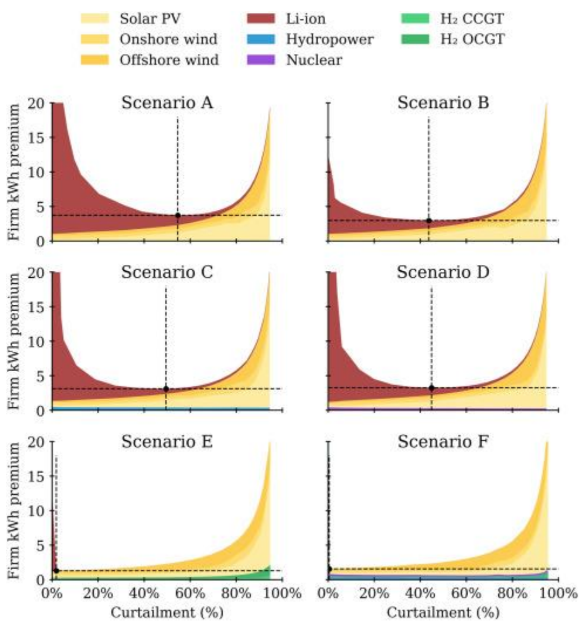


Figure 21: Firm kWh premium per scenario and curtailment ratio. The crosshairs indicate the optimal solution found for each scenario.

Conclusions and Implications

This study demonstrates that Europe can achieve a fully decarbonized electricity grid powered primarily by solar PV and wind, with all countries maintaining near or full self-sufficiency. Four key findings emerge: (1) Proactive curtailment combined with overbuilding significantly reduces system costs, with optimal overbuilding levels ranging from 55% in IRES-only systems to less than 2% with adequate dispatchable capacity and demand response; (2) While intermittent renewables and short-term storage directly provide 92.5% of electricity, the remaining 7.5% requires low-CAPEX dispatchable generation tolerant of low capacity factors; (3) Hydrogen infrastructure can serve a dual purpose as electrolyzers provide demand response while hydrogen storage enables seasonal smoothing, proving more cost-effective than massive lithium-ion deployment; (4) Multi-year analysis confirms that systems with hydrogen storage and dispatchable generation maintain stable costs across diverse weather conditions, while IRES-only systems struggle with extended low-generation periods.

The firm kWh premium of 1.32 in the optimal scenario represents only a 32% cost increase over unconstrained renewable generation, a remarkably modest premium for guaranteed reliability. This research provides robust evidence that firm power generation from intermittent renewables is technically feasible and economically attractive across Europe, with key enablers being strategic overbuilding with minimal curtailment, green hydrogen for seasonal storage and demand response, and low-CAPEX dispatchable generation.

3 STUDIES ADDRESSING OTHER ASPECTS OF FIRM POWER – MARKET TRANSITION, FIRM FORECASTS, DISTRIBUTED GENERATION AND FUNDAMENTALS

3.1 The use of PV forecasting to reduce the cost of firm/baseload PV generation and restore certainty of supply

Marco Pierro, Cristina Cornaro, David Moser, Richard Perez, Marc Perez, Jan Remund, Grazia Barchi (2025)

(Work in progress)

The current electricity system was designed to operate primarily with generation units that produce 24 hours a day (firm generation) and are able to provide a constant supply (such as baseload generation of nuclear power plants) or adjust supply according to demand (such as dispatchable generation of thermoelectric/hydroelectric power plants). In contrast, solar and wind generation changes according to weather conditions (variable generation) and cannot be delivered continuously 24/365 (intermittent generation), consequently it is difficult to schedule and cannot be adapted to demand. However, new research showed that solar firmness and dispatchability or baseload provision 24/365 can be achieved by the so-called flexible photovoltaic/wind systems, i.e. solar/wind systems equipped with battery energy storage (BESS), smart inverters and power plant controllers that allow solar/wind output to be increased/curtailed to provide flexible generation on demand. These flexible PV systems are seen as the natural evolution of variable renewable energy systems (Liu, et al., 2023). The firm generation cost depends on: (1) The fraction of the PV generation that is supplied as firm dispatchable or baseload, i.e. the proactive curtailment of the power not firmed (also called implicit storage); (2) The size of the battery of the flexible plants; (3) The certainty of the supply of the firm provision (i.e. the number of hours in which the firm power promised is actually supplied). The certainty of supply is ultimately related to the system flexibility requirements which define the amount of reserve required to resolve the imbalance generated when the flexible system is not able to supply the firm promise (due to prolonged periods of irradiance/wind shortage and insufficient storage capacity). A PV producer can promise a given firm power but with different certainty of supply: the higher is certainty of supply the lower are the system flexibility requirement but the higher are the firm production costs. It has been demonstrated that according to the CAPEX/OPEX of the PV and battery there is a cost-optimal firm production cost (LCOE) (Perez, et al., 2019). The authors showed that the cost-optimal fraction that a producer can promise with a given certainty of supply is a trade-off between the size/cost of the battery and the size/cost of PV plant. The higher the size/cost of PV the higher is the curtailment (implicit storage) i.e. the not firmed fraction but the lower is the size/cost of battery. Considering the production of firm/baseload generation 24/365, Figure 22 shows the cost-optimal LCOE and firm fraction with 99% and 75% of certainty of supply. In the first case, the promised power is expected to be actually delivered practically all the time but the lowest production cost (driven by the battery capex) corresponds to the firm/baseload supply of only 30% of the PV generation i.e. 40 kW/MWp for 24/365. The cost-optimal size of the battery is 2 MWh per MWp and the production cost is 414 €/MWh considering that 70% of the generation should be curtailed. In the second case, the cost-optimal firm fraction grows to 70% corresponding to 115 kW/MWp of firm/baseload provision. The cost-optimal size of the battery is 1.7 kWh/MWp and the production costs decrease to 171 €/MWh. However, the promise can be met only 75% of the time generating an imbalance of 25% between the promise and the actual supply. The 24-hour firm provision is respected only during summer days.

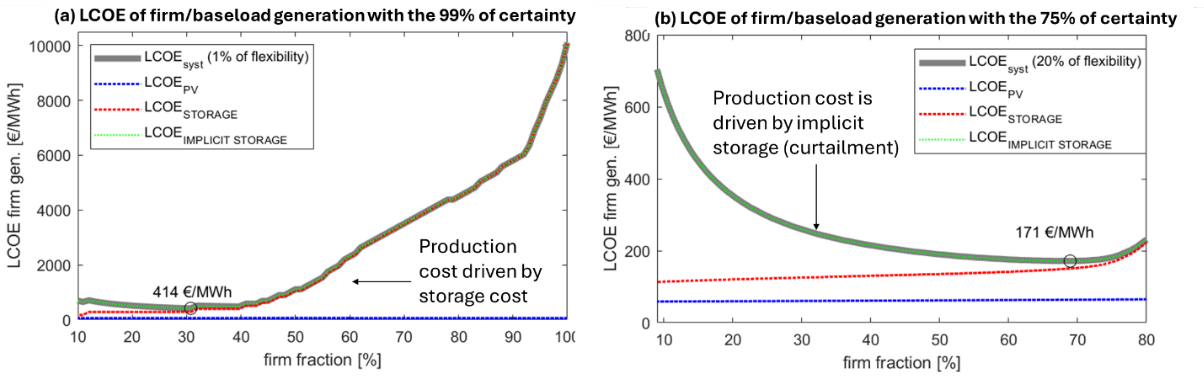


Figure 22: cost-optimal firm fraction considering 99% (a) and 75% (b) of certainty of supply.

In the H2020 SUPERNOVA project we investigated different strategies to reduce firm generation costs with high certainty of supply by using the day-ahead PV power forecast. Since the SOC of the battery is known the day before delivery, the best solution is to use the PV and SOC day-ahead forecast to set the optimal baseload promise that can be supplied for certain the next day (i.e., the predicted SOC should never reach zero during the next day). Figure 23a shows an example of a time series relating to actual SOC, firm photovoltaic supply, variable photovoltaic production to be reduced, and the base load commitment after daily optimization. It is worth noting that, during these days, the base load supply commitment on the wholesale market (resulting from forecast-based optimization) is always met. More generally, Figure 23b shows the firm generation that can actually be delivered with the same battery capacity of 1.7 MWh/MWp during the year considered. It can be observed that there are very few hours in which the promise is not respected. In this case, the plant can firm 63% of its generation with 96% certainty of provision and 1.3% of imbalance (due to firm PV power forecast errors). Thus, with the daily optimization strategy based on PV and SOC forecast, the firm PV supply is almost perfectly predictable, avoiding the use of additional reserves. At the same time, because of low curtailment (37%), the firm production costs (187 €/MWh) are similar to the one found with the 75% of certainty (174 €/MWh).

On the other hand, this strategy introduces daily and seasonal variability in firm/baseload provision that should be resolved by unit commitment of other programmable generators in the day-ahead wholesale market (with no additional balancing costs).

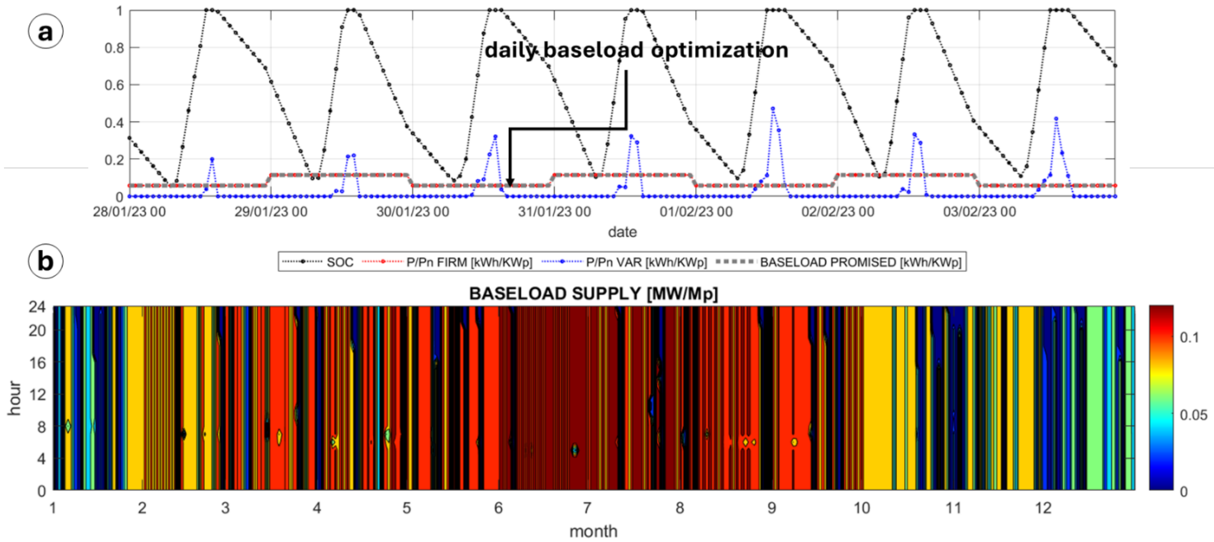


Figure 23: example of daily baseload optimization trend: actual SOC, PV firm supply, PV variable production to be curtailed and baseload promise (a); carpet plot of the baseload firm actually supplied (b).

3.2 Ancillary Services via Flexible Photovoltaic/Wind Systems and "Implicit" Storage to Balance Demand and Supply

M. Pierro, M. Barba, R. Perez, D. Moser, C. Cornaro, Solar RRL, (2022) [20]

https://onlinelibrary.wiley.com/doi/full/10.1002/solr.202200704

Achieving the EU RES penetration 2030 targets requires an increase in flexible resources to compensate for the variability/intermittency of solar and wind generation to ensure system safety and balancing. In this paper, we propose two readily deployable flexibility solutions to balance demand/supply as an alternative to building additional thermoelectric reserves. We show how the TSO can use the ancillary services provided by a flexible PV fleet (solar regulation) or PV/wind fleet (VRE regulation) together with a suitable under-forecast and pro-active curtailment of variable renewable generation (aka, implicit storage) to reduce current and future Italian imbalances. We also show how these flexibility solutions can become even more effective when combined with a strengthening of the transmission grid. We found that the imbalance reduction achievable by 2030/2040 through solar/VRE regulation strategies would be of the order of 20%-50% with zonal balancing and 27%-80% with nationwide balancing. Imbalance costs would remain comparable with the business-as-usual (thermal generation) costs. A proactive curtailment of 5% - 17% of the total VRE generation is the environmental cost of stabilizing the system using VRE plants, avoiding the construction of thermoelectric reserves.

Figure 24 shows the benefit in using our regulation strategies both in the current case of computing the Italian imbalance as the sum of the single market zones and in the case of using grid reinforcement to enable the use of a unique national balancing area. In the former case, the margin of reduction in imbalance volumes achievable through solar/VRE (PV and wind) flexible fleet ancillary services with implicit storage is about 20%-50% at 2030-2040. Coupling solar/VRE regulation-implicit storage strategies with grid reinforcement the reduction margin can be increased to at least 27%-75% by 2030-2040. Thus, enabling the enlargement of the forecast footprint at the national level notably increases the benefit of our strategies especially in the case of VRE regulation. Figure 24 also shows the diurnal imbalance reduction. By 2030-2040, solar regulation halves daytime imbalances while is almost completely removed by the

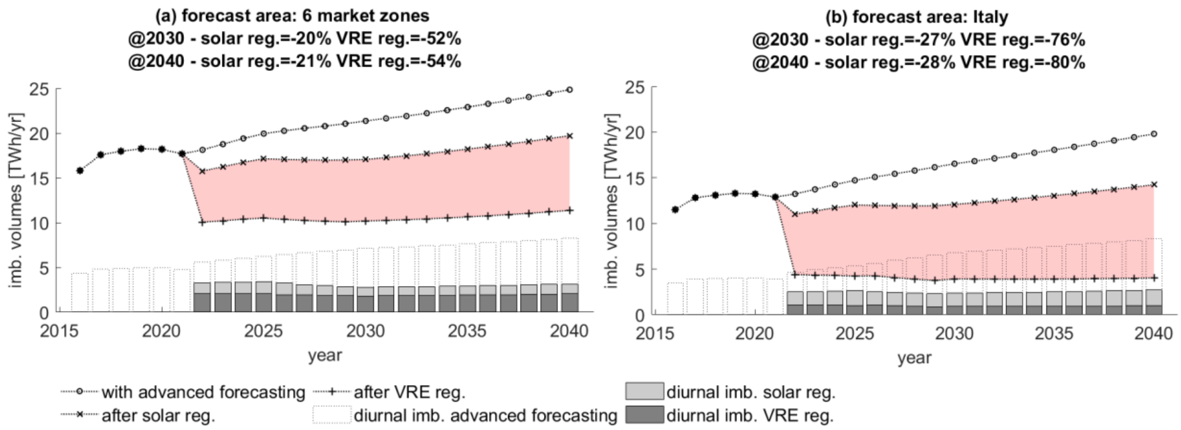


Figure 24: Imbalance achieved by the best our forecast (dotted line), margin of imbalance reduction obtained by solar/VRE regulation-implicit storage strategies (red area) and diurnal imbalance reduction both in the case of the imbalance resulting from the 6 market zones forecast (a) and in the case of a unique national prediction (b).

ancillary services provided by the flexible solar-wind feet.

Reference:

M. Pierro, M. Barba, R. Perez, D. Moser, C. Cornaro, Ancillary Services via Flexible Photovoltaic/Wind Systems and “Implicit” Storage to Balance Demand and Supply, Sol. RRL 2022, 2200704

3.3 Ground-breaking approach to enabling fully solar Renewable Energy Communities

Marco Pierro, Cristina Cornaro, David Moser, Richard Perez, Marc Perez, Stefano Zambotti Grazia Barchi (2024) [21]

https://doi.org/10.1016/j.renene.2024.121501

Renewable Energy Communities (RECs) are an important strategy of the EU, to promote and optimize the distributed deployment of renewable generation systems. At current incentives and costs, RECs that share the energy produced by PV/battery systems are expected to take the lion's share of distributed generation. In this paper, we highlight some important critical issues in electric system management that could result from the deployment of RECs if PV/battery system generation cannot meet the entire community demand. Thus, we show how a flexible PV system (PV/battery systems able to provide firm/dispatchable generation) can be cost-effectively dimensioned to supply 24/365 96%-97% of the demand of a residential users' community. Figure 25 summarizes the obtained results for 1 MWp/1.2 MWh commercial flexible PV system. It shows that the plant is able to firm 30% of its generation to supply a REC of 142 households, thus injecting into the grid only 70% of the output in the form of non-dispatchable variable generation. We call this strategy: “generation splitting”. The monthly average daily normalized production divided into firm/dispatchable and variable/non-dispatchable power generation is also depicted. In the winter season most of the generation is firmed, while in the summer season most of the generation is fed into the grid as variable energy.

We further provide two business models based on power purchase agreement to demonstrate that, at these production costs, fully solar RECs are currently techno-economically feasible and provide mutual benefits to both flexible PV producers and REC members. Suitable virtual corporate PPAs can reduce the electric bill of the REC members by 11%-5% without requiring any investments and increase the producer incomes by 18%-22%.

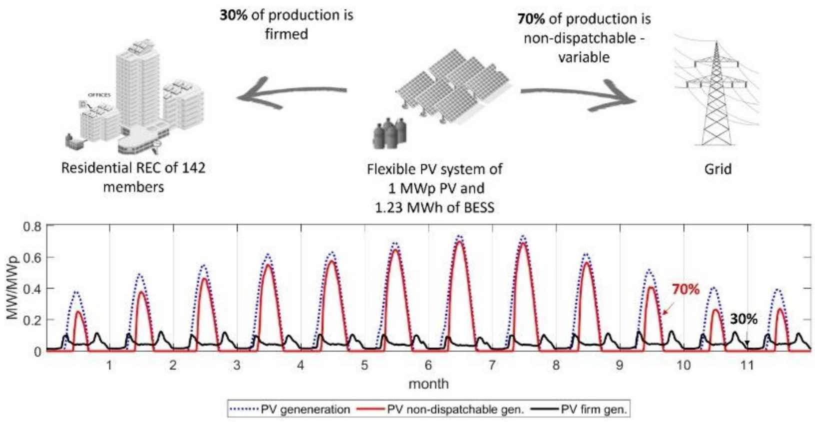


Figure 25: Diagram of the production of 1 MWp/1.2 MWh flexible PV system and monthly daily average of the normalized production.

Reference:

M., Pierro, Marco, C., Cornaro, Cristina, D., Moser, David, ... S., Zambotti, Stefano, G., Barchi, Grazia, Ground-breaking approach to enabling fully solar renewable energy communities, Renewable Energy, 2024, 237, Part A, 121501, https://doi.org/10.1016/j.renene.2024.121501

The research that led to these results received funding from the Horizon 2020 research and innovation program under Grant Agreements N. 952957, Trust-PV project.

3.4 Fully Solar Residential Energy Community: A Study on the Feasibility in the Italian Context

G., Barchi, Grazia, M., Pierro, Marco, M., Secchi, Mattia, D., Moser, Energies, 2025 [22, 23]

https://doi.org/10.3390/en18081988

Expanding the installation and use of renewable energy sources will help Europe reach its energy and climate goals. Additionally, users of small-scale photovoltaic systems will be essential to the energy transition by forming renewable energy communities (RECs). This paper offers a techno-economic analysis of the Italian REC incentive system and a suitable business model to encourage residential photovoltaic and battery installations and lower electricity costs. We present a community model that includes a set number of prosumers, a growing number of consumers, and various configurations and management strategies for photovoltaic (PV) and battery systems. The simulation results show that energy performance increases if a centralized battery management strategy is activated and more consumers join the community. Most importantly, we explore the techno-economic feasibility of RECs of residential PV/BESS prosumers to achieve the 98% of self-production (SP) using the most profitable control and management configuration (P2P-C): an aggregator control the PV/BESS plants generation/storage to maximize the self-production of the entire REC and not of the single prosumers and the storage is not distributed but centralized (with a dedicated grid connection point). In addition, when also consumers become members of the solar REC, the community's PV plants and battery can be managed by the aggregator in two different ways: just maximizing the self-production of the entire community (regardless if the members are prosumers or consumers) as in the previous case (P2P-C) or still providing the 98% of the demand of all the prosumers (by firm and dispatchable 24/365 power supply) and sharing to the consumers only the solar overgeneration (P2P-FC).

We found that, in Italy, a fully solar REC of residential prosumers (with Italian mean residential load of 3160 kWh/yr) to reach a self-production of 98% at lowest costs, needs in average 7 kWp of PV and 8.7 kWh of battery per prosumer. That means overbuilding the PV to produce 3 times the annual electrical demand but reduces the storage requirement to just 1 day of autonomy. Figure 26 shows that, with the Italian REC incentives system, fully solar powered communities are economically feasible if PV is over-built, the battery are centralized and the REC is managed by an Aggregator with P2P-C/P2P-CF control strategies. The highest discounted payback time would be 19 years with an estimated PV lifetime of 30 years and a BESS replacement after 15 years. P2P-C control is more cost-effective than P2P-CF, but it has been shown that the latter strategy based on firm generation is more grid-friendly because it puts less variable energy into the grid.

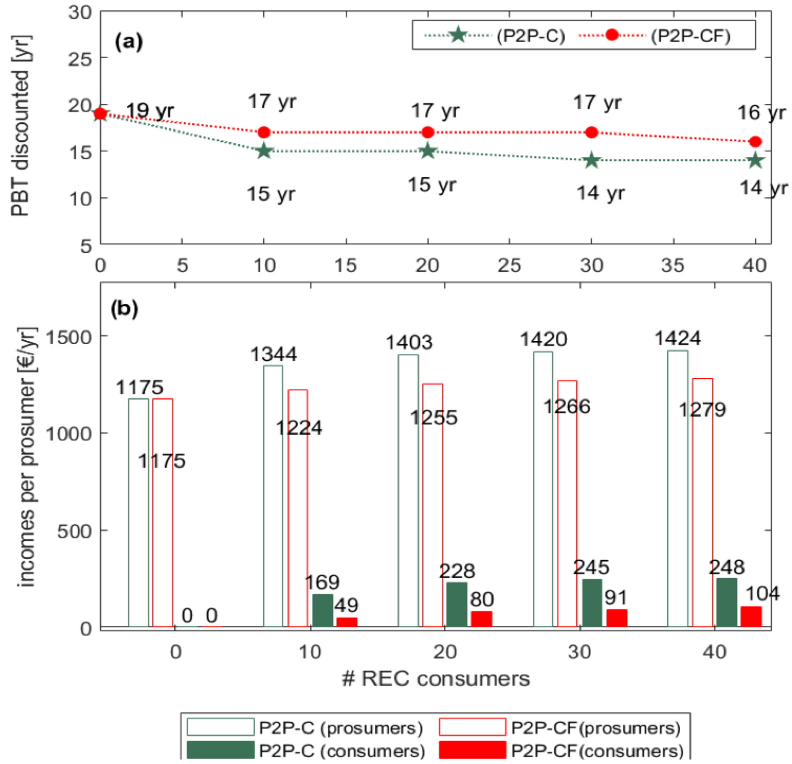


Figure 26: Discounted PBT (a) and prosumers/consumers revenues (b) in the case of a fully solar REC.

Reference:

- *G., Barchi, Grazia, M., Pierro, Marco, M., Secchi, Mattia, D., Moser, David, Fully Solar Residential Energy Community: A Study on the Feasibility in the Italian Context, Energies, 2025, 18(8), 1988; https://doi.org/10.3390/en18081988*
- *G. Barchi, M. Pierro, M. Secchi and D. Moser, "Residential Renewable Energy Community: a Techno-Economic Analysis of the Italian Approach," 2023 IEEE International Conference on Environment and Electrical Engineering and 2023 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe), Madrid, Spain, 2023, pp. 1-6, Doi: 10.1109/EEEIC/ICPSEurope57605.2023.10194754., Renewable Energy, 2024, 237, Part A, 121501, https://doi.org/10.1016/j.renene.2024.121501*

The research that led to these results received funding from the Horizon 2020 research and innovation program under Grant Agreements N. 952957, Trust-PV project.

3.5 A pathway for firm and dispatchable solar/wind supply through generation and markets splitting.

Marco Pierro, Cristina Cornaro, David Moser, Richard Perez, Jan Remund, Grazia Barchi (2025) [24]

Energy Conversion & Management

https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5288193

https://www.sciencedirect.com/science/article/pii/S0196890425011860?dgcid=author

The current mainstream strategy to allow a high share of variable renewable energy feed-in is mainly aimed at enabling new flexibility resources. Another strategy that could be implemented/incentivized is based on firmness and dispatchability of solar/wind power, which, conversely, could reduce/eliminate any demand for additional flexibility. In this work, we showed that solar/wind facilities can produce both variable/intermittent and baseload/dispatchable energy 24/365. Then, we proposed a new market design more suitable for this generation splitting approach. Using Italy as a case study, we have shown through energy simulations and cost optimization/analysis that the proposed market reform, combined with a firm energy feed-in tariff, would make it profitable to reduce variable energy feed-in from large PV/wind power plants and related induced flexibility requirements by 20%-30%-40%, in 2024-2030-2050. This flexibility reduction increases to 50%-60%-70% dealing with the joint generation of an optimal mix of PV/wind farms (Figure 27). In addition, in 2050, for PV and the optimal mix of solar/wind systems, incentives below 100 €/MWh will push producers to generate only dispatchable energy. We also showed that our approach could solve or mitigate the significant misalignments between the current market structure and the techno-economic characteristics of renewables: wholesale market price volatility and cannibalization, growth of balancing prices and system-charges.

The spot market should be divided into a variable renewable energy market (VRM) and a day-ahead firm energy market (DAFM). The first is a regulated market in which all variable/intermittent energy is paid for through public auctions that should guarantee the producers a defined markup against the production cost (Levelized cost of energy -LCOE-). DAFM is an energy market with high added economic value in which PV/Wind firm generation and other firm/dispatchable generation can compete at the same level at a high marginal price. It is still based on the merit-order scheme with a price cap.

We compute baseload generation costs and the minimum feed in tariff (FiT) (with 100 €/MWh cap) that ensure a production cost 20% below the system marginal price for different firm energy fraction.

Figure 27 shows that, as the RES transition unfolds, since CapEx decreases, a Feed-in-tariff below 80 € per firm MWh enables maximum energy profit by firming a growing fraction of generation.

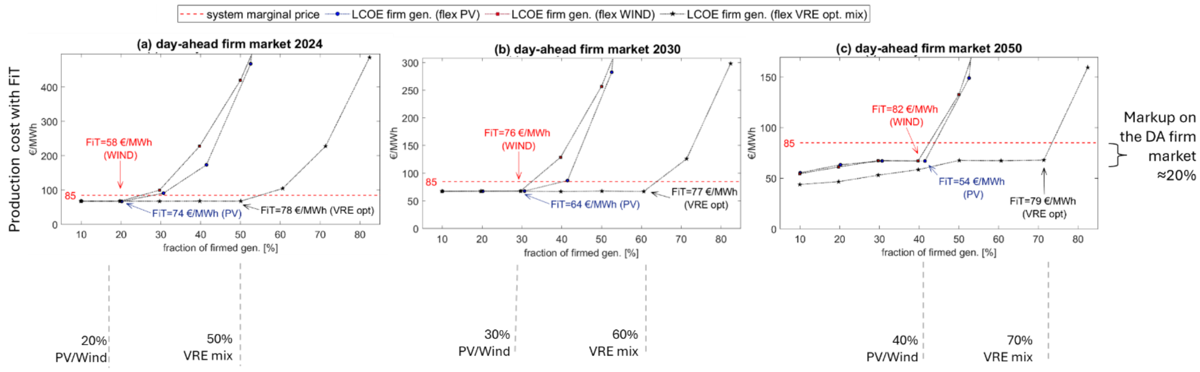


Figure 27: Levelized cost of energy discounted of the feed-in-tariff of the flexible PV/wind/optimal mix plants. In parentheses is the optimal FiT which maximizes the incomes on DAFM (below the cap of 100 €/MWh). The values in the graphs were calculated considering the CAPEX/OPEX of flexible systems at 2024 (a), CAPEX/OPEX projections of flexible systems at 2030 (b) and 2050 (c).

Reference:

Pierro, M., Cornaro, C., Moser, D., Perez, R., Remund, J., & Barchi, G. (2026). A pathway for firm and dispatchable solar/wind supply through generation and markets splitting. Energy Conversion and Management, 348, 120662. https://doi.org/10.1016/J.ENCONMAN.2025.120662

The research that led to these results received funding from the Horizon 2020 research and innovation program under Grant Agreements N. 952957, Trust-PV project and N. 101146883.

3.6 Mitigating Grid Impact of Distributed Solar Generation through a VPP-Based firm PV Strategy

M. Pierro, A. Donadello, D. Prando, D. Moser, G. Barchi (2025) [25]

Oral presentation [EUPVSEC 2025, Bilbao](#).

The growth of distributed generation from variable renewable energy sources, which is necessary to achieve the European Union's planned transition to renewable energy by 2050, poses significant challenges to the electricity system at both the distribution and transmission levels. It is increasingly occurring that distribution grids, especially at the low voltage (LV) level, are no longer able to transport excess solar energy (congestion on lines) as well as to release this energy to the national transmission grid (congestion on transformers), compromising the stability and quality of electricity supply. Thus, although distributed solar generation is essential for the energy transition, some local grids are no longer able to accommodate new solar plants (saturation of hosting capacity). In addition, the increasing self-consumption and the penetration of new loads such as heat pumps and electric vehicles generate increasing variability in the residual load (demand net of self-consumption) of the DSO's control area. Increased variability, together with unmetered distributed solar generation (DSOs do not monitor plant output), makes the residual load increasingly difficult to forecast. This results in higher imbalances between demand and scheduled supply and voltage fluctuations that must be compensated for by the transmission system operator (TSO) through the use of increased reserve of flexible and dispatchable resources.

How to limit the impact of distributed generation on the power system at the transmission level while simultaneously increasing the hosting capacity of the distribution grid is still a problem being researched and tested and is exactly the purpose of this study.

We propose a groundbreaking solution to address this issue based on the installation of batteries and inverter grid-forming in the primary/secondary stations and on an innovative logic of control of the battery management system (BMS). We tested the BMS control strategy using the netload data metered at a primary station under the control of a DSO in the north of Italy. We proved that if the system is suitably dimensioned, it reduces the number of reverse power flows by 96% and the maximum reverse power by 33%, limiting voltage standard violation or transformer overload. The solar energy generated in the area downstream of the cabin that is fed into the transmission grid (reverse power flows) is reduced from about 4% to less than 0.05%, so that almost all PV fleet's generation remains in the control zone. At the same time, the distribution of solar-induced residual load ramps is practically restored to the levels found in the absence of solar generation at all time scales. (15/60/240 min). Therefore, the TSO is not forced by distributed solar generation to increase secondary/tertiary/unit-commitment reserves.

The basic approach is that DSOs should consider solar DG in the control zone (downstream secondary/primary cabins) as produced by a Virtual Power Plant and place batteries/grid-forming inverters (BESS) near by the substations. The BMS should control the storage system with the following logic. During the daylight, batteries withdraw from the grid the fraction of the solar DG exceeding a predefined baseload target (*Figure* 28a). During the night batteries redispatch the baseload target as much as possible (*Figure* 28b).

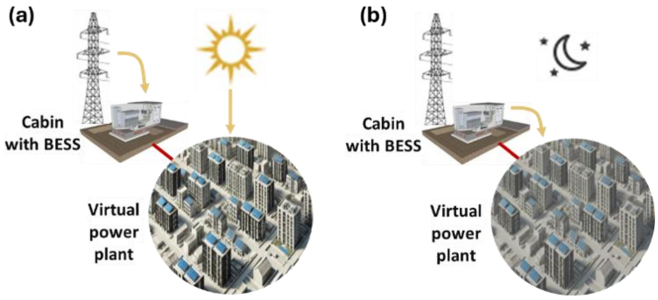


***Figure 28: Approach diagram*.**

Reference:

- *Oral presentation EUPVSEC 2025, Bilbao.*

The research that led to these results received funding from the Horizon 2020 research and innovation program under Grant Agreements N. 101146883, SUPERNOVA project. Cristina Cornaro thanks the Rome Technopole, Innovation Ecosystem funded by PNRR for the support.

3.7 Maximizing DPV Hosting Capacity with Regional Firm VRE Power

Marc Perez, Richard Perez, Upama Nakarmi, Thomas E. Hoff, Jeffrey Freedman, Elizabeth McCabe, Marco Pierro & Jan Remund, Solar 2024 Proceedings, 2024 [26]

https://www.proceedings.com/content/077/077496-0028open.pdf

This study explores how distributed photovoltaic (DPV) systems can play a transformative role in grid reliability and capacity when integrated into a broader strategy for firm variable renewable energy (VRE) generation. The authors investigate whether DPV hosting capacity—typically constrained by grid limitations—can be significantly expanded if DPV systems actively contribute to regional firm power generation objectives.

Using 20 years of hourly solar and wind data, the study models two case studies in Iowa and Louisiana, regions within the Midcontinent Independent System Operator (MISO). The analysis assumes a constant load (mimicking baseload generation) and optimizes the mix of PV, wind, battery storage, and a small share of dispatchable e-fuel thermal generation. Modelling incorporates both real and implicit storage (via overbuilding and curtailment), which allows VRE systems to deliver firm power at competitive costs.

A central insight is that DPV systems, when operated dynamically—i.e., with coordinated curtailment and storage—can dramatically increase hosting capacity on distribution circuits. This is especially true when DPV is part of a regional firm power strategy rather than operating independently. In Louisiana, where the optimal firm power regional mix is dominated by PV (95%) with no wind and 5% e-fuel flexibility, distributed hosting capacities can be increased by 650%, as shown in Figure 29 (top). In Iowa, where wind plays a larger role (47.5% wind, 47.5% PV with 5% e-fuel flexibility), distributed hosting capacities still increase by 260%, despite more complex storage coordination needs (Figure 29, bottom).

The study also highlights the limitations of current market structures, which discourage curtailment and overbuilding due to merit-order pricing. It advocates regulatory reforms that would allow VRE resources to be compensated based on capacity contributions, enabling the deployment of firm renewable systems and unlocking substantial DPV hosting potential.

In conclusion, the authors argue that integrating DPV into regional firm power strategies not only supports grid reliability but also enables multifold increases in hosting capacity on distribution systems —especially in PV-dominant regions. Realizing these benefits will require market reforms that support dynamic operation and capacity-based remuneration for VRE resources.

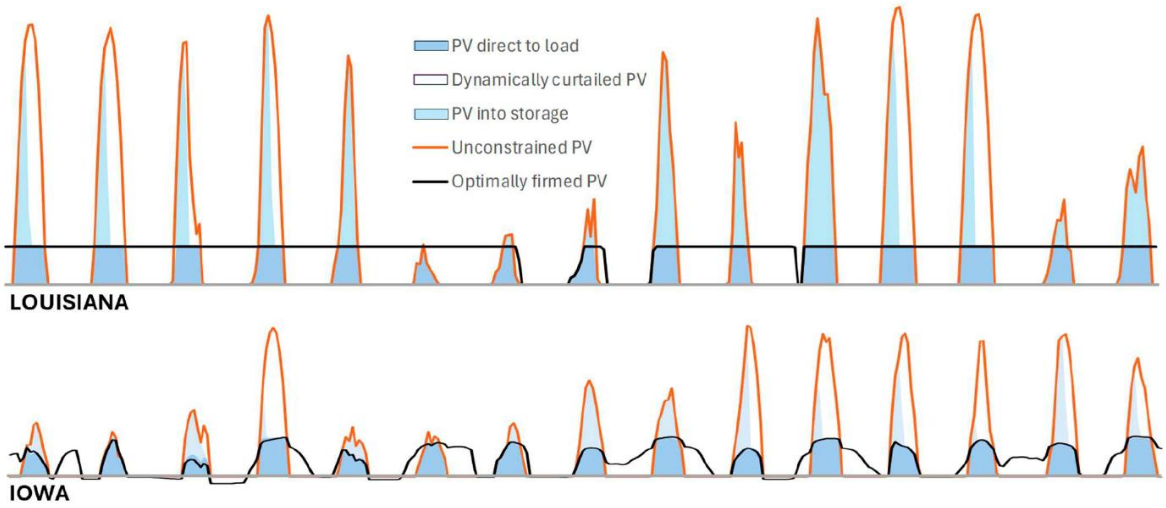


Figure 29: Contrasting distribution level unconstrained DPV and firm DPV contribution in two power grids where PV is the unique VRE (top) and where VRE consists of a blend of wind and PV (bottom)

Reference:

- *Invited oral presentation, Solar 2024 Conference, Washington, DC, USA*
- *IEEE PVSC Conference, 2024*

3.8 On the Complementary Variability of Solar and Wind Resources

Marc Perez & Richard Perez, 2025 [27]

Oral Presentation, 2025 IEEE PVSC Conference, Montreal, Canada

In their study, the authors explore how solar and wind energy resources vary across time and space in the continental United States, and what these patterns may imply for integrating renewables into the power grid. Using high-resolution data from 2023, they simulate hourly power production from both wind and solar sources and analyze how variability behaves across different temporal scales (from hours to years) and spatial scales (from local to continental).

Temporal Variability: The study reveals a striking contrast in how solar and wind power fluctuate over time. Solar power is highly variable at short (intraday) timescales. This is due to the predictable diurnal cycle—solar output rises and falls with the sun, leading to sharp changes in generation between day and night. Wind power, on the other hand, shows greater variability at longer timescales, such as days or weeks. This is driven by the passage of weather systems, which can cause significant and lasting shifts in wind patterns. Figure 30 presents variability signature curves that map how variability changes with time-averaging intervals. These curves show that solar variability peaks at around 8 hours, reflecting the day-night transition. Wind variability peaks at around 32 hours and remains considerably higher than solar for all longer time scales.

Spatial Variability: The study also examines how variability changes when power generation is averaged over larger geographic areas. Wind variability decreases significantly with spatial averaging. This is because wind patterns are influenced by large-scale atmospheric systems, so spreading wind farms across a wide area smooths out local fluctuations. Solar variability, however, is more localized. Even when solar farms are spread out, the variability remains relatively high due to the consistent timing of sunrise and sunset across entire regions and continents.

Seasonal Patterns and Capacity Factors: Wind power generally has a higher capacity factor than solar—more than double in most months. However, wind power also exhibits strong seasonal variability, with noticeable dips and peaks throughout the year. Solar output is more consistent, thanks in part to the use of fixed latitude-tilt systems in this study, which boosts winter production and reduces seasonal swings.

Implications for Grid Integration: The findings have important implications for designing a resilient and efficient renewable energy grid. Solar and wind are complementary resources both temporarily and spatially. Indeed, several of the studies in this report indicate that optimal firm PV/wind blend solutions can achieve considerably lower firm power generation LCOEs than either resource could individually. However, the optimal firm power blends tend generally to favor a higher proportion of PV than would be expected from the higher capacity factors exhibited by wind power generation. One of the key reasons for this is the higher variability of wind for multi-day time scales that matter most to achieving reliable 24/365 firm power solutions.

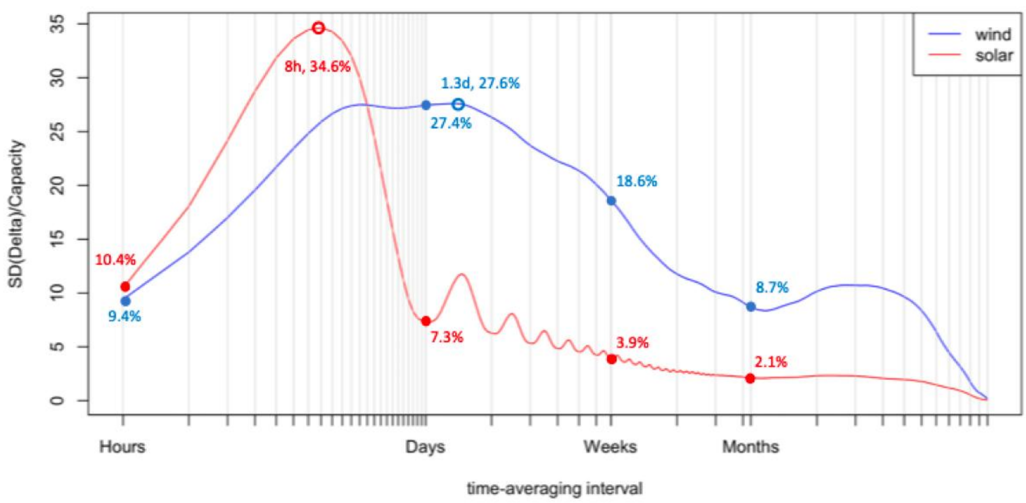


Figure 30: 2023 solar (red) and wind (blue) variability signatures as a function of timescale with variability at key time-averaging intervals called out.

3.9 Effectively dispatchable solar power with hierarchical reconciliation and firm forecasting

D Yang, G Yang, M J Perez, R Perez, Journal of Modern Power Systems and Clean Energy (2024) [28]

https://ieeexplore.ieee.org/document/10746396

This study investigates how to fully eliminate PV power forecast errors within the current operation regulations of the power grid. In a nutshell, the existing workflow for PV power forecasting is as follows: Weather centers generate forecasts of meteorological parameters and provide them to PV plant owners; upon receiving the raw forecasts, post-processing is performed at the plant level, and the processed meteorological data are converted into PV power forecasts based on the plant information and solar power curve, which are then submitted to grid operators. Nevertheless, this forecasting practice still fails to address the errors in regional PV power forecasts resulting from biases in meteorological forecasts and inaccuracies in the solar power curve modeling. To this end, this study introduces hierarchical forecast reconciliation and firm forecasting, to ensure that PV plants can indeed deliver solar power in full accordance with the forecasts.

The employment of hierarchical reconciliation aims to achieve aggregation consistency in PV power forecasts at various hierarchical levels within a power grid, and as a side benefit, enhancing forecast accuracy at all levels. Aggregation consistency refers to the phenomenon in which PV power observations at a higher-level node are equal to the sum of those at all corresponding lower-level nodes. Nonetheless, due to the diversity of forecasting methods and the information asymmetry, PV power forecasts across the hierarchy do not exhibit aggregation consistency. To overcome this challenge, this study presents two reconciliation techniques: minimum-trace (MinT) reconciliation and bottom-up (BU) reconciliation. Specifically, the BU method obtains upper-level forecasts by naturally summing forecasts from lower levels, while the MinT method generates aggregate-consistent forecasts across all levels by utilizing the interdependent relationships of forecast time series at each level.

Although hierarchical reconciliation improves the performance of PV power forecasts, it cannot guarantee perfect alignment between the grid-connected PV power curve and the forecast curve. The authors apply firm forecasting to accomplish this goal. In brief, PV plant owners should additionally deploy battery storage and reasonably expand their PV capacity, which allows the grid-connected power of the firm PV–battery system to match 100% with the forecast profile generated and issued to the plant level by grid operators using the hierarchical reconciliation technique. To determine the optimal configuration of a firm PV–battery system, this study develops a mixed-integer linear program to minimize the firm forecast premium, which is defined as the ratio of the LCOE of a firm energy system capable of achieving firm forecasting to that of an unconstrained PV plant. In addition, the authors utilize the commercial Gurobi solver to solve the optimization model and acquire the $/kW premium used to quantify the additional cost of transforming unconstrained PV into dispatchable generation sources.

Through case studies of 405 simulated PV plants and 34 substations in California, the following conclusions can be made:

- Regardless of the reconciliation method, as the PV overbuilding ratio increases, the firm forecast premium rapidly declines to a minimum value, after which it shows quasi-linear growth, as illustrated in Figure 31. For instance, when the PV overbuilding ratios for the MinT forecast are respectively 1, 1.27, and 3, the corresponding premiums are 13.82, 2.04, and 3.15, respectively.

- The premium for implementing firm forecasting at the plant level is larger than that at the substation level. This is attributed to the fact that the latter can share battery storage to some extent, hence reducing the required battery capacity.
- The height of the bar chart in Figure 32(a) is generally higher than that in Figure 32(b). This demonstrates that the MinT method, with its superior forecasting accuracy relative to the BU method, more effectively lowers the $/kW premium of a firm PV–battery system.

Building upon the current PV power forecasting framework of numerical weather prediction, forecast post-processing, and weather-to-power conversion, this study proposes a five-step workflow with the last two steps comprising hierarchical reconciliation and firm forecasting. At this point, as firm PV plants can generate electricity strictly in accordance with the forecast profile, their performance becomes comparable to traditional thermal power generators.

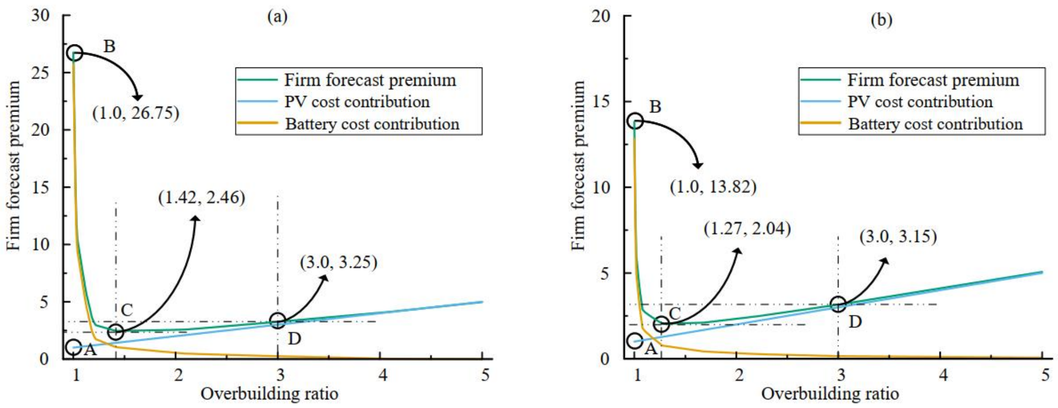


Figure 31: The optimization results of firm forecasting at substation 8 under different PV overbuilding ratios. The left subplot (a) corresponds to the reconciled forecasts from the BU method, whereas the right subplot (b) corresponds to the reconciled forecasts from the MinT method.

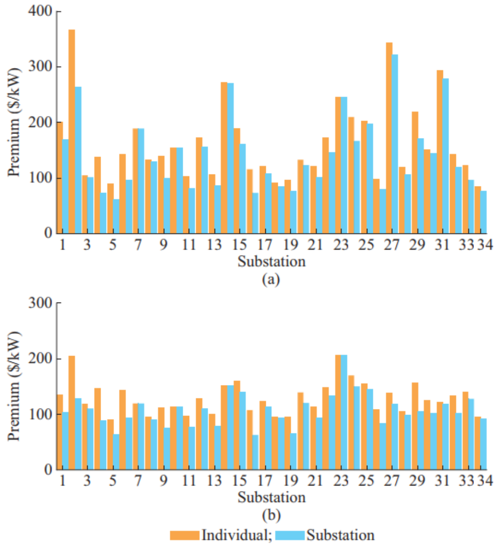


Figure 32: The required $/kW premium for firm forecasting at both the plant level and substation level under the BU method (a) and the MinT method (b)

3.10 Firm solar power forecast through battery storage and PV overbuilding with solar power curve modeling

Q. Gao and D. Yang, IEEE 7th International Electrical and Energy Conference (2024) [29]

https://ieeexplore.ieee.org/abstract/document/10583486

This study presents a firm solar power forecasting framework, which leverages battery storage and PV overbuilding to eliminate solar power forecast errors. The firm forecast premium is introduced as the objective function to gauge the additional costs required to achieve firm forecasting, under the constraints of the firm forecast, battery storage operation, and PV power balance.

The case study for an unconstrained PV plant with a DC capacity of 1 MW is conducted in Heihe, China. The daily energy generation of unconstrained PV and firm PV is illustrated in Figure 33. Besides, firm forecasting (Figure 34) is achieved at a premium of 1.85, when the PV oversizing ratio is 1.12 and the rated capacity of the battery is 2.61 MWh, resulting in an equivalent annual cost of $137,422. Compared to a battery-only solution (without PV overbuilding), the premium is reduced by 29%, and the rated capacity of the battery is decreased by 4.1 MWh.

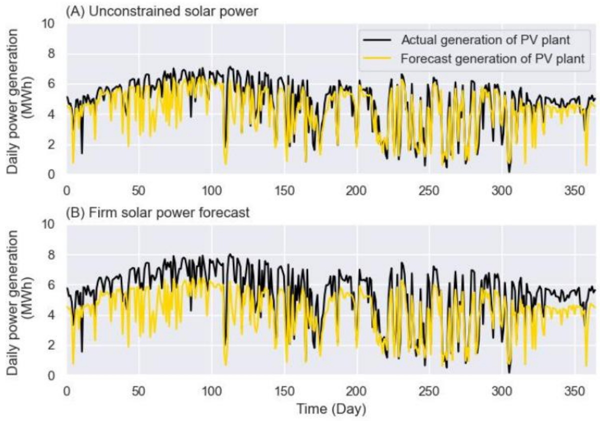


Figure 33 The daily power generation for unconstrained PV (a) and firm PV (b) obtained by accumulating hourly PV output

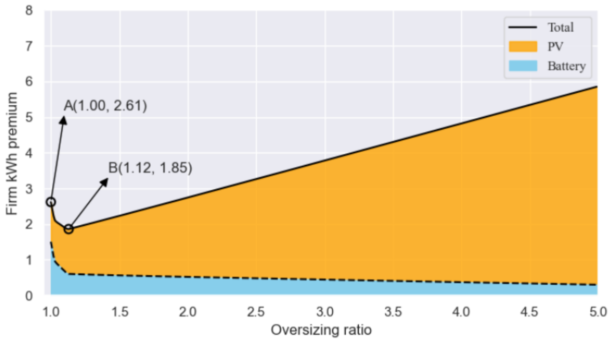


Figure 34: The premium of the firm PV–battery system under different PV oversizing ratios

3.11 The Perfect Forecast Metric (PFM)

Richard Perez & Marc Perez (2025) [30]

IEA PVPS Task 16 Subtask 3 — Internal Communication

The metric assesses a forecast's performance by determining the cost of transforming it into a 100%-accurate forecast. This cost could be inferred from existing market rules, e.g., penalties levied on over- and under- forecasts. However, because rules differ from location to location and change over time, a more robust cost assessment consists of pricing the hardware that can guarantee that the energy generated equals the energy forecasted at all times

The hardware costing approach is analogous to the firm power methodology of transforming a variable [PV or wind] output into a known output such as baseload by applying an optimal blend of physical and implicit storage (aka dynamic output curtailment). Here, we replace the load with the forecast PV output

The metric requires standardized cost and performance assumptions, including:

- Storage capex, suggesting $100/kWh
- Storage round-trip efficiency, suggesting 100%
- Solar system capex, suggesting $1000/kW

- Solar system size, suggesting 1 kW
- Value of solar-generated electricity, suggesting \$0.1/kWh
- System lifetime, suggesting 15 years
- Simple economics ─ zero inflation, zero cost of money

The 1 kW system size standardization ensures that the metric can be directly applied to irradiances as well as PV generation. Note that while the above economic assumptions will certainly impact on the magnitude of the metric, they should have little to no impact on the relative performance of models assessed by the metric (i.e., on the usefulness of the metric). Importantly, once standardized, the economic/technical assumptions should not change, so all assessments can be coherent and intercompared.

The metric calculation involves a minimization of the perfect forecast cost by optimizing physical and implicit storage (system overbuild). The PFM per se is the [dimensionless] sum of the optimized storage capex and the optimized overbuilding capex, normalized to the value of system's revenues over the assumed life.

Figure 35 compares the performance ranking of several forecast models at the one-hour time horizon using two metrics: the PFM (which measures the cost of missed forecasts) and the RMSE. The example covers one-hour-ahead forecasts for six U.S. SURFRAD sites over 1.5 years. When evaluated with the PFM metric, smart persistence performs better than all other models, even though its RMSE is noticeably worse than the leading RMSE-based models.

Looking only at the four Numerical Weather Prediction (NWP) models on the right side of the figure, the ordering also reverses: the model with the worst RMSE (HRRR) becomes the best performer economically, while the one with the best RMSE (ECMWF) becomes the worst under the PFM metric.

This reversal can seem counterintuitive. It becomes clear, however, when noting two points:

1. Smart persistence errors do not accumulate—they have zero long-term bias by definition.
2. PFM reflects the cumulative cost of mitigation measures (e.g., deploying backup resources), which is driven more by sustained or systematic errors than by short-lived, self-correcting error spikes.

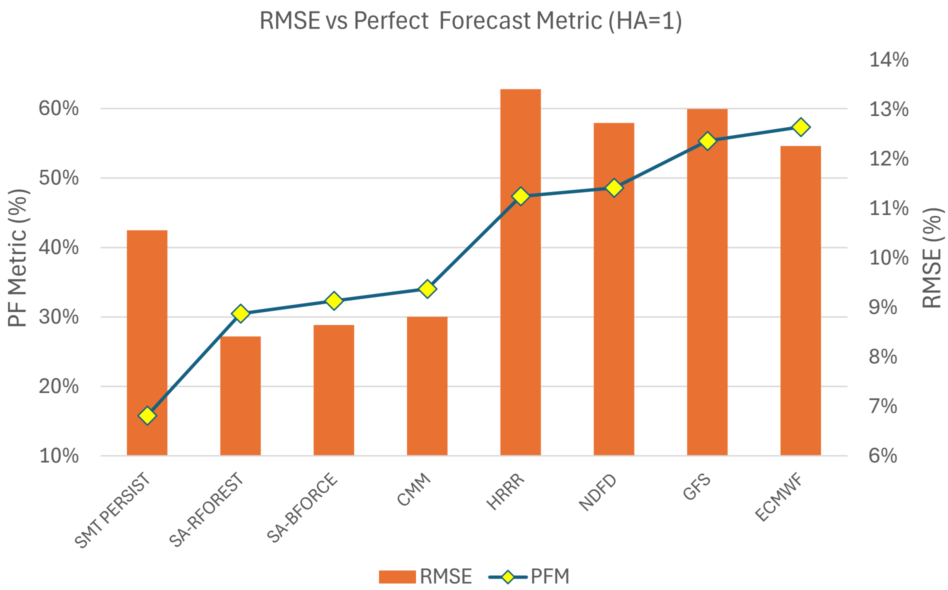


Figure 35: Comparing the performance of several forecast models at the one-hour time horizon using RMSE and PFM metrics. Models include smart measured persistence (SMT-PERSIST); a new version of SolarAnywhere optimized with machine learning (SA-RFOREST); the current version of SolarAnywhere (SA-BFORCE), satellite cloud motion (CMM), and four well-known Numerical Weather Processing (NWPs) models

3.12 Dark Doldrums – estimating the probabilities of successive days of low variable renewable energy (VRE)

John Boland (2024) [31]

IEA PVPS Task 16 Subtask 3 Activity 3.5 — Internal Communication

The International Energy Agency has identified six phases of variable renewable energy (VRE) integration, from no impact up to firm power. In 2024 South Australia became part of the elite group of two, along with Denmark, to achieve Phase 5, with significant volumes of surplus VRE across the year. Denmark is able to draw the equivalent of 100% of its maximum demand from connections to other grids, but for South Australia the maximum is 25%.

The major problem is how to cope with Dark Doldrums, or periods with low VRE. We measure how probable they are for the South Australian grid, for periods of 2 up to 7 days for example. We begin with six years of data and use non-parametric bootstrapping to generate 200 years of synthetic data to perform risk analysis. The synthetic data will have the same statistical characteristics as the original data but will have sequences that may not have appeared there.

Algorithm

- Construct a model for the six years of data that includes output from solar and wind farms, plus rooftop solar.
- This includes a seasonal Fourier series model and an AR(3) model for the difference between the data and the seasonal model. Figure 36 gives an example of the data plus the model fit.

- Use non-parametric bootstrapping via random selection with replacement for the noise of each month separately - as many years as desired. Sampling separately for each month is necessary, because as Figure 37 shows for January and July, the distributions are different for the different months.
- Amalgamate the noise terms into full years by adding each month sequentially.
- Concatenate the years.
- Apply the AR(3) model to the series to generate synthetic sequences using the formula.
- Add the seasonal model.
- Run code to count the number of times that successive days fall below some specified limit – in this example, 10% of maximum demand was used.

Table 1 gives the results of the calculations in terms of return period in number of years. The interesting outcome is that the longer periods of low VRE such as 5,6,7 days occur in South Australia predominately occur in Spring, when there is very low demand. So, the Dark Doldrums then may not have any consequences.

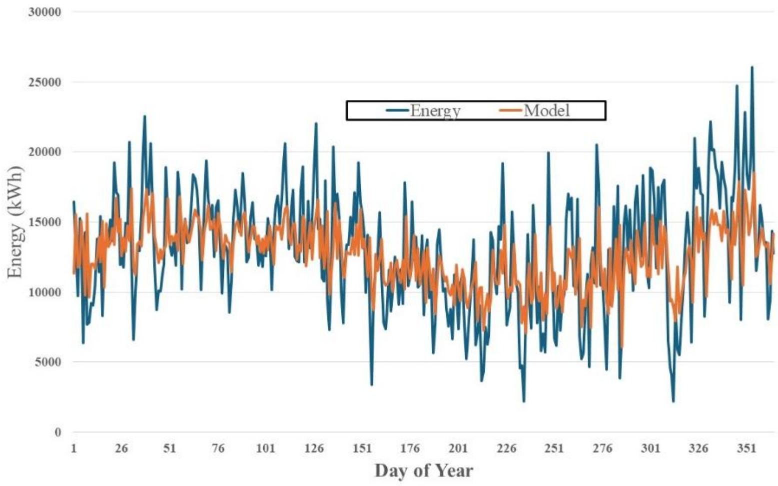


Figure 36: The combined energy plus model

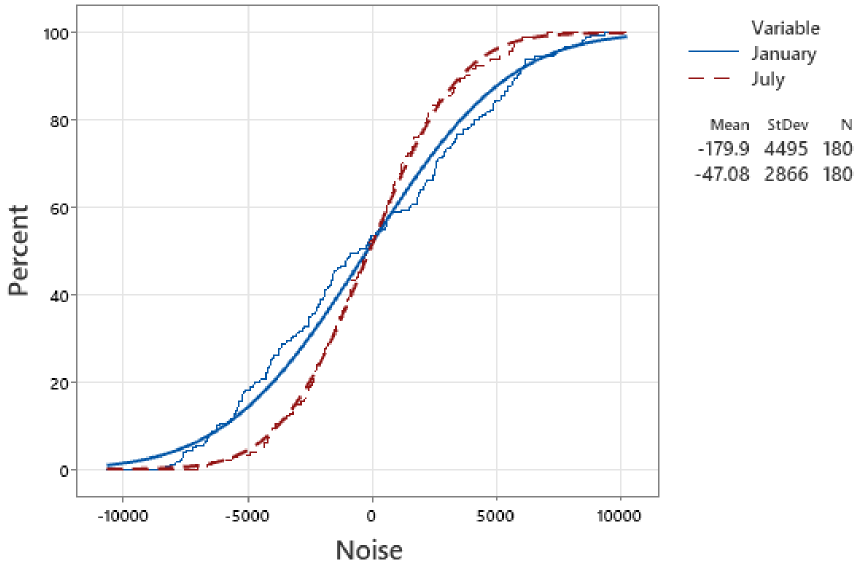


Figure 37: Noise distributions for January and July

Sequence	*Number*	*Return Period*
2	1136	0.17
3	380	0.52
4	141	1.4
5	36	5.6
6	9	22.2
7	9	22.2

Table 1: Return periods for low levels of VRE (Years)

4 CONCLUSIONS

The findings presented in this report reaffirm and expand upon the foundational insights from the 2023 Firm Power study: a fully renewable, firm power system is not only technically achievable but economically competitive across diverse geographies. Through comprehensive modeling and case studies, contributors demonstrate that variable renewable energy (VRE)—primarily wind and solar—can reliably meet 24/7 electricity demand when supported by strategic design choices. Central to this transformation are four pillars: **optimal VRE blending**, **[battery] energy storage**, **overbuilding with curtailment**, and **targeted flexibility measures.**

The evidence underscores that, in the absence of large-scale low-cost flexible resources, overbuilding and curtailment ─ often referred to as implicit storage ─ are indispensable for minimizing reliance on expensive seasonal storage and large-scale grid expansions. Geographic dispersion, demand-side management, and innovative uses of curtailed energy, such as hydrogen production, further enhance system resilience and economics. Importantly, limited dispatchable generation using renewable e-fuels providing *supply-side flexibility* can act as a cost catalyst, reducing the overall levelized cost of firm electricity (Firm LCOE) without undermining decarbonization goals.

Case studies from regions as varied as Canada (Nova Scotia), Italy, Switzerland, China, and Australia confirm the feasibility of these strategies under real-world conditions. They reveal that optimized configurations—tailored to local resource profiles and infrastructure—can deliver firm renewable power at competitive costs, even under scenarios of significant demand growth from electrification. Moreover, emerging approaches such as Virtual Power Plants (VPPs), advanced forecasting, and sector coupling offer pathways to accelerate deployment while mitigating grid integration challenges.

However, technical solutions alone will not suffice. The transition to least-cost firm renewable systems hinges on **market and policy reforms**As argued in this report [2], current electricity markets, designed around fuel-based power systems, where merit-order dispatch efficiently prioritized generators by marginal fuel cost, may not be optimal. They may not fully value the system services needed to integrate VREs, energy storage, and supply/demand flexibility into a reliable, low-cost supply portfolio. A transition toward capacity-centred remuneration, where resources are aggregated and compensated for their availability and firm contribution rather than only their marginal cost (essentially zero for VREs), could correct this misalignment. Such a market design could maximize optimal deployment of renewable generation by rewarding firming resources appropriately and enhance system reliability by ensuring adequate dependable capacity at all times..

In sum, the roadmap to firm renewable power is clear: combine robust modeling, strategic overbuilding, and flexible system design with enabling market reforms. By doing so, nations can achieve reliable, cost-effective, and fully decarbonized electricity systems—laying the foundation for a resilient global energy future.

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