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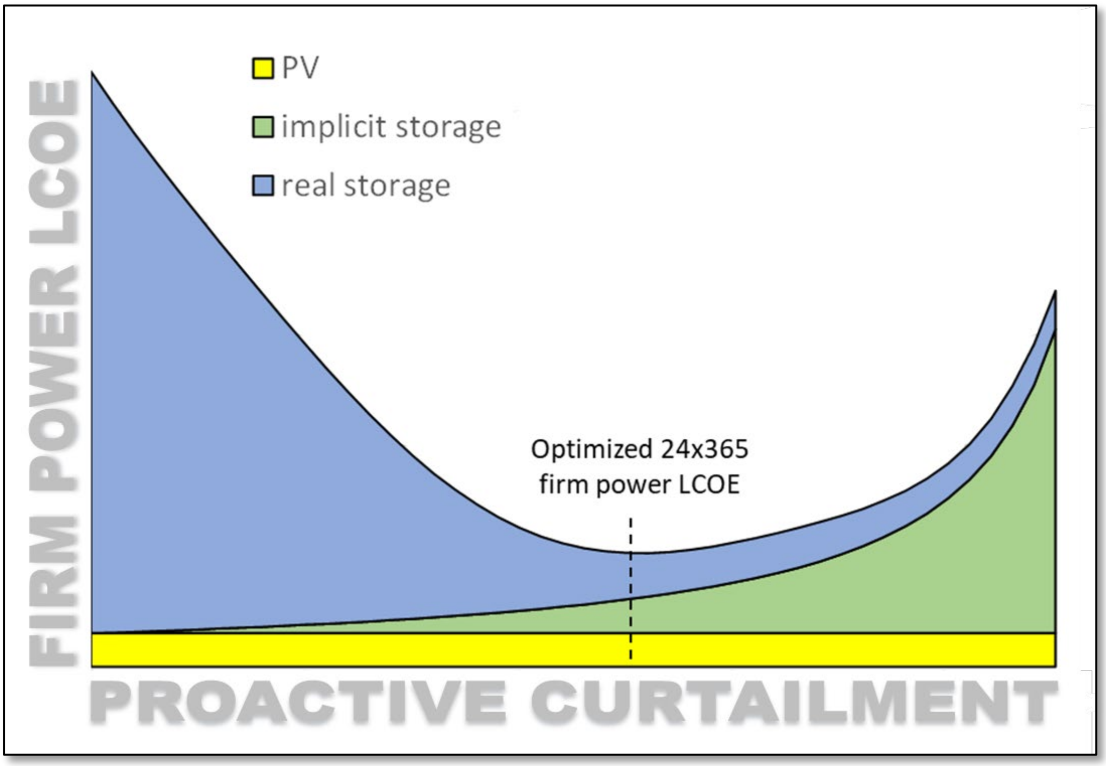

Task 16: Solar resource for high penetration and large scale applications

PVPS

Firm Power generation

2022

Report IEA-PVPS T16-04:2022

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, Chile, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Korea, Malaysia, Mexico, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Turkey, and the United States of America. The European Commission, Solar Power Europe, the Smart Electric Power Alliance (SEPA), the Solar Energy Industries Association and the Cop- per Alliance are also members.

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What is IEA PVPS Task 16?

The objective of Task 16 of the IEA Photovoltaic Power Systems Programme is to lower barriers and costs of grid integration of PV and lowering planning and investment costs for PV by enhancing the quality of the forecasts and the resource assessments.

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COVER PICTURE

R. Perez

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INTERNATIONAL ENERGY AGENCY
PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

Firm Power generation

IEA PVPS
Task 16
Solar resource for high penetration and large scale applications

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LIST OF ABBREVIATIONS & KEY DEFINITIONS

Abbreviations

BESS	Battery Energy Storage System
DA	Day Ahead
DOE	Department of Energy (of USA)
GHG	Greenhouse Gas
GW	Gigawatt
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KPI	Key Performance Indicator
kWh	Kilowatthour
LCOE	Levelized Cost of Energy
LRZ	Load Resource Zone
MAE	Mean Absolute Error
MISO	Midcontinent System Operator
MSD	Dispatching Services
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OpEx	Operational costs
PV	Photovoltaic
RE	Renewable Energy
RES	Renewable Energy System
RMSE	Root Mean Square Error
SFOE	Swiss Federal Office of Energy
TC	Technical Committee
TSO	Transmission System Operator
US	United States (of America)
VRE	Variable Renewable Energy
WACC	Weighted average cost of capital

Key Definitions

[VRE] Overbuild	Building More VRE capacity than would be needed on an energy-only basis
[VRE] Oversupply	Same definition as overbuild

[VRE] Dynamic Curtailment	Managed (proactive) curtailment of VREs when these exceed demand and full storage reserves cannot absorb excess production.
[VRE] Passive Curtailment	VRE curtailment imposed on generators by grid operators when their output cannot be injected into the grid (e.g., because of transmission congestion).
Implicit Storage	The overbuilt part of VREs that is curtailed (hence not monetized directly, but enabling a substantial reduction of physical storage capacity)

EXECUTIVE SUMMARY

Grid-connected solar power generation, either dispersed or centralized, has developed and grown at the margin of a core of dispatchable and baseload conventional generation. As the penetration of this variable resource increases, the management of the underlying core gradually becomes more complex and costly.

The challenge ahead for grid-connected solar is to evolve beyond the margin and the context of underlying conventional generation management. Activity 3.5 focuses on this challenge where the transformation of intermittent variable renewable energy (VRE) resources such as solar and wind into firm, effectively dispatchable, power generation resources is a prerequisite to the displacement of the underlying conventional generation core.

Substantiated by in-depth case studies, this report infers that nearly 100% VRE power grids firmly supplying clean power and meeting demand 24/365 are not only possible but would be economically sound if VRE resources are optimally transformed from unconstrained run-of-the weather generation into firm generation. VREs are thus capable of entirely displacing all climate disruptive conventional sources economically (provided now emerging grid-forming inverter technology resolves any grid frequency and stability issues resulting from the displacement of conventional rotating power generation). The variable-to-firm transformation enablers include energy storage, the optimum blending of VREs and other renewable resources, geographic dispersion, and supply/demand flexibility. Most importantly this transformation entails overbuilding and operationally curtailing the VREs ─ a strategy we term applying implicit storage. This strategy ensures acceptable VRE production costs.

This report summarizes ten experts' contributions focusing on firm power generation at near 100% renewable energy penetration. In addition, four contributions describe 'entry level' firm power generation objectives, easier to achieve in the short-term, but using the same enabling strategies, where firmness is defined in terms of meeting forecast VRE production instead of full load.

1 THE CONCEPT OF FIRM POWER GENERATION

Firm power generation represents the capability for a resource to meet electrical load on demand 24x365. Thermal generation (fossil fuel-based), nuclear, and hydro (in the absence of droughts) meet this criterion, although with different time response capabilities. Electrical generation on power grids has typically amounted to a mix of these 'conventional' firm power resources, with long time-response base-loading generation such as nuclear and large hydro, medium time response units (coal) and faster response units (natural gas and dispatchable hydro).

The two renewable energy (RE) resources acknowledged to be large enough to displace environmentally taxing conventional generation – wind and solar – do not meet this firm power criterion: they are variable and cannot be deployed full-time or on demand. They currently operate at the margin of a core of dispatchable generation. This is illustrated in Figure 1 in the case of PV. As PV penetration increases (Figure 1 bottom) this marginal position intensifies the underlying dispatchable generation management burden and associated costs – steeper dispatching ramps and duck curves, need for larger operating reserves, and greater accuracy of load and variable RE forecasts.

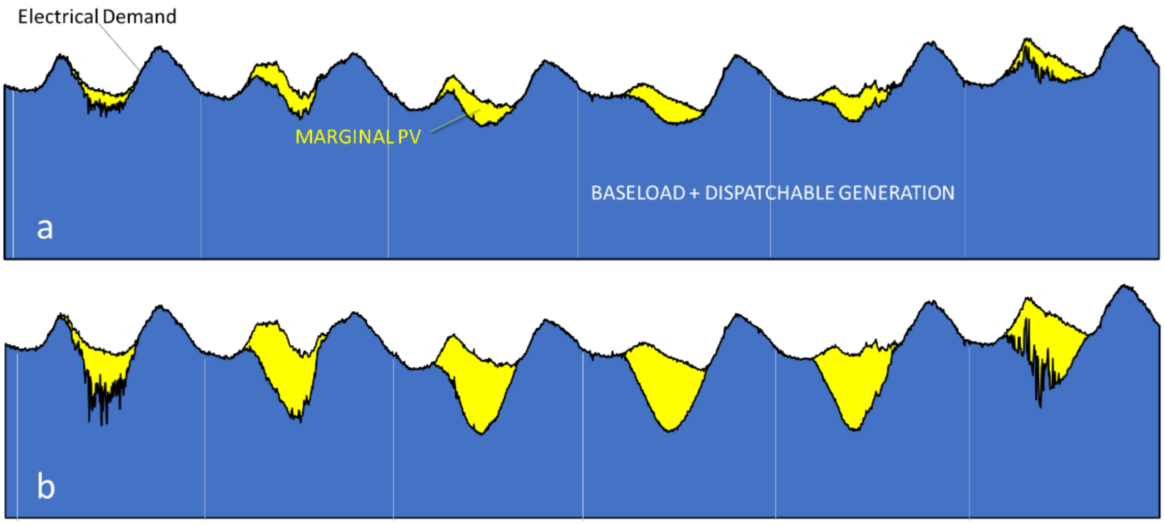


Fig. 1 – Illustrating PV resource operating at the margin of a core of conventional power generation at low (a) and medium (b) grid penetration levels.

To displace the underlying conventional generation, variable RE (VRE) resources must evolve from the margin. They must be transformed from intermittent to firm, i.e., they must be capable of meeting prescribed demand 24x365 by themselves. This transformation entails a portfolio of enabling strategies and technologies that includes:

- Energy storage, absorbing generation when it exceeds demand and releasing it when it falls short of demand.
- Optimum blending of different VREs (PV, wind, and hydro) that often exhibit complementary diurnal or seasonal generation profiles
- Geographic dispersion that reduces VREs' inherent variability.

- Demand flexibility achieved either via customer-side demand response, or by keeping a fraction of supply-side dispatchable thermal generation[1], thus modulating the demand seen by the VREs.

Most importantly – and counter-intuitively – the variable-to-firm transformation entails *overbuilding* and proactively *curtailing* the VRE resources, a strategy also known as applying *implicit storage*. Figure 2 illustrates the major impact of implicit storage in achieving low-cost firm power generation in the case of PV.

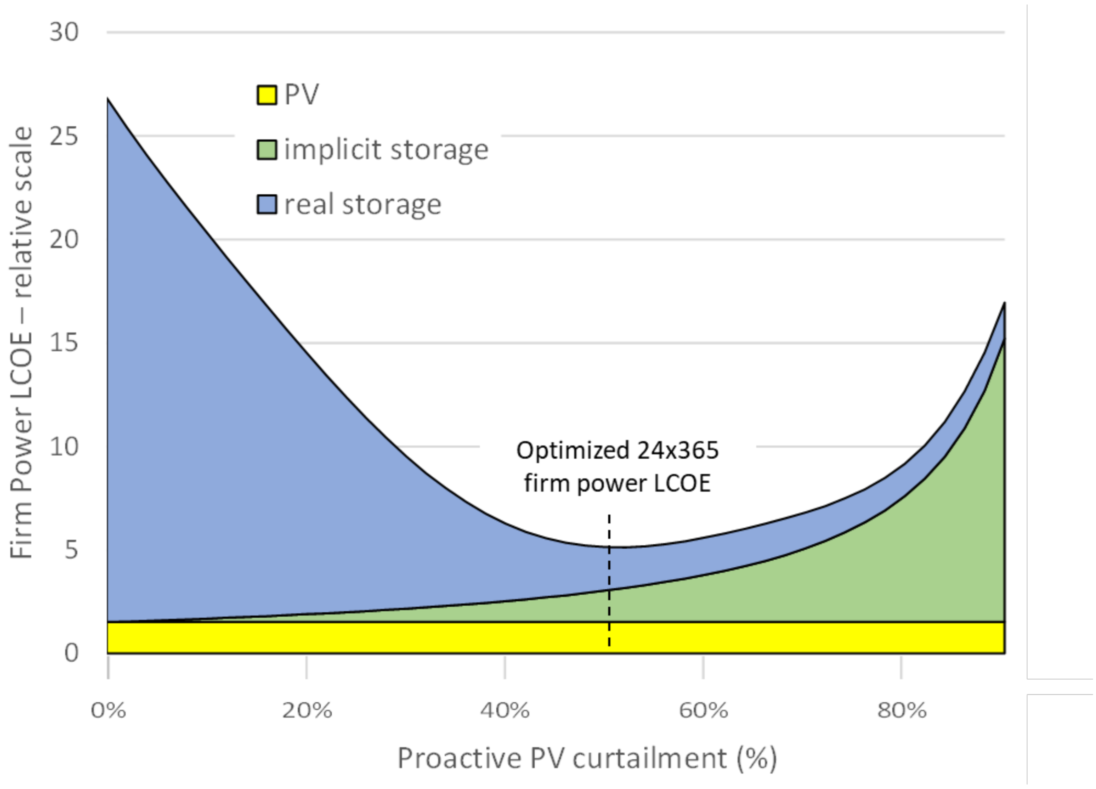


Fig. 2 – Respective contributions of PV, storage, and implicit storage (PV overbuild) to the cost of firm power as a function of proactive PV curtailment. The storage-alone option (zero curtailment) is significantly more expensive than an optimized real/implicit storage configuration.

These enabling firm power strategies have specific costs and operational specs (e.g., the cost of grid strengthening associated with geographic dispersion). Their optimal blending determines the most effective and lowest cost firm VRE configuration for a particular location/region. The economic factors and technical characteristics shaping this optimum configuration include

- The CapEx and OpEx (Capital and Operational costs) of the considered VREs,
- The CapEx and OpEx of the considered storage technologies,
- The CapEx and OpEx of demand and/or supply-side flexibility,

[1] Note that this supply-side flexible generation could be 100% renewable if renewable fuels such as e-fuels are applied.

- The CapEx and OpEx of grid strengthening,
- The considered electrical demand profile
- The generation profile of the considered VRE resources

For demand and VRE generation, time-coincident, multi-year hourly[2] (or better) time series are required to properly derive optimum configurations.

1.1 Structure of this report

This report summarizes the task experts' investigations undertaken in the context of Activity 3.5. It provides detailed summaries of, and links to reports/publications for each of these investigations.

It is helpful to separate investigations in two groups based on the nature of the load that is to be firmly served:

1. High VRE penetration studies, concerned with meeting the entire demand of a given power grid, or a significant fraction thereof, i.e., displacing the underlying conventional dispatchable generation core.
2. 'Entry-level' studies, analyzing easier to meet firm load targets such as the day-ahead forecasted VRE generation, or net load imbalances.

The firm power generation strategies and technologies identified above are the same for both high penetration and entry-level applications but employed on a smaller (entry-level) scale in the second case, where they can be readily and economically deployed/assessed early-on – exploiting existing energy market rules – and accompany the growth of VREs to ultimately reach firm 24x365 production for the entire demand.

On the topic of firm power generation for ultra-high VRE penetration, the investigations presented herein include:

- An introductory study on the fundamentals of firm power generation highlighting an initial case study for the US state of Minnesota: *Overbuilding & curtailment: The cost-effective enablers of firm PV generation*
- An analysis of solar and wind firm power generation solutions for the Midcontinent System Operator (MISO)
- An analysis of firm renewable power generation on the Swiss power grid.
- An analysis of the ultra-high renewable penetration on the Italian power grid including a transition from entry level imbalance mitigation to full demand firm generation
- An analysis of ultra-high PV penetration in the US State of New York, including a roadmap for gradual transition from entry step firm power forecasts to full load firm power generation.

[2] Hourly resolution should be sufficient in most cases since configurations optimized to handle major multi-day VRE deficits (e.g., cloudy winters) will include considerably more energy storage than needed to handle any short-term fluctuations. (Short-term fluctuations and spikes are of course a specification concern for equipment design so it always operates properly, but not for firm power system optimization.)

- An investigation comparing VRE curtailment strategies – passive vs. dynamic – and their effectiveness at achieving least cost firm power
- An update on Australian PV deployment illustrating how curtailment (albeit of the less effective passive type) is already penetrating markets.
- A study related to 100% PV electricity generation in the Island of La Réunion.
- A preliminary investigation of firm VRE power generation across the European continent.
- A technical evaluation of implicit storage operations via inverter controls.

On the topic of entry-level firm power generation, the investigations covered in this report include:

- A mitigation of load imbalances on the Italian power grid via flexible PV systems
- An analysis of the deficiencies in current imbalance cost pricing mechanisms for PV generation
- An analysis of entry level imbalance mitigation strategies on the Italian power grid.
- An introduction to perfect forecasts at the local and regional level.

1.2 Overall takeaways

All investigations undertaken as part of Activity 3.5 imply that 100% VRE power grids with full renewable resource adequacy guaranteeing 24x365 firm availability are not only possible but would also be economically sound insofar as supply and demand are concerned[3].

Entry-level firm power applications such as guarantying forecasted VRE production or minimizing load imbalances can be economically attractive today given existing market rules. Most importantly, these entry-level applications provide an operational learning curve for the optimal blending and management of VREs, real and implicit storage as well as other flexibility resources that would eventually lead to least-cost 24x365 firm renewable power generation.

VRE overbuilding and operational curtailment (i.e., implicit storage) are key to achieving economically acceptable firm 24x365 solutions.

It is essential that optimal implicit storage configurations be enabled by appropriate market rules and remuneration vehicles favoring firm power. At present, most market rules foster VRE production maximization, i.e., not enabling the least-cost solutions for very high, firm VRE penetration. The increasing deployment of inverter capped systems (passive curtailment) and the market rules fostering this deployment are limited steps in the right direction.

The earlier effective firm power market rules are put in place, the better, because achieving firm VRE power generation becomes gradually more difficult as the pool of unconstrained VREs continues to grow.

[3] *Of course, grid stability issues associated with the displacement of conventional [rotating] generation will have to be tackled in addition to the demand/supply issues addressed in this report (e.g., see Denolm et al., 2021). The now emerging grid-forming inverter technology shows potential to resolve this issue (e.g., see Stenson, 2022)*

Transmission System Operators are envisioned to play a central role in the management of intermittent VREs, including management of all real and implicit storage resources, gradually evolving from their present dispatchable conventional market management role.

2 EXPERTS INVESTIGATIONS: HIGH VRE PENETRATION FIRM POWER GENERATION STUDIES

2.1 Overbuilding and curtailment: The cost-effective enablers of firm PV generation

Year: 2019

Authors: Perez, M., R. Perez, K. Rabago & M. Putnam

Journal paper: Solar Energy 180, 412-422. [1]

Link: ***https://www.sciencedirect.com/science/article/pii/S0038092X18312714***

This study was published at a time when the overwhelming thinking considered that VRE output curtailment was a last resort measure to be avoided. The authors argued instead that supply-shaping, achieved through proactive dynamic curtailment associated with PV oversupply, was critical to achieving intermittency mitigation and delivering firm VRE generation at the lowest cost.

Focusing on PV generation, the authors investigated the premium to transform a low-cost, but intermittent solar kWh into a firm, effectively dispatchable kWh. They showed that a fundamental ingredient of minimizing this premium was to optimally overbuild and, as necessary and appropriate, curtail PV generation. Drawing on a case study in the State of Minnesota, they showed that firm, high-penetration-ready PV generation could be achieved at a production cost equal to or below current conventional generation, especially when optimally coupled with wind generation (Figure 3).

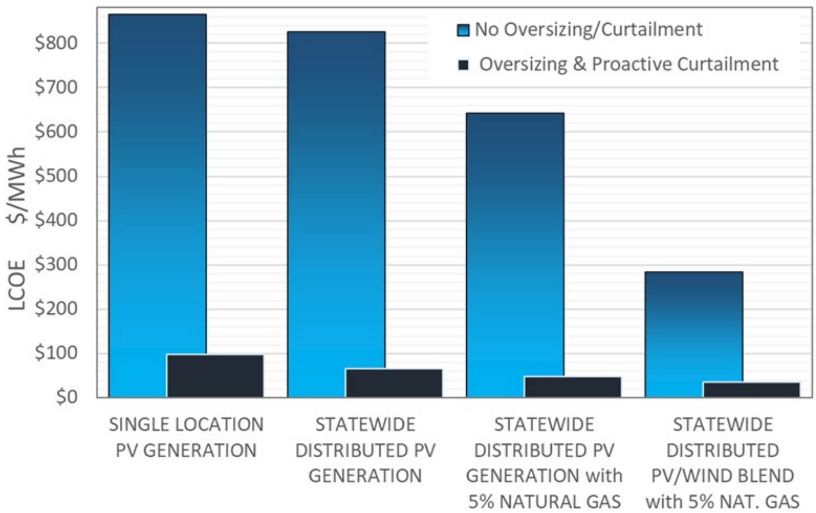


Fig. 3 –Illustrating the Levelized Cost of Energy (LCOE) impact of overbuilding/curtailment to firmly meet Minnesota load 365/24/7.

They concluded with a recommendation that, to achieve this lowest cost firm generation potential, proactive curtailment strategies should inform future transactional PV remuneration systems, hence, since PV remuneration systems depend on regulations, that proactive curtailment strategies should inform the latter.

2.2 Pathways to 100% Renewables across the MISO Region

Year: 2020

Author: Perez, M.

Link: ***https://www.osti.gov/servlets/purl/1668266***

This study funded by US DOE's Solar Technology Office modeled the generation costs of high penetrations of wind and solar across the Midcontinent Independent System Operator (MISO) region (Figure 4). It expanded upon the above preliminary study in the State of Minnesota where differing assumptions regarding future technology costs, sector electrification, and technological diffusion formed sixteen unique scenarios across which renewable capacity expansion and dispatch were optimized on a least-cost basis. Its key takeaways are:

- The unsubsidized cost of 100% renewable generation by 2050 could be on par with present-day wholesale electricity generation costs in the MISO system ($40/MWh vs. $30/kWh): Modeling indicates that wind, solar, and storage can firmly serve 100% of load across MISO by 2050 at an LCOE of $40/MWh, comparable to present-day fossil-dominated electricity generation costs ($30/MWh average LMP in MISO).
- The cost of 95% renewable generation by 2050 could be lower than present-day wholesale electricity generation costs across MISO ($20-$30/MWh) : Generation costs, which in the modeling include the operational and capital costs of electrochemical storage, as well as overbuilding + curtailment (implicit storage) of PV and Wind, can be roughly halved if existing gas or other similarly priced dispatchable assets are leveraged to provide backup 5% of the time.
- Overbuilding + curtailment of PV (implicit storage) yields more relative cost savings than the implementation of any other operational strategy studied: Overbuilding plus curtailment of PV acts as "implicit storage" by providing the same service otherwise provided by energy storage in a high penetration scenario: assuring supply in otherwise low-yield periods. Because of the corresponding reduction in storage needed to meet demand during these periods, the cost of firm power generation is reduced by a factor of ten. Relative to the cost-reduction from geographic dispersion of renewable generation assets or from the anti-correlation of wind and solar resources, this strategy delivered the most cost-savings.
- Wind+PV hybridization can reduce costs: Though not as dramatic a savings as the "implicit storage," wind + PV do complement each other, even in areas where one resource is dominant over the other. Across the MISO region, the wind tends to blow when the sun is not shining (and vice versa). The resources are "anti-correlated" and can deliver cost-savings if optimized.
    - The future cost assumptions for the technologies firmly meeting load (wind, PV, storage) influences the future optimal technological mix:
    - Raising the LCOE of wind relative to PV decreases the cost-optimal wind percentage.
    - Raising the LCOE of energy storage relative to renewables increases the amount of implicit storage used to achieve minimal cost.
- Confidence and consensus surrounding LCOE will help solidify understanding surrounding cost-optimal capital outlays when planning for high-penetration renewables.
- Because forecasted solar PV costs see a larger decline than wind costs at the 2050 horizon, PV ends up serving a larger percentage of load than wind across most regions and cost scenarios studied: In 2050, high technology development scenarios forecast a stronger cost decline for PV than wind. When capacities are optimized to serve load on a

cost basis, PV contributes more to load than wind across most MISO's 10 electrical Load Resource Zones (LRZ) regions, despite an extraordinarily strong wind resource in the northern part of MISO territory. The only exceptions are LRZ 3 and 7, where the wind resources are excellent (40% capacity factor in LRZ3).

- Interconnection across the entire MISO saves ratepayers money: Local variability of wind and solar level out in aggregate across MISO's footprint, saving ratepayers in MISO billions of dollars annually relative to the cost of balancing variation with wind, PV, and storage in smaller, isolated geographic regions. The caveat is that the transmission and distribution required to support this geographic dispersion will need to be bolstered. Although we did not study the marginal Transmission & Distribution (T&D) upgrades required to support the degree of renewable penetration in this study, our simple calculation indicates that the transmission components would be minimal (a small %) relative to costs resulting from energy supply.

The study points to some limitations in scope that would have to be addressed. Three factors that could affect the cost of high-penetration renewables were not researched as part of this study at the direction of its Technical Committee (TC):

- Regarding electrification, the project did not investigate changes in future load shape if electrification of the heating and transport sectors increases in MISO. This electrification was only addressed in LRZ1 (Minnesota) with the conclusion that, assuming driving behavior does not drastically change, the MN SPA showed that electrified transportation loads would not alter the load's seasonal shape, just its magnitude. However, Heating electrification was shown to alter the seasonality of MN's load shape given that heating demand occurs during the winter. Meeting future loads with electrified heating shifts the optimized wind/PV balance-point further towards wind. This was reflective of the better seasonal match between winter loads and the winter wind resource in Minnesota. Solar, being a summer-peaking renewable resource has a better seasonal match with air-conditioning loads. In LRZ1, LCOEs for meeting MN load increase by 5% when the heating sector was fully electrified. The expectation that a similar relative increase will occur when heating loads across MISO are electrified is reasonable.
- T&D costs: The project stakeholders decided to only investigate generation costs associated with reaching high penetration renewables futures.
- Load Shifting: The MISO SPA did not look at demand-side load shifting. Reductions in LCOE from shifting newly electrified (water and space) heating and transportation loads were discussed for LRZ1 and the lessons learned regarding the magnitude of generation-cost reduction could be applied across the MISO region. For reference, load-shifting of Domestic Hot Water (DHW) and Electric Vehicle (EV) loads was found to reduce LCOEs a further 10-20% in LRZ1.

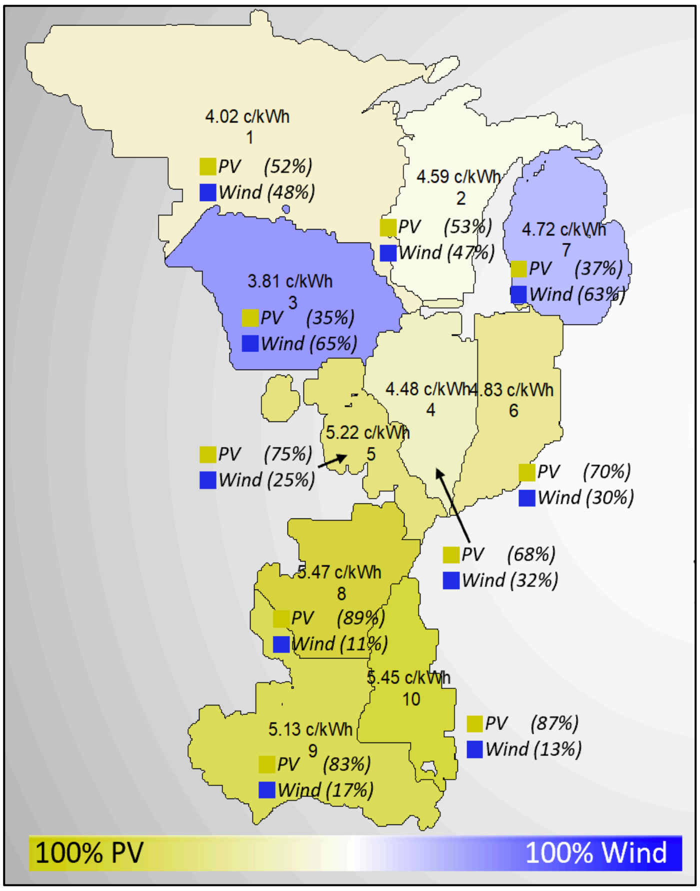


Fig. 4: Optimum distribution of PV and wind and resulting firm power LCOE in each of MISO's electrical Load Resource Zones. These numbers correspond to 2050 utility scale technology cost assumptions.

2.3 Firm PV Power Generation in Switzerland

Year: 2022

Authors: Remund, J., M. Perez & R. Perez

Conf. Paper / Report: IEEE-PVSC, Philadelphia, PA. 2022 [2]; SFOE report, Firm PV Power Switzerland [3]

Link: ***https://www.aramis.admin.ch/Texte/?ProjectID=49486***

The authors investigate whether PV can effectively and economically contribute to a massively renewable energy (RE) power generation future for Switzerland. Taking advantage of the country's flexible hydropower resources, they determine the optimum PV battery and implicit storage configurations that can meet the country's growing electrical demand firmly 24x365 at the least possible cost while entirely phasing out nuclear power generation. They examine several ultra-high RE scenarios where PV and hydro would meet the bulk of the country's demand. All scenarios are based on a CO2-neutral energy supply (Figure 5). 24 scenarios with optimistic and conservative cost assumptions based on NREL ATB[4] and on low and high electricity exchange with neighboring countries have been modelled.

Results demonstrate that high-RE solutions for Switzerland, with PV playing a significant role as a complementary resource to the country's hydropower system, are both physically and economically reasonable, despite the minor role wind power can play, and the mediocre PV resource in winter months.

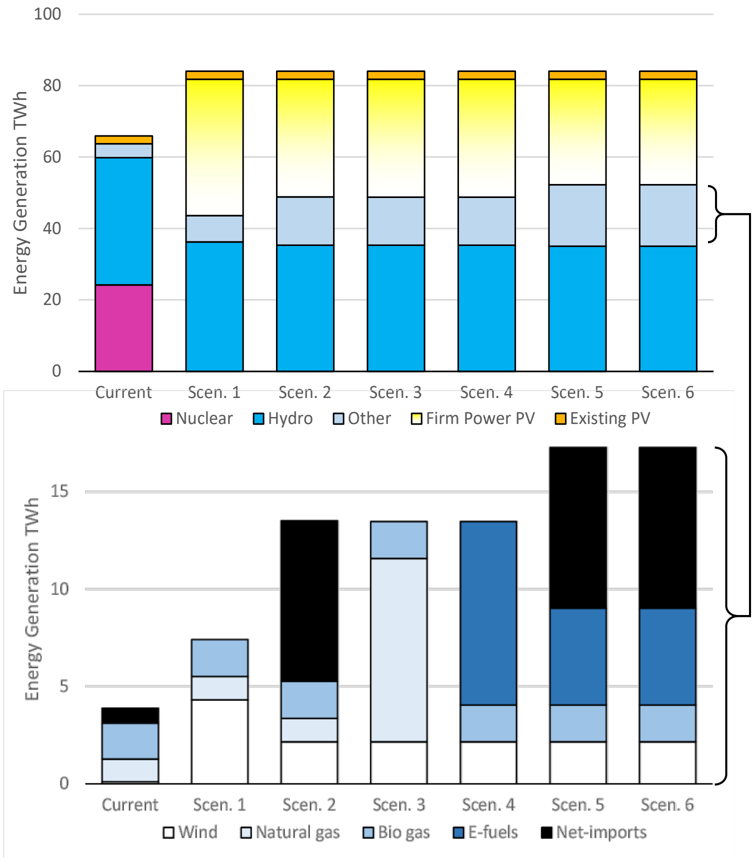


Fig. 5: Contrasting current and six future power generation mix scenarios for Switzerland, where the bulk of the task to replace nuclear generation and grow the load by 30% will be met by PV. Note that scenario #4 is 100% renewable

Depending on future cost predictions for PV and batteries, and a small contribution from domestic or imported dispatchable resources, the study shows that firm power production costs on the Swiss grid would range from 6 to 9 US ¢/kWh (Figure 6). The authors stress that operational costs in all considered scenarios are reasonable compared to current wholesale market prices in Switzerland (these have been well above 20 ¢/kWh during summer 2022). The present ultra-high RE costs are even reasonable when compared to earlier pre-crisis TSO wholesale prices (4-6 ¢/kWh) noting that these earlier TSO prices do not fully factor-in environmental or strategic externalities which, as we see today with international tensions, can be consequential.

[4] https://atb.nrel.gov/electricity/2021/data

Another particularly important observation is the result obtained for one of the scenarios with 100% RE. Not only are operational generation costs reasonable (6½/-8½ ¢/kWh depending on technology and autonomy assumptions), but they show the supply-side flexibility catalyst role that 100% renewable GHG-free e-fuel thermal generation can play, even as expensive as it is expected to be at 18-20 ¢/kWh.

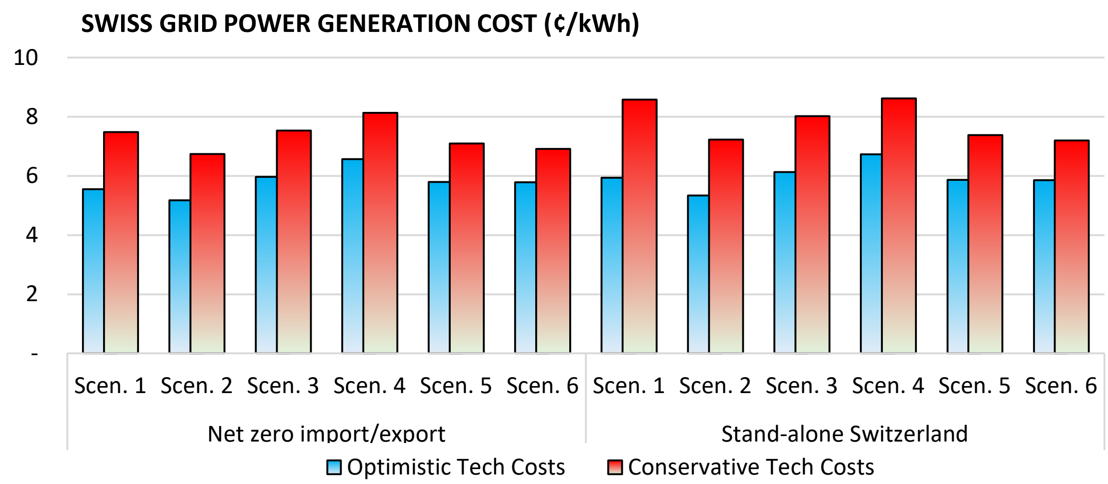


Fig. 6: Generation mix electricity LCOE for each above scenario (1-6) times two technological cost assumptions (large utility scale in blue, and small user-sited systems in red), and two country's autonomy configurations (net-zero interconnection with Europe, and full autonomy)

The authors stress the importance of implicit storage (i.e., optimally overbuilding the PV resources). Not implementing this deployment strategy would result in higher prices on the network. It is therefore important to operationalize optimal overbuilding and curtailment early-on, by e.g., implementing appropriate regulations that would lead to firm power monetization, instead of current run-of-the-wheather PV production.

Finally, it is important to note a few limitations of the study:

1. While the growing load due to electrification of building heating and mobility is considered, this was raised linearly by the factor of existing and foreseen energy consumption. No change regarding the seasonal distribution of demand was made.
2. The effects of climate change have been neglected. The results may thus be considered conservative. Indeed, climate change will reduce seasonal effects: shorter and warmer winters (lower heating and higher cooling loads) and lead to more precipitation in winter and less in summer, even if the Paris agreement limiting climate change to 1.5°C is reached. However, climate change could also induce higher variabilities with extreme dry or wet years.
3. Seasonal thermal storage has not been analyzed. Depending on achievable economics for this technology, this could ease resources integration and dispatching.
4. Power to X has not been modeled. Part of the curtailed energy could be used to produce e-fuels, which can be used for transport or for electricity generation.

However, the effects of the simplified load modelling and neglecting climate change could level each other out to a certain degree.

2.4 Italian protocol for massive solar integration: From solar imbalance regulation to firm 24/365 solar generation

Year: 2021

Authors: M Pierro, R Perez, M Perez, MG Prina, D Moser, C Cornaro.

Journal Paper : Renewable Energy 169, 425-436. [4]

Link : ***https://www.sciencedirect.com/science/article/pii/S096014812100029X***

This investigation outlines a path to achieve a cost-effective renewable transition in Italy by 2060 based on firm solar and wind 24/365 generation. The transition to renewables (RES) is driven by a gradual replacement of current unconstrained variable renewable generators with flexible PV/wind systems: systems that can operate in tandem with Battery Energy Storage Systems (BESS) and are equipped with smart inverters which can be remotely controlled by power plant controllers (PPCs) for dynamic, pro-active power curtailment of their output. Here the authors extend the concept of implicit storage from solar regulation to firm power generation. In the former case, implicit storage can be obtained through VRE under-forecast and proactive curtailment of the forecast shortfall while in the latter through VRE systems over-built and proactive curtailment of the resulting overgeneration.

The study shows that, using implicit storage, it will be possible to minimize the costs of not only solar regulation services (as was shown in the 'entry-level' investigation reported below), but also, transitioning first to fully predictable solar generation and, second, to solar/wind firm generation. In the proposed plan, solar regulation via the flexible PV fleet is to be used to mitigate the solar-induced imbalance resulting from forecasting uncertaintyuntil 2030, when the fleet will be able to match Italy's solar generation to that forecasted; thereafter, the flexible fleet should include wind systems and grow to allow full dispatchability of VRE by 2060. Therefore, by 2030 it will be possible to eliminate the uncertainty/non-programmability of solar generation, while by 2060 the intermittency of VRE production will also be overcome. For each transition step, the flexible VRE fleet was cost-optimally dimensioned, determining the implicit storage required to achieve the proposed goal. We also highlighted where the VRE systems needed to reach 92% of RE generation could be placed all over Italy, avoiding major environmental impacts together with the socio-economic benefits arising from the transition.

Finally, the study pointed out that the proposed transition plan implies two fundamental paradigm shifts:

1. VRE curtailment should not be avoided (as many experts in the field argue) but promoted if it is proactively managed.
2. Massive centralized VRE generation controlled directly by TSOs is more suitable/economic to achieve transition to RES than decentralized/distributed VRE generation

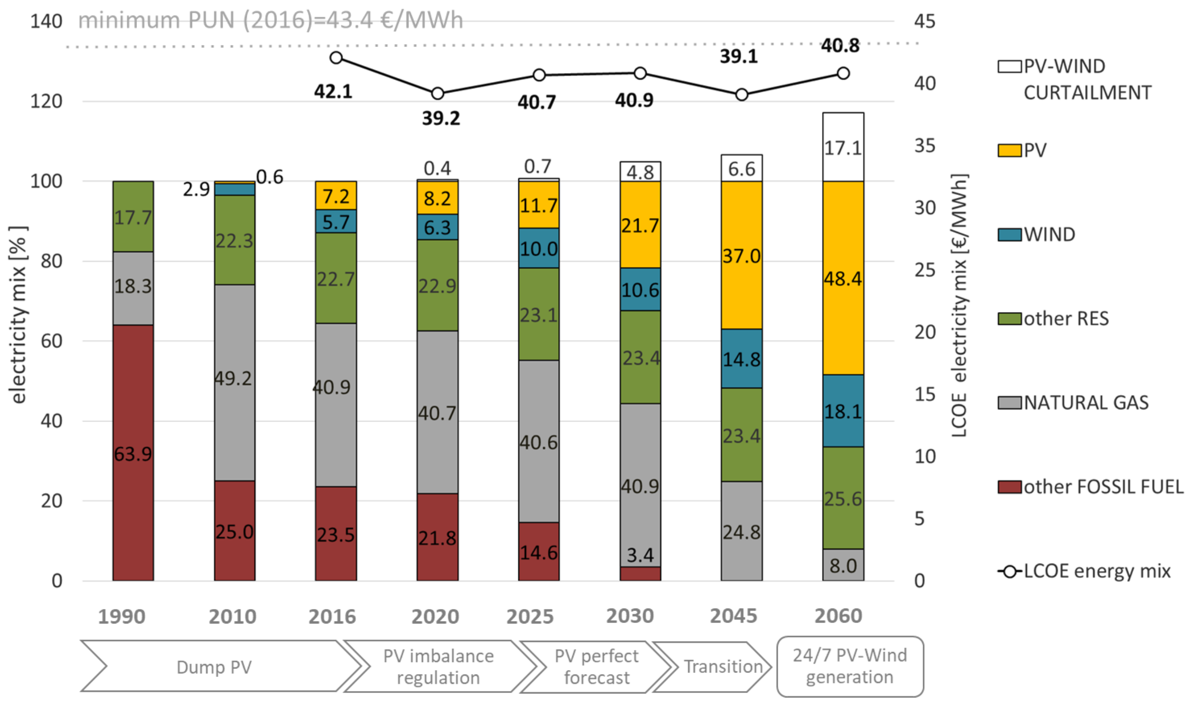


Fig. 7: Evolution of firm electricity generation mix through the transition. Taking advantage of the existing dispatchable hydroelectric, geothermal and biofuel power plants in Italy, the study demonstrates that it will be economically feasible to reach fully predictable solar production by 2030 and firm power generation by 2060 with a renewable penetration of 92%.

The detailed results illustrated in the Figure 7 imply that, in 2030, not only will coal no longer be part of the electric mix (as required by the PNIEC) but also that the imbalances due to the penetration of the photovoltaic systems will be completely removed. In 2060, it will be possible to eliminate all fossil fuels except for a small residual natural gas production.

At each transition stage, system LCOE is lower than the current energy cost and lower than the minimum National Unique Energy Price (PUN) of the last 8 years. Therefore, the proposed transition strategy can be considered economically sound.

Figure 8 shows the generation capacity of the different sources required to reach the transition stages shown above.

The residual natural or in future also e-fuel gas power plants are necessary to cost-optimally fill in for the few periods in which the PV and wind generation and/or the storage capacity are not enough to meet demand (due to prolonged conditions of lack of solar or wind resources).

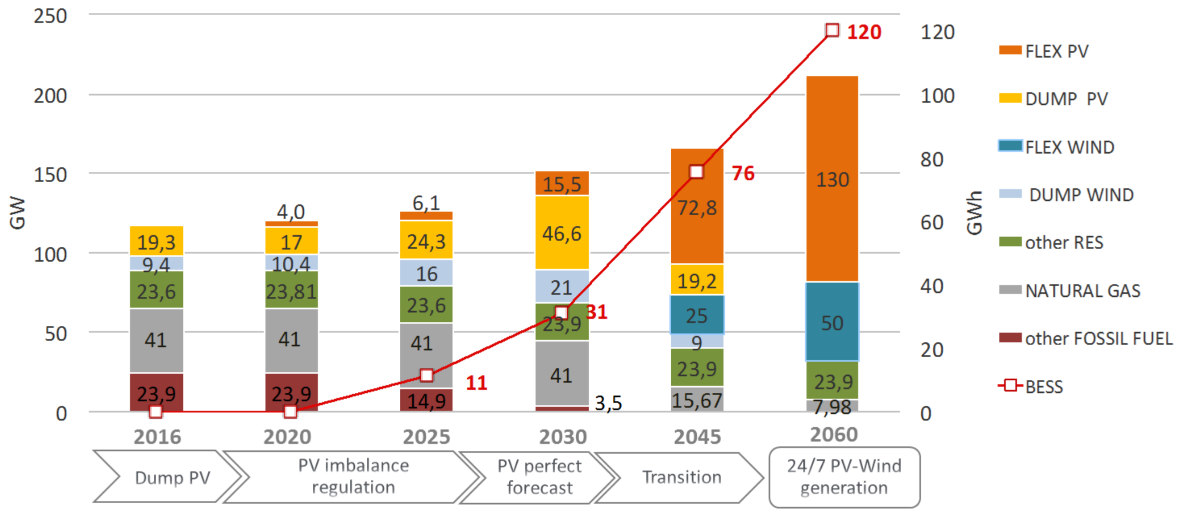


Fig. 8: Generation capacity of the different sources required to reach the transition stages (Note: flex PV/Wind = oversized-curtailed PV/Wind dump PV/Wind = unconstrained PV/wind)

2.5 From firm solar power forecasts to firm solar power generation an effective path to ultra-high renewable penetration a New York case study

Year: 2020

Authors: Perez, R., M. Perez, J. Schlemmer, J. Dise, TE Hoff, A. Swierc, P. Keelin, M. Pierro & C. Cornaro.

Journal Paper: Energies 13 (17), 4489 [5]

Link: ***https://www.mdpi.com/1996-1073/13/17/4489***

In this study, the authors introduce firm short-term solar forecasts as a strategy to operate optimally overbuilt solar power plants in conjunction with optimally sized storage systems to make up for any power prediction errors, and hence entirely remove load balancing uncertainty emanating from grid-connected solar fleets. A central part of this strategy is the plant overbuilding (aka implicit storage). The study demonstrates that this strategy, while economically justifiable on its own account at present, is an effective entry step to achieving least-cost ultra-high solar penetration where firm power generation will be a prerequisite. The authors stress that in the absence of such an implicit storage strategy, ultra-high solar penetration would be vastly more expensive. Using the New York Independent System Operator (NYISO) as a case study, the study quantifies current and future costs of firm forecasts for a comprehensive set of scenarios in each electrical region of the system operator, comparing centralized vs. decentralized production scenarios, and assessing load flexibility's impact. The authors simulate the systematic growth of the strategy from firm forecast to firm power generation, concluding that ultra-high solar penetration enabled by this strategy, whereby solar would firmly supply the entire NYISO load, could be achieved locally at electricity production costs comparable to current NYISO wholesale market prices.

An important observation of the investigation is that, while geographic dispersion has a significant impact on the operational cost of firm forecasts, this impact diminishes considerably when the objective evolves from firm forecasts to firm power generation. This is because weather-driven short-term fluctuations driving forecast models' uncertainty (and hence the cost of transforming these forecasts into firm forecasts) can be effectively reduced with geographic dispersion by exploiting the well-documented smoothing effect. These short-term fluctuations play less of a role compared to other factors such as seasonal variability when the objective evolves to meeting a given load shape. The authors noted that this observation had important implications. It suggests that large-scale geographic dispersion, implying strong transmission capabilities, would not be an absolute prerequisite to ultra-high penetration economics whereby locally resilient solutions contained in electrical sub-regions could be considered at a modest cost premium.

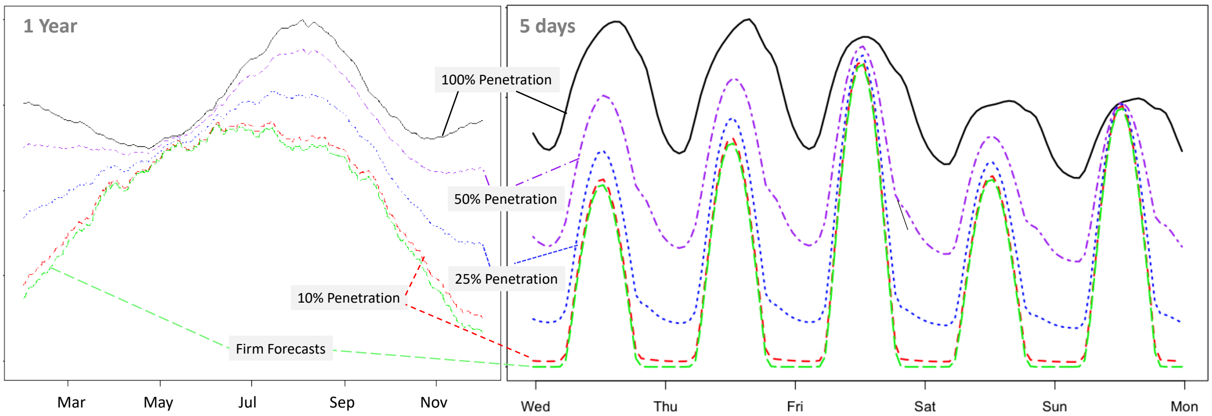


Fig. 9: The evolution of the yearly (left) and daily (right) target load shape from firm forecasts to firm power generation follows the penetration of the PV resource on the NYISO grid. Notes: (1) for visual clarity, the yearly load shape presented in this figure was smoothed using a 60-day running mean to remove day-to-day variability; (2) the y-axis scales are nominal and were selected for visual clarity to better distinguish between load shapes.

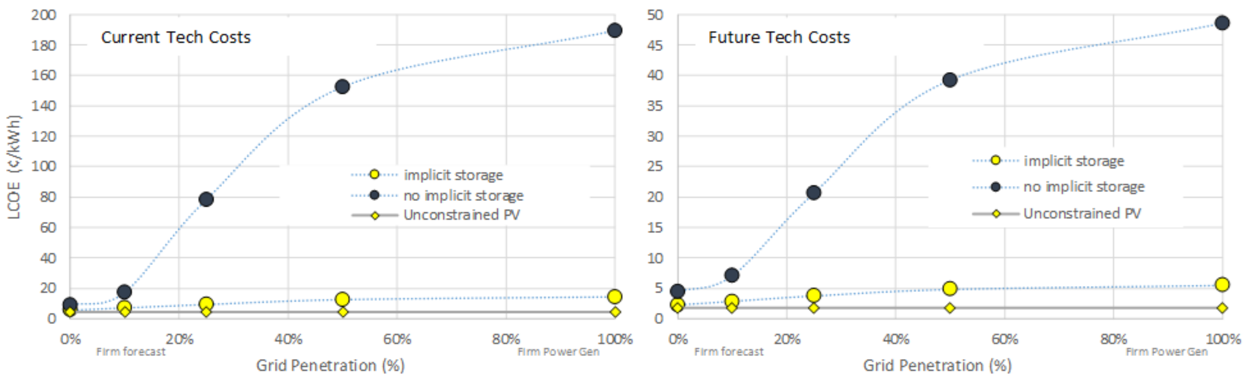


Fig. 10: Comparing firm power generation LCOE with and without an implicit storage strategy as a function of grid penetration (i.e., target load shape).

2.6 Least-Cost Firm PV Power Generation: Dynamic Curtailment vs. Inverter-Limited Curtailment

Year: 2021

Authors: M. Perez, R. Perez, T.E. Hoff

Conference Paper: IEEE 48th Photovoltaic Specialists Conference (PVSC), 1737-1741 [6]

Link: https://ieeexplore.ieee.org/document/9518445

This investigation examines two curtailment strategies – dynamic curtailment and inverter-limited (passive) curtailment – and their appropriateness to minimize the cost of firm VRE power generation.

As the above studies demonstrate, overbuilding and dynamic curtailment are increasingly acknowledged as central to cost-optimally transforming intermittent PV and wind resources into firm power resources. While this strategy is not currently monetizable, firm power generation will be a prerequisite at ultra-high renewable penetration when demand will have to be met 24/365 without reliance on underlying dispatchable generation.

As the following study suggests, a distinct overbuilding/curtailment strategy is increasingly implemented today: inverter-limited curtailment. This strategy can take advantage of some existing remuneration systems (Figure 11).

The investigation considers the extreme case of PV meeting demand with 100% certainty using two MISO's load balancing areas (#4 and #10) as experimental support. While both curtailment strategies can achieve firm power generation at a lower cost than curtailment avoidance would, dynamic curtailment is far more cost-effective than inverter-limited curtailment. Importantly, the study concludes that optimally combining both strategies can further reduce firm power generation cost (Figure 12).

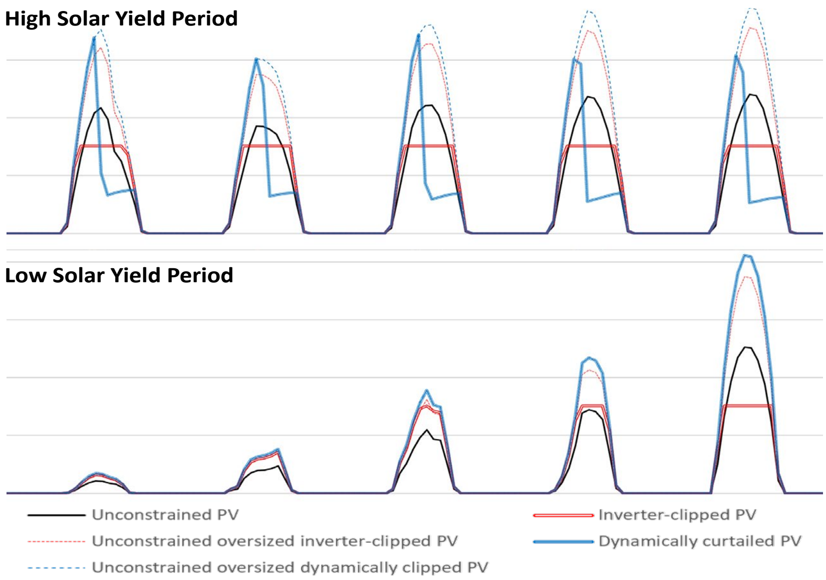


Fig. 11: Comparing unconstrained, oversized inverter-clipped and oversized dynamically curtailed regionally distributed PV production. The high solar yield period (top) shows dynamic curtailment occurring every day after storage spent at night is fully recharged and daytime demand is fully met by the uncurtailed portion. In the low yield

period, dynamically curtailed PV production can be maximized as needed to recharge storage spent during long cloudy periods, but the inverter-clipped system remains maxed-out at its clipping ratio. Note that the annual energy production of each of the three considered PV fleets integrates to the same annual value equal to annual load.

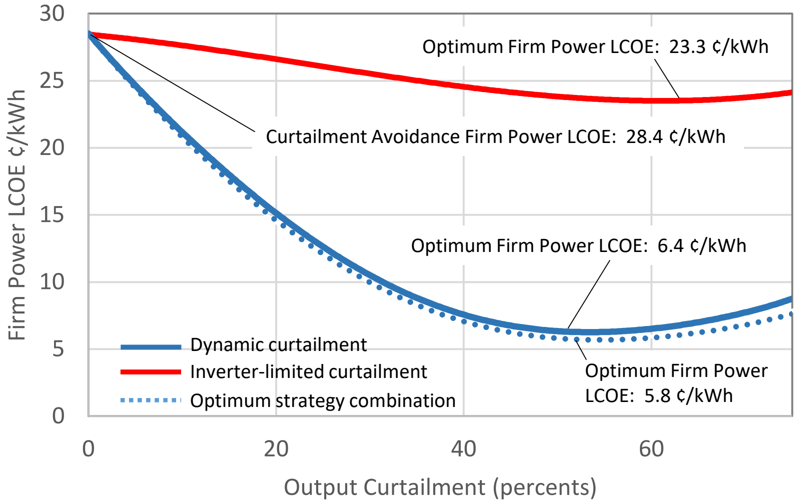


Fig. 12: Comparing firm power generation LCOE in balancing area #4 as a function of overbuilt PV resource curtailment for both curtailment strategies and for an optimal combination of both

2.7 PV Generation Oversizing in Australia

Author: John Boland

Source: short communication (unpublished)

As of the middle of 2022, the installed capacity of solar farms in Australia stood at almost 11 GW, out of approximately 70 GW for all forms of generation. Obviously, the generated electricity did not make up a similar percentage. But in the state of South Australia, solar and wind farms plus rooftop solar comprised around 70% of generated electricity in the financial year ending June 2022.

Many, if not most, solar farms in Australia have oversized fields of panels, with the capacity of the panels greater than the capacity of the inverters. See the following two examples of the impact of this attribute, with solar farms at Broken Hill, NSW and Port Augusta, South Australia. In both winter and summer, the farms' output reaches capacity on clear days for several hours. Damien Vermeer [7] discusses optimizing the financial benefits for solar farm operators from oversizing the field, under current Australia Energy Market Operator rules.

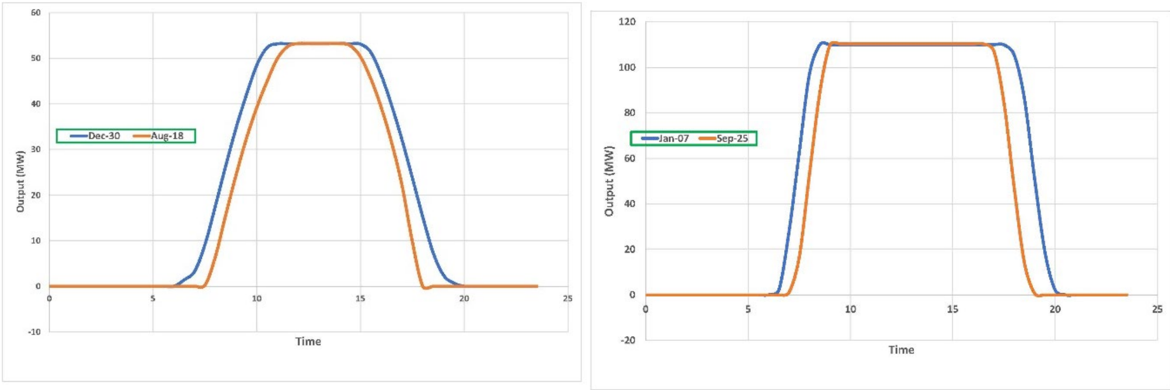


Fig. 13: Illustrating two examples of inverter-clipped (i.e., passively curtailed) PV output from plants operating in Australia

2.8 100% electricity generation from PV in Reunion Island

Authors: E. Tapachès, M. David, P. Lauret, M. Perez, R. Perez

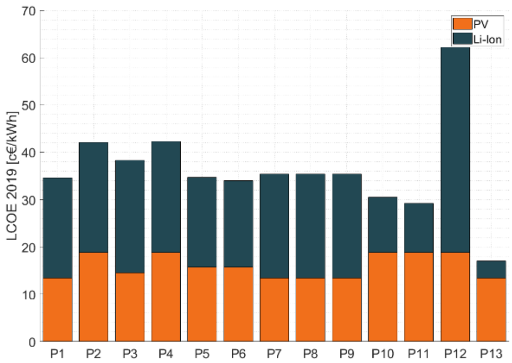
Source: short communication (unpublished)

This investigation contributes to define paths to reach the autonomy of the electricity generation in Reunion Island. Even if a production mix combining several renewable energy sources, such as solar, wind or local biomass, will probably result in a more cost-effective solution, the core of this work is devoted to distributed PV power generation. To this end, we use the least-cost firm power generation approach, which combines spatial distribution, overbuilding PV capacity and curtailment, to size an ideal storage based on Li-ion batteries controlled by the DSO. To ensure reliable results, we first fit our PV power generation model with the actual data recorded by the local DSO over the year 2018. The model is based on satellite estimates of solar irradiance and on aggregated PV capacities at the scale of the 13 transformer substations spread across the island. In a second step, thirteen scenarios (shortly described in Table 1) are tested to identify a possible pathway towards a 100% electricity generation from PV.

Table 1: Short description of the 13 scenarios of PV penetration in Reunion Island's electricity grid

P1 100% PV	P6 supply industry and tertiary sector	P11 100% PV during daytime
P2 substitute diesel plants	P7 constant base load of 50 MW	P12 remove evening peak
P3 substitute coal plants	P8 constant base load of 100 MW	P13 740 MWp firm solar power forecasts
P4 supply cooling demand	P9 constant base load of 200 MW	
P5 supply tertiary sector	P10 diurnal trapeze with a maximum power of 300 MW	

In the study, it is demonstrated that, compared to a classical approach, which does not consider overbuilding the PV capacity, the use of implicit storage reduces significantly the LCOE. The results of the least-cost firm power generation approach applied to each scenario are presented in Figure 14. We show here results obtained with CAPEX costs observed in 2019. But if we consider the high decrease in the PV and batteries prices observed recently, the generation costs of most of the studied scenarios (i.e. LCOE) will be below or equivalent to the current generation cost. Not surprisingly, the achievement of an electricity mix with only PV and storage (scenario 1) requires a consequent investment. Conversely, scenario P12, which corresponds to the evening peak shaving, needs a reduced investment but exhibits the highest LCOE.



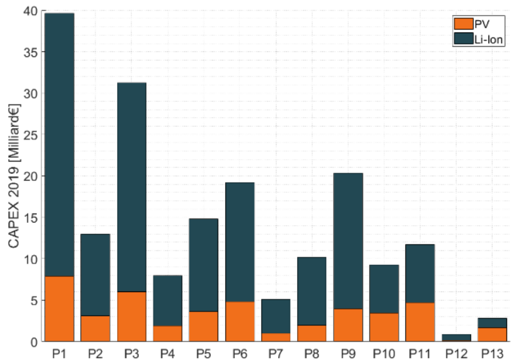


Fig. 14: Generation mix LCOE (left) and required additional capital expenditure (CAPEX - right) for each of the above scenarios (1-13) assuming investment costs observed in 2019. Contribution of the PV (orange) and batteries (dark blue) to the LCOE and to the CAPEX are also presented.

Figure 15, which shows the LCOE versus the CAPEX of the studied scenarios, highlights a clear roadmap to reach a 100% electricity generation from PV. Indeed, the most cost-effective path minimizes simultaneously the CAPEX and LCOE. The first step will be firm power forecasts (scenario P13) and then a 100% power generation from PV during daytime (scenario P11). In a second phase, PV generation will become a base load generation means (scenario P9) to fully replace the coal-fired plants (scenario P3). The last step will be the achievement of the 100% PV electricity generation.

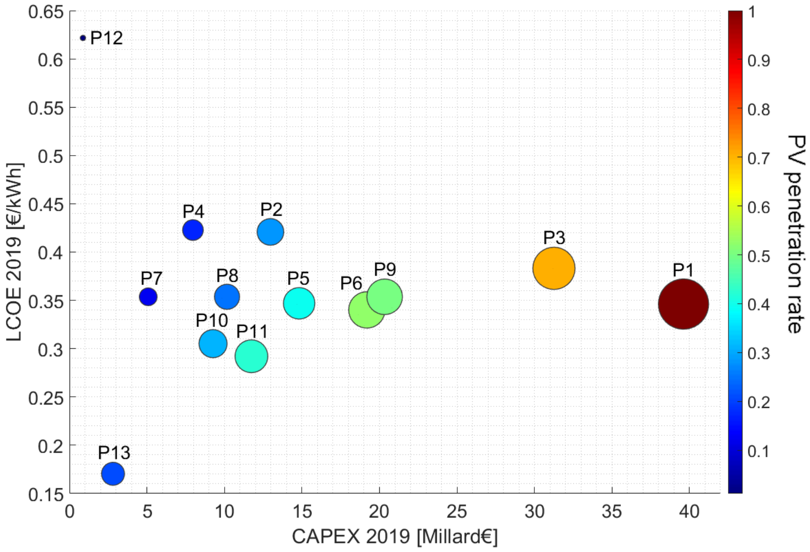


Fig. 15: Least-cost pathway to reach the 100% electricity generation from PV assuming investments with the prices observed in 2019.

As a take-away message, this study demonstrates that implicit storage can play a major role in the energy transition of Reunion Island while ensuring an affordable electricity generation.

2.9 A pan-European analysis of overbuilding wind and solar PV with proactive curtailment

Authors: Ruben van Eldik, Wilfried van Sark (Utrecht University)

Source: short communications (unpublished)

The European Commission aims to make Europe the first net-zero continent. The REPowerEU plan targets 45% of renewable electricity generation by 2030, which includes tripling the solar PV capacity to 600 GW. With a rapidly increasing share of variable renewable energy sources, it becomes ever more important to transform the intermittent power into firm power.

This study analyses what the optimal share of solar PV, and wind power is in combination with lithium-ion battery and hydrogen storage to guarantee firm power. This is accomplished by developing a model that optimizes both the deployment of production and storage capacities, as well the hourly dispatch of storage and interconnections for 37 European and neighbouring countries (Figure 16).

The Pan-European Intermittent Renewable Overbuilding and Curtailment Optimization Model (PEIROCOM) uses the demand and interconnection capacity projections for 2030 of the European Resource Adequacy Assessment (ERAA) as input. Bidding zones are modeled as nodes that are connected through interconnections. The potential for onshore and offshore wind energy as well as underground hydrogen storage are considered. The optimal deployment and dispatch values are found using linear programming (LP) in multiple steps with the time-hierarchical solution method (THS) developed by Weimann and Gazzani [8]. The combination of LP with THS makes it possible to optimize for both deployment and dispatch for multiple years simultaneously. This would otherwise be impossible due to the high number (106-108) of independent variables.

Fig. 16: Map of the 37 countries included in the research

To illustrate the relative costs of transforming intermittent power to firm power, Perez introduced in 2019 [1] the concept of the “firm kWh premium”, which is the ratio of the LCOE of a firm kWh and the LCOE of an unconstrained kWh. Under the technical and economic assumptions shown in Table 2, below, the preliminary results show that the ideal firm kWh premium in a lithium-ion only scenario would be 3.91 with 50% of all generated electricity curtailed. When hydrogen is added, the firm kWh premium falls to 2.90, while also reducing the curtailment to 31%. The results in Figure 17 do not show the curve up to 100% curtailment because more than three-quarters curtailment would be infeasible with the wind potential that was considered for each country. More extensive conclusions will be included in a future paper.

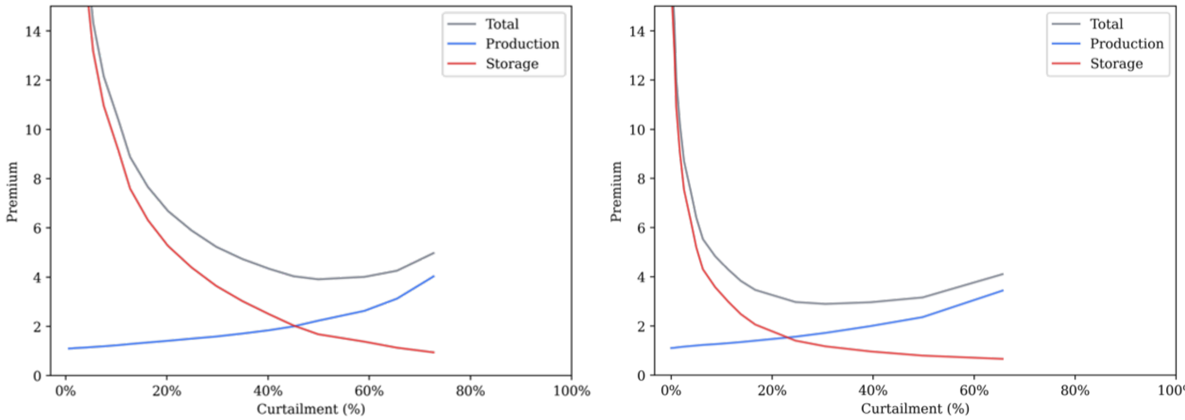


Figure 17: Left: Firm LCOE over curtailment with li-on storage. Right: Firm LCOE over curtailment with li-on and hydrogen storage

Table 2: Specifications and economic assumptions for PV, onshore and offshore wind generation, and for battery and hydrogen storage

	Solar PV	Onshore wind	Offshore wind	Li-on	Hydrogen
Economic life	30 years	30 years	30 years	15 years	18 years
WACC	4.4%	4.4%	4.4%	5.0%	5.0%
CAPEX	700 k€/MW	760 k€//MW	1945 k€//MW	243 k€//MW 81 k€/MWh	1300 k€//MW 1 k€//MWh
O&M	10 k€//MW/y	33 k€//MW/y	71 k€//MW/y	2.5% capex/y	2.5% capex/y
SoCmin				20%	0%
SoCmax				100%	100%
Efficiency				85%	40%

2.10 On the practical implementation of firm PV power with inverter controls

Authors: Javier Lopez-Lorente, George Makrides, George E. Georghiou (Univ. of Cyprus)

Source: short communications (unpublished)

The use of solar photovoltaic (PV) power as an effectively dispatchable resource for power generation is a key concept related to firm PV power. Along this concept, perfect operational solar forecasting (R. Perez et al. [9) has also attracted research interest in the recent years for the promotion of high, very-high and ultra-high PV penetration scenarios. Firm PV power is linked to two main enablers: overbuilding PV capacity and curtailment of PV energy (M. Perez et al., [1]). Overbuilding the installed capacity of PV responds to the need for an increased renewable energy generation share in power networks. This can be backed with the trends of lower costs of PV technology as reflected in IRENA's [10] evaluation of 2021's global weighted average levelized costs of electricity (LCOE) for utility-scale PV technology (0.048 USD/kWh) when compared to the typical LCOE ranges of conventional generation and very close to the global weighted average LCOE of onshore wind (0.033 USD/kWh). The second enabler is curtailment of PV energy, where the power output of smart PV inverters is limited or capped. Two curtailment strategies were identified in the context of firm PV, these are: inverter-limited curtailment (clipping) or by using dynamic curtailment [1, 6]. In inverter-limited curtailment, the inverter clips or limits the feed-in power when its maximum output power is reached. Dynamic curtailment, which is the focus of the results presented in this chapter, consists of adjusting the power output to a reduced setpoint in order to meet a specific power output (e.g., a power output committed for delivery during a specific period).

The management of inverter-based controls to support higher PV penetration is a topic covered by the literature at simulation level in electric distribution networks (Bonifacio and Pedrassa, [11]; Lopez-Lorente et al. [12]) and in control hardware-in-the-loop testing environments for prototypes and test benches (Strasser et al., [13]; Guillaud et al., [14]). Following these research streams, the conceptual aspects of firm PV power can be materialized and put in practice in pilot projects, which will help in establishing the future basis for massive deployment of PV in order to reduce our carbon footprint and ultimately achieve carbon neutrality.

This chapter presents three practical applications (use cases) of dynamic curtailment for smart PV inverters, including: (1) the change of active and reactive power setpoints based on predetermined daily schedules; (2) the periodic adjustment of the PV inverter's active power output to match day-ahead forecasts for a PV system; and (3) the periodic adjustment of the PV inverter's active power output to cover a constant share of the electric load in a nanogrid throughout the day. The dispatch of firm PV power is produced by leveraging the capabilities for active and reactive power control of a residential-scale smart PV inverter (2 kWp) within a grid-connected nanogrid. The case study presented is the nanogrid of the FOSS Research Centre for Sustainable Energy of the University of Cyprus, Cyprus.

The pilot study was implemented using the following methodological steps: (1) definition of the scheduled signals for the setpoint requests using arbitrary setpoint values and time-based triggering (Use Case 1); (2) the development of an automatic control algorithm for the adjustment of the inverter's setpoint embedded in a scheduler to periodically evaluate the current and targeted PV power setpoint (Use Case 2 and Use Case 3). The algorithms were developed in Python with the controllability of the PV inverter implemented through the communication protocol SunSpec Modbus, a TCP/IP-based protocol for distributed energy resource systems designed to meet the requirements of standard IEEE 1547.

2.10.1 Use Case 1: Adjusting PV Power Output as Required

The basic strategy for PV power management is the adjustment of the feed-in power by defining operational setpoints, which are typically defined as a percentage of the inverter's rated power. Smart PV inverters usually allow for both active and reactive power management. In practice, the signals for the setpoint requests of the inverters could be prescheduled or remotely defined by System Operators and could respond to real-time conditions of the network. For example, a power injection 100%, 50%, 33% or 0% of the rated power, or even PV system shutdown to address an emergency state due to a network constraint or disturbance. Fig. 18 presents an example of scheduled setpoint requests for active and reactive power throughout a sunny day and how the PV inverter responded. It is illustrated how the real (P) and reactive (Q) power output are independent from one another and can be controlled independently as required. The scheduled setpoints for P take the steps 100%, 50%, 33% and 0% of the rated power with different durations, whereas the scheduled setpoints for reactive power take positive (consume Q) and negative (inject Q) values with setpoints 0% (unity power factor), 50%, -50% and -75%. In the example, the PV system's real power is set to 0% (just before noon) for circa 10 minutes and Q dispatch is set to -75%, which aims to illustrate a case when a disturbance in the network could be partially mitigated by the reactive power injection of a PV plant for a short period of time.

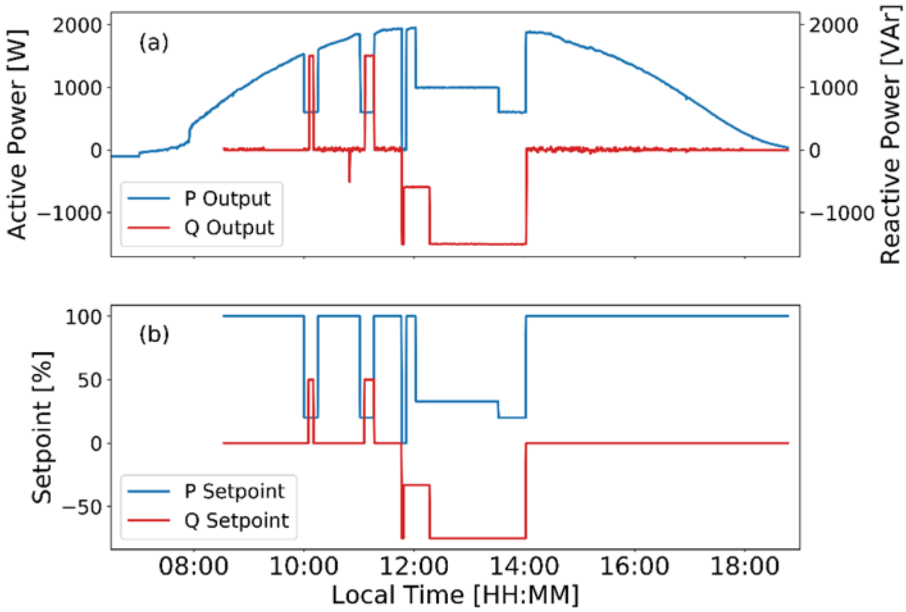


Fig. 18: Demonstration of scheduled setpoints requests for real and reactive power on a sunny day (August 31th, 2022): (a) active and reactive power output; and (b) active and reactive power setpoints. The scheduled setpoints illustrate the possibility for independent power management of real and reactive power dispatch in a variety of setpoints and durations. Data samples at 1-second resolution.

2.10.2 Use Case 2: Perfect Operational Forecast

Another application of PV power management in the context of firm PV power is perfect operational forecasts. With increased PV capacity, the feed-in power could be curtailed to match PV forecasts of smaller system's capacities. As a result, the PV system would have a perfect forecast with the following benefits for PV generators:

- Possibility to compensate the error of day-ahead and intra-day forecasts used.
- The ability to deal with unpredicted variability in solar resource in short-term forecasting horizons.
- Avoiding any potential penalties or charges for mismatches between the forecast submitted to the system operator or electricity market and the actual delivered energy for specific periods.

Fig. 19 exemplifies the practical implementation of firm PV for a perfect operational forecast application during a sunny day for the 2 kWp PV system evaluated with a day-ahead (DA) forecast for a 1.8 kWp PV system (10% lower capacity). The control algorithm was set to adjust the real power output to the nearest 10 Watts at 10-minute intervals throughout the day, where the curtailment was applied when the available power exceeded the DA forecast. The PV power dispatch resulted in stepped output; and the timeseries of the setpoints illustrates the action of the control algorithm, whose minimum setpoint was 87%. The test demonstrated perfect operational forecasts at 10-minute intervals; however, the PV power output could be even smoother with control algorithms working at higher time resolutions (e.g., 1-minute or sub-minute intervals) provided that the smart inverters are allowed to operate and process the signals and control commands at such resolutions.

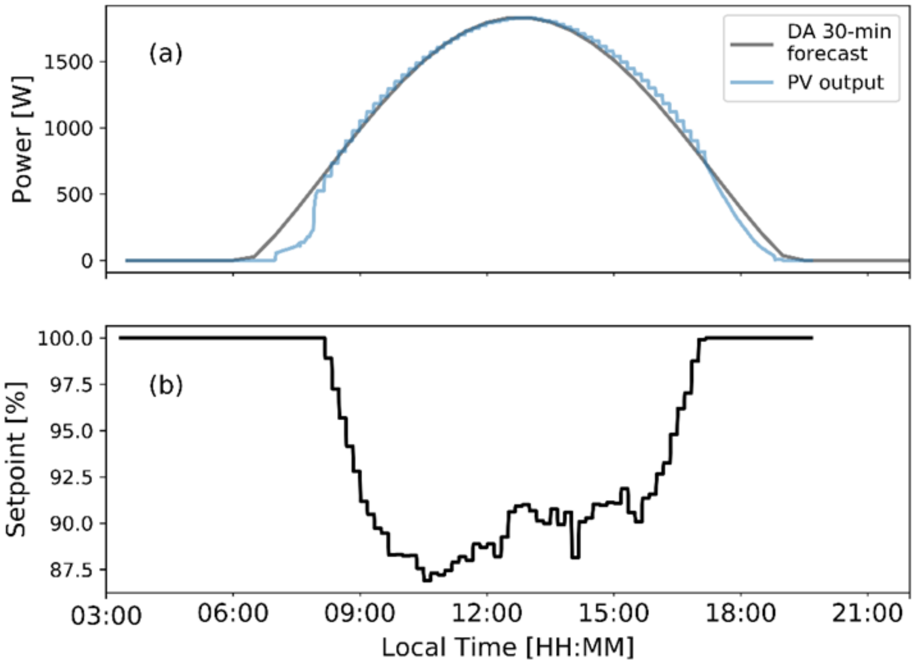


Fig. 19: Demonstration of perfect operational forecast on a sunny day (August 30th, 2022): (a) power output and 30-minute day-ahead (DA) forecast; and (b) active power setpoint. The control algorithm was implemented to adjust PV power output every 10 minutes to match a DA forecast 10% lower than the PV installed capacity. Data samples at 1-minute average values.

2.10.3 Use Case 3: Load following

A final application tested in the pilot was the dispatch of PV power following the electric load consumption of the nanogrid. With a load following strategy, PV can provide a constant share of energy. When PV power was not available due to diurnal cycles or cloudy weather conditions, electric battery energy storage could complement the inverter-based power output to match the required share of solar-based energy. Under this approach, a load following operation would permit the dispatch of PV (and hybrid PV and storage) plants as a conventional generator with the ability to become baseload generation and contributing to lower-carbon unit commitment in electric power systems.

An example for PV dispatch under load following (without battery energy storage) is shown in Fig. 20 for the nanogrid tested. As the electric load (Fig. 20) is typically higher than the PV capacity installed, the PV dispatch algorithm was set to cover 10% of the total demand. The tested day (September 13th, 2022) was a sunny day with partly cloudy conditions in the afternoon as observed in the timeseries of the global tilted irradiance (Fig. 20b). As implemented in the case of perfect operational forecasts, the control algorithm for the dispatch of the PV system was set to adjust every 10 minutes to match 10% of the real power level of the nanogrid as read in a smart meter located in the nanogrid's incomer using Modbus TCP/IP. Fig. 20c illustrates the PV output throughout the day compared to the target load to be supplied. The 10-minute interval for the inverter's control shows the fluctuation in the PV contribution between the setpoint requests due to both variations in the electric load and available solar resource (see Fig. 20d). Overall, the PV system was able to maintain a share around 10% with slight variations throughout the day when the solar resource was available.

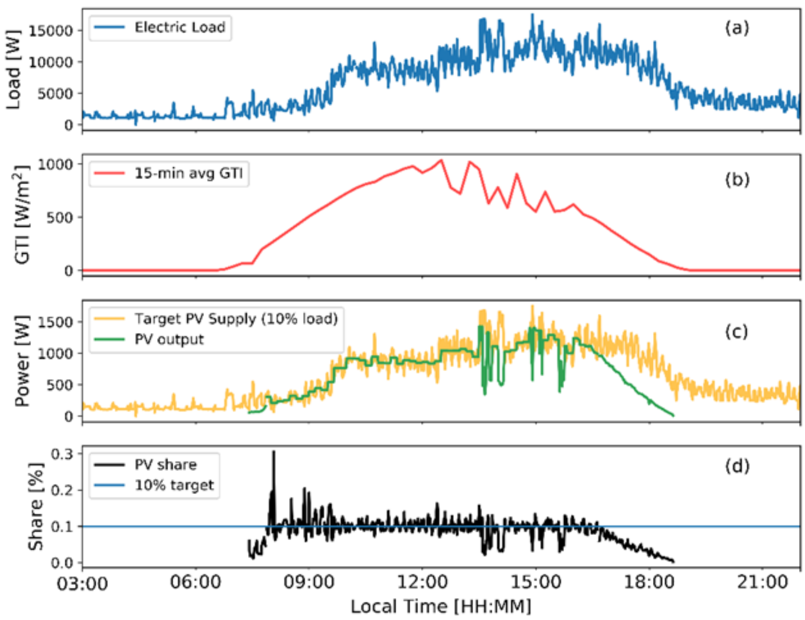


Fig. 20: Demonstration of PV inverter operating under load following for a test day (September 13th, 2022) with sunny and partly cloudy conditions. The aim was for PV firm power to contribute 10% of the total load during daylight hours with periodic setpoint requests with 10-minute intervals in the control algorithm: (a) total load during test day; (b) global tilted irradiance (GTI) during test day; (c) target load and PV dispatched power; (d) share of PV during the test day. Data samples at 1-minute average values unless otherwise specified.

2.10.4 Summary and key points

In summary, three use cases of firm PV power were presented in a small-sized smart PV inverter. Applications based on strategies related to perfect operational forecasts and load following in small grid-connected systems (e.g., nano- or microgrids) were tested. The results of the pilot demonstrated how the principles of firm PV power can be practically implemented with current commercially available smart inverter technologies. The reliance on curtailment of firm PV power opens new ways for further research related to multi-asset control strategies for solar generators (e.g., what PV plant should curtail, for how long and under what eligibility criteria?). Lastly, the revenue streams for PV plants operating in a firm PV context will completely change the dynamics of payments made to solar generators, which will not be based on a maximization of exported (sold) energy anymore, but rather a combination of amount of energy exported and energy curtailed

3 ENTRY-LEVEL FIRM POWER GENERATION STUDIES

3.1 Imbalance mitigation strategy via flexible PV ancillary services: The Italian case study

Year: 2021

Authors: M Pierro, R Perez, M Perez, D Moser, C Cornaro

Journal Paper: Renewable Energy 179, 1694-1705. [15]

Link: ***https://www.sciencedirect.com/science/article/pii/S096014812101079X***

This investigation centers on solar regulation by exploring the potential of ancillary services provided by flexible solar systems in mitigating not only solar prediction errors (as in earlier work), but also mis-scheduling resulting from errors in net load prediction. In this case, the flexible PV fleet, directly controlled by the TSO though the power plant controllers, provides load-following and unit commitment ancillary services to reduce the daytime residual demand/supply imbalance. Therefore, flexible solar systems are considered for all intents and purposes secondary reserve just like the thermoelectric gas turbines currently used for balancing purposes. The proposed strategy is a way to increase the flexibility of the Italian system while avoiding the construction of new conventional power plants. Indeed, the high quantity of non-programmable renewable sources will require keeping available a sizable portion of thermoelectric generation capacity, to guarantee the necessary reserve margins for the safe operation of the system.

In this work, the flexible fleet and the implicit storage are sized to lock the imbalance at a desired value regardless of the PV penetration, keeping the proactive curtailment as close as possible to a reasonable value (6% of the national PV generation) without any optimization of the solar regulation costs. As in earlier work, the present analysis evaluates the techno-economic benefits of using solar regulation at current and future penetration levels using a photovoltaic capacity growth scenario that incorporates the government target to 2030 and utility-scale lithium batteries learning curve from Bloomberg NEF.

Finally, the study investigates the effects of non-uniform spatial and capacity distribution of the flexible PV fleet and the impact of changing load/PV/wind profiles on the imbalance mitigation potential of the proposed strategy.

<u>Key takeaways</u>: In Figure 21, the top left (a) plot displays both the residual imbalance that should be resolved by traditional flexible resources and all the energy components involved in the solar regulation. Solar regulation not only can bring the imbalance lower than the 2016 value (dashed gray line) but also can notably reduce the imbalance obtained by an accurate “state of the art” forecast (line with red dots): 13% of reduction at 8% of penetration (2020), 29% at 21% of penetration (2030) and 49% at 37% (2040).

The top right graph (b) illustrates the costs of residual imbalance regulation on the Dispatching Energy Market and the costs of the flexible PV ancillary services according to the proposed business model: PV power to BESS, PV curtailment and BESS night recharging rewarded at PUN energy price, Battery CAPEX (inclusive of BESS annual replacement) and OPEX funded by government grant. The total imbalance costs using solar regulation and using only the selected state-of-the-art forecast remain comparable at all the penetration levels and lower than the current ones until 2033.

The two bottom graphs (c & d) report the total and annual capacities of the flexible PV systems that should be deployed to reach the imbalance target with a solar curtailment as close as possible to 6%.

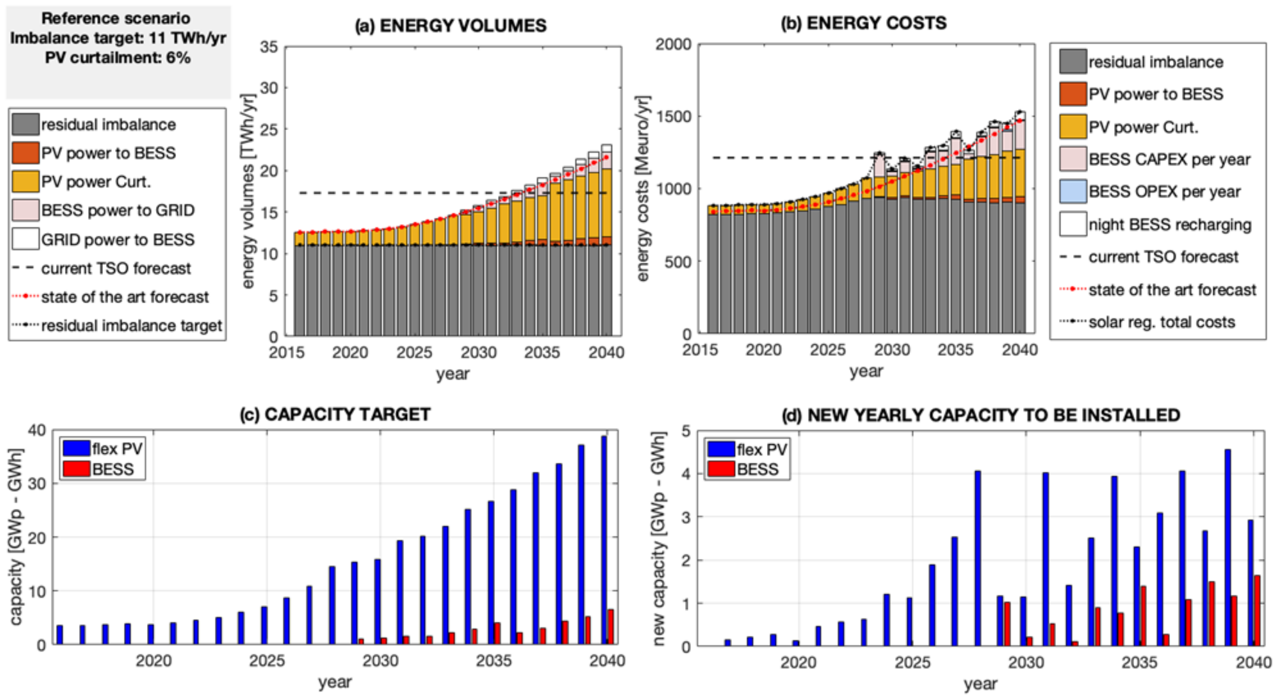


Fig. 21: Residual imbalance/solar regulation energy volumes and costs (a and b); flexible PV total capacities (PV and BESS) required to achieve the residual imbalance target with 6% of proactive curtailment (c); flexible PV capacities that must be installed to reach the required flexible PV total capacities target (d).

The analysis points out that the most reasonable and realistic assumption – the flexible fleet is made of many plants with different capacity randomly distributed all over the country – provides an optimal solar regulation performance if the flexible solar systems are sufficiently high in number (in this case four hundred plants across the country).

Finally, the study demonstrates that the effectiveness of solar regulation is not directly related to the load, wind, irradiance, and energy prices profiles per se, but mainly depends on solar prediction accuracy that can only improve over time.

3.2 The value of PV power forecast and the paradox of the "single pricing" scheme: The Italian case study

Year: 2020

Authors: M Pierro, D Moser, R Perez, C Cornaro

Journal paper: Energies 13 (15), 3945. [16]

Link: ***https://www.mdpi.com/1996-1073/13/15/3945***

Unlike most other studies in this firm power generation field, where the TSO point of view is assumed, suggesting the use of solar regulation via flexible PV ancillary services, this investigation focuses on the point of view of a single PV producer that manages a utility-scale PV farm. In Italy, owners of PV systems greater than 10 MWp must submit the next day's production schedule to the TSO and are responsible for their forecast errors (imbalances). This study analyses the economic impact of the accuracy of PV power forecasts by considering the “single pricing” scheme used in the Italian dispatch market to calculate the imbalance value of an individual utility-scale PV system. Results show that, from a perspective of promoting solar regulation, the current regulatory framework and market rules are inadequate not only because they do not make the ancillary services provided by flexible PV systems profitable, but even before that, because they do not reward the best forecasts. Indeed, results show that under the single pricing scheme, poorer forecasts could produce higher revenues for the producers than high quality predictions or even perfect forecasts. This implies that the current market rules are completely at odds with the physical requirements of balancing demand and supply using accurate solar power forecasting. In addition, results also show that the single price scheme promotes speculative/inside trading and illegal arbitrage activities on the market. In fact, we have demonstrated that it is much more profitable for a PV producer/trader to predict whether the day-ahead imbalance in the Italian balancing zone will be positive/negative and thus provide the TSO with a strong under/over prediction (illegal arbitrage) than to supply the most accurate forecast.

As previous work that pointed out the need for a new business model that enables profitable solar regulation for TSOs, here the authors strongly suggest that, at the very least, we should move beyond the single price scheme, proposing an alternative rule that enhances the use of the most accurate forecasts.

Key takeaways: The main findings of this investigation are:

1. Net imbalance absolute values (that range from -5 to 5 k€/MWp per year) are very small if compared to the total energy incomes on the Day-ahead (DA) and Dispatching Services (MSD) markets (that range from 50 to 150 k€/MWp per year); hence with the current market rules, the imbalances have a small impact on the total energy revenues of the PV producers/traders.
2. The annual economic loss/gain due to the errors in the PV generation scheduling is equal to the value of the PV forecast (net-imbalance value). The net-imbalance value can be computed as the difference between the total energy incomes on DA - MSD markets and the energy revenues that could be realized with a perfect forecast (no imbalance).
   Figure 22a shows that the net imbalance values are costs in all the Italian regions except for Lazio, Campania, Calabria, and Sardinia where there are some locations in which the imbalance could bring profits. Hence, in some regions poorly predicted PV generation could lead to higher profits than an “ideal” perfectly predictable generation (that will not produce solar-induced imbalance).
3. Looking the gains of using a state-of-the-art PV power forecast with respect to a persistence forecast (figure 1b) it is evident that negative gains appear in regions of Centre-North and Sardinia with average zonal values between -0.5 and -0.3 k€/MWp per year. Therefore, from an economic standpoint, in these zones the persistence model should be preferred to a more accurate forecasting method, so there is no economic need to improve the forecast accuracy reducing the solar imbalance volumes.

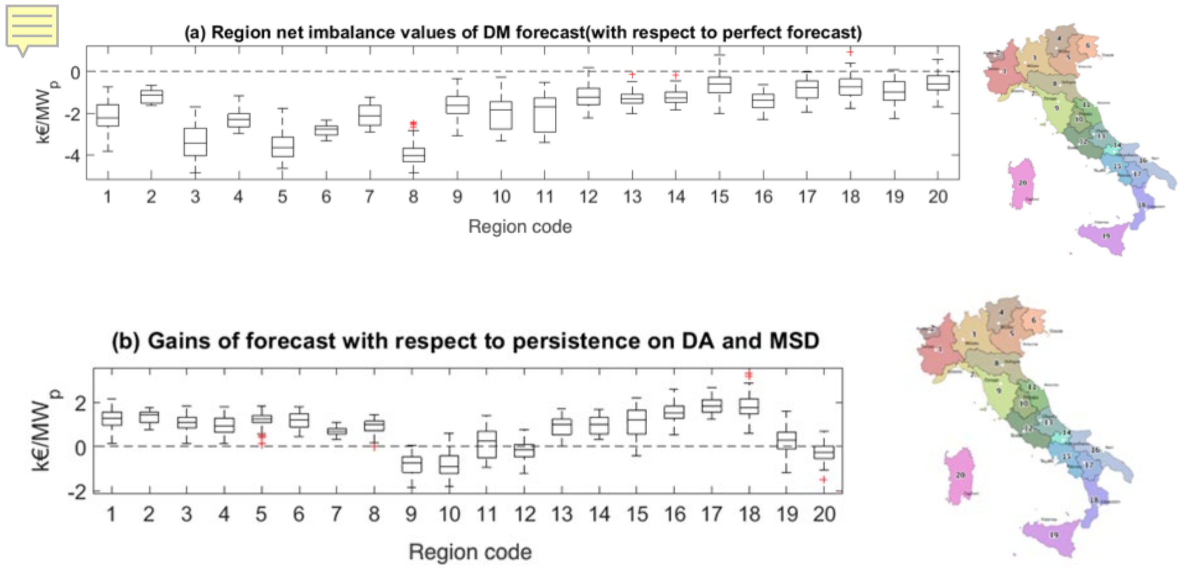


Fig. 22: Net imbalance values aggregated by regions (a); Gains on DA and MSD markets per unit of PV capacity resulting from the use of our PV generation forecast instead of persistence prediction (b).

4. The average imbalance unitary value ⟨V_(Z)^B ⟩ embeds both the MSD energy prices (for upward or downward regulation) and the match between the signs of production unit (UP) imbalance and imbalance of the Balancing zone in which the UP is located: same signs (both negative or positive) or different signs (negative/positive and vice versa). Figure 23 clearly shows that the imbalance values on the MSD market are considerably more correlated with the average imbalance unitary values (left graph) than with the imbalance volumes defined as the annual sum of absolute forecast errors (right graph). This means that, for energy producers/traders under “single price” rule, it is much more important to predict the right sign of the zonal imbalance and thus to provide Terna an adequate under/over forecast (to get the right imbalance signs match) rather than to deliver the most accurate forecast minimizing the volume of solar imbalance.

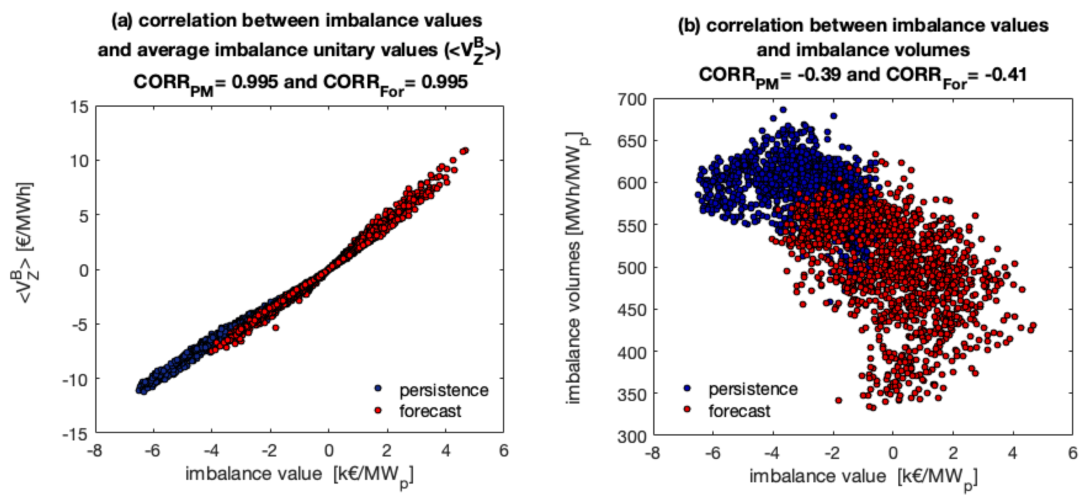


Figure 23: Scatter plot of the average imbalance unitary values on MSD vs the imbalance values per unit of PV capacity (a); scatter plot of the imbalance volumes per unit of PV capacity vs the imbalance values per unit of PV capacity (b).

3.3 Italian protocol for massive solar integration: Imbalance mitigation strategies

Year: 2020

Authors: M Pierro, R Perez, M Perez, D Moser, C Cornaro

Journal paper: Renewable Energy 153, 725-739 [17]

Link: ***https://www.sciencedirect.com/science/article/pii/S0960148120301671***

This investigation is a first logistic step toward the full 24/365 firm solar power generation (see above). It explores the possibility of reducing the solar-induced demand/supply imbalance via flexible solar systems. These systems are PV plants equipped with smart inverters, plant power controller (PPC) and battery energy storage systems (BESS). They can be managed remotely (through the PPC) to decrease their output through proactive energy curtailment (by means of smart inverters) or increase their generation through the injection of additional energy from BESS. With suitable PV and BESS capacity sizes, flexible solar systems can modulate their generation, provide perfect forecasting (adapting their production to the predicted one) as well as supply full dispatchable base-load generation 24/365.

In this work, the authors show how the TSO can remotely control a suitably sized flexible fleet of PV plants to reduce the forecast errors of the Italian PV generation and therefore reduce the solar-induced imbalance. They also show how the amount of storage of the flexible solar fleet needed to reach a given imbalance reduction can be reduced simply by using a probabilistic under-forecast of the national PV generation. Indeed, in this way, the TSO will reduce the number of events in which the observed solar generation is less than the predicted one, and thus additional power injection from storage is needed to compensate for this forecast error. Therefore, since the actual generation is more likely to be higher than the forecasted generation, the TSO must make an additional proactive curtailment of the flexible PV fleet to adjust the real time solar generation to the forecast shortfall. Thus, under-forecast/curtailment function as “implicit” storage reducing the need for batteries and its related costs.

The final objective of this investigation is to propose two imbalance mitigation strategies to remove the effect of increasing solar forecast errors on the scheduled supply at current and future penetration levels.

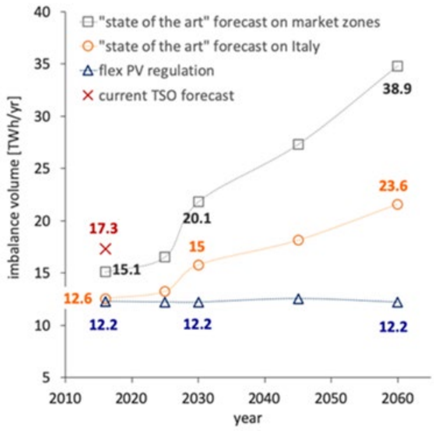
The first strategy is based on accurate PV “state of the art” power forecasts and on the expansion of the TSO forecast controlled area from the current market zones to the entire nation (i.e., TSO would have to carry out a series of transmission grid upgrades aimed at completely removing the capacity transit constrains between market zones in which Italy is currently divided).

The second strategy aims at fixing the Italian imbalance at a desired value, regardless of solar penetration, through the regulating services provided by an optimally sized flexible PV fleet and the use of appropriate implicit storage (solar regulation).

In each case, the balancing costs of solar regulation are evaluated against the current and future business-as-usual balancing costs.

Key Takeaways: Figure 24 shows the yearly imbalance volumes and costs from 2016 onward obtained through the TSO net load forecast and the imbalance volumes and costs in 2016 and expected future PV penetration levels obtained with the “state of the art” PV power forecast on the Italian balancing market zones, by the “state of the art” PV power forecast on the unique national balancing zone, and after applying our solar regulation strategy.

In 2016, the TSO's forecasts produced an imbalance of 17.3 TWh with an estimated cost of 1,213 million euros, while if the Italian TSO increased the accuracy of solar forecasts of each market zone to the "state of the art" level, it could reduce the volume and cost of imbalance by 12.6 % and 17.6 %, respectively. If the TSO also expanded the forecast-controlled area from individual market zones to the entire country, the volume and cost of imbalance would be 27.4 % and 30.5 % lower than the 2016 values. Finally, if the solar regulation strategy were also adopted, the national imbalance volume/cost would be further reduced by 29% and 36%.



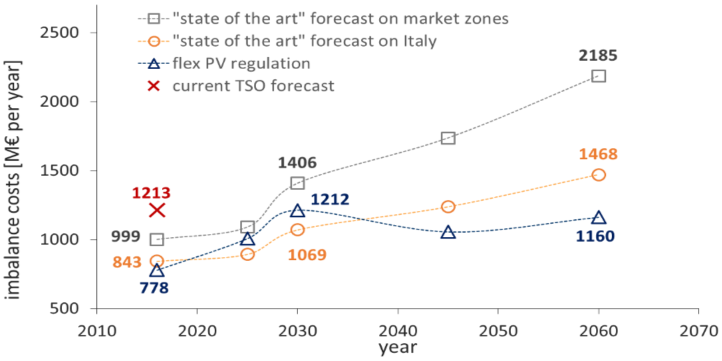


Figure 24: Imbalance scenarios (left) and imbalance costs scenarios (right)

Figure 24 also shows that, at the expected future PV penetration, the use of a "state of the art" PV power forecast cannot avoid significant growth in volumes and imbalance costs induced by the increasing uncertainty on the day-ahead solar generation. While the expansion of the forecast areas can only limit this growth, the solar regulation strategy can lock the imbalance volume at a specific value, regardless of the PV energy share. It is worth noting that due to the implicit storage that reduces the volume/cost of batteries, the costs of solar regulation are comparable to those of business- as-usual.

Figure 25 reports the corresponding cost-optimal sizes of the PV and BESS capacities of the flexible solar fleet needed to reach the above-mentioned results.

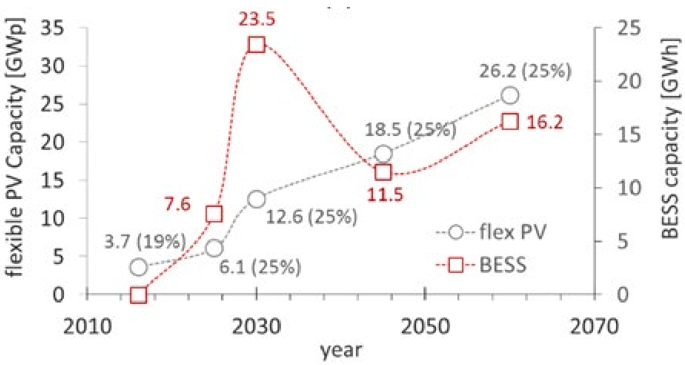


Figure 25: Flexible PV and BESS capacities of the PV Plants that should be used for solar regulation to limit the imbalance volume at 12.2 TWh/yr

3.4 Perfect Operational Solar Forecasts: A Scalable Strategy toward Firm Power Generation

Authors: Perez, R., M. Perez, M. Pierro, J. Schlemmer, S. Kivalov, J. Dise, P. Keelin, M. Grammatico, A. Swierc, J. Ferreira, A. Foster, M. Putnam, and T.E. Hoff

Year: 2019; reference: [9]

Link: ***http://proceedings.ises.org/paper/swc2019/swc2019-0220-Perez.pdf***

The authors of this study present the perfect forecast concept as both an effective forecast validation metric and an operational strategy to integrate increasing amounts of variable solar power generation on power grids.

The costs incurred in transforming imperfect into perfect predictions define the new forecast validation metric: these include the costs of backup storage and output curtailment necessary to make-up for any over/under predictions. The concept is illustrated with the most recent version of the SUNY forecast model for hour-ahead and day-ahead forecast examples with single power plants as well as regionally distributed PV fleets. As shown in Figure 26, a key finding of the study is that [smart] persistence forecasts score very well using perfect forecast as a KPI. It implies, that persistence is a more robust forecast in terms of operational economics than it would appear using standard KPIs such as MAE or RMSE. This is because while other forecast models produce less scatter and score higher on standard metrics, [smart] persistence does not produce prolonged over or underestimations that are operationally costly.

Results show that delivering perfect predictions – i.e., fully eliminating grid-operators uncertainty -- is achievable at small operational cost. Most importantly, they highlight that a perfect forecast strategy with optimized least-cost storage and overbuild/curtailment is an effective first step of a long-term strategy to cost-optimally transform variable PV generation into firm, effectively dispatchable generation capable of displacing conventional dispatchable and baseload generation (Figure 27).

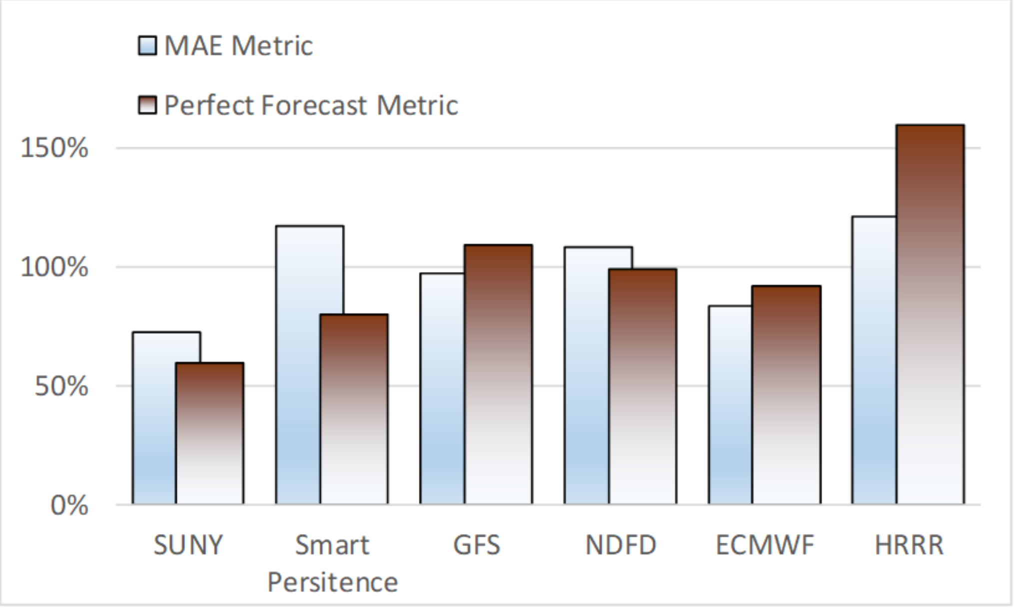


Fig. 26: Comparing model performance ranking across all locations and time horizons for standard and perfect forecast metrics. The value of 100% amounts to the mean error metric of all models/locations/time-horizons.

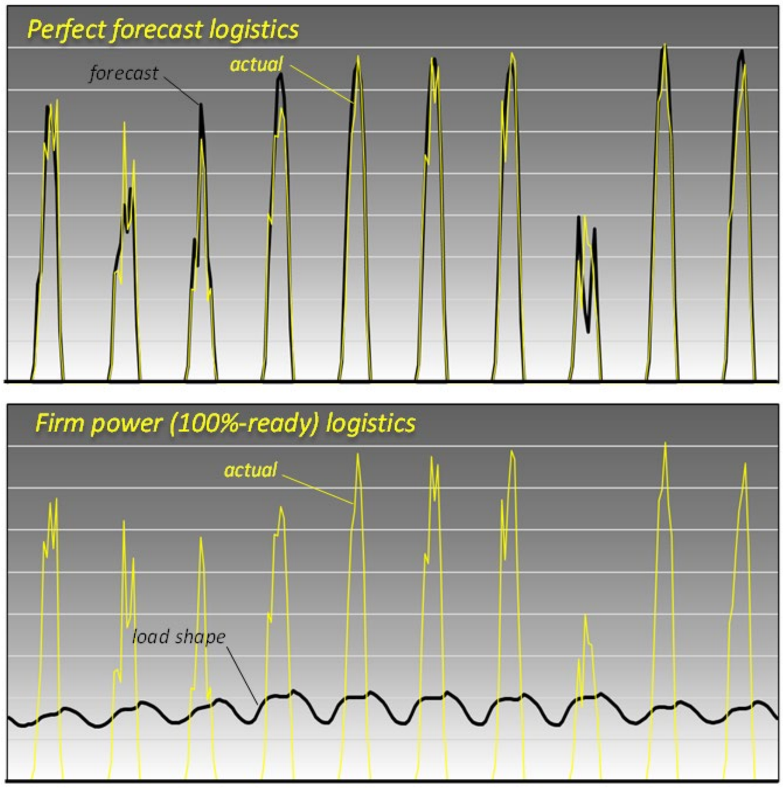


Figure 27: Comparing the perfect forecast entry-level task of transforming PV output into predicted PV output (top) to the high-penetration firm power generation task of transforming PV output into the grid's load shape (bottom).

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