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Optimized operation of distributed energy resources: The opportunities of value stacking for Power-to-Gas aggregated with PV☆

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ABSTRACT

This analysis investigates the business case of a virtually aggregated unit with PV and Power-to-Gas, outlining the added value of enhanced operation modes for the deepened market integration of distributed energy resources in an aggregated form. Based on empirical generation and market data, the presented analysis outlines the added benefit of the so-called value stacking that considers the exploitation of short-term arbitrage opportunities, the provision of secondary and tertiary frequency reserve, and active imbalance management to balance forecast errors. A multi-stage and multi-period optimization approach is presented to generate an aggregated bidding strategy on multiple energy and ancillary service markets. On a case study basis with hourly resolution, annual energy flows and financial outcomes are derived for the modelled plant. Overall, nine different operating modes with different levels of market integration of the aggregated unit are analysed. While static baseline operation results barely profitable, proper integration into energy markets raises the annual cash flow from operating activities to around 60 k€ per aggregated MW. This six-fold increase is accompanied by a much more price-specific dispatch with the equivalent full-load hours of controllable output effectively dropping to about one-third. Integrating the aggregated unit further into balancing markets and performing active imbalance management leverages the freed-up capacity margin and further increases the operational results up to 150 k€ per MW. The provided empirical insights from the case study are beneficial for both practitioners in the energy sector that want to evaluate the potential value of virtual aggregation with enhanced operation and policymakers that consider further regulatory amendments to open markets and enable further integration of new energy sources.

1. Introduction

Attractive economic opportunities for Distributed Energy Resources (DERs), and Renewable Energy Resources (RESs) in particular, are crucial for accelerating the ongoing energy transition towards a carbon-free power system. Remuneration should thereby originate from market-based revenues to ensure economic efficiency and reduce subsidy dependence. However, the market framework conditions in power systems are at the same time rigidly regulated to ensure that individual economic interests do not jeopardize the system's stability [2]. While regulatory frameworks are thus only relatively cautiously adapted to the needs of new stakeholders, recent advancements, such as the Clean Energy Package at the European level, finally paved the way for improving the market integration of DERs [3]. Amongst other things, higher time resolution allows to trade electricity closer to real-time with finer product granularity, virtual aggregation of different generation and consumption resources is allowed, and the provision of system services such as balancing, congestion management and ancillary services is enabled for DERs [4]. In an analysis based on empirical data, this paper demonstrates how an optimized DER operation, which leverages the full scale of such deepened integration into existing market frameworks, provides significant room for enhancing the benefits of individual resource operators and connected external benefits for power system operators. Specifically, the opportunities of a utility-scale Photovoltaic (PV) unit in combination with a Power-to-Gas (P2G) unit are analysed in a detailed case study as further explained in the following.

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Nomenclature

Indices and Sets

act	Active operation of P2G plant.
DAM	Day Ahead Market.
DW	Downward balancing service.
exp	Export.
H2O	Demineralized water consumption.
H2	Hydrogen production related variables.
IDM	Intra-Day Market.
imb	Imbalance settlement mechanism.
imp	Import.
mkt	Previous market.
P2G	Power to Gas.
PV	Photovoltaic.
q	Losses.
sby	Stand-by operation of P2G plant.
T	Transformer.
UP	Upward balancing service.
$t \in T$	Set of time periods.

Other acronyms

BESS	Battery Energy Storage Systems.
BRP	Balancing Responsible Party.
DER	Distributed Energy Resource.
DSR	Demand-Side-Response.
FRR	Frequency Restoration Reserve.
GO	Gurantees of Origin.
ICT	Information and Communication Technologies.
PEM	Polymer Electrolyte Membrane.
PPA	Power Purchase Agreement.
RES	Renewable Energy Resource.
RR	Replacement Reserve.
SOCE	Solid Oxide Electrolysis Cell.
TSO	Transmission System Operator.
VPP	Virtual Power Plant.

Parameters and Constants

Δt	Timestep of the simulation [h].
η	Efficiency [p.u.].
$\overline{P}$	Rated power [kW].
LHV	Lower Heating Value [kWh/kg].
P_t^{PV}	Hourly photovoltaic production at time t [kW].
c_t	Price at time t [€/kWh or €/kg].
$imbal_t$	Imbalance at time t [kW].

Variables

α_t^*	Binary variable at time t.
β_t^*	Binary variable at time t.
$\dot{m}_t^*$	Mass flow rate at time t [kg/h].
γ_t^*	Binary variable at time t.
E_*^*	Energy [kWh].
Obj_*	Objective function [€].
$P_{*,t}^*$	Power at time t [kW].

1.1. Background

Market integration of DERs concerns three fundamental aspects: the commodity trade on energy markets, the provision of system services on ancillary services and balancing markets, as well as the handling of balancing responsibility with respective imbalance management.

Concerning *energy markets*, most DERs still trade their generated commodity based on dedicated support schemes that provide them with fixed (minimum) prices. With the evolution of the support schemes from feed-in tariffs to feed-in premiums and further to contracts-for-differences, the generated energy is already increasingly integrated into the energy markets through third party trading activities such as direct marketers [5,6]. However, the individual DERs retain their guaranteed price level and thus remain exempt from the risks and opportunities of effectively variable market prices so that their operational behaviour remains basically detached from real-time price fluctuations. Beyond this rather indirect integration, DERs can be directly exposed to price fluctuations in a deeper integration by interacting with the full spectrum of Day-Ahead Markets (DAMs) and Intra-Day Markets (IDMs) and their respective sub-sessions. While few DER units have opted for such merchant approach as of now, their number is likely to increase as a notable number of comparably old RES units starts dropping out of support schemes and an increasing number of new RES installations reaches grid-parity [7].

Ancillary services and *Balancing Markets* represent a second category of markets through which power system operators procure the necessary resources to actively manage the system. Given their relevance for the system's stability, such markets are the most rigid to enter with, as of now, often notable entry barriers for DERs [8–10]. Wherever already existent, aggregators with their associated Virtual Power Plants (VPPs) are a key partner to facilitate market access, especially for smaller DERs for which individual access is yet not possible or economically viable [11–13]. The integration into balancing markets is thereby not only a question of economic operation but also of technical requirements, as integrated assets require enhanced Information and Communication Technologies (ICT) for direct dispatch control. While the traded volumes on balancing markets are notably smaller, the remuneration is usually higher than on energy markets, providing the operators with a price premium for their flexibility services [14].

Finally, *imbalance management* occurs not on a specific market but through a dedicated approach that can consist of multiple elements. Whenever potential imbalances from updated consumption or generation forecasts are registered sufficiently ahead of time, a first approach is to settle them through remaining energy market sessions, especially on the IDM. Besides market sessions, the deployment of flexibility abilities of the individual resource (or the aggregate of resources that share balancing responsibility) represents a second, internal approach of imbalance management. Virtual aggregates of programmable and non-programmable units (such as RES with Battery Energy Storage Systems (BESS), Power-to-Gas (P2G) units or other flexible loads that enable Demand-Side-Response (DSR)) provide a common case-study for such internal imbalance management [15–17]. Imbalances not tackled through market position adjustments or internal flexibility are settled through real-time system balancing and face respective imbalance payments. Imbalance settlement represents therefore the third and last element of imbalance management, originally designed as a last-resort settlement of unforeseen fluctuations that could not be handled otherwise. In line with this "classic" imbalance management approach, Balancing Responsible Parties (BRPs) are usually legally required to minimize their imbalances as much as possible and imbalance (settlement) prices are published only ex-post with an often notable time lag of several days or even up to several weeks as in Germany [18]. Nonetheless, academic authors proved that imbalance prices are effectively predictable ahead of time [19,20] and that BRPs are actually exploiting them under certain conditions [21,22]. In contrast to active balancing provision through balancing markets, leveraging on imbalance prices by intentionally deviating from market schedules is then often referred to as "passive balancing" [23].

Overall, imbalance management is a fundamental element of market interaction that every energy consuming or power generating unit performs. Other than ancillary service provision through balancing market integration, enhanced imbalance management has no technical requirements for but is rather an economic activity that leverages the operational capabilities of a plant. It is therefore easily applicable to any type of DER and yet offers significant advantages, as highlighted in the further course of the paper. The type of imbalance management is often linked to the level of integration into energy and balancing markets. If energy market integration is rather superficially handled by a direct marketer and no balancing market integration occurs, the respective BRP will most likely focus only on the first element of imbalance management by adjusting updated forecasts through remaining energy market sessions and taking on imbalance payments for remaining imbalances. On the other hand, if the DER is also integrated into balancing markets, for example while being part of an aggregator's VPP, the chances for a more pronounced imbalance management that includes also the element of internal flexibility are higher. Whether or not the BRPs imbalance management goes beyond the first two elements and carries out also passive balancing is notwithstanding the above and depends on the BRP's risk aversion as well as its ability to predict the imbalance price.

In the further context of this paper, full market integration is meant as proposed by the Association of European Energy Exchanges (Europex) in the sense that DERs participate in all markets under the same conditions as any other conventional, large-scale asset and that they are subject to the same rules [24]. Each of the three aforementioned aspects of market integration comes along with individual market interactions, whereby deepened integration results in amplified product offerings and eventually in multiple cash flows. Such concept is called value stacking [25], revenue stacking [26], or benefit stacking [27].

Beyond the named market interactions, financial products can complement the revenue streams from advanced market integration and virtual aggregation. The two most notable are thereby Power Purchase Agreements (PPAs) that hedge price-risks on a long-term basis, or Gurantees of Origins (GOs) that provide an additional value streams based on the green value of renewables. The analysis of the additional impact of these financial products goes however beyond the scope of this paper and remains subject to further research.

1.2. Contributions

This analysis investigates the economic opportunities from enhanced operations based on the case study of full market integration for an exemplary VPP that aggregates one programmable and one non-programmable DER, namely a PV and a P2G unit.

The study builds thereby on previous work of other researchers that analyse individual aspects such as the scheduling processes [28] or the economic viability [29] of a VPP that operates one type of market. VPPs that operate on multiple markets in parallel and that follow the concept of value stacking have been as of now modelled with lower granularity for future energy scenarios [30] or usually consist of a PV unit in combination with a BESS unit [31,32]. The flexibility of such VPPs is however limited by the inherent capacity constraints of BESS with the corresponding operational limitation. It operates in a kind of "closed" flexibility cycle, meaning that all service provided in one direction is limited in time and must be accompanied by some operation in the opposite direction before being able to re-provide the same service again [33]. VPPs with P2G units instead offer a wider flexibility range and operate in a somewhat "open" flexibility cycle, meaning that any service can be provided without specific time limitations [34].

As outlined in Table 1, the paper contributes to the existent body of literature by presenting the first full-fledged analysis of the economic opportunities that recent market reforms enabled for unconstrained DERs in a virtual aggregate. Based on empirical generation and real market data, the analysis outlines the added benefit from a fully enhanced and optimized operation mode with value stacking, combining the balance of forecast errors, the exploitation of short-term energy market arbitrage opportunities, and the provision of different frequency reserves. Most notably, the main novelty in this work is a methodology for evaluating the value of operating in both energy and balancing markets, stacked with the benefits deriving from imbalance management. The latter considers both *Classic* imbalance management (i.e., settlement of involuntary imbalances with regard to the scheduled operation) and *Passive Balancing* (i.e., voluntary deviation from schedule to leverage on imbalance prices). Specific research questions that are addressed are:

1. What are the plant-specific benefits that advanced operation modes with value stacking provide to DERs?
2. Which are tangible, system-wide benefits that full market integration of virtually aggregated DERs enables?
3. To which degree increase the respective benefits with various levels of increased market integration?

The paper follows thereby the logic of recent regulatory developments with respective new openings of market segments for DERs (e.g., European Electricity Regulation 2019/943 and Electricity Directive 2019/944 with resulting market openings such as through the UVAM pilot project in Italy [9,37,38]). The focus is thus not how to optimize the operation but on where to operate under optimized conditions. The presented study is thereby complemented by extended analyses concerning renewable uncertainty [39], interaction of different DER asset types in a VPP's bidding strategy [40], coordinating the bidding strategy across different markets [41], bidding in a competitive market (or under pay-as-bid) [42].

The remainder of the paper is structured as follows. Section 2 describes the material and methods that have been utilized as the basis of the model before Section 3 outlines the multi-stage and multi-period optimization approach that is applied to model the enhanced operating mode. Section 4 discusses then the results of the VPP's aggregated bidding strategy on multiple energy and balancing markets in combination with different types of imbalance management, before Section 5 finally concludes.

2. Material and methods

The modelled VPP of the case study consists of a 20 MW_{peak} PV unit and a 6.2 MW_{peak} Polymer Electrolyte Membrane (PEM) electrolyzer P2G unit, connected at medium voltage level. To comply with current Italian regulations for virtual aggregation, it is assumed that the two units share the same primary substation. However, without loss of generality, the two units could also be located at two different grid connection points. Likewise, other types of non-controllable DERs such as wind turbines could be used without loss of generality, which would just translate into different generation profiles and respective distributions of forecast errors. Other types of controllable DERs, such as BESS, instead would reduce the operational flexibility of the VPP due to their capacity limitations and would thus be less opportune as a case-study on the potential range of value stacking opportunities. Same is true for other types of P2G technologies, such as Solid Oxide Electrolysis Cells (SOECs), with their slower response times and overall limited operational flexibility [43]. A schematic representation of the modelled VPP is shown in Fig. 1.

The VPP is assumed to be located on the island of Sicily, Italy, as the comparably contained bidding zone allows for a reasonable extrapolation of the zonal forecasts to the level of individual plants. For the PV plant, operational data is extrapolated from historical forecasts

Table 1
Detailed comparison of this study with relevant case study literature on DER integration into energy and balancing markets as well as imbalance management.

Reference	Intermittent resource	Controllable resource	Energy markets		Balancing markets		Imbalance management		Additional integrations
			DAM	IDM	RR	FRR	Classic	Passive	
[15]	Wind	BESS	✓	x	x	x	✓	✓	Capacity market
[16]	Wind	P2G	✓	✓	x	✓	x	x	–
[17]	PV	DSR	✓	x	x	x	✓	x	–
[23]	Wind	x	✓	✓	x	x	✓	✓	–
[26]	–	BESS	✓	x	✓	✓	x	x	Primary reserve
[29]	Wind	P2G	✓	x	✓	x	x	x	RES curtailment
[30]	Wind & PV	CHP* & BESS	✓	x	✓	✓	x	x	–
[31]	PV	BESS	✓	x	x	x	(✓)	x	primary reserve & reactive power
[32]	PV	BESS	✓	x	x	✓	x	x	Congestion management
[35]	Wind	BESS	✓	✓	x	x	✓	x	RES curtailment
[36]	Wind	P2G	✓	x	x	x	(✓)	x	Emission trading scheme
This study	PV	P2G	✓	✓	✓	✓	✓	✓	–

*CHP = Combined Heat and Power plant.

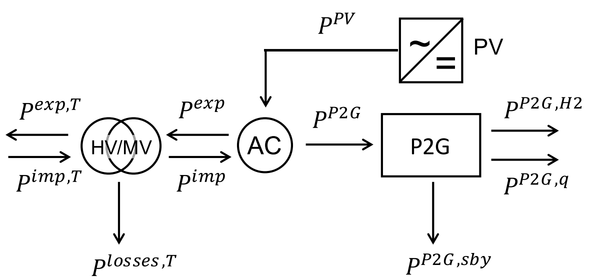

Fig. 1. Power scheme of the modelled VPP.

Table 2
Applied P2G model characteristics.

Model parameter	Value	Reference
Min power	1.00 MW	[46]
Rated power	3.75 MW	[46]
Peak power	6.20 MW	[46]
Efficiency* at min power	65%	[49]
Efficiency* at rated power	55%	[49]
Efficiency* at peak power	49%	[49]
Load ramp	10%/s	[52]
Stand-by consumption	0.001 MW/MW_{rated}	[49]
Demineralized water consumption	9 kg/kg_{H2}	[53]
Demineralized water costs	0.0007 €/kg	[53]

*With regard to lower heating value, incl. all auxiliaries

available through the transparency portal of the European transmission system operators ENTSO-E [44]. To simulate the forecast errors, the normalized day-ahead forecast profile is utilized as DAM input profile, while the actual profile is used as IDM generation input. Balancing market and IDM share the same gate closure time of one hour before delivery, hence the generation profile used in these sessions is the same. Real-time power profiles used in the imbalance management process are obtained by applying perturbation coefficients to the IDM profile. These coefficients are drawn from Gaussian distributions obtained considering the intra-day schedule, in each hour, as the mean and assuming a standard deviation of 5% [45]. For the P2G plant, operational parameters of a plant with identical dimensions as in the Mainz Energy Park [46] are used as reported in Table 2.

As can be seen from Table 2, the dynamic characteristics of the P2G unit, in particular the ability to vary its absorption by up to 10% of rated power per second, allow its participation in both energy and balancing markets. In Italy, energy markets require to complete a ramping interval between two hourly products within 30 min [47]. Balancing service requirements are in line with European standards for response times, ranging from 30 s in the case of Frequency Restoration Reserve (FRR in ENTSOE terminology) to 15 min in the case of Replacement Reserve (RR in ENTSOE terminology) [48]. All such requirements are well below the technical capabilities of the P2G unit. Engineering projects in which P2G plants have been able to provide a much more demanding service such as frequency containment reserve service have been already reported in the literature [49,50]. Moreover, stand-alone renewables have been able to provide ancillary services as reported in [9,51]. As the technical requirements pose no limitation to the modelled VPP with its P2G unit, no technical distinction is made between FRR and RR in the model. The model's choice of offering one product over another is thus purely based on economic reasoning with respective price forecasts (see Section 3.3). The model can therefore be used in the case of a power market where no distinction is made regarding the balancing products (as in the Italian one, used as a reference for this work as discussed in the following) but also in the case of a VPP operator which is not differentiating between reserve products. Nonetheless, a further subdivision of the offered products could be made with the same approach, provided that the VPP is eligible for exchanging such products.

While the regulatory framework for P2G units is not yet fully developed, it is assumed that such a unit will purchase electricity from the Italian spot market as other large-scale consumers. Besides the actual spot market price, it is thus assumed that the P2G unit will pay grid charges as other medium voltage connected large consumers while being exempted from additional taxes or levies for not being an electricity end-user. Respective grid charges resulted in being 15.77 €/MWh for 2019 [54]. For the spot market prices, publicly available market data is used as published by the Italian market operator GME [55] while, for the balancing market, a weighted average price per product category and time period is derived based on a methodology as described in [9].

In Fig. 2, the relevant segments of the Italian market concerning energy and balancing services are shown. The DAM is settled in a single session on a pay-as-cleared basis which closes at 12:00 in the day prior to delivery, resulting in one single price per market zone and time period. Both IDM and balancing market are settled on a pay-as-bid basis with the operators being able to submit their bids continuously until gate closure one hour prior to the beginning of the delivery interval. Imbalance management instead is executed in real-time. Although he IDM and balancing market dispose the same gate closure of $h-1$, the clearing process is different. Bids on the IDM are immediately cleared with the applied continuous trading approach. In the balancing market instead, offers can be presented until $h-1$ but are activated according to the TSO's needs in real-time during the interval h. In the figure, the bidding logic implemented in the model is shown for a generic hourly interval h on the right-hand side. It highlights the timing of an operator's bidding on the different markets with respective gate closures and timeframes for offer presentation, selection and activation (delivery). The bidding logic follows thereby the market sequences in a simple and practicable way. With the DAM closing prior to the opening

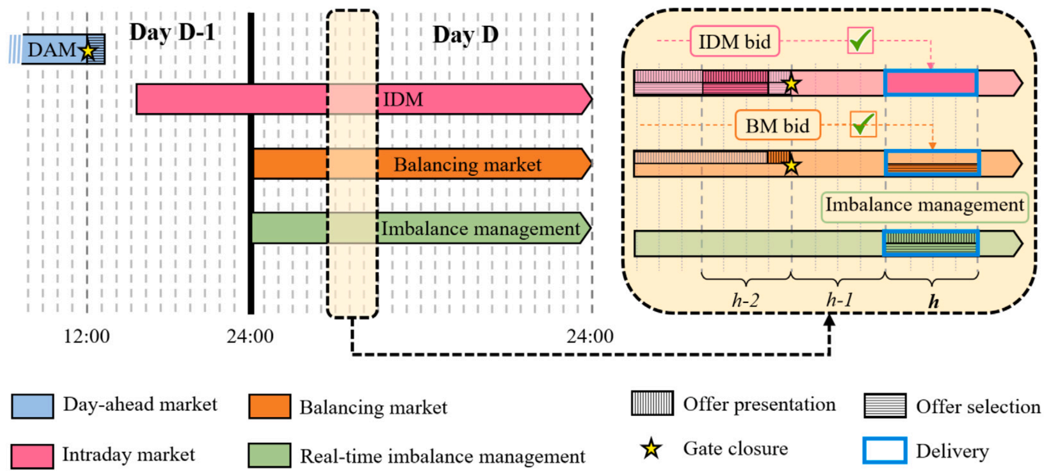

Fig. 2. Time sequence of considered Italian markets with relative bidding mechanism for an exemplary hour h.

of any other market session, naturally the operation on this market is conducted in the first place. Subsequently, if the operator wants to change its schedule for hour *h*, it needs to present an offer in the IDM within the hourly interval from $h-2$ until gate closure at $h-1$ (yellow star). Such offer gets it automatically cleared as soon as a match with a respective counter-offer is available (horizontal & vertical stripes combined in figure). With balancing market offers being subject to the same gate-closure but being accepted (and activated) only in real-time during the interval *h*, the success of such offers lags in time. It is thus decided to consider the two market interactions sequentially within each hourly interval with balancing market biddings occurring only in the last instance of time before gate closure (see zoom area in the figure). During the hour of delivery *h* (light blue framed in figure), the imbalance management operations are then finally decided in real-time based on all previous market results, including the up-to-date balancing market activation.

Unlike the energy and balancing markets, the imbalance settlement process is managed by the Italian Transmission System Operator (TSO) Terna. Imbalance settlement prices are based on: (i) the DAM price, (ii) the prices of activated balancing market services, as well as (iii) the zonal imbalance sign as explained in [21]. The resulting price is calculated and then published by the TSO [56]. In this work, the prices of the macro-Southern imbalance price area, to which Sicily belongs, are used in the form that applies to Italian DERs, i.e., the so-called Single Pricing scheme [57]. On the Hydrogen (H2) side, no spot market exists, which is why a fixed sales price of 4 $€/kg_{H2}$ was assumed in line with the current average of renewable H2 projects in Europe [58].

The proposed enhanced operational approaches consider the combined interaction with multiple markets of the VPP. Simulation is performed with an hourly resolution for the entire year 2019 to provide an extensive case study that takes into account also hourly and seasonal fluctuations. After each market interaction, data input such as PV production and price forecast are updated to simulate an improvement of forecast accuracy approaching real-time. To assess the added benefit of value stacking, nine different scenarios with increasing levels of commitment to the markets are proposed in this work as summarized in Table 3.

In the first scenario, the VPP is not deeply integrated into any market mechanism. The P2G plant runs at peak power for the entire simulation horizon and absorbs available PV generation as far as possible. Excess PV generation and lacking energy to supply the P2G whenever PV is not available are traded in the DAM. In case the day-ahead forecast profile was not accurate, eventual imbalances are not addressed internally by adapting the consumption profile of the P2G unit but simply settled through the TSO's imbalance settlement scheme. This type of operation is reasonable for current (pilot project) implementations whose primary goal is not necessarily economic sustainability but to prove technical feasibility.

A first set of scenarios outlines the effects of step-wise energy market integration. Scenario II models a light energy market integration where the VPP makes optimal decisions based on DAM prices. Depending on the economic advantage, the PV generation can be sold directly on the DAM or consumed by the P2G plant, which converts it into H2. Furthermore, the P2G plant can also draw electricity directly from the grid if market prices are low enough to enable economic H2 generation. Therefore, being the most simple approach that contains active VPP operation, this scenario is utilized as the benchmark for the following scenarios with increasing market integration. Scenario III adds the subsequent IDM for deepened energy market integration of the VPP. In this case, as in the previous two scenarios, it is not performed any active imbalance management since no internal flexibility from the P2G plant is involved. Moreover, although IDM operation is simulated, it does not take forecast errors into account and therefore does not correct them. Scenarios IV and V integrate two different imbalance management approaches into the previous scenarios, by adjusting the PV's day-ahead forecast error with IDM interactions (scenario IV) and additional the PV's real-time forecast error by activating internal P2G flexibility as far as possible (scenario V). The real-time adjustment is thereby performed without knowledge of future imbalance prices, hence it could lead to economic losses or limited revenues depending on the final imbalance price. Imbalance management in scenario V closely simulates the classical scheme with the use of internal resources and market solutions to minimize internal imbalances.

A second set of scenarios considers the effects of balancing market integration. In scenario VI, the balancing market interaction is introduced with the VPP offering balancing services according to its adjusted IDM baseline. The adjusted baseline is the resulting grid exchange profile at the substation, being the sum of PV and P2G profiles from previous energy market operations. Tertiary reserve RR, is offered either in upward or downward direction. As before, perfect price forecasting and full offer acceptance are assumed, in a first approximation, for individual offers based on the weighted average price of actually accepted offers at the market zone level. Scenario VII adds the offer of the second balancing service which is publicly traded in Italy, namely the faster secondary reserve FRR. Other services such as primary reserve or congestion management are not considered, as they are either not publicly traded or locational sensitive services with high modelling uncertainty. Imbalance management is treated in both balancing market integration scenarios as in the previous scenario V.

Finally, a third set of scenarios expands the operational modes of imbalance management to passive balancing. This requires the P2G

Table 3
Scenario compositions with different levels of market integration of the VPP.

Market integration scenario	Day-ahead market interaction	Intraday market interaction	Balancing market interaction	Imbalance management interaction
Scenario I: *Baseload*	Price inelastic[a]	Not considered	Not considered	Classic approach[b] w/o internal flexibility w/o market correction
Scenario II: *Light energy market integration*	Price elastic	Not considered	Not considered	Classic approach[b] w/o internal flexibility w/o market correction
Scenario III: *Intermediate energy market integration*	Price elastic	Partially Price elastic[c]	Not considered	Classic approach[b] w/o internal flexibility w/o market correction
Scenario IV: *Full energy market integration*	Price elastic	Price elastic[d]	Not considered	Classic approach[e] w/o internal flexibility
Scenario V: *Active imbalance management*	Price elastic	Price elastic[d]	Not considered	Classic approach[f]
Scenario VI: *Light balancing market integration*	Price elastic	Price elastic[d]	RR only	Classic approach[f]
Scenario VII: *Full balancing market integration*	Price elastic	Price elastic[d]	RR & FRR	Classic approach[f]
Scenario VIII: *Limited passive balancing*	Price elastic	Price elastic[d]	RR & FRR	Passive balancing with limitation[g]
Scenario IX: *Unlimited passive balancing*	Price elastic	Price elastic[d]	RR & FRR	Passive balancing[h]

[a]P2G operated at full capacity.
[b]VPP imbalance position exposed to day-ahead & intra-day forecast errors of PV.P2G does not perform internal imbalance correction and no imbalance correction performed in IDM.
[c]IDM operation does not consider day-ahead forecast errors of PV.
[d]IDM operation considers day-ahead forecast errors of PV.
[e]VPP imbalance position exposed to intra-day forecast errors of PV. P2G does not perform internal imbalance correction.
[f]Forecasting the system's imbalance price and the deviation of VPP's programmed profile to counter PV intra-day forecast errors even if it involves an economic loss. This leads to the minimization of internal imbalance.
[g]Forecasting the system's imbalance price and deviating VPP's programmed profile to counter PV intra-day forecast errors only if economically sensible.
[h]Forecasting the system's imbalance price and deviating VPP's programmed profile to counter PV intra-day forecast errors and to exploit arbitrage opportunities.

to forecast the imbalance prices and adjust the internal imbalances accordingly in such a way as to avoid economic losses. Scenario VIII applies a limited passive balancing which considers only the relative adjustment of actually occurring real-time imbalances from remaining PV forecast errors. Scenario IX implements instead unlimited passive balancing and therefore the maximum degree of VPP integration to electricity markets. In addition to energy and balancing markets, the VPP exploits in this scenario the forecast on the imbalance prices not only to avoid internal imbalances but also to make an economic profit by changing the P2G load profile and deviating intentionally from the established energy market schedules.

3. Calculation methodology

In this section, the proposed optimization model of the VPP system to analyse the optimal management of the P2G is presented. To model the participation in consecutive markets, four optimization problems are solved sequentially for every time step of one hour. Each of this optimization problems comes with a different objective function but similar constraints, taking into account the results of the previous market. Fig. 3 provides a schematic overview of the optimization framework with its respective input and output variables. Recalling the market structure and the resulting bidding mechanism as previously depicted in Fig. 2, such a modelling approach mimics a simplified but realistic operational behaviour of a potential market agent partaking in the sequence of energy and balancing markets. Following the described bidding logic, no cross-market optimization is done as such would require anticipation of future market results. Instead, the optimization approach exploits the latest updated price & generation forecasts and considers the commercial position (baseline) from previous sessions. As the clearing results of different hourly time intervals of one market do not depend on one another and furthermore no asset with any such time dependencies, i.e. BESS, is modelled in the VPP portfolio, the model can bid independently on an hourly basis. This flexible framework allows to simulate different levels of commitment, implementing the market integration scenarios introduced in 3, c to a selected number of markets achieving different economic results.

The unit commitment problem is implemented as a Mixed Integer Linear programming (MILP) problem in Matlab using YALMIP and Gurobi as solver. It will be solved with an optimization horizon of 8760 h and with timestep Δt of 1 h. For the sake of simplicity, formulas are reported for a generic instant t, which are then applied to the entire optimization horizon. PV and grid connection are modelled with active sign convention, while P2G is modelled with passive sign convention.

3.1. Day-Ahead Market (DAM) participation

In this first energy market session, the VPP aims at minimizing the operating costs in the considered period. The objective function (1) consists of the gross power exchanged with the grid, both import ($P^{i,T}_{t,DAM}$) and export ($P^{e,T}_{t,DAM}$), and the output/input of the P2G plant, i.e. the H_2 produced and the H_2O consumed. With this arrangement, the objective function considers the costs of importing energy from the grid and acquiring H_2O for the electrolysis process. Exporting energy to the grid and selling H_2 on the other hand is seen as a revenue.

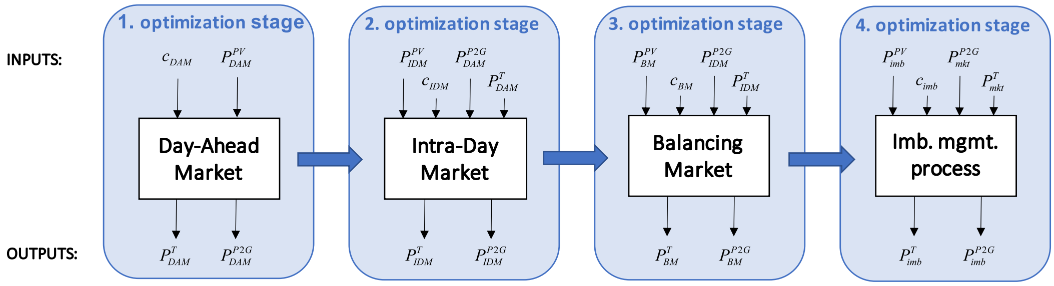

Fig. 3. Schematic overview of the optimization framework with sequential market interactions and respective input and output variables.

Respective prices are derived as explained in the previous subsection.

$$\min_{P^{\mathrm{imp,T}}_{\mathrm{DAM}},P^{\mathrm{exp,T}}_{\mathrm{DAM}},\dot{m}^{\mathrm{P2G,H2}}_{\mathrm{DAM}},\dot{m}^{\mathrm{P2G,H2O}}_{\mathrm{DAM}}} \mathrm{Obj}_{\mathrm{DAM}} = \sum_{t\in T}\Big(c^{\mathrm{imp}}_{t,DAM}P^{\mathrm{imp,T}}_{t,DAM} + c^{\mathrm{exp}}_{t,DAM}P^{\mathrm{exp,T}}_{t,DAM} - c^{\mathrm{H2}}_{t,DAM}\dot{m}^{\mathrm{P2G,H2}}_{t,DAM} + c^{\mathrm{H2O}}_{t,DAM}\dot{m}^{\mathrm{P2G,H2O}}_{t,DAM}\Big)\Delta t \quad \text{s.t.}\quad (2)\text{–}(7) \tag{1}$$

The objective function is subject to a number of constraints that ensure the power balance of all VPP components and that model the behaviour of the P2G plant. Since the constraints apply to all market sessions, the subscripts indicating the specific market are omitted. To ensure the power balance of the VPP, the sum of all powers injected and absorbed has to be equal to zero at each instant t. This is ensured by constraint (2), where the sum of all powers downstream the transformer (see Fig. 1) is equal to zero.

$$P^{\mathrm{imp}}_t + P^{\mathrm{exp}}_t + P^{\mathrm{PV}}_t - P^{\mathrm{P2G}}_t = 0 \tag{2}$$

P^{PV}_t is the photovoltaic production profile which is given as an input in the model with profiles obtained as explained in the previous section. The other three addends are variables managed by the solver. P^{i}_t and P^{e}_t are respectively the net import and the net export power flowing through the transformer. These variables do not include the losses linked to the transformer. The last addend, P^{P2G}_t, is the power absorbed by the P2G plant including standby and losses.

A set of constraints is given to bound these three variables. Import and export are constrained as in (3). (3b,c) set a lower and upper bound while, at the same time, in addition to (3d,e) they ensure that import and export do not happen simultaneously through the use of additional binary variables. Moreover, since P^{i}_t and P^{e}_t are net powers, they have to be divided/multiplied by the transformer efficiency to model the actual power exchanged with the market (4).

$$P^{T}_t = P^{\mathrm{imp}}_t + P^{\mathrm{exp}}_t, \tag{3a}$$

$$0 \le P^{\mathrm{imp}}_t \le \alpha^{\mathrm{imp}}_t\overline{P^{\mathrm{T}}}, \qquad -\alpha^{\mathrm{exp}}_t\overline{P^{\mathrm{T}}} \le P^{\mathrm{exp}}_t \le 0, \tag{3b,c}$$

$$\alpha^{\mathrm{imp}}_t + \alpha^{\mathrm{exp}}_t \le 1, \qquad \alpha^{\mathrm{imp}}_t, \alpha^{\mathrm{exp}}_t \in \{0,1\} \tag{3d,e}$$

$$P^{\mathrm{imp,T}}_t = P^{\mathrm{imp}}_t/\eta^{\mathrm{T}}, P^{\mathrm{exp,T}}_t = P^{\mathrm{exp}}_t\cdot\eta_{\mathrm{T}}, \tag{4a}$$

The last set of constraints is associated with the operation of the P2G plant, as in (5), (6) and (7). The P2G can operate in two operational statuses: either it is in standby mode, with a power consumption P^{sby} of 3.75 kW (corresponding to the losses during the plant's idle mode), or it is in active operation with a minimum of 1 MW (3a). These two states are mutually exclusive hence the use of auxiliary binary variables (3b,c). To model P2G losses, including those related to all consumers (compression, cooling, purification, control) it has been employed an efficiency curve dependent on absorbed power $P^{\mathrm{P2G,act}}_t$ whose values are derived from [49]. To avoid non-linearity, the piecewise linear approximation is adopted to linearize $\eta_{\mathrm{P2G}}(P^{\mathrm{act}}_t)$ as proposed in [59]. The resulting power is the net equivalent power associated with the production of H_2. To obtain the mass flow rate of produced hydrogen, this value is divided by the Lower Heating Value (LHW) of the hydrogen equal to 33.33 kWh/kg. Moreover, as stated in [49], the consumption of demineralized water corresponds to 9 kg per kilo of hydrogen produced.

$$P^{\mathrm{P2G}}_t = \beta^{\mathrm{P2G,act}}_t P^{\mathrm{P2G,act}}_t + \beta^{\mathrm{P2G,sby}}_t P^{\mathrm{P2G,sby}}_t, \tag{5a}$$

$$\beta^{\mathrm{P2G,act}}_t + \beta^{\mathrm{P2G,sby}}_t = 1, \qquad \beta^{\mathrm{P2G,act}}_t, \beta^{\mathrm{P2G,sby}}_t \in \{0,1\} \tag{5b,c}$$

$$P^{\mathrm{P2G,H2}}_t = P^{\mathrm{P2G,act}}_t \cdot \eta_{\mathrm{P2G}}(P^{\mathrm{P2G,act}}_t), \tag{6a}$$

$$\dot{m}^{\mathrm{P2G,H2}}_t = \frac{P^{\mathrm{P2G,H2}}_t}{\mathrm{LHV}^{\mathrm{H2}}}, \tag{7a}$$

$$\dot{m}^{\mathrm{P2G,H2O}}_t = \dot{m}^{\mathrm{P2G,H2}}_t \cdot 9, \tag{7b}$$

3.2. Intra-Day Market (IDM) participation

The second step of the optimization process models the participation of the VPP in the IDM. Since the gate closure of this market is placed one hour before delivery, updated profiles for PV production and price curves are applied.

$$\min_{P^{\mathrm{imp,T}}_{\mathrm{IDM}},P^{\mathrm{exp,T}}_{\mathrm{IDM}},\dot{m}^{\mathrm{P2G,H2}}_{\mathrm{IDM}},\dot{m}^{\mathrm{P2G,H2O}}_{\mathrm{IDM}}} \mathrm{Obj}_{\mathrm{IDM}} = \sum_{t\in T}\Big(c^{\mathrm{imp}}_{t,IDM}(P^{\mathrm{imp,T}}_{t,IDM} - P^{\mathrm{imp,T}}_{t,DAM}) + c^{\mathrm{exp}}_{t,IDM}(P^{\mathrm{exp,T}}_{t,IDM} - P^{\mathrm{exp,T}}_{t,DAM}) - c^{\mathrm{P2G,H2}}_{t,IDM}(\dot{m}^{\mathrm{P2G,H2}}_{t,IDM} - \dot{m}^{\mathrm{P2G,H2}}_{t,DAM}) + c^{\mathrm{P2G,H2O}}_{t,IDM}(\dot{m}^{\mathrm{P2G,H2O}}_{t,IDM} - \dot{m}^{\mathrm{P2G,H2O}}_{t,DAM})\Big) \quad \text{s.t.}\quad (2)\text{–}(7) \tag{8}$$

The new objective function aims to minimize the deviation from the previous profile at the transformer interface in case of increasing imports and to maximize it in the case of exports. In addition, the P2G plant acts as a responsive market participant which is available to change its consumption profile accordingly to the updated price inputs. The objective function is subject to the same constraints as in the previous market session.

3.3. Balancing market participation

The third modelled market session is the balancing market. This market is held in parallel with the IDM with gate closure one hour before delivery, hence it has been applied the same PV production profile as in IDM. Since in this market the pay-as-bid mechanism is adopted and offer acceptances are based not only on economic merit but also on the technical conditions of the grid, it was cautiously chosen to prioritize the IDM in the succession of optimization steps. In a first approximation, it is assumed that every offer presented on the balancing market that is more competitive than the average price of effectively accepted other offers would also be accepted and that the VPP has perfect price forecast.

$$\begin{aligned} \min_{P^{\mathrm{DW}}_{\mathrm{BM}}, P^{\mathrm{UP}}_{\mathrm{BM}}, \dot{m}^{\mathrm{P2G,H2}}_{\mathrm{BM}}, \dot{m}^{\mathrm{P2G,H2O}}_{\mathrm{BM}}} \quad \mathrm{Obj}_{\mathrm{BM}} = \sum_{\mathrm{t}\in\mathrm{T}} \Big(& c^{\mathrm{DW}}_{t,BM} P^{\mathrm{DW}}_{t,BM} - c^{\mathrm{UP}}_{t,BM} P^{\mathrm{UP}}_{t,BM} \\ & - c^{\mathrm{P2G,H2}}_{t,BM} (\dot{m}^{\mathrm{P2G,H2}}_{t,BM} - \dot{m}^{\mathrm{P2G,H2}}_{t,IDM}) \\ & + c^{\mathrm{P2G,H2O}}_{t,BM} (\dot{m}^{\mathrm{P2G,H2O}}_{t,BM} - \dot{m}^{\mathrm{P2G,H2O}}_{t,IDM}) \Big) \\ \text{s.t.} \quad & (2)\text{–}(7),\ (10) \end{aligned} \tag{9}$$

In this third market session, the costs of the objective functions include the costs linked to the change in P2G operation resulting from the participation in the balancing market and the costs related to the services provided by the VPP. The objective function is subject to the above constraints (2)–(7) plus the constraints associated with the definition of upward and downward services.

$$P^{\mathrm{imp,T}}_{\mathrm{t}} - P^{\mathrm{imp,T}}_{\mathrm{t,mkt}} = P^{\mathrm{imp}}_{t,\Delta}, \qquad P^{\mathrm{exp,T}}_{\mathrm{t,mkt}} - P^{\mathrm{exp,T}}_{\mathrm{t}} = P^{\mathrm{exp}}_{t,\Delta}, \tag{10a,b}$$

$$P^{\mathrm{imp}}_{t,\Delta} = P^{\mathrm{imp,UP}}_{t} + P^{\mathrm{imp,DW}}_{t}, \qquad P^{\mathrm{exp}}_{t,\Delta} = P^{\mathrm{exp,UP}}_{t} + P^{\mathrm{exp,DW}}_{t}, \tag{10c,d}$$

$$P^{\mathrm{DW}}_{t} = P^{\mathrm{imp,DW}}_{t} + P^{\mathrm{exp,DW}}_{t}, \qquad P^{\mathrm{UP}}_{t} = P^{\mathrm{imp,UP}}_{t} + P^{\mathrm{exp,UP}}_{t}, \tag{10e,f}$$

$$0 \le P^{\mathrm{DW}}_{t} \le \gamma^{\mathrm{DW}}_{t} \overline{P^{\mathrm{P2G}}}, \qquad 0 \le P^{\mathrm{UP}}_{t} \le \gamma^{\mathrm{UP}}_{t} \overline{P^{\mathrm{P2G}}}, \tag{10g,h}$$

$$\gamma^{\mathrm{DW}}_{t} + \gamma^{\mathrm{UP}}_{t} \le 1, \qquad \gamma^{\mathrm{DW}}_{t}, \gamma^{\mathrm{UP}}_{t} \in \{0,1\} \tag{10i,j}$$

Upward and downward services can be achieved both by deviating from the previously obtained power exchange profile. An increase in imports can be seen as a downward service as well as a decrease in export. Similarly, an upward service can be achieved both by reducing imports or increasing exports. This behaviour is modelled with Eqs. (10a)–(10f). The flexibility services are limited to the rated power of the P2G as in (10g)–(10h), and since upward and downward services are mutually exclusive in each hour t, auxiliary binary variable are also used as in (10i)–(10j). Eqs. (10a)–(10b) are given for a generic previous market *mkt* since these constraints will be applied also in the imbalance management process.

3.4. Imbalance management process

The final optimization stage is the imbalance management process. In this stage, the objective function is structured as in the previous stage with the deviation of the profile at the transformer interface quantified by $P^{\mathrm{DW}}_{t,imb}$ and $P^{\mathrm{UP}}_{t,imb}$ and the change in P2G operation quantified by $(\dot{m}^{\mathrm{P2G,H2}}_{t,imb} - \dot{m}^{\mathrm{P2G,H2}}_{t,mkt})$ and $(\dot{m}^{\mathrm{P2G,H2O}}_{t,imb} - \dot{m}^{\mathrm{P2G,H2O}}_{t,mkt})$. The imbalance management process occurs in real-time once the operator is able to know the actual output of the PV plant and (potentially) able to accurately predict the price and sign of zonal imbalance. The optimization model is flexible enough to allow the implementation of the imbalance management process after the desired market session. In this way, different scenarios are implemented each with a varying number of market sessions simulated. For this reason following equation contain the notation *mkt* indicating a generic previous market which could be DAM, IDM or balancing market.

$$\begin{aligned} \min_{P^{\mathrm{DW}}_{\mathrm{imb}}, P^{\mathrm{UP}}_{\mathrm{imb}}, \dot{m}^{\mathrm{H2}}_{\mathrm{imb}}, \dot{m}^{\mathrm{H2O}}_{\mathrm{imb}}} \quad \mathrm{Obj}_{\mathrm{imb}} = \sum_{t\in T} \Big(& c^{\mathrm{DW}}_{t,imb} P^{\mathrm{DW}}_{t,imb} - c^{\mathrm{UP}}_{t,imb} P^{\mathrm{UP}}_{t,imb} \\ & - c^{\mathrm{P2G,H2}}_{t,imb} (\dot{m}^{\mathrm{P2G,H2}}_{t,imb} - \dot{m}^{\mathrm{P2G,H2}}_{t,mkt}) \\ & + c^{\mathrm{P2G,H2O}}_{t,imb} (\dot{m}^{\mathrm{P2G,H2O}}_{t,imb} - \dot{m}^{\mathrm{P2G,H2O}}_{t,mkt}) \Big) \\ \text{s.t.} \quad & (2)\text{–}(7),\ (10) \end{aligned} \tag{11}$$

Given a prediction of PV production and imbalance prices, four different P2G operating modes are implemented:

- P2G does not participate in the imbalance management process;
- P2G is prioritized in the imbalance management process;
- Price driven P2G participation in the imbalance management process;
- Price driven P2G participation in the imbalance management process and passive balancing.

In the first operating mode, the P2G does not contribute to the adjustment of the internal VPP imbalances, hence the VPP is required to pay/receive the corresponding imbalance fees through the TSOs imbalance settlement. In order to simulate this behaviour, additional constraints (12) are implemented to prevent the P2G to change its consumption profile. This P2G operating mode is implemented in scenarios I–IV.

$$\dot{m}^{\mathrm{P2G,H2}}_{t,imb} = \dot{m}^{\mathrm{P2G,H2}}_{t,mkt}, \tag{12a}$$

$$\dot{m}^{\mathrm{P2G,H2O}}_{t,imb} = \dot{m}^{\mathrm{P2G,H2}}_{t,mkt}, \tag{12b}$$

The second operating mode consists of prioritizing the P2G in the adjustment of internal imbalances in order to minimize if not eliminate any imbalances internally. In this case, the P2G deviates from the programmed absorption profile in order to counter PV imbalances even if it involves an economic loss. To implement this adjusted prices $c^{\mathrm{DW}}_{t,imb}$ and $c^{\mathrm{UP}}_{t,imb}$ are applied in order to minimize $P^{\mathrm{DW}}_{t,imb}$ and $P^{\mathrm{DW}}_{t,exp}$. Once the correct power profiles are obtained, the true price profiles are used in order to assess the economic results. This P2G operating mode is implemented in scenarios V–VII.

Unlike the previous case, in the third operating mode, the P2G chooses to participate in the adjustment of internal imbalances only if it leads to an economic benefit, taking into account (predicted) TSO imbalance prices. Eq. (13) is added as constrain to ensure that the downward imbalance services $P^{\mathrm{DW}}_{t,imb}$ and the upward imbalance service $P^{\mathrm{DW}}_{t,exp}$ are bounded to the internal imbalance need of the VPP, imbal_t defined as in (14). This P2G operating mode is implemented in scenario VIII.

$$0 \le P^{\mathrm{DW,imb}}_{t} \le \mathrm{imbal}_t, \tag{13a}$$

$$0 \le P^{\mathrm{UP,imb}}_{t} \le \mathrm{imbal}_t, \tag{13b}$$

$$\mathrm{imbal}_t = P^{\mathrm{T}}_{t,imb} - P^{\mathrm{T}}_{t,mkt} \tag{14}$$

The last operating mode consists of simulating the so-called passive balancing. In this case, with imbalance prices being again perfectly forecasted, the VPP fully exploits them within its technical boundaries to gain an economic benefit.[1] This economic benefit is even obtained by deliberately increasing the imbalance if the price differential between imbalance prices and P2G costs is positive. In this case, no additional constraints are added. This P2G operating mode is implemented in scenario IX.

4. Results and discussion

In the following section, the modelling results of the different levels of enhanced operation modes for the VPP are discussed. First, the implications of enhanced operation modes are outlined with a detailed analysis of an exemplary day. This serves to highlight the influence of market conditions as input factors on VPP decisions and to illustrate the interdependencies of the operation on successive markets. Hereafter, the full-scale results of the four most significant operation scenarios are presented in form of annual energy flows and financial outcomes. This serves to highlight the implications of a long-term implementation of the operation modes. Last but not least, an overall overview of all analysed scenarios is provided, summarizing the economic implications of gradually increasing market integration.

[1] Financial considerations to exploit them also beyond the technical boundaries, i.e., taking a short position that exceeds the absorption capacity of the P2G, are not included as such would require dedicated interactions on previous energy markets that go beyond the scope of this paper.

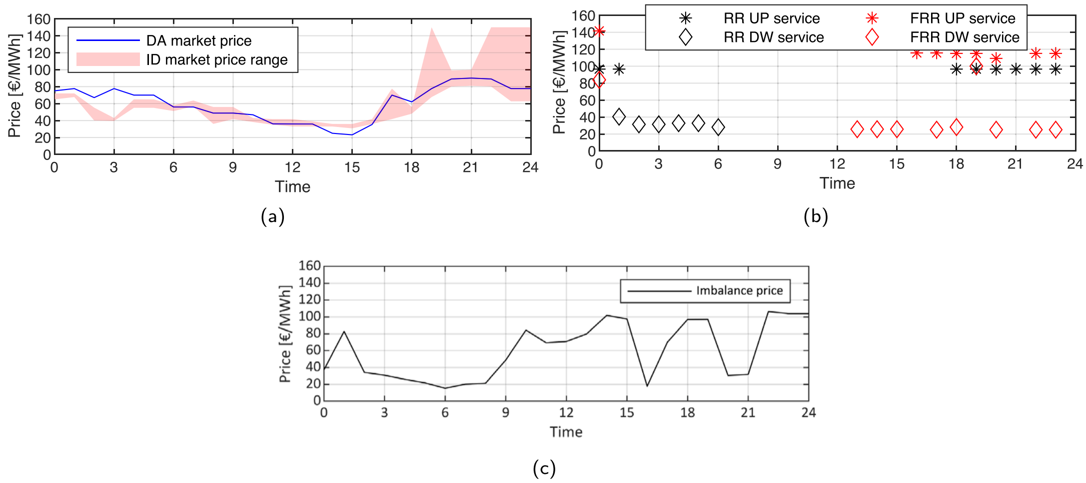

Fig. 4. Day-ahead and intraday market prices (left chart), balancing market prices (right chart), as well as system's imbalance prices (lower chart) on one exemplary day (07.07.2019) in the Italian market zone of Sicily.

4.1. Detail view: market integration on an exemplary day

To better illustrate how individual elements of market integration affect the VPP's operational decisions, Fig. 5 shows first of all how the VPP's power profiles change for the sequential optimization stages on the 07.07.2019, as an exemplary day in 2019. Price profiles for the compared markets on the same day are reported in Fig. 4.

Following the operational logic as outlined in Fig. 3, the first stage concerns DAM interactions. For the case of superficial baseload integration as with scenario I, Fig. 5-(a-i) visualizes the resulting power profiles over 24 h. With the P2G unit (blue line) operating constantly at full capacity, market interactions are limited to integrating excess PV generation (red line) or purchasing electricity for P2G operation whenever PV is not available. The resulting grid exchange profile is represented by the black line. Comparing the exchange profile with the applicable DAM prices, it emerges that, with a baseload operation approach, the VPP is a net-exporter during the lowest price moments around midday and a net-importer during the high price times in the late afternoon and the following night hours. As a result, the economic profitability is low compared to the one of interactions with the same market when taking into account the economic viability as in scenario II, shown in Fig. 5-(a-ii). Cash flows from electricity import and export are in this case optimized along with the one of hydrogen generation, resulting in no electricity import during night hours as prices are too high, gradually increasing self-consumption in the morning hours when DAM prices decrease with increasing PV presence, and increased electricity exports during high price hours such as from 17:00 to 18:00. The otherwise inelastic PV generation transforms thereby thanks to the aggregated P2G flexibility into a price-responsive unit. This is beneficial both for the overall system operation with more dynamic units that follow price incentives and for individual unit operation in terms of financial gains as further discussed in the following section.

Entering the subsequent optimization stage, the VPP faces a new set of prices on the IDM and an updated forecast of the PV generation profile. This results in an adjustment of the P2G profile as illustrated in the changes from dashed to solid lines in Fig. 5-(b). Based on new prices, the varied PV generation is, for example from 10:00–11:00, absorbed by the P2G unit as prices are too low to sell it conveniently on the IDM. On other occasions, such as for example from 08:00 to 10:00, the new IDM prices might be higher instead so that not only the additionally forecasted PV generation is sold but that even the P2G consumption is slightly reduced for additional IDM sales. Conversely, the comparably lower IDM prices in the early morning hours drive the VPP to absorb a notable amount of electricity through the P2G unit outside the hours of PV generation. All in all, the IDM is used as an adjustment stage for the VPP to cope with the day-ahead forecast error of the PV and to optimize its economic position about updated market prices. Following these close-to-real-time prices provides also an additional benefit to the power system as a whole, as these prices reflect updated scarcity (or excess) information of the system. In fact, even without active balancing market integration, only through deep energy market operation, this already results in reduced VPP imbalances and a tangible implicit flexibility potential that follows price signals.

In the third stage, balancing market operation is introduced with the provision of the two service types RR and FRR. The operational decision is based in this case on the one hand on the price expectations of the respective services. Downward services might be convenient as they enable the consumption of low-priced electricity, for instance in the range from 25–40 €/MWh on the exemplary day (see Fig. 4-(c)), and thus below the price of energy markets. Upward services instead might be convenient as they enable the sale of electricity at high prices, for instance in the range from 85–140 €/MWh on the exemplary day, and thus above the price of energy markets. The second driver for operational decisions is the ability to provide such services based on the VPP's baseline from previous energy market interactions. For example, in the night hours from 20:00 to 02:00 of the exemplary day, no upwards services are possible as the P2G unit has a baseline of zero and no PV generation is available. On the contrary, around midday of the same day, downward services are by default inconvenient as the P2G absorbs already close to full capacity and any reduction of the grid exchange could be achieved only by curtailing the PV. Despite these limitations, balancing service provision results in a highly profitable value stacking as further discussed in the following section. The VPP offers thus whenever possible, resulting typically in upward services during the day as long as PV generation is available and not yet fully sold on energy markets, as well as downward services at any time when the P2G is not yet operating at full capacity.[2]

In the fourth and final stage of optimization, the VPP must decide on the management of its remaining real-time imbalances that can no longer be compensated in the energy markets. As outlined in the previous section, the plant has a variety of strategic options to approach its imbalance management. If it decides to remain idle, the real-time imbalances are simply settled through the TSO's imbalance settlement. If it decides to use its internal (P2G) flexibility to reduce imbalances,

[2] Building up intentional margin in one direction or the other on energy markets has not been considered as no preference for a single service direction emerged and, moreover, the probability for hourly clearing of each balancing direction remains uncertain.

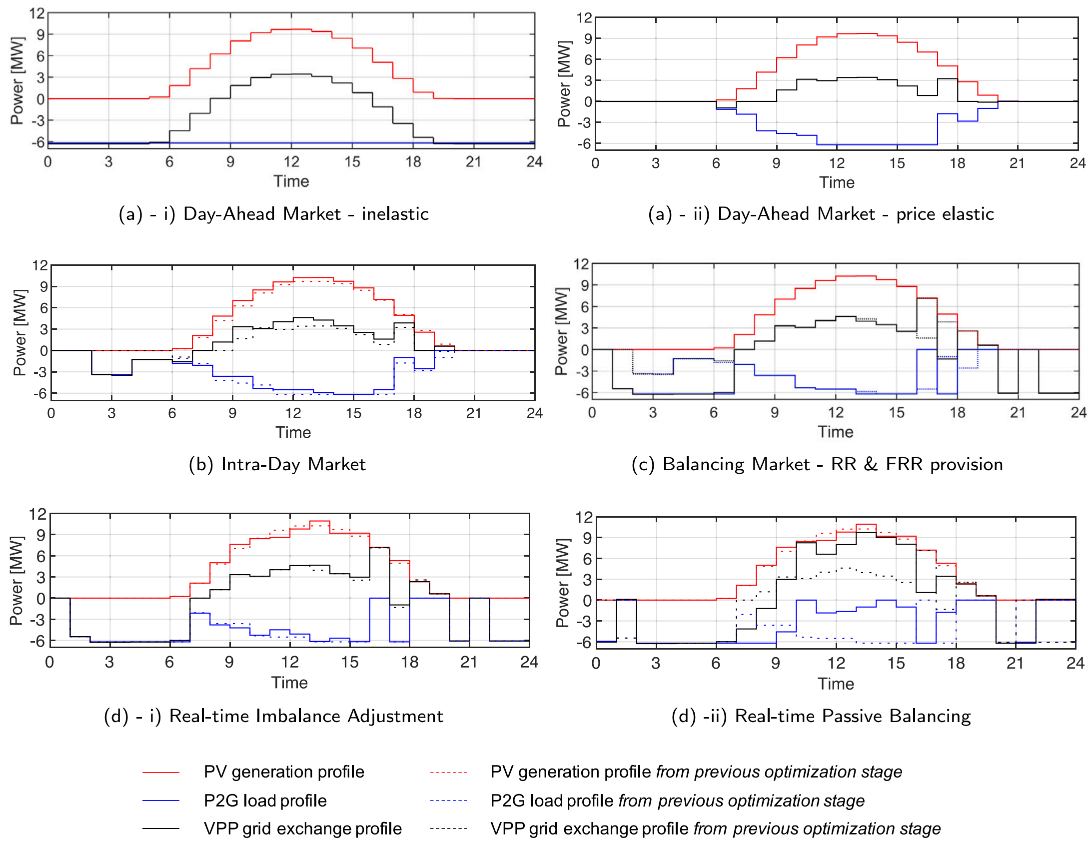

Fig. 5. VPP power profiles offering (a-i) on DAM only in baseload operation, (a-ii) on DAM only with price sensitive operation, (b) adjusting PV forecast errors on IDM, (c) providing RR and FRR on the balancing market, and (d-i) adjusting real-time imbalances through internal flexibility where convenient or (d-ii) applying full-scale passive balancing on imbalance prices.

it can do so either to reduce them as far as possible (ignoring potential economic consequences, especially if such might be unknown) or to reduce them only as far as economically reasonable by taking into account projected imbalance prices. Fig. 5-(d-i) illustrates the latter case with the real-time forecast error of the PV unit as the difference between the dashed and full red line and the remaining imbalance of the VPP as the difference between the dashed and full black line. Following the economic optimization, the plant prefers to eliminate its real-time imbalances for all hours during the day except four, namely from 13:00 to 14:00, from 15:00 to 16:00, and from 17:00 to 19:00. In the first three of these hours the VPP has a long imbalance position, i.e., is injecting more electricity into the grid than scheduled. With the system's imbalance price being reasonably high around 80-100 €/MWh in these hours (see Fig. 4-(c)), the modelled VPP prefers to "sell" its imbalance at this price rather than settling it internally by producing hydrogen. In the last hour the VPP has a short imbalance position,i.e., is injecting less electricity than scheduled. However, with the P2G baseline being zero in this hour, the VPP has no internal flexibility to cope with this imbalance and, as a result, has to accept to pay for the imbalance despite a high price.

The implications for the case where this economic assessment is not limited to the real-time imbalance but extended to the entire grid exchange profile are shown in Fig. 5-(d-ii). Considering the entire VPP flexibility to leverage on the real-time imbalance price signal constitutes the so-called passive balancing and eventually shifts the grid exchange profile significantly in line with the (passive) system's (im-)balance incentive. For the exemplary day, this expresses in increased electricity absorption from the grid during the morning hours when imbalance prices are low (indicating that the overall system might be long). High imbalance prices during the day drive the VPP instead to inject more (i.e., consume less), presumably as the system is short in these hours.[3] Overall, passive balancing as an operating mode for imbalance management triggers a remarkable flexibility activation from the VPP towards the grid. As previously, the extent to which this is possible is determined by the hourly power profile that results from previous energy and balancing market interactions. In contrast to the activations on the balancing energy market, which are (at least from the perspective of the individual plants) rather binary one-off activations, the activation in passive balancing increases gradually with rising or falling price signals. The effects of the different operating modes on the year-round operating results are described below.

4.2. Full-scale view: Baseload operation

In the first scenario that serves as an example of current DER operation with limited market integration, the VPP is modelled to operate in a baseload mode with the P2G unit operating statically at full capacity independent of specific energy market prices or PV availability (scenario I from Table 3).

PV generation is fully absorbed as far as not exceeding the P2G capacity and out of an annual PV generation of 20.73 GWh, only 12% or 2.48 GWh are exported to the grid through the DAM at an average price of 52.27 €/MWh. At the same time, the P2G generation is maximized,

[3] Under simple single pricing as implemented for DERs in Italy, imbalance prices are directly linked to the overall imbalance of the respective imbalance price area. If the system is short, the hourly imbalance price results in the weighted average price of activated upward balancing services or the DAM clearing price in case no balancing services should have been activated. If the system is long, the imbalance price is based instead on the weighted average price of activated downward balancing services [21].

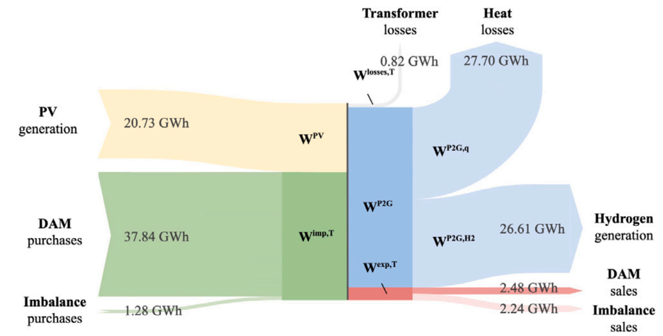

Fig. 6. Energetic flow scheme of the modelled VPP under Scenario I. Time horizon: entire year 2019. Bidding zone: Sicily, Italy.

absorbing 54.31 GWh of electricity and generating 26.61 GWh of hydrogen. To do so, the significant amount of 37.84 GWh is bought by the VPP on the DAM at an average market price of 64.79 €/MWh plus applicable grid charges of 15.77 €/MWh. Imbalances from PV forecast errors of on average 0.4 MWh/h are not actively managed through additional market interactions or internal flexibility activation but simply settled through the system operator's imbalance settlement scheme. Fig. 6 reports the resulting energy flows of one year of operation for the modelled VPP under this scenario.

The overall financial results of the VPP's importing and exporting DAM interactions with resulting hydrogen generation amount under this operation mode to an annual revenue of 227 k€. With the unmanaged forecast error being positive, the overall positive imbalances add another 32 k€ to an overall operational result of 260 k€ (equalling ~10 k€/MW of VPP capacity) from the VPP's baseload operation. To set this result into context, the individual (non-aggregated) operation of the (non-incentivized) PV would result in a modelled revenue of 1075 k€ on the DAM plus the previous 32 k€ from unmanaged imbalances (overall ~55 k€/MW of PV capacity). The individual P2G operation instead would result in a loss of 1164 k€ or ~188 k€/MW of P2G capacity if operated constantly at full capacity and importing all electricity from the DAM. A first finding from the modelling results is thus that the VPP generates an added value of 56 k€ through internal aggregation synergies, even if operating with overall low market integration.

4.3. Full-scale view: Deepened energy market integration

The second scenario focuses on an operation mode with advanced energy market integration and a dynamic P2G operation that follows not only market price signals but also compensates PV forecast errors as far as possible, assuming that no imbalance price forecast is available. This is represented by scenario V in Table 3. With the assumed H2 sales price of 4 €/kg_{H2}, the resulting marginal electricity price for which the P2G unit starts operating is a spot market price of 78.00 €/MWh. Below this price, the VPP's optimization algorithm will drive the aggregate to start consuming PV generation through the P2G unit, above this price rather sell to the grid. As the P2Gs efficiency decreases with increasing load, the price needs to fall below 58.20 €/MWh until it turns economically convenient that the P2G unit consumes PV generation with full (peak) capacity. Furthermore, given the additional grid charges for consumed electricity, the spot market price must fall even below the price of 62.23 €/MWh before the optimization algorithm drives the VPP to start purchasing electricity from the grid for H2 generation if no PV generation is available. Given an average DAM price of 62.77 €/MWh in Sicily in 2019, it becomes immediately clear that the baseload operation of the P2G unit as in scenario I is not a particularly efficient operation mode. This inefficiency is also visible in P2G energy flows. In the baseload operation, the energy converted to

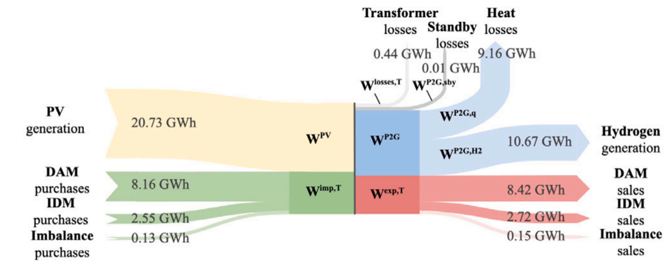

Fig. 7. Energetic flow scheme of the modelled VPP under Scenario V. Time horizon: entire year 2019. Bidding zone: Sicily, Italy.

H2 is less than the energy lost in thermal losses (26.61 against 27.70 GWh), whereas in the second scenario the energy actually consumed is higher than the energy losses (10.67 against 9.16 GWh). This behaviour is due to the non-linear efficiency curve implemented in the model. As can be seen in Table 2, a peak operation of the P2G implies an efficiency of 49%, while an optimized operation allows it to work with efficiencies between 65% and 49%, thereby decreasing losses.

Generally speaking, two major operational effects become visible when applying market-based VPP operation. First of all PV generation is exported to the grid more often. As shown for the exemplary day in Section 4.1, such happens now not only whenever the P2G capacity is unable to absorb the full PV generation but also whenever market prices are reasonably high so that it becomes economically more convenient to sell electricity generation to the grid rather than to self-consume it. Taking together DAM and IDM interactions, the overall exported electricity increases thereby to 54% (11.14 GWh) of the annual PV generation in 2019. The average price of electricity exports increases thereby to 65.99 €/MWh. Secondly, imported electricity is significantly reduced by this operation mode, with the P2G system consuming electricity from the grid only when prices are low enough for economic hydrogen production. The overall import from DAM and IDM that the model calculates under this operation mode for 2019 sums up to 10.71 GWh, minus 72% compared to the energy market imports from the baseload scenario. The average price of electricity imports decreases thereby to 62.39 €/MWh plus grid charges. With the operational approach following the market sequences, thus selling as much as possible on the DAM and using the IDM then only subsequently for adjustments in case of improved prices or updated generation forecasts, DAM interactions clearly dominate the energy market interactions with an overall share of roughly 75% of imports and exports.[4] Fig. 7 reports the resulting annual energy flows of such price-sensitive operation.

The VPP's price sensitivity is paid at the expense of reduced capacity utilization of the P2G, lowering the absorbed electricity by 64% to 19.83 GWh (equivalent to 3200 full-load hours). Nonetheless, the modelled operational results from energy market interaction improve significantly and rise to an overall annual revenue of 1546 k€ (equalling ~60 k€/MW of VPP capacity). This occurs thanks to significantly improved economics by selling PV generation at high prices to the grid and consuming it internally at low price times, as well as purchasing additional electricity from the grid only at very low price moments. The energy market based operational approach maximizes therefore the valorization of PV generation, the utilization of P2G capacity instead remains limited.

Concerning imbalance management, the model demonstrates that additional market interactions with the IDM and subsequent use of

[4] The operational approach is not only motivated by the market sequences but also by the fact that DAM and IDM prices generally follow a common pattern as visible for example in Fig. 4. A potential approach to leave out DAM interactions and only focus on IDM interactions appears therefore little convincing.

remaining internal VPP flexibility manage to eliminate potential imbalances nearly completely. Although the PV forecast error remains the same, the average hourly imbalance of the VPP reduces with the modelled approach to 0.03 MWh/h. While the modelled imbalance approach might eventually not be the most convenient from an economic point of view as further discussed in Section 4.6, it still represents an in practice commonly adopted imbalance management approach as BRPs are in multiple European countries legally obliged to reduce potential imbalances to a minimum [21,60].

4.4. Full-scale view: Deepened balancing market integration

The third focus is on modelling results of an operation mode that is not only integrated into energy markets but also in balancing markets. The P2G operation remains thereby dynamic and follows market price incentives from both market types while continuing to compensate PV forecast errors as far as possible. This enhanced operation mode is represented by scenario VII, distinguished from scenario V by additional balancing market integration.

With all other conditions remaining unchanged, the VPP interactions with the two energy markets DAM and IDM remain equal to the previously outlined scenario V. On top of the energy market profile, the balancing market adds then however a considerable layer of interactions with imported and exported electricity from the trade of balancing services. With the assumed modelling approach, downward services of the two product categories RR and FRR result to add overall 12.27 GWh of additional electricity imports to the VPP, on top of the previous 10.71 GWh from energy markets (+114%). On the export side, upward services add 9.34 GWh to the previous 11.14 GWh from energy market interactions (+96%). Concerning the split between the two product categories, both product categories appear to add significant market interactions to the VPPs operational baseline whereby FRR seems to be in the case of the market zone of Sicily the slightly more attractive downward service whereas RR prevails the upward service.[5]

Another noteworthy aspect concerns the utilization of the P2G unit with additional balancing market integration. With a modelled absorption of 22.57 GWh of electricity, the capacity utilization is with 42% (equivalent to 3650 full-load hours) still less than half compared to the baseload operation as in scenario I and only slightly increased compared to the previous scenario V. However, the capacity is only at first glance still underutilized with the free capacity partly consisting of offered and ultimately accepted flexibility services. In particular, upward services swap originally planned P2G absorption in the short term for a more economically valuable activity. Adding the upward services results in an originally planned electricity volume of 31.91 GWh and thus a capacity utilization of 59% (equivalent to 5150 full-load hours). For the remaining 41% of the time, apparently, no economic operation results from interaction with existing markets, neither with the energy markets DAM and IDM, nor the balancing market with its two product categories FRR and RR. Fig. 8 reports the Sankey diagram of the resulting energy flows from this scenario.

From a financial perspective, the integration into balancing markets untapps a valuable new type of revenue streams. Also here the aggregation of DERs in the VPP provides additional benefit as individual resources would either not be able to provide the full range of balancing services (PV unit) or for significantly less time due to a reduced baseline from energy markets (P2G unit). While the physical outcome of balancing market interactions is ultimately comparable to the one of energy markets in which the VPP imports or exports more or less electricity, the economic concept is fundamentally different and complex.[6] However, if the DER operator or an appointed third party has the necessary capabilities to implement such a process, the economic opportunities of this additional interaction are significant. With the implemented bidding assumptions as described in Section 2, the advanced operation mode of scenario VII adds around 70% or 1065 k€ of annual revenues to the modelling results of previous scenarios without balancing market interactions. The overall annual cash flow from this operating mode amounts therefore to 2611 k€ or ~100 k€/MW of VPP capacity.

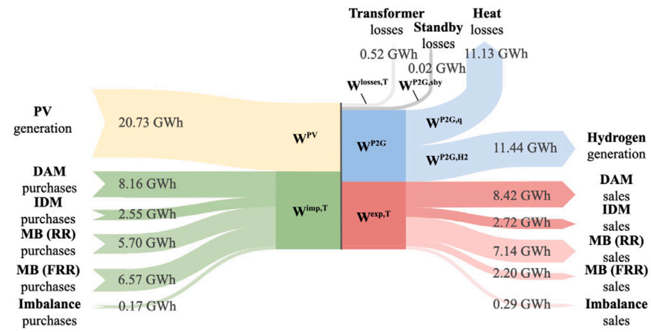

Fig. 8. Energetic flow scheme of the modelled VPP under Scenario VII. Time horizon: entire year 2019. Bidding zone: Sicily, Italy.

This notable increase in economic performance is the result of two general effects. By providing downward services, the VPP agrees to absorb more electricity on short notice. Originally thought of as a service that, from the perspective of a conventional generation unit, implied reducing electricity generation and thus saving on fuel costs, this service comes along with payment for not producing electricity that has already been sold on energy markets. Vice versa, for a consumption unit, this implies absorbing more electricity than previously purchased on energy markets for a discounted price. Downward services represent therefore an opportunity for the VPP's P2G unit to integrate additional hydrogen production at a low-cost input price. The economics behind this service are straightforward in that the service becomes more convenient to the VPP the larger the gap between the marginal hydrogen generation price (i.e., 78.00 €/MWh) and the effective service price. Average downward service prices amounted in Sicily in 2019 to 38.76 €/MWh for FRR and 27.02 €/MWh for RR, respectively.

To provide upward services instead, the unit absorbs less electricity by waiving hydrogen production. The convenience of this service offering depends therefore on the gap between the effective service price and the marginal revenue of foregone hydrogen production. In general, upward service prices clear considerably above energy market prices and amounted on average to 126.68 €/MWh for FRR and 132.43 €/MWh for RR, respectively, in Sicily in 2019. Based on the average prices of the considered case study, no clear preference between the two service directions is discernible in this particular case. With upward price clearing on average as high as 229.31 €/MWh in other Italian market zones (i.e., Centre-South), this depends however on a case-by-case basis.

In any case, the VPP will base its offerings always in the first place on the underlying power profile that results from energy market interactions. Upward balancing offers can only be made with sufficient

[5] Note that, as outlined in Section 2, balancing markets can only be modelled with less certainty compared to energy markets. Given the high local specificity of system operators balancing services needs, the presented results of this interaction type should thus not be interpreted as definite results but rather as a reasonable approximation of potential market opportunities.

[6] The economic counterpart is in this case not a plenitude of market actors but the single power system operator. Depending on the specific locational power system needs, a clearing of each product category in each time slot is therefore not guaranteed. Pricing is furthermore not based on a pay-as-cleared mechanism but on pay-as-bid with a single chance to offer products for each hourly time slot. The market interaction to obtain the respective revenue streams is therefore associated with significantly increased complexity.

margin to reduce consumption, and, vice versa, downward offers with sufficient margin to further increase consumption. In that sense, balancing market interaction functions as a pure ex-post “add-on” to energy market interactions but not as an independent decision-driver of VPP operation.

4.5. Full-scale view: Full market integration with pro-active imbalance management

The fourth focus is on a modelled operation mode with full market integration. The VPP interacts thereby not only with all energy and balancing markets but dispatches its internal flexibility also for pro-active imbalance management with unlimited passive balancing. This optimized operation mode is represented by scenario IX with detailed characteristics as provided in Table 3.

Leaving the energy and balancing market interactions unchanged from previous scenarios, the major difference occurs by the VPP anticipating the imbalance price and further adapting its schedule to deviate intentionally if convenient from an economic point of view. The decision of doing so or not is therefore again driven by the underlying power profile that results from previous market interactions in combination with the forecasted imbalance price. Other than “active balancing” with service provisions through the balancing market, this passive balancing approach is not market-based and therefore neither limited by any explicit balancing need of the system operator nor any clearing probability.[7]

As it emerges from the model, the economic potential of passive balancing is huge. If applied without any limitations and with the forecast assumptions as outlined in Section 2, the resulting annual cash flow from this activity amounts to an additional gain of 1385 k€ and thus overall 3996 k€ or ~150 k€/MW of VPP capacity. The reason for this massive gain is the huge energy flow that is connected with unlimited passive balancing, at prices that are based for a fair amount of time on balancing market prices. By linking real-time operation adjustments to these (predicted) prices as if they were regular market prices, the model drives the VPP to absorb additional 21.65 GWh by taking a deliberately short market position, i.e., consuming more than previously scheduled on energy and balancing markets. With an average imbalance price of 23.45 €/MWh in these hours, the VPP untapps another source of cheap import electricity and contributes at the same time passively to system stability (as the overall system is long in these hours). In other hours where the system is short, the VPP is driven by the then high imbalance prices to take a long position, i.e., consuming less than scheduled, and exporting thereby an additional 6.67 GWh at an average price of 137.35 €/MWh.

The overall electricity absorption of the P2G unit amounts in this scenario to 37.54 GWh (equivalent to 6050 full-load hours) as visualized in Fig. 9. Adding the initially scheduled but eventually assigned quantities for upward balancing services and long imbalance positions, the overall capacity planned for the P2G unit sums up to 53.55 GWh, reaching an effective capacity utilization of 99%, equivalent to 8640 potential full-load hours. Full market integration with pro-active imbalance management makes therefore full use of the available asset capacities. Other than simple baseload operations, the underlying operation mode results however significantly more profitable by integrating the available DER flexibility potential in the full range of market frameworks.

[7] Although it is admittedly limited by legal requirements, which individual BRPs may take into account to a greater or lesser extent as outlined in Section 1.1.

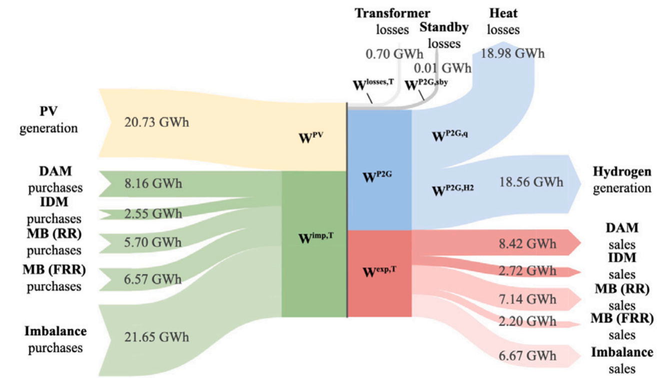

Fig. 9. Energetic flow scheme of the modelled VPP under Scenario IX. Time horizon: entire year 2019. Bidding zone: Sicily, Italy.

4.6. Overview: Economic implications of gradually increasing market integration

To complete the analysis on the implications of enhanced operation modes for DERs, Table 4 finally summarizes the financial results of all eight analysed operation modes with sequential levels of market integration. Taking active DAM integration with a VPP that operates based on a minimum of price signals (as in scenario II) as the reference for economic comparisons, the added value of the other operating scenarios is evaluated.

Adding IDM integration as a second market session for improved trading of PV generation and P2G consumption - *ceteris paribus* - improves the financial results by 4% (scenario III). An additional, more pronounced benefit is gained if the IDM is not only used for commodity trading but also to handle updated PV forecasts (scenario IV). By settling the day-ahead forecast error in this market closer to delivery, the VPP reduces its imbalances and associated cash flows (even if such were overall positive) while increasing IDM cash flows. The overall gain of such imbalance management amounts for the modelled VPP to 6%, or an additional 25 k€.

Reducing the remaining forecast error of the PV in real-time by dispatching all available P2G flexibility eventually turns out surprisingly inconvenient. For the modelled case study it results that such real-time imbalance management deteriorates the overall financial outcome by 0 to 3 k€ (scenario V–VII). This can be explained by the fact that the costs of P2G dispatch are apparently on average higher than potential savings on imbalance payments. The costs and availability of such dispatch depend on the available P2G flexibility, which itself is a function of the baseline after the interaction with previous market sessions.

As mentioned previously, the addition of balancing market into an enhanced operation mode adds a valuable revenue stream. The product category RR is therefore the first to be considered (scenario VI), as its provision by DERs has for example just been enabled in Italy in 2019 [9]. The provision of this service alone contributes already significant economic potential, adding 776 k€ of positive cash flows in the modelled scenario. The slightly more advanced product category FRR, whose provision by DERs has just recently been enabled too in Italy, integrates another notable cash flow from balancing market interactions. In the modelled scenario VII, this amounts to 289 k€. Taking together the two product categories, advanced operation modes with balancing market integration add thereby 1065 k€ of revenues, +73% compared to the revenues of the reference scenario.

Focusing on the implications of pro-active imbalance management with so-called passive balancing, it emerges that such provides another worthwhile layer for value-stacking. Predicting the system’s imbalance price and adjusting real-time forecast errors on this basis (or also not) enhances the annual cash flow of the model associated with imbalance

Table 4
Operational results for different levels of market integration of the VPP.

Resulting cash flows from:		Energy market interactions	Balancing market interactions	Imbalance management	*Total* -Absolut-	-Relative-	
Baseload	Scenario I	227 k€	–	32 k€	260 k€	10 k€/MW$_{VPP}$	
Energy market integration	Scenario II	1430 k€	–	32 k€	1463 k€	56 k€/MW$_{VPP}$	*-reference-*
	Scenario III	1489 k€	–	32 k€	1522 k€	58 k€/MW$_{VPP}$	+4%
	Scenario IV	1546 k€	–	1 k€	1547 k€	59 k€/MW$_{VPP}$	+6%
	Scenario V	1546 k€	–	–2 k€	1543 k€	59 k€/MW$_{VPP}$	+5%
Balancing market integration	Scenario VI	1546 k€	776 k€	–1 k€	2320 k€	89 k€/MW$_{VPP}$	+59%
	Scenario VII	1546 k€	1065 k€	1 k€	2611 k€	100 k€/MW$_{VPP}$	+78%
Passive balancing	Scenario VIII	1546 k€	1065 k€	10 k€	2621 k€	100 k€/MW$_{VPP}$	+79%
	Scenario IX	1546 k€	1065 k€	1385 k€	3996 k€	152 k€/MW$_{VPP}$	*+173%*

management by 9 k€. Extending this operational approach from internal forecast error management to a complete readjustment of the grid exchange profile potentiates the associated cash flow to the vast amount of 1385 k€. It exceeds therewith the cash flows from active service provisions on balancing markets and reaches nearly the same amount as from energy market interactions. While the potential repercussions of passive balancing are still the subject of vivid debate among academic authors and policy experts, the model results demonstrate that its application not only activates massive flexibility potential in the form of rebalanced energy flows but also contains significant economic opportunities for DER operators.

To summarize, it can be stated that value stacking from deepened integration of DERs provides a significant added value compared to simple baseload operation. Following a sequential operation approach that leverages the full spectrum of available market sessions provides therefore not only a strong improvement of the DER operator's business case but untaps also valuable flexibility resources for system operators. As the conducted case study is based on the currently implemented market framework in Italy (and being thereby similar to most other national frameworks in Europe), it emerges that already the exploitation of the given opportunities provides genuine added benefits. Nonetheless, a reasonable number of DER are yet not leveraging these opportunities for a number of reasons.[8] Instead of the sole focus on completely new market frameworks, further research and regulatory attention should thus focus on the removal of remaining market entry barriers so that DERs can make full use of their already existing operational opportunities. Given the limitations of this study concerning uncertainty rates of renewable generation patterns, market acceptance for ancillary services, as well as the predictability of imbalance prices, future studies will focus moreover on a deepened risk and uncertainty assessment to provide a more robust financial analysis.

5. Conclusions

The operation of an aggregated unit composed of PV and Power-to-Gas is simulated with a multi-period and multi-stage optimization approach to assess the value of enhanced operation modes that leverage recent regulatory framework advancements for deepened market integration of distributed energy resources. The case study is conducted with hourly resolution on an annual optimization horizon and is based on empirical market data from Italy. The results demonstrate that enhanced operation modes with value stacking prove to be highly favourable and offer numerous advantages.

From the system's point of view, optimized and synergistic management of distributed energy resources provides a tangible contribution by unlocking previously untapped flexibility potential. Deepened energy market integration already turns previously inelastic units into price-responsive units, enabling thereby an implicit flexibility potential that follows market-based price signals. Further balancing market integration enables an additional, explicit flexibility potential for active balancing service provision. Finally, the integration of passive balancing in imbalance management schemes proved to further boost the contribution of distributed energy resources to stabilize the system through enhanced operation modes.

From the individual plant operator's perspective, virtual aggregation with other distributed energy resources enables a multitude of benefits based on internal synergies. Advanced operation of such plants enables first of all to increase the valorization of electricity generation from renewable resources during low price instances. Second, it provides access to revenues from markets and services otherwise not accessible. Third, it facilitates pro-active imbalance management to tackle real-time deviations for which no more market-based settlement is available and to capitalize on passive balancing opportunities.

The sequential analysis of increasing market integration showed that the individual stages of market integration bring varying degrees of benefits. Intra-day market integration on top of day-ahead market interactions provides moderate benefits as an additional trading session with updated price patterns, but more profound benefits if used as a market-based imbalance management opportunity to adjust updated generation and or consumption forecasts. Balancing market integration furthermore adds a significant value layer to enhanced operation modes. However, this integration level unveiled a tangible complexity of operational interdependencies as the ability to offer specific service provisions depends on the resulting baseline from previous energy market interactions. The separate analysis of different product offerings on balancing markets showed that there is currently no one product that would be most valuable from a flexibility provider's perspective. Instead, each product adds its very own value in an often complementary way. In that sense, the full opening of ancillary services and balancing market with the full set of products to distributed flexibility providers appears most reasonably. Finally, passive balancing provided by an optimized plant demonstrates its great potential, both in terms of activated real-time flexibility as well as in terms of financial results. Identified cash flows from the modelling results exceed the ones from active balancing service provision and nearly reach the ones from energy market interactions.

Overall, the analysis of the various benefits of deeper market integration has shown that, in the end, it is advanced operation modes that exploit the full extent of market integration that generate the most added value. Future research opportunities include, among other things, the leverage of additional benefits from the provision of additional services such as primary reserve as well as enhanced optimization approaches with cross-market arbitrage.

CRediT authorship contribution statement

Jan Marc Schwidtal: Conceptualization of this study, Methodology, Investigation, Formal analysis, Writing – original draft. **Marco Agostini:** Conceptualization of this study, Methodology, Investigation,

[8] For the specific Italian case, please refer to an analysis of the recent market framework adaptation and its Pro's and Con's for DERs within the UVAM project [9].

Formal analysis, Writing – original draft. **Massimiliano Coppo:** Investigation, Validation, Writing – original draft. **Fabio Bignucolo:** Validation, Writing – review & editing. **Arturo Lorenzoni:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Publicly available datasets were analysed in this study. The respective data can be found as follows: Renewable forecast and generation data at European level: https://transparency.entsoe.eu/# (accessed: 2021-11-12) [44], raw electricity market data at Italian level https://www.mercatoelettrico.org/En/download/DownloadDati.aspx?val=OfferteFree_Pubbliche(accessed: 2021-11-12) [55].

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