Participation of aggregated DER to the Ancillary Services Market: a Monte Carlo simulation based Heuristic Greedy-Indexing model

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EXTENDED SUMMARY

NOMENCLATURE

ACRONYMS:

ASM	Ancillary Services Market
BESS	Battery Energy Storage System
BM	Balancing Market
CHP	Combined Heat and Power
DER	Distributed Energy Resources
HP	Hydro Power
NDRES	Non-dispatchable Renewable Energy Sources
PV	Photovoltaic (plant)
RR	Replacement Reserve
SR	Secondary Reserve
VPP	Virtual Power Plant
WT	Wind Turbine

CONSTANTS:

η_{chgi}, η_{dis}	Charging, discharging efficiencies
η_{el}	Electrical efficiency
$\eta_{m,el}$	Mechanical-electrical efficiency
η_{th}	Thermal efficiency
LHV_f	Lower Heating Value of the fuel
$n_{cycles,tot}$	Number of expected storage cycles at $DoD = 80\%$

INPUTS:

p_{bid}	Bid price: cash flow from VPP to market
p_{MB}, q_{MB}	Generic price, quantity on the Balancing Market
p_{MGP}	Day-Ahead Market price
p_{off}	Offer price: cash flow from market to VPP
$\boldsymbol{s}_{ctrl}$	Secondary Regulation control signal
$\boldsymbol{s_z}$	Imbalance zonal sign

PARAMETERS:

$c_{inv,sto}$	Investment cost per unit capacity of storage
C_s	Factor modulating extra storage commitment
Δt	Timestep of the simulation
$E_{nom,sto}$	Nominal storage capacity
h_{eq}	Equivalent hours of storage operation
K_p	Factor modulating bid price aggressiveness
K_q	Factor modulating the aggressiveness of quantities
$P_{tot,VPP}$	Total nominal power of the VPP
S	Scaling parameter of storage systems
T_{sim}	Simulated time period

VARIABLES:

$\boldsymbol{bid}_{RR}$	Quantities bid in a RR market session
$\boldsymbol{bid}_{SR}$	Quantities bid in a SR market session
c_{DR}	Cost of DR regulation for the aggregator
$c_{ex,sto}$	Cost of storage exchange per unit energy
$CF(t)$	Cash flow at time t
c_{imb}	Worst-case scenario cost of imbalance
$c_{wear,sto}$	Average cost of battery wear per unit energy
DoD	$\equiv 1 - SoC$, Depth of Discharge of a storage system
$E_{av,sto,i}$	Total energy available from the i-th storage system
E_{curt}	Energy available for curtailment for the i-th RES
$E_{ex,i}$	Real-time energy exchange for the i-th system
E_{imb}	Energy imbalance w.r.t. market commitments
$e_{MB,RT}$	Estimate of earnings from next ASM session
$\boldsymbol{e}_{RR}$	Expected price of RR up/dn regulation
$\boldsymbol{e}_{SR}$	Expected price of SR up/dn regulation
P_{av}	Up/down band available for bidding
$\boldsymbol{P}_{CHP,flex}$	CHP residual flexibility bands
$\boldsymbol{P}_{err}$	Error correction in bidding
$P_{lim,i}$	Technical limit on power of the i-th storage
$P_{req,sto}$	Energy to bring storage to set level within session
$P_{tot,j}$	Aggregate power of the j technology
Q_f	Fuel burned per unit extra kWh_{el} produced
R	Revenues, opposite of Costs C

I. INTRODUCTION

The formidable growth sustained by Distributed Energy Resources (DER) in the last decades was both a boon, and a major challenge for the safe and economical dispatch of energy to the electrical grid. Larger adoption of DER raises concerns regarding the reliability of the transmission system, which must improve its *flexibility* – defined as *"the ability of a power system to respond to change in demand and supply"* [1] – as a consequence of:

1) increased supply-side variability and uncertainty;
2) decreased availability of conventional flexible resources (peaking thermal generation) on the system, displaced in favor of DER;
3) reduction of base load conventional power plants – consequent reduction in programmable generation capacity;
4) added strain on distribution networks, no longer only having loads connected to them.

Designs that propose to improve the fitness of the electricity markets for a high DER penetration future have been thoroughly researched in the past years, with a focus on:

1) counteracting the problem of number and small size, which causes DER to be unmanageable and "invisible" to the Transmission System Operator (TSO), by aggregating them into bigger market entities, able to deliver dispatchable electricity – these are known as **Virtual Power Plants** (VPP);
2) changing rules in the current Electricity Markets; in particular, improving income opportunities for Ancillary Services Markets (ASM) – reducing minimum capacities and relaxing restrictions on technical requirements – may contribute to cost recovery for both variable and dispatchable power plants, and provide cost reduction for the TSO [2].

Italy is steadily implementing and transforming the European Directives about DER integration into norms and regulation ([3]), requiring all grid-connected actors – including loads – contribute to the efficiency and security of the system. Recently, and perhaps most importantly, the consultation 298/2016/R/eel and the resolution 300/2017/R/eel [4], [5] have been approved. These are a major step towards opening the ASM (Mercato per il Servizio di Dispacciamento) to NDRES plants, DG and loads – in aggregated form and on a voluntary basis – starting the first phase of the Riforma Dispacciamento Elettrico (RDE-1) project.

Aggregation of DER has been proven to yield several improvements to grid operation and market performance: not only does it help hedging against the risks of imbalance fees within the Day-Ahead Market by sheer effect of diversification (initially the first driver for market aggregates), but it also provides

- better controllability of small scale generators [6];
- management of imbalances with flexible demand, CHP plants or storage systems [7];
- participation in ASM – increased visibility [8];

all propositions which offer synergies with one another [9].

According to the issues at hand, the problem of DER aggregation for ASM participation shall be tackled in this work through a Greedy-Indexing heuristic simulation model, where uncertainties related to NDRES production are decoupled through Monte Carlo draws, applied to the features of the Italian Electric system.

The **purpose** of this work is to:

- evaluate the business opportunities and the technical challenges that arise from the participation of a Virtual Power Plant to the ASM;
- determine the most profitable and effective VPP configuration and regulation units sizing;
- evaluate the specific weight and profitability of different ancillary services, and their effect on the day-to-day plant operation.

In Section II, the framework for the model is set up; Section III investigates the logics that it follows and Section IV provides its validation. Results are then assessed and commented in Section V, and a sensitivity analysis is performed in Section VI.

II. Model definition and hypotheses

The proposed greedy-heuristic model simulates and evaluates the behavior of a Virtual Power Plant operating in the Ancillary Services Markets, and providing Secondary and Replacement Reserve services. Given a VPP scenario, drawn within a Monte Carlo method frame, the model runs through the simulation period (up to one year), determining the market commitments (in advance) as well as the real time operation, with the information available at that time.

The configuration of choice for the aggregate comprises photovoltaic plants, wind turbines and run-of-river hydroelectric (Non-dispatchable Renewable Energy Sources), with Combined Heat and Power plant flexibility, and storage systems as regulating units, providing the system with error correction, as well as reserve capabilities.

Real time decisions enacted by the algorithms are based both on technical aspects – such as available flexibility and ramp limits – and on economical aspects which play a large role in the operation of market entities such as Virtual Power Plants. For instance, a full battery system, which would otherwise be compelled to bring its charge level back to the set point as soon as possible, may be better off by delaying its discharging in case of low demand (and consequently low prices) for up regulation, or if it believes higher prices will be reached in the near future. On the other hand, the energy exchanged by a CHP plant at a given time does not affect the amount exchangeable in the next market session, and therefore the decision should be only based on the cost of fuel saved/expended. Moreover, some particular market scenarios may call for the operator to imbalance the grid, as at those times penalties would be lower than the cost of fuel or storage capacity.

The overarching logic that governs the model is presented in Figure 1. After defining a VPP configuration (scenario), statistically representative of the real distribution of NDRES in Italy (see Table I), the Day-Ahead Market schedule is determined by means of persistence model forecasting. This is a (purposefully) rudimentary technique of weather prediction, based on the assumption that meteorological phenomena vary slowly enough that the most likely outcome for the weather in D +1 is to be the same as D. Bids for the ASM are defined through the available flexibility – in both up/down directions,

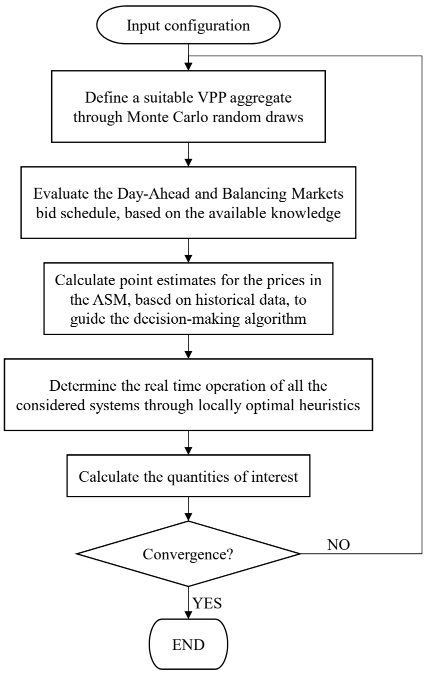

Figure 1. Logic flowchart

suitably modified to take into account error correction with respect to an updated forecast (at the time of BM sessions) and the state of charge (SoC) of the storage systems.

Between market session, market prices are predicted through point estimates based on historical data, and the operation of all the regulation systems is determined. The results stemming from these operation in the span of the simulated period are calculated and stored with the ones from previous scenarios. When Monte Carlo convergence is achieved, i.e. the error on the estimate of the quantities of interest is below a given threshold, the algorithm is stopped, and the results deemed satisfactory.

A. RES production

The production of NDRES was modeled through gathering, acquisition and re-elaboration of weather data (solar radiation, wind speed and hydrometric level) from 135 stations scattered around northern Italy. These profiles were suitably transformed to per-unit power, and then fed to the Monte Carlo scenario creation algorithm.

B. Market data

Market prices for the year 2016 were collected from GME's FTP server, and re-elaborated to determine the accepted average, maximum and minimum prices for each session of ASM and Day-Ahead Market [12]. Zonal sign (required to determine imbalance settlements) and Secondary Regulation control signal – which modulates the regulation over the bands accepted in the ASM – were downloaded from Terna's website [13].

C. Regulating resources modeling

1) Storage: Electrochemical storage systems are modeled on the basis of the following parameters:

- $S = {}^{P_{nom,sto,i}}/_{P_{tech,i}}$, the sizing parameter that determines the percentage (in terms of power) of RES plants that are equipped with batteries;
- $h_{eq,i} = {}^{E_{nom,sto,i}[\mathrm{kWh}]}/_{P_{nom,sto,i}[\mathrm{kW}]}$, equivalent hours of operation – time required to completely deplete a full storage system at nominal power $P_{nom,sto}$.

Characteristics of run-of-river hydroelectric storage, on the other hand, depend on the hydraulic turbine they refer to, and are limited by its flow rate at any given time: they may store as much as $P_{lim,up}(t) = P_{HP}(t)$, and discharge $P_{lim,dn}(t) = (P_{nom} - P_{HP}(t))\eta_{dis}$.

2) CHP: The CHP flexibility $\boldsymbol{P}_{CHP,flex}$ was modeled under the assumption that its production is known in advance, and it follows the electricity demand of the industry it serves, while meeting the surplus heat demand with a gas boiler. This allows to exploit the up/down flexibility at no additional cost to the VPP, other than the cost of fuel, which is offset by the quantity saved by producing extra heat.

Starting from the production profile of the considered CHP plant (which in the actual simulation was from a pair of Internal Combustion Engines, data courtesy of Enel S.p.A.) the remaining up/down flexibility was calculated considering the number of engines operating, and their technical minimum.

III. Implementation and logic

The VPP configuration for each Monte Carlo run is chosen through a sequence of random draws that define each unit i within the aggregate: first, the technology j is picked from a stepwise distribution with weights $\boldsymbol{w}_{tech}$, then a power class is selected from $\boldsymbol{w}_{power,j}$ (different for each technology – classes range logarithmically from $P_{min} = 100\,\mathrm{kW}$ to $P_{max} = 6\,\mathrm{MW}$ – based on Medium Voltage networks regulation [14]) and the nominal power $P_{nom,i}$ is then randomly drawn within that class. This process is repeated until $\sum_i P_{nom,i} \geq P_{tot,VPP}$, that is the size of the VPP reaches the total nominal power that was set as parameter; then the last unit's power is cut to achieve a total size of $P_{tot,VPP}$.

Each VPP scenario is then evaluated by the model along a timeframe starting from t_{start} to $t_{end} = t_{start} + T_{sim}$, with timesteps $\Delta t = 15\,\mathrm{min}$ (characteristic of ASM) which allow to appreciate the dynamics of the market while limiting the computational effort required. A finer time discretization would better capture the dynamics of following the SR control signal, but since the regulating units offer flexible ramp rates,

Technology	P_{class} [kW]	*133.971*	*179.482*	*240.454*	*322.139*	*431.573*	*578.182*	*774.597*	*1037.735*	*1390.264*	*1862.550*	*2495.277*	*3342.948*	*4478.581*	*6000*
Photovoltaics	**91.93%**	*16.18%*	*10.47%*	*17.90%*	*5.78%*	*6.22%*	*8.19%*	*6.59%*	*24.21%*	*0.57%*	*0.91%*	*0.94%*	*0.86%*	*0.57%*	*0.63%*
Wind Turbine	**1.50%**	*2.87%*	*3.58%*	*48.03%*	*0.72%*	*0.36%*	*0.00%*	*2.51%*	*34.41%*	*0.36%*	*1.43%*	*1.43%*	*1.08%*	*2.51%*	*0.72%*
Hydroelectric	**6.57%**	*10.59%*	*6.65%*	*9.03%*	*10.34%*	*9.77%*	*10.76%*	*11.00%*	*8.78%*	*7.96%*	*4.93%*	*3.37%*	*2.96%*	*2.05%*	*1.81%*

Data from GSE [10], [11]

Table I

DISTRIBUTION OF TECHNOLOGIES $\boldsymbol{w}_{tech}$ AND POWER $\boldsymbol{w}_{power}$

capable of accommodating sudden changes ([15], [16]), the information loss from the proposed solution is little (although underestimation of sustained storage cycles may occur).

A. Market schedule and forecasts

Due to the heuristic nature of the model, all market decisions must be taken with the knowledge and information available at the time of closure of the relevant session. This is, for the Day-Ahead Market (DAM), 09:00 of D -1 (where D is day of dispatch), and for the Ancillary Services Market, hours 03:00, 07:00, 11:00, 15:00, 19:00, 23:00 of D (Balancing Markets closing times[1]).

Predictions for market participation were based on the **persistence model**, a weather forecasting approach based on the slow variability of conditions, which are most likely not to change from one day to the next:

$$P_{expected,d}\left(t\right) = P_{measured}\left(t - d \cdot 24\,\text{h}\right) \tag{1}$$

In accordance, the schedule for quantities offered on the DAM (with a price-taker approach) is obtained by time-shifting the available production data forward by $d = 1$ day and 2 days, for hours respectively before and after 09:00. On the other hand, the updated prediction used in the BM bidding process is based on the previous day.

B. Reserve bidding

A bid for the Ancillary Services Market must include a quantity-price pair, which – if accepted – is remunerated on a pay-as-bid basis. Starting from prices, a conservative estimate of the price for both Secondary and Replacement Reserve services must be assessed. This will be used to determine which service to bid, and will also serve as the price submitted to the market. A mean value is considered, based on n_{av}-day historical data from the same market session, calculated for the time t as follows:

$$\begin{aligned} e_{SR,up}\left(t\right) &= \sum_{d=D-1-n_{av}}^{D-1} \frac{p_{SR,up,d}\left(t\right)}{n_{av}} \cdot K_{p,up} \\ e_{SR,dn}\left(t\right) &= \sum_{d=D-1-n_{av}}^{D-1} \frac{p_{SR,dn,d}\left(t\right)}{n_{av}} \cdot K_{p,dn} \end{aligned} \tag{2}$$

where $K_{p,up}$, $K_{p,dn}$ are parametric coefficients that modulate the aggressiveness of bid prices as a compromise between earnings and likelihood of acceptance. The same logic is applied for the evaluation of $\boldsymbol{e}_{RR}$, as well as for the estimate on the total quantities sold $\boldsymbol{q}_{RR}$; note that RR bidding allows for four quantity-price pairs with a constraint on upwards concavity of the offer: this aspect was neglected due to complexity.

Once price estimations are calculated, the available capacity for reserve should be assessed. First, the level of the storage systems is verified, to determine energy excess or deficit, calculating the energy required to reach the set level in the next 4 hours (by the end of the current session – $P_{req,sto} = {}^1\!/\!{}_4 E_{req,sto}\,[{}^{\text{kWh}}\!/\!{}_{4\text{h}}]$) where:

$$\begin{aligned} E_{req,sto}\left(t\right) = \sum_i \big(\min[&\left(E_{set,i} - SoC_i\left(t\right)\right)\eta_{sto,i}, \ldots \\ &\ldots P_{lim,i}\left(SoC_i\right)] + E_{extra,i}\big)\ [\text{kWh}] \end{aligned} \tag{3}$$

- SoC_i, is the State of Charge of the i-th storage system;
- $P_{lim,i}\left(SoC_i\right)$ is the technical limitation on power, determined from the characteristic curve of the storage system;
- $$\eta_{sto,i} = \begin{cases} \eta_{chg,i} & \Delta SoC > 0 \\ \frac{1}{\eta_{dis,i}} & \Delta SoC < 0 \end{cases}$$
  is the efficiency of the i-th storage system, which depends on the direction of the exchange[2];
- $E_{set,i} = {}^1\!/\!{}_2 E_{nom,sto,i}$ is the set level of the storage, equal to half its size (assuming symmetric up/down regulation and neglecting the effects of losses);
- $E_{extra,i} = C_s \cdot E_{nom,sto,i} \cdot \text{sign}\left(SoC_i - E_{set,i}\right)$, where the parameter C_s modulates the artificial extra storage usage.

Next, the expected error between DAM schedule ($\boldsymbol{P}_{MGP}$) and updated forecasts available at the time of bidding ($\boldsymbol{P}_{MB}$) is calculated as

$$\boldsymbol{P}_{err} = \boldsymbol{P}_{MB} - \boldsymbol{P}_{MGP} \tag{4}$$

producing an estimate of the expected imbalance, and attempting to later fix it through the bid. From these quantities, the available band for up/down regulation for each 15 min period

[1]Reserve services are also traded in the BM, closer in time to dispatch

[2]for most intents and purposes, $\eta_{chg} = \eta_{dis}$ holds

of the session can be calculated as

$$\begin{aligned}\boldsymbol{P}_{av,up} &= \boldsymbol{P}_{CHP,flex,up} + \boldsymbol{P}_{err} - P_{req,sto} \cdot \ldots \\ &\ldots (\max(\boldsymbol{e}_{RR,up}, \boldsymbol{e}_{SR,up}) > \bar{c}_{wear,sto}) \\ \boldsymbol{P}_{av,dn} &= \boldsymbol{P}_{CHP,flex,dn} - \boldsymbol{P}_{err} + P_{req,sto} \cdot \ldots \\ &\ldots \left(\boldsymbol{p}_{MGP} - \min\left(\boldsymbol{e}_{RR,dn}, \boldsymbol{e}_{SR,dn}\right) > \bar{c}_{wear,sto}\right)\end{aligned} \tag{5}$$

taking into account:

- CHP flexibility per unit hour, through $\boldsymbol{P}_{CHP,flex}$, in both directions;
- prediction error correction $\boldsymbol{P}_{err}$;
- storage state, through $P_{req,sto}$ – conditional (logic operations: 1 if true, 0 if false) on the profitability of its employment, through the quantities
  - $\max(\boldsymbol{e}_{RR,up}, \boldsymbol{e}_{SR,up},)$, $\left(\boldsymbol{p}_{MGP} - \min\left(\boldsymbol{e}_{RR,dn}, \boldsymbol{e}_{SR,dn}\right)\right)$, these are the expected earnings from up and down regulation respectively;
  - $\bar{c}_{wear,sto} = \frac{1}{P_{nom,sto}} \cdot \sum_i c_{wear,sto,i} P_{nom,sto,i}$, the size-averaged cost of wearing down the batteries, calculated for each technology as

    $$c_{wear,sto,i}\,[€/\mathrm{kWh}] = \frac{c_{inv,sto,i}}{n_{cycles,tot,i} \cdot 0.8 \cdot 2} \tag{6}$$

    where $c_{inv,sto}\,[€/\mathrm{kWh}]$ is the investment cost of storage in € per kWh of capacity, $n_{cycles,tot}$ is the number of expected cycles at $DoD = 80\%$; causing the correction based on storage SoC to be only considered when the algorithm trusts that wear costs would be covered.

Given the available regulation bands, in the intervals where RR is deemed more profitable than SR – that is $\boldsymbol{t}$: $(\boldsymbol{e}_{RR,up} > \boldsymbol{e}_{SR,up}) \vee \left(\boldsymbol{e}_{RR,dn} < \boldsymbol{e}_{SR,dn}\right)$ – the vector $\boldsymbol{P}_{av,RR}(\boldsymbol{t}) = \min(\boldsymbol{P}_{av}(\boldsymbol{t}), \boldsymbol{q}_{RR})$ is compiled, and the RR bid is set to the amount

$$\begin{aligned}\boldsymbol{bid}_{RR,up} &= \boldsymbol{P}_{av,RR,up} + \boldsymbol{P}_{DR,flex,up} \cdot (\boldsymbol{e}_{RR,up} > c_{DR,up}) \\ \boldsymbol{bid}_{RR,dn} &= \boldsymbol{P}_{av,RR,dn} + \boldsymbol{P}_{DR,flex,dn} \cdot \left(\boldsymbol{p}_{MGP} - \boldsymbol{e}_{RR,dn} > c_{DR,dn}\right)\end{aligned} \tag{7}$$

where offering $P_{DR,flex}$ is conditional on the expected earnings exceeding the cost for the aggregator

$$c_{DR} = \begin{cases} p_{MGP} \cdot pr_{DR} & \text{up} \\ -p_{MGP}/pr_{DR} & \text{down} \end{cases} \tag{8}$$

where pr_{DR} is a premium awarded to the flexibility-providing customer over the DAM price.

The remaining flexibility is offered for the Secondary Reserve service

$$\begin{aligned}\boldsymbol{bid}_{SR,up} &= K_{q,up}\left(\boldsymbol{P}_{av,up} - \boldsymbol{P}_{av,RR,up}\right) \\ \boldsymbol{bid}_{SR,dn} &= K_{q,dn}\left(\boldsymbol{P}_{av,dn} - \boldsymbol{P}_{av,RR,dn}\right)\end{aligned} \tag{9}$$

with K_q parameter that modulates the quantities committed to Secondary Reserve, based on the accepted level of risk, since the control signal $\boldsymbol{s}_{ctrl}$ rarely commands the whole of the auctioned band.

C. Real-time operation: commitments to market

The VPP scenario evaluation runs through the simulation period with the configuration prescribed by the input flags (x_{CHP}, $x_{el.chem.,STO}$, $x_{hydro,STO}$ acting as a switch on regulating units), by P_{CHP}, and by the characteristics of the storage systems, at every time t reading market prices and ASM commitments for the current session. Then, it is possible to determine whether bids for reserve services were accepted, by running the test $e_{X,dn}(t) > p_{min,bid}$, $e_{X,up}(t) < p_{max,off}$ for the X-th service: accordingly, the accepted quantities will be

$$\begin{aligned}q_{acc,X,up}(t) &= \min\left(bid_{up}(t), q_{X,off}(t)\right) \\ q_{acc,X,dn}(t) &= \min\left(bid_{dn}(t), q_{X,bid}(t)\right)\end{aligned} \tag{10}$$

where $q_{X,off}(t)$ and $q_{X,bid}(t)$ are the quantities actually accepted in t (from market data). From these, the SR regulation requested in the relevant Δt can be determined as

$$\begin{aligned}E_{reg,SR,up} &= \sum_{>0} \boldsymbol{s}_{ctrl}(\Delta t) \cdot q_{acc,SR,up}(t) \cdot 1/60 \\ E_{reg,SR,dn} &= \sum_{<0} \boldsymbol{s}_{ctrl}(\Delta t) \cdot q_{acc,SR,dn}(t) \cdot 1/60\end{aligned} \tag{11}$$

while the RR regulation will be $E_{reg,RR} = \pm q_{acc,RR}(t) \cdot 1/4$ (negative for down regulation). Note that the TSO will not accept RR band in both directions; if this occurs, the following formula applies:

$$\begin{aligned}E_{reg,RR,up} &= \max\left(0, E_{reg,RR,up} + E_{reg,RR,dn}\right) \\ E_{reg,RR,dn} &= \min\left(0, E_{reg,RR,up} + E_{reg,RR,dn}\right)\end{aligned} \tag{12}$$

The obligation towards the market will be calculated as

$$\begin{aligned}E_{sold} = E_{MGP} &+ E_{reg,SR,up} + E_{reg,SR,dn} + \\ &+ E_{reg,RR,up} + E_{reg,RR,dn}\end{aligned} \tag{13}$$

from which, the real time imbalance is

$$E_{imb} = E_{prod} - E_{sold} = \sum_i {}^{P_i(t)}/4 - E_{sold} \tag{14}$$

It is now useful to provide a valuation for aspects that affect actions that could be taken to extinguish this imbalance.

1) Cost of CHP plant fuel: Under the previously stated assumption on the operation of the Combined Heat and Power plant, each $\mathrm{kWh_{el}}$ that is produced in excess (shortage) is accompanied by a number (depending on engine load $l\%$ at time t) of $\mathrm{kWh_{th}}$ from the combustion of fuel that would be saved (spent). The model employs an interpolation of the engine's characteristic curves to evaluate the quantity of fuel $Q_f\left[{}^{\mathrm{Sm}^3}/_{\mathrm{kWh_{el}}}\right] = Q_{f,el} - Q_{f,th}$ that is burned (saved) as a consequence of each $1\,\mathrm{kWh_{el}}$ increase in production.

Considering sole generation of electricity, the fuel expenditure per unit energy increase may be calculated as

$$Q_{f,el} = \frac{288.15\,\mathrm{K}}{273.15\,\mathrm{K}}\left[\frac{\mathrm{Sm}^3}{\mathrm{Nm}^3}\right]\frac{c_{s,f}\left[{}^{\mathrm{MJ}}/_{\mathrm{bkWh}}\right]}{\eta_{m,el}\cdot LHV_f\left[{}^{\mathrm{MJ}}/_{\mathrm{Nm}^3}\right]} \tag{15}$$

where

- $c_{s,f}\,(l\%)$ is the specific fuel consumption, expressing input heat required per output mechanical work;
- $\eta_{m,el}$ mechanical-electrical efficiency, takes into account to mechanical friction, inertia and generator losses;
- LHV_f, Lower Heating Value of the fuel, defined as the energy released by combustion of a unit of fuel within a calorific bomb brought back to 25 °C.

Switching to the thermal side of the equation, given the quantities

- $\eta_{el,CHP}\,(l\%)\left[{}^{\mathrm{kW_{el}}}/_{\mathrm{kW_{th}}}\right]$ I principle efficiency of the engine, accounting for electricity production;
- $\eta_{th,CHP}\,(l\%)\left[{}^{\mathrm{kW_{th}}}/_{\mathrm{kW_{th}}}\right]$ thermal efficiency of the CHP, accounting for heat production;

the fuel saved due to the production of $\eta_{th,CHP}/\eta_{el,CHP}\,\mathrm{kWh_{th}}$ is:

$$Q_{f,th} = \frac{288.15\,\mathrm{K}}{273.15\,\mathrm{K}}\cdot\frac{{}^{\eta_{th,CHP}}/_{\eta_{el,CHP}}\left[\mathrm{kWh_{th}}\right]\cdot 3.6\left[{}^{\mathrm{MJ}}/_{\mathrm{kWh_{th}}}\right]}{\eta_{th,boiler}\cdot LHV_f\left[{}^{\mathrm{MJ}}/_{\mathrm{Nm}^3}\right]} \tag{16}$$

where $\eta_{th,boiler} = 0.94$ is the reference efficiency of the auxiliary/back-up boiler for steam generation.

For a cost of natural gas $c_{NG}(t)$, the fuel cost is calculated as

$$c_f\left[{}^{€}/_{\mathrm{kWh_{el}}}\right] = Q_f\,(l\%)\left[{}^{\mathrm{Sm}^3}/_{\mathrm{kWh_{el}}}\right]\cdot c_{NG}(t)\left[{}^{€}/_{\mathrm{Sm}^3}\right] \tag{17}$$

2) Real-time cost and valuation of storage use: From an analysis of the bidding algorithm, it is evident that the *SoC* of storage systems at time *t* has a strong influence over quantities bid in the following ASM session: the latter are shifted by an amount proportional to the distance from the set level. Any time the storage is charged – $SoC\uparrow$ – $E_{req,sto}\downarrow$ which in turn causes $\boldsymbol{P}_{av,up}\uparrow$ and $\boldsymbol{P}_{av,dn}\downarrow$; the reverse is true for discharge. An instinctive valuation of energy exchange with storage will therefore be

$$e_{ex,sto} = \left(e_{MB,RT,up} - e_{MB,RT,dn}\right)\cdot \mathrm{sign}\left(E_{imb}\right) \tag{18}$$

where $e_{MB,RT}$ are an estimate of Balancing Market prospective **earnings** from the following session. An adequate estimate may be found as

$$\begin{aligned} e_{MB,RT,up} &= \sum_{t\in MB}^{4}\left(\sum_{d=D-1-n_{av}}^{D-1}\frac{p_{MB,up,d}(t)}{n_{av}\cdot 4}\right)\cdot K_{p,up} \\ e_{MB,RT,dn} &= \sum_{t\in MB}^{4}\left(\sum_{d=D-1-n_{av}}^{D-1}\frac{p_{MGP,d}(t) - p_{MB,dn,d}(t)}{n_{av}\cdot 4}\right)\cdot K_{p,dn} \end{aligned} \tag{19}$$

where the best option between SR and RR was chosen out of the last *n*-days average clearing price for each hour of the *following* MB session:

$$\boldsymbol{p}_{MB}(t) = \begin{cases} \max_p\left(p_{SR,up}(t), p_{RR,up}(t)\right) & \text{up} \\ \min_p\left(p_{SR,dn}(t), p_{RR,dn}(t)\right) & \text{down} \end{cases} \tag{20}$$

the rationale behind the formula in 19 is to consider the average earnings out of prices cleared in each hour of the relevant session for the previous week (to have a conservative estimate), then average this again over the four hours in the session, since the effect of E_{req} within a MB session is spread on its whole duration (by its definition 3).

Furthermore, due to the large investment cost associated to storage systems, and the comparatively low number of cycles that electrochemical battery systems can withstand (see [16]), when considering these systems a penalty is added, equal to the *wear* that any given energy exchange exercises. This quantity is defined in 6, and must be added to the contribution in 18 (changed in sign) to obtain the cost of exchange with the *i*-th storage system

$$\begin{aligned} c_{ex,sto,i} = &\left[\left(e_{MB,RT,dn} - e_{MB,RT,up}\right)\cdot \mathrm{sign}\left(E_{imb}\right) + \right. \\ &\left. + c_{wear,sto,i}\right]\cdot \eta_{sto,i} \end{aligned} \tag{21}$$

3) Cost of imbalance: Also the prospect of not acting on the imbalance should be considered. To valuate this option, Article 40 of the AEEGSI deliberation n. 111/06 [17] was taken into account (dual pricing), stating that, given the zonal time $s_z(t)$ (indicating the direction of the overall imbalance in the market zone) and the VPP imbalance sign $s_p = \mathrm{sign}\left(E_{imb}\right)$, two situations are considered:

- if $s_z\cdot s_p < 0$ – since such imbalance actually helps the system reach stability – the exchange is not penalized, and the price paid by the aggregator is $p_{imb} = -p_{MGP}\cdot s_p$;
- if $s_z\cdot s_p > 0$, that is concordant signs, the imbalance is detrimental to the grid, and shall be penalized:
  - if $s_p > 0$, excess energy enters the grid, and its cost is $p_{imb} = -\min\left(p_{MGP}, p_{min,bid,MB}\right)$;
  - if $s_p < 0$, not enough energy is provided, and the missing portion is paid $p_{imb} = \max\left(p_{MGP}, p_{max,off,MB}\right)$ – usually a steep penalty above DAM price.

According to a pricing mechanism known as *single-dual*, which currently applies to non-dispatchable plants, two different tariffs are prescribed, based on the magnitude of the imbalance. Up to the exemption limit, equal to $ex_{imb} \cdot E_{MGP}$, a *single* pricing mechanism is considered, which only depends on the sign of the unit's imbalance s_p; quantities exceeding this limit, on the other hand, are remunerated with the more penalizing aforementioned *dual* pricing mechanism, depending on s_p and s_z both [18]. Nonetheless, the VPP imbalance policy proposed in the AEEGSI deliberation 298/2016 [4] is the *dual* scheme, therefore $ex_{imb} = 0$ will be considered when calculating the results, while for validation purposes $ex_{imb} = 7.5\%$ is set to showcase the model's flexibility with respect to uncertain future regulatory decisions.

Moreover, under some circumstances, it is possible to earn from an imbalance by disregarding an order from the Transmission Service Operator; this happens when:

1) the TSO has accepted an **offer** from the dispatching unit, and the following is verified $s_z > 0,\ s_p < 0$: in this case, if unchecked, the VPP would earn both from the regulation it has sold $p_{off,MB}$, and would only pay p_{MGP} for its imbalance (which helps the grid); in this case the TSO is due for a payment of

$$CF_{CMR}\,[€] = q_{off,MB}\left(p_{off,MB} - p_{MGP}\right) \tag{22}$$

("Corrispettivo di Mancato Rispetto degli ordini di dispacciamento") – effectively reimbursing the arbitraged quantity;

2) the TSO has accepted a **bid**, while $s_z < 0,\ s_p > 0$; the payment will be

$$CF_{CMR} = q_{bid,MB}\left(p_{MGP} - p_{bid,MB}\right) \tag{23}$$

as a consequence, curtailment – otherwise never viable – may be the preferable option (i.e. when $(-p_{MGP} + {}^{CF_{CMR}}/_{|E_{imb}|}) > 0 = c_{curt}$).

Nevertheless, zonal signal is not known in real time, but it is released *ex-post* by the TSO to allow for calculation of cash flows. Real time **decisions**, on the other hand, have no reliable information about it, and must therefore assume the worst-case scenario for c_{imb}, that is either $s_p \cdot s_z > 0$, evaluated with prices from the previous n_{av} days (across the span of 4 hours h), or $s_p \cdot s_z < 0$ with

$$c_{CMR} = CF_{CMR}/\,|E_{imb}|\,[€/\mathrm{kWh}] \tag{24}$$

being the cost ascribed to E_{imb}: finally, when $s_p > 0$

$$\begin{aligned} c_{imb} = \{&\alpha_{imb} \cdot (|E_{imb}| - ex_{imb}E_{MGP}) \cdot \\ &\cdot \max\left[-p_{MGP} + c_{CMR}, -\min\left(p_{MGP}, \min_h\left(p_{min,bid,SR,h}\right)\right)\right] + \\ &+ (-p_{MGP} + c_{CMR}) \cdot ex_{imb}E_{MGP}\} \cdot {}^1/_{|E_{imb}|} \end{aligned} \tag{25}$$

and when $s_p < 0$,

$$\begin{aligned} c_{imb} = \{&\alpha_{imb} \cdot (|E_{imb}| - ex_{imb}E_{MGP}) \cdot \\ &\cdot \max\left[p_{MGP} + c_{CMR}, \max\left(p_{MGP}, \max_h\left(p_{max,off;SR,h}\right)\right)\right] + \\ &+ (+p_{MGP} + c_{CMR}) \cdot ex_{imb}E_{MGP}\} \cdot {}^1/_{|E_{imb}|} \end{aligned} \tag{26}$$

with $\alpha_{imb} = 1$ if $|E_{imb}| - ex_{imb}E_{MGP} > 0$, $\alpha_{imb} = 0$, otherwise; taking into account the single-dual pricing mechanism to weigh the worst-case cost on the exempted part.

D. Real-time operation: imbalance processing logic

The final step in the real time logical sequence is the decision on regulation, the heart of the greedy-indexing heuristic model, building upon all the aforementioned calculations. This is shown in the flowchart in Figure 2.

The algorithm receives the current state of the VPP (including $E_{av,CHP} = {}^{P_{CHP,flex}}/_4$), the time t, and the valuations for all regulation options (c_f, c_{imb}, $\boldsymbol{e}_{SR}$) as input; and initializes the auxiliary values $s_{imb} = \mathrm{sign}(E_{imb})$, $E_{imb} = |E_{imb}|$.

The cost of CHP regulation will be equal to $c_{CHP} = -c_f \cdot s_{imb}$, while the cost of curtailing RES is assumed to be $c_{curt} = 0€/\mathrm{kWh}$. Of course, the energy available to be curtailed is, at most, $E_{curt,i} = P_i(t) \cdot \Delta t$ for the i-th RES[3].

To evaluate the cost of intervention of the j-th storage system, the following quantities need to be taken into account:

- energy exchangeable from storage

$$E_{av,sto,j} = \begin{cases} (E_{sto,j} - SoC_j) \cdot \eta_{charge,j} & s_{imb} > 0 \\ {}^{(SoC_j)}/_{\eta_{discharge,j}} & s_{imb} < 0 \end{cases} \tag{27}$$

- technical limits $P_{lim,j}(SoC_j)$;
- cost of storage energy exchange, as defined in 21.

Once economic valuations are known, a list of options, sorted in order of increasing cost, is produced. The algorithm runs through all regulation options in order, calculating the energy exchanged with the i-th system ($i =$ storage (3), CHP, curtailment) as

$$E_{ex,i} = \min\left({}^{P_{lim,i}}/_4, E_{av,i}, E_{imb}\right) \tag{28}$$

updating the imbalance, $E_{imb} = E_{imb} - E_{ex,i}$, until either $E_{imb} = 0$, or the selected option is not to act on the imbalance, in which case $E_{imb} = E_{imb} \cdot s_{imb}$.

The last step of the real time regulation algorithm involves the update of

$$SoC_i = SoC_i - {}^{E_{ex,i}}/_{\eta_{sto,i}} \tag{29}$$

and the calculation of immediate cash flows

$$CF_{RT} = -c_{CHP} \cdot E_{ex,CHP} \tag{30}$$

[3]Note that if hydroelectric storage is considered, its curtailment is not.

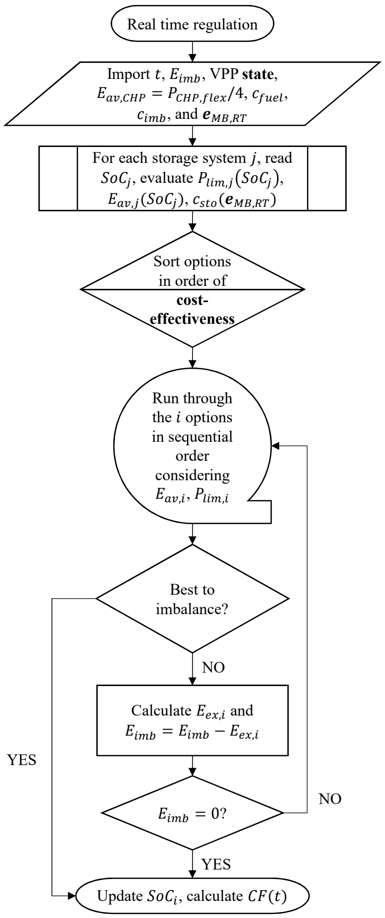

Figure 2. Real time regulation – Greedy-indexing heuristic

which are output, together with the exchanged energy, to the time-series

$$\begin{aligned} CF(t) = CF_{RT} + E_{MGP} \cdot p_{MGP} + E_{reg,SR,up} \cdot p_{off,SR} + \\ + E_{reg,SR,dn} \cdot p_{bid,SR} + E_{reg,RR,up} \cdot p_{off,RR} + \\ + E_{reg,RR,dn} \cdot p_{bid,RR} - E_{reg,DR} \cdot c_{DR} + CF_{imb} \end{aligned} \tag{31}$$

where $ex_{imb} = 0\%$ is the imbalance volume exemption recognized to dispatchable plants, while

$$\begin{aligned} CF_{imb} = s_{imb} \left(|p_{imb}| - p_{MGP}\right) \max\left(|E_{imb}| - ex_{imb} E_{MGP}, 0\right) + \\ + p_{MGP} E_{imb} - CF_{CMR} \cdot (E_{imb} \neq 0) \end{aligned} \tag{32}$$

is the cash flow associated with imbalance; the logic operation ensures that $CF_{imb} = 0$ if $E_{imb} = 0$.

IV. Validation

In order to assess the validity and accuracy of a mathematical model, it is crucial to verify and validate its performance. Reasonable and recognizable outputs must be produced from controlled inputs.

Since the first source of input unpredictability is found in the VPP characterization process, for the extents of validation, an artificial configuration is considered, where each technology's aggregate power $P_{tot,j}$ is assessed as the weighted average

$$P_{tot,j} = P_{tot,VPP} \cdot \frac{w_{tech,j} \cdot w_{power,j}}{\sum_j w_{tech,j} w_{power,j}} \tag{33}$$

resulting in the following distribution

$$\frac{P_{tot,j}}{P_{tot,VPP}} = \begin{cases} 49.23\% & \text{PV} \\ 2.89\% & \text{WT} \\ 47.88\% & \text{HP} \end{cases} \tag{34}$$

Ancillary Services Market prices, due to their fickle nature, are another difficult-to-interpret input: as such, they will be set arbitrarily by scaling the p_{MGP} profile.

A. Bidding

To validate the ASM bidding algorithm, the determination of the available power $P_{av,up/dn}$ is first put into question. Flexibility aside, two contributions apply to this quantity, as seen in 5:

- $\boldsymbol{P}_{err}$, error between DAM schedule and updated forecast; can be decoupled by imposing a perfect knowledge of RES production corresponding to perfect market predictions, resulting in $\boldsymbol{P}_{err} = \boldsymbol{0}$;
- $E_{req,sto}$, depending on the position of $\sum_i SoC_i$ with respect to the set level; it cannot be set arbitrarily as it is not an input.

Outputs from a simulation ran with both contributions zeroed out are visible in Figure 3: as expected, the bid profile exactly mimics the available flexibility from the CHP plant.

It is now interesting to relax the constraint on perfect forecasting: some degree of error correction can be expected from the bidding algorithm: to underline this, the plot in Figure 4 keeps both $\boldsymbol{P}_{CHP,flex}$ and $E_{req,sto}$ to zero by switching the flags x_{CHP}, $x_{el.chem.,STO}$, $x_{hydro,STO}$ off.

The resulting bids nicely match the difference between schedule and forecast, in a way such that provision of regulation would help reduce the predicted imbalance.

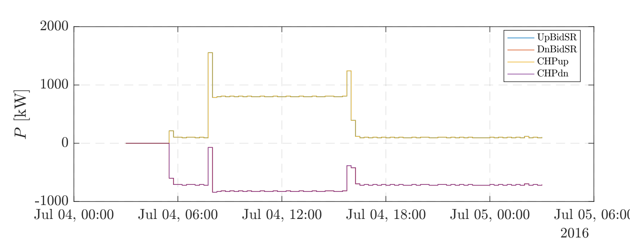

Figure 3. $\boldsymbol{P}_{CHP,flex}$-only bidding

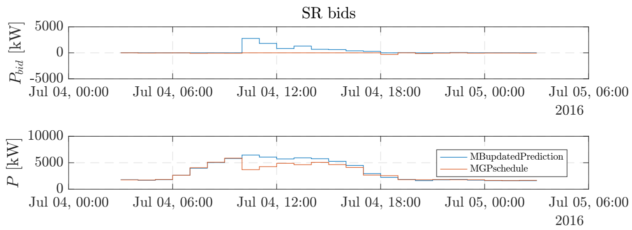

Figure 4. Error correction bidding

B. Real-time decision making

In order to evaluate the operation of the decision making algorithm, as well as the effect of $P_{req,sto}$ on bidding, a variable pricing scenario was considered (shown in Figure 5), and applied to a $T_{sim} = 24\,\text{h}$ period starting from 03:00 of July the 4th 2016.

Production and market forecasts are shown in Figure 6; the market plot shows a large surplus in the updated prediction with respect to the Day-Ahead schedule: the algorithm will try to settle this through bids in the ASM; furthermore, the actual production schedule, while keeping a similar shape to the forecast, will cause additional imbalance, which will be processed in real time.

1) Electrochemical storage regulation: The sole use of battery systems as regulator units will be addressed first. According to the valuation described in 21, these systems will exchange energy with the grid only when the prices of the ASM are deemed sufficiently profitable to cover costs.

Market results are shown in Figure 7. The up-regulation in the central hours of the day that would occur according to

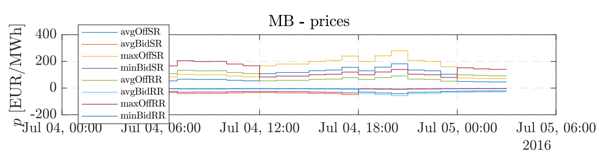

Figure 5. Artificial prices

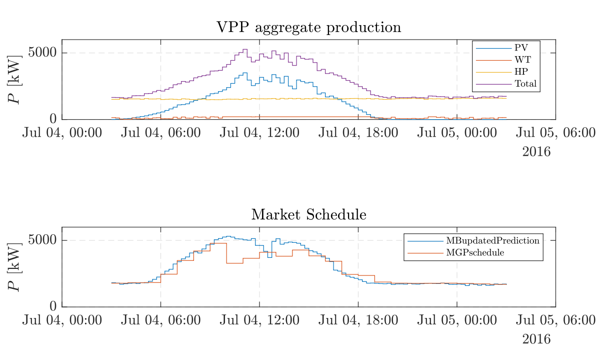

Figure 6. VPP production and forecasts

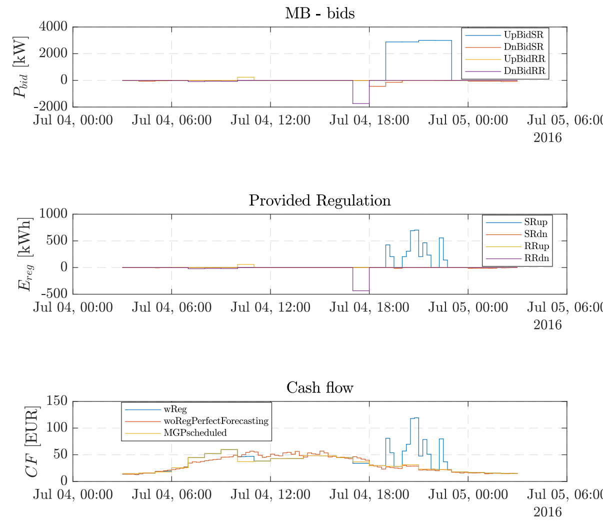

Figure 7. Battery regulation market results

Figure 4 is cut to allow for battery charge while prices are low, and discharge as market prices rise in the later hours of the day, as shown in Figure 8.

According to the cash flow plot in Figure 7, large revenues are attained with up regulation, while the system manages to retain DAM earnings while charging its batteries with excess production.

At nighttime, when the considered artificial prices for the ASM are lower, small amounts of curtailment occur, since storage operation is not worthwhile.

2) CHP flexibility regulation: Regulation through modulation of CHP output shows different dynamics, as it allows for flexibility bands in both directions. Figure 9 shows the results under this configuration. Cash flows in this case already

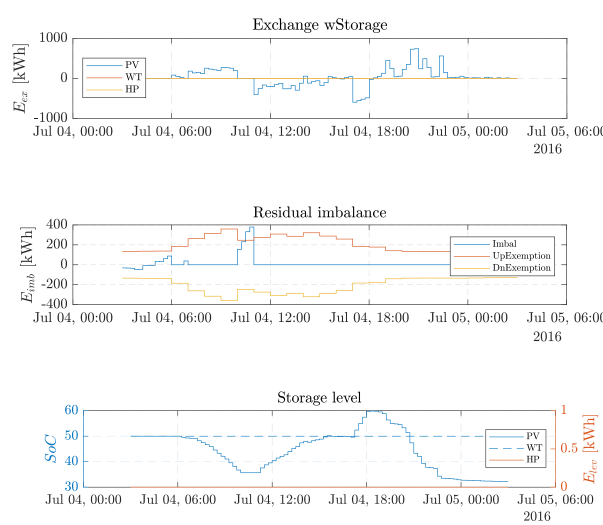

Figure 8. Battery regulation technical results

consider the cost of fuel, showing better results than with ideal forecasting (but no participation to the ASM).

The energy exchange plot shows that utilization of CHP flexibility is almost always preferred to imbalance, and the only instances where the latter is left unchecked is when flexibility is insufficient to cover the forecasting error.

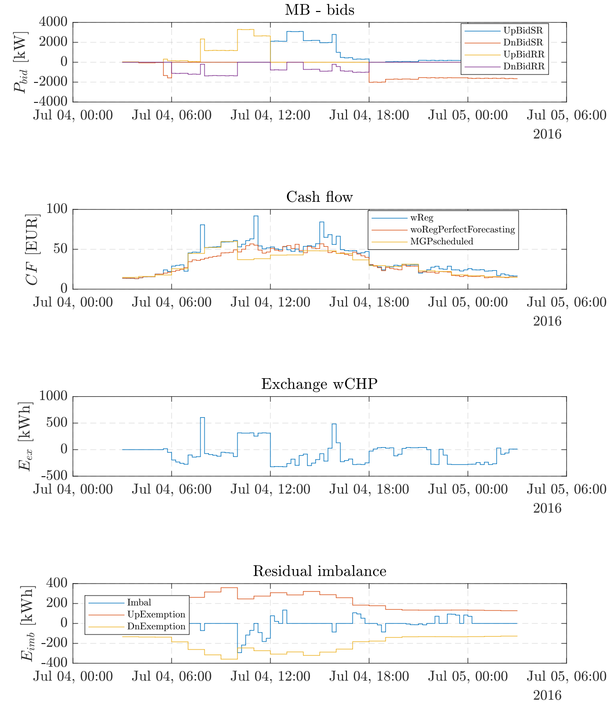

Figure 9. CHP flexibility results

V. Results

The simulation was run through the length of the year 2016 (350 days – some were skipped at the start to provide historical data), starting from the 11th of January, for a $P_{tot,VPP} = 10\,\text{MW}$ sized configuration. Starting parameters (storage characteristics, bidding) were set to standard realistic values, listed in Table II; moreover, the total size of storage systems was scaled to $S = 20\%$ of the respective technology's nominal power, to match the overall flexibility band of the $P_{CHP} = 1605\,\text{kW} \times 2$ sized CHP, amounting to about $2\,\text{MW}$.

In order to provide a fair comparison between CHP regulation – for which CF for fuel expenditure are already considered – and battery storage systems, subject to wear (they can withstand a limited number of cycles $n_{cycles,tot}$) a cost C_{wear} must be discounted from economical results, equal to

$$C_{wear} = \sum_i n_{cycles,i} \cdot c_{wear,sto,i} \cdot \underbrace{E_{cycle,i}}_{E_{nom,sto,i}\cdot 1.6} \tag{35}$$

A. Base case

A base case with no regulation was considered in order to provide a benchmark to compare results to. The following quantities are taken into account:

- total ($E_{imb,tot}$) and average nonzero ($t^\star = t : \; X \neq 0$) imbalance to grid $E_{imb,av} = \text{mean}\left(\left|E_{imb}\left(t^\star\right)\right|\right)$;
- average relative imbalance with respect to quantities sold $E_{imb,rel} = \text{mean}\left({|E_{imb}(t^\star)|}/{E_{MGP}(t^\star)}\right)$;
- total curtailment $E_{curt,tot} = \sum_t E_{curt}\left(t\right)$;
- total revenues in the considered period $R = \sum_t CF\left(t\right)$.

Results in this configuration are shown in Table III.

	X	e_X
R [€/y]	343,495.55	±2.49 %
$E_{imb,tot}$ [kWh/y]	4,340,647.97	±0.69%
$E_{av,imb}$ [kWh]	129.67	±0.33 %
$E_{imb,rel}$ [p.u.]	0.241	±3.72 %

Table III
Base case results

B. Discussion on tests results

Several VPP configurations were run through the model and evaluated, as shown in Figure 10: revenues R and costs C are categorized by source, and their sum is plotted in red with the relative Monte Carlo uncertainty. As a reference, the base case is showed in a dashed green line.

h_{eq}	4 kWh/kW	$n_{cycles,tot}$	4000	
$P_{nom,sto}$	1 p.u.	K_q	1.2	1.4
η_C	0.85	K_p	0.95	1.05
$c_{inv,sto}$	500 €/kWh	C_s	0.1	

Table II
Starting parameters

In general, configurations with CHP (C) and/or Hydro Power (H) show promising economical returns, as well as improvements to the reliability of operation and security of supply. These are a viable solution, given the availability of said plants. On the other hand, ASM participation and error correction provide insufficient economic yields to justify investments in electrochemical storage (S), considering current costs, despite their potentiality in terms of technical performance.

Furthermore, provision of RR only provides a more constant and predictable demand, which helps with error correction and CHP regulation; when BESS are considered, though, the lower prices associated to this service cause an insufficient employment of storage.

The configuration with both CHP and batteries (when considering $P_{CHP} = 802.5\,\text{kW}$ and $P_{sto,i} = 0.1 \cdot P_{nom,i}$ – labeled

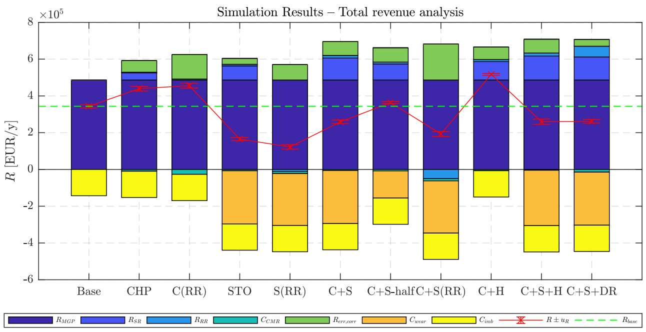

Figure 10. Economical results of the proposed VPP configurations

"C+S-half") shows some promise – as it achieves marginally better results than the base case, keeping in mind that:

- most of the assumptions in the model were conservative;
- both the price estimation and schedule forecast are purposefully unoptimized, to consider a worst-case scenario;
- other services may be offered in parallel to further justify the use of battery systems from an economic point of view.

Figure 11 displays the energy exchanges resulting from market commitments. As a consequence of the modulating effect of $\boldsymbol{s}_{ctrl}$, cases in which only RR is considered show much larger traffic. In general, CHP regulation is biased towards the down direction, due to its available flexibility.

The analysis of the use of BESS is carried out in Figure 12, where the number of sustained cycles ($DoD = 80\%$) , n_{cycles} is plotted against the number of hours in which the storage is empty $h_{@SoC=0}$ and the number of hours at which the storage is full $h_{@SoC=1}$. These quantities represent how the storage systems are managed: high n_{cycles} and low spread between hours with SoC at saturation signify a correct sizing of the storage system for the required operation. This is far from being the case when only Replacement Reserve is offered, as – due to the lower margins for profit on average – storage systems charging seldom justified. Moreover, the time required to wear down the batteries is presented, inversely proportional to n_{cycles} – $T_{inv} = 15\,\mathrm{y}$ is on the upped bound of the acceptable range for battery lifetimes (and investment horizons), but higher values are unsatisfactory: in this case, C_{wear} should be rescaled to consider that the battery must be replaced earlier

$$C'_{wear} = C_{wear} \cdot {}^{n_{cycles,tot}}\!/_{n_{cycles}} \cdot 15\,\mathrm{y} \tag{36}$$

making both RR cases wildly unprofitable.

VI. Sensitivity analysis

In order to evaluate how to best assemble a Virtual Power Plant, it is useful to simulate the behavior under different starting conditions to perform a sensitivity analysis and determine a trend that could serve as a guideline for sizing of aggregates. The period of the sensitivity simulations is reduced to eight weeks, two from each season, and the same standardized VPP configuration evaluated in Section IV was taken into account.

Validation of this methodology will be provided in the following lines by comparing non-regulating case results obtained on the whole year to the following:

$$R_{NOreg} = 99{,}910\,{}^{€}\!/_{8\mathrm{w}} \rightarrow\sim 624{,}438\,{}^{€}\!/_{\mathrm{y}}$$
$$E_{imb,av,NOreg} = 115.580\,\mathrm{kWh}$$

where the result for $8\,\mathrm{w}$ was rescaled on the $\sim 50\,\mathrm{w}$ in a simulated year, providing outputs comparable to $R_{NOreg} = 637{,}883\,{}^{€}\!/_{\mathrm{y}}$ and $E_{imb,av,NOreg} = 99{,}692\,\mathrm{kWh}$. Some degree of correlation between the considered weeks and the whole year may thus be assumed.

From this point forwards, the considered average quantities ($E_{ex,av,i}$, $E_{imb,av}$) will also account for null values, to provide a proxy for the magnitude of the exchange.

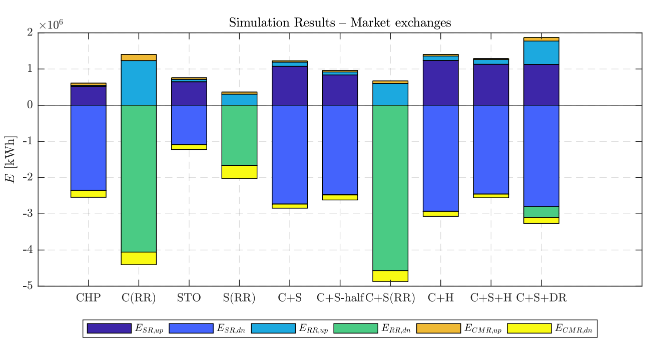

Figure 11. Market exchanges

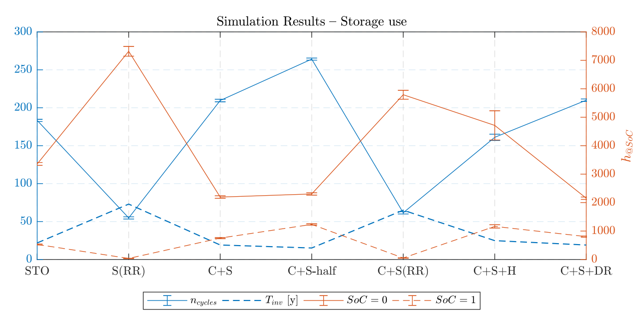

Figure 12. Usage of battery storage

A. CHP nominal power

Nominal power of the CHP plant has a direct influence on the flexibility bands available for regulation. An interesting analysis is carried out by evaluating how revenues of a 10 MW VPP can be improved, increasing the size of the associated CHP up to the maximum allowed by [4], 10 MW, at which it would become a *relevant* unit.

The effect of different values of $P_{nom,CHP}$ on revenue R are assessed on the left axis of Figure 13: as expected, an increase in CHP size results in a linearly proportional ($R^2 = 0.9925$) improvement for revenues – keeping in mind that such CHP plant would not participate in the Day-Ahead Market, only providing its flexibility bands. The right hand side of the graph shows average grid-exchanged quantities over the considered time period: an interesting feature is the minimum at $P_{nom,CHP} \sim 2500$ kW, after which larger market commitments cause an increment of the average imbalance $E_{imb,av}$.

B. Storage characteristics

1) Size: The size of electrochemical storage systems is parametric in terms of the percentage of PV and WT plants within the VPP that are equipped with batteries. This allows to vary the total capacity of the systems without changing the ratio $S_i = {}^{P_{nom,sto,i}}/_{P_{nom,i}}$ of the single unit, which in practice is rarely different from 1.

Eight values of S were taken into account in Figure 14, with $h_{eq} = {}^{E_{nom,sto}}/_{P_{nom,sto}} = 4$ h in all cases.

The only configurations that are competitive with respect to the *NOreg* case are those with $S = \begin{bmatrix} 0.01 & 0.05 & 0.1 \end{bmatrix}$: beyond that size, the investment costs far outweigh the benefits. While total revenues keep growing with the size (as shown by the total length of the bars), most of it must be forfeited to depreciation and replacement of batteries, and penalties for missed dispatching orders.

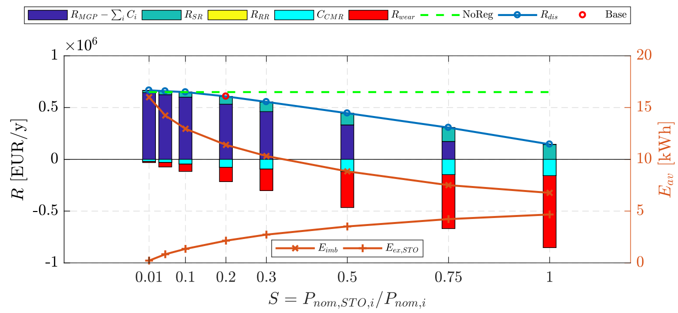

Figure 14. Storage size sensitivity analysis

2) Investment cost: It is interesting to assess what would happen in case of changes to the cost of electrochemical storage systems per unit capacity. This would have a deep impact on both the economical results of simulations, and the real-time behavior of the algorithms. Lower costs $c_{wear,sto}$ [€/kWh] increase the storage utilization (see 6), which in turn promote bidding on the ASM; at the same time, the increased wear will penalize final returns to a lower extent. According to Figure 15, given $S = 20\%$, battery prices up to $c_{inv,sto} \leq 400$ €/kWh yield a positive net result over the case with no regulation.

VII. Conclusions

This work provides a framework to evaluate the performance that can be expected of any Virtual Power Plant configuration operating on the Italian future Ancillary Services Market framework, by simulating its behavior through heuristic greedy decision-making algorithms. The resulting model may be employed to determine the feasibility of any regulating technology, as well as any given production mix.

Despite all the advantages that come from sheer aggregation of DER (increased dispatchability, visibility to TSO, observability of distribution network), the error with respect to forecasts – reduced by 25% with respect to the same plants unclustered – is still too significant: regulating units

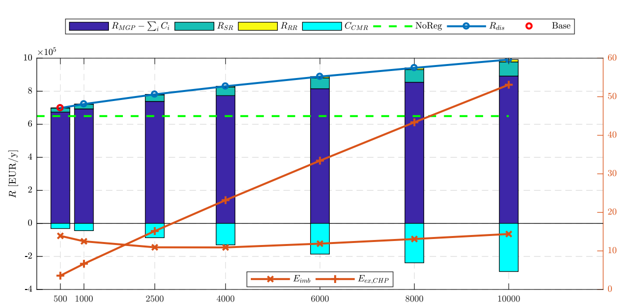

Figure 13. $P_{nom,CHP}$ sensitivity analysis

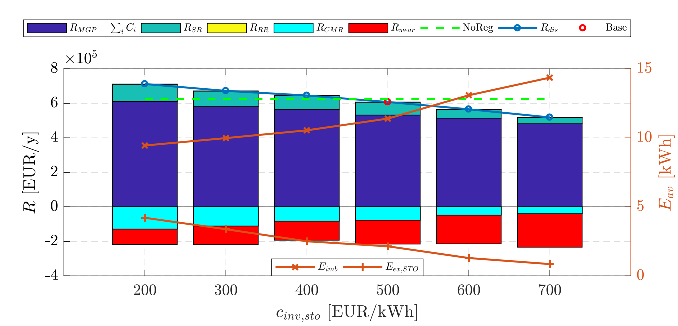

Figure 15. Storage investment cost sensitivity analysis

are required to make the VPP fully programmable and reap the rewards that come from ASM participation. This is where the proposed model can step in and offer crucial insights.

The following considerations have been observed within this study:

- addition of two $P_{CHP} = 1605\,\mathrm{kW}$ cogenerative Internal Combustion Engines to provide flexibility for participation in the ASM can improve VPP returns – with respect to a non-regulating case – by as much as 27.93% (even more – 32.71% – if only Tertiary Reserve is offered), at no extra cost to either party (industry and aggregator) – moreover, increasing the size to the maximum allowed ($P_{CHP} = 10\,\mathrm{MW}$) no diminishing returns effect is observed;
- similarly, if run-of-river hydroelectric plants with *pondage* capacity were available for regulation, their slow energy accumulation and release would complement CHP regulation, to **further** increase returns by 22.54%;
- despite dynamic regulation performances, which make them ideal to improve DER flexibility, BESS may only be viable on small scales ($S \downarrow$) due to their current costs (assumed at 500€/kWh), as they show diminishing returns with size, for insufficient utilization throughout their lifetime;
- the evaluated configuration, which considered $S = 20\%$ of RES plants to be equipped with batteries, was found to worsen results by -51.97%;
- still, sensitivity analysis suggests that the price required to break even with the given value of S lays in the $400 \div 450$€ range, not too far from the one that was assumed;
- combining battery storage and CHP flexibility, provided the correct sizing is employed for both, may yield interesting results, with 5.85% benefit which might be further improved upon by providing additional services with the batteries, as well as by exploiting synergies between units if the regulatory framework were to allow it (e.g. using up-flexibility to charge batteries).

From a regulatory point of view – and from a System Operator perspective – although aggregation brings multiple benefits, attentive examination of the problem raised the following insights::

- increasing the amount of available flexibility resources and encouraging investment in flexibility measures should be the main focus, as they've been shown to directly correlate to lower imbalances;
- imbalance pricing policies should be accurately devised, so that they could not be arbitraged upon;
- spatial definition of aggregates must be evaluated very carefully, as rather large energy flows may occur at times.

The hypotheses followed in the development of the model have been necessary to keep the complexity of the problem under examination at bay. However, the flexibility of the code within the model allows it to be perfected and refined through future revisions.

Vast room for improvement, especially within the methodology of market price estimation, may be exploited in future developments. Prices are used both in determining the ASM strategy (affecting revenues), as well as determining imbalance cost estimate and valuation of storage operation (affecting real-time decision making process). Optimal performance of a greedy-indexing heuristic is strictly dependent on perfect information, while the proposed algorithm – albeit sufficient for the proposed purposes – does not provide great accuracy. This would be a great application for the use of Artificial Neural Networks, a data-mining technique that is very efficient in discovering patterns in large data-sets.

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