Politecnico di Torino
Master's Degree in Energy and Nuclear Engineering

Analysis of the possible effective imbalances within a potential energy community

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Abstract

The spread in last years of new distributed and aggregated energy entities such as the several configurations among Energy Community (EC) and Virtual Power Plant (VPP), is boosted by a structural reformation of the power systems. Indeed, this diffusion is basically increasing the Non-Programmable Renewable Sources (NPRS) injection, while increasing the power reserve procurement and decreasing the availability of the current flexibility sources of the Ancillary Services Market (ASM). In such a scenario, decreasing the forecasting errors and opening the Ancillary Services (AS) procurement to new flexibility sources appear to be absolutely needed: otherwise, the dispatching net costs supported by a Transmission System Operator (TSO), and itself by the end-users, would increase.

In light of this, the thesis aims to quantify the systemic impacts of a potential energy community located in Turin (Northern Italy), in terms of effective imbalances, i.e. the differences between the Real Time (RT) and Forecasted (FO) grid exchange. The case study consists of 3,377 households spread over several districts and owning 13.7 MW of Photovoltaic (PV) rooftop systems: the latter was sized by imposing the yearly production equal to the yearly consumption. Then, the imbalances were build from normal distributions looking at the typical forecasting errors in literature and by roughly linking the case study consumption imbalances to the ones of Northern Italy. Given the random nature of the imbalances, 10 runs were implemented, while 2 scenarios were involved: Scenario 1 (S1) with and Scenario 2 (S2) without PV, simulating hence the passage from simple end-users to an EC.

The imbalance settlement was yearly computed through flexible Python routines by declining them in light of the Italian legislation: payments from the TSO to the EC in case of positive imbalances and vice-versa, while the imbalances are valued depending only on the Macro-Zone (MZ) imbalance sign, namely Imb_{MZ} sign. After a quite detailed analysis of the main ASM quantities involved in the imbalance settlement, the latter is performed showing the results for each run and then comparing among them, the scenarios and the years. First, the imbalances, namely Imb_{EC}, and the charges, namely $ImbC$, are computed: overall, 2018 and 2019 present similar values, while on average becoming an EC, i.e. S2, increase the total systemic costs of about 93% compared to S1. Then, due to the way the Imb_{EC} were build and to the Italian legislation, as expected there were an higher occurrence of positive Imb_{EC}: this, compared to the higher occurrence of positive Imb_{MZ}, let overall to negative net payoffs, namely $ImbP$, for the EC.

Since in literature there weren't found any comparative result involving the ECs, some indicators were provided, to depict how the charges would change by changing the community size. They are ratios between the $ImbC$ and: the grid exchange, the Imb_{EC}, the number of users and the consumption and production peaks.

Finally, the yearly and daily seasonality of Imb_{EC} and P_{imb} were studied, showing how the highest increase of Imb_{EC}, hence the charges, occured during the highest producibility PV periods, while the P_{imb} present trends and values more similar to downward ASM prices than upward ones.

In conclusion, this works showed how the total energies and monetary volumes handled at systemic level seems to be higher in such a scenario of Distributed Generation (DG), ECs and VPPs diffusion.

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I want to express deep gratitude to many people, starting with my actual family: far away from Turin, but always close to me in difficult moments with kind words or the famous *pacchi da giù*, especially during the last year. I am sorry if I felt distant sometimes, but for sure you were not for me.

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Acronyms

aFRR	automatic Frequency Restoration Reserve	22
ABM	Agent-based Model	xii
AC	Active Costumers	5
AiD-EM	Adaptive Decision Support for Electricity Markets	ix
ARERA	Regulatory Authority for Energy, Networks and Environment	xi
AS	Ancillary Services	i
ASM	Ancillary Services Market	i
AU	Acquirente Unico	16
BM	Balancing Market	20
BRP	Balance Responbile Party	2
BSP	Balance Service Provider	19
CACM	Capacity Allocation and Congestion Management	11
CBA	Cost-Benefit Analysis	54
CCHP	Combined Cooling Heat and Power	54
CDF	Cumulative Density Function	vi
CEC	Citizen Energy Community	5
CESI	Centro Elettrotecnico Sperimentale Italiano	54
CEP	Clean Energy Package	xi
CHP	Combined Heat and Power	7
CPP	Critical Peak Pricing	10
CS	Coordintation Scheme	46
CU	Consumption Unit	xii
DA	Day Ahead	v
DAM	Day Ahead Market	v
DB	Demand Bidding	10
DC	Dispatching Cost	ix
DG	Distributed Generation	i
DLC	Direct Load Control	10

DMS	Distribution Management System	41
DP	Dual Pricing	xi
DR	Demand Response	xii
DSM	Demand Side Management	2
DSO	Distribution System Operator	6
EBGL	Electricity Balancing Guideline	50
EC	Energy Community	i
EDisON	Electricity Dispatch Optimization	46
EDR	Electric Dispatching Reform	8
EDRP	Emergency Demand Response Programme	10
Entso-e	European Network of Transmission System Operators for Electricity	27
EG	Emergency Generators	54
ESCo	Energy Service Company	6
ESS	Energy Storage System	xii
EU	European Union	v
EV	Electric Vehicles	39
FCR	Frequency Containment Reserve	22
FO	Forecasted	i
GAUDI	Gestione Anagrafica Unica Degli Impianti	20
GHG	Greenhouse Gasses	1
GME	Gestore Mercati Energetici	16
GSE	Gestore Servizi Energetici	7
HG	High gain	102
HL	High loss	127
HV	High Voltage	19
I/C	Interruptible/Curtailable load	10
ICE	Internal Combustion Engine	54
ID	Infra Day	v
IDM	Infra Day Market	xi
IPEX	Italian Power EXchange	15
IRR	Internal Rate of Return	39
ISO	Indipendent System Operator	40
KDE	Kernel Density Estimation	78
LG	Low gain	103

LL	Low loss	102
LP	Linear Programming	47
LV	Low Voltage	7
mFRR	manual Frequency Restoration Reserve	22
MAPE	Mean Absolute Percentage Error	xii
MAS	Multi-Agent System	47
MASCEM	Multi-Agent Simulator of Competitive Electricity Markets	ix
MASGriP	Multi-Agent Smart Grid Platform	ix
MB	Mercato di Bilanciamento	20
MCP	Market Clearing Price	40
MxCP	Mixed Complementarity Problem	xii
MGP	Mercato del Giorno Prima	15
MI	Mercato Infra-giornaliero	15
MIBEL	Iberian Electricity Market	55
MILP	Mixed Integer Linear Program	39
MINLP	Mixed Integer Non-Linear Program	40
MiSE	Ministero dello Sviluppo Economico	6
MPC	Model Predictive Control	43
MPE	Mercato Elettrico a Pronti	15
MPEG	Mercato dei Prodotti Giornalieri	15
MPU	Monitoring Peripheral Unit	33
MSD	Mercato dei Servizi di Dispacciamento	15
MTE	Mercato Elettrico a Termine	15
MZ	Macro-Zone	i
NG	Natural Gas	12
NECP	National Energy and Climate Plan	4
NLP	Non-Linear Programming	40
NPRS	Non-Programmable Renewable Sources	i
NRMSE	Normalised Root Mean Square Error	ix
OPF	Optimal Power Flow	43
OPTIMATE	Open simulation Platform to Test Integration in MArkeT deisgn of massive intermitten Energy	47
OTC	Over-the-counter	16
PA	Paris Agreement	1
PAB	Pay-As-Bid	xii

Chapter 1

Introduction

The integration within the power systems of new distributed and aggregated energy entities such as EC and VPP configurations is an important issue in the energy transition, which is currently being addressed.

Indeed, a structural reformation of the power grid and power markets is under development: for the European countries the reference legislative frameworks are the CEP and the EU Green Deal, that aim to reduce the Greenhouse Gasses (GHG)s emissions, increase the Renewable Energy Sources (RES) penetration and decrease the energy consumption with medium- and long-term ambitious targets in accordance with the Paris Agreement (PA) ([1]).

The EU intends to reach these targets in a harmonised but differentiated way through all the countries: currently, the directives and regulations about RES, energy efficiency and power markets composing the CEP are at the transposition phase in Italy, which depicted its own energy and climate policies within the PNIEC ([2]). The latter main outcomes show a huge increase of PV installation from th 20.9 GW of 2019 to 52 GW in 2030 ([3]), while decommissioning the coal power plants until 2025 and starting a pilot phase about ECs ([4]) and VPPs ([5]).

The current legislative framework is hence reducing the programmable power plants online and increasing the NPRS power injection, which are more volatile sources: at the same time the need for power reserve is increasing while the available modulation power within the ASM is reducing. The latter was designed during an historical phase in which the Italian energy mix was dominated by conventional power plants, i.e. hydro and fossil fuels power plants: hence, the Grid Code still reflects this structure today, allowing only big programmable units to offer AS ([6]). Indeed, besides some pilot projects such as the UVAM one ([7]), the excluded subjects are the NPRS, the DG and the demand-side: without structurally include them into the AS procurement, the increasingly penetration of solar and wind sources within the national energy mix, as observed during the first pandemic months in 2020, may increase the quantities handled during the ASM, hence the system costs supported by Terna and reflected on the costumers bills ([4]).

In such a context of energy sector decentralisation, aggregation and demand-side empowering, the conception, modelling and planning of the energy systems is changing: higher attention is currently given to the short-term and balancing markets, due to the volatile nature of NPRS ([8]), while the need for new flexibility sources may further investigate the Demand Side Management (DSM) and DR schemes; the introduction of ECs increases the social dimensions attention and integration with the techincal and econmical ones ([9]).

One of the possible new issues to consider resulting from the increasingly diffusion of distributed and aggregated energy entities is the forecasting error of consumption and production, laeding to the so-called effective imbalances. Indeed, the actual grid exchange of PUs and CUs compared to the market programs increases the physical and economic movements within the ASM as described in **Section 3.4**: this can cause higher dispatching costs incurred by the Terna, hence by the end-users, as depicted in **Section 2.4**. Due to the volatile nature of NPRS, imbalance risks are higher for PV: the next spread of ECs and VPPs should hence lead to an increasing regard for their potential imbalances. This thesis draws attention precisely to this, analysing the possible imbalances within a fictitious EC, applying the Italian imbalance settlement. Indeed, when the market programs are not respected, the Balance Responbile Party (BRP)s, i.e. the subjects responsible of the imbalances, settle particular fees with Terna.

The presented work is organised as follows: **Chapter 2** offers a wide overview of the energy transition issues, underlying the main criticalities related to the ECs and VPPs spread, especially about the power markets. In light of this, the thesis objectives are described in **Section 2.5**. Then, the power markets are further thorough in **Chapters 3** and **4** presenting the current structure of the Italian power markets, the main problematic and the possible solution, with a focus on the ASM. A wide analysis of the state of the art is described in **Chapter 5**, considering the 3 main study fields strictly related to the thesis, i.e. the ECs, the DR and the power markets. The methodology and the case study are presented respectively in **Chapters 6** and **7**, while the imbalance settlement results are discussed in **Chapter 8**. Finally, the main outcomes of the work are summarised in **Chapter 9**.

Chapter 2

Context

This chapter provides the general context in which the analysis performed in the thesis lies: the energy transition (see **Section 2.1**). It has many aspects and issues, and the following sections present the ones directly and indirectly related to this work, namely:

1. **Distributed energy entities diffusion**: the ECs and VPPs are spreading in recent years, and togheter with the NPRS constitute an important issue in terms of policies and grid integration (**Section 2.2**).

2. **Demand empowering**: with the spread of the above-mentioned entities, the demand-side is increasing the possibilities for active roles within the power markets (**Section 2.3**).

3. **Power markets changes**: the increasingly ambition of the energy policies makes necessary the opening of the power markets to new entities. (**Section 2.4**).

Finally the chapter concludes with **Section 2.5** explicating the thesis objectives in light of the presented context.

2.1 Energy transition

A valid and succint definition of energy transition is offered by [10]: it is the global transformation from a fossil fuel based energy sector to a zero-carbon one until 2050, by increasingly reducing the energy related emissions to fight the climate change.

The energy transition involves the production, the transport and the consumption of thermal and electric energy. Lots of processes, stakeholders and policies are interested, making this transformation towards a more sustainable energy sector like an ensemble of pathways that intersect with each other and aims at null net-emissions, i.e. $emission - withdrawal$ of GHG, trough several intermediate steps.

These steps are the short-,medium- and long-term energy targets of the worldwide countries: by the purpose of the thesis, the main Italian and European ones are now briefly described.

The energy and climate governance of the EU and the member states was updated between 2018 and 2019, with the adoption of the CEP, that fixes the medium- and long-term targets in this area, respectively until 2030 and 2050: the former are summarised in **Table 2.1**, while the latter are in accordance with the PA objective to keep the global surface average temperature increase well below 2°C in this century wrt the pre-industrial levels, pursuing efforts to not exceed 1.5 °C ([1]).

Table 2.1: UE and Italian 2030 targets depicted by the CEP.

Key target	UE	Italy
GHG emissions reduction [%]	40 (wrt 1990)	33 (wrt 2005)
RES share within the gross final energy consumption [%]	32	30
Energy efficiency improvement (i.e. consumption reduction) wrt 2007 scenario [%]	32.5	43

The GHG target was enhanced to at least 50 % and towards 55 % within the EU Green Deal ([11]), that is the EU plan for making the european economy carbon-neutral ([12]).

The CEP comprises 8 among directives and regulations about RES, energy efficiency and power market, currently at the transposition phase in Italy ([2]). Furthermore, each Member States are called to contribute to the EU targets fixing their own objectives until 2030 within the so-called National Energy and Climate Plan (NECP), namely PNIEC in Italian, whose key targets are the ones of **Table 2.1**.

Focusing now on the PNIEC and on how to reach the above-described targets, the main measures are explained below.

About the energy production, the phase-out of the carbon power plants is planned for 2025, while a huge increase of PV is aimed from the 20.9 GW of 2019 to 52 GW planned for 2030 ([3]).Then, Ricerca sul Sistema Energetico (RSE) in the scenario analysis presented in [5], explores the possibility to reach between 200 GW and 275 GW of installed capacity until 2050, aiming at Italian carbon neutrality. The details of this important PV policies and scenarios are summerised in **Table 2.2**: about 2030 targets some category association as Italia Solare seems to be quite skeptic according to [13], since between 2025 and 2030 it is expected to install 23 GW of PV.

Table 2.2: Italian PV targets from 2019 to 2050 based on PNIEC measures summarised in [14] and on RSE scenarios presented in [5].

Size	2019	2020	2025	2030	2050
PV [GW]	20.9	21.7	28.5	52	200-275
PV/year [GW/y]	-	-	1.4	4.7	7.4-11.15

The installation in 2020 detail is given to show how much indeed the PV installation rate would change in the next decade to reach these targets.

The importance of the rooftop installation, hence of ECs and VPPs, is recognized by [5]: considering the 2050 scenario with 200 GW, RSE forecasts 132 GW of rooftop PV, about the 66 % of the total installed capacity. The final document presented by Italy to European Commission at the beginning of 2020 is considered too generic about the role of the ECs within this process: however the legislation changed just last year, with important news as explained more in detail in **Section 2.2**

2.2 New distributed forms of aggregation: EC and VPP

This section distinguishes among the ECs and the VPPs within 2 separated paragraphs, but with a similar structure: the passagges from the EU legislation to the Italian one are temporally and qualitetvely described, wihtout going into too much detail and pointing out how these new distributed and aggregate energy entities present an increasingly importance in light of the energy transition just presented.

2.2.1 ECs development

The *Renewable Energy Directive 2018/2001*, from now on RED II, and the *Directive on common rules for the internal market for electricity 2019/944*, from now on IEM, belong to the policies within the CEP and depict the legislative framework for the ECs. These directives introduce how these new energy entities should be created and integrated within the power grid and markets: the main concepts are summarised in **Table 2.3**. There are several types of ECs: Renewable Energy Community (REC), Renewable Self-Consumers (RSC), Citizen Energy Community (CEC) and Active Costumers (AC). While RECs and CECs are required to create a legal entity, RSC and AC are less complex and less extended entities. Furthermore, while RECs and RSC activities are quite geographically limited, the other forms of communities have wider range.

Table 2.3: Different types of ECs introduced with the RED II and IEM directives ([9]).

Directive	**EC**	**Energy carriers**	**Activities**
RED II	REC	Renewable energy carriers	Production, consumption, selling
	RSC	Renewable electricity	
IEM	CEC	Electricity	Production, consumption, selling, flexibility offering
	AC	Electricity	

Despite some differences within the legislative definition, the main prerequisite for forming any EC is that, subjects whose main activity is energy-related (e.g.

Distribution System Operator (DSO), energy traders or Energy Service Company (ESCo)), cannot control the community. Then, a general characterisation can be the one offered by [9]:

- **Features**:
    1. Open and voluntary membership for people, small and medium enterprises and/or local authorities.
    2. Primary purpose: provide environmental, economic and/or social community profits instead of financial ones.
    3. Activities: energy production, consumption, sharing and market participation.
- **General purposes**:
    1. Increase the acceptance of new energy projects by the public.
    2. Mobilize more private capital supporting the energy transition.
    3. Increase the flexibility in the market.

The above described directives are currently at the transposition phase, temporally summarised in **Figure 2.1**, while the main steps are briefly described below:

1. **Milleproroghe decree**: introduction within the national legislation of the RECs and RSCs.
2. **ARERA Resolution 318/2020**: resolution about the economic settlement of the energy shared within the RECs and the RSC.
3. **Implementing decree of the Ecnomic Development Ministry**: definition by the Ministero dello Sviluppo Economico (MiSE) of the incentives to the shared energy.

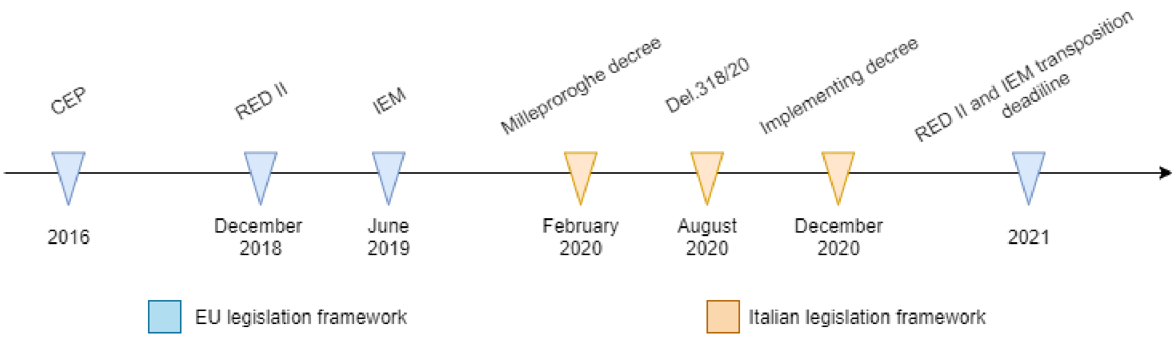

Figure 2.1: Temporally visualization of the EU and Italian legislation frameworks about ECs: figure reprocessed from [4]

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As underlined in [4], before these measures the electric self-consumption was allowed to single user, while from now on an inventive of 20 years is offered to support the spread of these new entities in the ways described below:

- **Incentives**:
    1. *Shared energy*: 100 EUR/MWh and 110 EUR/MWh respectively for RSC and RECs.
    2. *Shared energy*: 9 EUR/MWh for the minor system costs pointed by ARERA.
    3. *Energy injected*: 40-50 EUR/MWh for the dedicated withdrawal by Gestore Servizi Energetici (GSE) or market selling.
- **Constraints**:
    1. *Perimeter*: same building and secondary station respectively for RSC and RECs.
    2. *Size*: maximum 200 kW/system.

For the sake of completeness, the critical issues are now briefly described, since these measures still refer to a first pilot phase. According to [4], the main issues are: the requirements for the ECs to be connected to the Low Voltage (LV) grid and/or under the same secondary substation, limiting the audience of possible participant subjects; the introduction of high efficiency Combined Heat and Power (CHP) as allowed production systems.

Among the Member States and besides Italy, only some countries started the transposition process of the RED II, such as Spain, Belgium, Portugal and France, while the latter is the only one that introduced in the national legislative framework the IEM ([4]).

2.2.2 VPPs development

The ECs aren't the only aggregation forms to deal with energy activities. In particular, the power market is opening in recent years to new flexibility sources, such as DG and VPPs, the latter referred to as UVA in Italy: these entities are decentralised groups of production, consumption and storage units, interconnected and centrally dispatched, while they may remain independent in terms of ownership ([15]).

In other words, trough the VPPs the power markets are open to more flexible and distributed resources: indeed, in Italy the UVA started to be regulated to provide new flexibility in the ASM, given the increasing diffusion of NPRS and the necessity to deal with the power system effects, as it is further explained in **Section 3.3.2**. About this, the Italian dispatching reform started in 2015 with the publication of [16] by ARERA, i.e. the Authority, leading in 2 years to the ASM opening to new subjects, such as the UVA pilot projects: the main legislative steps of the Authority until nowadays are here listed and briefly described. Please note that in the references the ARERA legislation is indicated with *Resolution*, while here is used the shorted form *Del.*, in contintuity with the Italian form *Delibera*.

1. **Del.393/2015/R/eel**: need of an organic reformation within the ASM starting the Electric Dispatching Reform (EDR) project ([16]).
2. **Del.300/2017/R/eel**: opening of ASM to pilot projects indicated by Terna and accepted by the Authority ([17]).
3. **Del.422/2018/R/eel**: approval of the UVAM Regulation [7] proposed by Terna ([18]).
4. **Del.153/2020/R/eel**: approval of the modifications of [7] ([19]).

The first pilot projects introduced by Terna were Unità Virtuali Abilitate di Consumo (UVAC) and Unità Virtuali Abilitate di Produzione (UVAP), while currently they converged as sub-cases within the so-called UVAM [20]. The latter is renewed for the 2021, while other pilot projects are under consultation such as the secondary reserve and the voltage regulation from units not yet enabled: however, they are considered here, while **Table 2.4** summarises the main characteristics of the UVA just presented, while the timeline of the pilot projects introduced by Terna is depicted in **Figure 2.2**. The meaning of CU, PU, as well as the involved AS (e.g. Replacemant Reserve (RR)) is clarified in **Chapter 3**.

The minimum requested power of 1 MW allowed Italy to be one of the leading European countries in the enabling process of distributed resources from 2017 to 2019: according to [21], in 2019 the available capacity was 830 MW, the highest in EU with Belgium, while before the updating of the UVAM regulation for 2021, the aggregated capacity reached 1.4 GW.

Table 2.4: Different types of UVA pilot projects. Table reprocessed from [21].

Pilot project	Units	Minimum requested power	AS	Remuneration
UVAC	CU	From 10 MW to 1 MW	Upward tertiary reserve and balancing	ASM offers, penalties and forward contracts
UVAP	non relevant PU	From 5 MW to 1 MW	Upward and/or downward: -Congestion resolution. -Spinning and RR tertiary reserves. -Balancing.	ASM offers, penalties
UVAM	-UVAC, UVAP. - relevant UP not yet enabled. -Storage systems.	1 MW	The same as UVAP	The same as UVAC

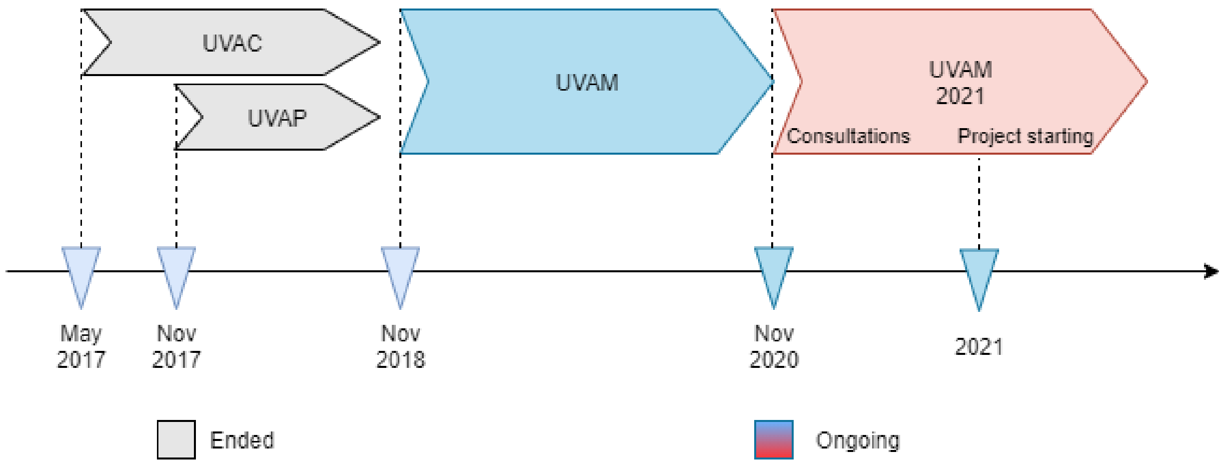

Figure 2.2: Temporally visualization of the Italian legislation frameworks about UVA: figure reprocessed from [5].

Since the effective imbalances belong to the ASM dominion, a further deepening about the UVAM is offered within **Chapter 4**, discussing the main features and requirements needed by these new entities for their enabling to the ASM.

2.3 DR generalities

The reduction of the effective imbalances within a certain production or consumption portfolio can be performed by the BRP through RT adjustments: the internal balancing or re-balancing described in [22] is very similar to the DR mechanisms, for which an overview is offered in this section.

An exhaustive definition of the DR is the one of the American Department of Energy reported by [23]: "a tariff or program established to motivate changes in electric use by end-use customers, in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized." The DR programs are hence energy management strategies: while [23] considers the DR as a part of the DSM, several articles presented in [24] distinguish them from the time horizon point of view. Indeed the DR may refer to short-term consumption adjustments lasting from some minutes to some hours, while the DSM may refer to the energy efficiency of the end-users in the long-term.

Beyond these definitions and differences, one of the main distinction among the DR programs refers to the offered motivation ([23]), leading to the so-called price-based and incentive-based schemes, whose main characteristics are briefly described below:

- **Price-based**: the programs offer time-dependent electricity prices, with the aim of making them consume less electricity when prices are high, i.e. during peak hours. The main ones are:

1. *Time of Use (ToU)*: flat tariffs in different time periods, e.g. off-peak, mid-peak and peak hours.
2. *Critical Peak Pricing (CPP)*: similar to ToU, but the price may change during at least one period, e.g. when the grid reliability is at risk.
3. *Peak Load Pricing (PLP)*: different prices for different periods determined the day ahead.
4. *Real Time Pricing (RTP)*: different prices for different periods determined near the RT, e.g. 15 minutes before the time period.

- **Incentive-based**: the programs offer fixed and/or time-varying incentives for adjustments during system stress periods. In some cases penalties are present for non respecting the scheme. The main ones are:

  1. *Direct Load Control (DLC)*: cycling or turning off the costumers' electrical appliances, e.g. air-conditions and water heaters. These programs are usually offered to residential or small commercial consumers.
  2. *Interruptible/Curtailable load (I/C)*: curtailment of a certain part/total load during system emergencies. These schemes are usually offered to larger customers, from 200 kW up to 3 MW of consumption, in terms of bills discount.
  3. *Emergency Demand Response Programme (EDRP)*: sort of market-based programs for reducing the consumption during reliability triggered events.
  4. *Demand Bidding (DB)*: usually curtailment offers within the wholesale power market.

A DR scheme for reducing the internal imbalances doesn't exists, as it's pointed out in **Section 5.2**: however, a particular pricing scheme of the imbalance settlement is considered non penalizing, as it is explained in detail in **Section 3.4**.

2.4 Power markets changes

The changes discussed in this section refers both to the new legislation on the power markets and the prices and quantities handled within them in recent years.

2.4.1 Legislative framework

The future guidelines about the power markets, in particular referring to the electric dispatching, are offered by ARERA in the consultation document [25] and they are resumed in 2 macro-objectives:

1. **AS**: structural changing within the AS procurement, in light of the increasingly spread of NPRS and DG and of the European 2030 targets.

2. **European markets integration**: complete integration of the power markets within the EU, with particular attention to the IDM coupling and the harmonization of the ASM.

These changes are dictated by the European legislation on power markets, whose framework involve the *Capacity Allocation and Congestion Management (CACM) Regulation* about the DA and ID markets organization, the *Balancing Regulation* about the AS exchange between the European TSOs, the *IEM Directive* that fouces on the new distributed entities and the new possible roles for the DSO, and finally the *IEM Regulation* banning any upper and lower limits to the electricity prices, allowing hence negative prices.

The main proposed changes to cite for the purposes of this thesis involve the timing of the power markets participation, the opening of the ASM to new resources and the evolution of the DSO role, as explained below:

1. **Power market participation and timing**: postpone the IDM gate closure one hour before the RT and introduce negative prices for DA and ID markets.
2. **ASM**: guarantee the maximum ASM participation potentially to each units, introduce the System Marginal Price (SMP) instead of the current PAB scheme, use 15 minutes as the relevant period also for non-enabled units (see **Chapter 3**) and build the imbalance prices for the imbalance settlement in a zonal mode instead of the actual macro-zonal (see **Section 3.4**).
3. **DSO new role**: make more active the distribution grid management by the DSOs, introducing local AS, i.e. a sort of ASM on a distribution level.

It's clear how the diffusion of DG, ECs and VPPs must be integrated within the power grid through wide and relevant structural changes of the power markets, since some effects are already visible in the prices and handled quantities in recent years, as descibed in the following paragraph.

2.4.2 Prices and moved quantities changes

The spread of DG, hence NPRS, influences both the power grid reliability and the power markets prices: a good way to visualise what may happen in the next years is to show the effect of the first lockdown during 2020, caused by the Coronavirus pandemic.

The relevant consumption reduction during the Spring 2020 caused a production decrease, pursuing the NPRS within the Italian energy mix at the expense of fossil fuels. According to [4] the higher penetration of PV and wind compared to the previous year had 2 main effects: a reduction of the SMP, the Italian Unique National Price (PUN), and the average ASM prices from one hand, an increase of the handled ASM quantities and the management grid costs from the other one. The above described events chain is quantified in **Table 2.5**.

Table 2.5: Pandemic effects on the Italian power markets and comparison with the same period of 2019. The considered months are March,April and May and the data are taken from [4].

Covid effect	Effect quantification	Comparison wrt 2019
Consumption reduction	Energy esxchange on DAM= 62 TWh	-12 %
NPRS share increase	-PV share: 13 %	-PV: +4%
	-Natural Gas (NG) share: 36 %	-NG: -7%
PUN reduction	-Average PUN= 30 EUR/MWh	-50 %
ASM prices reduction	-Downward prices= 5-10 EUR/MWh	-(60-70)%
System costs increase	-System costs= 829 millions of EUR	+54 %

The exceptional nature of the pandemic made the above mentioned changes quite sudden, but not unexpected: indeed, in recent years the quantities handled in the ASM increased, as well as the system costs supported by Terna and hence by the community within the bills, i.e. through the so-called DC. And considering the energy policies presented in **Section 2.1**, wihotut opening the AS procurement possibility to new subjects, this costs increase may continue in future: indeed, the increasing power injection from NPRS mainly causes more volatility in energy production and less availability of the conventional power plant (e.g. the coal-based power plants are the third AS provider after NG and pumping hydro-power ones, and the phase out is planned for 2025). This situation decreases the reliability grid, and about this Terna bases its grid management on 5 key dimensions, briefly described below:

1. **Adequacy**: system capable to supply the expected demand with suitable production, storage, capacity transport and demand control.

2. **Security**: system capable to support sudden working state changes, without exceeding grid leakage limits. The capacity of the system to support an imbalance between production and consumption in the first time instants after the occurring is called grid inertia.

3. **Resilience**: system capable to come back to nominal working state after system leakage limits overcoming. This dimension is fundamental in the new energy and climate scenario, with more frequent metheorlogical extreme events.

4. **Quality**: system capabale to offer a continuative service.

5. **Efficiency**: system management at the minimal possible costs for the community.

In light of the above-mentioned criteria, the main implications of the increasing NPRS penetration power system management are summarised **Figure 2.3**, while more details on the critical issues related to expected power system evolution are explained in **Paragraph 3.3.2**.

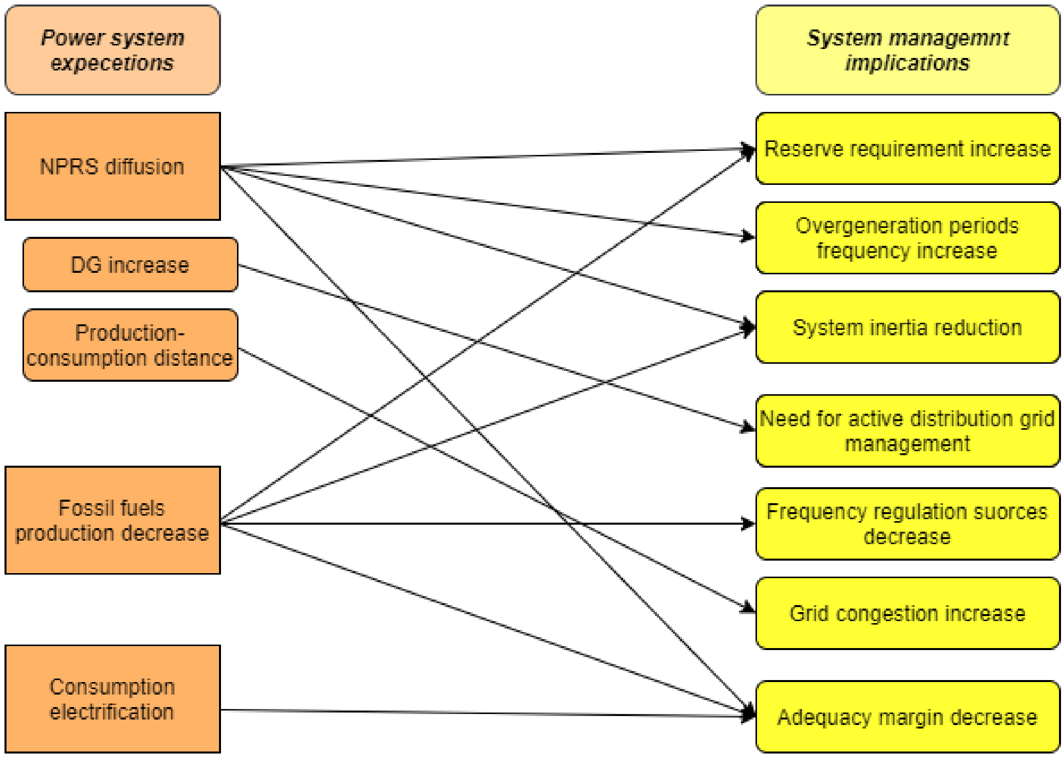

Figure 2.3: Overview of the system implication of the expected power system evolution: figure reprocessed from [4]

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2.5 Thesis objectives

The main thesis purpose is to quantitatively and qualitetevly estimate the possible effective imbalances of a fictitious aggregation of thousands of households, owning several PV rooftop systems. This entity is generally called EC, without stressing too much on the aggregate configuration typology and on the sizing of the PV (e.g. ESS are not considered): however, right this flexibility allows further and future analysis by declining this aggregate of CUs and PUs by the meaning of the different existing ECs configuration (e.g. RSC) or of the Terna pilot project UVAM.

The value of the work is increased by the fact that in literature the effective imbalances issue is not yet treated involving these new entities: indeed, the found state of the art mainly focuses on the legislative framework, the PUs imbalances, with a few cases involving the end-users and just one thesis that considers one consumer with PV and batteries, i.e. a so-called prosumer.

Having in mind this, the thesis aims to estimate how much an EC may imbalance the system in terms of energy and monetary fluxes along a whole year, providing:

- A clear picture of the Italian imbalance settlement principles.
- An analysis of the last trends within the ASM quantities and prices strictly related to the imbalance settlement.

- A general coding structure that can be easily integrated in future with an actual case study.
- Absolute results in terms of yearly imbalances and corresponding charges.
- Relative results in terms of indicators, to better visualise the potential impacts changing the size of the EC.

Chapter 3

Power markets

After introducing the power markets in **Paragraph 2.4** and **Section 2.4**, this chapter is devoted to explain how they works, with a particular focus on the ASM, since the imbalance settlement belongs to its dominion. First, an overview on the markets stakeholders and on the markets working is presented in **Section 3.1**, then the DA and ID markets are briefly described in **Section 3.2**. **Section 3.3** involves a more detailed explanation of the ASM offered, while the imbalance settlement process is presented in **Section 3.4**.

3.1 Power markets: overview

The Italian power market, also known as Italian Power EXchange (IPEX), consists of several markets, as depicted in **Figure 3.1**. Energy and AS are there negotiated in a ruled way and within different sessions and timing, as pointed below:

- **Spot market**: the Italian Mercato Elettrico a Pronti (MPE) hosts the daily buying and selling of energy within the DAM, namely Mercato del Giorno Prima (MGP), the IDM, namely Mercato Infra-giornaliero (MI) and daily energy products, namely Mercato dei Prodotti Giornalieri (MPEG), and the buying and selling of AS within the ASM, namely Mercato dei Servizi di Dispacciamento (MSD).

- **Forward energy market**: the Italian Mercato Elettrico a Termine (MTE) hosts the forward contracts signing.

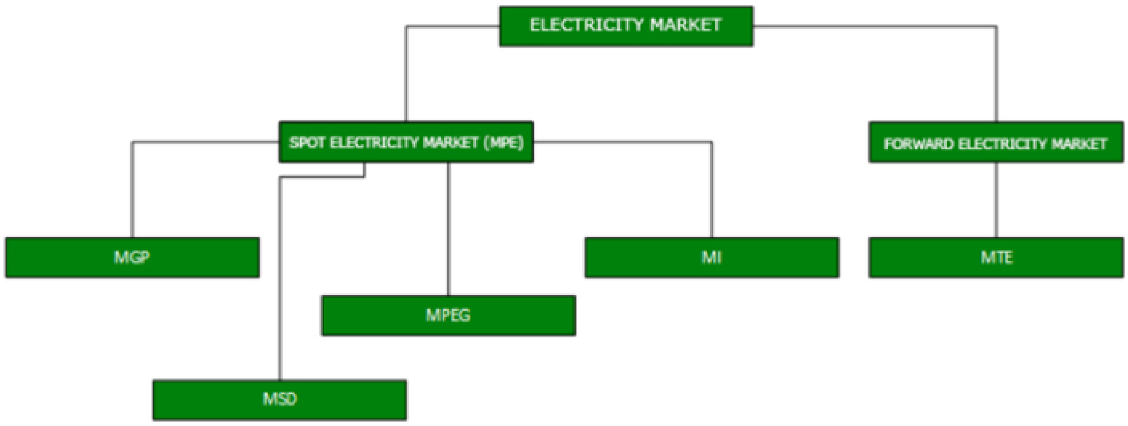

Figure 3.1: Structure of the Italian power market: figure taken from [26]

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Besides the MSD in which AS are traded, the other markets are qualified as energy ones. Furhermore, bilateral contracts called Over-the-counter (OTC) contracts can be traded outside the IPEX, but they still contribute to the market prices formation within the energy markets ([27]). Before describing the general working of the IPEX, hereafter are reported the main decision-making bodies of the power markets:

- **ARERA**: public authority that regulates and oversees activities in the sectors of electricity, natural gas, water services, waste cycle and district heating.
- **GSE**: society owned by MiSE that incentives and pursuits the RES penetration.
- **Gestore Mercati Energetici (GME)**: society owned by GSE that manages the IPEX, the NG market and the environmental ones.
- **Terna**: unique Italian TSO that manages the ASM.
- **Acquirente Unico (AU)**: society owned by GSE that buys electricity in the captive market.

A snapshot of the IPEX trading is shown in **Figure 3.2**: the arrows refers to the commercial programs, i.e. the selling and the purchases, that as explained in the next sections can be performed by both the production- and consumption-side. The black arrows involves the DAM and IDM, the red ones refers to the ASM, while the blue ones indicate the OTC contracts. Final costumers can directly or indirectly participate to the energy markets, while only enabled units may offer AS within the ASM. In the former case, the participation is indirect when a provider buys the needed energy and then sell to the final costumers. Currently there are two types of costumers:

- **Captive costumers**: they belong to the so-called captive market, since their providers are the the local distributors that sell, at tariff fixed by ARERA, the electrictiy bought by AU. The captive market end was recently extended to 2023 ([28]).
- **Eligible costumers**: they belong to the so-called free-market, since they can choose their own electricity provider, namely the wholesaler. The free-market was born in 2004 with the IPEX as a result of the power market liberalisation process started in 1999 [26].

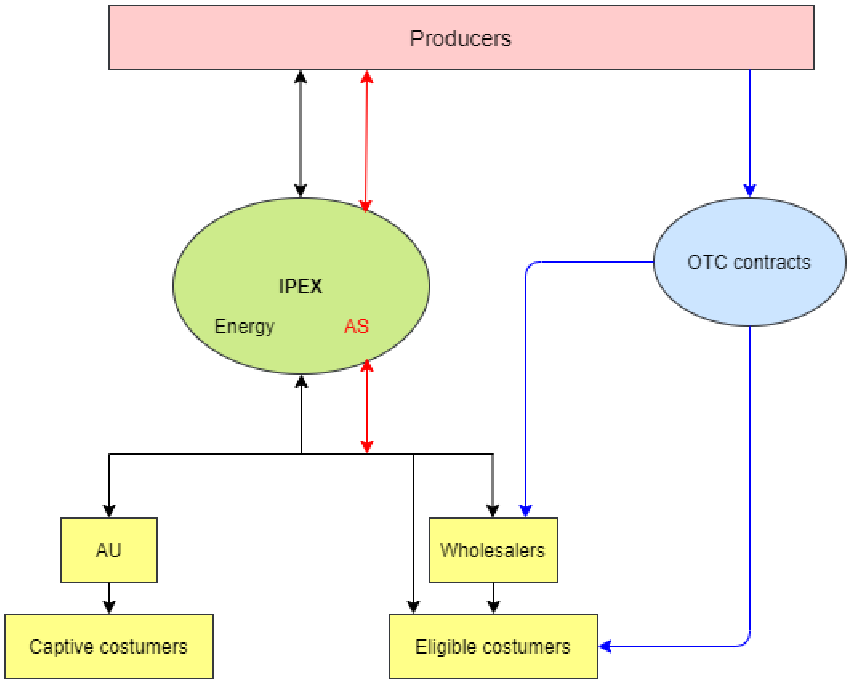

Figure 3.2: Structure of the Italian power markets: figure reprocessed from [27]
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3.2 DA and ID markets

For the DAM and IDM Italy is divided into geographical and virtual zones, reflecting the physical transit limits on the transmission line: indeed, a grid congestion may born if the interconnection between two zones doesn't allow all the energy exchanges derived from the markets outcomes, because of the exceeding of the transport capacity limits. To the zones shown in **Figure 3.3**, must be added *Montenegro* as foreign virtual zone and *Rossano* as national virtual zone, according to [29].

Each zone is composed of many injection and withdrawal offers points, that themselves may be single production/consumption units or aggregate of them: each offer point corresponds to hourly energy programs that should be respected during the RT ([27]).

Figure 3.3: Zones of the DA and ID markets ([27])

.

The majority of IPEX transactions occurs during the DAM ([26]): from now on the day related to the markets offers is indicated with D (e.g. one day ahead D is D-1). The only session of DAM starts D-9 and ends at 12:00 D-1, with the outcomes publication not before 12:55 D-1. The offers are a couple price-energy and the ones accepted defines the preliminary cumulative hourly programs.

The outcomes are defined considering a merit-order criterion and the transmission capacity limits between zones. For each zone and for each hour of D the sales offers are increasingly ordered, while the purchases ones are decreasingly ordered: the intersection point determines the equilibrium quantity and price, the latter called zonal price, from now on P_{DA}, i.e. the System Clearing Price (SCP). This auction system is depicted in **Figure 3.4** and aims to minimising the system costs: furthermore, the OTC sales contracts are considered at null price, the purchases contracts are considered without price, but both have the highest priority if the capacity limits are respected.

The remuneration follows the SMP scheme: each sales offers below the SCP is accepted and payed at P_{DA}, while each purchases offers above the SCP is accepted and must pay the so-called PUN, i.e. the average zonal price weighted for the quantities purchased in the zones.

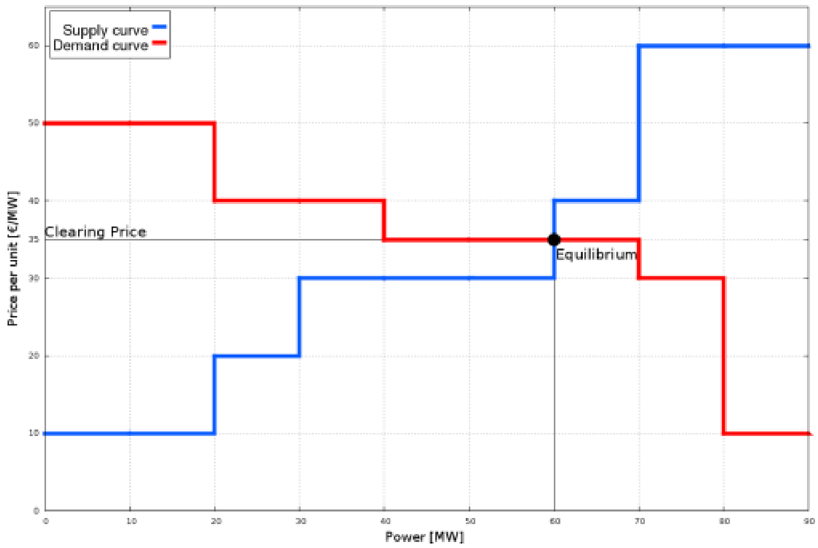

Figure 3.4: DAM clearing scheme ([30])

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During the IDM the participants can modify their DA position by further offers: producer may sell additional energy or purchase a reduction injection, while a consumer may sell a consumption reduction or buy additional energy. The auction scheme is the same as the DAM, while the purchase offers are valued at P_{DA}. The accepted offers modify the preliminary positions into the cumulative updated hourly programs, while the transit limits between the zones may change.

There are 7 sessions, starting at D-1: the first 3 close at D-1 as well, while the other closures are distributed along D. A detailed descrpition of the timing of DA, ID and AS markets is offered in **Table 3.1**.

3.3 ASM

The ASM is regulated by Terna as depicted in chapter 4 of the *Grid Code* [31], the latter defined in [32] as "The Transmission, Dispatching, Development and Grid Security Code governs the procedures which Terna must adopt in relation with grid users". Indeed, since the electricity cannot be stored in huge amount, Terna must assure the balancing between injections and withrawals, procuring the so-called AS.

Before describing the working of this market, it may be important to present some definition from [31]:

- **BRP**: the subject that signs a dispatching contract with Terna. This user is hence allowed to exchange electricity with the High Voltage (HV) grid and has a balance responsbility in the sense that it should respect the commercial position at the closure of all the markets, during the RT. Each commercial position corresponds to injection and/or withdrawal dispatching points.

- **Balance Service Provider (BSP)**: the subject that is allowed to offer AS to the ASM.

- **PU**: one or more production units under the same BRP. The PUs are registerd into the Gestione Anagrafica Unica Degli Impianti (GAUDI) and they have a corresponding CU.
- **CU**: one or more consumption units under the same BRP. The CUs are registerd into the Registro delle Unità di Consumo (RUC).
- **RU**: PU with nominal power $P \leq 10MWV$. The Relevant Unit (RU)s are registered into the Registro delle Unità di Produzione (RUP) and they have their own dispatching point.
- **Relevant period**: time period against which the BRP has the right and the obligation for exchaning electricity with the HV grid. Hence, this period is the minimum one against which the ASM programs are build for the BSP. It results 15 min, from now on q, for the RU and 1 h for the units not allowed to participate to the ASM.

During the ASM, the TSO ensures the resolution of intra-zonal congestion, the creation of power reserves and the real-time balancing, for the managing and the control of the power grid, allowing the system stability.

Currently the only units allowed to participate to the ASM are the RUs that are not supplied by NPRS: the accepted offers of the operators are remunerated by the TSO in the way PAB, i.e. at the offered price., aiming to minimise the system costs.

The ASM is divided into 2 parts, each consisting in 6 sessions, as described below

- **Ex-ante ASM**: it is referred to as MSD in Italy. This market is used for the congestion resolution and power reserves procurement. The offers are presented all in the first session at D-1 and the ones valid are then accepted during the other sessions: e.g. in MSD2 are accepted the valid offers referred to the period 04:00-24:00 of D. The accepted offers transform the cumulative hourly programs exiting the IDM session into the binding programs.
- **Balancing Market (BM)**: it is referred to as Mercato di Bilanciamento (MB) in Italy. This market is used for the real-time balancing: the first session uses the valid offers made during MSD1 and referred to 00:00-4:00, while the other valid offers are accepted during D near RT: e.g. MB2 closes at 03:00 and handles offers referring to 04:00-08:00. The accepted offers transform the binding programs exiting the ex-ante ASM session into the modified binding programs. In case a particular AS called *Secondary reserve* is used, the latter programs become modified and correct binding programs. The modified, in case correct, binding programs are the ones compared with the RT grid exchange by the BRP and later one are referred to as more generally *BM programs*.

The detailed timing of ASM sessions are linked to the IDM ones in **Table 3.1**, using the Italian nomenclature and putting together the sessions whose lower limit referred period is the same.

In the following paragraphs a more detailed description of the AS procurement and of the so-called imbalance settlement is instead provided.

Table 3.1: Sessions timing of IDM and ASM, using the Italian nomenclature ([33]).

Sessions	Opening	Closure	Outcomes	Period
MI1	12:55 *	15:00 *	15:30 *	D
MI2	12:55 *	16:30 *	17:00 *	D
MSD1	12:55 *	17:30 *	21:45 *	D
MB1	-	-	-	0–>4
MI3	17:30 *	23:45 *	00:15	4–>24
MSD2	-	-	02:15	4–>24
MB2	22:30 *	03:00	-	4–>8
MI4	17:30 *	03:45	04:15	8–>24
MSD3	-	-	06:15	8–>24
MB3	22:30 *	07:00	-	8–>12
MI5	17:30 *	07:45	08:15	12–>24
MSD4	-	-	10:15	12–>24
MB4	22:30 *	11:00	-	12–>16
MI6	17:30 *	11:15	11:45	16–>24
MSD5	-	-	14:15	16–>24
MB5	22:30 *	15:00	-	16–>20
MI7	17:30 *	15:45	16:15	20–>24
MSD6	-	-	18:15	20–>24
MB6	22:30 *	19:00	-	20–>24

**This time refers to D.*

3.3.1 Ancillary services and requirements

The several AS required by the TSO for ensuring the RT equilibrium between production and consumption, hence for assuring the secure management of the power grid are summarised in **Table 3.2**: while some services are traded during the ASM, other ones must be necessarily supplied by particular units or can be procured outside the market.

A first difference refers to the direction of the regulation:

- **Upward**: increase of injection or decrease of consumption when there is respectively a consumption surplus and a production deficit.
- **Downward**: decrease of injection or increase of consumption when there is respectively a consumption deficit and a production surplus.

The traded services are provided through 2 kind of products: a dedicated offer for the secondary reserve, and a more general offer for other services. The latter are further articulated: e.g. set-up change or shutdown ([6]).

Table 3.2: AS needed by Terna for the grid stability; re-elaboration from [20] and [34].

AS	Actions	Porpuses	Market sessions
Primary power reserve	Automatic active power upward or downward modulation	Stop grid frequency variation	No
Primary voltage reserve	Automatic reactive power modulation	Combat a local voltage change	No
Secondary voltage reserve	Automatic reactive power modulation	Combat a regional voltage change	No
System recovery	Autonomous starting without external supply	Combat a wide blackout	No
I/C and Telescatto	CU and PU automatic disconnection from the grid	Combat system emergencies	No
Secondary power reserve	Automatic active power upward or downward modulation	Bring back the grid frequency to the nominal value	ex-ante ASM
Tertiary power reserve	Manual active power upward or downward modulation	Restore the secondary reserves	ex-ante ASM
Congestion resolution	Modify the cumulative updated programs (post IDM)	Solve the intra-zonal congestion	ex-ante ASM
RT balancing	Modify the BM programs	Ensure the balancing between injections and withdrawals, solve the residual congestion and restore the secondary reserve margin	BM

The AS are hence needed for the grid stability in case of sudden disturbances, that can cause the changing of the nominal grid parameters such as the frequency and the voltage: **Figure 3.5** shows the frequency regulation trough the above-mentioned reserves wrt the timing intervention, in case of generation units loss. The European nomenclature involves Frequency Containment Reserve (FCR) for the primary reserve, automatic Frequency Restoration Reserve (aFRR) for the secondary one, manual Frequency Restoration Reserve (mFRR) and RR for the tertiary ones, while the grid inertia effect is omitted. The latter is the capacity of the system to resist in the first time instants to an imbalance between production and consumption: it is offered by the rotating generators connected to the grid and it manifests itself with a big and rapid power increase that delays the frequency change. Furthermore, balancing and congestion resolution resources may be used after the nominal frequency restoration ([34]).

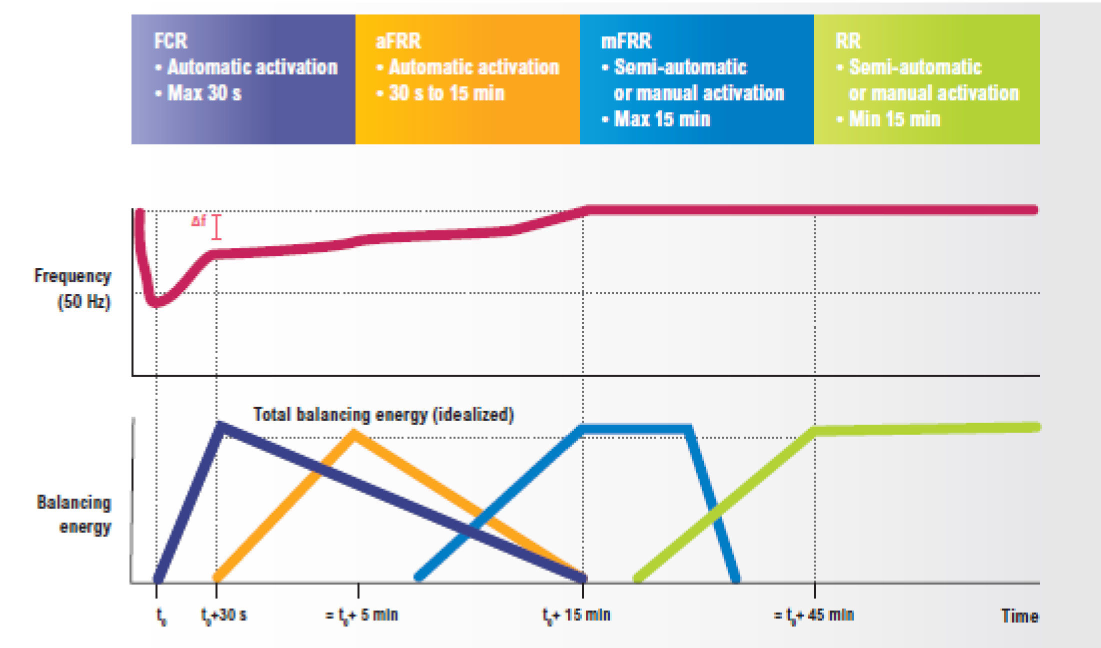

Figure 3.5: Frequency restoration wrt timing intervention ([35])

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The minimum requirements for accessing the ASM reflect the electric system asset of the years of their definition: the majority of PU were conventional programmable plants and the CU were not so flexible. Indeed, besides the specific features required for each AS, the minimum requirement for providing AS is to be a RU, but not supplied by solar or wind sources: hence, despite the pilot projects presented in **Paragraph 2.2.2**, single non relevant units, NPRS and the demand-side are actually left out of the ASM [20].

Without a structural opening of the ASM to new flexibility resources, the current situation may decrease the system stability as further investigated in the next paragraph.

3.3.2 Current critical issues and their overcoming

The increase of NPRS due to decarbonization policies is leading to significant changes in both the national energy mix and the ASM: an overview is given in **Figure 3.6**. The increasing power injection from NPRS causes the reduction of the production from conventional power plants, that coincide with the programmable RUs (i.e. fossil fuel and hydro power plants). There is a double negative effect: an increasing volatility in energy production, hence an increase in reserve need, but a decrease in the availability of the plants more capable to offer regulation services (e.g. difficulties occur especially in load-following ramps when the PV production is falling down). Hence, the start-ups of more flexible sources increase, as well as the associated costs, while the absence of down (up)-regulation sources in production (consumption), forces the NPRS curtailment and/or a decrease in the import.

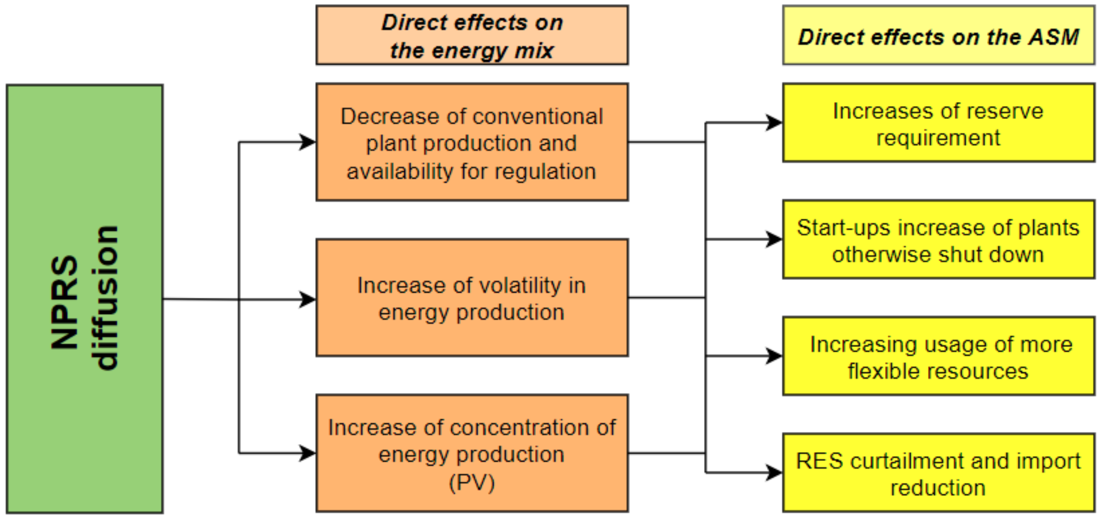

Figure 3.6: Current ASM critical issues due to the increasing NPRS diffusion: figure reprocessed from [20]

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Of course, these conditions have impacts on the DCs, hence on the final users' prices as shown in **Section 2.4**. However, the solution for overcoming the above described criticalities are present and currently object of some pilot projects, but need a further important boost for a complete and more rapid development, as pointed out in the below.

Besides the pilot projects presented in **Paragraph 2.2.2**, the current ASM opening is depicted in **Figure 3.7**.

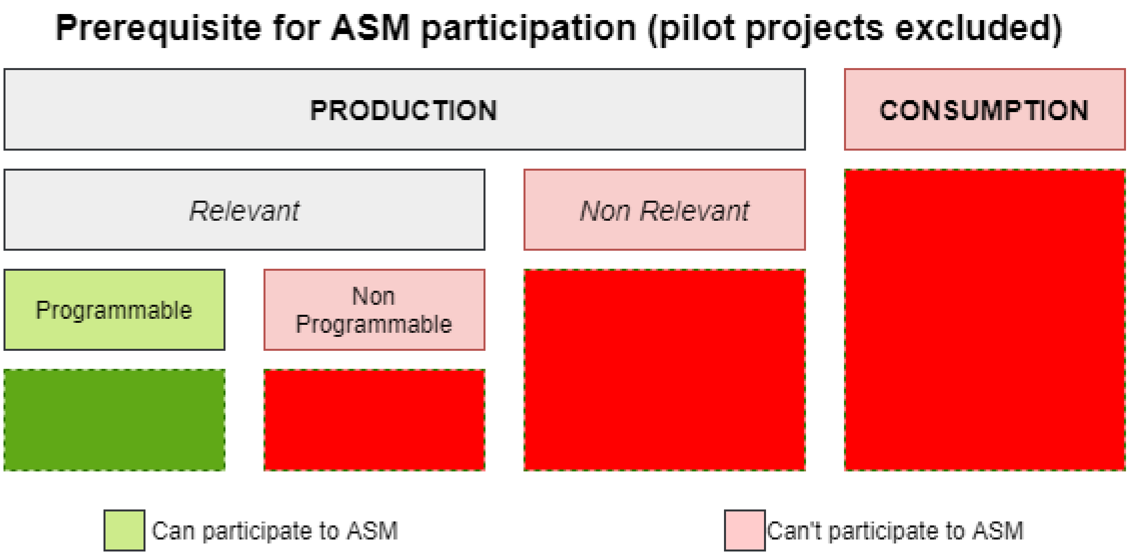

Figure 3.7: Current ASM prerequisite excluding the pilot projects: figure reprocessed from [20]

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In light on the criticalities deriving from the increasing spread NPRS, it appears more and more evident and urgent the need for structurally opening the ASM to new resources, since they have an important potential as described below ([20]):

- **Relevant NPRS**: they may offer downward modulation.
- **DG**: the programmable ones may offer both upward and downward modulation, while for the non programmable ones, hence PV and wind connected to the distributed generation (e.g. supplying the ECs or VPPs) it's the same as the relevant NPRS.
- **Storage**: they may offer with almost null timing both upward and downward. A critical issues could be the system capacity.
- **Demand-side**: they are comparable to the programmable production units and furthermore they can have rapid modulation response.

However, several difficulties may arise, as well described in [20]: NPRS can incurr in economic barriers, since the incentives and the almost null operating costs may discourage to offer downward modulation; CHP systems may not always have modulation capability since they are usually sized based on the associated users, incurring hence in technological barriers; finally, the seasonality of some systems such as district heating can clashes with offers constraints, incurring hence in regulatory barriers.

The overcoming of the criticalities and of these barriers is under analysis with several pilot projects, as preliminary phase of a structural change in the Italian power system. About this, **Chapter 4** focuses on the UVAM pilot project.

3.4 Imbalance settlement

The imbalances analysed in this thesis are the so-called effective imbalances, ruled within several ASM regulations, briefly described in **Table 3.3**: these imbalances are associated to each BRP in terms of physical and economic settlement.

The former is the difference between the actual energy exchanged with the grid and the BM program, hence it is evaluated after the closure of all the markets, both the energy and the AS one. Since the imbalanced energy has not been traded, it is valued trough an imbalance price, that quantitatively depends on the balancing costs in the belonging market zone of the BRP.

Hence, the imbalance settlement involves also monetary exchanges between Terna and the BRP, leading both of the them to gain and losses, as explained more in detail in the following paragraphs.

Table 3.3: ASM legislation behind the actual imbalance issue.

Regulation	Legislator	Purposes
[36]	ARERA	Dispatching operations: conditions and services procurement
[37]	ARERA	Physical and economic settlement within the ASM
[38]	Terna	Economic settlement related to the dispatching and transmission services

3.4.1 Physical settlement

The physical settlement is the algebraic sum between the BM programme, with the changed sign, and the real grid exchange ([36], art.23): to clarify this formulation, **Table 3.4** summarises the sign convention adopted by ARERA in [36].

Table 3.4: ARERA resolution sign convention ([36], art.13).

>0	<0
Purchase	Sale
Injection programme	Withdrawal programme
Actual injection	Actual withdrawal

Despite the sign differences between the PU and the CU, this convention leads to an unique definition of the effective imbalance sign: a positive (negative) imbalance means a surplus (deficit) of energy on the grid, caused by an increase (decrease) of injection by the production side and/or a decrease (increase) of withdrawal by the consumption one.

The physical settlement defined by [36] matches the convention adopted by Terna in [38] and in this thesis: indeed positive quantities are used and the imbalance is computed as a difference, instead of the algebraic sum mentioned. In particular, the programme is here defined as FO, the actual energy as RT and the effective imbalance as Imb_{BRP}. A summary of the physical settlement convention pursued in the thesis is given in **Table 3.5**: to respect the legislations sign convention, RT and FO are positive for both PUs and CUs.

Table 3.5: Effective imbalance sign convention adopted in the thesis and complying with the ARERA and Terna regualtions.

Units type	Imb_{BRP} formula	$Imb_{BRP} > 0$	$Imb_{BRP} < 0$
PU	$RT - FO$	Higher actual production	Lower actual production
CU	$FO - RT$	Lower actual consumption	Higher actual consumption

The imbalances are settled between Terna and the BRP in terms of fees, whose direction is defined by the units imbalance sign: indeed, the BRP is payed by Terna for surplus in production and deficit in consumption, while vice-versa Terna is the creditor.

3.4.2 Economic settlement

Terna determines the imbalance fees (or imbalance charges), from now on $ImbC$, for each BRP by daily computing the effective imbalance economic settlement: it is the algebraic sum between the economic value of the physical settlement, as defined in [38], and the fees already settled between the parts, with positive sign for payments from the BRP to the TSO, and vice-versa ([36], art.21). This rule leads to an unique definition of the fees direction:

- $\boldsymbol{ImbC > 0}$: Terna pays the BRP, that is creditor for the surplus of energy produced or for the deficit of energy consumed.
- $\boldsymbol{ImbC < 0}$: the BRP pays Terna, that is creditor for the deficit of energy produced by the PU or for the surplus of energy consumed by the CU.

The next step is to understand how much the effective imbalances are valued, i.e. how the imbalance price P_{imb} is chosen. The main current schemes are here briefly described ([39]):

- **SP**: P_{imb} depends only on the so-called zonal aggregate (or macro-zonal) imbalance sign, from now on Imb_{MZ} sign. It is applied to the CUs and to the non-relevant programmable PUs. Furthermore, it is the scheme suggested by European Network of Transmission System Operators for Electricity (Entso-e) ([40]).
- **DP**: P_{imb} depends on both Imb_{MZ} and Imb_{BRP}. It is applied to the RUs and it is penalising.
- **NPRS**: these units can choose between the single pricing applied to all the effective imbalance, or an alternative scheme. The latter provides a single pricing only if the imbalance exceeds of a certain fraction the BM programme: this fraction depends on the source type, such that the higher the volatility the higher the fraction ([36], art.40).

The imbalance fees are then computed as

$$ImbC = Imb_{BRP} \cdot P_{imb} \tag{3.1}$$

Before going into details of the meaning of penalising, it is appropriate to define Imb_{MZ}: according to [38], it is computed for each MZ as

$$Imb_{MZ} = \sum_{CU} FO_{CU} - \sum_{PU} FO_{PU} - Exchange \tag{3.2}$$

- $\boldsymbol{\sum_{CU} FO_{CU}}$: BM programmes of all the CUs within the MZ.

- $\sum_{PU} \boldsymbol{FO_{PU}}$: BM programmes of all the PUs within the MZ.
- ***Exchange***: exchanged fluxes with the neighboured MZ and/or foreign zones (positive if incoming)

In simple terms, Imb_{MZ} is the energy procured by Terna during the ASM, and it has the same sign convention of the effective imbalance.

Given a certain BRP, the possible imbalance prices for each relevant period are summarised in **Tables 3.6** and **3.7**: P_{up} and P_{down} are the macro-zonal average BM prices weighted respectively on the sells and on the purchases within the belonging MZ, while P_{DA} is the DAM selling price within the belonging zone.

Table 3.6: Definition of the imbalance price: SP.

Imbalance price		Imb_{MZ}		*Payment direction*
		≥ 0	<0	
Imb_{BRP}	>0	$\min(P_{down}, P_{DA})$	$\max(P_{up}, P_{DA})$	TSO → BRP
	<0	$\min(P_{down}, P_{DA})$	$\max(P_{up}, P_{DA})$	BRP → TSO

Table 3.7: Definition of the imbalance price: DP.

Imbalance price		Imb_{MZ}		*Payment direction*
		≥ 0	<0	
Imb_{BRP}	>0	$\min(P_{down}, P_{DA})$	P_{DA}	TSO → BRP
	<0	P_{DA}	$\max(P_{up}, P_{DA})$	BRP → TSO

Usually $P_{down} < P_{DA} < P_{up}$ and $(P_{DA} - P_{down}) < (P_{up} - P_{DA})$, with very high differences sometimes ([41]): the imbalance fees can then become rewards or penalties, namely gains or losses compared to the case without effective imbalances. Behind this statement there is a physical meaning: when $Imb_{MZ} > 0$, Terna procured more downward resources during the ASM, with helpful effective imbalances only if $Imb_{BRP} < 0$. While in SP the fees can be both rewards or penalties, in DP only penalties: since no gains are possible compared to the case without imbalance, this scheme is defined penalising. These concepts are schematised in **Tables 3.8** and **3.9**: hence, the imbalance payoffs, using the term from [42], are

$$ImbP = Imb_{BRP} \cdot (P_{imb} - P_{DAM}) \tag{3.3}$$

- **CU**:$P_{DAM} = PUN$
- **PU**:$P_{DAM} = P_{DA}$

Table 3.8: Payoffs qualitative value: SP.

Imbalance payoffs		Imb_{MZ} ≥ 0	Imb_{MZ} <0
Imb_{BRP}	>0	Low penalty	High reward
	<0	Low reward	Low penalty

Table 3.9: Payoffs qualitative value: DP.

Imbalance payoffs		Imb_{MZ} ≥ 0	Imb_{MZ} <0
Imb_{BRP}	>0	Low penalty	No reward
	<0	No reward	High penalty

The effective imbalances refer to each relevant period of the day, but the settlement is performed after their aggregation, with the following timeline:

- **Daily**: Terna computes the economic settlement by the end of all the DAM sessions.([36], art.21).
- **M+1**: by the last day, Terna makes available to the BRP the *ImbC* ([37], art.22).
- **M+2**: the fees are settled (i.e. the payments are executed) around mid-month ([37], art.22).

3.4.3 Effective imbalances: other fees and bill costs

The imbalances just presented are related to other fees about the arbitrage. Generally speaking, the arbitrage is an operation providing for purchasing (selling) something on a market and selling (purchasing) it on another market, by gaining from the price differences between the two markets. In this context, Terna and the BRP settle 2 non-arbitrage fees, from now on NAC:

- $\boldsymbol{NAC}$: it considers the price differences between the zonal P_{DA} and the national PUN.
- $\boldsymbol{NAC_{MZ}}$: it considers the price differences between the zonal prices and the macro-zonal ones, since the ASM works trough MZs division. The macro-zonal price P_{MZ} in question is the average zonal price among all the zone within the reference MZ, weighted on the relative binding withdrawal programme ([38]).

$$NAC = -Imb_{BRP} \cdot (P_{DA} - PUN) \tag{3.4}$$

$$NAC_{MZ} = Imb_{BRP} \cdot (P_{DA} - P_{MZ}) \tag{3.5}$$

These fees are computed for each relevant period with the same sign convention of the ImbC, i.e. positive charges are payed by Terna to the BRP, and vice-versa ([36], art.41, 41bis): since the Northern MZ coincides with the Northern zone, NAC_{MZ} is null for the thesis case study.

The fees related to the effective imbalances belong to the so-called uplift, i.e. the cost incurred by Terna for AS procurement ([36], art.44): it is updated each quarter, contributing to the net system burden incurred by Terna for dispatching service. The latter is then payed by the end-users trough the electric bill, under the DC heading.

As well depicted by [20], the uplift is the main component within the net system burden, while the DC affects for about 7 % of the bill ([43]). However it varies during the year: as reported by [44], in 2020 the weight within the bill increased from about 6 % in the first quarter, to 7.5 % in the second one and up to 10 % in the last one. Of course these values are influenced by the pandemic situation.

For more details about the uplift and DC component, see **Figure A.1** and **Figure A.2**.

Chapter 4

UVA focus

This chapter is devoted to further describe the UVAM, currently the reference virtual configuration among the pilot projects managed by Terna in this first phase of opening the ASM to new subjects.

These VPPs are characterised in terms of subjects involved and their roles in **Section 4.1**, in terms of requirements in **Section 4.2** and offering an overview of the management, economics and last trend in **Section 4.3**.

The chapter is mainly based on [7], not yet updated with the 2021 regulation: however, the latter offer more stringent the participation to the pilot project, in terms of stricter control of the effect AS procurement availability, according to [45].

4.1 UVAM characterisation

The actors involved in the creation and the operation of the UVAM are the aggregated units, the BSP, the BRP, the DSO and the TSO. Their active roles are summerised in **Table 4.1**.

The holder of the UVAM is the BSP (called also the Applicant): it creates and manages the virtual unit technically and economically, hence it operates as an aggregator.

After the agreement with the BRP holding the points of connection aggregated, the BSP asks for the creation of one or more UVAM through an informatic procedure. Once Terna approves the creation request, the Applicant uploads on a dedicated online portal the needed documentation, i.e.:

1. Dispatching contracts codes of the units.
2. DSO of the grid to which the units are connected.
3. Adjustable power for each units (in MW, with 3 decimal digits).
4. Identification codes for each PU and CU, namely the Point of Delivery (POD).
5. AS to which enable the UVAM.

Before the final enabling, Terna verifies the documentation with the DSO and the Sistema Informativo Integrato (SII): the connection points of the UVAM are validated with or without technical limitations, or refused. The latter is the case of the non-conform points.

Then, technical tests are performed and before 3 working days from their conclusion, Terna communicates the results. If the UVAM configuration is modified after the enabling, in case the %-variations of maximum and minimum power are higher than 30 %, the technical tests are repeated.

Table 4.1: Active roles of the actors involved in the UVAM creation and operation: table reprocessed from [20]

Actor	UVAM creation	UVAM operation
BSP	x	x
Units	x	x
BRP	x	
TSO	x	x
DSO	x	

The aggregated units can be non relevant PU, CU and storage systems, that can be aggregated within the so-called UVAM A, and RUs not yet enabled to ASM such as NPRS, that can be aggregated within the so-called UVAM B. An overview of the structure of one UVAM with 2 BRPs is offered in **Figure 4.1**, while the VPPs main requirements and features are further explained in the next paragraph.

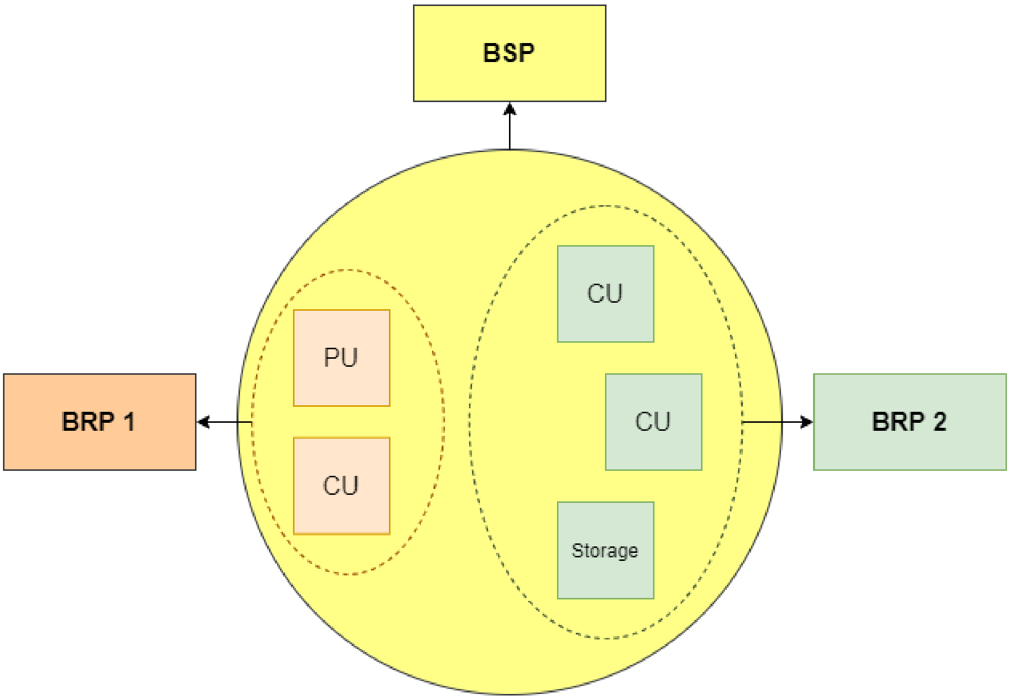


Figure 4.1: Overview of the UVAM structure: example with 2 BRPs
.

4.2 UVAM requirements

The units that can be aggregated within an UVAM are further characterised below:

- **PU**: non relevant or RU not yet enabled. The latter must share the grid Point of Connection (PoC) with a consumption unit, that must itself consume at least 50 % of the energy produced.
- **CU**: are included the ones serving the I/C service, but without involving the loads linked to this latter, while are excluded the captive costumers and the CU involved in the Capacity Market.
- Storage units: stand-alone, linked to PU and/or CU and Vehicle-to-grid (V2G).

The PoC should be treated on hourly basis: if not, they must have a measure device allowing the DSO to detect the hourly data. Furthermore each point must belong to the same aggregation perimeter, i.e. the provincial, and Monitoring Peripheral Unit (MPU) must be present: the latter is described in **Paragraph 4.3**.

The AS associated to the UVAM are the resolution of the congestions , the creation of tertiary reserves and the real-time balancing: the modulation's timing depend on the AS and are summarised in **Table 4.2**.

Then, maximum and minimum enabled power, P_{max} and P_{min} , are respectively defined as the maximum injection increase and decrease served by the UVAM when needed: the limits differ among the up- and down-modulation and are shown in

Table 4.3, having in mind the sign convention of **Table 3.4**, i.e. net injection are assumed positive, while net withdrawal negative.

Table 4.2: AS that can be procured through an UVAM.

AS	Maximum response time [min] *	Minimum modulaton time [min]
Congestions resolution, mFRR and balancing	15	120
RR	120	480

**Maximum time span between the request and the delivery.*

Table 4.3: UVAM power constraints for upward and downward modulation.

Injection power	Updward and downward	Upward	Downward
P_{max}	$\geq$ 1 MW	$\geq$ 1MW	-2 kW
P_{min}	$\geq$ 1 MW	2 kW	$\geq$ 1 MW

Moreover, for the resolution of the congestions and tertiary reserves there is another limit, with the possibility of future deletion. For each UVAM, indeed:

$$\frac{P_{up,np}}{P_{max,en}} < 50\% \tag{4.1}$$

where $P_{up,np}$ is the summation of the up-modulating powers of the PU feeded by non-programmable sources.

The physical and economical settlements between Terna and the UVAM are the same as regulated in [31]. However, besides the PAB of the accepted offers, the BSP may be payed also for the capacity availability: a PAB auction is implemented to assign monthly capacity through forward contracts. In case an UVAM ensures itself a certain capacity, then it must respect some bidding obligations. Indeed, the fixed charges for the capacity availability are payed only for the time these mandatory offers are done: the price offered cannot exceed a strike price of 400 EUR/MWh.

After the eventual accepted offers during the sessions of the ASM, the other economical settlements are:

1. **Orders execution check**: settlement between the BSP and Terna. In case of Imb_{UVAM}, that is computed as in the CU case, or a number of missing meausures higher than a certain threshold, payments my occur.

2. **Imbalance settlement**: settlement between the BRP and Terna, using a SP scheme (see **Section 3.4**).

3. **Penalties**: settlement between the BSP and Terna. The measures of the non-treated hourly points are compared to the DSO ones: depending on the differences, the BSP may pay a simple penalty, or exclude some units up to the complete UVAM from the pilot project.

4.3 Management architecture, economics and last trend

According to [20], the management architecture consists of 4 key elements:

1. **MPU**: exchange information such as UVAM data and modulation orders with the concentrator.

2. **Concentrator**: aggregates the UVAM data, sends them to Terna and then sends to the single units the dispatching orders.

3. **MPU-Concentrator connection**: managed by the BSP, with Terna supervision.

4. **Concentrator-Terna systems connection**: managed by Terna respecting the [7] and [31] regulations.

The above mentioned scheme is shown in **Figure 4.2**: also the possible fixed costs are presented, with UPM the Italian form for MPU. However they refer only to the installation, while some invoices my be avoided: the concentrator-Terna systems connection may be already present, as well as the concentrator. Furthermore, the number of units influences the MPU and MPU-Concentrator connection costs, whle for BRP and DSO there are no signficant additional investments to perform.

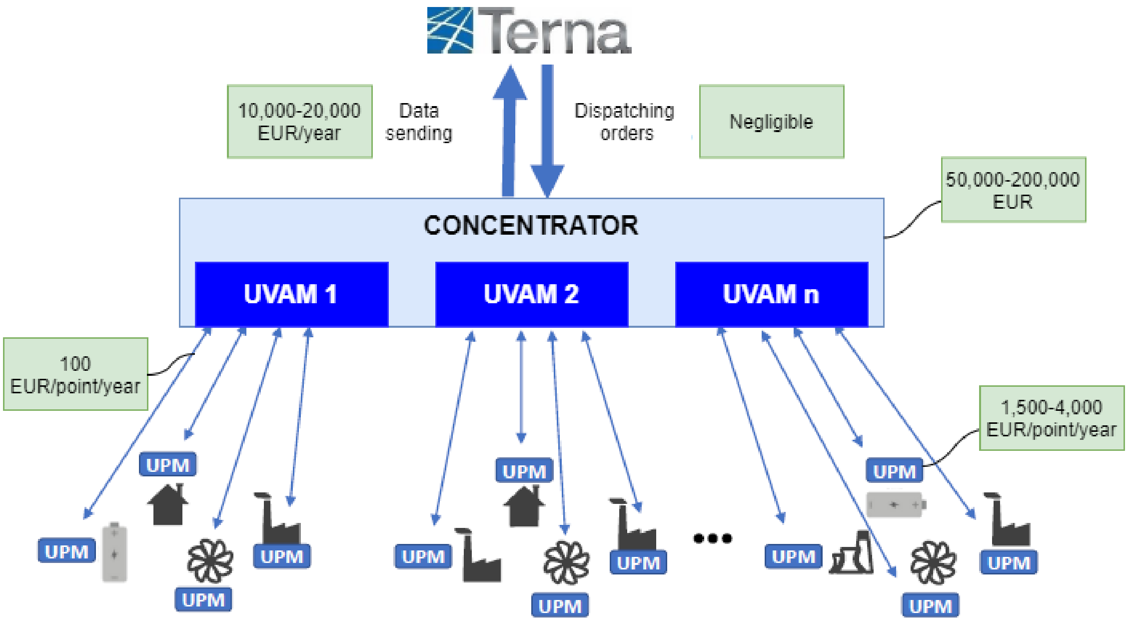


Figure 4.2: Overview of the UVAM architecture management structure and related costs estimation: figure reprocessed from [20].

Finally, the last trend are taken from [4]. Last year 20 BSP participated to the forward procurement auction, about the 26 % less than the 2019. Among them, the main ones involve companies belonging to the ENI and ENEL groups, 2 italian multinationals among the leaders of the energy sector.

However, the number of UVAM increased up to 246 in July 2020, i.e. 58% more than the previous year: the 68% of the projects is composed of 1 POD, followed by the UVAM with 2 POD. Then, 146 UVAM consists of both PU and CU, followed by only production and only consumption.

The production units involved in the enabled UVAM are 402:

- **Thermal power plants**: 206.
- **Hydro power plants**: 146.
- **PV systems**: 50.

while the consumption units are 302. It's importan to underline that usually the PV is not used as flexibility soruces, but in combination with ESS.

The total upward capacity is 1423 MW, with P_{max} varying between 1 MW and 62 MW and with an average of about 6 MW. Instead, the total downward capacity is 2017 MW, with P_{min} varying between 1.5 MW and 28 MW and with an average of about 7 MW. The majority of the capacity is located in the Northern zone, with more than 70 % of the total enabled upward and downward enabled power.

The offers accepted during the first 8 months of 2020 within the BM are 5 upward and 27 downward, with a higher order fulfilment in terms of energy for the latter. Instead, the mandatory offers result very close to the strike price of 400 EUR/MWh.

Despite the UVAM participation increased from 2019 to 2020, the main feautures in terms of aggregates composition and localization, and price offered, remained quite constant. About the orders execution, a good reliability is shown: from August 2019 to March 2020, about the 86 % of the accepted offers were respected, with 4 upward and 4 downward failures during the first 8 months of 2020.

In conclusion, the UVAM pilot project presents a wide margin development also for 2021, since it was updated at the end of 2020. The majority of units involved are the thermal power plants, with less information about the demand-side, but it is expected that with the spread of ECs, the demand-side will acquire more value in terms of AS procurement.

Chapter 5

State of the art

This chapter includes a broad and rather comprehensive representation of the state of the art. It is structured in 3 sections, which consider the main study fields related to the thesis: the ECs, the DR and the power markets.

The main reason behind such an analysis is a better understanding on how this work can contribute to the actual literature: hence, starting with an overview of the general concepts of the above-mentioned topics, the analysis proceeds declining them by virtue of the purpose of the thesis, i.e. the systemic evaluation of the internal imbalances inside a consumption units aggregate.

The procedure carried on is summarised in **Table** 5.1.

Table 5.1: Structure of the analysis about the state of the art: the chapter sections, the general concepts and the focus ones are expressed.

Topic	Chapter section	General concepts	Focus
EC	5.1	EC modelling	Internal imbalances and impacts on the grid
DR	5.2	Price- and incentive-based schemes	Management of the internal re-balance
Power markets	5.3	Power markets modelling	Participation of the final demand to the ASM

First, the chapter briefly describes the ECs literature. Then, more detailed analysis of the DR schemes and ASMs are performed: the latter section is further divided in paragraphs exploring some of the ASMs facets, such as the market environment modelling, the pricing schemes and the demand participation. Finally, the thesis contributes to the state of the art are summarised.

5.1 EC modelling

A quite wide and various state of the art is presented by [46], where can be identified 3 strands of publications, here briefly described:

- *Informative*: introduction to the topic and to the involved technologies.
- *Energy planning*: optimisation algorithms for EC management.
- *Regulatory schemes*: impacts of regulatory schemes in EC deployment .

Besides the informative articles, [46] almost contrasts papers about energy planning to the ones involving the regulatory schemes: indeed, the firsts are mainly focused on the optimisation of the self-consumption, the battery management and the Electric Vehicles (EV)s integration. End-users' costs are minimised without involving the billing procedure and the regulatory schemes, considered fundamental in the EC development and management. These latter aspects are treated quantitatively by [46]: a Mixed Integer Linear Program (MILP) is used to identify the most cost-effective scheme among feed-in-tariffs, resulted the best, net metering and self-consumption, within an EC of 166 dwellings.

The need for modelling the ECs-legal provisions is also underlined in [9]. Starting with the related European legislation, the authors present a high level representations of these new energy entities and the elements for their modelling required by all the stakeholders: regulators, system operators, ECs planners and academics.

The internal imbalances issue is not directly faced by the above-described articles, while the possible impacts on the grid are briefly discussed in [46]: a key-point is to prevent excessive energy dumping to the LV grid, especially in case of feed-in-tariffs schemes. Instead, the design of a cost-reflective and fair network is considered the main modelling challenge by [9], in a framework in which the ECs are allowed to manage distribution networks and to participate to the power markets.

A separate mention goes to [4]: it is a very comprehensive report, whose contents are well summarised in the sub-title *Decentralisation, Electrification, Digitisation: which perspectives for ECs and virtual aggregations?*. Here the ECs are modelled in 2 ways:

1. Economic sustainability: the conventional indicators Internal Rate of Return (IRR) and Payback Time (PBT) are computed for 6 types of ECs, starting from a condominium up to an industrial district.
2. Development potential: *moderate*, *intermediate* and *accelerated* scenarios are considered to evaluate the penetration of the ECs.

The economic analysis shows as ECs developers are a key-figure in the implementation of these systems for many reasons: reduction of investment costs, community management optimisation and further payoff with the participation to the ASM. On the other hand, the scenario analysis underlines the importance of ECs for reaching the PNIEC targets.

In conclusion, the state of the art here described doesn't strictly address the imbalances issues within the ECs, while recognises their importance in the energy transition and the need for technical and regulatory actions, to better integrate these new entities in the power systems.

5.2 DR schemes

The internal balancing, or re-balancing, can be defined as the RT adjustments within the production and consumption portfolio of a BRP, to minimise its imbalances fees ([22]). Looking at the demand side, in case of remunerated internal balancing, it would well fit in the DR world: while **Section 2.3** provides an overview, this one explores some schemes, considered relevant to frame this thesis within the DR topic.

The supply- and demand-side imbalances must be faced by the system operators with a view to grid safe management. As introduced in **Section 2.3**, some DR schemes are used when the grid is jeopardised, such as I/C, EDRP and DB: [47] observes how the typical resources are interruptible services for large commercial and industrial customers, but the value of residential loads is increasing, especially at the distribution level, due to the spread of distributed and aggregated energy systems in recent years. The main characteristics of the papers analysed in this perspective are summarised in **Table 5.2**

A residential EDRP prototype to solve distribution system overloads is presented by [47]. The program is defined as targeted selective shedding, since it selects only the houses that minimise the costs and disruption: the incentives have a fixed component for participation, and a variable one for the amount shed. No details about the load types and quantity and the amount of incentives are given.

DR must benefit to utilities and costumers, too. In this context, [48] pursues a scenario-analysis exploring incentives-penalties combos within an I/C scheme to reduce the peak-demand. First, an economic model is build to obtain the optimal costumers' consumption, maximising their daily profits. Then, the model is tested considering the peak day of the 2007 and simulating the whole load-profile. According to the authors, the work explores the point of view of end-consumers, utilities and Indipendent System Operator (ISO).

This also happens in [49], where DB scheme is considered and tested on a reference bus system: large consumer are considered for dealing with contingencies and/or price spikes. First, the costumer perspective is considered, building a model to maximise its profit and to bid the optimal demand reduction, while the incentive is imposed by the ISO. The latter is then considered in a second optimisation, to get the optimal supply schedule: Mixed Integer Non-Linear Program (MINLP) is used. As results, there are an increase in the costumers' profits, and a decrease of Market Clearing Price (MCP) and supply costs.

A sort of internal market within a VPP is modelled in [50]: extensive data management and mining modules are used to categorise costumers based on their curtailment bids, offered as a couple price-capacity and to support the decision-making process. The latter lies in a DA optimisation minimising (Non-Linear Programming (NLP)) the total VPP operation costs, which includes the I/C and the supply costs: the results are optimal energy flows. One day of the Columbian market is simulated: the model show positive results for all the actor, increasing the participation to I/C and decreasing the VPP costs.

About internal markets, [51] proposes to balance internally the surplus of RES energy of a smart-grid community of residential households: after storing the energy in the ESS, the prosumers owning RES can sell their surplus to the consumers. Then, a ESS optimisation is performed, to minimise the grid consumption costs. A monthly case study with 4 prosumers and 6 consumer is simulated. External modules are used to simulate the RES and load profiles, while data market prices of May 2013 are taken from the Finnish Nord Pool Spot database: the integration of RES supported by DR provide costs reduction by 10 %.

[52] is the only paper among the cited that faces the imbalances through a well known DR scheme such as the EDRP, within a micro-grid environment. Load imbalances caused by load and DG are included in the micro-grid uncertainties: multiple scenarios are created using Monte Carlo method. The model tests several customer participation level and incentives. A day within a reference system is simulated, minimising the hourly micro-grid operating costs: participation levels higher than 50 % lead to peak reduction, while an unreasonable increase of incentives increase the operating costs.

Only 3 articles directly face the internal imbalance issue: their overview is presented in **Table 5.3**. The papers considers the PV forecasts error as the only cause of the imbalances within end-users' aggregates. Starting from real measurements, [53] imposes 2 error scenarios looking at typical literature values and considers as production units only PV rooftop systems. Instead, [54] uses auto-regressive models to build the forecasts and includes residential CHP within a VPP. A PV simulator estimating the output of roof-top PV in urban areas is adopted in [55]. Furthermore, [53] and [54] presents an imbalance settlement working roughly as the Italian case.

A Distribution Management System (DMS) is modelled in [55] with the aim to control the power exchange at primary substation, namely the PoC. The steps involved in the DMS are described below:

1. The loads aggregator sends to the DSO informations about the scheduled demand profile and loads flexibility.
2. The imbalance power is computed as the difference between the FO and the RT active powers requested at the PoC.
3. If this difference exceeds a certain threshold, the DSO asks the aggregator to use load flexibility: an OPF is run and the dispatchable loads are adjusted. The flexibility is represented through parasitic generators: if the nodes have different costs, the OPF minimises the cost, otherwise the power losses.

Basically, the DMS is build as a co-simulation framework, which involves: the OPF algorithm, the real distribution network modelled on Simulink and run on a digital RT simulator and the agent-based aggregator. The model is succesfully tested on an urban district area in Northern Italy, during a cloudy day, when the PV output is less predictable: controlling the power exchange at the PoC, the peak demand is reduced of about 30 %. The authors underline how the internal dynamics of the DR are out of scope of their paper, hence they don't considers any incentives for the end-users.

In [53] the authors intend to minimise the internal imbalance using PV forecasts updated each hour and shifting the so-called flexible loads, like refrigerators, heat

Table 5.2: Comparison between the papers (identified in column #) describing the DR as support to a jeopardised grid. In column *Scheme*, information additional to the DR scheme are listed, such as the grid issue to be faced.

#	Scheme	Incentives	Reference market	Energy systems	Aim	Method
[47]	-EDRP -Overloads	Fixed + Variable components, not specified	N.A.	Residential loads	Min scheme costs and load disruption	N.A.
[48]	-I/C: 10 % of load curtailment -Demand peaks	9 incentives-penalties combinations, around the flat-rate price	Iranian	Aggregated national load	Max costumers' daily profits	Price elasticity of demand
[49]	-DB -Contingencies and price spikes	20 \$/MWh imposed by the authority	N.A.	Bus-aggregated: hundred of MWs per each bus	-Max costumers' profits -Min supply schedule	MINLP
[50]	-I/C	Between a minimum bid price and the wholesale one	Columbian	VPP: -residential, commercial and industrial loads (hunderd MWs per load-period) -solar and wind DG -ESS	-Min operating costs	NLP
[51]	N.A.	No incentives	Finnish	Smart grid community: -prosumers and consumers -PV and ESS systems	-Min grid consumption costs	Geometric programming
[52]	-EDRP -Smart-grid uncertainties: supply and lines failures, load and DG forecasts errors	-Incentive: 5 to 10 times the micro-grid power price, which is 15 Eur/MWh -Optimal value results 120 Eur/MWh -Load shedding costs: 400 eur/MWh	N.A.	Smart grid: -Loads: not-specified types, 90 kW during peak load -2 micro-turbines -15 kW of PV and 25 kW of wind generation -1 battery	-Min operating costs	MINLP

Table 5.3: Structure and aims of the only papers facing the internal imbalance issue within end-users' aggregate. In the *Methods* column, the TR is indicated, too.

#	Energy systems	Aims	DR scheme	Method	Reference market
[55]	2200 Residential loads (fed by 43 sub-stations) and PV	Costs or grid losses minimisation	Not specified, no incentives	Optimal Power Flow (OPF) TR= 15 min	N.A.
[53]	Residential and service loads (hundreds of MWh/year) and PV	Minimisation of imbalances	DLC, no incentives	Model Predictive Control (MPC) TR= 15 min	Duth
[54]	3 detached duellings, each with a micro-CHP and PV	Imbalances vs costs minimisation	Market-based	MILP TR= 15 min	Belgian

pumps and ventilation systems: the maximum time-shift is 2 hours and the method used is a MPC, with a time-step of 15 minutes. The model is tested along 1 year between 2012 and 2013, with a focus on the 4 months representing the seasons and considering both residential and commercial loads. The imbalances are reduced up to 30 %, while the associated fees remain practically the same: this is due to the absence of financial incentives for the BRP. Reason why, here the internal re-balancing is useful only from the TSO perspective.

In [54], the VPP is allowed to participate both to DA and AS markets: after a DA costs optimisation, 2 re-scheduling processes are explored, against a base scenario in which the unmanaged imbalances are settled in the market:

1. *Forced strategy*: imbalances minimisation, through MILP.
2. *Economic strategy*: total operational costs minimisation, through MILP.

Both strategies serve themselves of CHP and imbalance market, for re-balancing purposes. However, the *Forced* one works regardless economics, while the *Economic* one includes 2 sub-cases regarding the imbalances prices: one case considers well known prices, the other estimates them using DA prices (well known) and reserve power forecasts, since in the Belgian market there is such a correlation. The results show how both the strategies can reduce the internal imbalances, up to 90 % with the *Forced* one. About economics, the only profitable action is the *Economic* strategy: however, the savings are very small, due to the low electric efficiency of the considered CHP technology.

The internal imbalances are strategically managed in [41], by forecasting the Italian MZ imbalance sign: indeed, its dynamic is quite predictable according to this study, such that BRPs can draw economic benefits. However, the authors underline the prohibition of voluntary unbalancing, and consider their work useful for the Authority, to prevent possible abuses. The paper focuses mainly on the statistical analysis of the MZ imbalance sign and by the purpose of this section, the relevant outcomes are:

- The probability to get a certain sign depends mainly on the load period and the macro-zone. Then, it's time-dependent, while the time-series are not independent.
- Several linear parametric and non-linear non-parametric models are tested, finding different reliability levels.
- Several strategies can led to significant extra-profit, up to 7 euros for each imbalance MWh.
- The DA average prices are much closer to the lowest ASM prices than the highest ones: hence, betting erroneously on a positive sign can lead to losses higher than the expected profits. Reason why, the approach based on the most probable estimation that bets for all the periods always the most probable sign, leads to losses instead of profits.

Last but not least, [56] is the only paper directly facing the Italian imbalance settlement within an actual case study. The main topics are 2:

- Proposal of several forecasting models for both the PV production and consumption side, obtainging forecasting errors in accordance to the typical ones found in literature.
- Proposal of some storage strategy to reduce the effective imbalances of a prosumer.

About the imbalance settlement, first the imbalances on the production of a 20 kW system is considered along 2016 and reported for typical months and hours of the day: among the quantities computed, there are the net imbalance charges and the differences wrt the case without imbalances, the latter in terms of net gain or net loss and from now on net payoffs. Positive charges indicate payments from the prosumer to Terna, the Italian TSO and vice-versa, while positive net payoffs indicate a net gain and vice-versa. These values range as follows:

- **Monthly**: the net charges go from -251 EUR to 338 EUR, while the net payoffs from -188 EUR to 242 EUR.
- **Hourly**: the net charges ranges from -1.63 EUR to 1.57 EUR.

Then, a sensitivity analysis is implemented in terms of forecasting errors: decreasing the latter, the charges decrease in absolute value, while the payoffs trend depends on the single case due to how the imbalance are settled (see **Section 3.4**).
Then, the usage of the ESS is tested to reduce the imbalances through 2 strategies and considering a PV rooftop system of 50 kW installed near the Calabria University, a storage system of 5 kW and capacity of 10 kWh:

1. *Real time strategy*: the battery is always used 1 minute after the real time, almost completely re-balancing the imbalances.
2. *Hourly strategy*: the battery is used a little amount of time, taking advantage of the possible hourly compensation of the opposite imbalance signs.

January 2015 is analysed: the first strategy allows to have a net imbalance of 0.5 kWh, while the second one provides 4.19 kWh, a value 9 times higher.
Finally, another case study is used to settle the imbalance of a prosumer owning 1 kW of PV and a battery of 1 kW with a capacity of 1 kWh: considering again Janaury 2015, the net imbalance charges are 0.36 EUR and this value will be used as rough comparison with the thesis results, as described in **Paragraph 8.1.2**. As a result, increasing the battery allows to reduce the imbalances: in particular, the higher the size, the lower the imbalanced energies and the charges and passing to 10 kWh of capacity, the former reduce of 60 %, the latter of 6.6 %.

According to the literature just presented, a specific DR scheme managing the imbalances appears to be undeveloped yet. Such a scheme would well fit among the ones related to the grid safety and reliability: indeed, [52] includes the load imbalance in a bunch of events faced through an EDRP. Only 3 papers treat individually the internal imbalance within a DR framework: however, except for [54] that look at the BM, none of the others consider any incentives. They are necessary to deploy such a DR scheme and to benefit system operators, utilities and costumers. Finally, one paper address the usage of the battery to reduce the imbalances in light of the imbalance settlement: the ESS may be fundamental to reduce the effective imbalances within a DR scheme.

5.3 ASM modelling

In **Chapter 2** is introduced the increasing validity of the demand-side within power markets, especially the ASMs: [20] and [57] underline how the aggregated loads flexibility can contribute in reducing the AS procurement costs and [58] considers the demand-side more suitable in the short-term correction of final programmes deviations. Hence, the internal re-balancing within EC and UVAM would well lies in the ASMs, especially the BMs, since it is the market closest to the RT in many countries worldwide.

This section is further divided in paragraphs: starting from an overview of the ASMs modelling, then a focus on the PAB mechanisms and the marked-based DR are presented.

5.3.1 Markets environment modelling

Both liberalisation of power markets and rapid growth of RES are responsible for an increase in variety and importance of electricity market models in the last decades ([59]). An overview of the ASMs models is provided in this paragraph, with a little focus on the ABMs, but without deepen too much: indeed, it would be out of the scope of thesis. A list of detailed review literature is given below:

- Power markets models: [59].
- Short-term European markets: [60].
- ABMs: [61].

Some of the analysed papers are illustrated in **Table 5.4**: they use market models defined within European projects.

In [62] the Electricity Dispatch Optimization (EDisON) model is extended to include the BM: an overview of the model inputs/outputs is given in **Figure A.3**. Only thermal and pumped-hydro power plants are allowed to provide balancing services. After testing the model on 1 year (2013) quite successfully, several balancing market designs are evaluated: as results, it would be preferable to separately provide capacity and energy products, as well as up- and down-regulation.

The authors in [63] recognise the need for a review of the TSO-DSO Coordintation Scheme (CS) to open the ASM to distribution flexibility to face balancing and network congestions. The model used is SmartNet, consisting of 3 layers: bidding and dispatching block to model the bidding of several technologies, a market block with a Pay-As-Clear (PAC) scheme and a physical block for the grid. The access of the DSO to distributed resources, among which DR, leads to an improvement of reserves activation: residual imbalances and the usage of aFRR are limited compared to the current CS, in which only the TSO can participate.

A comparison between explicit and implicit balancing is performed in [64] using the ABM Open simulation Platform to Test Integration in MArkeT deisgn of massive intermitten Energy (OPTIMATE). In both balancing method the TSO aims to minimise the total balancing costs, while compared to the implicit case, in the explicit one technical constraints are not considered and explicit offers are done. As a result, the implicit case leads to more curtailment and higher balancing costs for the BRP. The loads don't participate to the market.

Table 5.4: Comparison between the papers modelling the ASM within the context of European projects. In column *Time features* TP refers to the modelled time period, while thermal refers to fossil fuel power plants and ESS to batteries.

#	Market types	Reference market	Time features	Methods	Supply Side	Demand Side
[62]	-DA -BM	Central Europe	-TR: 1 hour, 30&15 min -TP: 1 year	-Linear Programming (LP) -Matlab	-Thermal -RES	N.A.
[63]	BM	Spanish (2030)	-TR: 15 min -TP: 1 day	1) Qualitative * discussion 2)Aim: min activation costs 3)AC power flow	-Thermal -Nuclear -RES -ESS	-Thermal and curtailable loads -ESS
[64]	-DA -ID -BM	Central Western Eurozone	-TR: 1 hour -TP: 3 months	MILP	-Thermal -Nuclear -RES	Highest load of 201 GW

**The numbers refer to the SmartNet simulator layers.*

According to [61], ABMs offer a flexible, modular and wide modelling framework very suitable for analysing the new paradigms within the electricity systems: smart grids, DR, DG and power markets can be fully integrated. Not surprisingly, ABMs are used by lots of the found papers, whose main characteristics are expressed in **Table 5.5**.

Before describing the papers, a brief introduction to the ABMs is here resumed from [24]. The modelled systems are build as a Multi-Agent System (MAS), i.e. an environment composed of several entities called agents. They are autonomous, interactive, reactive and pro-active: hence, they can achieve the goals they are programmed for, interacting with other agents and the surrounding environment (see **Figure A.4a)** In this context, a key-role is played by the Reinforcement Learning (RL) methods, that allow the agents to learn from past experiences (see **Figure A.4b)**.

Proceeding with the RL topic, in the power markets context it is used for optimal bidding strategies. In [65] strategic bidding is applied to build reserves bids starting from the marginal costs of thermal and hydro power plants, while 10 strategies are explored in [66] through the so-called Q-learning. Strategic behaviours are also considered in [67] and [68].

Since many models involve the DAMs, a dispatch optimisation may be needed for the generation plants to minimise their operating costs: [65] uses a MILP, while [68] is able to considere the most appropriate model among MILP and stochastics methods. Instead, in [8] prices and capacity are fixed.

Passing to the demand-side, [69] and [66] consider the demand as an input data for the BMs, while the others papers model the loads aggregating them as agents directly participating to the markets ([65] and [67]), or represented by retailers ([8], [70] and [68]). Finally, the demand is allowed to participate to the ASM only in [69], letting the EVs to regulate the grid frequency, and in [67], in response to RT price signals.

As can be seen in **Table 5.5**, ABMs are used for a wide variety of power markets, including small local markets within single microgrids, such as in [66] and [68]. The scalability and modularity of ABMs is also evident in more complex simulations with many agents: examples are [70] and [67], that use the JAVA-based model Repast, and [68] and [71], that use the MASCEM environment. The working principle of Repast can be observed in **Figure A.5**, while further details on MASCEM are now presented: it is chosen as example representing how the modelling of power markets follows their evolution towards systems more deregulated, decentralised, competitive and hence complex.

MASCEM borns in 2003 aiming to be a valuable framework for studying new rules, new behaviour and new participants in several power markets ([72]). The overall structure of MASCEM is presented in **Figure A.6**, while the agents are now briefly described. The market is coordinated by a *Market Facilitator*, while the *Market Operator* manages the bids and clears the sessions, and the *Market Regulator* ensures the grid stability. The market players are *Sellers* and *Buyers*: they can delegate *Traders*, such as retailers and aggregators. Subsequently *VPPs* are introduced as a coalition of agents ([73]). Several bidding strategies can be implemented as showed in [74], while after the restructuring presented in [75], the model results 10 times faster and fully integrable with other multi-agent systems, as shown in **Figure A.7**. According to [75], the model shows experimental results coherent with the real markets behaviour.

Several ASM models are present in the literature. All the ASs are treated, such as congestions, capacity and energy reserves and RT imbalances, while most of models can deal with other kind of markets, from the DAM to small-scale local ones, and with lots of actors, from conventional supply to DG and demand-side. Despite the latter is not allowed to participate to ASM in the most of the found papers, the state of the art shows great ability and potential of many models, especially the ABMs, to face the current evolution of the power markets and systems.

Table 5.5: Comparison between the papers modelling the ASM through ABMs. Info abou the supply- and demand-side of [65] are found in [76]. In case of MASCEM, details about the agents are given in the text.

#	**Market types**	**Reference market**	**Time feautures**	**Supply Side**	**Demand Side**	**Agents' types**
[8]	-Spot (DA) -BM	Nord Pool	-TR: 15 min -TP: 1 month	-RES -Others not specified	100,000 users	-Producers -Utilities -End-users
[65]	-DA -Reserves markets	German	-TR: 1 hour -TP: 1 year	-Thermal -RES -Net import	Aggregated load for the whole market area	-Supply and demand
[69]	BM	N.A.	-TR: 1 hour -TP: 120 days	EVs (from 16 to 100)	-Historical load data -EVs	EVs
[66]	BM	Small-scale microgrid	N.A	6 players not further specified	-Imbalance demand from normal distribution	-6 players
[70]	-DA -Congestions market	Colombian	-TR: 1 hour -TP: 2 years	103 generation plants	Nodal aggregated demand (22 nodes)	-Generators -Retailers -Transmission companies -System operator
[67]	-DA -BM	British	N.A	-Thermal -Wind	-Small and large demand-sites	-Market -System operator -Settlement company -Supply and demand -Message board
[68]	-DA -Local markets	Iberian	-TR: 1 hour -TP: 1 day	-RES -ESS -EVs	-150,000 users (27 microgrids) -ESS -EVs	MASCEM
[71]	-DA -ID -BM	Iberian	-TR: 1 hour -TP: 1 day	N.A.	N.A.	MASCEM

5.3.2 PAB mechanisms

Although the Electricity Balancing Guideline (EBGL) establishes a PAC clearing mechanisms within the process of harmonisation and integration BMs within the EU ([77]), many countries still adopt PAB schemes ([78]), including Italy and so the UVAM pilot projects (see **Chapter** 3). Hence, the small overview of the PAB strategies and modelling described below, aims to present another element to consider within the energy transition.

The paragraph addresses firstly a comparison between PAC and PAB, then focuses on the modelling of the latter.

According to [76] and [65], strategic bidding seems to be very effective in case of PAB and quite useless in PAC pricing schemes: the authors simulate respectively a DAM and reserve markets within the same ABM and compare the market prices obtained with and without RL with the historical data. In [76], in most cases the marginal cost based simulation, hence without strategies, fits better the historic spot prices. The contrary happens in [65]: however, sometimes the simulated prices overestimate and underestimate the real averages reserves ones.

Another comparison between PAB and PAC is performed in [66], considering a BM: as a result, expected profits are higher in case of PAC, while the bidding strategy is more effective for the PAB.

No strategies are considered in [62], where marginal and discriminatory schemes are compared within a very thorough analysis of several BM designs and concluding that is would be better use a PAC system, without further information on the reasons.

A comparison between the papers focusing on the PAB modelling is given in **Table 5.6**: all the models aim to maximise the expected profit of the market participants, while differences occur in the used methods. According to [79], the existing models are mainly non-linear, such as [80] and [81]: hence, the authors develop a linear model starting from a non linear one, reaching more or less the same results but much faster. A LP method is also used in [82], while [83] aims to forecast the SMP to bid just less than it.

A common point among the models is the constraint for the bid prices to be under the clearing one: while [83] use directly historical data, [80] and [81] consider a normal PDF, [79] a set of scenarios and [82] a marginal costs linear function.

Finally, speaking about applications, in [80] is stated that in literature can be found a spirited debate about PAB vs PAC: hence the authors provide a comparison between this 2 pricing scheme, as well as in [82]. Instead, the other papers focus on fitting their models within a realistic market environment and only [83] considers the demand participation, through a VPP.

This paragraph presents only some insights about the state of the art on the PAB mechanisms, since its literature is quite wide. However, there are all the elements to understand how challenging would be formulating models for strategic bidding in the context of demand-side particiaption to power markets.

Table 5.6: Comparison between the papers modelling the PAB mechanisms.

#	Method	Market clearing	Applications	Results
[80]	NLP	Normal PDF of SMP	1) Comparison with PAC 2) 2 Perfect* markets with 50 and 26 unit	1) Different optimal offers 2) PAC is financially riskier
[81]	NLP	Normal PDF of SMP	Scenarios analysis changing the PDF standard deviation	-Optimal bidding capacity is the maximum one -The lower the prices uncertainties, the higher the profits
[79]	MILP	Set of SMP scenarios	1) Comparison with NLP model 2) DAM+BM: Co-optimisation vs sequential offering	1) Similar solutions, but MILP 115 is times faster than NLP 2) Higher profits in co-optimisation
[82]	LP	Marginal costs function	Comparison with PAC under perfect competition and monopoly	In general, PAB leads to lower supply profits and higher consumers' surplus**
[83]	Seasonal autoregressive	Market historical data	Simulation of the participation of an industrial utilities VPP to secondary and tertiary control markets	Participating to both secondary and tertiary control markets is 29 % more profitable than only the tertiary one.

**The adjective perfect refers to theoretical markets with the highest possible level of competition: unlike the monopolistic markets, where there is a price maker, the perfect ones have only price takers.*

***The consumers' surplus is defined as the difference between what consumers are able to pay and what they actually pay ([84]).*

5.3.3 AS market-based DR

This paragraph analyses some publications on the participation of the demand-side to ASM in terms of DR actions and UVAM participation: the features of aggregated flexibility such as fast reaction, smooth activation and good dispersion within the power grid, make the aggregated flexibility very suitable to face the short-term operational deviations within the balancing markets ([58]).

A comparison between the papers focusing on ASM DR is given in **Table 5.7**. Except for [85] that considers a generic elastic demand, the others cover several loads types: [86] and [87] model the residential loads participation to BM respectively through electric load shifting and heat storage management, while [88] focuses on the grid balancing through V2G.

The bids prices are strictly related to the historical imbalance prices: [86] computes the costumer bidding price as a fraction of the spot one, [88] build a kind of pricing profile for the EVs looking at the historical trend and the relation with the electrical demand and [87] apply non-defined bonus to the DA prices. Instead, the general idea in [85] is to match the debits for inelastic demand deviations from the schedule with the credits of supplier and elastic demand.

Despite the above-mentioned differences, all the papers conclude by stating an improvement in balancing services supply including the DR, but also underlying some crucial issues in its modelling: [88] and [87] highlight the capabilities to respond to real-time tariffs respectively of EVs and heat storage, while [86] consider fundamental to have a wide variety of flexible loads and to include aspects like demand seasonality and weather data to model the DR bidding mechanisms.

Since the starting of Italian pilot projects on UVA, many related reports and thesis have been written: among the latter, 3 are compared in **Table 5.8**.

The modelled UVAM are quite similar: they consist of PV systems, typical residential loads and batteries, but with some differences. Indeed, while in [89] there are a not further specified PV systems aggregate and a stand-alone ESS, [90] and [91] consider explicitly rooftop PV and domestic batteries. These units cannot participate at the same ways the to ASM: ESS are used in all the thesis, PV only in [89], while loads shifting and load curtailment are exploited in [90], by using dish-washers, washing-machines and air conditioning systems.

Other differences occur in term of bidding strategy. Basically, the ASM historical prices are considered as reference, as most of the cases in literature ([90]) : then, [89] and [91] use forecasts respectively through a commercial model and a point estimation (i.e. considering n-previous days), while [90] performs a very in-depth and accurate statistical analysis on 2017 offers and prices, ending up with acceptance probabilities. The latter are used in 2 of the 3 analysed scenarios. Furthermore, in [89] a bill discount is also considered within a detailed economic analysis about the investments needed to build a VPP.

Table 5.8: Comparison between the thesis modelling the UVAM participation to the ASM. The UVAM units are categorised as PUs, CUs and ESS.

#	PUs	CUs	ESS	Markets	Aims	ASM offers
[89]	PV (7 MW)	1000 residential (3 kW)	Stand- alone (4 MW)	-DA -ID -ASM	Max markets gain	-PV and ESS -Forecasts of prices
[90]	Rooftop PV (4 kW/user)	3000 residential and 1 commercial	Domestic (3 kW each)	-DA -BM	3 scenarios 1)Min supply costs (if no market participation) 2)Max markets gain 3)Min operating costs	-Larger appliances and ESS -Optimal bids (scenario 2) based on acceptance probability
[91]	Rooftop PV (0.5 kW/user)	100 residential (2170 kWh/y/user)	Domestic (3 up to 5 kW each)	-DA -BM	Max self-consumption	-ESS -Average marginal prices (7 previous days)

Table 5.7: Comparison between the papers modelling the ASM DR schemes. The MxCP is a generalisation of the non-linear complementarity problems.

#	Description	Market types	Reference market	Methods	Loads for DR	Offers scheme
[86]	Model the load-shifting DR within the BM	BM	Nord Pool	Market auction build on MATLAB	300 laundry machines, 2kW each	15 %,30 %, 45 %,60 % of the imbalance spot price
[88]	Model the EVs energy balancing in a power system with high wind penetration	BM	British	-Stochastic trip generation -Charge/Discharge only if it is profitable	EVs with battery capacity of 24 kWh	Historic prices and demand to build EVs pricing profiles
[87]	Model the DR within a 2-stages market framework	-DA -BM	Finnish	LP	Residential speace heat storage	Not defined bonus based on finnish market
[85]	Model the DR bids implicitly as a function of regulation supply offers	-DA -BM	N.A.	MxCP	Elastic and inleastic demand (around 12 MW per time period)	Price signal derived from the upward and downward regulation by the generators

The profitability for the demand and its capability to offer ASs and to reduce the market costs within the Italian framework, are evaluated in 3 reports, summarised in **Table 5.9**.

The authors of [92] analyse the capability to offer ASs and the resulting economic benefits for 3 different demand-side units. The flexibility is offered by auxiliary services such as ESS and Emergency Generators (EG) in multi-site telecommunication systems (hereafter *case 1*) and a big data center (hereafter *case 2*) and by a Combined Cooling Heat and Power (CCHP) Internal Combustion Engine (ICE) located in an university campus (hereafter *case 3*). First, the availability of these resources is discussed: the emergency feeding is not compromised in *case 1* and *case 2*, since the power outages are very infrequent, in some cases negligible; instead, the ICE has suitable ramps features, while further considerations are needed for the power-efficiency relation and the tariff structure to which the system is subject. The resources seems to be valuable. Then, a Cost-Benefit Analysis (CBA) is implemented considering investment and operating costs and markets movements both in DAM and ASM: upward offers are structured based on a statistical historical analysis, resulting in profitable participation only using both the auxiliary services in *case 1* and *case 2* and allowing the capacity remuneration, with slight profits increase for *case 3*.

More systemic analysis estimating the impacts on the ASM are performed by [57] and [20].

In [57] the DR lies in 1 of the 3 UVA categories considered in a scenario analysis: their participation to the ASM is simulated up to 2030, using the Centro Elettrotecnico Sperimentale Italiano (CESI) model MODIS. The projections of some key-figures such as the national load and the NPRS and ESS penetrations are taken considering several studies and the PNIEC, while the DR participation is linearly projected looking at the 2019 data on UVA pilot project. A base scenario with no UVA participation is compared to intermediate and advanced ones, allowing the UVA to offer respectively only balancing and also tertiary reserve. As expected by the authors, the ASM costs decreases, especially thanks to DR, DG and NPRS, and the latter overgeneration decreases drastically, leading to a better integration into the power grid.

A similar scenario analysis is performed in [20]: the DR participation to the ex-ante ASM is generally included in the UVA one and using several tools of RSE. Here, the base scenario refers to the business-as-usual, without implementing the most recent EU directives and it is compared to Strategia Energetica Nazionale (SEN) scenarios, further divided in 3 cases: SEN, without new market participants, Moderate SEN and High SEN, allowing to participate respectively only the NPRS and also the ESS and the UVA. The base scenario has the lowest costs, comparable only to the High SEN ones: the others scenarios have much higher costs, since the power system is less flexible.

Table 5.9: Comparison between the reports evaluating the economic advantages resulting from the DR participation to the ASM.

#	Case studies Aims	Demand-side units	Markets simulation	Results
[92]	Test demand capabilities and estimate profitability in ASM participation	1) Telecommunication system: multi-site, auxiliary sources 2) Data center: single connected to MV, auxiliary sources 3) CCHP: 1 ICE in a university campus	ASM offers based on acceptance probabilities	-Capabilities: quite high availability from ESS and standby generators and wide flexibility from CCHP ramps -Profitability: 1) More profitable both the auxiliary sources 2) Profitable only using both the auxiliary sources 3) Slight profits increase
[57]	Show system benefits from UVA participation in the ASM	Flexible demand that can reduce the withdrawals	MODIS	Compared to the Base scenario (at 2030): -ASM costs: 25 % (Intermediate), 57 % (Advanced) -Overgeneration drastic decrease
[20]	Show impacts on ASM ex-ante from power markets evolution	Not specified and considered within general UVA	RSE simulation tools	Costs compared to the Base scenario (at 2030): -SEN: x5 -Moderate SEN: x2 -High SEN: similar

The many works just presented show how valuable could be the DR in providing AS, from both market participants and system perspectives. A wide variety of loads, both electrical and thermal, can be used, while the thesis and reports analysing the Italian conditions reflect the changes in recent years of the legislation on the ASM, increasingly open to new distributed and aggregated units, such as the UVA.

5.4 Contributions of the thesis

This chapter shows how well the thesis fits in some recent and important aspects of the energy transition, such as the spread of ECs and the opening of ASMs to new flexible resources .

Indeed, there are few papers directly facing the internal imbalance of consumption units and how it can be managed using DR schemes, while most of the emergency ones uses the industrial loads.

Then, there are many papers modelling the ASMs, while a few allow the participation of consumption units: they explore all the ASs supply by a wide range of new actors, from VPPs to EVs and for several reference markets, from Iberian Electricity Market (MIBEL) to Nord Pool. Compared to these works, the Italian studies are more recent, hence fewer: the main reason is that the legislation and the experiences about new energetic subjects as the ECs and UVAM are quite recent, as already explained in **Section 2.2** and **Chapter 4**.

There are few references to the internal imbalance topics such as the imbalance settlement and the imbalances impacts: only [56] faces these issues considering a prosumer and mainly focusing on the battery usage. In light of this, the thesis aims to provide the possible impacts of ECs imbalances both in absolute and relative values, the latter creating suitable indicators to explore how much these impacts would change modifying the community extension: of course, from one hand this increases the value of the work, from another makes necessary similar comparative analysis.

In conclusion, being this work quite a systemic and not yet diffused analysis, it can be considered as a starting point to explore the technical and economical impacts of the internal imbalances within prosumers' aggregates and how they can be valuable in light of the ASM.

Chapter 6

Methodology

The methodology adopted in the thesis is here described, visually and analytically presenting the needed inputs and the obtained outcomes. The imbalance settlement is performed trough Python, as all the data and results processing: an overview of the inputs and outputs is provided in **Section 6.1**, while a detailed description of the created routines is offered in **Section 6.2**.

Furthermore, since lots of acronyms are present in the thesis and were already used in previous chapter, for reasons of clarity they are here reported in the full versions.

6.1 Inputs and outputs: overview

The imbalance settlement basically depends on 3 quantities, as expressed by **Equations 3.1**, i.e. $ImbC = Imb_{BRP} \cdot P_{imb}$ and **3.3**, i.e. $ImbP = Imb_{BRP} \cdot (P_{imb} - P_{DAM})$:

1. $\boldsymbol{Imb_{EC}}$: the effective imbalances within the users' aggregate under the Balance Responbile Party (BRP), i.e. the Energy Community (EC).

2. $\boldsymbol{Imb_{MZ}}$: the macro-zonal imbalance of the BRP belonging Macro-Zone (MZ).

3. **Market prices**: the prices from Day Ahead (DA) and Ancillary Services (AS) markets, useful to compute the imbalance price (see **Tables 3.6** and **3.7**). The prices of DAM are the Unique National Price (PUN) and the zonal one $\boldsymbol{P_{DA}}$, both considered within the invoice $\boldsymbol{P_{DAM}}$, while the prices of ASM are the upward balancing mean one, i.e. $\boldsymbol{P_{up}}$, and the downward balancing mean one, i.e. $\boldsymbol{P_{down}}$.

The imbalance settlement is performed for each relevant period and the general scheme is depicted in **Figure 6.1**. Basically there are 3 main inputs sources, i.e. the EC for Imb_{EC}, the ASM for Imb_{MZ} sign, P_{up}, P_{down} and the DAM for P_{DAM}: then, the main outputs are $ImbC$ and $ImbP$, i.e. respectively the imbalance charges and the imbalance payoffs.

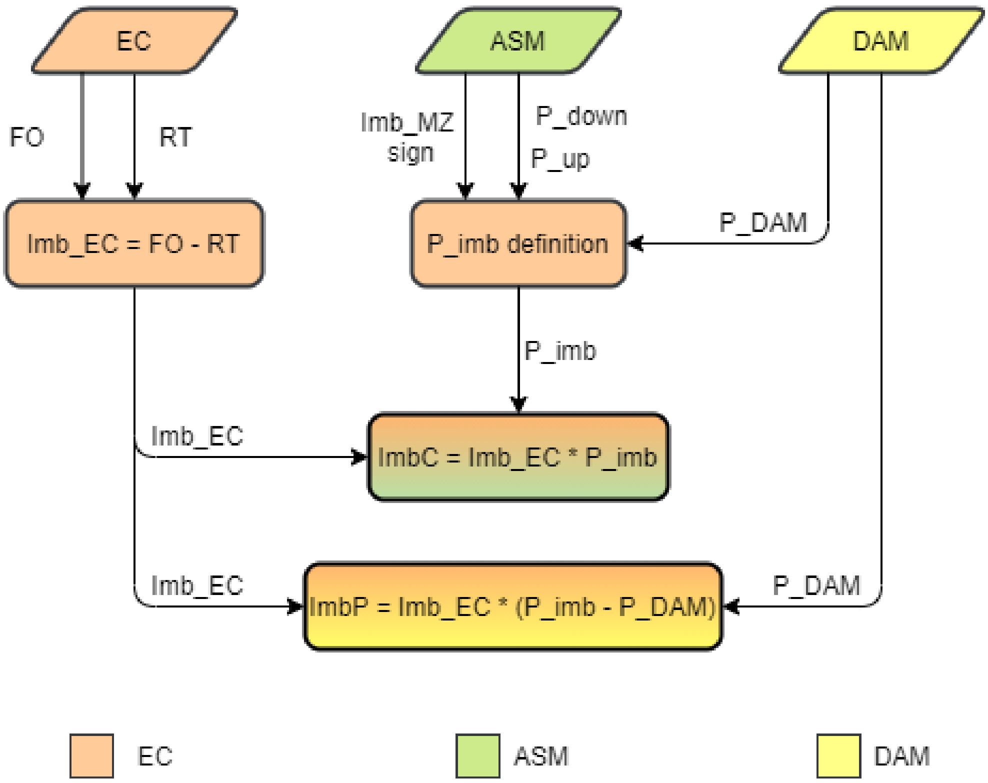


Figure 6.1: Flowchart of the imbalance settlement for one relevant period.

6.2 Routine description

An analytical overview of the imbalance settlement methodology is offered in **Algorithm 1**: basically, after chosen the year and the relative period to analyse (e.g. 1 day, 1 month, the whole year), the process involves 2 routines:

1. **Prepare data**: the data needed as input for the imbalance settlement calculation are extracted from files previously downloaded (the latter process could be automatised).

2. **Single imbalance settlement**: for all the involved scenario, the imbalance settlement is performed considering all the relevant periods, i.e. q, within the analysed period.

Algorithm 1: Overview of the imbalance settlement methodology

Input: Period to analyse: year, start date, end date
Output: Imbalance settlement for the input period
for *year* **do**
  Run *Prepare Data*
  for *scenario* **do**
    for q **do**
      Run *Single imbalance settlement*
    end
  end
end

The input data for the imbalance settlement are the output from the *Prepare data* routine, explained in the **Algorithm 2** The involved data-set may contains more information than the needed, such that a suitable extraction must be performed: e.g. the Italian macro-zonal data takes into account the Southern MZ, while only the Northern one is needed. The data-set sources with the corresponding needed data are listed below:

- **ASM**: Imb_{MZ} sign, P_{up}, P_{down}.
- **DAM**:P_{DAM}.
- **EC**: Imb_{EC}, eventually build through the RT and FO.

Algorithm 2: Prepare Data

Input: Period to analyse: year, start date, end date
Output: P_{up}, P_{down}, Imb_{MZ} sign, P_{DAM}, Imb_{EC}
From *ASM* **take** Imb_{MZ}, P_{up}, P_{down}
From *DAM* **take** P_{DAM}
From *EC* **get** Imb_{EC}

Finally, the effective imbalances are settled throughout the whole chosen period, aggregating the 15-min settlements. Since there are lots of output from the *Single imbalance settlement* routine, the **Algorithm 3** shows only the most important results, i.e. the imbalance price P_{imb}, $ImbC$, $ImbP$ and the effects on the grid, already used to characterise the Italian imbalance settlement legislation in **Section 3.4**. However, **Table 6.1** shows all the results, e.g. the non-arbitrage charges NAC, with the relative adopted formula.

Algorithm 3: Single imbalance settlement

Input: P_{up}, P_{down}, Imb_{MZ}, P_{DAM}, Imb_{EC}
Output: 15-min imbalance settlement (see **Table 6.1**)
From Imb_{MZ} *sign* **get** P_imb
$ImbC = Imb_{EC} \cdot P_{imb}$
$ImbC = Imb_{EC} \cdot (P_{imb} - P_{DAM})$
From Imb_{MZ} *and* Imb_{EC} *signs* **get** *Effect on the grid, Payoffs value*
Compute *Other outputs (see* ***Table 6.1****)*

Table 6.1: Outputs of the **Algorithm 3**:the Italian case is referenced through **Tables 3.6** and **3.8**

Output	Formula
Imb_{EC} [MWh]	$FO_{EC} - RT_{EC}$
Imbalance sign (of the EC)	+, -, Null
P_{imb} [EUR/MWh]	Based on Imb_{MZ} (see **Table 3.6**)
ImbC [EUR]	$Imb_{EC} \cdot P_{imb}$
ImbP [EUR]	$Imb_{EC} \cdot (P_{imb} - P_{DAM})$
Payment direction	Based on Imbalance sign (see **Table 3.6**)
Effect on the grid	reward, penalty, neutral (see **Table 3.8**)
Payoffs value	high, low (see **Table 3.8**)
Payoffs price difference [%]	$100 \cdot (P_{imb} - P_{DAM})/PUN$
Payoffs price difference [EUR]	$P_{imb} - P_{DAM}$
NAC	-$P_{imb} \cdot (P_{DA} - PUN)$
NACvsImbC difference [%]	$100 \cdot (NAC - ImbC)/ImbC$
Zonal price vs PUN difference [%]	$100 \cdot (P_{DA} - PUN)/PUN$

The declination of the methodology to the thesis case study is shown in **Section 7.4**, while the structure just described underlines the flexibility of the adopted routines.

Chapter 7

Case study

This chapter is devoted to present the thesis case study, by analysing all the ingredients needed to evaluate the imbalance settlement, the results of which are discussed in **Chapter 8**.

Since several database are used to get these quantities, **Table 7.1** can be useful to frame the input context.

Table 7.1: Sources of the quantities needed as inputs for the imbalance settlement: the Imb_{BRP} is indirectly obtained from the users' consumptions and PV production data.

Quantities	**Source**
Users' consumption	[93]
PV production	[94]
Imb_{MZ}, P_{up}, P_{down}	[95]
PUN, P_{DA}	[96]

The following sections are then organised as follows: **Section 7.1** explains how the EC is created and how the effective imbalances are considered, while **Sections 7.2** and **7.3** show some recent trends about the Imb_{MZ} and the needed market prices. Finally **Section 7.4** tests the methodology presented in the previous chapter on a daily basis

Some statistical analysis are also implemented: however, they are just basic ones, since it would be out of the scope of the work to implement more extensive investigation, e.g. stationarity, correlation and predictive ones, being the latter quite interesting to insert in future possible development of the thesis.

7.1 Users' aggregation: from households to EC

This thesis doesn't consider an actual EC: a potential one is however created, starting from the London households electricity consumption of [93] and adding the PV production simulated in Turin trough [94].

The build EC is composed of 3,377 users distributed over more districts in Turin: the PV nominal power is sized so as to supply the yearly consumption, while no ESS is considered, well knowing its fundamental role in maximising the self-consumption and in decreasing the effective imbalances.

Despite this EC is not real, and some aspects as the self-consumption and the ESS are basically neglected, this users' aggregation is considered suitable for the scope of the thesis, as shown in the following paragraphs.

7.1.1 Consumption data

The starting database involves 5,567 households belonging to the *United Kingdom (UK) Power Networks led Low Carbon London* project between November 2011 and February 2014. The electricity consumption are measured with smart meters at half hourly sampling, distinguishing over all the households: the latter have an identifier code and a particular classification from [97], that provides a geo-demographic segmentation of UK population. In this case 3 types of households are considered:

- **Affluent**: wealthier families (39 % of the end-users).
- **Comfortable**: countryside communities (28 % of the end-users).
- **Adversity**: middle class and poorer families (33 % of the end-users).

Another specification of the data is that for the 2013 approximately 1100 costumers are subjected to ToU electricity prices.

The operations implemented before getting the final data-set are now described.

First, the *Comfortable* type is excluded, since the EC isn't located in a countryside, while only the 2013 data are considered, because it is the unique entire year for which the consumption are measured for almost all the households, as can be seen in **Figure 7.1**.

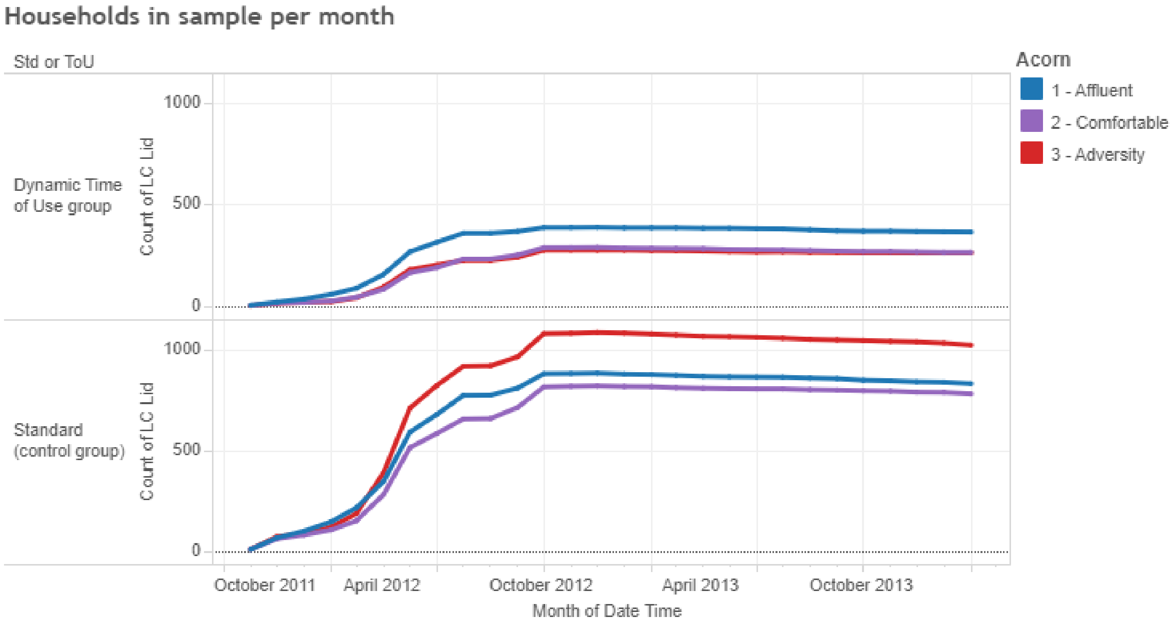


Figure 7.1: Households in sample per month during the whole measurements period. Figure elaborated by [93].

Furthermore, to ensure that the remaining households have as much data as possible compared to the maximum measures in one year, i.e. 17,520, a tolerance is used to filter a second time the data-set: considering at least 17,500 measures, after this last screening, the final data-set involves 3,377 households.

The next step is to fill any holes in the time-series by interpolating, working separately for each households. As just explained, the maximum missing point can be 20: however, about the 5 % of households have more than 10 missing measures, while the majority 0 or 1. The absence of some measures can be seen also from the perspective of the aggregation of households: in some sampled periods along 2013, may be lacking around 100 households measured. These data are graphically shown in **Figure 7.2**.

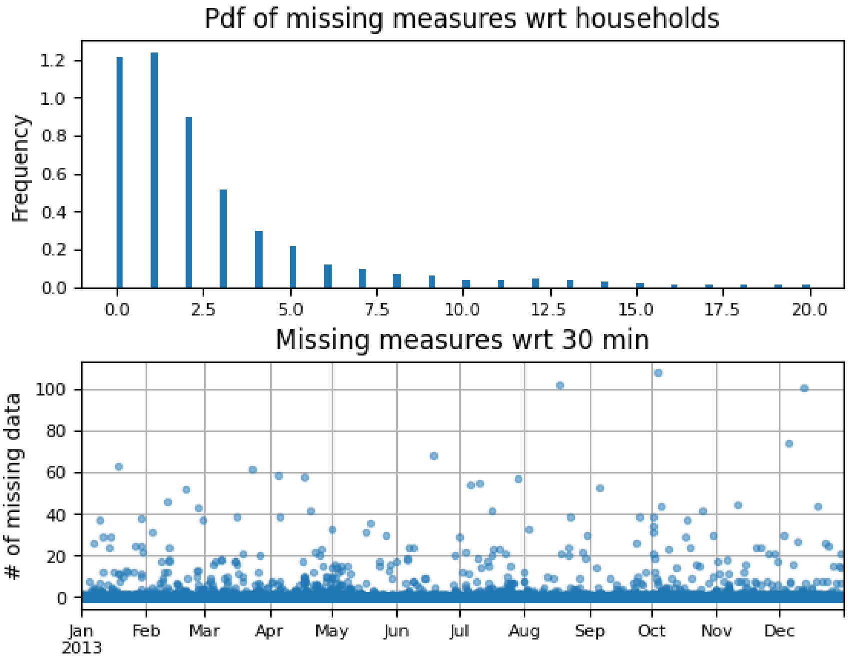


Figure 7.2: Missing data wrt households along 2013 pictured as a pdf and missing data wrt sampled periods.

The last step is hence to re-sample the data from consumption per half hour to consumption per 15-min, dividing by 2, being the quarter of an hour the chosen relevant period: **Table 7.2** resumes the main differences between the starting database and the final data.

Table 7.2: From starting to final consumption data: feautures comparison.

Feautures	Starting data	Final data
# of households	5,567	3,377
Period	November 2011- February 2014	2013
Sampling	30 min	15 min
Types	Affluent, Comfortable, Adversity	Affluent, Adversity

Aggregating the consumption, the final time series is obtained: it represents the actual consumption of the EC, from now on RT_{Cons}: the yearly consumption is about 12.5 GWh/year, resulting in approximately 3690 kWh/year/household. This data is in accordance with the average yearly UK domestic consumption of 3700 kWh/year reported by [98], while it results higher than the average Italian values between 2,300 and 3,200 kWh/year proposed by [99]. A reason behind this difference could be a higher usage of electricity for cooking in UK than in Italy.

Finally, the UK load used in this thesis is here compared quite summarily with the Italian one, just to be sure that there aren't such relevant differences: the comparison in not so detailed, since the needed data for the comparison is the effective imbalance of the EC and of course the order of magnitude of the consumption per end-user would not change passing from London to Turin.

The daily average load curves during weekdays and holidays within the winter and summer seasons are presented in **Figures 7.3** and **7.4**, normalising for the peak power: the italian data are obtained from the figures **Figures A.8** and **A.9** of [100]. The authors analysed 1200 italian families for 2 year, computing an average yearly consumption of 2800 kWh/year/household, while the plotted data are obtained trough [101], a tool allowing to exctract data from plots. The meaning of winter, summer, weekdays and holidays is explained below:

- **Winter**: January, February and December.
- **Summer**: June, July and August.
- **Weekdays**: all but Saturday, Sunday and other holidays such as Christmas.
- **Holidays**: Sunday and other holidays such as Christmas.

In general, the peaks hours are very close and the UK consumption seems to be qualitatively similar to the italian one: 2 exceptions occur for less difference from the peak power during UK summer weekdays and a more pronounced first peak for the Italian winter holidays.

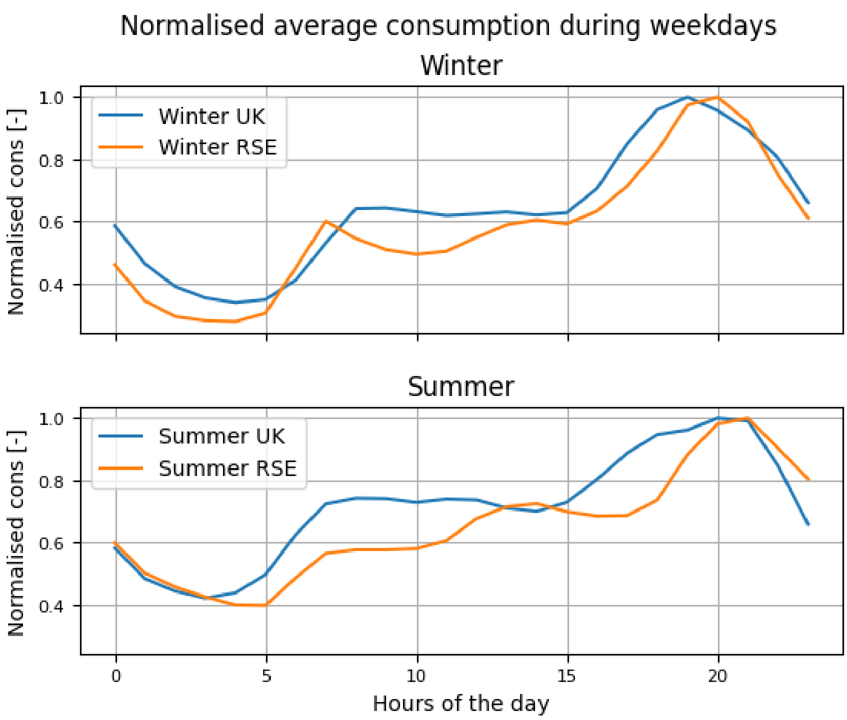


Figure 7.3: Daily average load curves during weekdays of winter and summer: comparison between italian data, namely RSE, and the UK data. The Italian consumption are taken from [100].

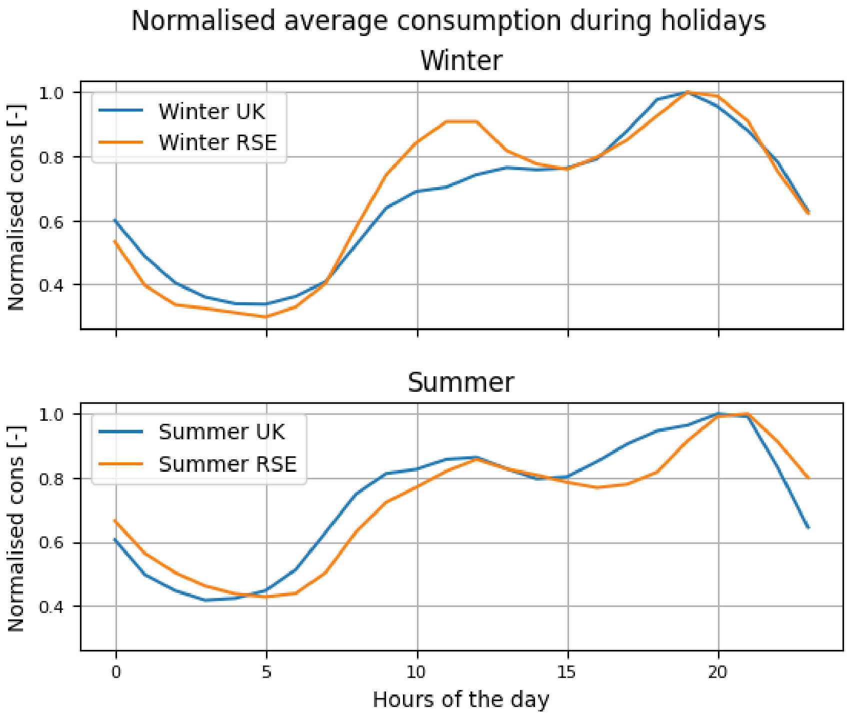
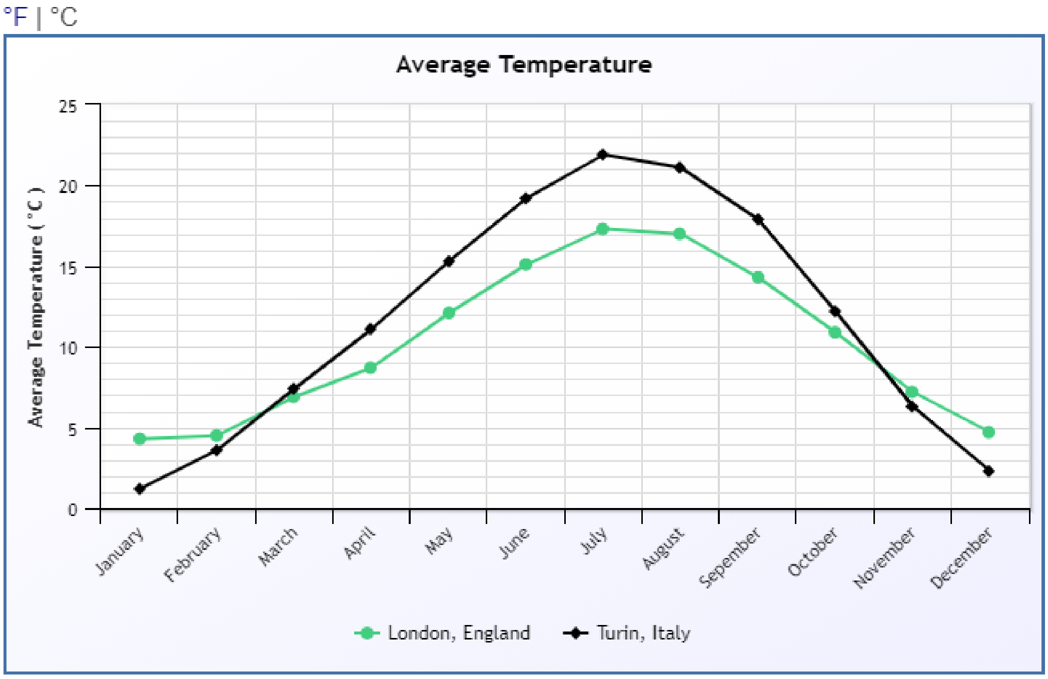


Figure 7.4: Daily average load curves during holidays of winter and summer: comparison between italian data, namely RSE, and the UK data. The Italian consumption are taken from [100].

According to [56], the electric load, as well as the thermal, are influenced by several meteorological variables, especially the temperature: despite the global warming, with even more warm summers and extreme meteorological events, Turin and London seems to have a similar mean temperature along the year: the former has warmer summer and colder winter than the latter, with more precipitation, according to [102]. The average monthly temperatures along a year are shown in **Figure 7.5**.



AVERAGE TEMPERATURE (°C)

City	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
London	4.3	4.5	6.9	8.7	12.1	15.1	17.3	17.0	14.3	10.9	7.2	4.7	10.3
Turin	1.2	3.6	7.4	11.1	15.3	19.2	21.9	21.1	17.9	12.2	6.3	2.3	11.6

Figure 7.5: Average monthly temperatures along the year: comparison between Turin and London by [102].

7.1.2 PV data

The PV production is simulated through the model presented in [94], locating the panels over some Turin districts.

The starting data-set involves the production from 69.2 MW, sampled each 15 min, for 2018 and 2019. Then, the **Equation 7.1** is applied to compute the yearly equivalent solar hours, obtaining respectively about 1154 and 1274 h/year, quite close to the values presented for the Piedmont by [103].

$$E_{AC} = P_N \cdot h_{eq} \cdot PR \tag{7.1}$$

- $\boldsymbol{E_{AC}}$: energy produced.
- $\boldsymbol{P_N}$: nominal power, as the sum of the nominal powers of all the modules (in standard test condition).
- $\boldsymbol{h_{eq}}$: equivalent solar hours.

- ***PR***: performance ratio, which involves several losses, such as the ones due to the frontal glass, the electric wires and the inverter. A design value of 0.75 is chosen ([104]).

Assuming constant h_{eq} and PR, the PV size for the EC, from now on $P_{PV,EC}$ is chosen by supplying the yearly households consumption: applying again the **Equation 7.1** , and considering an average value between the 2018 and 2019, the final results is about $P_{PV,EC} = 13.7MW$, with a size per households of about 4.1 kW/household. The values for the single years are summarised in **Table 7.3**.

Table 7.3: Sizing of the PV for the EC: key figures by year.

Feautures	2018	2019
P_N *[MW]*	14.4	13.0
yearly h_{eq} *[h/year]*	1154	1274
Size per household [kW/household]	4.3	3.9

The sizing of the rooftop PV systems is not further investigated, but a brief discussion is now faced about the validity of these results. An interesting analysis about the sizing of PV and ESS systems within the collective self-consumption scheme is carried on in [105]: considering an average useful surface available of 250 m^2 for the apartment buildings and 12 m^2/kW for the flat roofs, the maximum allowable size should be about 20 kW. Hence, in case of 4 kW/household, an average building apartment could host maximum 5 families, a number quite low for a typical Italian condominium ([106]). However, the sizes presented above are considered valid for the thesis purpose, since the considered area presents different building types: indeed, in case of pitched roofs, 6 m^2/kW are sufficient ([105]).

7.1.3 Data visualisation

This paragraph helps to visualise the consumption and production within the EC and check eventual seasonalities.

The yearly daily and monthly totals are depicted in **Figures 7.6 Figure 7.7**: as expected, the consumption are lower during summer than winter, while the opposite occurs for the PV production, while the latter exceeds the consumption during the colder months, such as January, February, March, October, November and December, whit the highest production during March 2019.

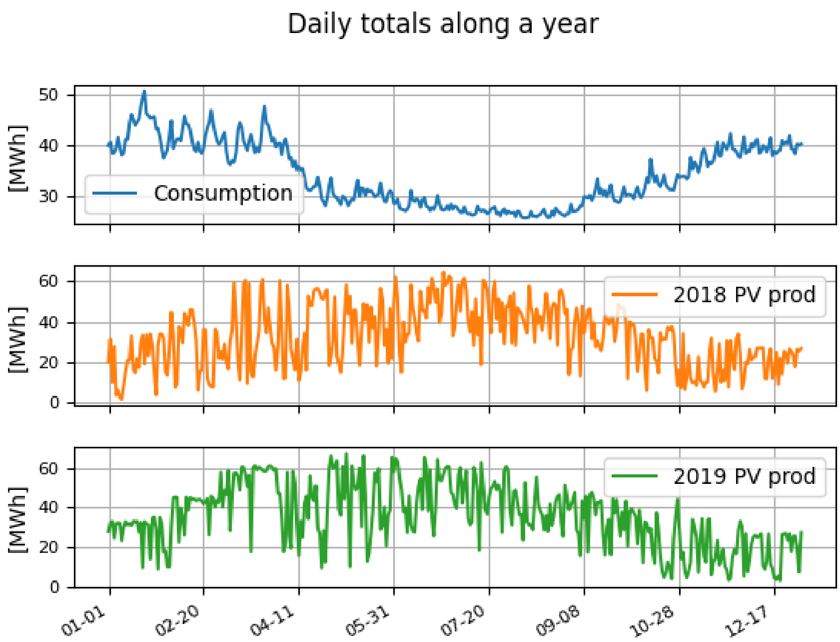


Figure 7.6: Daily totals consumption and production along one year: on the x-axis, to avoid the distinction between 2013, 2018 and 2019, the data are formatted as month-day.

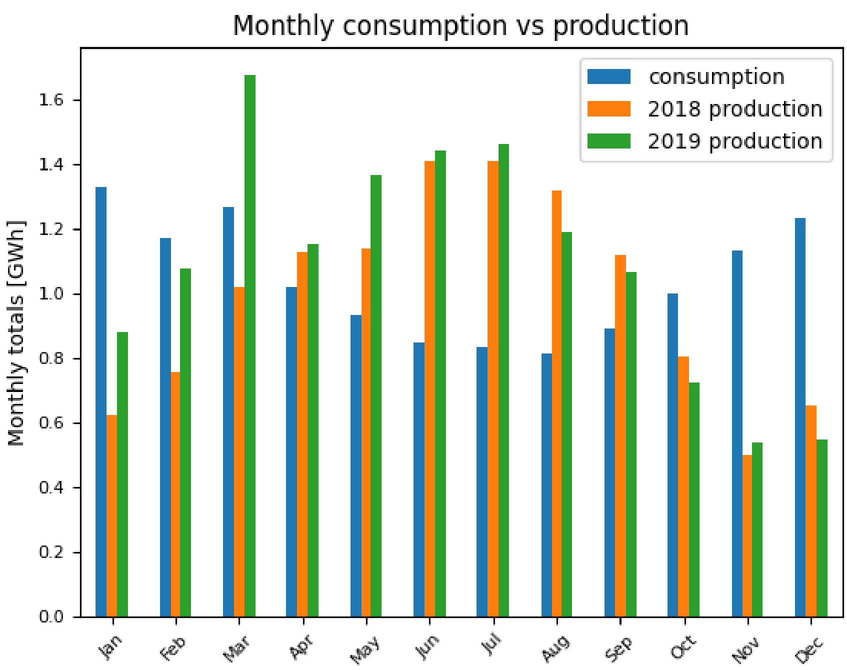


Figure 7.7: Monthly totals consumption and production along one year.

A more detailed daily comparison between the consumption and production is offered in **Figure 7.8**: average days of January, April, July and October are plotted in terms of hourly consumption (cons) against production (prod). The production already exceeds the consumption during the colder months, but in a smaller time interval than the warmer day, while during July the peak PV production almost reaches 6 times the related consumption: of course this isn't an optimal optimisation, and the usage of batteries seems to be necessary. However, as already said more times, the optimal sizing with the battery is out of the scope of the thesis, making this fictitius case study a very flexible starting point for building and/or simulating more realistic ECs and VPPs.

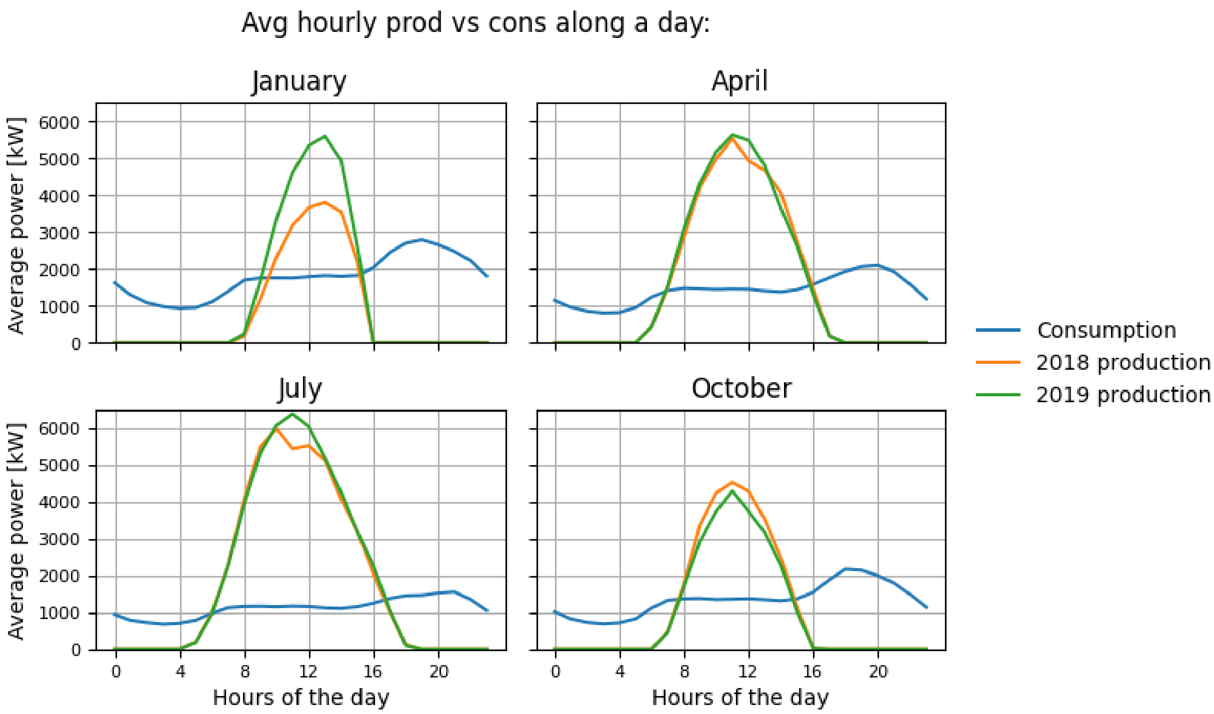


Figure 7.8: Daily average hourly consumption and production along 4 characteristic months.

As last visualization focus, the seasonalities are explored trough suitable boxplots, starting from the yearly one shown in **Figure 7.9**, where 2018 and 2019 are put together: the trend respects what was already observed before, with higher variability for the PV production than the consumption, while within this latter, less variability can be observed during summer months.

Continuing with the weekly seasonality, the consumption appear to be higher during Sunday as shown in **Figure 7.10** , meaningn higher consumption during the weekends, in accordance with [107].

Finally, the daily seasonality is explored considering the hourly consumption and production within a day in: the y-scales are not the same, otherwise the consumption plot would be too less visible, since the productions are higher. However, the trend are the ones expected, with the typical 2 daily peaks for the consumption and the unique for the production. Some outliers are present during the central hour of the day for the consumption, probably due to holidays.

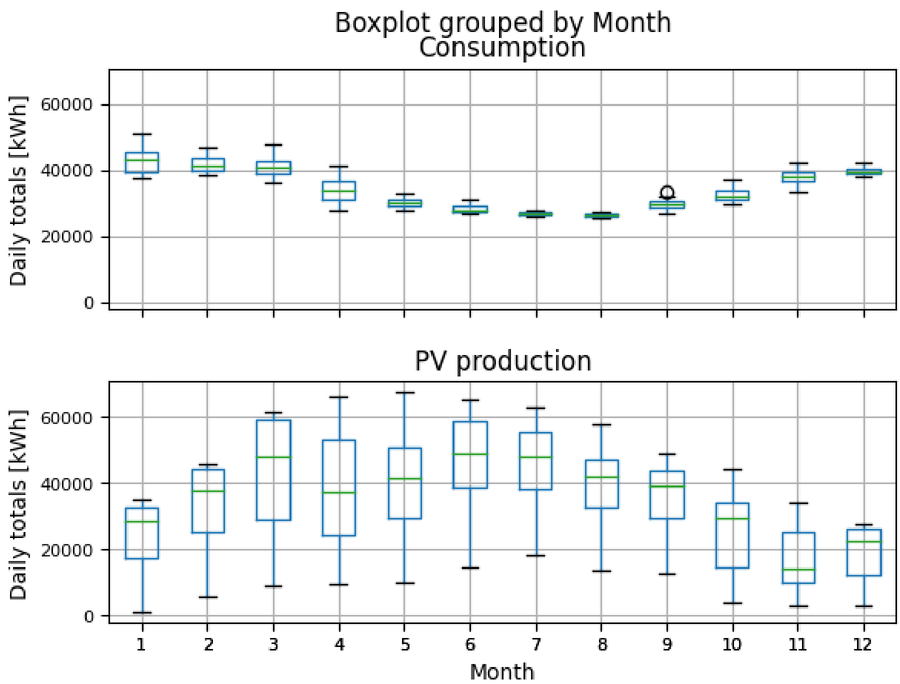


Figure 7.9: Daily totals boxplot by month: 2018 and 2019 are considered together.

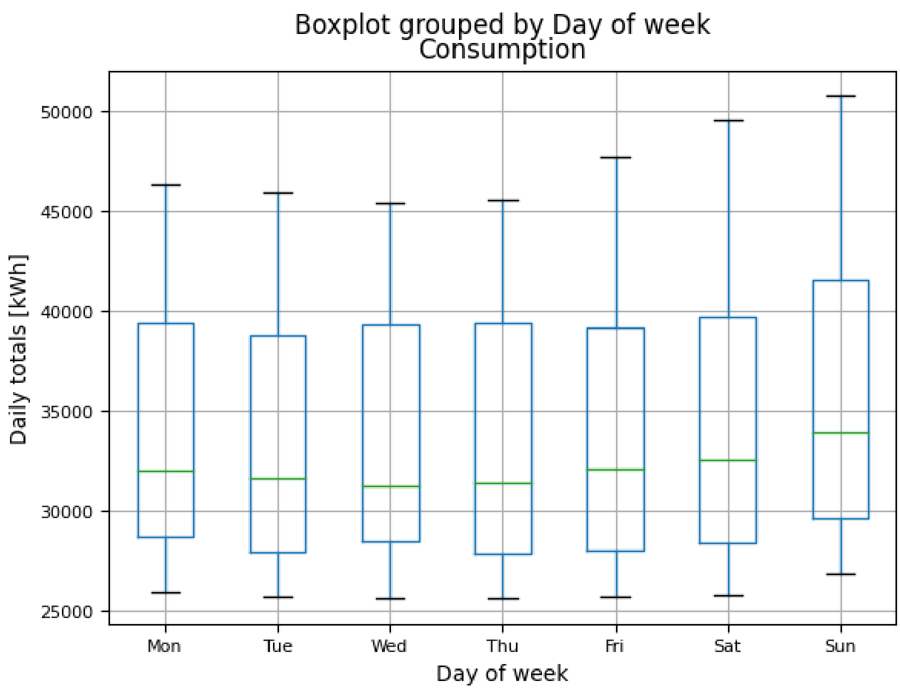


Figure 7.10: Daily totals boxplot by week of the day: only the consumption is involved.

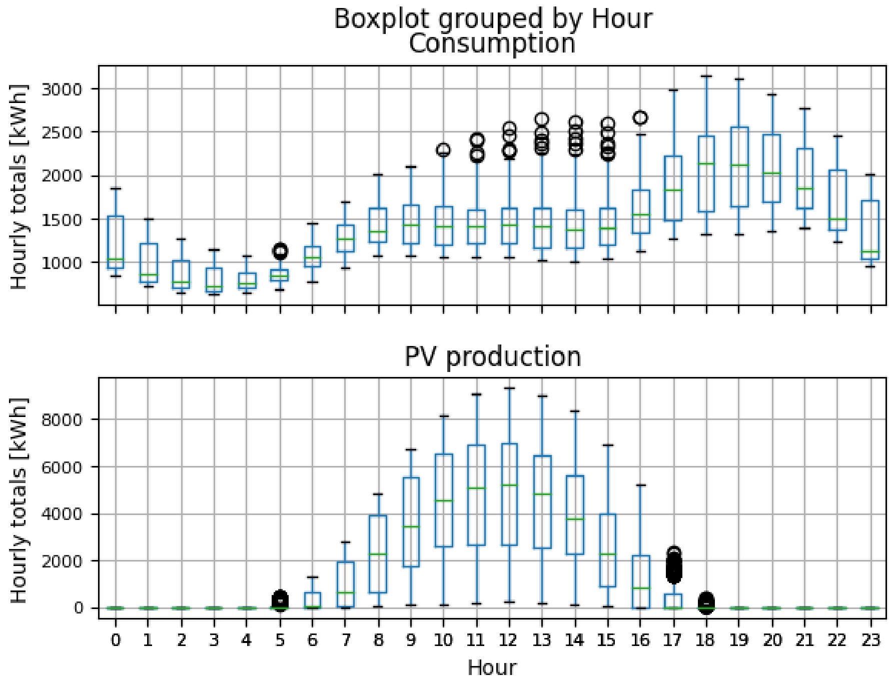


Figure 7.11: Hourly totals boxplot by hour of the day: 2018 and 2019 are considered together, without sharing the y-axis between consumption and production.

7.1.4 Potential effective imbalances estimation

The effective imbalances are potential because the EC is fictitious and they are estimated because there aren't actual RT and FO values to compare for both the households consumption and the PV production. Starting from the data analysed in the previous paragraphs, considered as the RT measures, the imbalances are then build ad hoc respecting the typical forecasts errors and drawing from a Gaussian distribution: because of the latter element of causality, 10 runs are implemented for both the consumption and the production imbalances.

Building the consumption imbalance

The consumption imbalance is defined as the imbalance of a CU, namely

$$Imb_{cons} = FO_{cons} - RT_{cons} \tag{7.2}$$

- $\boldsymbol{FO_{cons}}$: forecasted EC consumption, unknown.
- $\boldsymbol{RT_{cons}}$: actual EC consumption, i.e. the final UK data-set analysed in **Paragraph 7.1.1**.

The Imb_{cons} was hence build for each 15-min from a normal distribution and assuming 2 kind of relationships with the imbalance of the Italian Northern zone total load, from now on $Imb_{load,north}$, such that Imb_{cons} is not so casual. Before explaining how the imbalances were created, the $Imb_{load,north}$ is now briefly described: it is the difference between the DA FO and actual total load within the Northern zone. The total load is itself the active power representing the net internal consumption, i.e.

$$TotalLoad = Production + Import - Export - Consumption_{aux} \tag{7.3}$$

where the energy absorbed by pumping, namely $Consumption_{aux}$ and the network losses are respectively excluded and included, according to [108]: hence the total load doesn't refer only to the residential load, but the latter is included in the former. The data-set on $Imb_{load,north}$ is taken from [109]: they are power sampled each 15-min, hence they were transformed in energies.

The building of the the Imb_{cons} is based on the following concepts:

1. **Gaussian noise**: $Imb_{cons} \sim \mathcal{N}(\mu, \sigma)$, where μ depends on the $Imb_{load,north}$ sign and σ on the typical forecasts errors that according to [110] go from 1-2 % at substation level up to 30 % at single level. After several attempts it was chosen $\sigma = 40kWh$, such that the obtained forecasted errors are summarised in **Table 7.4**: the errors considered are the MAPE and the NRMSE, since they are usually used in literature ([110]). Furthermore, 2018 northern total load presents MAPE = 2.5% and MAPE = 2.9%, while the 2019 data have MAPE = 2.8% and MAPE = 3.4%: these errors are less than the UK data-set ones and this is in accordance with [110].

   Among the 10 runs, there is maximum 1 % of difference, hence the order of magnitude remains the same: furthermore, these values are similar to the one obtained in [111], that for about 3,000 aggregated users get a NRMSE of about 8 % (see **Figure A.10**), as well as in [56].

2. **Qualitative relationship with $\boldsymbol{Imb_{load,north}}$**: the Imb_{cons} sign is related to the $Imb_{load,north}$ one, such that there is a higher probability that the 2 signs are the same than the opposite for each 15-min. To do so, after several attempts it was chosen $\mu = 4kWh$ if $Imb_{load,north} > 0$, $\mu = -4kWh$ if $Imb_{load,north} < 0$ and null mean if $Imb_{load,north} = 0$, even if the latter is a case negligible: as a result, the sign correspondence between the EC_{cons} and the Northern zone is summarised in **Table 7.5**.

   The positive concordance occurs when Imb_{cons} and $Imb_{load,north}$ signs are positive, while the opposite refers to negative concordance: comparing the concordance occurrences, it is found that the positive one happens in the majority of positive Imb_{cons} cases among all the runs, while this happen only once for the negative concordance. This is valid for both 2018 and 2019.

   Table 7.5 shows also the positive Imb_{cons} sign occurrence wrt total cases, higher than the negative Imb_{cons} sign one: this is in accordance with the occurrences for $Imb_{load,north}$, for which the differences are much higher.

3. **Quantitative relationship with $\boldsymbol{Imb_{load,north}}$**: to avoid too much variability of the Imb_{cons}, a constraint is imposed passing from a time-step to another, since of course a sort of correlation is present, but not further investigated. Indeed, looking at **Figure 7.12**, without this constraint the changes would be

too frequent. Instead, there aren't too sudden sign changes during consecutive 15-min for the Northern total load and applying the quantitative relationship just described. The Imb_{cons} is hence valid iff

$$|Imb_{cons,\%}(q)-Imb_{cons,\%}(q-1)| \leq |Imb_{load,north,\%}(q)-Imb_{load,north,\%}(q-1)|+0.5\% \tag{7.4}$$

where $Imb_{cons,\%}$ and $Imb_{load,north,\%}$ are the relative imbalances respectively wrt FO_{cons} and $FO_{load,north}$.

Table 7.4: Relative errors in forecasting the EC consumption: for each year, the ranges of MAPE and NRMSE occurred during the 10 runs are reported.

Year	**MAPE** [%]	**NRMSE** [%]
2018	6.2-7.0	7.9-8.8
2019	6.3-7.2	7.8-8.9

Table 7.5: % of occurrence of: positive concordance wrt total Imb_{cons} sign, negative concordance wrt total Imb_{cons} sign, positive Imb_{cons} sign and positive $Imb_{load,north}$. The ranges refer to the 10 runs.

Year	**Occurrence of positive concordance (+,+) wrt to total positive Imb_{cons} signs** [%]	**Occurrence of negative concordance (-,-) wrt to total negative Imb_{cons} signs** [%]	**Occurrence of positive Imb_{cons} wrt to total signs** [%]	**Occurrence of positive $Imb_{load,north}$ wrt to total signs** [%]
2018	52.0-63.3	38.7-50.3	51.5-62.4	70.7
2019	53.2-64.4	32.5-50.0	52.8-64.9	72.7

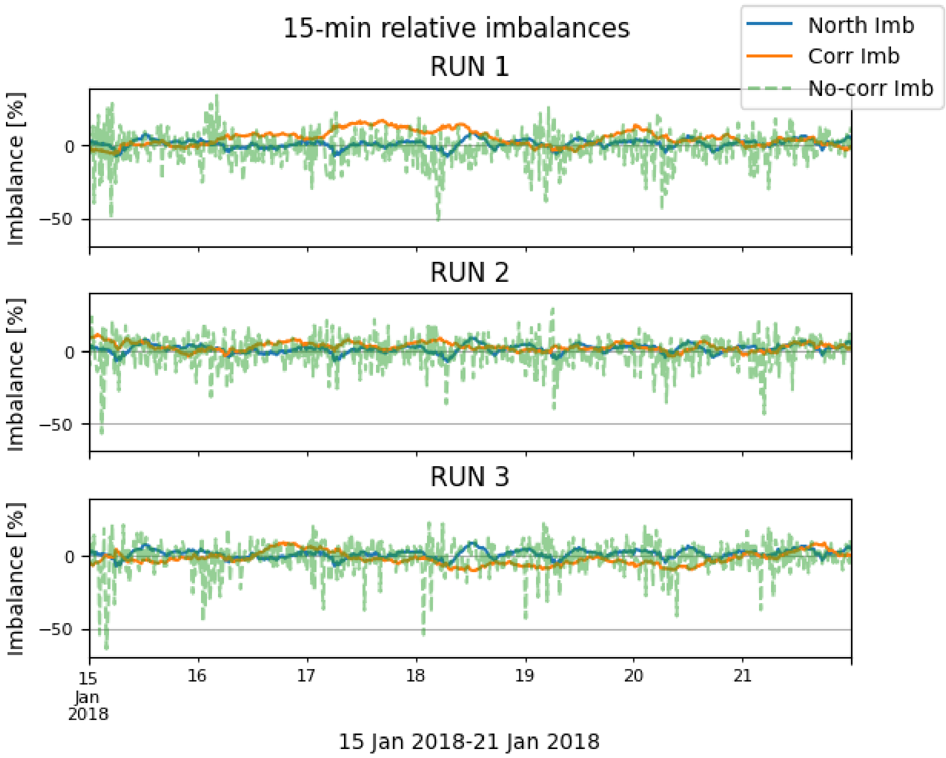


Figure 7.12: 15-min imbalances during a week of January: comparison between $Imb_{load,north}$ and Imb_{cons}, the latter with (*Corr Imb*) and without (*No-corr Imb*) the quantitative relationship with the total northern load.

Building the production imbalance

The production imbalance is defined as the imbalance of a PU, namely

$$Imb_{PV} = FO_{PV} - RT_{PV} \tag{7.5}$$

- $\boldsymbol{FO_{PV}}$: forecasted PV production, unknown.
- $\boldsymbol{RT_{PV}}$: actual PV production, i.e. the final PV data-set analysed in **Paragraph 7.1.2**.

The Imb_{PV} was hence build for each 15-min from a normal distribution with zero mean: hence, also in this case 10 runs are implemented, while $\sigma = 80kWh$ is chosen after several attempts to obtain a NRMSE of 15.2-15.5 % among all the runs. This is in accordance with some literature values for the DA FO presented in [56].

Building the EC imbalance

The general effective imbalance defined using the convention of **Table 3.4** is

$$Imb = RT - FO \tag{7.6}$$

while the grid exchange is

$$GridExchange = Consumption + Production \tag{7.7}$$

The imbalances of the EC can be hence computed as

$$Imb_{EC} = RT_{EC} - FO_{EC} \tag{7.8}$$

where RT_{EC} is the actual grid exchange, while FO_{EC} is the forecasted one.

The substitution of **Equation 7.7** allows to write **Equation 7.8** as

$$Imb_{EC} = Imb_{cons} + Imb_{PV} \tag{7.9}$$

Having in mind the imbalance formulation used in this thesis for a PU, hence the PV production, and for a CU, hence for the households consumption (see **Table 3.5**), the **Equation 7.9** is respected in 2 cases:

- **EC as CU**:
  - $GridExchange = Consumption - Production$
  - $Imb_{EC} = FO_{EC} - RT_{EC}$
- **EC as PU**:
  - $GridExchange = Production - Consumption$
  - $Imb_{EC} = RT_{EC} - FO_{EC}$

The EC is considered as a CU, respecting both the ARERA and thesis conventions. Furthermore, the latter are respected even if the actual production is higher than the actual consumption. About this, **Table 7.6** resumes all the possible cases of imbalances for the EC. Then, when there is a net injection the DAM price used for computing $ImbP$ is P_{DA}, while when a net withdrawal occurs the PUN is considered: indeed, as explained in **Section 3.2** the sellers are remunerated at the zonal price.

Table 7.6: Sign analysis of all the involved imbalances: null imbalances cases are not considered.

Imb_{cons}	Imb_{PV}	Imb_{EC}
<0	<0	<0
>0	>0	>0
<0	>0	<0 if $\lvert Imb_{cons}\rvert > Imb_{PV}$ >0 if $\lvert Imb_{cons}\rvert < Imb_{PV}$
>0	<0	<0 if $Imb_{cons} < \lvert Imb_{PV}\rvert$ >0 if $Imb_{cons} > \lvert Imb_{PV}\rvert$

The effective imbalances are analysed only for 2018 and 2019 for 2 main reasons:

1. Absence of MZ prices data before 2018. In particular from [95] these prices are availabel only from mid-2017, while before only imbalances data are present until 2015.

2. Absence of consumption data during 2020 that would involve the pandemic effect on the consumption reduction. However, MZ data are present, hence 2020 is involved in the MZ imbalances and prices analysis implemented in **Section 7.2**, as well as 2015, 2016 and 2017.

Then 2 scenario are considered depending on the presence of PV production:

1. **Scenario 1**: PV production is not involved, hence it's a sort of ante-EC phase. Being Imb_{PV} null, it's easy to obtain from **Equation 7.9** $Imb_{EC} = Imb_{cons} = Imb_{scen1}$. The MAPE averaged among the runs is 6.5 % for both 2018 and 2019.

2. **Scenario 2**: PV production is here considered, hence $Imb_{EC} = Imb_{cons} + Imb_{PV} = Imb_{scen2}$. The MAPE averaged among the runs is about 12.2 % for both 2018 and 2019.

7.2 Macro-zonal imbalances

The macro-zonal imbalance sign determines the imbalance price for valuing the Imb_{EC}, as shown in **Table 3.6**. This section analyses some trends over the last years in terms of 15-min Imb_{MZ} probability distributions and sign occurrence: data from [95] are available by month since 2015.

Before starting, it's important to underline that the legislation about the Imb_{MZ} calculation changed in 2017 with the deliberation [112], from

$$Imb_{MZ,old} = \sum_{PU}(RT_{PU} - FO_{PU}) - \sum_{CU}(RT_{CU} - FO_{CU}) \tag{7.10}$$

to **Equation 3.2**, such that

$$Imb_{MZ,current} = Imb_{MZ,old} - \triangle_{losses} \tag{7.11}$$

- $\boldsymbol{\triangle_{losses}}$: difference between the effective transmission losses and the standard ones.

- Each term of the equations is positive.

For deepening the passages, see [40]: the main advantages of the new formulation, from now on just Imb_{MZ}, are

- Involving the effects of the transmission losses provides a more accurate evaluation of the actual system state .

- The only measures needed are the exchanges ones, such that the computation of the Imb_{MZ} is faster and can be estimated until D+1 with a very high accuracy.

According to [113], the new methodology just presented well fit the trend of the $Imb_{MZ,old}$, with an average hourly difference of -91 MWh within the Northern MZ and 97 MW for the Southern one during 2015 (see **Figure** A.11).

7.2.1 Imbalances distributions

This paragraph shows the statistics of Imb_{MZ} in terms of PDF and CDF, starting from a comparison from 2015 to 2020. For the PDF the Kernel Density Estimation (KDE) is used, since in the first instance it's unknown if the data follow a particular distribution type: the KDE allows indeed to estimate the PDF in a non-parametric way. The results from **Figure 7.13** are:

- **PDF**: from 2015 to 2020, the Imb_{MZ} seem to be decreased in absolute value, with a net distinction between 2015 and 2016 from one hand, and 2018, 2019 and 2020 from another hand, with 2017 in the middle.
- **CDF**: from 2015 to 2020, the probabilities to find a negative or very high imbalance seems to be decreased.

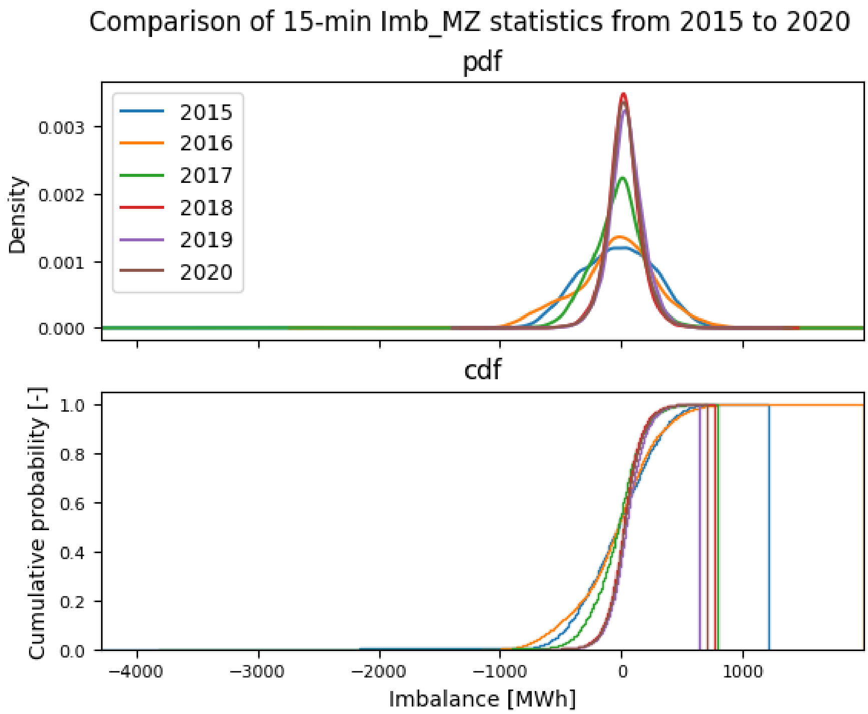


Figure 7.13: PDF and CDF of the Imb_{MZ} from 2015 to 2020.

The tails are mainly due to 2015, 2016 and 2017, respectively shown in **Figures 7.14, 7.15** and **7.16**, while 2018, 2019 and 2020 seem to have a sort of symmetry, as shown in **Figures 7.17, 7.18** and **7.19**.

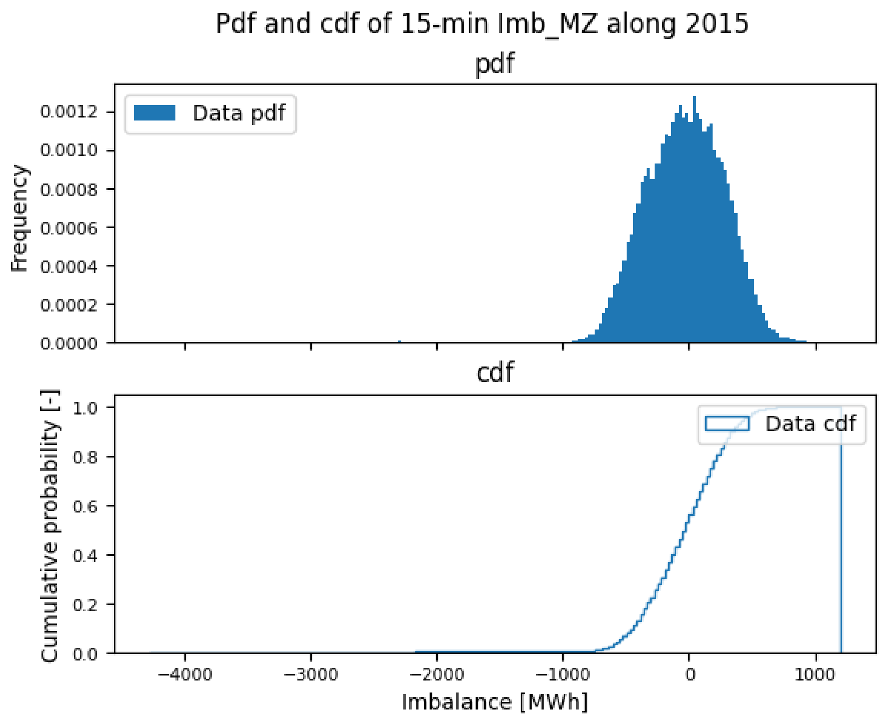


Figure 7.14: PDF and CDF of the Imb_{MZ} along 2015.

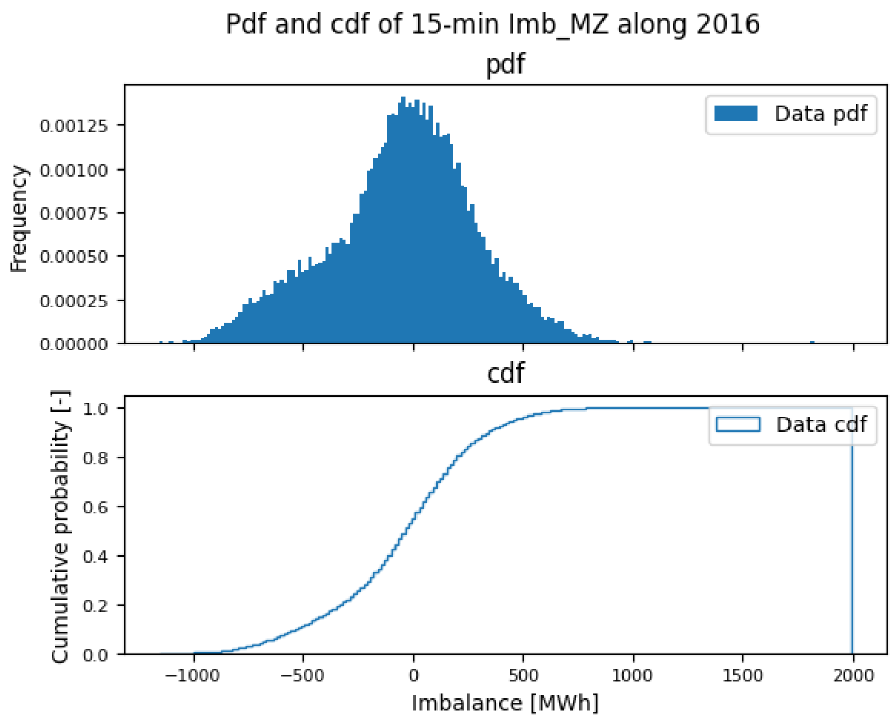


Figure 7.15: PDF and CDF of the Imb_{MZ} along 2016.

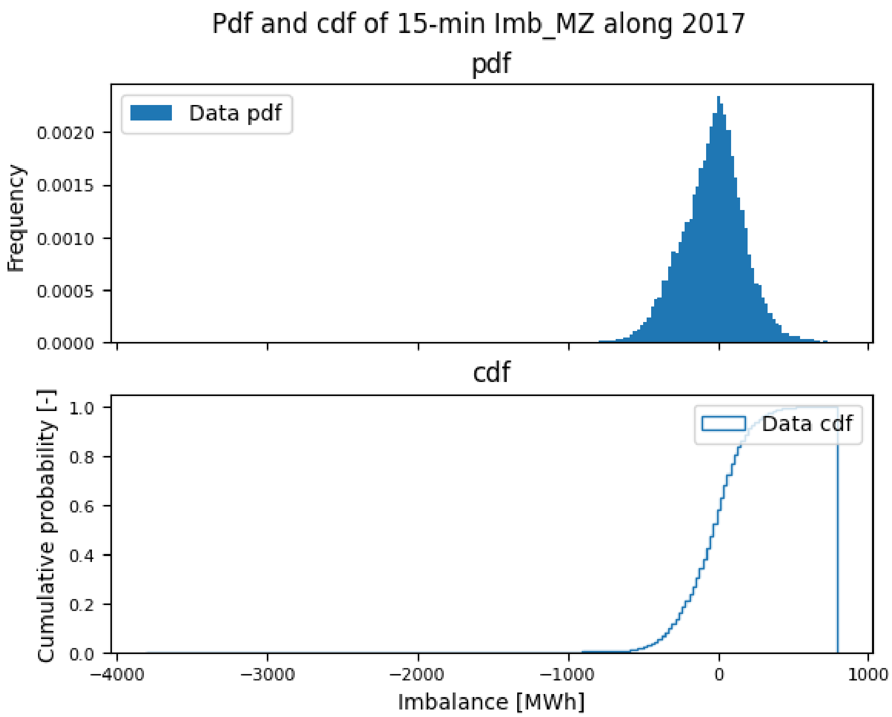


Figure 7.16: PDF and CDF of the Imb_{MZ} along 2017.

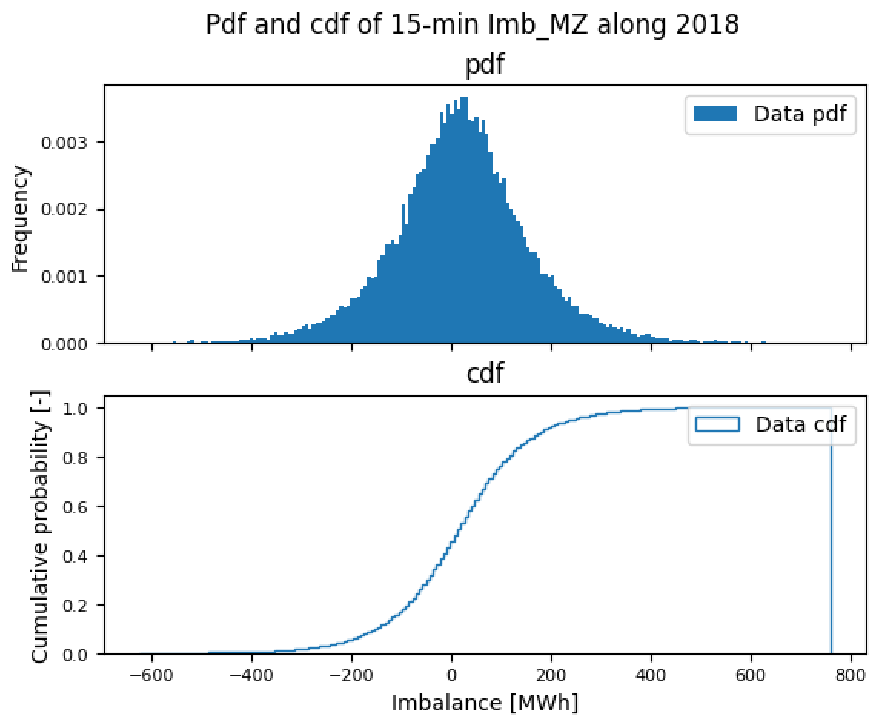


Figure 7.17: PDF and CDF of the Imb_{MZ} along 2018.

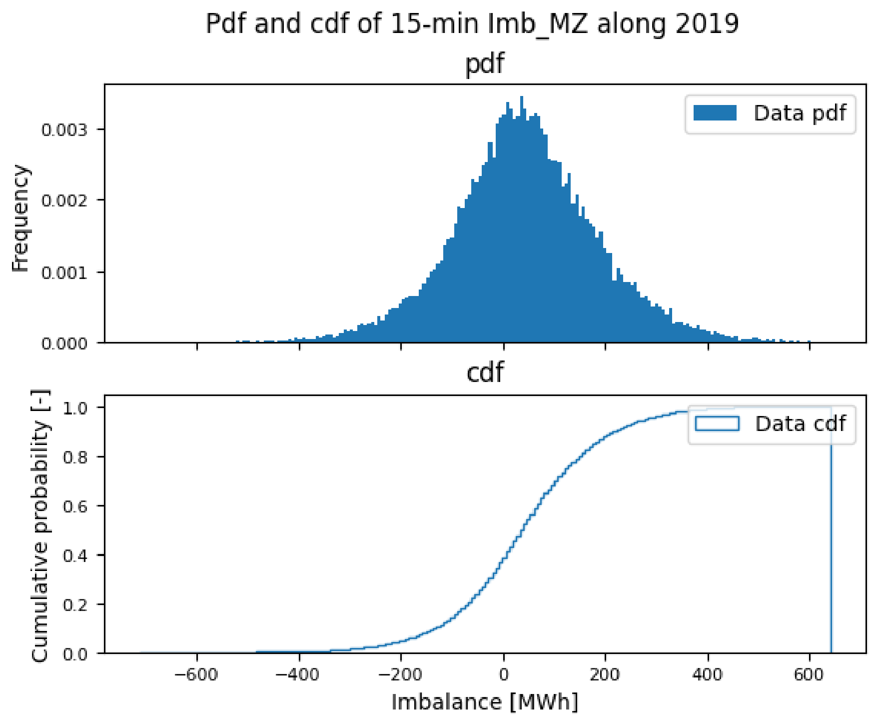


Figure 7.18: PDF and CDF of the Imb_{MZ} along 2019.

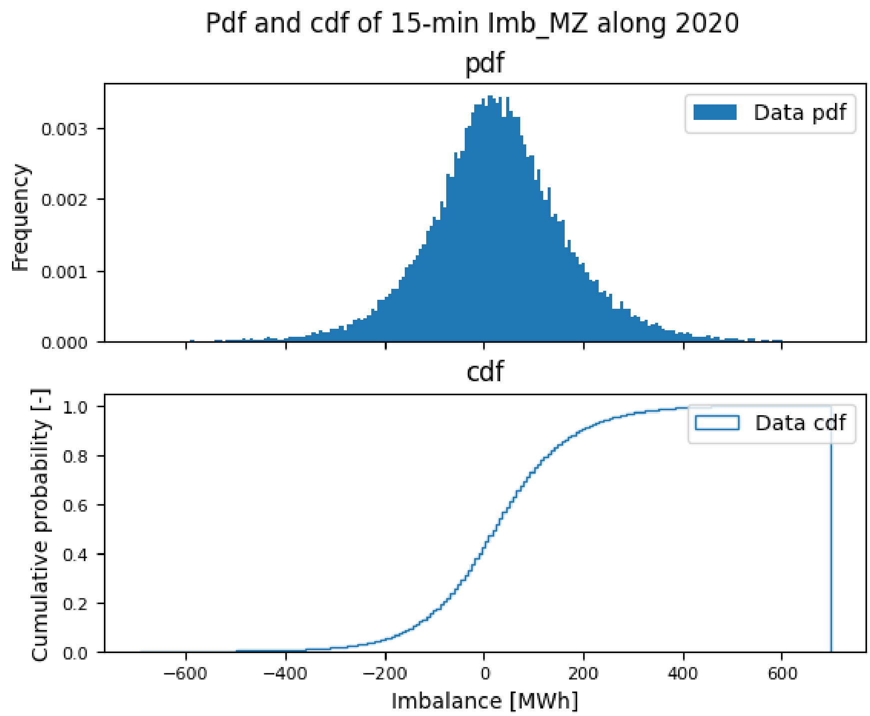


Figure 7.19: PDF and CDF of the Imb_{MZ} along 2020.

The PDFs of 2018, 2019 and 2020 suggest to study eventual gaussianity for these years, using both graphical and quantitative methods, as explained below for the

2018, since the same results are obtained for 2019 and 2020 as shown in **Figures, A.12, A.13, A.14** and **A.15**.

1. **Histograms**: simple graphical method. It consists in plotting the actual PDF and CDF, from now on *Data*, together with the expected Gaussian ones: as can be seen from **Figure 7.20**, the actual data frequencies are higher for the values closest to 0 MWh, while lower for the ones more distant. However, from this plot the Gaussian distribution seems to be not so qualitatively different from the data.

2. **Q-Q plot**: graphical method. The Qs stand for quantile: dividing a data-set in quantiles leads to samples containing the same amount of data. E.g.: the quartiles divide the data in 4 equal parts, where the second quartile coincides with the median of the distribution, since the 50 % of the data stays below the median. In this regard, the quantiles are position indexes. Coming back to the Q-Q plot, it compares the quantiles of the data-set with the expected theoretichal ones of a probability distribution, in this case the Gaussian Normal distribution: if the data fits the latter, the points lies on the straight line $y = x$. The plot for the 2018 is shown in **Figure 7.21**: the tails differ from the straight line and according to [114] this is due to data too peaked in the middle, as can be seen in **Figure 7.20**. For the sake of completeness, the 2017 is reported in **Appendix A**: the Q-Q plot in **Figure A.17** proves the left-skeweness shown in **Figure A.16**.

3. **Statistical tests**: quantitative methods, used to quantify how likely is that the data-set follows a Gaussian distribution. A statistical test assume the null hypothesis, hence that the dare are normal distributed: then, the so-called p-value is computed and compared to a threshold, usually 0.05, such that if $p <= 0.05$, the null hypothesis is rejected and it is likely the data aren't normal distributed. Several statistical tests exist, that can test several probability distribution: the Normal, Rayleigh and Gumbel ones are explored, from 2015 to 2020, without finding any $p > 0.05$.

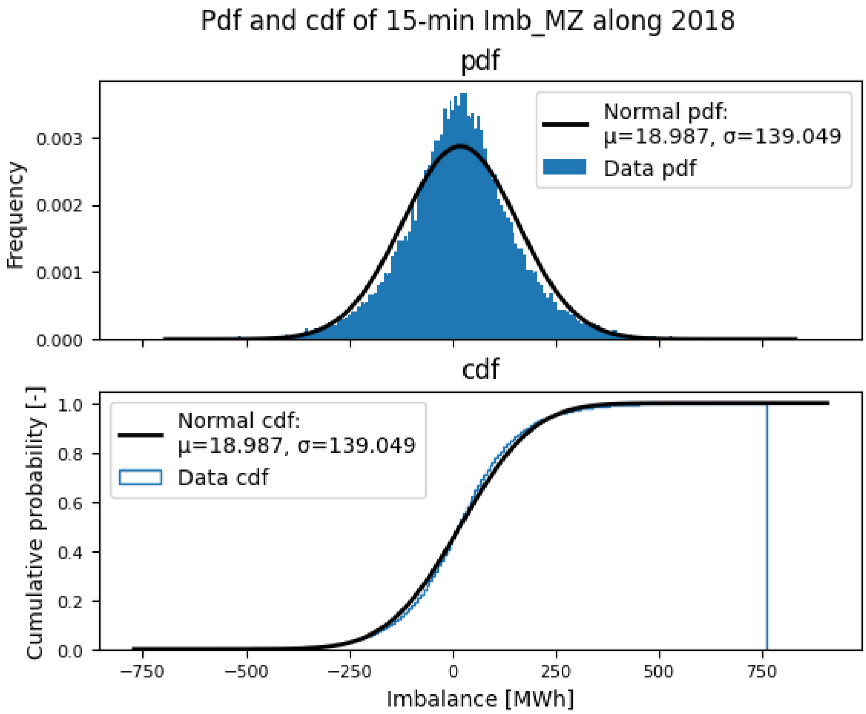


Figure 7.20: Comparison between the Imb_{MZ} data and the expected normal distributions during 2018.

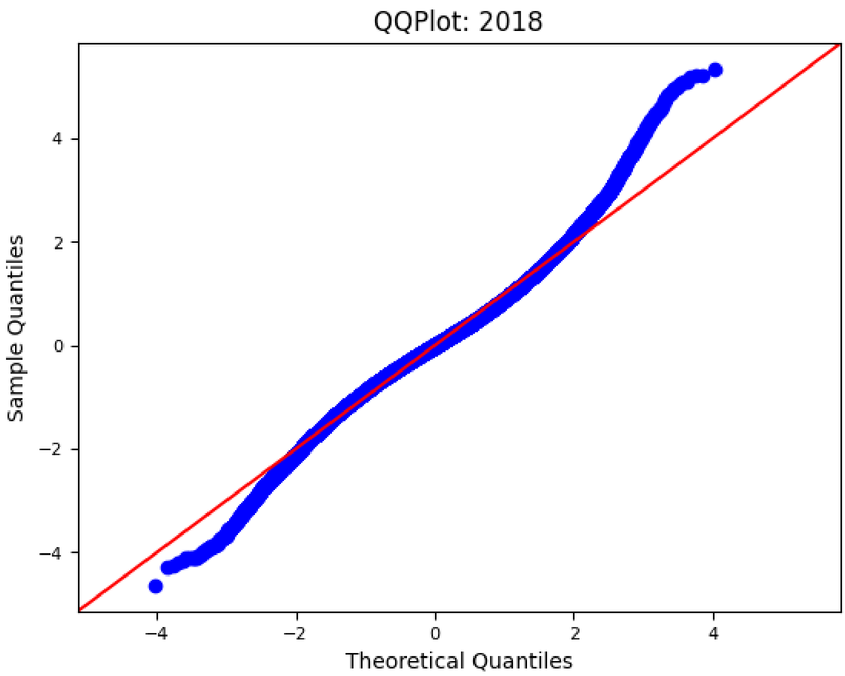


Figure 7.21: Q-Q plot for the Imb_{MZ} during 2018.

7.2.2 Imbalance sign occurrence

This paragraph analyses the imbalance sign occurrence trends from 2015 to 2020 and within the single year, by month and by hours of the day. First, the % of sign occurrence within the year are summarised in **Table 7.7**, together with the yearly average Imb_{MZ} in absolute value, without distinguishing between positive, from now on *Pos*, and negative, from now on *Neg*: these results are in accordance with the statements expressed previously analysing **Figure 7.13**.

Table 7.7: Imb_{MZ} sign occurrence and yearly average $|Imb_{MZ}|$, namely $|Imb_{MZ,avg}|$ from 2015 to 2020.

Key figure	2015	2016	2017	2018	2019	2020
Pos [%]	47	46	45	56	63	58
Neg [%]	53	54	55	44	37	42
$\|Imb_{MZ,avg}\|$ *[MWh]*	252.7	261.4	163.9	105.2	115.0	108.0

The Imb_{MZ} became lower in absolute value and more positive in terms of occurrence in the last years, leading to more cases in which $P_{imb} = min(P_{down}, P_{DA})$, hence possible low gain or losses, as stated by **Tables 3.6** and **3.8**.

The sign occurrence are then analysed by hours and months, comparing 2017, 2018 and 2019. In particular:

1. **By quarter of the day**: the day is divided into 4 quarters, starting from 00:00 to 05:45, and so on. The comparison is presented in **Figure 7.22**: while 2017 presents more or less the same % apart from the third quarter, 2018 and 2019 have higher difference between *Pos* and *Neg* during the night. The latter trend is the same for 2020 as depicted in **Figure A.18**, while the 2015 and 2016 share qualitatively and almost quantitatively the occurrence, as shown in **Figures A.19** and **A.20**.

2. **By season**: the months are grouped by seasons, namely

   - Winter: January, February and December.
   - Spring: March, April and May.
   - Summer: June, July and August.
   - Autumn: September, October and November.

   The comparison is presented in **Figure 7.23**: the yearly predominance of the negative sign during 2017 is due to Spring and Summer months. In 2018 and 2019, instead, the occurrence of postive signs is higher in each season, with the highest difference wrt negative ones during Winter and Spring. This time the 2020 data differ from 2018 and 2019 ones, in particular the slight preponderance of *Neg* signs during Autumn (see **Figure A.21**), while the 2016 present the same trend of 2017 (see **Figure A.23**), unlike the 2015 (see **Figure A.22**).

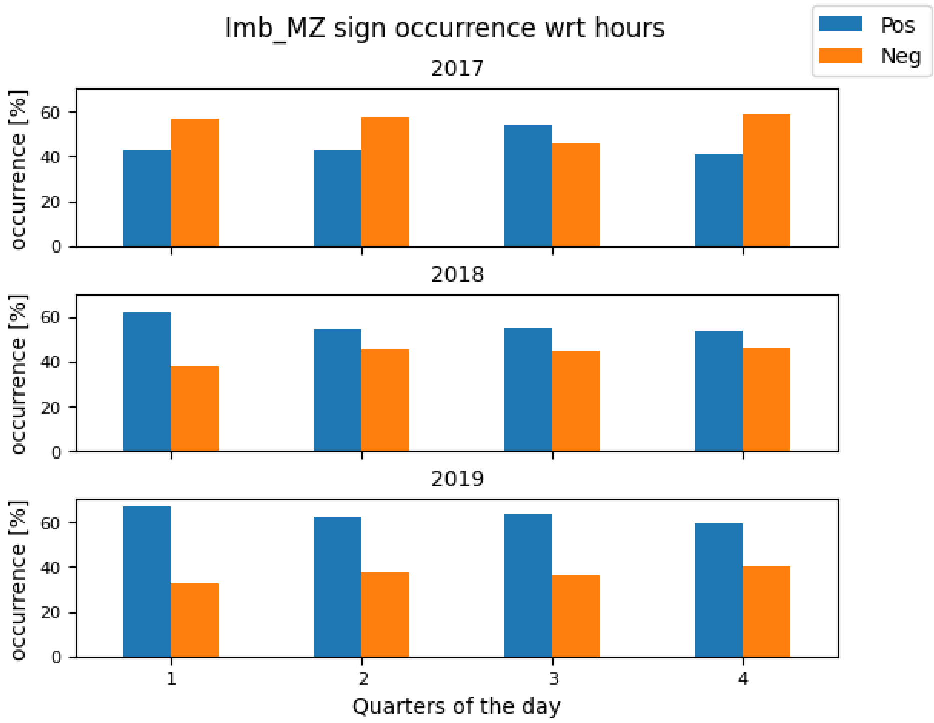


Figure 7.22: Imb_{MZ} sign occurrence by quarter of the day: comparison between 2017, 2018 and 2019.

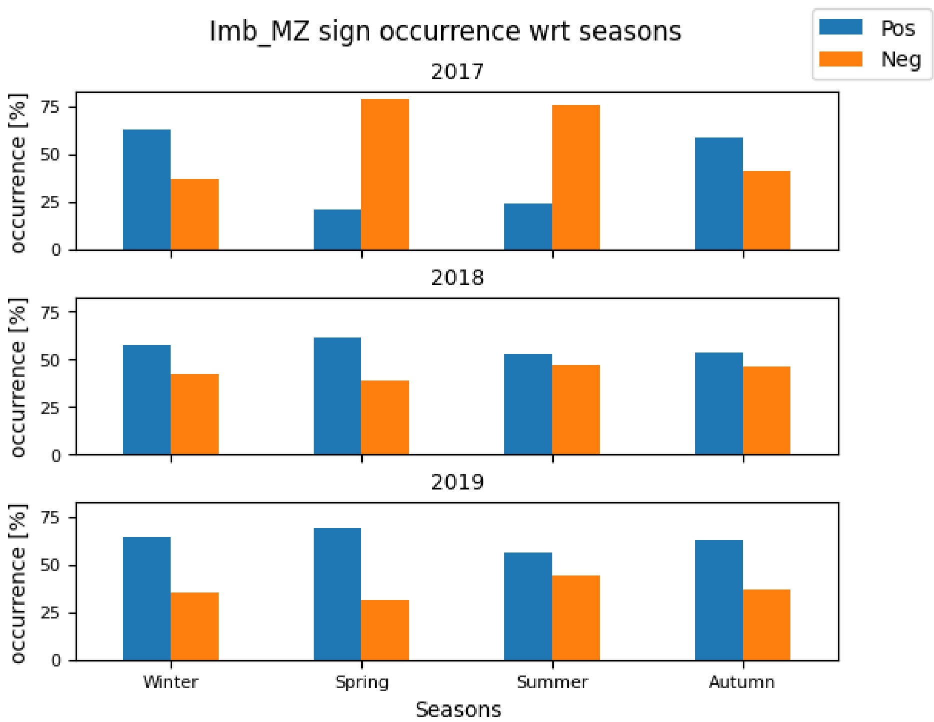


Figure 7.23: Imb_{MZ} sign occurrence by season: comparison between 2017, 2018 and 2019.

Overall, from the above-described analysis results that 2018, 2019 and 2020 are quite similar years: in particular, the *Pos* signs have the highest occurrence from 00:00 to 05:45 and during Winter and Spring. Instead, 2017 is sometimes similar to 2015 and 2016.

Comparing then Imb_{MZ} and $Imb_{load,north}$, the latter used to build the Imb_{cons}, as described in **Paragraph 7.1.4**, it may be interesting to show the sign concordance:

- **Positive concordance**:
  1. *2018*: 61.4 %
  2. *2019*: 68.3 %
- **Negative concordance**:
  1. *2018*: 56.1 %
  2. *2019*: 50.4 %

Looking at the results of **Table 7.4**, it's clear that in the majority of 15-min with positive Imb_{cons} sign, during both 2018 and 2019, $Imb_{load,north}$ has a positive sign. Then, in turn also $Imb_{load,north}$ and Imb_{MZ} have a positive concordance: this may prelude to a same situation between Imb_{scen1} and Imb_{MZ}, since in *Scenario 1.* $Imb_{EC} = Imb_{cons} = Imb_{scen1}$, hence to a majority of negative effects on the grid (see **Paragraph 3.4.2**), at least when $Imb_{cons} > 0$.

7.3 Market prices

This section provides a comparison between the market prices involved in the imbalance settlement, that are:

- $\boldsymbol{P_{up}}$, $\boldsymbol{P_{down}}$: from ASM.
- $\boldsymbol{PUN}$, $\boldsymbol{P_{DA}}$: from DAM.

As already explained in **Paragraph 3.4.2**, usually $P_{down} < P_{DA} < P_{up}$ and $(P_{DA} - P_{down}) < (P_{up} - P_{DA})$, and this is valid also for PUN instead of P_{DA}. To visualise these statements, some analysis are implemented in the following paragraphs.

7.3.1 Hourly, daily and monthly prices

This paragraph shows the time-series of the prices along 2018, 2019 and 2020.

The hourly trends of the market prices are shown in **Figure 7.24**: PUN is not clearly visible, probably because it overlaps P_{DA}, but both remains constantly between P_{up} and P_{down}: rarely the first goes down to 0 [EUR/MWh] and the latter almost reaches 100 [EUR/MWh], while stands out the value of 800 [EUR/MWh] reached by P_{up} around March 2018. Looking at the 2019, the highest P_{up} values occur at the end of the year, while for the 2020 no outliers are present during the first pandemic phase. The same plots, but for the single years, are shown in **Figures A.24**, **A.25** and **A.26** .

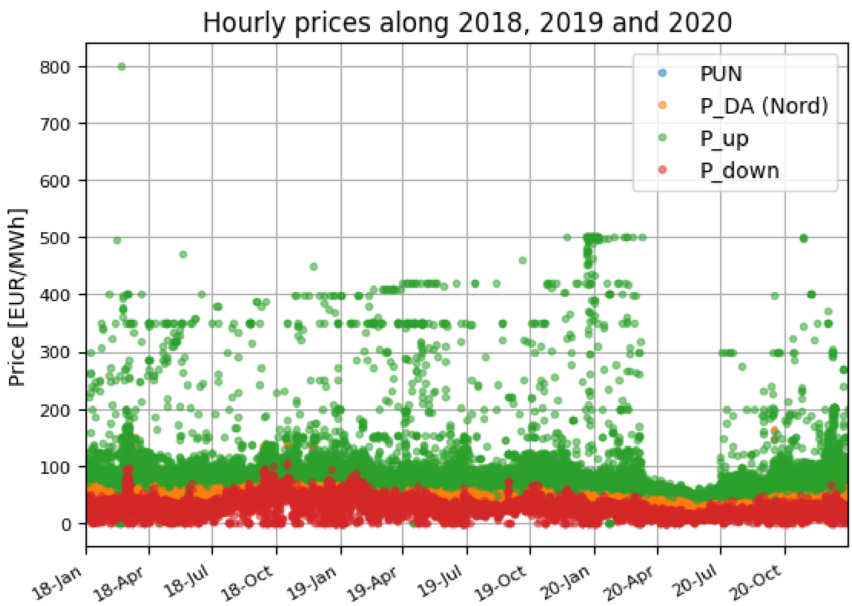


Figure 7.24: Hourly market prices along 2018, 2019 and 2020 The x-ticks labels are in the abbreviate form year-month.

The same pattern reappears in case of daily and monthly mean: however, the PUN is here visible, and it results very close to P_{DA}, remaining slightly higher than the latter during the second and third quarters of the year. In **Figure 7.25** is depicted the 2018, while for 2019 and 2020 see **Figures A.27** and **A.28**.

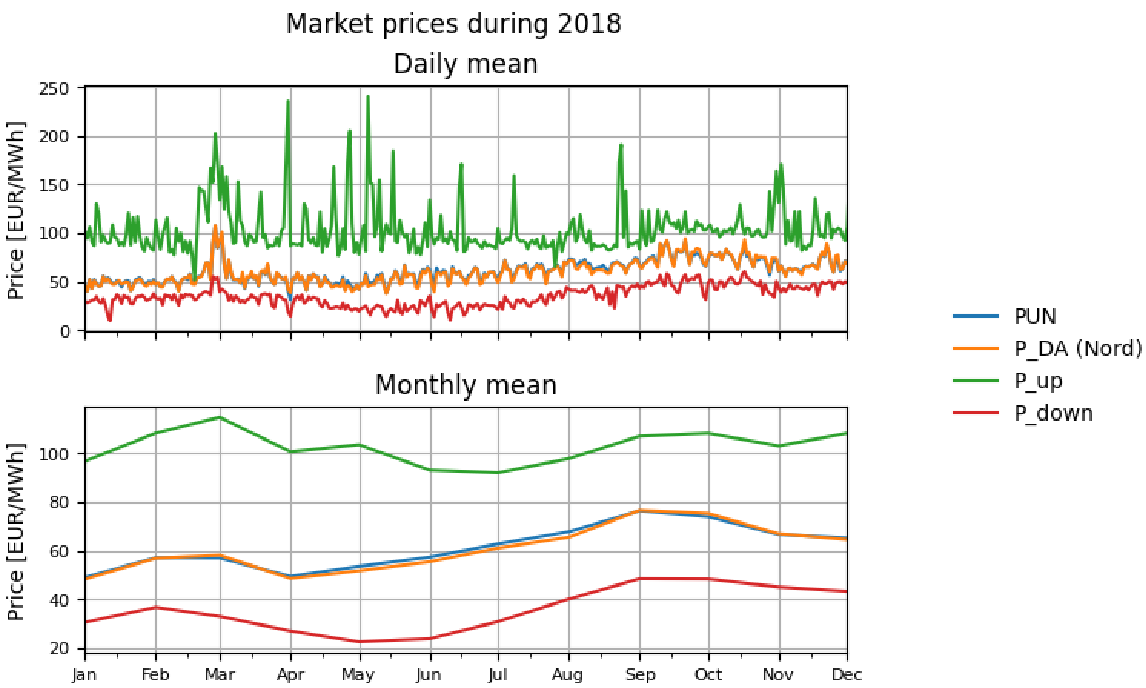


Figure 7.25: Daily and monthly market prices mean along 2018.

A comparison between 2018, 2019 and 2020 is instead offered in terms of monthly mean in **Figure 7.26**: in general, the 2020 values are the lowest, with the evident pandemic effect from March, while from June the 2018 presents the highest, apart from P_{up}, that present a peak during December 2019.

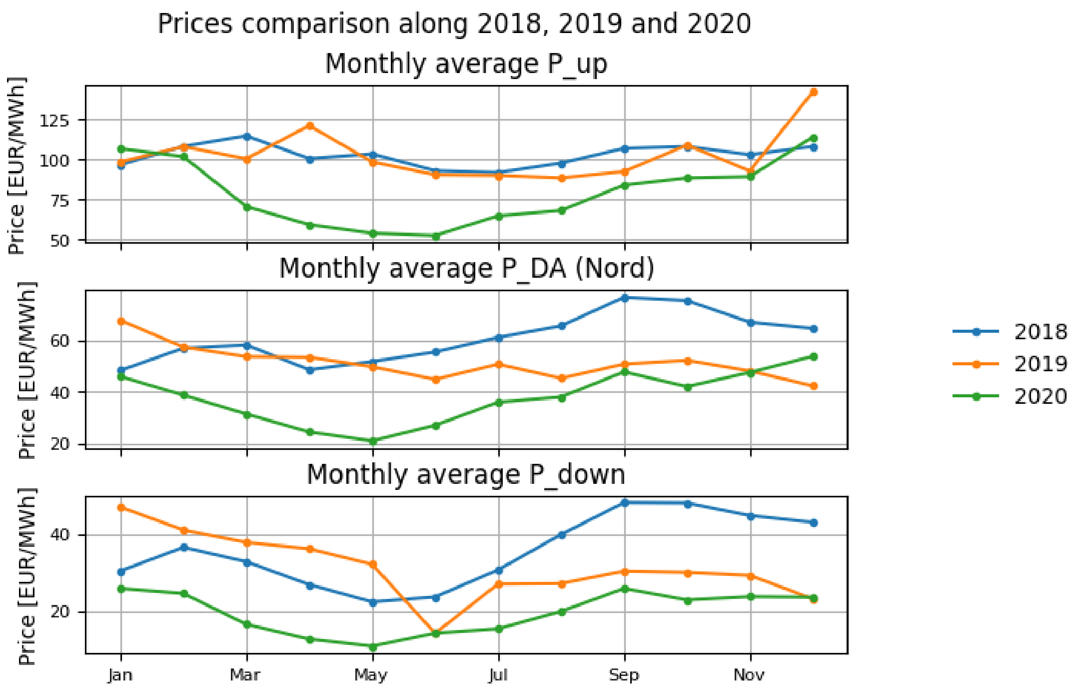


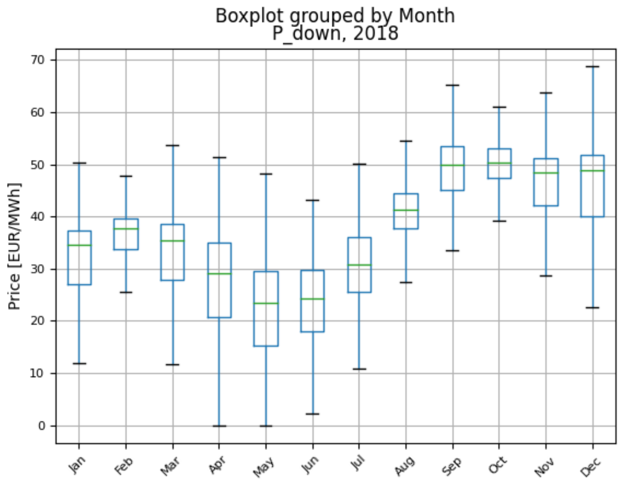
Figure 7.26: Monthly market prices comparison between 2018, 2019 and 2020.

7.3.2 Possible seasonalities

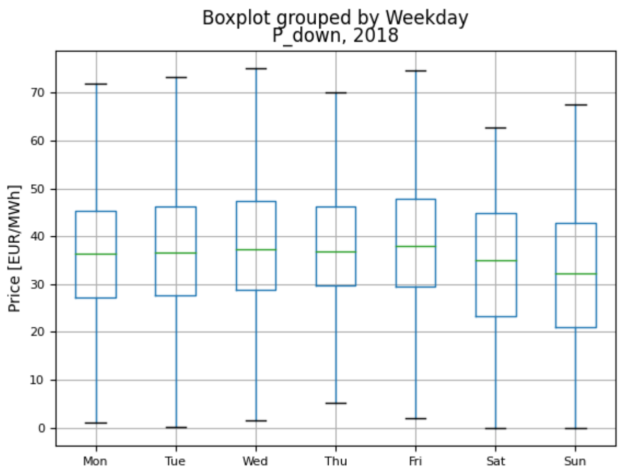
Eventual seasonalities can be investigated trough the boxplots: first, the ASM prices are analysed, showing here only the 2018, while 2019 and 2020 figures are put in the **Appendix A**.

The P_{down} values are depicted in **Figure 7.27** and grouped by different time periods:

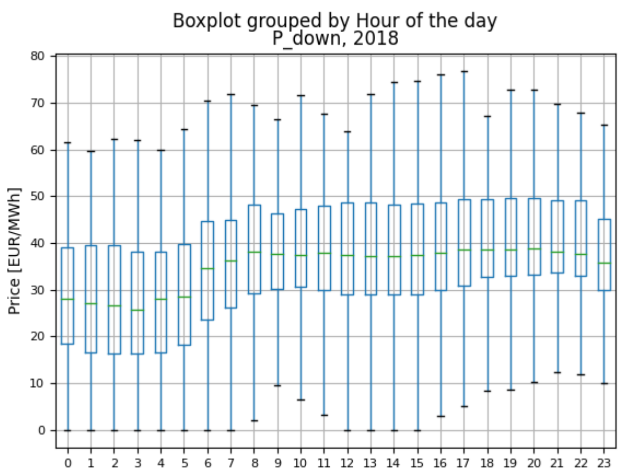
- **By month**: lower values seems to occur approaching the spring and the summer. The distributions are then left-skewed, i.e. the median is closer to the third quartile than the first, showing a higher variability for the first (and lowest) 50 % of the prices than the second one (see **Figure 7.27a**).
- **By day of week**: lower values occur during the weekends (see **Figure 7.27b**).
- **By hour**: lower values occur during the first 5 hours of the day (starting from hour 0, i.e. midnight). The distributions seems to be quite symmetric, apart from 18:00 to 23:00, when it is right-skewed (see **Figure 7.27c**).



(a) P_{down} *grouped by month*



(b) P_{down} *grouped by day of week.*



(c) P_{down} *grouped by hour.*

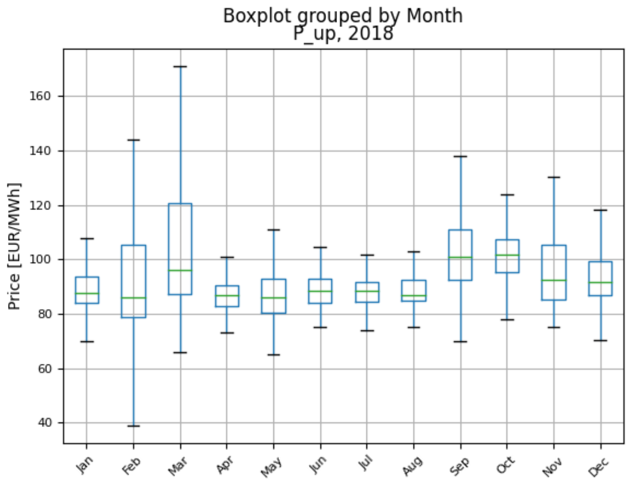
Figure 7.27: P_{down} boxplots along 2018.

The P_{up} values are instead depicted in **Figure 7.28** and grouped by different time periods as well:

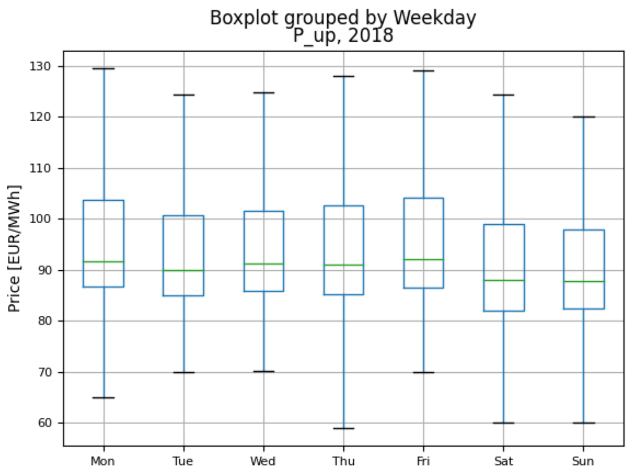
- **By month**: lower values occur during the spring and the summer, when sometimes P_{up} reaches null values. The distributions seem to be usually right-skewed, i.e. the median is closer to the first quartile than the first, showing a lower variability for the first (and lowest) 50 % of the prices than the second one. However, the high presence and variability of the highest outliers make less evident these statements than the P_{down} case. (see **Figure 7.28a**).
- **By day of week**: lower values occur during the weekends, while null values are reached during Sunday, Monday and Tuesday (see **Figure 7.28b**).
- **By hour**: differences are little evident: lower values seems to occur beween 3:00 and 5:00, while null values are reached between 17:00 and 21:00. The distributions tend to be right-skewed (see **Figure 7.28c**).

From these figures, the main differences between P_{down} and P_{up} are listed below, and more or less this analysis may be valid for 2018 and 2020, too (see **Figures A.30, A.31, A.32, A.33**):

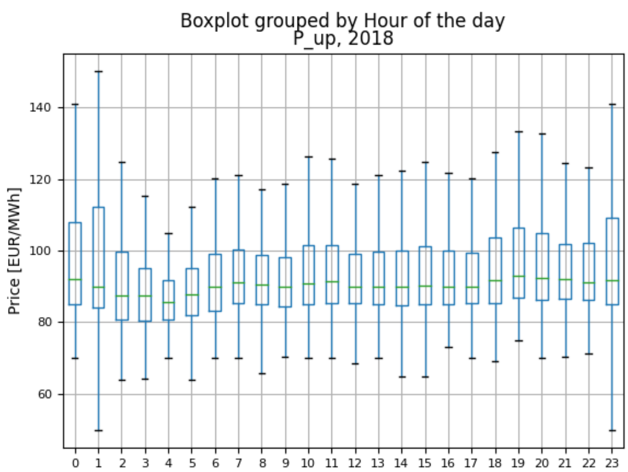
1. P_{down} always reaches 0, while P_{up} only in few occasions.
2. P_{down} presents left-skewness along the months, P_{up} seems to be mostly right-skewed
3. P_{up} can be one order of magnitude higher than P_{down}.



(a) *P_{up} grouped by month*



(b) *P_{up} grouped by day of week.*



(c) *P_{up} grouped by hour.*

Figure 7.28: P_{up} boxplots along 2018.

Looking instead at the P_{DA} (even if this is valid also for the PUN), the boxplots are useful to show how the prices usually follow the consumption levels: during the weekends the prices are usually lower, as depicted in **Figure 7.29**, while they are higher during the 2 daily peaks, usually occurring around the 8:00 and the 18:00 as depicted in **Figure 7.30**. Furthermore, there are more outliers in 2018 and in 2019, than in 2020. Further investigations would be out of the thesis scope: however the monthly grouping is shown in **Figure A.29**

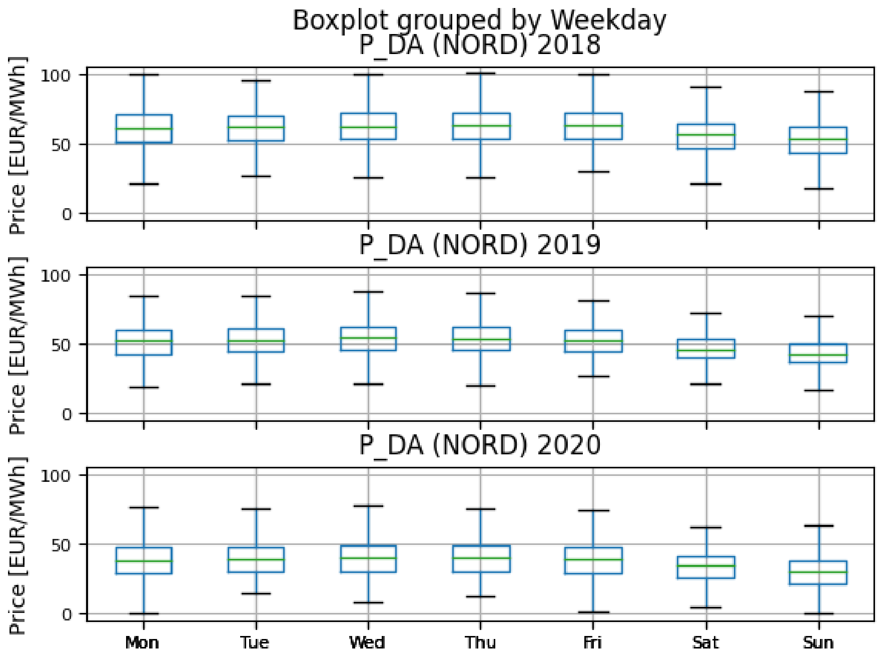


Figure 7.29: P_{DA} grouped by weekday along 2018, 2019 and 2020.

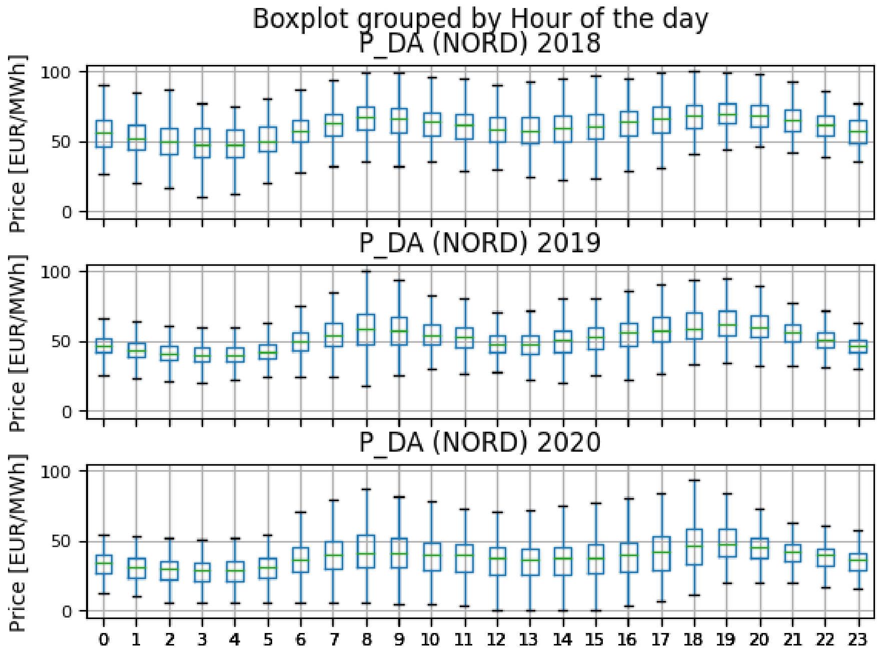


Figure 7.30: P_{DA} grouped by hour of the day along 2018, 2019 and 2020.

7.3.3 Prices differences

As last focus of the section, the differences between the ASM and DAM prices are analysed in terms of relative difference wrt PUN: **Figure 7.24** shows indeed how PUN and P_{DA} tend to be higher than P_{down} and lower than P_{up}, leading to the low/high losses and gains explained in **Table 3.8**.

To carry on this analysis, 3 prices differences are defined and reported in **Table 7.8**: the main expectations are $P_{down} < PUN < P_{up}$ and $(PUN - P_{down}) < (P_{up} - PUN)$, in most of the cases.

Table 7.8: Definition of the prices differences analysed in the last focus of the paragraph.

Price difference	Formulation	Meaning	Expected	Not-expected
$\triangle_{up}$	$(P_{up} - PUN)/PUN$	How much P_{up} is bigger than PUN	$P_{up} > PUN$ (>0)	<0
$\triangle_{down}$	$(PUN - P_{down})/PUN$	How much P_{down} is lower than PUN	$P_{down} < PUN$ (>0)	<0
$\triangle_{DA}$	$(P_{DA} - PUN)/PUN$	How much P_{DA} differs from PUN	-	-

The yearly results are then summarised in **Table 7.9** for 2018, 2019 and 2020: besides mean and edges, the other rows refers to % wrt to the total number of observations during the year. Then, edges refers to the maximum and minimum values of price differences $\triangle$: about this, positive values for $\triangle_{down}$ mean that P_{down} is lower than PUN. Hence -100 % means null P_{up}, while +100 % means null P_{down}: however these cases are usually less than 1 %o of the yearly observations, hence they are neglected in the table.

Looking at $\triangle_{up}$ and $\triangle_{down}$, the not-expected cases are less than 1 % of the total yearly observations, while the mean and the edges % values are much higher for $\triangle_{up}$ than $\triangle_{down}$: these results confirm the above mentioned expectations. It's interting to note that the % of *Expected, Not-expected and No values* remain quite similar along the year. However 2 things have to be underlined:

- **No values**: this means no values observed. In the imbalance settlement P_{DA} is chosen as imbalance price in case of absence of P_{up} and P_{down}, more frequent for the former than the latter.
- **$\triangle_{up}$,Edges, 2020**: +58000 is an outlier, caused by a very low value of PUN. Indeed, in April, the latter reached null, or close to null, values.

Looking at $\triangle_{DA}$, on average $P_{DA} < PUN$ than a little, while the case $P_{DA} = PUN$ is the second occurrence yearly condition for 2018 and 2019, the first one for 2020. Since P_{DA} is mainly very close to PUN, NAC may be negligible compared to $ImbC$.

Table 7.9: Yearly analysis of the price differences analaysed in the last focus of the paragraph.

Delta	[%]	2018	2019	2020
$\triangle_{up}$	*Mean of expected*	76.6	121.0	160.4
	Edges	(+2731,-100)	(+9704,-100)	(+58000,-100)
	Expected	60.2	55.3	63.9
	Not-expected	0.6	0.4	0.5
	No values	39.1	44.2	35.5
$\triangle_{down}$	*Mean of expected*	42.7	40.3	48.4
	Edges	(+100,-132)	(+100,-63)	(+100,-67)
	Expected	92.1	95.3	95.4
	Not-expected	0.2	0.4	0.1
	No values	6.9	3.7	4.1
$\triangle_{DA}$	*Mean*	-1.0 (4.2,-4.6)	-2.0 (4.8,-6.4)	-2.7 (4.6,-7.2)
	Edges	(+102, -37)	(+52,-57)	(+38,-68)
	NORD>PUN	20.3	19	11.6
	NOR<PUN	40.7	45.8	43.9
	NORD=PUN	39	35.1	44.5

The mean for $\triangle_{up}$ and for $\triangle_{down}$ are the ones of the expected cases, while for $\triangle_{DA}$ the overall and the positive and negative cases are shown, the latter within parenthesis.

Then, it may interesting to compare also P_{up} and P_{down} for the years invovled in the imbalance settlement presented in **Chapter 8**: excluding the cases with P_{down} very close to zero, e.g. 0.00001 [EUR/MWh], on average P_{up} resulted higher than P_{down} of:

- **2018**: 300 %.
- **2019**: 597 %.

The prices seasonality was analysed in **Paragraph 7.3.2** and resulted more evident for PUN and P_{DA} than the ASM prices. Since the former lye in the definition of the relative price differences presented in this focus, it may be interesting to investigate possible seasonalities also for the different $\triangle$.

Starting with $\triangle_{down}$ and $\triangle_{up}$, namely respectively $PUN - DOWN$ and $UP - PUN$ in the plots, **Figures 7.31** and **7.32** seem to be in accordance with the trend of PUN and the ASM prices. Indeed:

- $\boldsymbol{PUN}$: higher and lower values occur respectively during the daily peaks and the weekends.
- $\boldsymbol{P_{down}}$: lower values seem to occur during spring and summer months and during the weekends.
- $\boldsymbol{P_{up}}$: lower values seem to occur during spring and summer months.

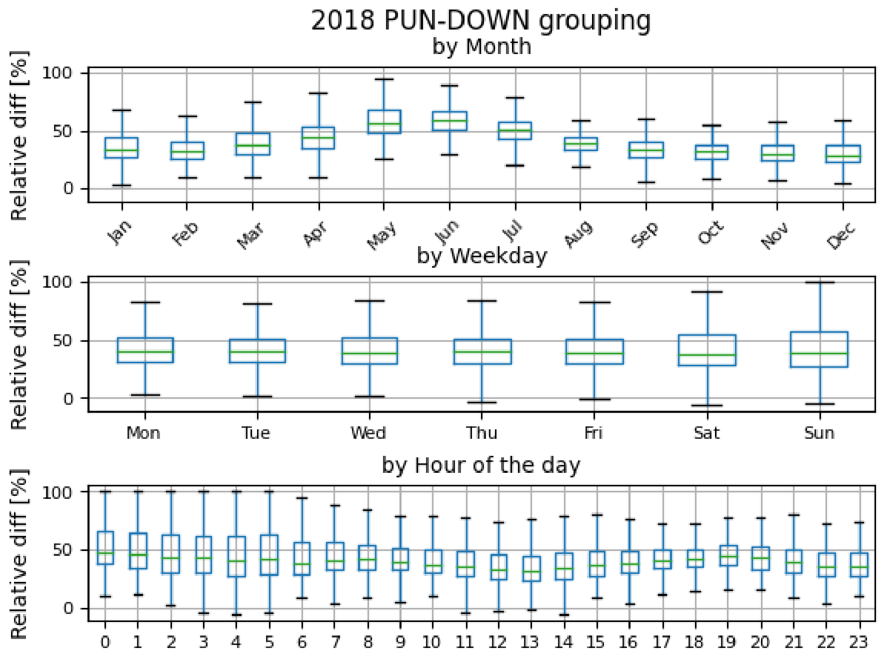


Figure 7.31: Boxplots of $\triangle_{down}$ along 2018 grouped by month, day of week and hour of the day.

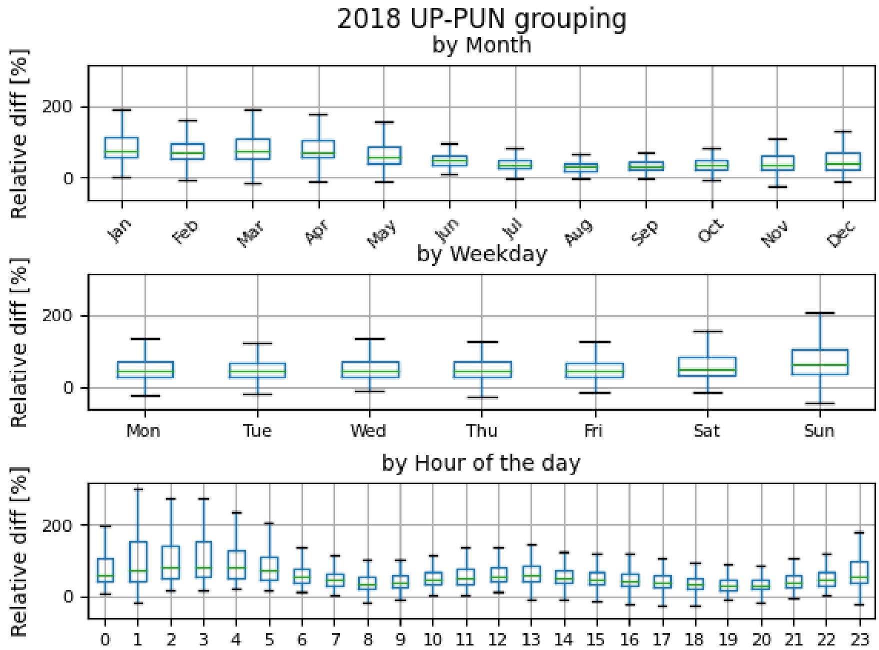


Figure 7.32: Boxplots of $\triangle_{up}$ along 2018 grouped by month, day of week and hour of the day.

Based on the above mentioned facts and the definition of the price differences, **Figure 7.31** shows higher $\triangle_{down}$ during the summer period, the night hours and the daily peaks hours, while **Figure 7.32** shows the opposite and then higher values during Sunday. Overall, the same trend can be be spotted along 2019 and 2020 in **Figures A.34**, **A.37**, **A.36** and **A.37**.

Finally, relevant similarities can be seen in **Figures A.38**, **A.39** and **A.40**, especially in the boxplots grouped by the hour of the day: P_{DA} tends to be higher than PUN mainly between the 2 daily peaks.

7.4 Methodology declination to the case study

Declining the methodology presented in **Chapter 6** lead to the imbalance settlement depicted in **Figure 7.33**, in which the P_{imb} block is explained following **Table 3.6**.

Then, the Italian data-set used in **Algorithm 2** are listed below:

- **ASM**: hourly data for P_{up}, P_{down} and 15-min data for $Imb : MZ$ sign (from [95]).
- **DAM**: hourly data for PUN and P_{DA} (from [96]).
- **EC**: 15-min data for Imb_{cons} and Imb_{PV} obtained as a result of the imbalances construction presented in **Paragraph 7.1.4**.

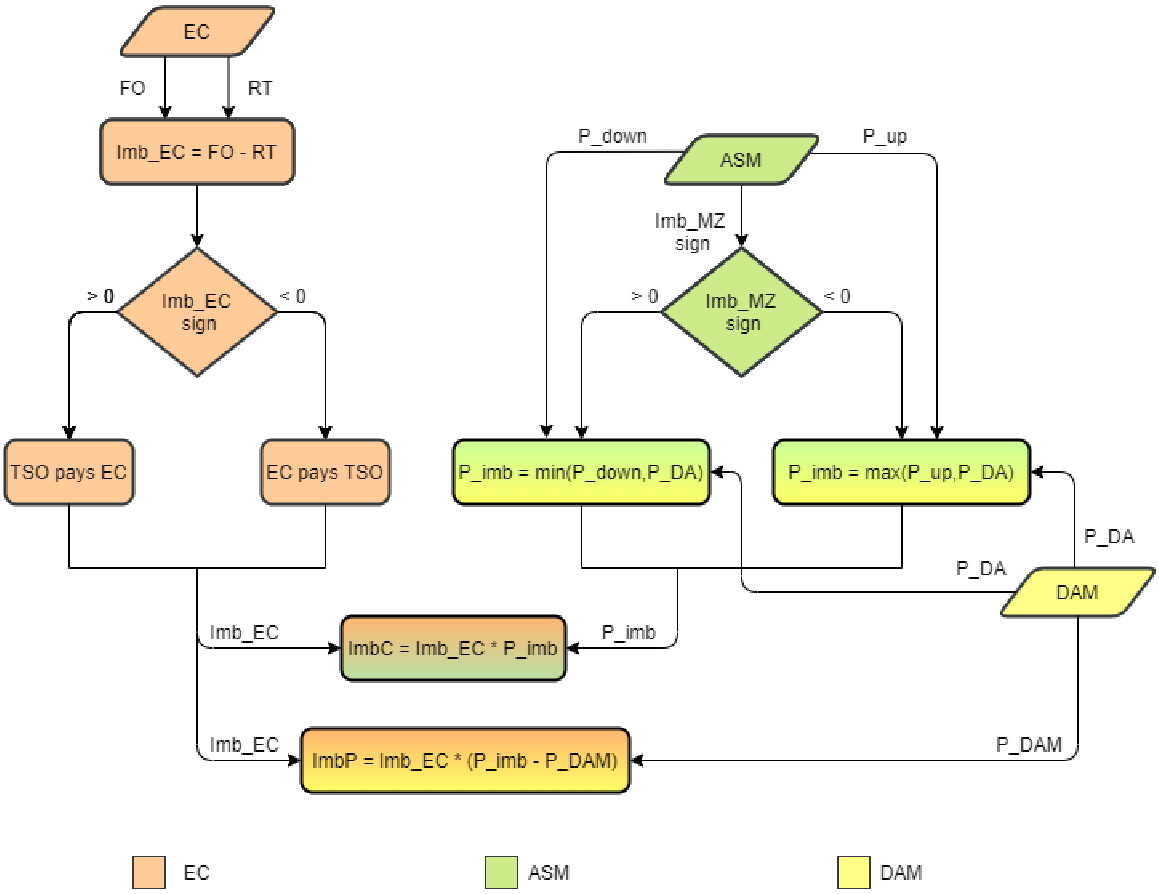


Figure 7.33: Flowchart of the imbalance settlement for one relevant period, declined to the thesis case study.

A good way to visualise the methodology just declined, is to plot the main results of some characteristic days: starting from the differences between FO and RT grid exchange, the following figures show the process of the imbalance settlement, hence the P_{imb} definition and the resulting charges and payoffs.

A winter working day, i.e. Wednesday 24^{th} of January, is now described: the imbalances are higher during the daylight hours in both S1 and S2. In **Figure 7.34** can be appreciated the low irregularity of Imb_{EC} obtained through the constraints explained in **Paragraph 7.1.4**, while in **Figure 7.35** when the PV systems start to produce, the imbalances become more irregular and higher than in S1. It's important to underline that the y-scale is different from grid exchange (upper subplot) to imbalance (lower subplot) and the former is negative when there is a net injection to the grid.

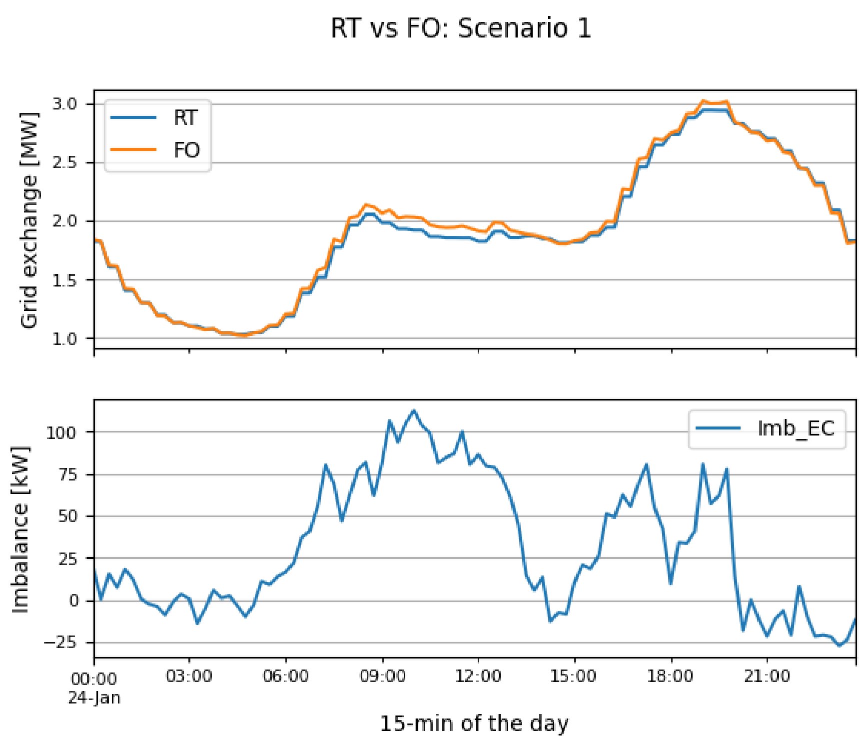


Figure 7.34: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2018-01-24, Scenario 1.

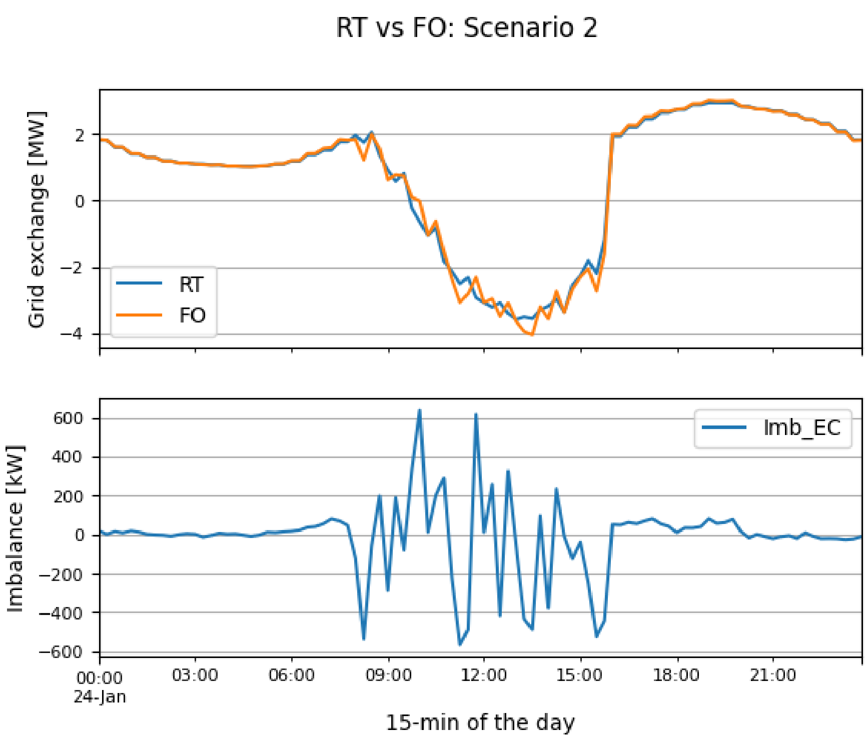


Figure 7.35: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2018-01-24, Scenario 2.

The imbalances must be valued: depending on the sign comparison between Imb_{EC} and Imb_{MZ}, high or low gain and losses may arise, as shown in **Figures 7.36** and **7.37**: red and green stand respectively for penalty and reward, while the *high* (*low*) cases are indicated with lower (higher) bars and lighter (darker) colours. The diferences between *high* and *low* cases is reflected into the differences between the P_{imb} and the P_{DAM}, being these latter PUN in case of withdrawal from the grid, P_{DA} in case of injection to the grid: in particular there is a peak around the 18:00, while the other *high* cases almost reaches around 100 EUR/MWh and the *low* ones always stay below the P_{DAM} as expected.

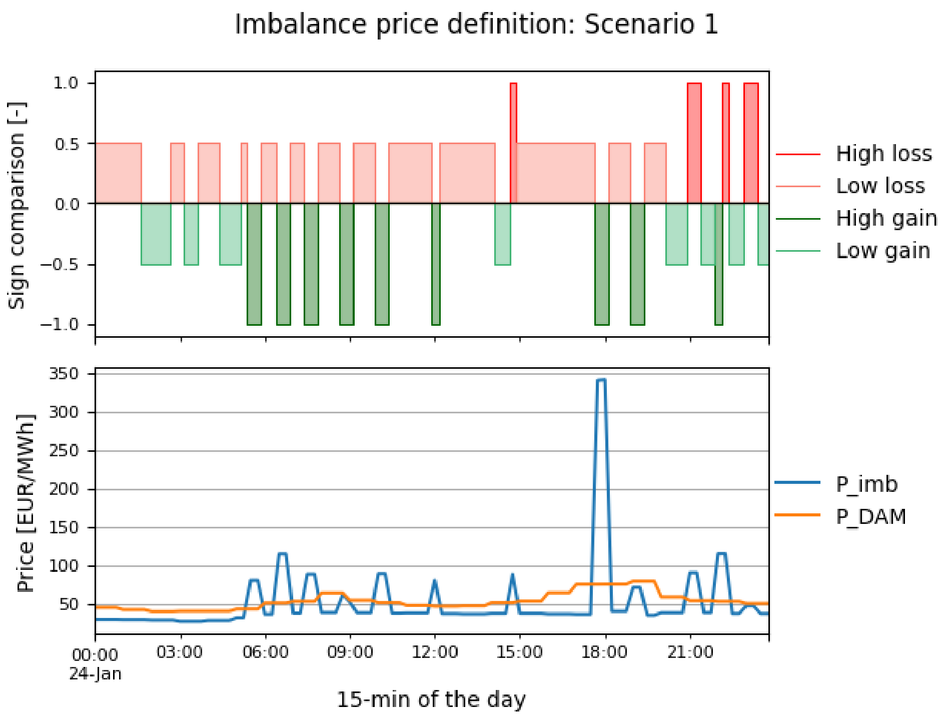


Figure 7.36: Sign comparison and imbalance price definition: 2018-01-24, Scenario 1.

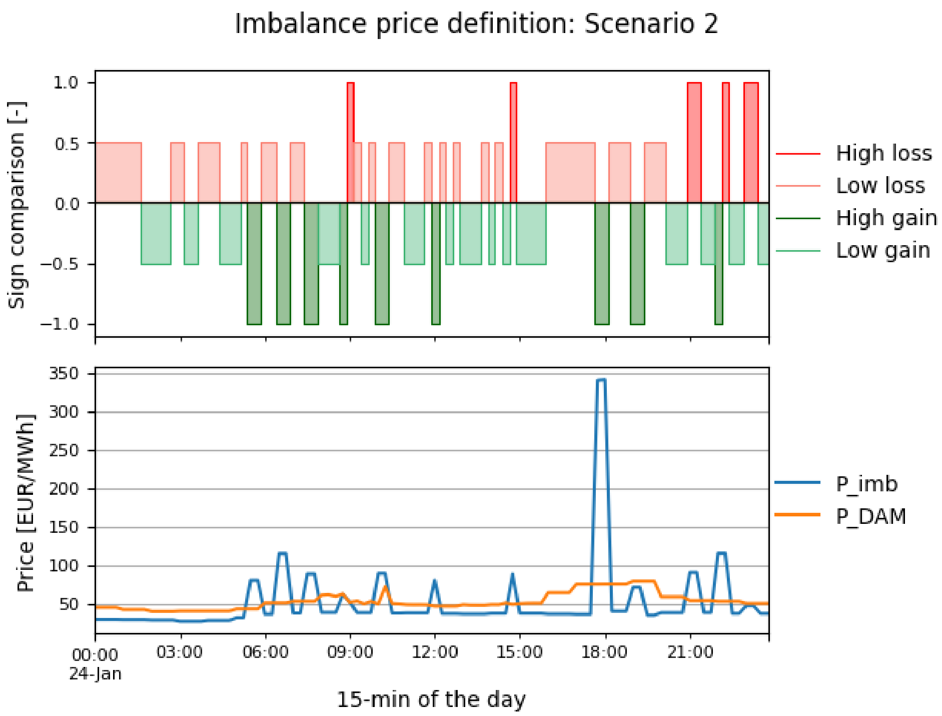


Figure 7.37: Sign comparison and imbalance price definition: 2018-01-24, Scenario 2.

Finally, the $ImbC$ and $ImbP$ are compared for the 2 scenarios: S2 presents higher charges and payoffs in absolute value when the PV production starts, and the 2 cash flows doesn't always have the same sign, meaning that sometimes even if EC receives money from Terna, there is no gain wrt the not imbalanced case.

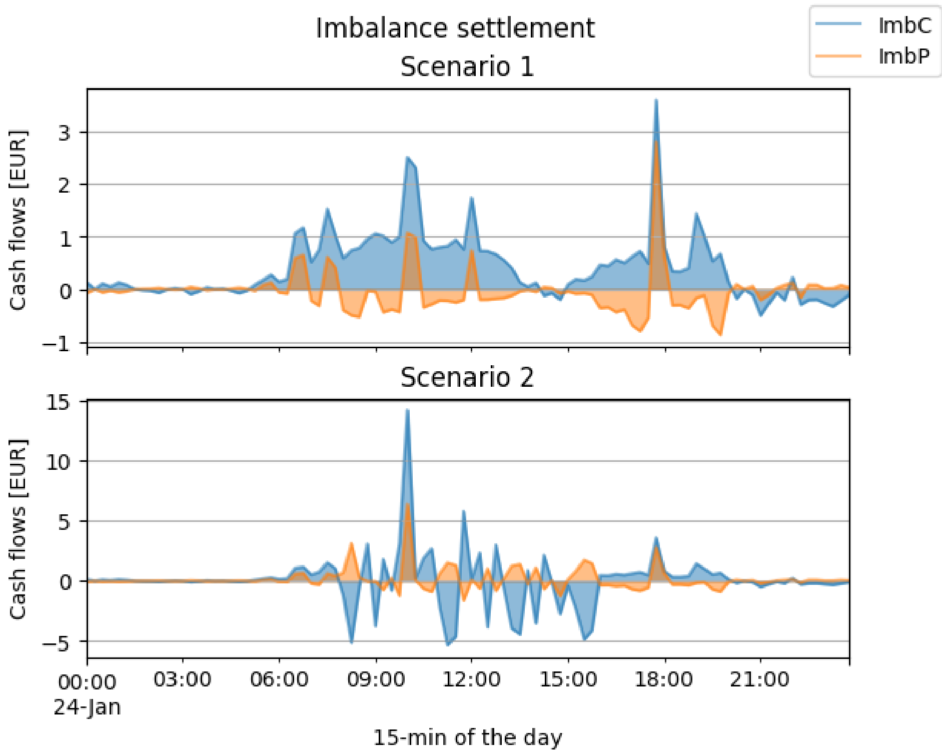


Figure 7.38: Charges and payoffs: 2018-01-24, scenario comparison.

The summary of the imbalance settlement by Imb_{EC} sign is reported in **Table 7.10**: the positive imbalance occurrence is higher in both the scenario. Passing from S1 to S2, the imbalances, hence the charges, increases in absolute value, i.e. there are more negative Imb_{EC} in S2 than in S1: maybe because of the higher increase for the negative Imb_{EC}. This leads also to a net $ImbC$ higher in S1 than S2, respectively 39.72 EUR and 4.71 EUR.

Table 7.10: Imbalance settlement at the end of the day: 2018-01-24, scenario comparison.

Imbalance sign	**Sign occurrence [%]**		**Imb_EC [MWh]**		**ImbC [EUR]**	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*
+	72.9	56.3	0.830	1.190	43.40	62.06
-	27.1	43.8	-0.079	-1.456	-3.69	-57.35

The higher the occurrence of positive Imb_{EC}, the higher the Low loss (LL) and/or High gain (HG), according to **Table 3.8**: indeed, the highest occurrence is of LL in both the scenarios, as shown in **Table 7.11**. Then, the prices differences between the cases can be further appreciated numerically: finally, there is a net loss in S1 and a net gain in S2, since in the latter the second highest occurrence, i.e. Low gain (LG), and the associated Imb_{EC} are much higher than in the former.

Table 7.11: Payoffs from imbalance settlement at the end of the day: 2018-01-24, scenario comparison.

Effect	Sub-effect	Sub-effect occurrence [%]		Avg P_imb [EUR/MWh]		ImbP [EUR]	
		S1	*S2*	*S1*	*S2*	*S1*	*S2*
penalty	*high*	6.3	7.3	79.48	75.54	-0.51	-1.70
	low	56.3	40.6	34.97	34.11	-12.48	-14.49
reward	*high*	16.7	15.6	117.16	121.51	8.44	12.19
	low	20.8	36.5	33.24	34.94	0.80	17.58

Finally, other days are now plotted for testing the methodology also during weekends and other seasons:

- **2018-01-21**: Sunday.
- **2019-07-10**: Wednesday.
- **2019-07-28**: Sunday.

As expected, during the weekends both in January and in July the consumption seems to be higher looking at S1 grid exchange, while during July the consumption are quite lower than in the winter time. Then, summer days have higher net grid injection than the winter ones.

Looking at the imbalance price definition, in some cases of LL or LG, the P_{imb} almost reaches the P_{DAM}.

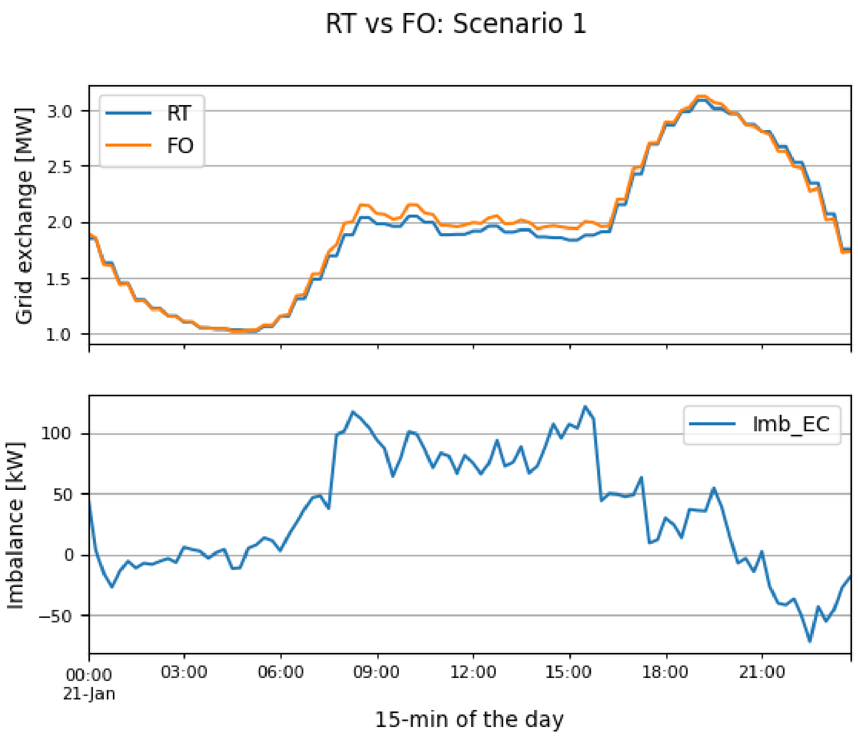


Figure 7.39: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2018-01-21, Scenario 1.

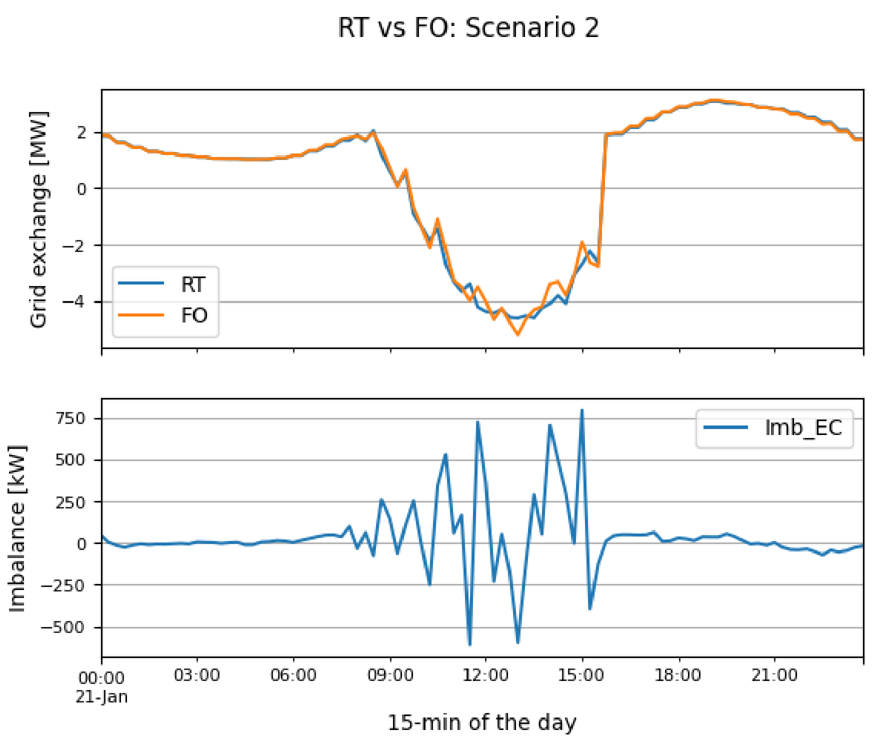


Figure 7.40: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2018-01-21, Scenario 2.

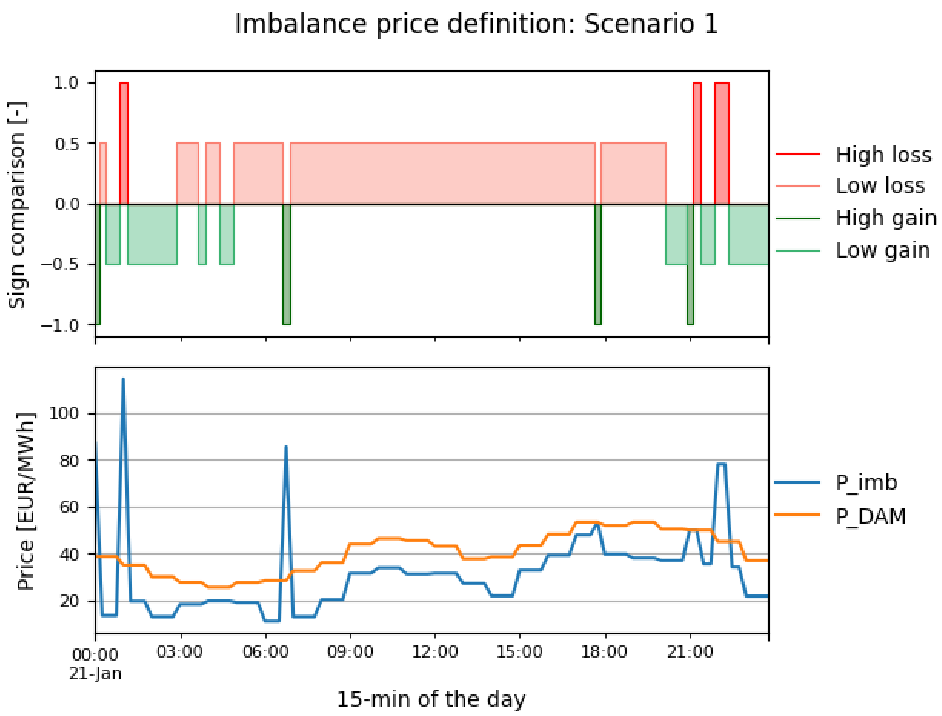


Figure 7.41: Sign comparison and imbalance price definition: 2018-01-21, Scenario 1.

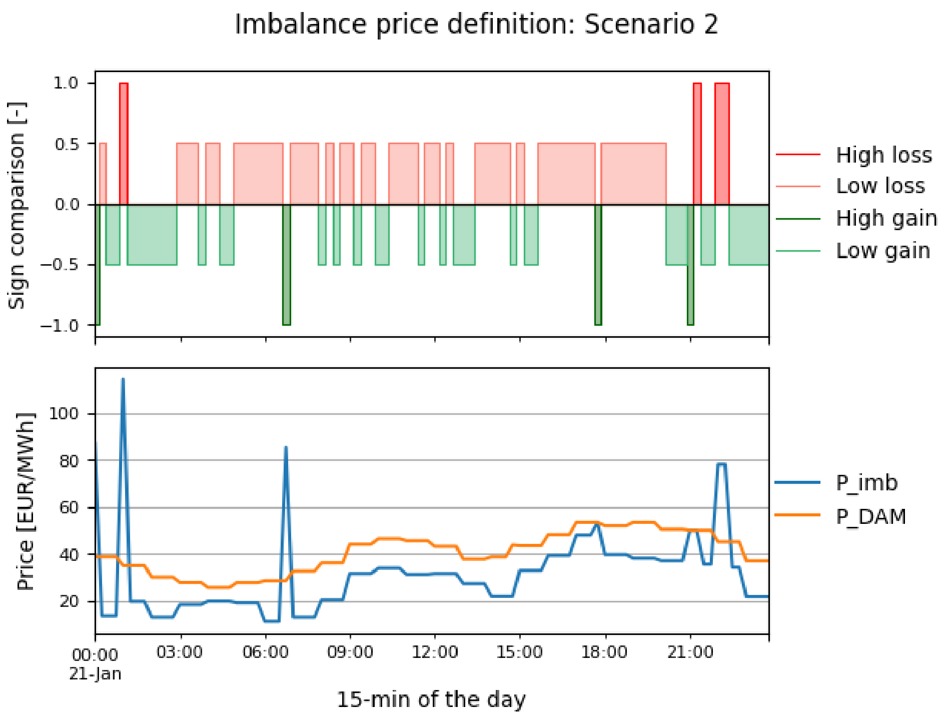


Figure 7.42: Sign comparison and imbalance price definition: 2018-01-21, Scenario 2.

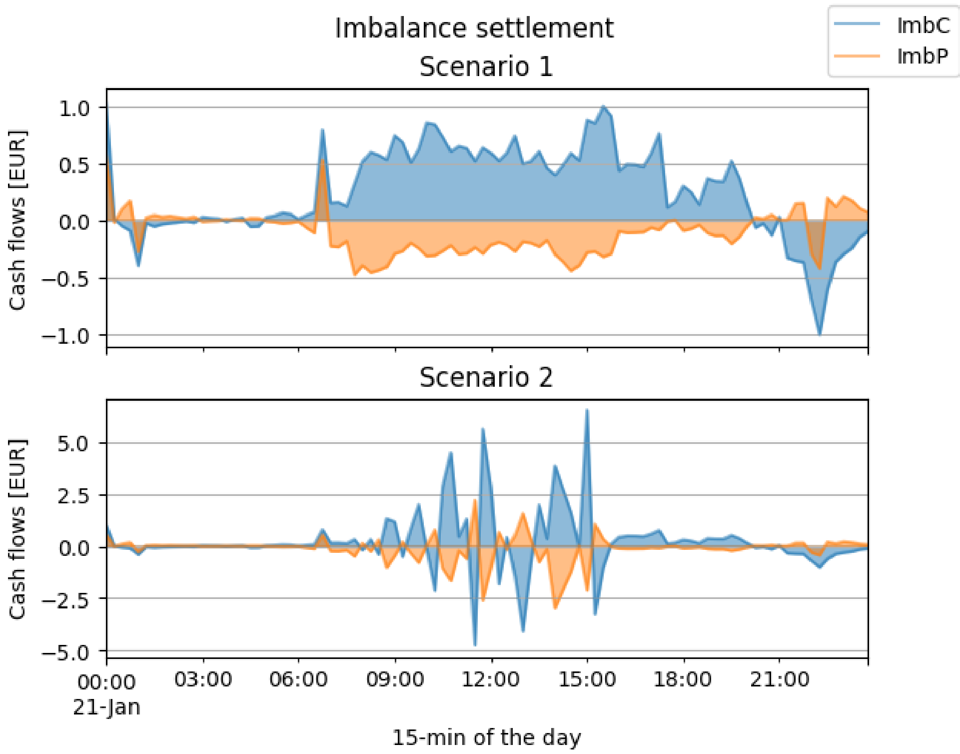


Figure 7.43: Charges and payoffs: 2018-01-21, scenario comparison.

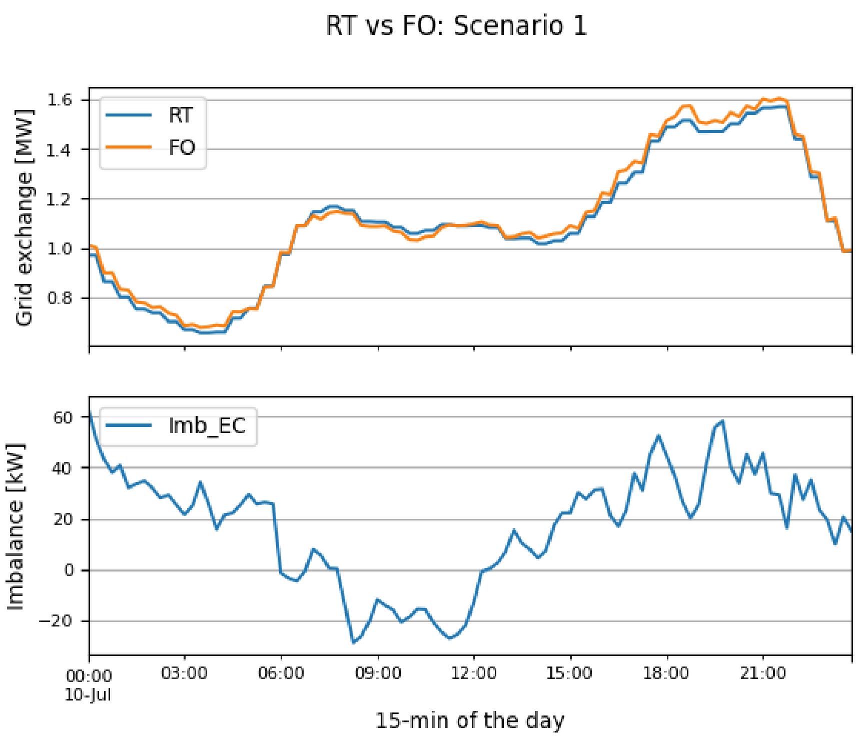


Figure 7.44: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2019-07-10, Scenario 1.

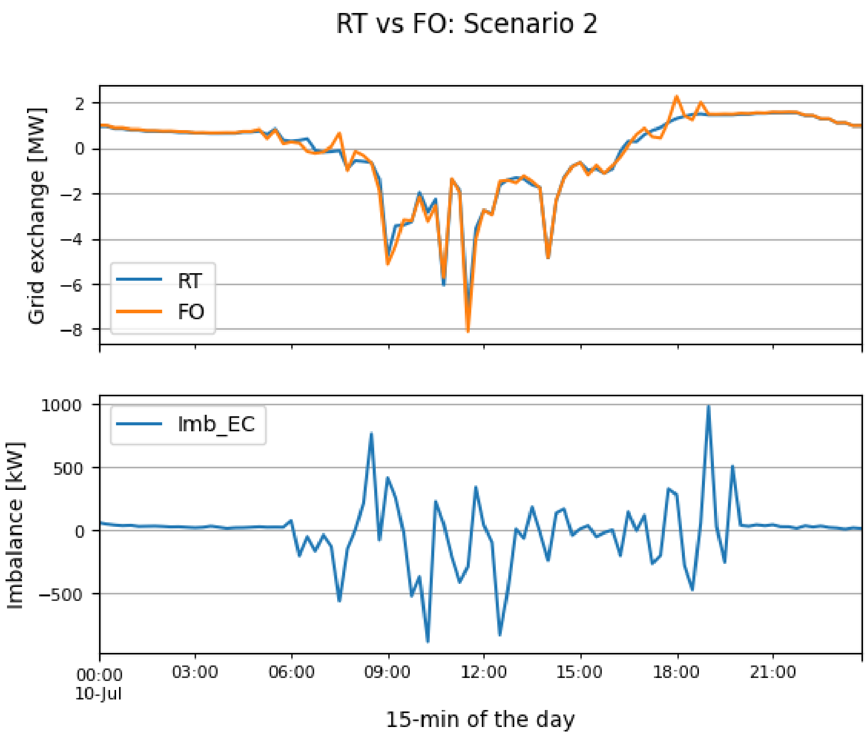


Figure 7.45: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2019-07-10, Scenario 2.

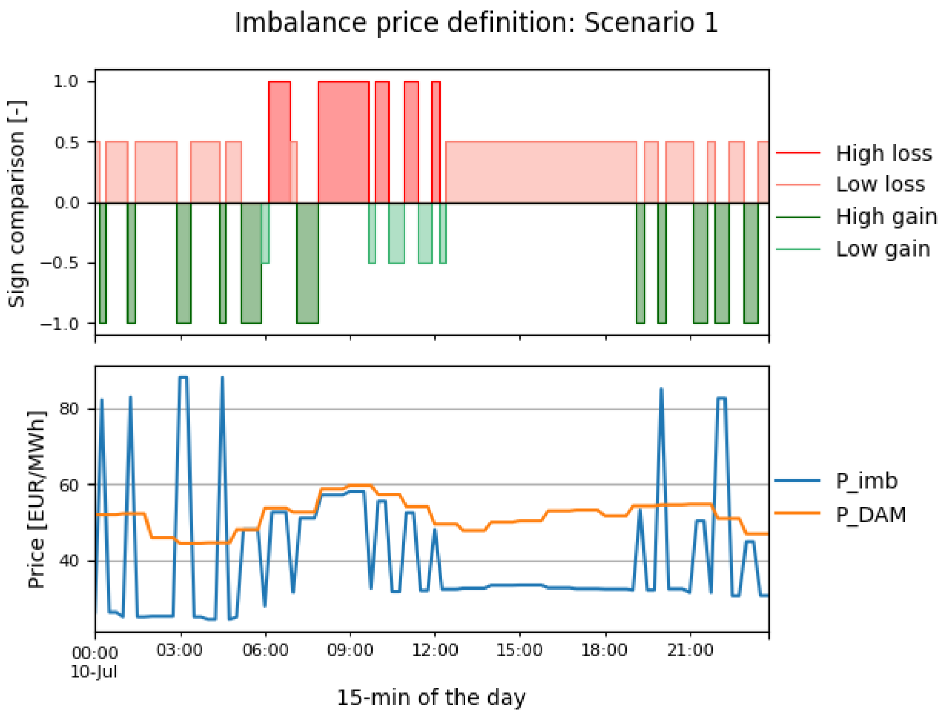


Figure 7.46: Sign comparison and imbalance price definition: 2019-07-10, Scenario 1.

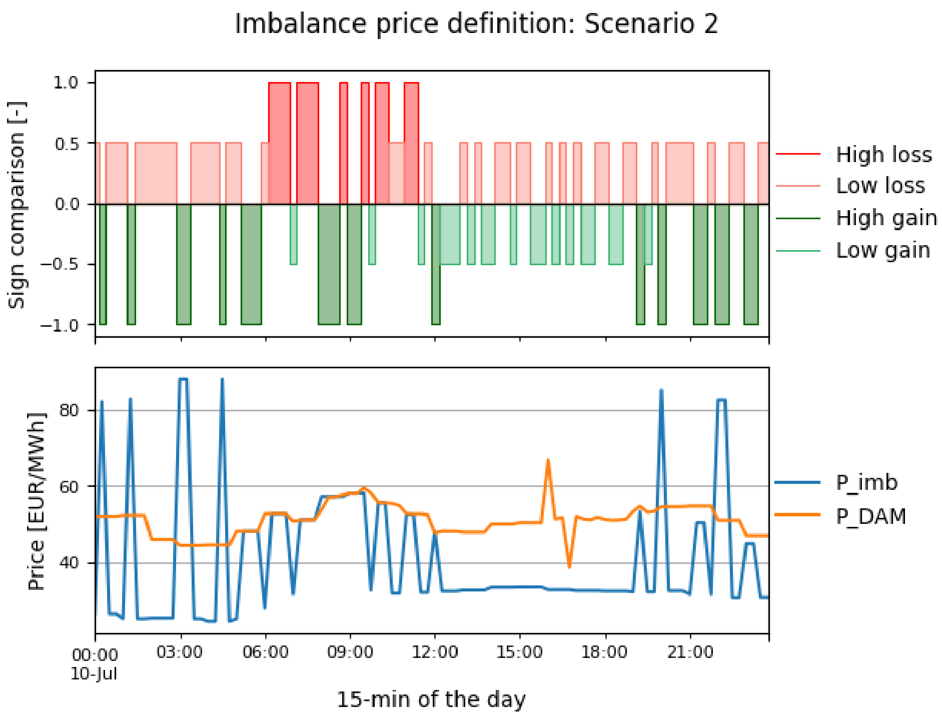


Figure 7.47: Sign comparison and imbalance price definition: 2019-07-10, Scenario 2.

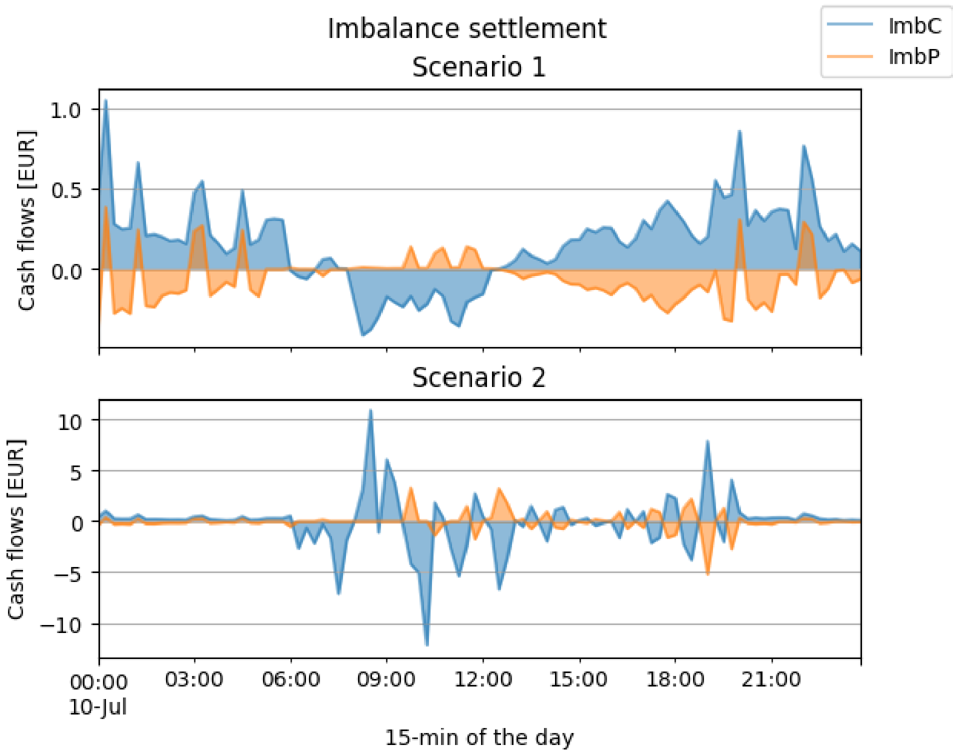


Figure 7.48: Charges and payoffs: 2019-07-10, scenario comparison.

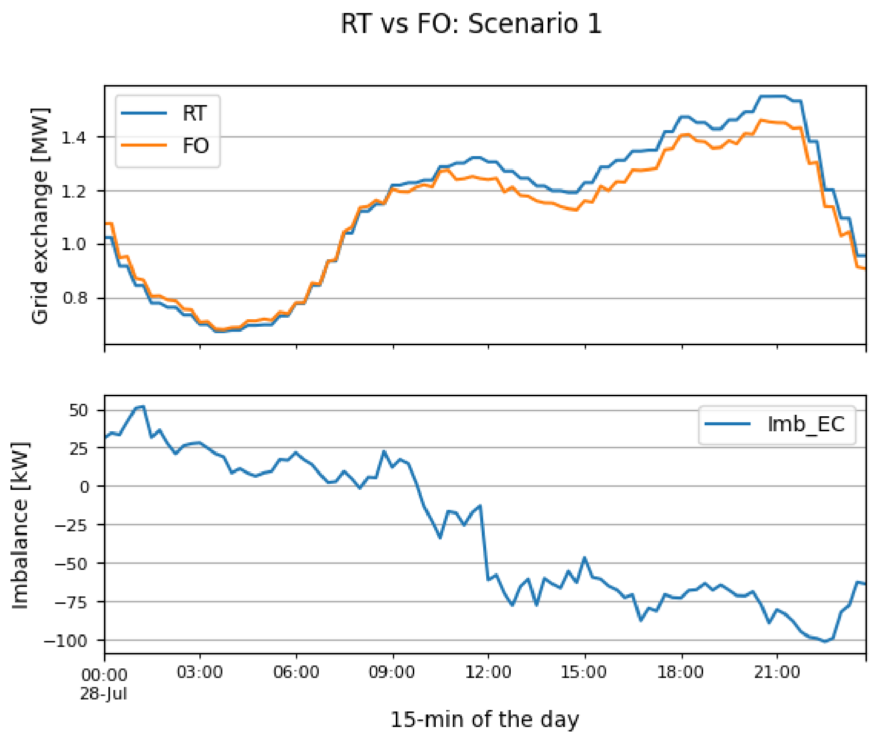


Figure 7.49: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2019-07-28, Scenario 1.

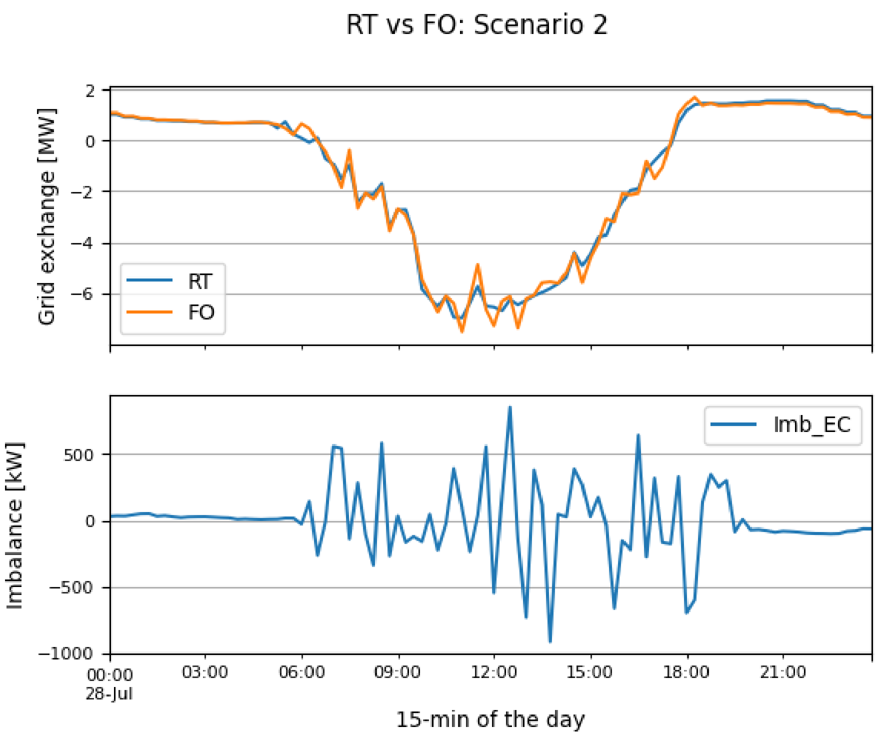


Figure 7.50: Forecasted and actual grid exchange of the EC with the resulting imbalances: 2019-07-28, Scenario 2.

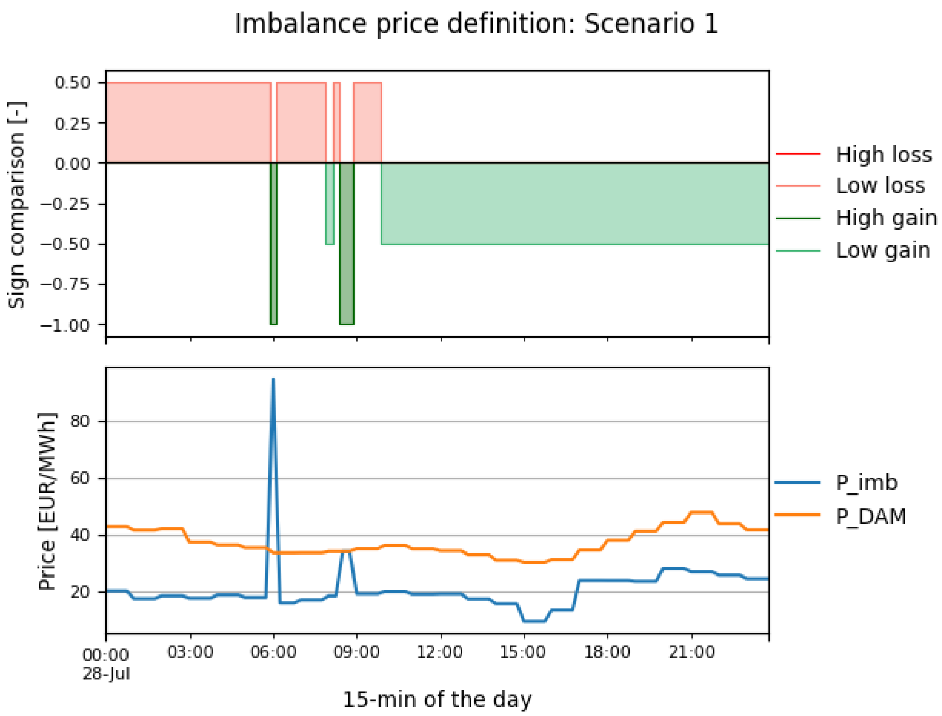


Figure 7.51: Sign comparison and imbalance price definition: 2019-07-28, Scenario 1.

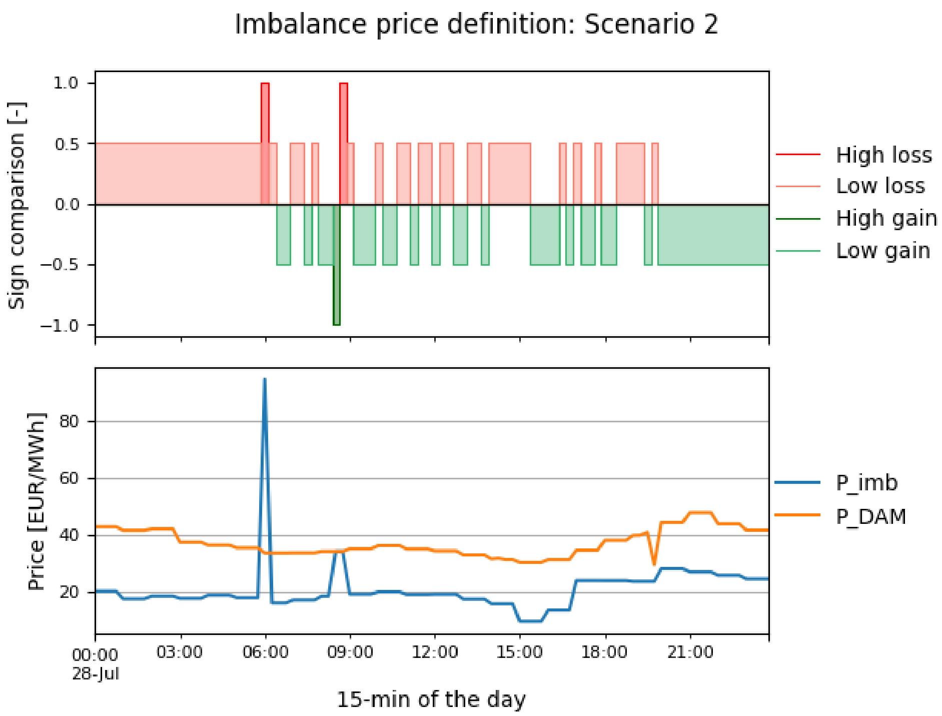


Figure 7.52: Sign comparison and imbalance price definition: 2019-07-28, Scenario 2.

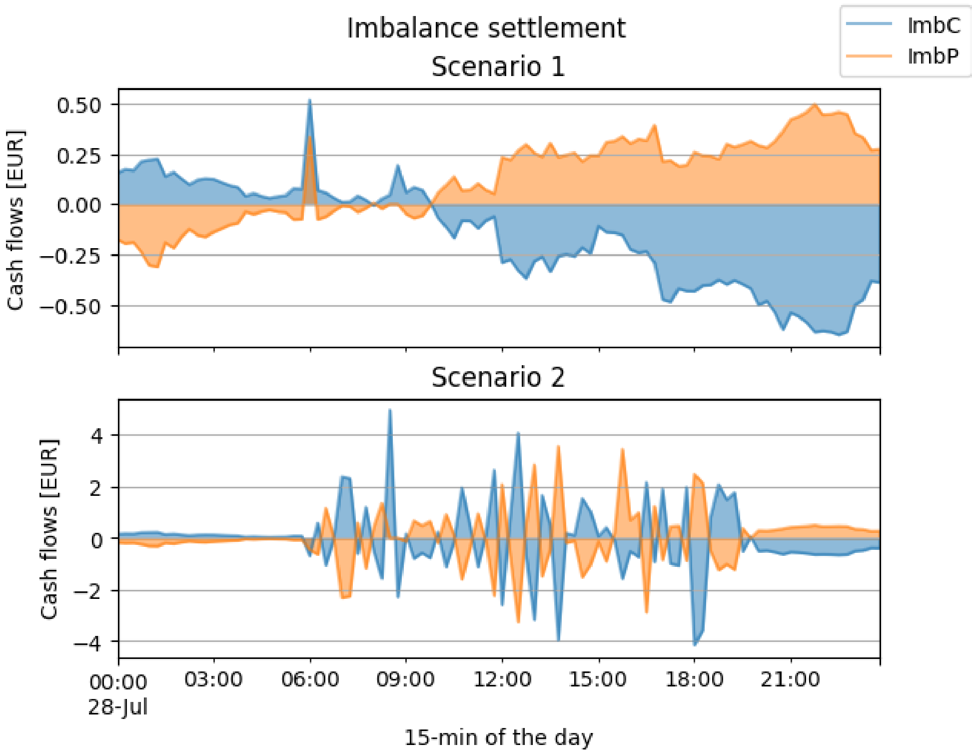


Figure 7.53: Charges and payoffs: 2019-07-28, scenario comparison.

Chapter 8

Imbalance settlement results

The imbalance settlement results are presented in this chapter: the analysed periods are 2018 and 2019, comparing 2 scenarios and 10 runs, given the random nature of the imbalances (see **Section 7.1.4**). However, these 10 runs can be also seen as 10 different ECs placed in Turin.

The chapter is organised in 2 parts: **Section 8.1** presents the yearly settlement, comparing the runs, the scenarios and the involved years, while **Section 8.2** analyses the seasonality of some settlement results.

The NAC is not involved in the results discussion, since among all the runs and scenarios, this is at least 2 order of magnitude lower than the $ImbC$: indeed, depends on the PUN-P_{DA} difference, that is very low along a year as described in **Paragraph 7.3.3**.

8.1 Yearly settlement

The first results set refers to the yearly imbalance settlement: it is presented in terms of Imb_{EC} and $ImbC$ in **Paragraph 8.1.1**, figuring out some relevant indicators in **Paragraph 8.1.2**, while the $ImbP$ are discussed in **Paragraph 8.1.3**.

8.1.1 Effective imbalances and imbalance charges

The yearly effective imbalances and the corresponding charges are reported for 2018 respectively in **Tables 8.1** and **8.2**, comparing the 10 runs and distinguishing by:

- **Pos**: positive Imb_{EC} sign, i.e. upward imbalances (positive imbalances and charges).
- **Neg**: negative Imb_{EC} sign, i.e. negative imbalances (negative imbalances and charges).
- **Tot**: total charges, summing the charges in absolute value. This is indicative of the total payments handled at systemic level.
- **Net**: net charges, summing the charges with sign. Indeed, Terna considers the net settlement of all the ASM operations for computing the DC payed by the end-users within the bills.

The positive imbalances cases are higher in both the scenarios: in S1 this result is strictly related to the qualitative relationship between Imb_{cons} and $Imb_{load,north}$, being the latter positive in the 71 % of the total cases during 2018 and 73 % in 2019 (see **Table 7.5**). Then, the presence of casual PV imbalances in S2 that are higher in absolute value wrt the consumption one, determines an increase of the negative imbalances occurrence. As a result, comparing S2 wrt S1:

1. Imb_{EC} and $ImbC$ increase in absolute value for both the positive and negative cases.

2. The downward quantities increase more than the upward ones: on average 119% against 79% in terms of Imb_{EC}.

3. The net $ImbC$ increas, apart from runs 6,7,9 and 10: this may be due to the above-mentioned differences in the increase of positive and negative Imb_{EC}.

4. The tot $ImbC$ increase on average of 93%.

These results are shown only for 2018, while a comparison between with 2019 is shown in terms of average values among the runs in **Tables 8.3** and **8.4**. The orders of magnitude are the same, and the quantities don't differ so much: the comparison between scenarios is the same as 2018, while the latter presents higher charges, probably due to the lower average P_{imb} in 2019 (see **Table 8.5**).

Table 8.1: Yearly Imb_{EC} by run and imbalance sign: 2018.

RUN	**Pos Sign occurrence [%]**		**Neg Sign occurrence [%]**		**Pos Imb_{EC} [MWh]**		**Neg Imb_{EC} [MWh]**	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
1	59.7	57.3	40.3	42.7	488.570	884.763	-262.271	-601.012
2	59.2	56.2	40.8	43.8	500.070	879.167	-333.420	-666.536
3	58.0	55.8	42.0	44.2	499.109	887.949	-303.759	-663.600
4	52.5	53.4	47.5	46.6	491.251	870.709	-321.531	-664.100
5	60.3	56.7	39.7	43.3	502.946	865.158	-301.171	-668.137
6	51.5	50.7	48.5	49.3	410.757	766.030	-335.137	-720.939
7	55.5	53.9	44.5	46.1	426.754	800.957	-355.235	-725.248
8	59.9	57.2	40.1	42.8	485.427	857.475	-273.853	-629.085
9	62.4	58.0	37.6	42.0	513.741	867.819	-250.674	-613.759
10	55.3	53.4	44.7	46.6	453.647	802.539	-302.556	-669.183
Mean	**57.4**	**55.3**	**42.6**	**44.7**	**477.227**	**848.257**	**-303.961**	**-662.160**

Table 8.2: Yearly $ImbC$ by run and imbalance sign: 2018.

RUN	Pos ImbC [EUR]		Neg ImbC [EUR]		Tot ImbC [EUR]		Net ImbC [EUR]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
1	30,834.04	54,370.65	-14,837.22	-34,637.54	45,671.26	89,008.18	15,996.82	19,733.11
2	29,815.12	52,094.06	-21,576.35	-41,220.57	51,391.47	93,314.63	8,238.77	10,873.50
3	29,043.24	52,258.18	-19,009.40	-40,236.71	48,052.64	92,494.90	10,033.83	12,021.47
4	29,333.03	52,339.62	-18,670.75	-39,373.05	48,003.78	91,712.66	10,662.28	12,966.57
5	30,571.27	52,195.21	-18,158.82	-39,678.10	48,730.09	91,873.32	12,412.44	12,517.11
6	23,652.98	45,175.47	-20,560.31	-43,875.17	44,213.29	89,050.64	3,092.67	1,300.29
7	24,099.49	46,294.60	-23,458.02	-45,722.40	47,557.52	92,017.01	641.47	572.20
8	29,724.77	51,755.45	-16,025.15	-37,632.82	45,749.92	89,388.27	13,699.61	14,122.63
9	31,761.93	52,520.90	-14,818.96	-36,410.17	46,580.89	88,931.07	16,942.98	16,110.72
10	26,618.07	47,944.96	-18,317.25	-40,199.04	44,935.32	88,144.00	8,300.81	7,745.93
Mean	**28,545.39**	**50,694.91**	**-18,543.22**	**-39,898.56**	**47,088.62**	**90,593.47**	**10,002.17**	**10,796.35**

Table 8.3: Yearly mean Imb_{EC} by year.

Runs mean	Pos Sign occurrence [%]		Neg Sign occurrence [%]		Pos Imb_{EC} [MWh]		Neg Imb_{EC} [MWh]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
2018	57.4	55.3	42.6	44.7	477.227	848.257	-303.961	-662.160
2019	58.8	56.1	41.2	43.9	504.368	875.905	-283.4	-647.24

Table 8.4: Yearly mean $ImbC$ by year.

Runs mean	Pos ImbC [EUR]		Neg ImbC [EUR]		Tot ImbC [EUR]		Net ImbC [EUR]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
2018	28,545.39	50,694.91	-18,543.22	-39,898.56	47,088.62	90,593.47	10,002.17	10,796.35
2019	25,275.41	44,030.83	-14,743.51	-33,259.19	40,018.91	77,290.02	10,531.90	10,771.64

The increases of both positive and negative imbalances occur also monthly. About this, **Figures 8.1** and **8.3** show the monthly pos and neg Imb_{EC} respectively for the first run of 2018 and 2019, while the corresponding imbalance sign occurrences are plotted in **Figures 8.2** and **8.4**: passing from S1 to S2 Imb_{EC} increases more during the summer months.

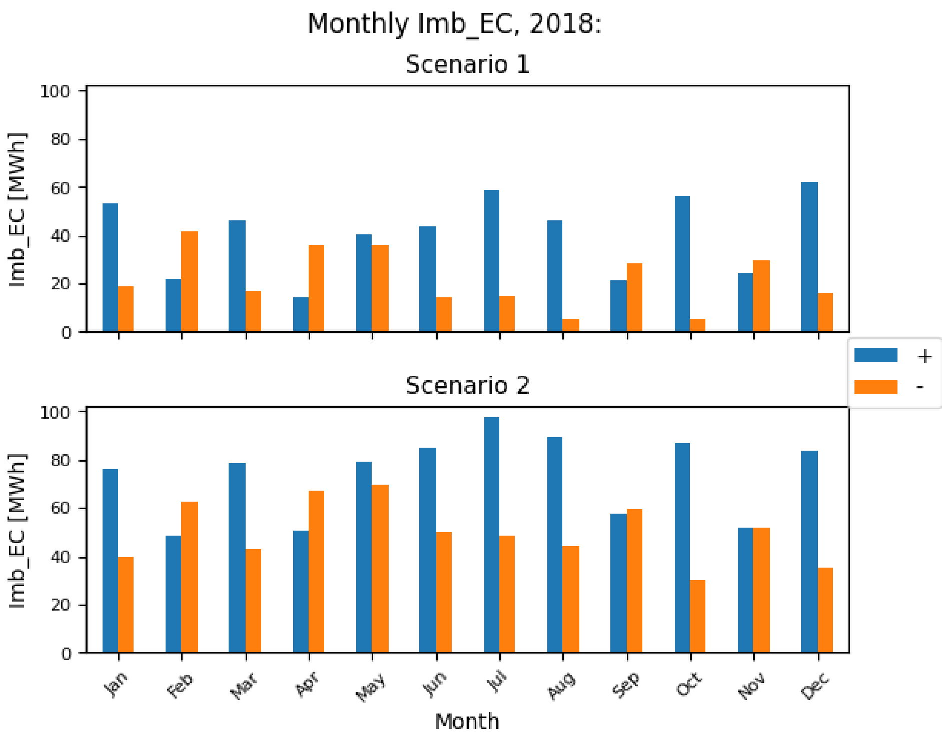


Figure 8.1: Monthly pos and neg Imb_{EC}: run 1, 2018.

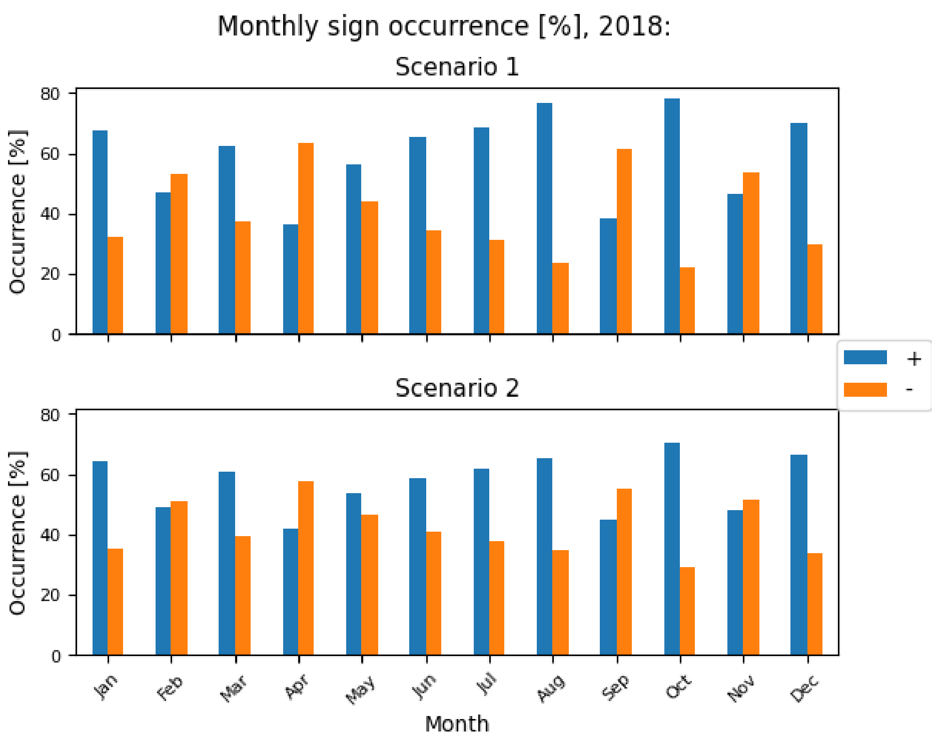


Figure 8.2: Monthly pos and neg Imb_{EC} sign occurrences: run 1, 2018.

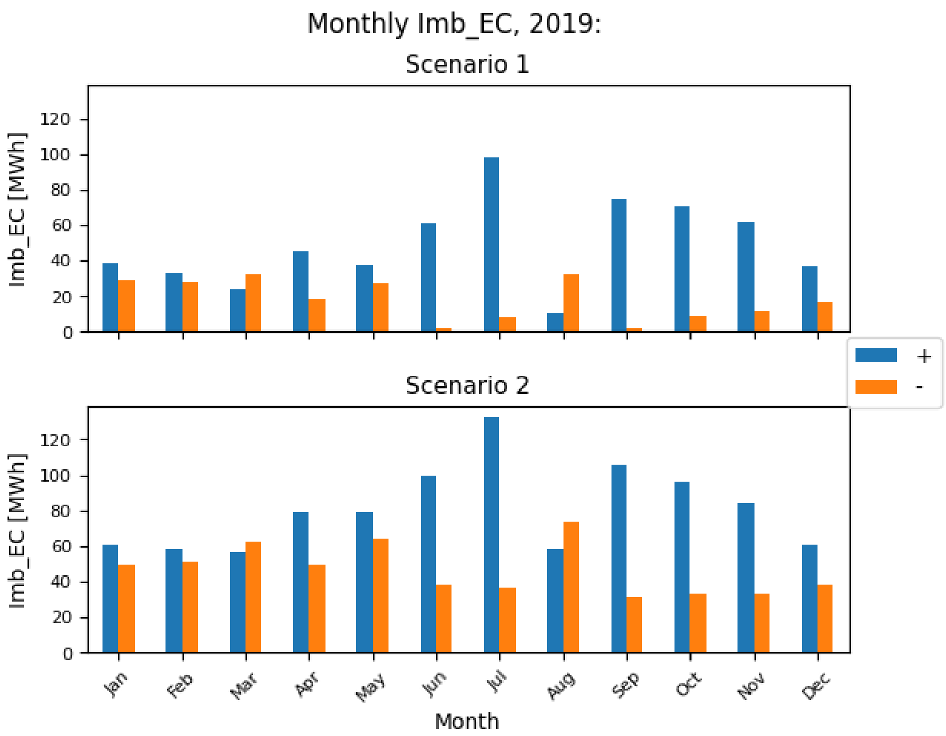


Figure 8.3: Monthly pos and neg Imb_{EC}: run 1, 2019.

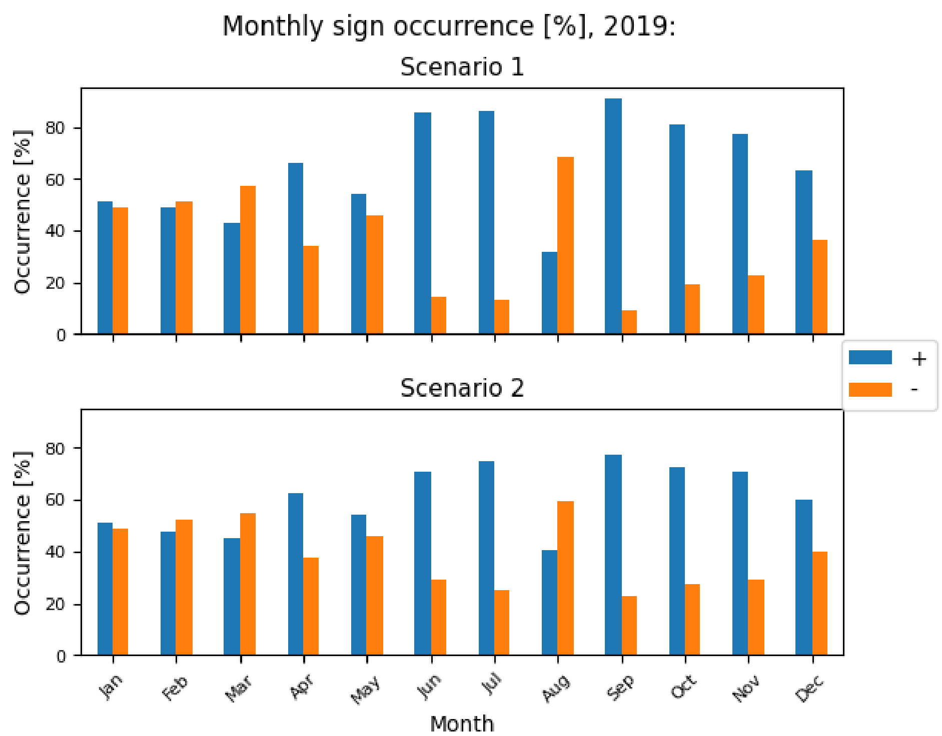


Figure 8.4: Monthly pos and neg Imb_{EC} sign occurrences: run 1, 2019.

Despite overall the runs present a similar yearly settlement in terms of pos and neg $ImbC$, the monthly values can differs among the different simulation: **Figures 8.5** and **Figures 8.6** show respectively the monthly tot and net $ImbC$ comparison between 3 runs for 2018, while **Figures A.41** and **Figures A.42** for 2019.

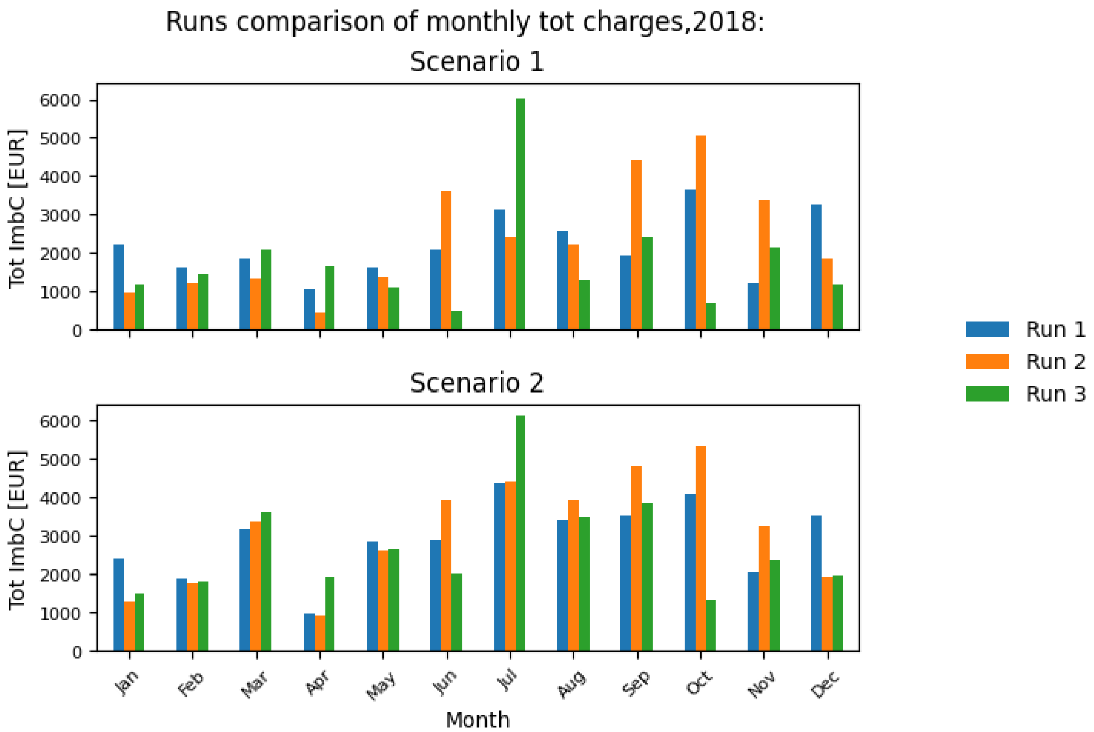


Figure 8.5: Monthly tot $ImbC$: runs 1,2,3, 2018.

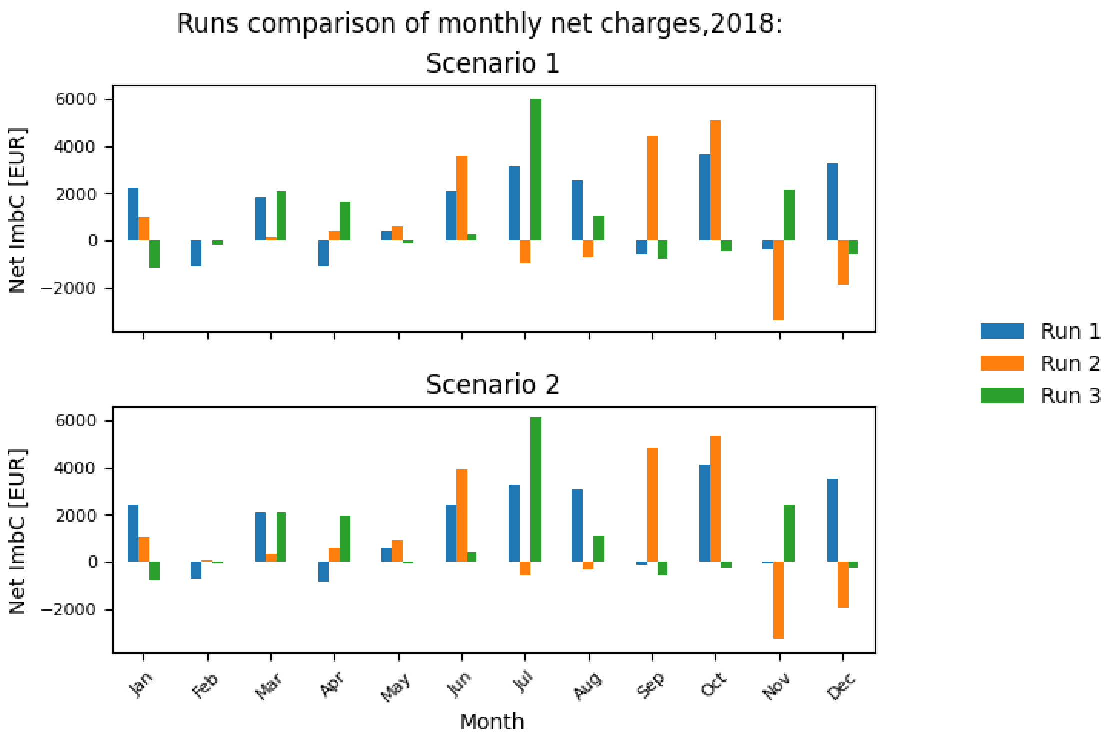


Figure 8.6: Monthly net $ImbC$: runs 1,2,3, 2018.

The yearly average P_{imb} remains the same among the runs and the scenarios, since it is determined by the Imb_{MZ} sign. The mean value for 2018, without distinguishing by the imbalance sign, is 58.71 EUR/MWh. As shown in **Table 8.5**, the latter is quite close to the yearly PUN and P_{DA}, in accordance with the higher Imb_{MZ} positive occurrence: this means that in the majority of cases, a price bewteen P_{down} and P_{DA} is chosen along the year. This discussion is valid also for 2019, as expected: furthermore, the differences between 2018 and 2019 prices are computed in %, leading to values quite similar for all the prices apart from P_{up}, while the 2020 data are shown to underline the pandemic effect on the prices decrease.

Table 8.5: Yearly average P_{imb}, DAM and ASM prices: 2018, 2019 and 2020 are involved.

Yearly average prices [EUR/MWh]	**2018**	**2019**	**% diff 2018-2019**	**2020**
P_{down}	35.42	31.16	-12%	19.74
P_{imb}	58.71	49.41	-16%	-
PUN	61.31	52.32	-15%	38.92
P_{DA}	60.71	51.25	-16 %	37.79
P_{up}	102.66	102.74	0 %	78.78

These results show how building an EC from aggregating thosuands of end-users would increase in the majority of cases the net $ImbC$, while increasing a lot the total $ImbC$: then, being the net $ImbC$ positive leads to a negative effect on the net system costs supported by Terna, hence on the DC building.

8.1.2 Imbalances indicators

In literature there weren't found any comparative results, apart from [56], that however considers only one prosumer and mainly focuses on the battery usage. For this reasons, some indicators are now described with the aim of better visualising the effects of Imb_{EC}. These indicators are computed for all the runs and then averaged among them.

Charges per grid exchange

The first proposed indicator is I_{ge}, i.e. the charges per grid exchange computed as

$$I_{ge} = \frac{ImbC_{ge}}{GE} \qquad [EUR/MWh] \tag{8.1}$$

- $\boldsymbol{ImbC_{ge}}$: charges corresponding to a certain grid exchange, i.e. withdrawal, injection or total grid exchange, being the latter the sum of the formers in absolute value, without distinguishing by sign (withdrawal is positive and injection is negative for the thesis convention).
- $\boldsymbol{GE}$: energy grid exchange in absolute value.

Before going into the details of the indicator, it may be interesting to describe the occurrence of the grid exchange direction: on average, during 2018 and 2019 in about 30 % of cases there were injections to the grid, while the majority were withdrawals, with negligible perfect self-consumption situations.

Then, the energies exchanged are reported in **Table 8.6**, distinguishing by injection, withdrawal and imbalance sign: as expected, during S1 the injection are null, and the withdrawals are the same among the runs in S1 and equals to about to 12.5 GWh; instead, passing to S2 the withdrawal decreases. In all cases, the positive cases present higher quantities in absolute values, due to higher occurrences of upward Imb_{EC}.

As for Imb_{EC} and $ImbC$, the 2019 trend are the same and the mean values among the runs are summerised in **Table 8.7**:

Table 8.6: Yearly *GE* by run and imbalance sign: 2018.

RUN	Pos Injection [MWh]		Neg Injection [MWh]		Pos Withdrawal [MWh]		Neg Withdrawal [MWh]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
1	0.000	-4,023.904	0.000	-3,435.228	7,427.742	4,734.235	5,031.932	3,313.424
2	0.000	-4,151.286	0.000	-3,307.846	7,244.584	4,545.895	5,215.090	3,501.764
3	0.000	-4,023.393	0.000	-3,435.739	7,140.023	4,495.140	5,319.651	3,552.519
4	0.000	-3,872.945	0.000	-3,586.187	6,621.258	4,361.251	5,838.415	3,686.408
5	0.000	-3,922.889	0.000	-3,536.243	7,292.535	4,586.481	5,167.139	3,461.178
6	0.000	-3,737.374	0.000	-3,721.758	6,336.673	4,083.017	6,123.001	3,964.642
7	0.000	-3,902.512	0.000	-3,556.620	6,811.099	4,324.447	5,648.574	3,723.212
8	0.000	-4,030.700	0.000	-3,428.432	7,442.341	4,723.383	5,017.332	3,324.275
9	0.000	-4,131.330	0.000	-3,327.802	7,632.075	4,768.893	4,827.599	3,278.766
10	0.000	-3,890.037	0.000	-3,569.095	6,862.336	4,323.424	5,597.337	3,724.235
Mean	**0.000**	**-3,968.637**	**0.000**	**-3,490.495**	**7,081.067**	**4,494.616**	**5,378.607**	**3,553.042**

Table 8.7: Yearly mean grid exchange by year.

Runs mean	Pos Injection [MWh]		Neg Injection [MWh]		Pos Withdrawal [MWh]		Neg Withdrawal [MWh]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
2018	0.000	-3,968.637	0.000	-3,490.495	7,081.067	4,494.616	5,378.607	3,553.042
2019	0.000	-4,604.552	*0.000*	-4,004.957	7,250.348	4,547.429	5,209.326	3,412.167

Finally, the indicators are computed as average values among the runs, considering the withdrawal, injection and the total exchange: they are reported in **Tables 8.8**, **8.9** and **8.10**, comparing 2018 and 2019. Apart from the net I_{eg}, the others range from 2 EUR/MWh to 6 EUR/MWh, with higher values during the upward imbalances since these case have the higher occurrence. Furthermore, S2 presents higher values than S1: in the case of withdrawals this is due to the presence of PV, that decrease the grid consumption. Then, the withdrawals and the total exchange are equals for S1, while this latter is absent for the I_{eg} relative to the injections: in this case, 2019 has lower values, maybe due to the higher production of PV (see **Table 8.7**).

Table 8.8: Yearly mean I_{eg} by year: withdrawals are involved.

Runs mean, Withdrawal	Pos I_{eg} [EUR/MWh]			Neg I_{eg} [EUR/MWh]			Tot I_{eg} [EUR/MWh]			Net I_{eg} [EUR/MWh]		
	S1	*S2*	*%-diff*	*S1*	*S2*	*%-diff*	*S1*	*S2*	*%-diff*	*S1*	*S2*	*%-diff*
2018	4.03	6.32	57%	3.44	6.11	78%	3.80	6.23	65%	0.80	0.83	4%
2019	3.48	5.30	52%	2.82	4.89	73%	3.20	5.12	60%	0.85	0.93	9%

Table 8.9: Yearly mean I_{eg} by year: injections are involved.

Runs mean, Injection	**Pos I_{eg} [EUR/MWh]**		**Neg I_{eg} [EUR/MWh]**		**Tot I_{eg} [EUR/MWh]**		**Net I_{eg} [EUR/MWh]**	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
2018	-	5.61	-	5.2	-	5.42	-	0.55
2019	-	4.33	-	4.14	-	4.24	-	0.39

Table 8.10: Yearly mean I_{eg} by year: total exchanges are involved.

Runs mean, Exchange	**Pos I_{eg} [EUR/MWh]**			**Neg I_{eg} [EUR/MWh]**			**Tot I_{eg} [EUR/MWh]**			**Net I_{eg} [EUR/MWh]**		
	S1	*S2*	*%-diff*	*S1*	*S2*	*%-diff*	*S1*	*S2*	*%-diff*	*S1*	*S2*	*%-diff*
2018	4.03	5.99	49%	3.44	5.66	65%	3.80	5.84	54%	0.80	0.70	-13%
2019	3.48	4.81	38%	2.82	4.48	59%	3.20	4.66	45%	0.85	0.65	-24%

Linking the grid exchange to $ImbC$ allows to have an idea on how much these fees can impact on the bills. In particular, the DC is the bill invoice through which Terna reflects the net costs supported in the grid management. The main element of the DCs is the uplift: looking at the quarterly values of 2018 and 2019 in **Table 8.11**, pos, neg and tot I_{eg} for S2 are quite close to them. The DCs are net system costs, hence is the net I_{eg} that should be considered: unfortunately, Terna publishes the uplift without distinguishing among the single invoices, that remain aggregated as in the ARERA Resolution [36]. The only useful information is that the invoice within lie the net $ImbC$ is about one order of magnitude lower than the uplift, net of sign. However, an estimation on the bills weight of the net I_{eg} may be done from the weight estimation of the DCs offered by [44]: considering as reference the weiht of 6% for 5.86 EUR/MWh, i.e. the DC of the first quarter of 2020, in proprotion the net I_{eg} for the withdrawals would weight almost 0.90 % averaging among 2018 and 2019.

Table 8.11: Quarterly uplift along 2018 and 2019: data reprocessed from [115].

Quarterly uplift [EUR/MWh]	*1*	*2*	*3*	*4*
2018	6.60	6.28	6.32	6.79
2019	5.31	7.27	7.31	7.29

Charges per imbalanced energy

The second indicator is I_{ie}, i.e. the charges per imbalanced energy computed as

$$I_{ie} = \frac{ImbC}{Imb_{EC}} \qquad [EUR/MWh] \tag{8.2}$$

where the $ImbC$ is compared to the corresponding Imb_{EC}, that can be positive, negative, total or net, with the meaning as explained at the beginning of the section.

This indicator is basically an average value of P_{imb} and it is reported in **Tables 8.12**. As expected, from 2018 to 2019 the indicator decreases, since the ASM prices decreased, while from S1 to S2, the value remains almost the same, since the P_{imb} is defined by the Imb_{MZ} sign, that doesn't change among the runs and the scenarios: the only very small differences are due to different Imb_{EC} sign occurrences within the 2 scenarios. Then, the neg I_{ie} are slightly higher than the pos one: probably, in the majority of negative Imb_{EC} cases, the Imb_{MZ} was negative as well, leading to higher P_{imb} (see **Table 3.6**). Finally, also the yearly average P_{imb} is reported and it results very close to all the I_{ie} apart from the net one.

Table 8.12: Yearly mean I_{eg} by year.

Runs mean	Pos I_{ie} [EUR/MWh]		**Neg** I_{ie} **[EUR/MWh]**		**Tot** I_{ie} **[EUR/MWh]**		**Net** I_{ie} **[EUR/MWh]**		Avg P_{imb} [EUR/MWh]
	Scen 1	Scen 2	Scen 1	Scen 2	Scen 1	Scen 2	Scen 1	Scen 2	-
MEAN 2018	59.72	59.74	60.78	60.19	60.27	59.98	52.98	52.03	58.71
MEAN 2019	50.10	50.27	52.07	51.39	50.80	50.74	47.19	46.71	49.41
2019 vs 2018	-16%	-16%	-14%	-15%	-16%	-15%	-11%	-10%	-16%

This indicator can be useful especially to understand how valuable were the upward and downward imbalances in light of the market, i.e. about 60 EUR/MWh. According to [4], in 2020 the accepted offers of the UVAM were valued in the following way:

- **Upward**: 5 accepted offers, 4 of 400 EUR/MWh and 1 of 60 EUR/MWh.
- **Downward**: 27 accepted offers of 30 EUR/MWh.

It's important to remember that the upward offers refer to selling, while the downward ones refer to purchases: hence, it seems reasonable to consider the pos and neg I_{ie} as a starting point to evaluate the possible participation of the EC to the ASM in terms of UVAM.

Charges per users, peak consumption and peak production

The last indicators refer to invariant quantities among the runs, i.e.:

- **Number of users**: 3,377. The indicator is I_{user}.
- **Peak consumption**: 3.2 MW. The indicator is $I_{p,cons}$, where p stands for peak and cons for consumption.
- **Peak PV production**: 9.3 MW in 2018, 9.5 MW in 2019. The indicator is $I_{p,prod}$, where p stands for peak and prod for production.

The average indicators among the runs are summarised in **Tables 8.13**, **8.15** and **8.16**. Since the denominators don't change passing from S1 to S2, the differences between the 2 scenarios depends only on the increase of Imb_{EC}, hence $ImbC$, already described at the beginning of the section: as expected, the positive indicators are higher than the negative, while the net one may be compared to on of the [56] case study. The latter considers 1 end-user with 1 kW of PV, located in the South of Italy, obtaining a net $ImbC$ of 0.36 EUR during January: considering a reference mean yearly net I_{user} among 2018 and 2019 of 3.12 EUR/user, it would correspond to monthly 0.26 EUR/user, close the [56] result. Furthermore, looking at the effective monthly net I_{user} of 2018 averaged among the runs and reported in **Table 8.14** these values present the same order of magnitude of [56]. However, the net monthly I_{user} were considered in absolute value, just to have an idea of the order of magnitude.

Table 8.13: Yearly mean I_{user} by year.

Runs mean	**Pos** I_{user} **[EUR/user]**			**Neg** I_{user} **[EUR/user]**			**Tot** I_{user} **[EUR/user]**			**Net** I_{user} **[EUR/user]**		
	S1	*S2*	*% diff*	*S1*	*S2*	*% diff*	*S1*	*S2*	*% diff*	*S1*	*S2*	*% diff*
MEAN 2018	8.45	15.01	78%	5.49	11.81	115%	13.94	26.83	93%	2.96	3.2	8%
MEAN 2019	7.48	13.04	74%	4.37	9.85	125%	11.85	22.89	93%	3.12	3.19	2%

Table 8.14: Monthly mean I_{user}: 2018.

Monthly net I_{user}		*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Mean*
Runs mean	*S1*	0.27	0.26	0.41	0.34	0.20	0.60	0.87	0.69	0.71	0.71	0.42	0.41	0.50
	S2	0.26	0.25	0.42	0.34	0.23	0.64	0.85	0.68	0.69	0.74	0.41	0.42	0.50

The peak consumption is the same for S1 and S2, while only the latter is involved in the $I_{p,prod}$ calculation. About this, the above mentioned [56] example can be used as a comparison, i.e. 0.36 EUR/kW: approaching as for the net I_{user}, monthly mean values are computed for net $I_{p,prod}$, again considering in absolute value the net $ImbC$ just to have in mind the order of magnitude: as a result, it seems to be similar to 360 EUR/MW of [56].

Table 8.15: Yearly mean $I_{p,cons}$ by year.

Runs mean	**Pos** $I_{p,cons}$ **[EUR/MW]**		**Neg** $I_{p,cons}$ **[EUR/MW]**		**Tot** $I_{p,cons}$ **[EUR/MW]**		**Net** $I_{p,cons}$ **[EUR/MW]**	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
MEAN 2018	8,996.91	15,977.97	5,844.43	12,575.19	14,841.34	28,553.16	3,152.47	3,402.78
MEAN 2019	7,966.28	13,877.59	4,646.84	10,482.60	12,613.12	24,360.19	3,319.43	3,395.00

Table 8.16: Yearly mean $I_{p,prod}$ by year.

Runs mean	**Pos** $I_{p,prod}$ **[EUR/MW]**		**Neg** $I_{p,prod}$ **[EUR/MW]**		**Tot** $I_{p,prod}$ **EUR/MW]**		**Net** $I_{p,prod}$ **[EUR/MW]**	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
MEAN 2018	-	5,430.51	-	4,273.99	-	9,704.50	-	1,156.52
MEAN 2019	-	4,630.73	-	3,497.87	-	8,128.60	-	1,132.86

Table 8.17: Monthly mean $I_{p,prod}$: 2018.

Monthly net $I_{p,prod}$		*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Mean*
Runs mean	*S2*	95.68	91.85	152.26	122.19	82.55	231.56	309.52	247.76	251.89	266.90	148.67	151.01	179.32

8.1.3 Imbalance payoffs

The imbalances can lead to penalty or reward for the BRP wrt to the case with a perfect math between RT and FO grid exchange: 2018 payoffs are summarised in **Table 8.18**, where the positive and negative cases are again separated.

Compared to the $ImbC$, there is no pre-defined trend passing from S1 to S2: sometimes the net payoffs increase, sometimes decreases, however on avarege the upward imbalances lead to net penalties, the negative ones to rewards, resulting in a net penalty among the runs and scenarios. This is due to the fact that the $ImbP$ depends on the sign comparison between Imb_{EC} and Imb_{MZ} and it is an indirect result of the qualitative relationship between Imb_{EC} and $Imb_{load,north}$. Indeed:

- Imb_{MZ} and $Imb_{load,north}$ have higher positive sign occurrence for both 2018 and 2019. Furthermore, in the majority of positive Imb_{MZ} cases, also $Imb_{load,north}$ is positive (see **Paragraph 7.2.2**).
- In the majority of positive $Imb_{load,north}$ cases, also Imb_{EC} is positive, hence it is expected an higher probability of relevant positive concordance between Imb_{EC} and Imb_{MZ}, leading to highest occurrence of LL (see **Table 3.8**).

The means among the runs are compared between 2018 and 2019 distinguishing among net penalty and net reward, as shown in **Table 8.19**: on average, the penalty are higher in absolute value than the reward

Table 8.18: Yearly $ImbP$ by run and imbalance sign: 2018.

RUN	Pos ImbP [EUR]		Neg ImbP [EUR]		Net ImbP [EUR]		Reward occurrence [%]		Penalty occurrence [%]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
1	-211.80	-1,761.19	1,201.18	2,619.13	989.39	857.94	50.4	50.6	49.6	49.4
2	-2,406.04	-3,924.38	-120.80	1,077.68	-2,526.84	-2,846.71	47.1	48.1	52.9	51.9
3	-2,488.43	-3,730.54	403.38	1,675.31	-2,085.05	-2,055.23	47.6	48.5	52.4	51.5
4	-932.15	-1,917.88	1,609.41	2,602.54	677.26	684.65	51.2	50.5	48.8	49.5
5	-1,234.21	-2,438.65	669.55	2,275.00	-564.66	-163.64	50.3	49.7	49.7	50.3
6	-2,114.34	-2,986.25	918.06	1,878.61	-1,196.28	-1,107.64	47.7	48.6	52.3	51.4
7	-2,453.64	-3,606.38	-141.34	830.50	-2,594.98	-2,775.87	46.4	48.1	53.6	51.9
8	-1,140.82	-2,557.23	1,005.09	1,696.04	-135.73	-861.19	49.1	48.8	50.9	51.2
9	-1,542.92	-2,990.61	492.40	1,649.17	-1,050.52	-1,341.44	48.2	48.6	51.8	51.4
10	-1,735.91	-2,543.15	716.64	1,892.52	-1,019.27	-650.63	47.1	48.7	52.9	51.3

Table 8.19: Yearly $ImbP$ by year: net penalty and reward are separated.

Runs mean	Net reward $ImbP$ [EUR]		Net penalty $ImbP$ [EUR]		Reward occurrence [%]		Penalty occurrence [%]	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
MEAN 2018	833.32	771.30	-1,396.67	-1,475.29	48.5	49.0	51.5	51.0
MEAN 2019	750.68	1,070.55	-1179.44	-1449.26	47.5	48.2	52.5	51.8

Looking at the single runs, usually a higher occurrence of penalties leads to a net yearly penalty, and vice-versa, apart from run 5, where there is almost a payoffs parity, i.e. 50% of reward occurrences and 50% of penalty ones: given the presence of sub-cases within reward and penalty, it may be interesting to describe how much they differ each others, especially in terms of price as shown in **Table 8.20**. Indeed, the high-cases present prices higher more than 2 times the low-cases ones: this doesn't surprise in light of the detailed ASM prices analysis implemented in **Section 7.3**, while the above cited differences can be visually appreciate in **Figures 8.7** and **8.8**, where the monthly mean are plotted for run 1 S1, being the prices defined from Imb_{MZ} sign, that is invariant among the runs and scenarios (for S2 see **Figures A.43** and **A.44**).

Table 8.20: Yearly average P_{imb} by payoffs sub-case: 2018, run 1.

Avg P_{imb} [EUR/MWh] (RUN 1)							
Penalty				Reward			
high		low		high		low	
S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
88.66	89.05	36.00	36.00	88.69	88.42	34.67	34.74

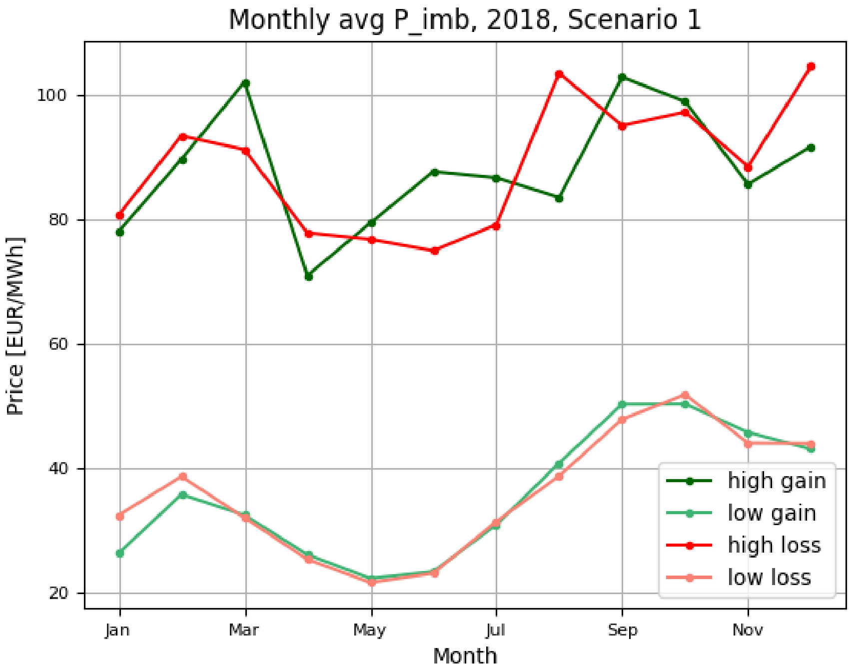


Figure 8.7: Monthly average P_{imb} by payoffs sub-case: run 1, S1, 2018

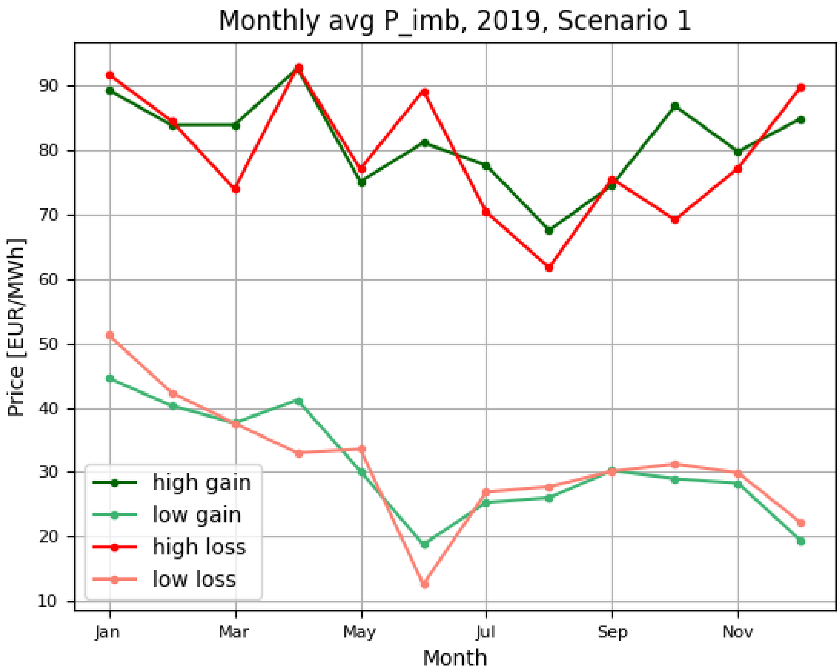


Figure 8.8: Monthly average P_{imb} by payoffs sub-case: run 1, S1, 2019

Hence, instead of stopping the evaluation at the total reward and penalty occurrence, it may be needed to further investigate the sub-cases occurrences to understand how much they weight on the $ImbP$ definition: such an analysis is present in **Table 8.21**, considering run 1 (net reward with higher reward occurrence), run 2 (vice-versa in terms of penalty) and run 5 (higher reward occurrence, but net penalty).

The sub-cases occurrence are in accordance with the comparison above-described between Imb_{EC}, Imb_{MZ} and $Imb_{load,north}$ signs and with the higher occurrence of upward Imb_{EC}, hence the highest occurrence is for LL, followed by HG. Furthermore, the ratio between the $ImbP$ and the % of occurrence, i.e. the number of cases, is computed, involving then the occurrences, the prices and the imbalanced volumes in a sort of indicator. The main observations that can be done are:

- Negative values mean penalty, hence losses, while positive reward, hence gains.
- From S1 to S2 these ratios increase, due to the incresing Imb_{EC}.
- The sub-cases occurrences seems to be very similar from one run to another and among the scenarios.
- Despite the LL occurrence is almost 2 times the High loss (HL) one, this difference is much lower comaparing the payoffs per occurrence ratio.

Table 8.21: Yearly $ImbP$ by run and by sub-case: 2018.

RUN	Sub-case occurrence [%]								Payoffs/occurrence [EUR/%]							
	penalty				reward				penalty				reward			
	high		low		high		low		high		low		high		low	
	S1	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*	*S1*	*S2*
1	16.8	17.9	32.8	31.5	26.9	25.8	23.5	24.8	-151	-319	-181	-354	212	365	159	336
2	18.7	19.7	34.2	32.2	25.0	24.0	22.1	24.1	-217	-365	-209	-380	190	347	178	343
5	16.6	18.7	33.1	31.6	27.2	25.0	23.2	24.6	-210	-358	-197	-358	195	355	179	363

8.2 Settlement seasonality

This section analyses the yearly and daily seasonality of Imb_{EC} and P_{Imb}.

Starting from 2018 yearly seasonality, **Figures 8.9** and **8.10** show the upward, i.e. positive, and downward, i.e. negative, 15-min imbalances by 2018 months: passing from S1 to S2 the imbalances increases in absolute value in both the directions, and the higher differences occur especially during the warmer months. Then, the imbalances are not symmetric: upward and downward Imb_{EC} have respectively negative and positive skewness. Finally, the upward imbalances increase from S1 to S2 presents higher values in summer than the other seasons, while in 2019 this happens also for the downward imbalances, as shown in **Figures 8.11** and **8.12**.

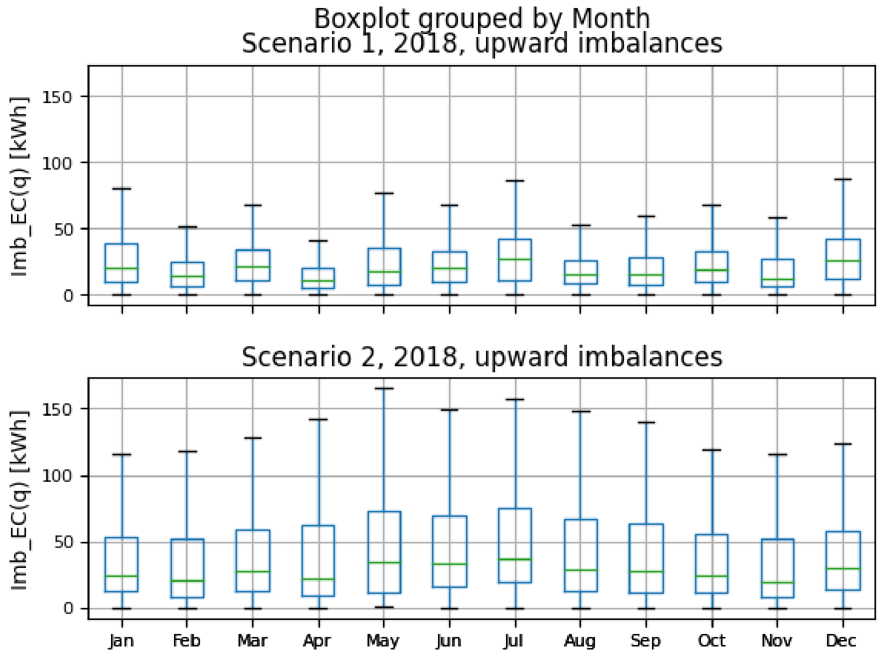


Figure 8.9: Boxplots of upward Imb_{EC} by month: scenario comparison along 2018, run 1.

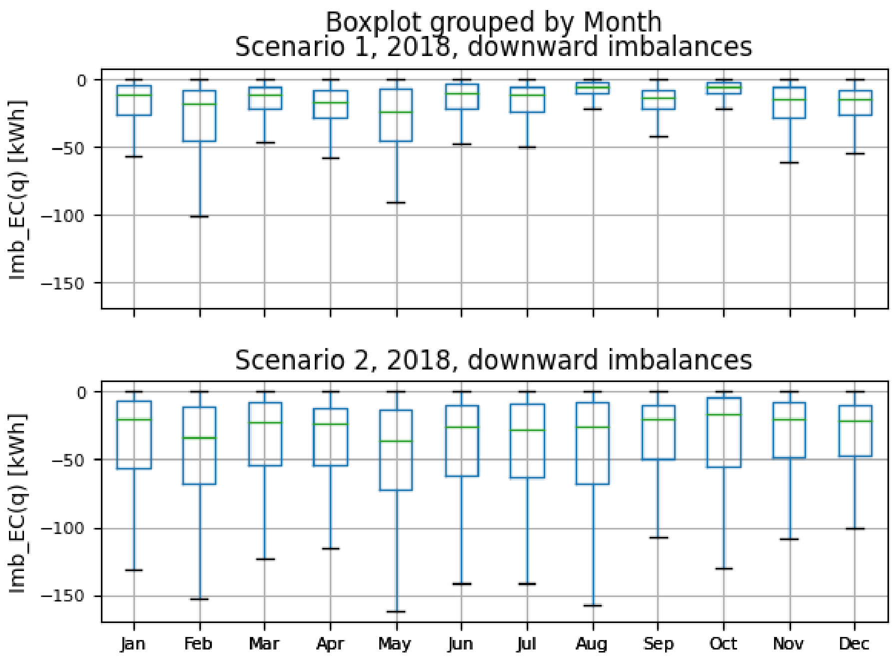


Figure 8.10: Boxplots of downward Imb_{EC} by month: scenario comparison along 2018, run 1.

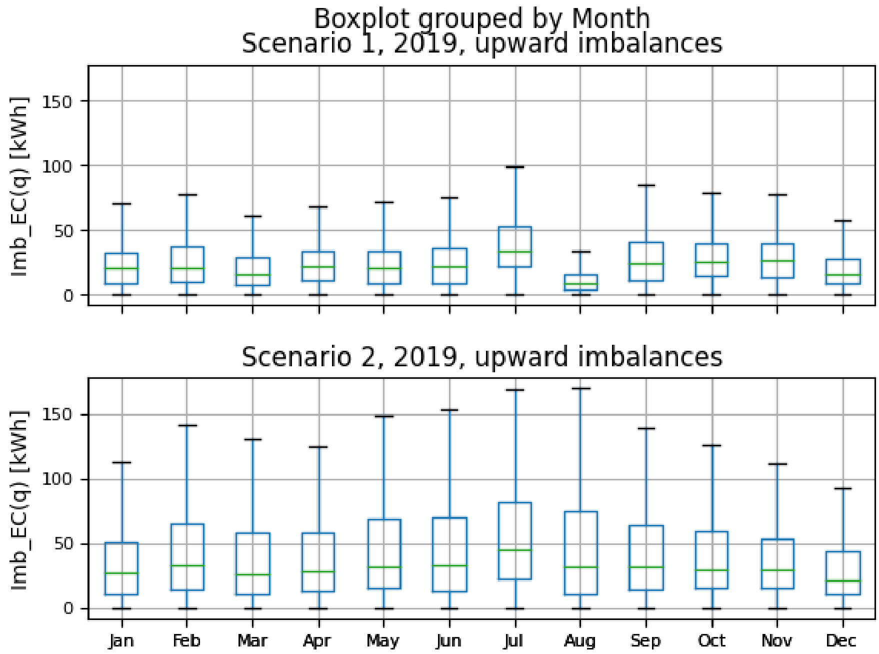


Figure 8.11: Boxplots of upward Imb_{EC} by month: scenario comparison along 2019, run 1.

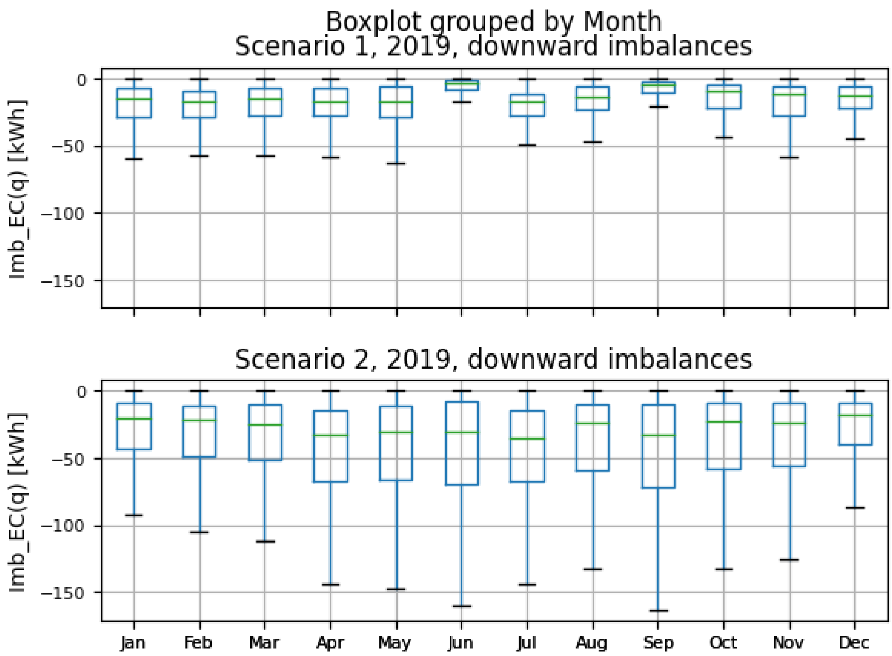


Figure 8.12: Boxplots of downward Imb_{EC} by month: scenario comparison along 2019, run 1.

Passing to the P_{imb}, without distinguishing between upward and downward cases, S1 and S2 would present basically the same trend and values, since this price depends only on the Imb_{MZ} sign and the latter doesn't change through the scenarios. Instead, the upward prices can have higher values than the downward ones, as shown in **Figures 8.13** and **8.14**, in accordance with the higher values of yearly average P_{imb} for run 1 (respectively 59.8 EUR/MWh and 57.2 EUR/MWh), while the depicted trends are similar to the ones of P_{up} and P_{down} presented in **Paragraph 7.3.2**, with lower prices during summer.

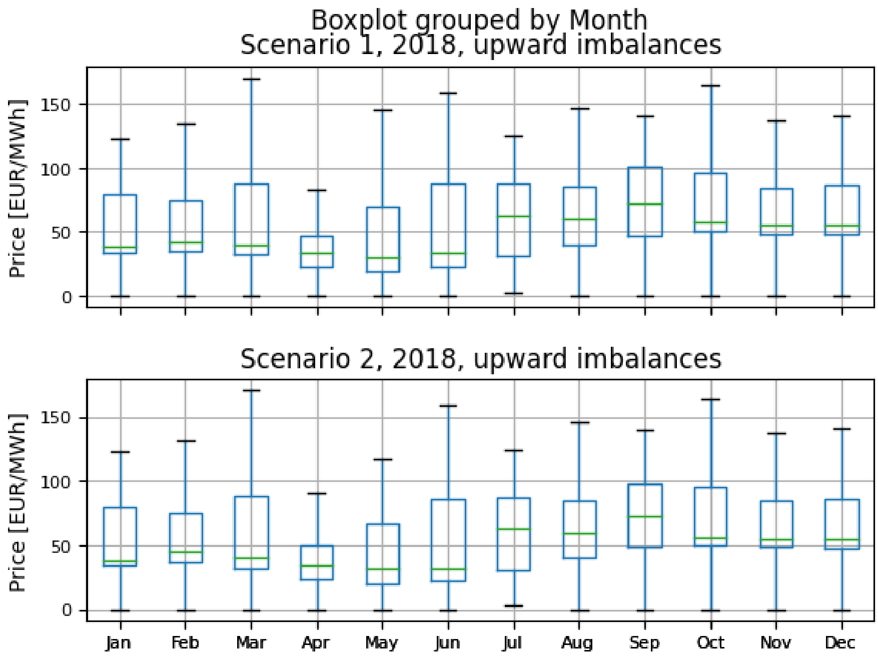


Figure 8.13: Boxplots of upward P_{imb} by month: scenario comparison along 2018, run 1.

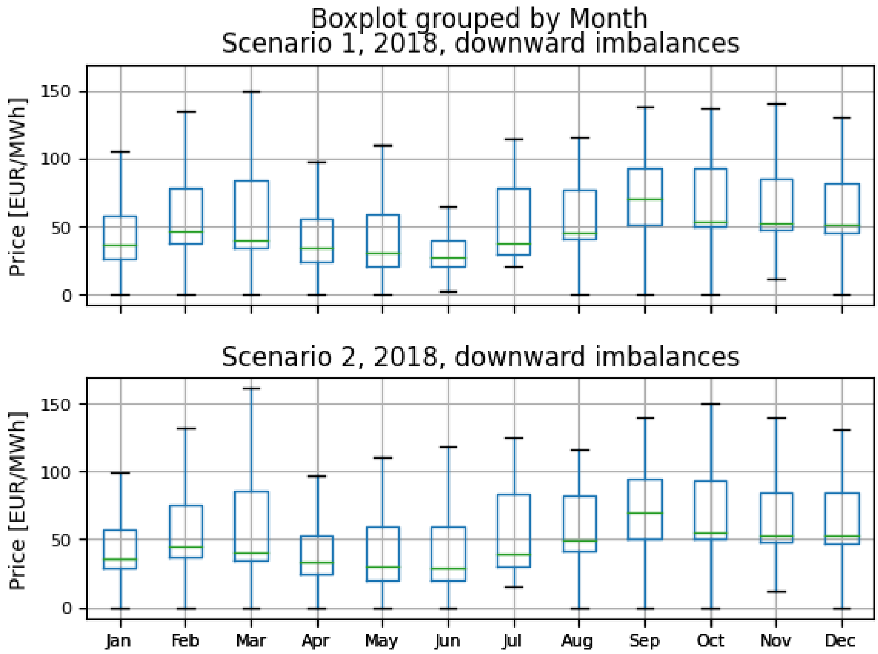


Figure 8.14: Boxplots of downward P_{imb} by month: scenario comparison along 2018, run 1.

The daily seasonality is now analysed in the same way as the yearly one, but distinguishing between the seasons:

- **Winter**: December, January, February.
- **Spring**: March, April, May.
- **Summer**: June, July, August.
- **Autumn**: September, October, November.

The 2018 upward Imb_{EC} is reported in **Figures 8.15**, **8.16**, **8.17** and **8.18**, while the 2018 downward one in **Figures 8.19**, **8.20**, **8.21** and **8.22**: as expected, for both upward and downward cases the imbalances increases in absolute value from S1 to S2, and the the interval in which this increase occur is higher in Spring and Summer than in Autumn and Winter, due to the seasonal producibility of the PV. Then, in S1 is visible a correspondence between the Imb_{EC} peaks hours and the consumption peaks ones. This analysis is valid also for 2019.

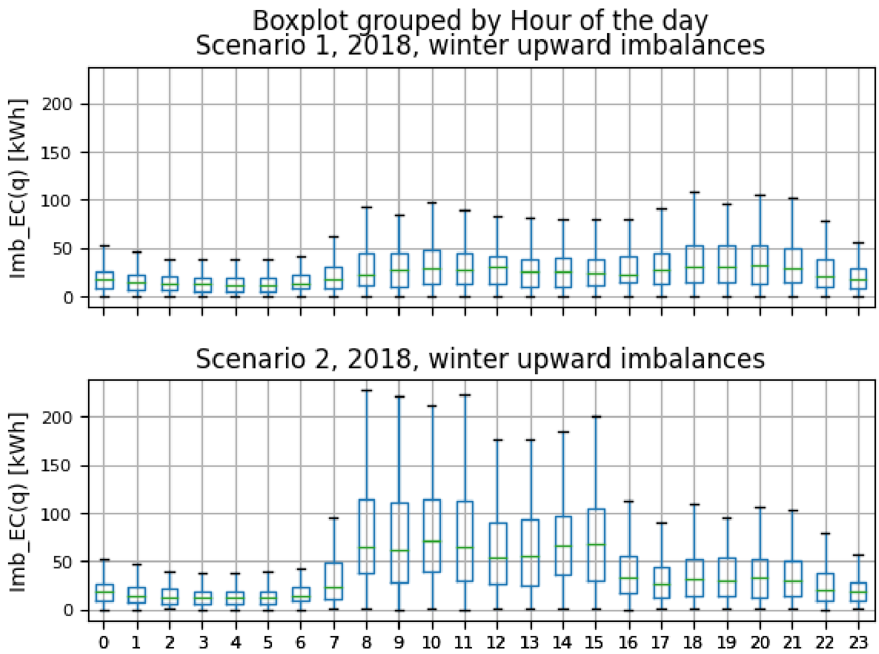


Figure 8.15: Boxplots of winter upward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

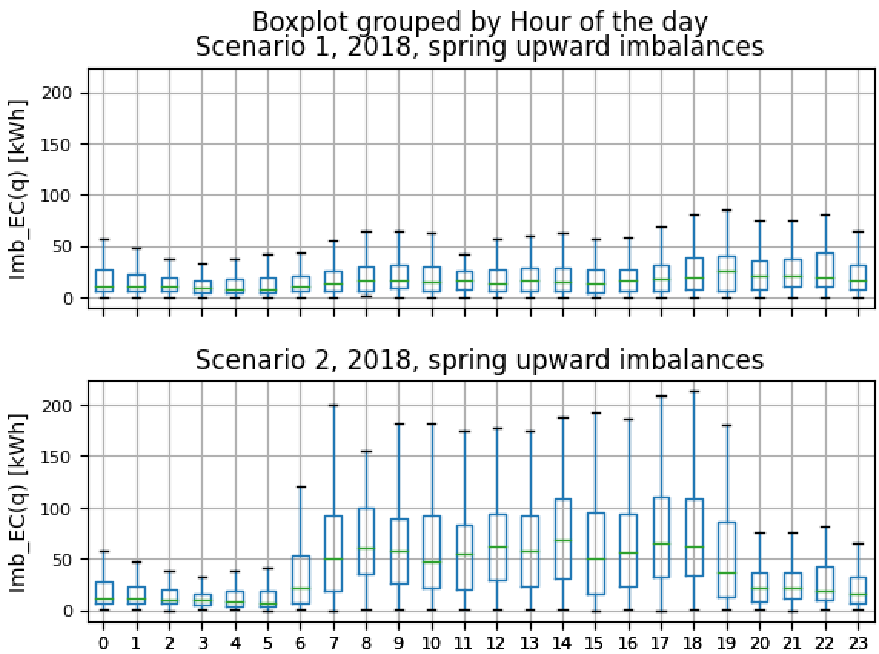


Figure 8.16: Boxplots of spring upward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

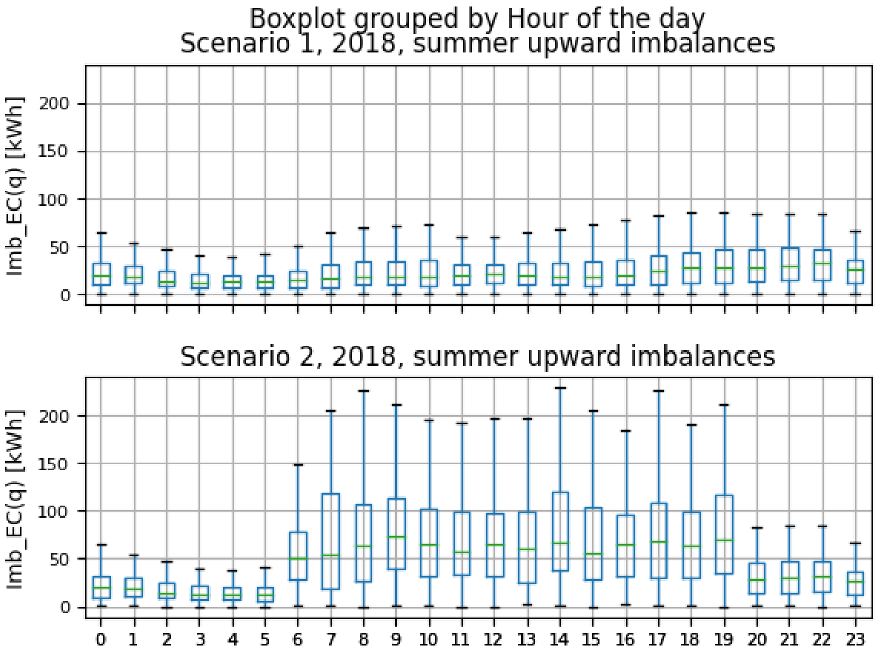


Figure 8.17: Boxplots of summer upward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

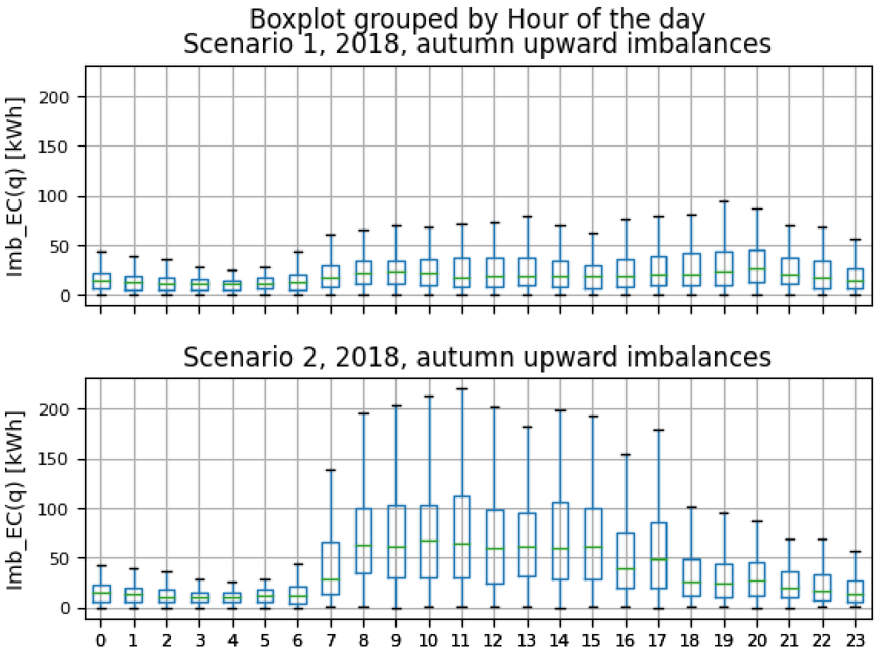


Figure 8.18: Boxplots of autumn upward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

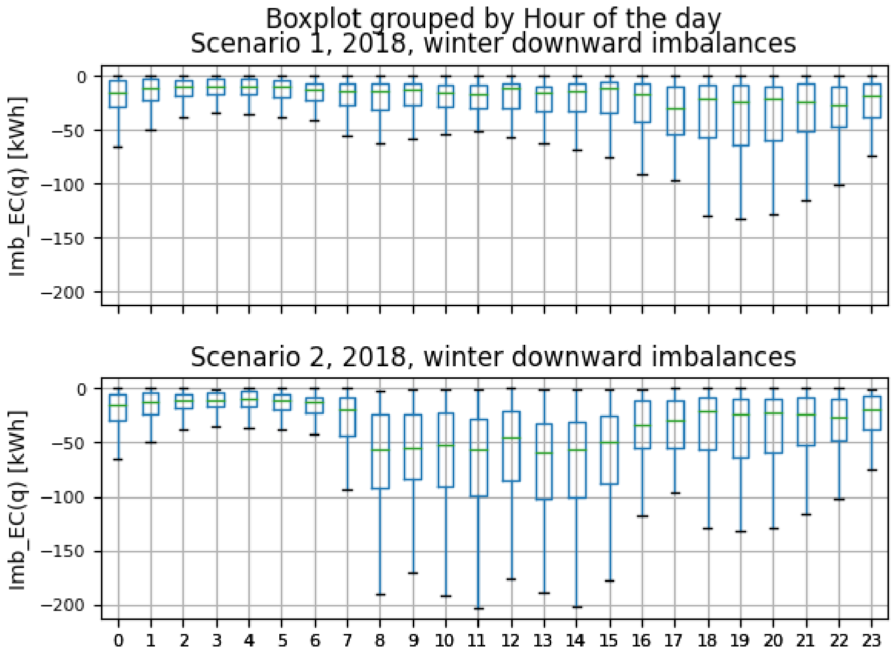


Figure 8.19: Boxplots of winter downward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

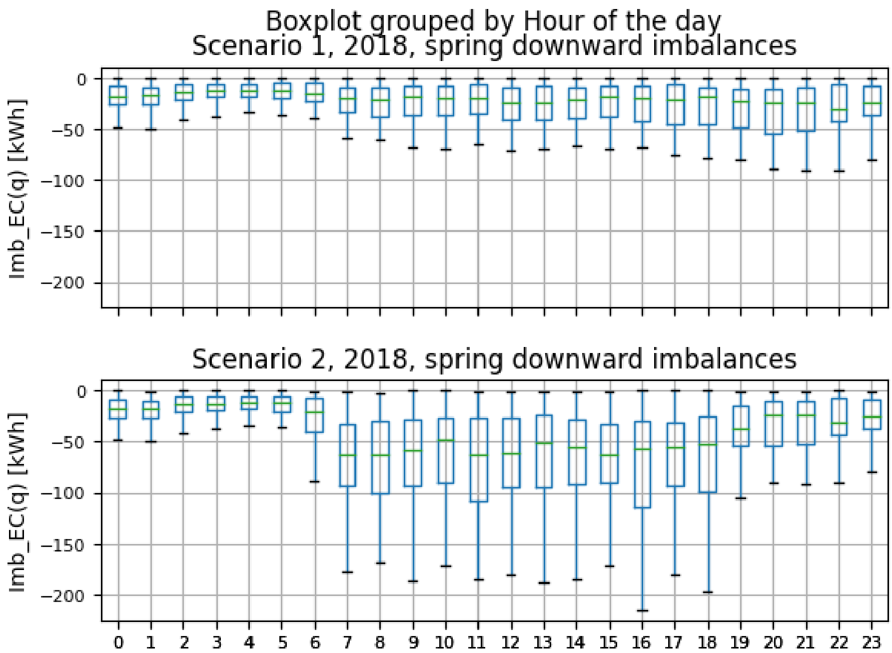


Figure 8.20: Boxplots of spring downward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

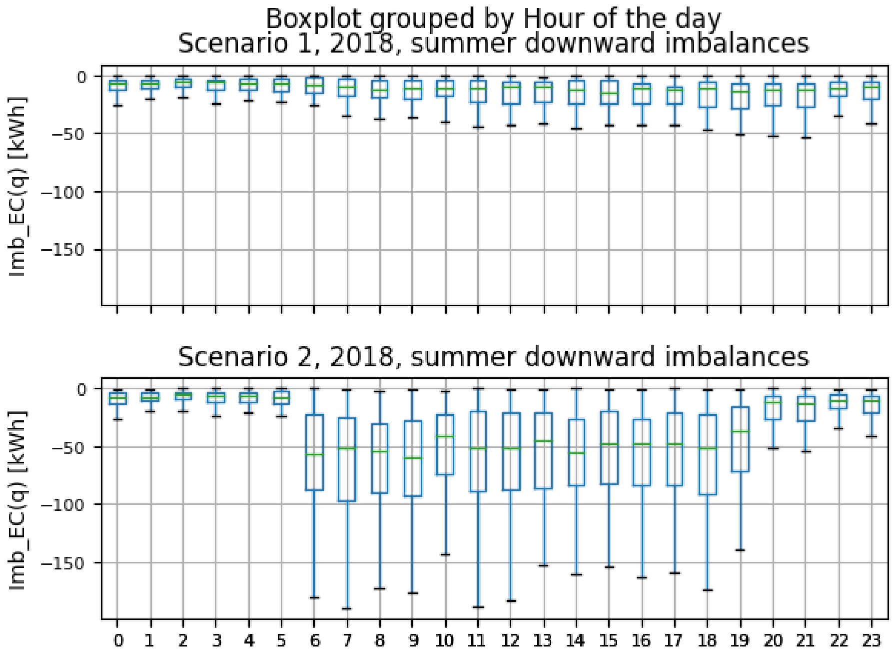


Figure 8.21: Boxplots of summer downward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

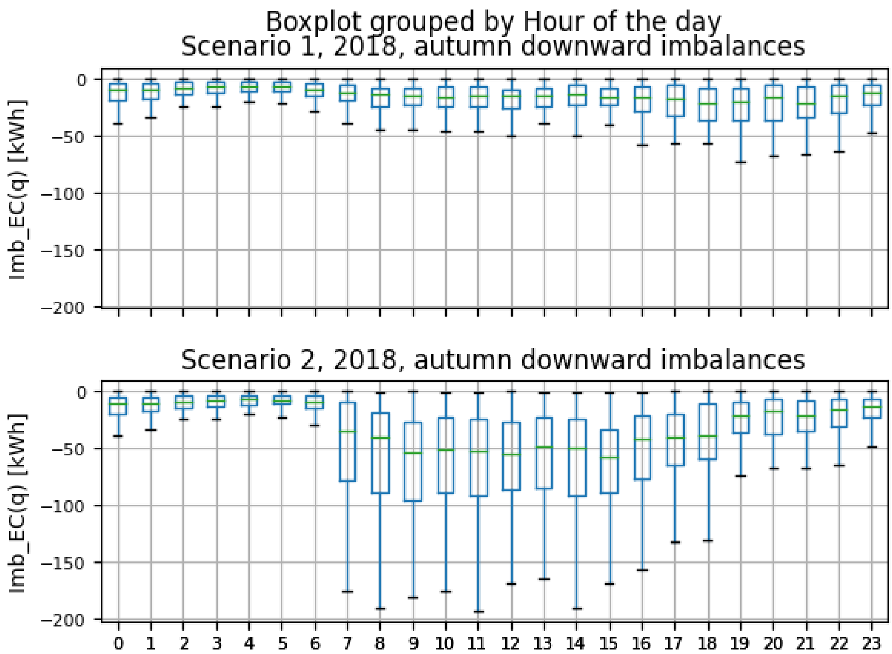


Figure 8.22: Boxplots of autumn downward Imb_{EC} by hour of the day: scenario comparison along 2018, run 1.

Finally, the prices are considered: the 2018 upward ones in **Figures 8.23**, **8.24**,

8.25 and **8.26**, while the downward one in **Figures 8.27**, **8.28**, **8.29** and **8.30**. As for the monthly grouping, S1 and S2 present the same trend and almost the same values of P_{imb}, while the upward prices seems to have higher values in general. Then, in Winter and Spring the values appear lower than in other periods, since in these seasons there is a higher occurrence of positive Imb_{MZ}, when P_{imb} is valued as P_{down} and P_{DA}. This analysis is valid also for 2019

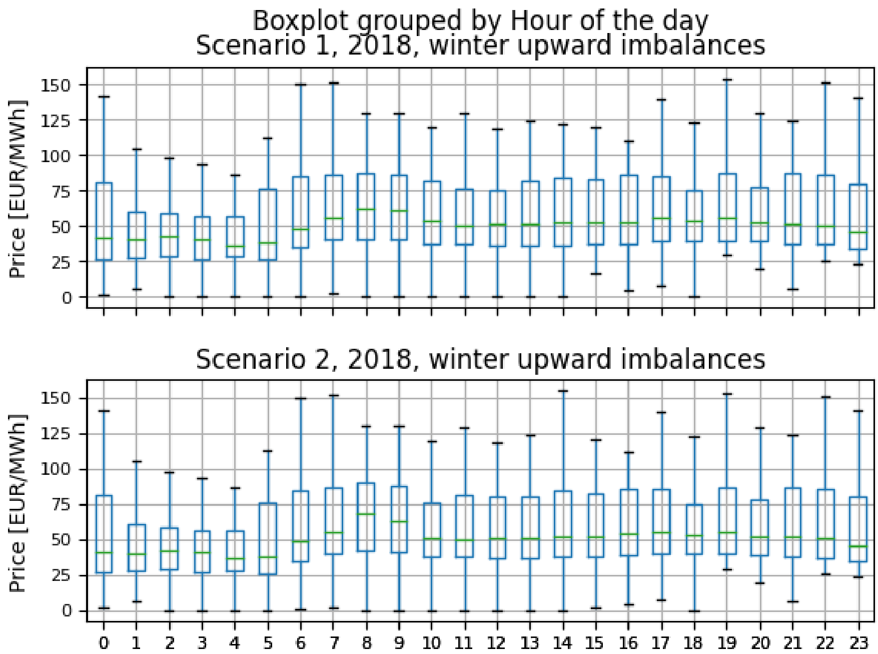


Figure 8.23: Boxplots of winter upward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

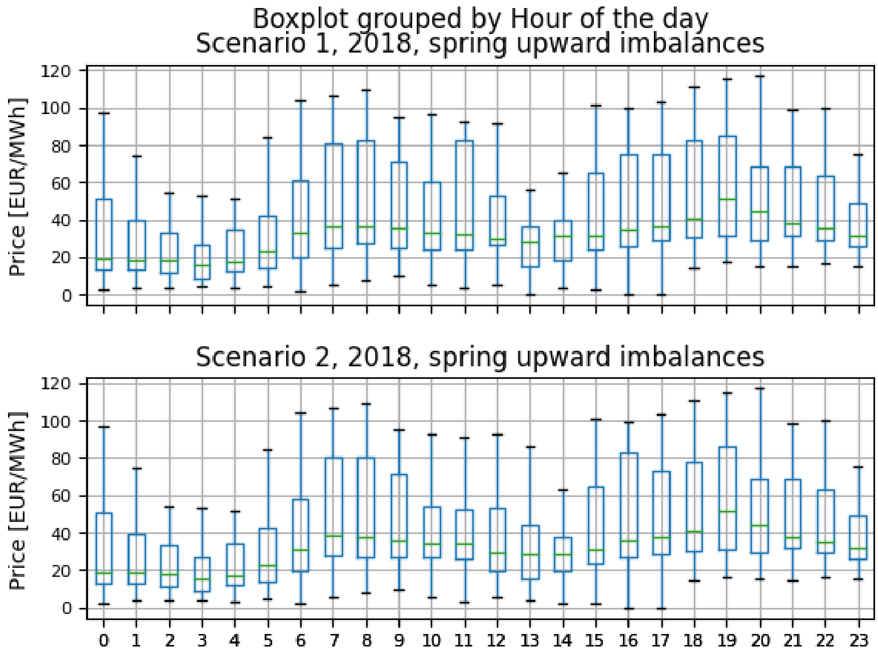


Figure 8.24: Boxplots of spring upward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

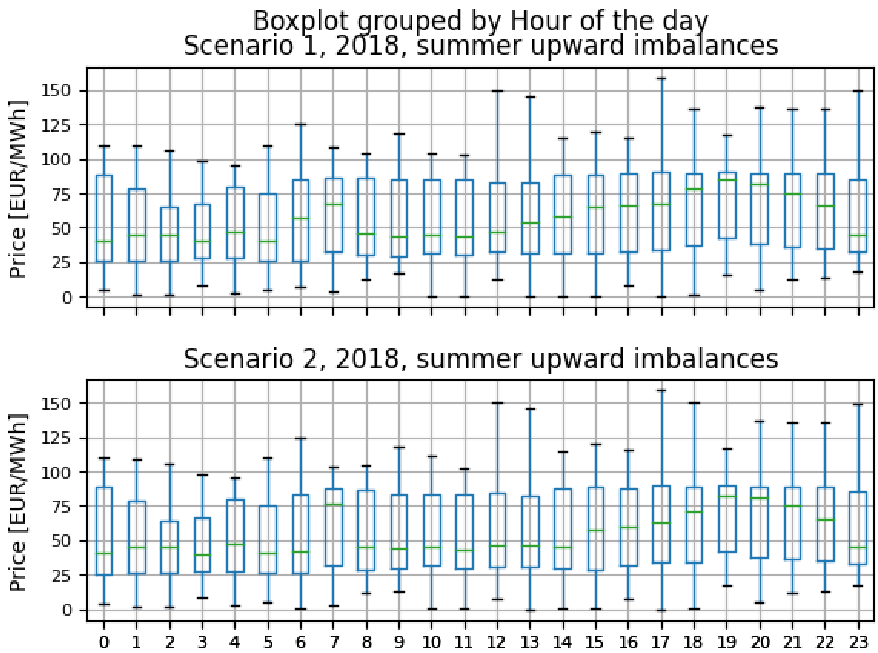


Figure 8.25: Boxplots of summer upward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

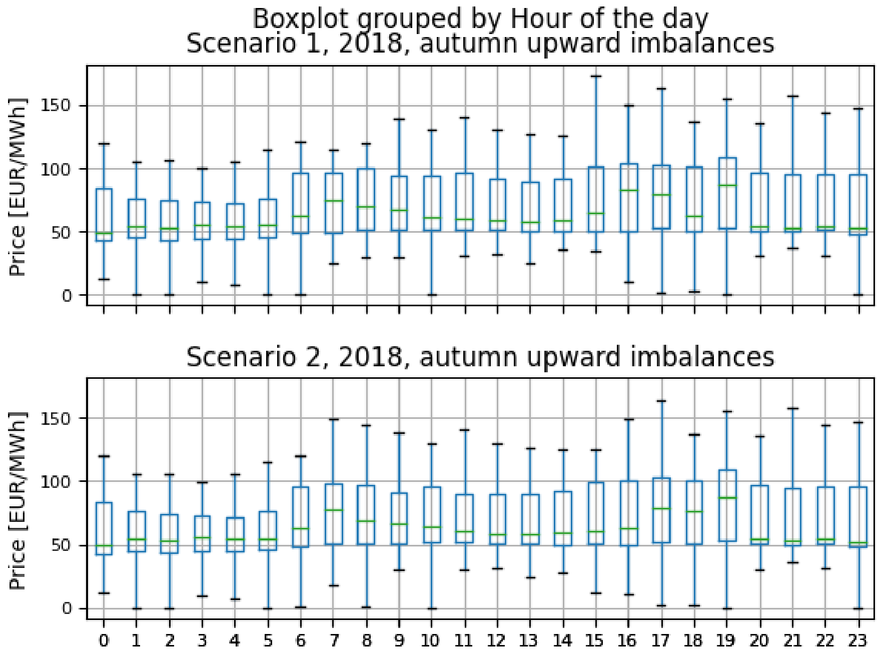


Figure 8.26: Boxplots of autumn upward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

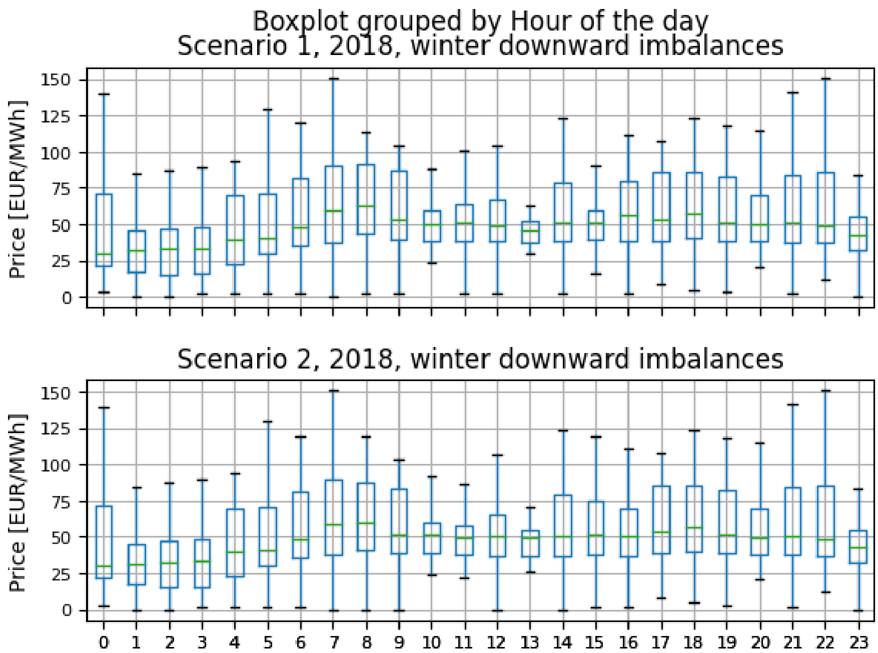


Figure 8.27: Boxplots of winter downward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

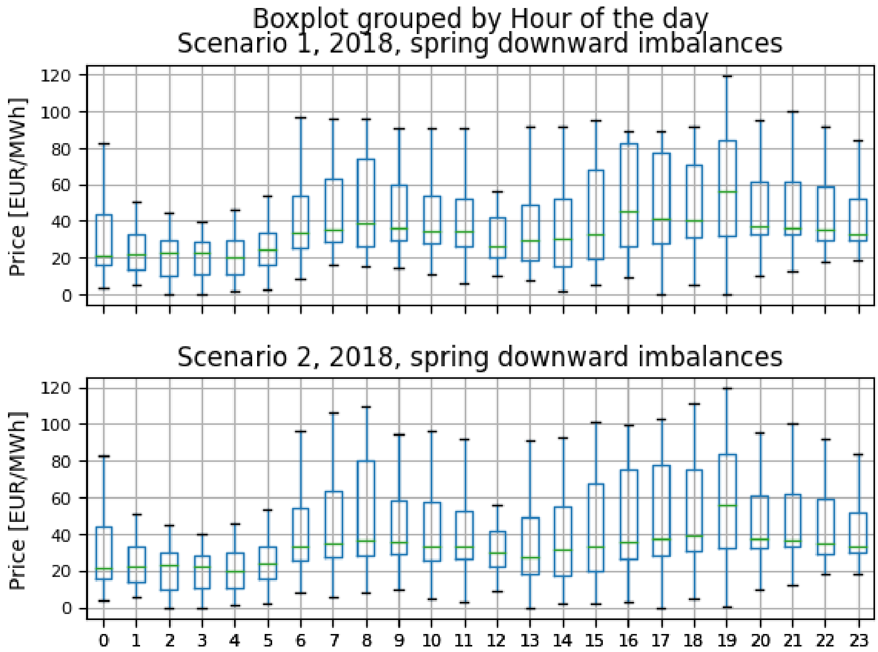


Figure 8.28: Boxplots of spring downward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

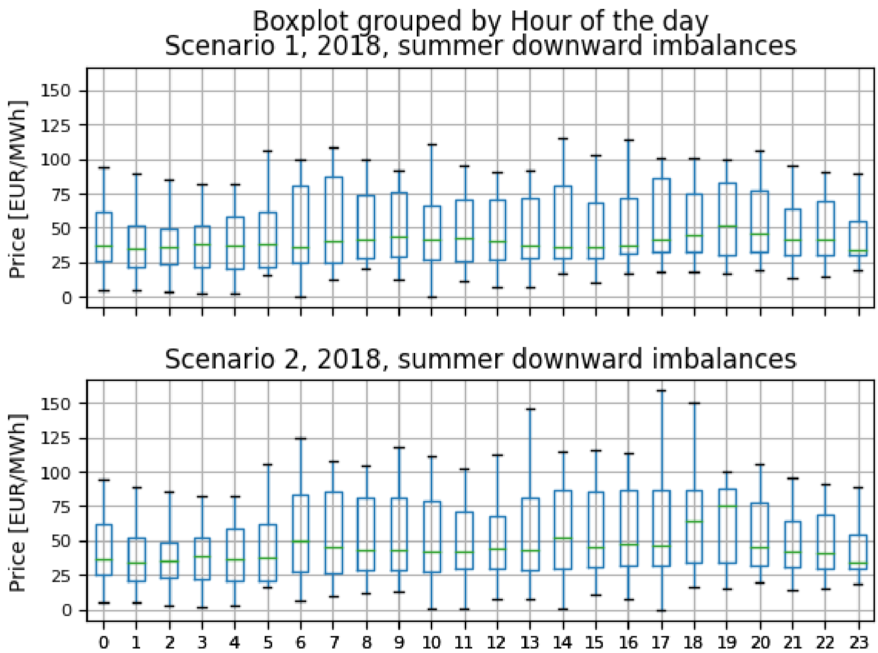


Figure 8.29: Boxplots of summer downward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

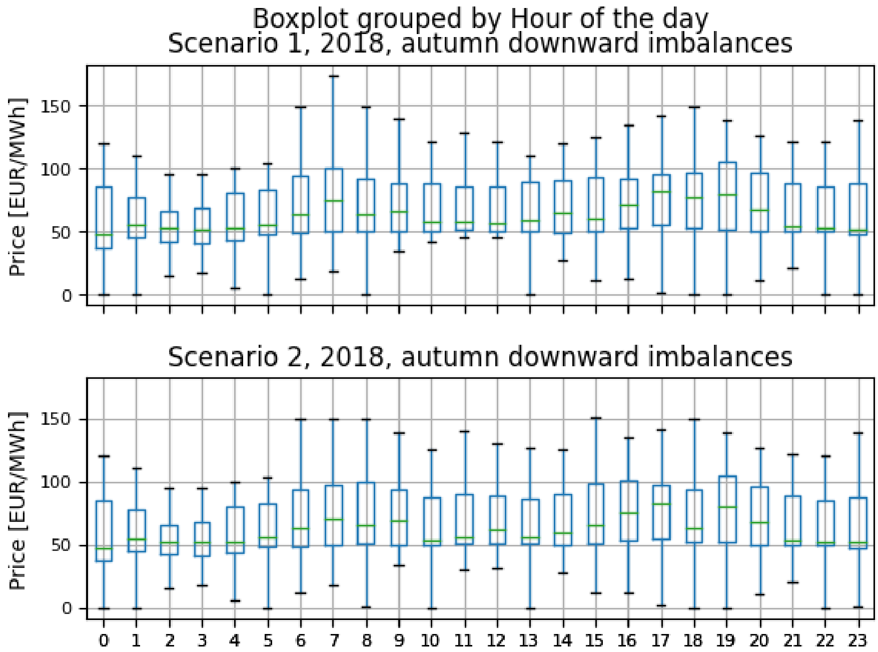


Figure 8.30: Boxplots of autumn downward P_{imb} by hour of the day: scenario comparison along 2018, run 1.

These results are quite similar in broad terms among all the runs, however here only the first one is considered. Of course, the presence of actual measured imbalances would provide more outcomes (e.g. the real imbalances may be higher during cloudy days and summer months). However, these results are interesting since they describe how the presence of PV production in general increases the imbalances during the period of higher production, hence summer and the daylight hours. Then, also the consumption peak hours present higher values of Imb_{EC} and P_{imb}.

Chapter 9

Conclusions

The energy transition is currently facing an increasing spread of distributed and aggregated energy entities: the ECs and VPPs deployment, with their DG sources, is boosted by a strong and ambitious European and national regulatory framework, that needs to deal especially with the integration within the power systems such as the grid and the markets. The main effect of such a diffusion is the increase of NPRS injection and a decrease of conventional programmable power plants, causing some technical difficulties in the dispatching operations: indeed the penetration of the former increases the power reserve needs, while decreasing the available modulation power offered by the latter.

In such a scenario, this thesis estimates the potential imbalances caused by an EC: it is placed in Northern Italy and consists of 3,377 end-users owning in total 13.7 MW of PV rooftop systems (see **Section 7.1**). The mismatch between FO and RT grid exchange were build adding to the former a normal distributed error, having in mind the typical forecasting errors for domestic consumption and PV: for the former is obtained a NRMSE around 8%, while for the latter around 15%. Due to the randomness of the imbalances, 10 runs are implemented, which can be also seen as representing of 10 different ECs: then, 2 scenarios are implemented, with and without PV, simulating the passage from simple households to an EC.

The imbalances were evaluated adopting the Italian imbalance settlement regulated by ARERA and Terna, consisting of a SP non penalising scheme, as described in **Section 3.4**: positive imbalances mean electricity excess on the grid (increase/decrease in production/consumption compared to the forecast) and a payment of $ImbC$ from the BRP to the TSO, vice-versa for the negative ones. This charges refer to 15-min and are settled within an time horizon of 2 months. Then, the net charges converge into the DC, a bill invoice through which Terna recover the net costs supported for the dispatching operations. The above-described scheme is non penalising since it allows the BRP, in this case the EC aggregator, also to gain from their imbalances: indeed, if the Imb_{EC} sign is opposite compared to the Imb_{MZ} one, basically the former helped Terna to compensate the latter and the imbalances are valued in a better way wrt the case without imbalances (higher price than the P_{DA} in case of injection, lower price than the PUN in case of withdrawal). Vice-versa for the sign concordance, leading to reward or penalty called $ImbP$.

Hence, the imbalance settlement is striclty related to 2 market quantities: Imb_{MZ} and ASM prices and by the purpose of the thesis they are analysed in **Sections 7.2** and **7.3**. In recent years, the positive Imb_{MZ} occurrence increased since 2015, becoming the highest occurrence in 2018, 2019 and 2020 (especially during Spring and Summer), meaning P_{imb} closest to P_{down} than to P_{up} (see **Table 3.6**). Furthermore, since in the majority of positive Imb_{MZ}, also $Imb_{load,north}$ is positive, as well as for the latter and Imb_{EC} (see **Paragraph 7.1.4**), it was expected to have higher occurrence for positive Imb_{EC} than negative and higher occurrence for penalty than reward, in particular according to **Table 3.8**.

The ASM prices focus was instead mainly for testing that in general $P_{down} < P_{DAM} < P_{up}$, $(P_{DAM} - P_{down}) < (P_{up} - P_{DA})$ and PUN is very close to Northern P_{DA}. As a result, in the majority of cases: P_{up} is higher than P_{DAM} and P_{down} on average of 77% and 300% during 2018, of 121% and almost 600% during 2019 (similar values for 2020); P_{down} is lower than P_{DAM} on average of 43% in 2018 and 40% in 2019 (similar values for 2020); P_{DA} is lower than PUN, with an overall mean of 1% in 2018 and 2% in 2019 (3% in 2020). Then, there is a general prices decreases from 2018 to 2019 for P_{down} and P_{DAM} that ranges from 12% to 16%, with huge decrease in 2020 due to Covid pandemic. From these results were expected relevant differences among the $ImbP$ sub-cases depicted in **Table 3.8**.

The imbalance settlement was performed along 2018 and 2019. First, a daily focus is performed to test the Python routines created for the 15-min settlement. Then, the results are aggregated on yearly basis, distinguishing among the 2 scenarios and the 10 runs (or ECs depending on how they are seen): the averaging among the runs is shown in terms of mean ± standard deviation. The quantities are shown separately for the positive imbalances, the negative ones, then they are aggregated both in absolute value and with sign: the former refers to the overall handled imbalances, the latter to the net cost supported by Terna. As expected, in S1 the positive Imb_{EC} have the highest occurrence, with a runs mean of 57.4% ± 3.4% during 2018 and 58.8% ± 4.0% during 2019. This leads to higher positive $ImbC$, resulting in a positive net $ImbC$ for all the runs, implying a yearly net loss from Terna point of view in the formulation of the DC. The introduction of the PV in S2, given the random nature of its imbalances, increases both the negative and the positive Imb_{EC} in absolute value, the former more than the latter: however the positive occurrences still remain the highest. Among the 2018 runs, the yearly mean Imb_{EC} and $ImbC$ resulted:

- pos Imb_{EC}: 848.257 MWh ± 40.261 MWh in S2, with an average increase of 79% wrt S1.
- neg Imb_{EC}: -662.160 MWh ± 38.368 in S1, with an average increase of 119% wrt S1.
- tot $ImbC$: 90,593.47 EUR ± 1,762.01 in S1, with an average increase of 93% wrt S1.
- net $ImbC$: 10,796.35 EUR ± 5,765.10 EUR in S2, remaining quite similar wrt S1.

In 2019 the orders of magnitude are the same, while the charges are slightly lower than 2018, due to a general prices decreases that affected also P_{imb}: since the latter depends only on Imb_{MZ} sings, it doesn't change among runs and scenarios. The yearly means are 58.71 EUR for 2018 and 49.41 for 2019: as expected, these values are closer to P_{down} and P_{DAM} than to P_{up}, and the difference between the years is around 16%, a value similar to the one affecting P_{DAM}.

About the $ImbP$, a similar yearly analysis was performed: apart from 2 runs, the others present higher occurrence of penalty cases for the EC, i.e. sign concordance between the latter and the Northern MZ, confirming the first expectations after having analysed the ASM trends. The 2018 yearly mean net $ImbP$ ranges as follow in S2:

- Penalty net $ImbP$: -1,475.29 EUR $\pm$ 829.02EUR, remaining quite similar wrt S1 and in 2019.
- Reward net $ImbP$: 771.30 EUR $\pm$ 86.6445 EUR, remaining quite similar wrt S1 and in 2019.

The main outcomes of the payoffs analysis refers to the sub-cases presented in **Table 3.8**: the HG and HL present yearly mean P_{imb} values more than 2 times higher than the LG and LL. The latter presents also the highest yearly occurrence, because of the already described sign concordance between Imb_{MZ}, $Imb_{load,north}$ and Imb_{EC}.

In literature there weren't found any comparative results, apart from [56], which however focuses the analysis on the usage of batteries to reduce the imbalances: hence, some indicators were provided to better visualise the impacts of Imb_{EC}, in terms of size changing. These indicators involve pos, neg, tot and net $ImbC$. The first indicator proposed was I_{ge}, i.e. the charges per grid exchange, considering the withdrawals, the injections and the total exchange in absolute value: these may be an indicator on how much the imbalances can impact on the bills. Considering runs mean, indeed, while pos, neg and tot I_{eg} have the same order of magnitude of the DCs, ranging from 3.00 EUR/MWh to 6 EUR/MWh, the net I_{eg} appears to reach values one order of magnitude lower, that net of sign is the same as for the DC invoice involving the net $ImbC$: the net I_{eg} for withdrawals resulted 0.83 EUR/MWh $\pm$ 0.45 EUR/MWh in S2, 2018, with similar values in S1 and 2019.

The second indicator consists in I_{ge} the charges per imbalanced energy, a sort of mean P_{imb}: indeed, the values for pos, neg and tot indicators are similar to the yearly mean P_{imb}, with the downward values slightly higher. This indicator can be useful to understand how valuable were the upward and downward imbalances in light of the market, i.e. about 60 EUR/MWh in 2018 and 50 EUR/MWh in 2019 averaging among the runs.

Finally, the charges are divided per quantities invariant among the scenarios and the runs, i.e. the number of users, the peak consumption and production, and then compared to the single value found in literature (see [56]) of net 0.36 EUR per user and per kW of PV, obtained during a monthly simulation. Considering a mean yearly net I_{user} among the runs and the years of 3.12 EUR/user, the corresponding monthly value would be 0.26 EUR/user. Furthermore, the mean monthly net I_{user} were computed, net of sign, to test their order magnitude: the latter seems to be in accordance with the [56] value. Such as analysis were also done for $I_{p,prod}$, obtaining orders of magnitude similar to the 360 EUR/MW of [56]: in particular, yearly speaking, the net $I_{p,prod}$ averaged among the runs resulted 3,152.52 EUR/MW ± 1,561.32 EUR/MW.

As last analysis, the yearly and daily seasonality of Imb_{EC} and P_{imb} are studied: as expected, the highest Imb_{EC} increase from S1 to S2 occurred in the summer months and during the central hours of the day, hence during the periods of highest PV production. Then, the P_{imb} presents similar trends in both scenarios and imbalancing direction: in particular, lower prices can be observed during the summer months as for P_{up}, P_{down} and P_{DAM}, and during Spring and Winter, since in this seasons there is a higher occurrence of positive Imb_{MZ}, hence of cases in which the P_{imb} was valued as P_{down} or P_{DA}. (questi commenti sono aggiungere anche nella corrispondente section in results discussions)

The innovative points of the thesis are strictly related to the possible future deployments of this work, as pointed below:

- The lack in literature of works involving the imbalances within an EC, from one hand increases the value of the thesis, from another makes necessary the developing of further comparative analysis.

- The potential EC considered in this thesis is build without stressing the attention on the configurations or on the PV sizing: hence, this work can be easily declined in terms of RSC or UVAM, introducing the usage of batteries and testing DR schemes.

- The methodology, based on a 15-min imbalance settlement, allows to easily implement such an analysis considering any time horizon and case study of course analogous to the thesis one, such as an actual EC with measured imbalances.

In conclusion, becoming an EC would increase the Imb_{EC}, hence the $ImbC$ in both upawrd and downward directions, generating a relevant increase at systemic level, up to 93% in 2018, averaging among the 10 runs: hence, the total energies and monetary volumes handled by Terna seems to be higher in such a scenario of DG, ECs and VPPs diffusion.

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Appendix A

Appendix

COMPONENTE			DESCRIZIONE
UP-LIFT	MSD	Approvvigiona-mento servizi	Tale componente si riferisce alle contrattazioni sul MSD finalizzate all'approvvigionamento dei servizi di dispacciamento. È pari a quota parte della lettera b) del comma 44.1 della deliberazione 111/06.
		Componente energia	Tale componente rappresenta il saldo economico tra lo sbilanciamento del sistema e l'energia acquistata e venduta sul MSD a copertura dello stesso sbilanciamento. Il valore di tale componente risulta, in generale, non nullo data l'applicazione di un'asta discriminatoria (c.d. Pay-as-Bid) per la valorizzazione delle offerte accettate sul MSD e l'applicazione di prezzi di sbilanciamento non cost-reflective per specifiche tipologie di unità.
	UPLIFT – MSD	Corrispettivi di sbilanciamento	Il corrispettivo di sbilanciamento effettivo relativo a ciascun punto di dispacciamento è pari al prodotto tra lo sbilanciamento effettivo in un determinato periodo rilevante e il prezzo di sbilanciamento applicabile nel medesimo periodo rilevante al medesimo punto di dispacciamento, in base alla tipologia di punto di dispacciamento e al segno dello sbilanciamento effettivo.
		Le rendite da congestione e le relative coperture	Presupposto per una concorrenza effettiva nel mercato interno dell'energia elettrica sono corrispettivi per l'uso della rete trasparenti e non discriminatori, incluse le interconnessioni nel sistema di trasmissione. La capacità disponibile di queste linee dovrebbe essere stabilita entro il limite massimo che consente la salvaguardia delle norme di sicurezza per il funzionamento della rete.
		Il servizio dell'interconnes-sione virtuale (art.46)	Tale componente è espresso in euro/MW/anno (determinato dall'Autorità ai sensi dell'articolo 32, comma 6, della legge n. 99/09) e che i soggetti selezionati sono tenuti a riconoscere a Terna a fronte delle misure volte a consentire, a partire dalla conclusione del contratto di mandato per la programmazione e la progettazione di cui all'articolo 32, comma 3, della legge n. 99/09, fino alla messa in servizio dell'interconnector e comunque per un periodo non superiore a sei anni, l'esecuzione, nei limiti della capacità di trasporto oggetto della richiesta di esenzione di cui al medesimo comma 3, degli eventuali contratti di approvvigionamento all'estero.

Figure A.1: Uplift components description from [20].

COMPONENTE	DESCRIZIONE
UPLIFT	Il Corrispettivo per l'approvvigionamento delle risorse nel MSD, di cui alla Delibera AEEGSI n. 111/06, rappresenta l'onere netto associato alle seguenti partite energia: acquisti e vendite sul MSD a pronti e a termine (questi ultimi rappresentativi dei premi dei contratti stipulati in alternativa alla dichiarazione di essenzialità), remunerazione dell'avviamento impianti sul MSD (c.d. Gettone di avviamento e di cambio assetto), sbilanciamenti, rendite da congestione e relative coperture finanziarie, servizio di interconnessione virtuale (c.d. Interconnector) e altre partite minori.
MODULAZIONE EOLICA	Compenso per la mancata immissione di energia elettrica a causa della capacità di trasporto ridotta della rete di sub-trasmissione. Nei periodi di elevata disponibilità eolica, per effetto della limitata capacità di trasporto della rete di sub-trasmissione, Terna può essere costretta al taglio dell'immissione (MPE-Mancata Produzione Eolica). Terna riconosce al produttore un corrispettivo a compensazione della mancata produzione (e conseguente vendita).
UP ESSENZIALI	Remunerazione per gli impianti considerati «essenziali» da TERNA ai fini della sicurezza del sistema elettrico.
COSTO FUNZIONAMENTO TERNA	Compenso per i costi operativi sostenuti da TERNA per lo svolgimento del servizio di dispacciamento e quelli relativi alle attività di monitoraggio.
CAPACITY PAYMENT	Valori del corrispettivo unitario a copertura dei costi per la remunerazione della disponibilità di capacità produttiva.
INTERROMPIBILITÀ	Remunerazione per le unità di carico che in caso di deficit di potenza garantiscono il loro distacco dalla rete.

Figure A.2: DC components description from [20].

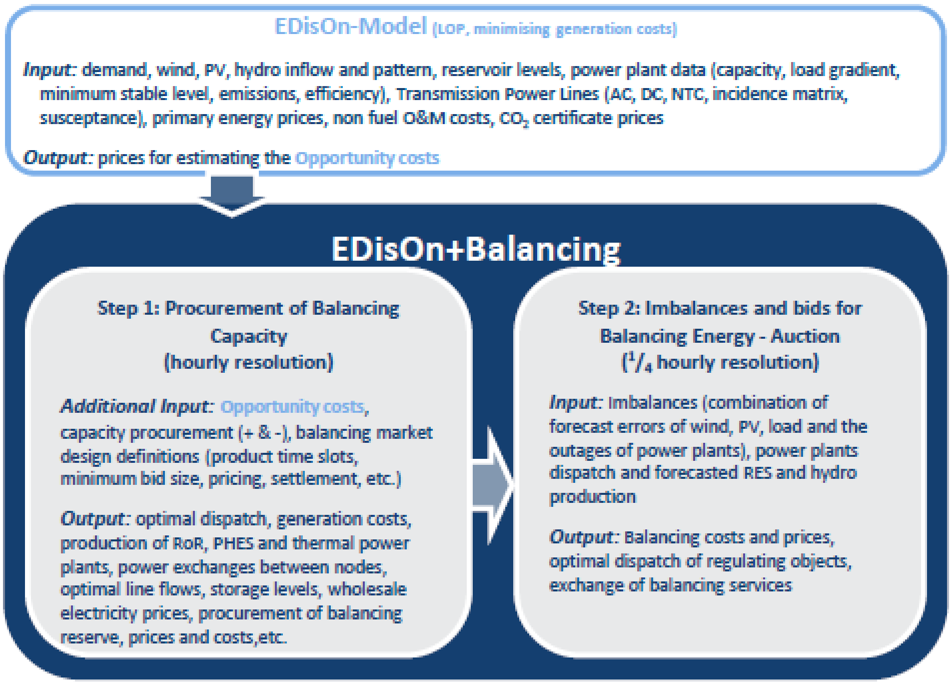
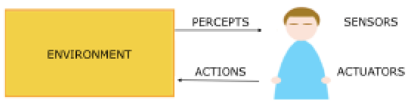
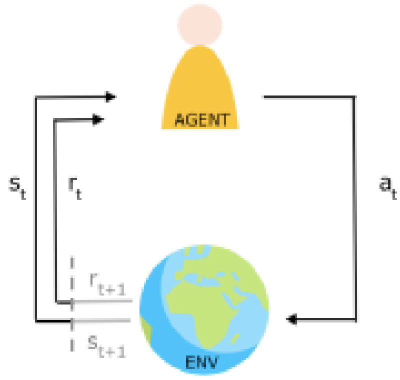


Figure A.3: Overview of EDisON different steps, inputs and outputs from [62].



(a) *Environment-agents interactions.*



(b) *Agents' learning process: state (s), action (a), reward (r).*

Figure A.4: Agents' main concepts from [24].

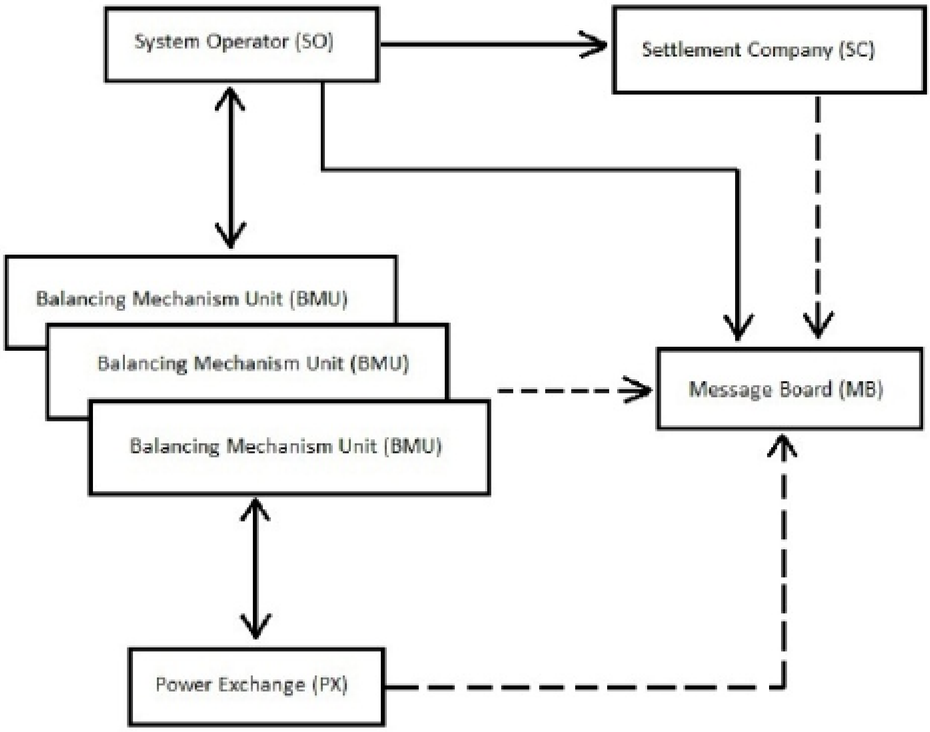


Figure A.5: Overview of Repast agents' interactions in the British short-term electricity market from [67].

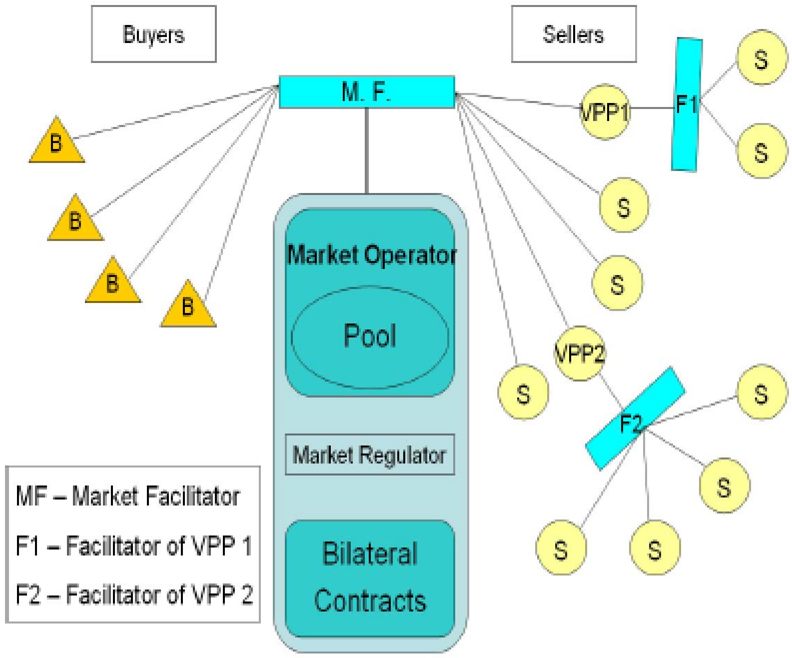


Figure A.6: Overview of MASCEM agents' interactions from [73].

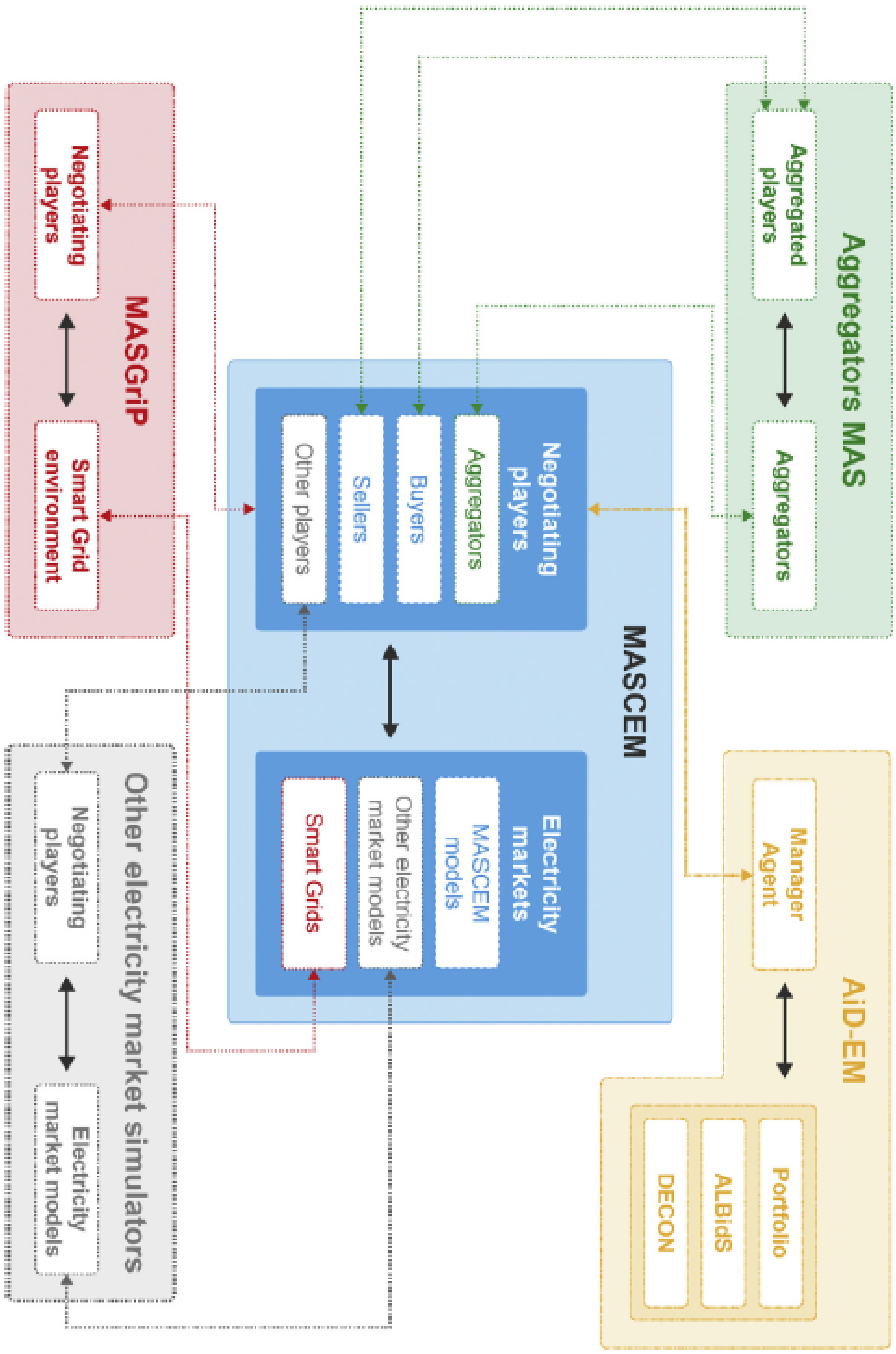


Figure A.7: Overview of MASCEM collaboration with other models from [75].Among them, quite relevant are AiD-EM as decision supporting tool and MASGriP for modelling smart-grids environments.

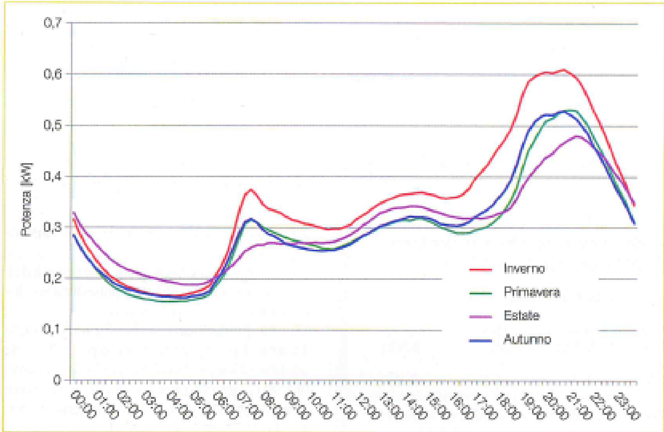


Figure A.8: Daily average load curves during weekdays of the Italian families analysed by [100].

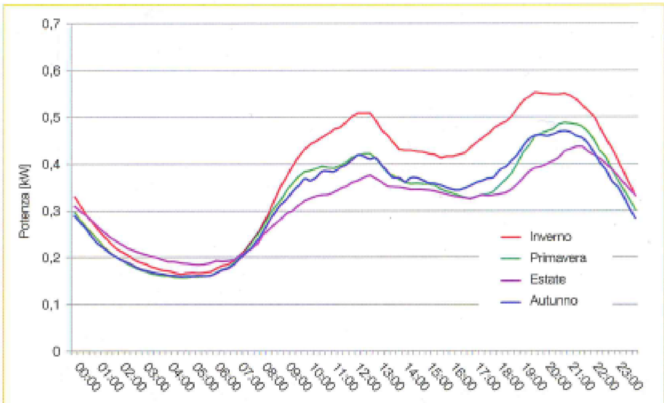


Figure A.9: Daily average load curves during holidays of the Italian families analysed by [100].

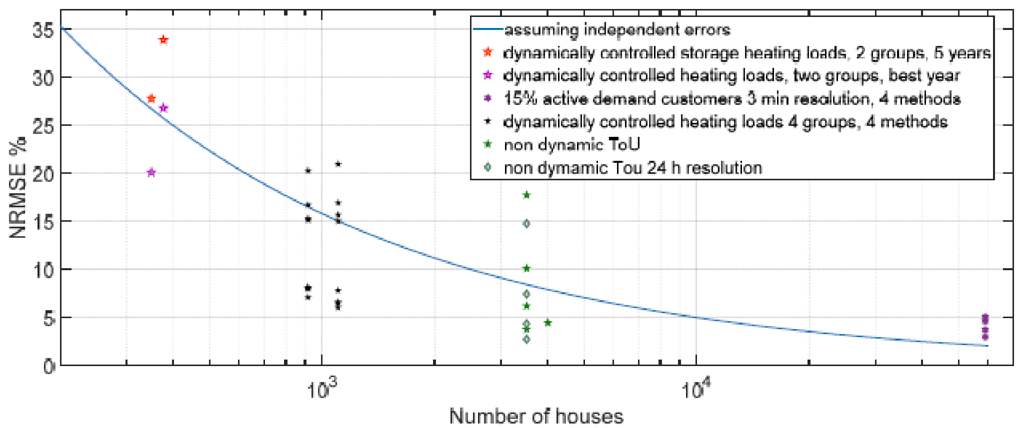


Figure A.10: Load forecation accuracy in terms of NRMSE as a function of the number of aggregated cosutmers ([111]).

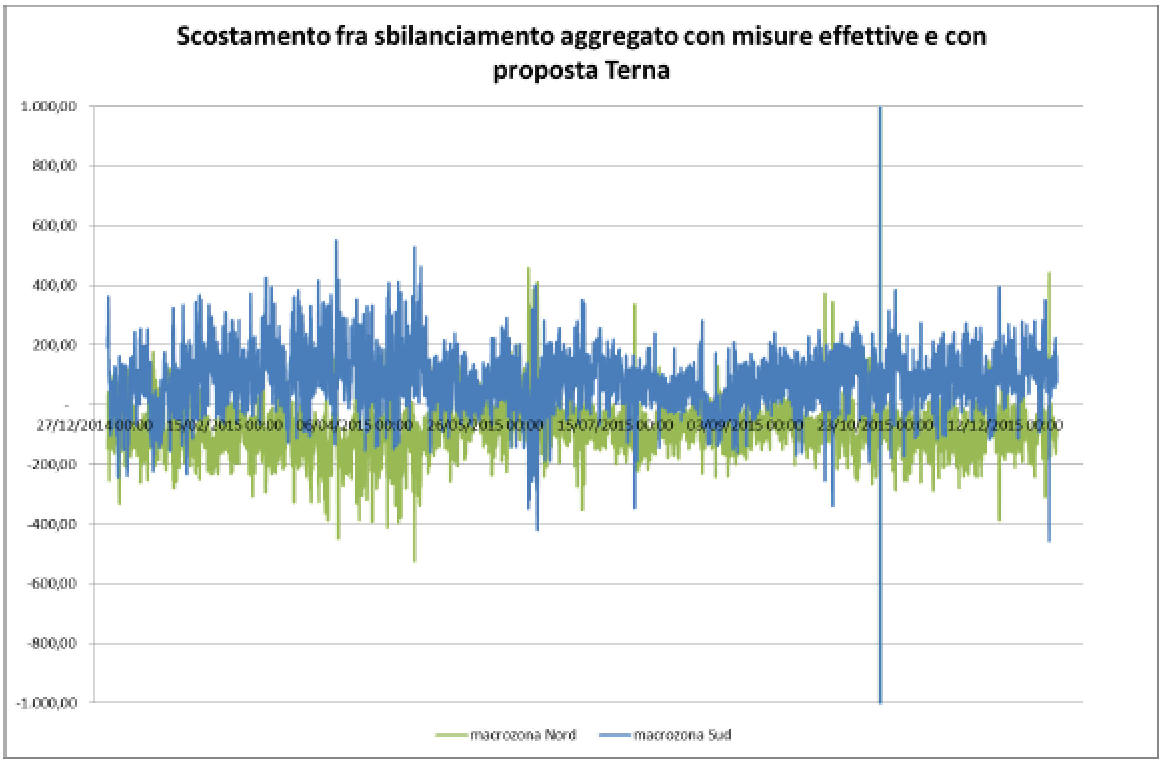


Figure A.11: Difference between $Imb_{MZ,old}$ and $Imb_{MZ,current}$ during 2015, from [113]
: the anomaly around October refers to the passage from legal to solar hour.

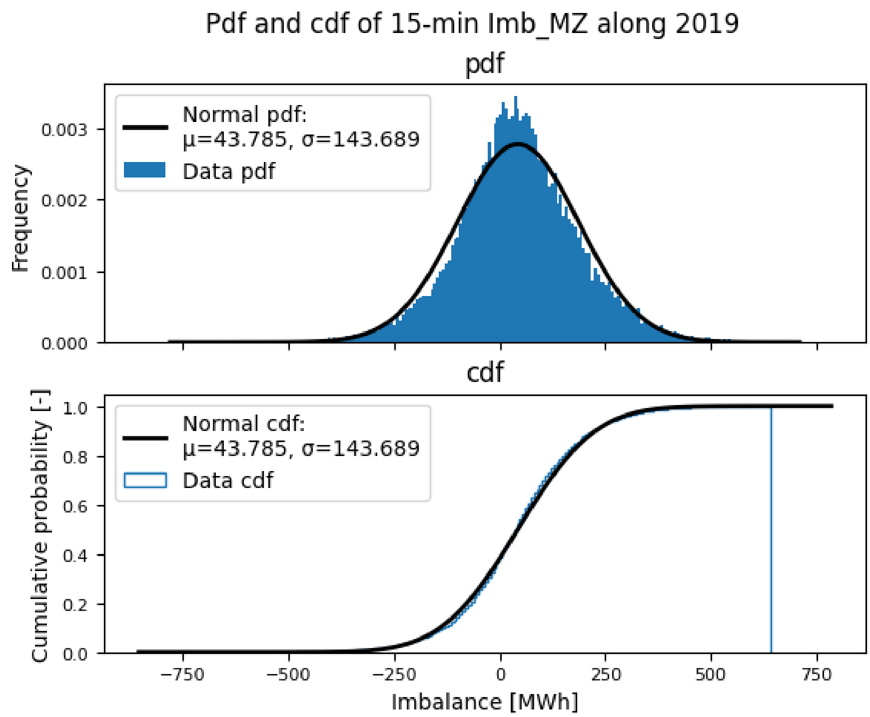


Figure A.12: Comparison between the Imb_{MZ} data and the expected normal distributions during 2019.

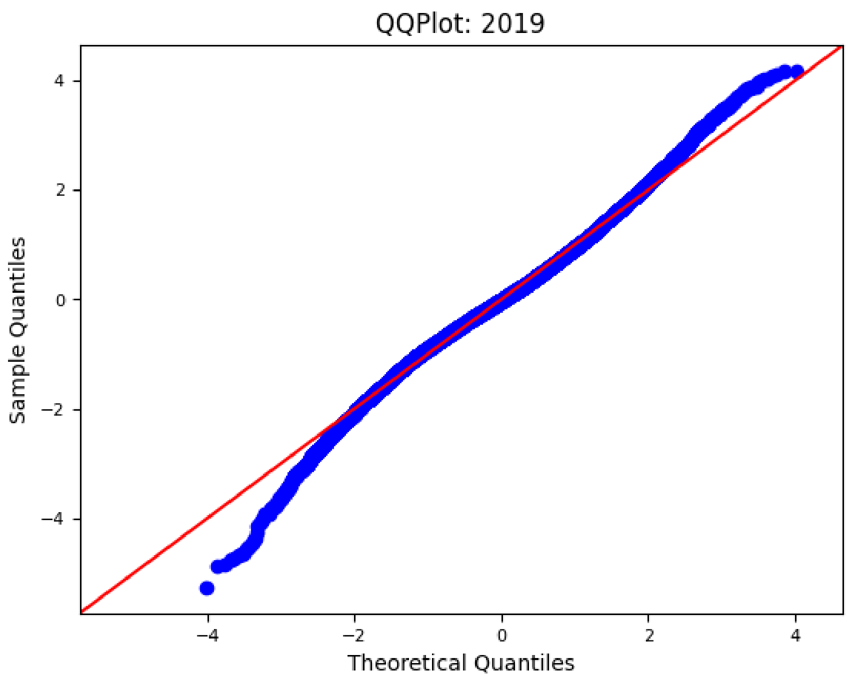


Figure A.13: Q-Q plot for the Imb_{MZ} during 2019.

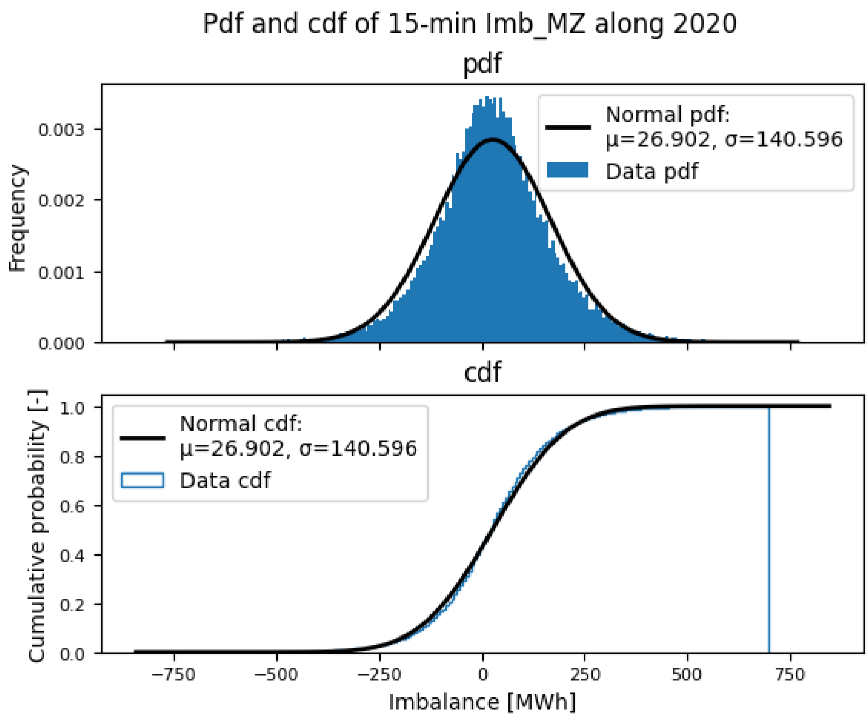


Figure A.14: Comparison between the Imb_{MZ} data and the expected normal distributions during 2020.

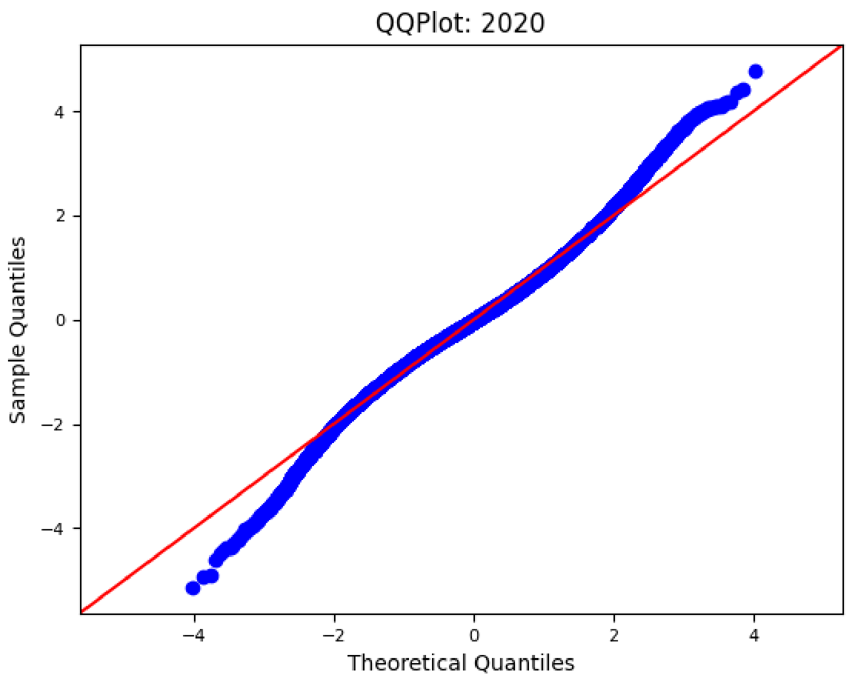


Figure A.15: Q-Q plot for the Imb_{MZ} during 2020.

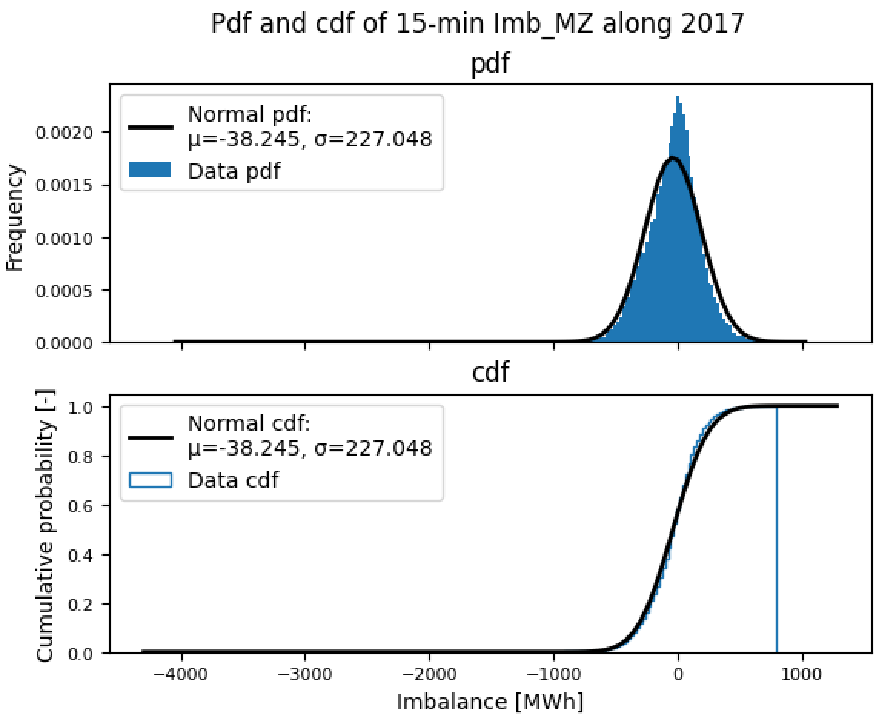


Figure A.16: Comparison between the Imb_{MZ} data and the expected normal distributions during 2017.

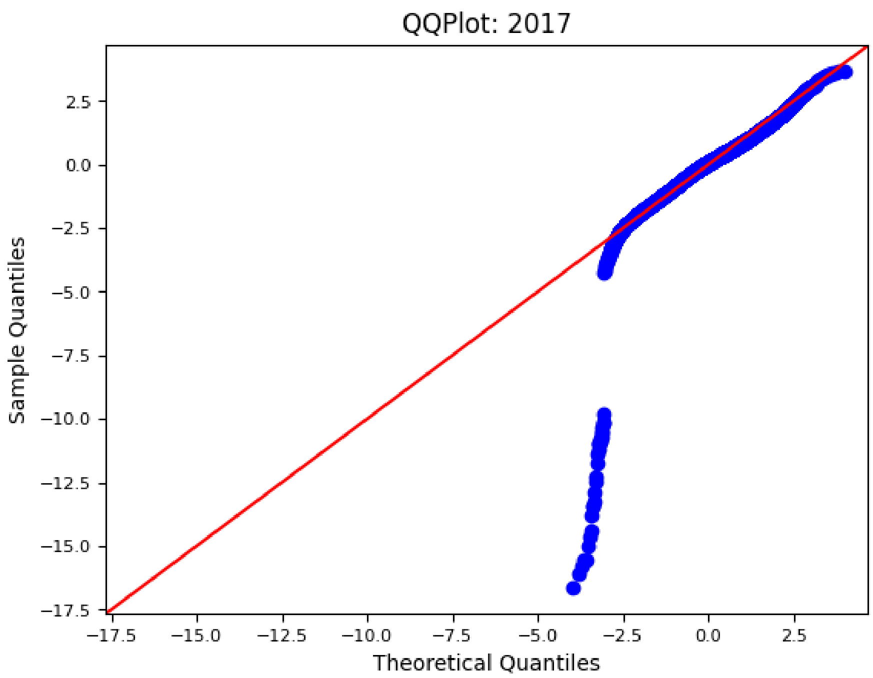


Figure A.17: Q-Q plot for the Imb_{MZ} during 2017.

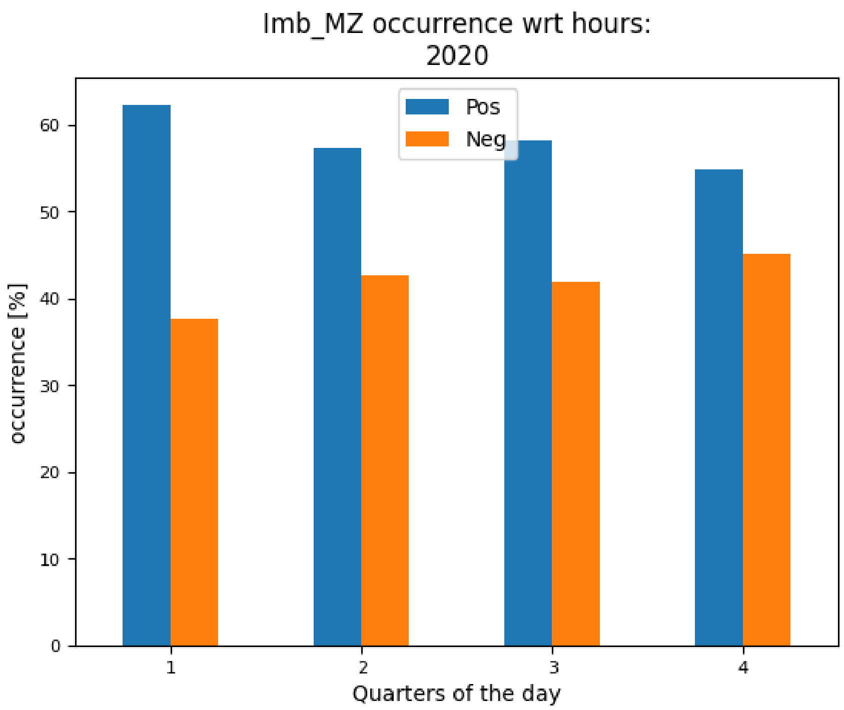


Figure A.18: Imb_{MZ} sign occurrence by quarter of the day along 2020.

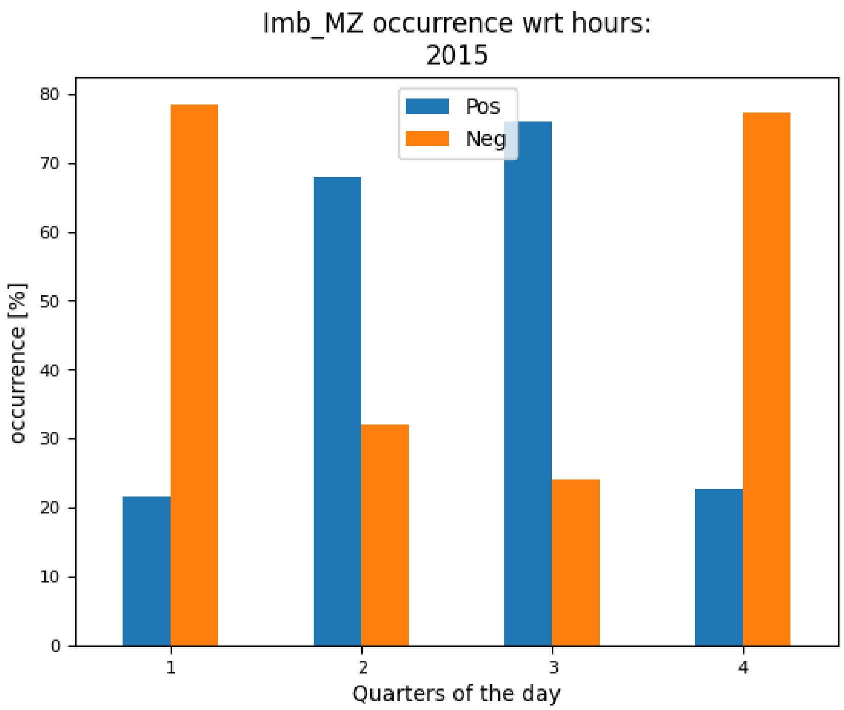


Figure A.19: Imb_{MZ} sign occurrence by quarter of the day along 2015.

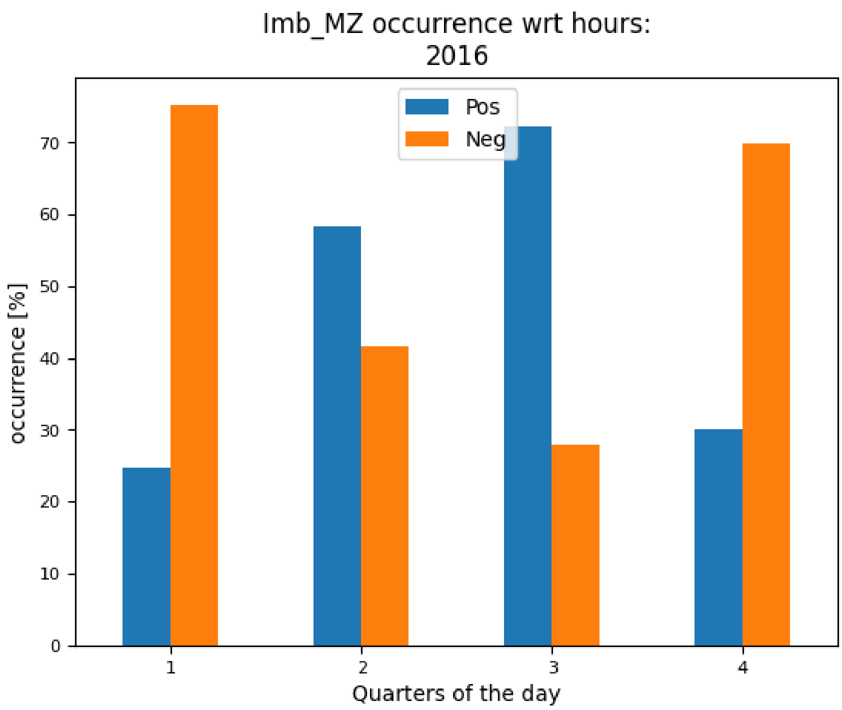


Figure A.20: Imb_{MZ} sign occurrence by quarter of the day along 2016.

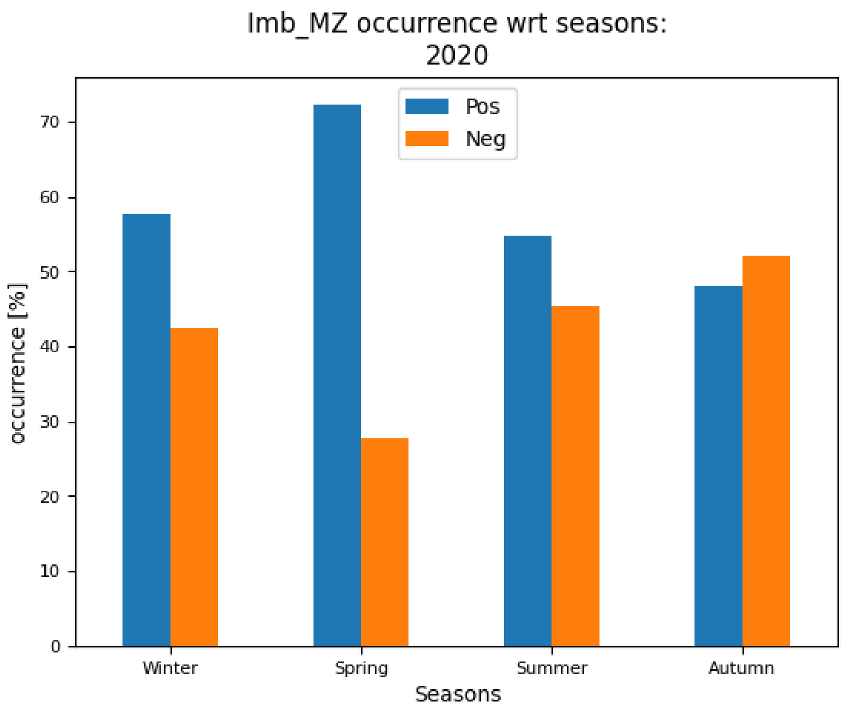


Figure A.21: Imb_{MZ} sign occurrence by month along 2020.

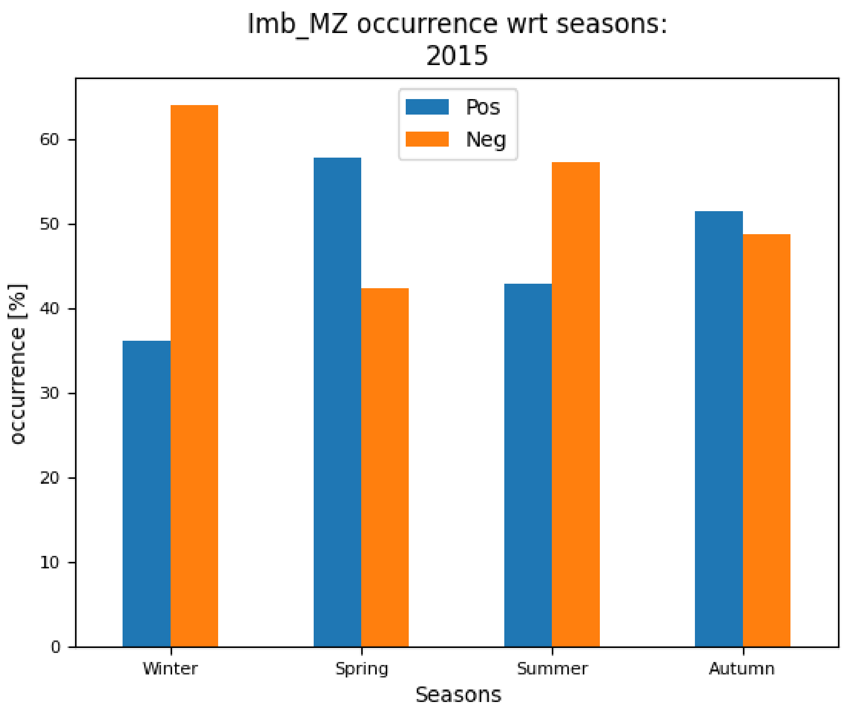


Figure A.22: Imb_{MZ} sign occurrence by quarter of the day along 2015.

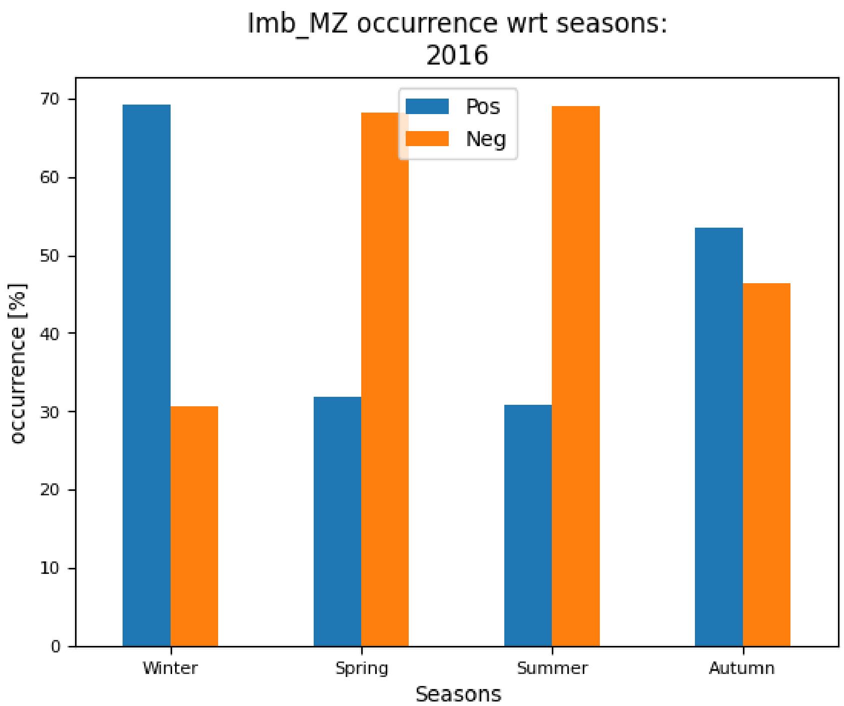


Figure A.23: Imb_{MZ} sign occurrence by season along 2016.

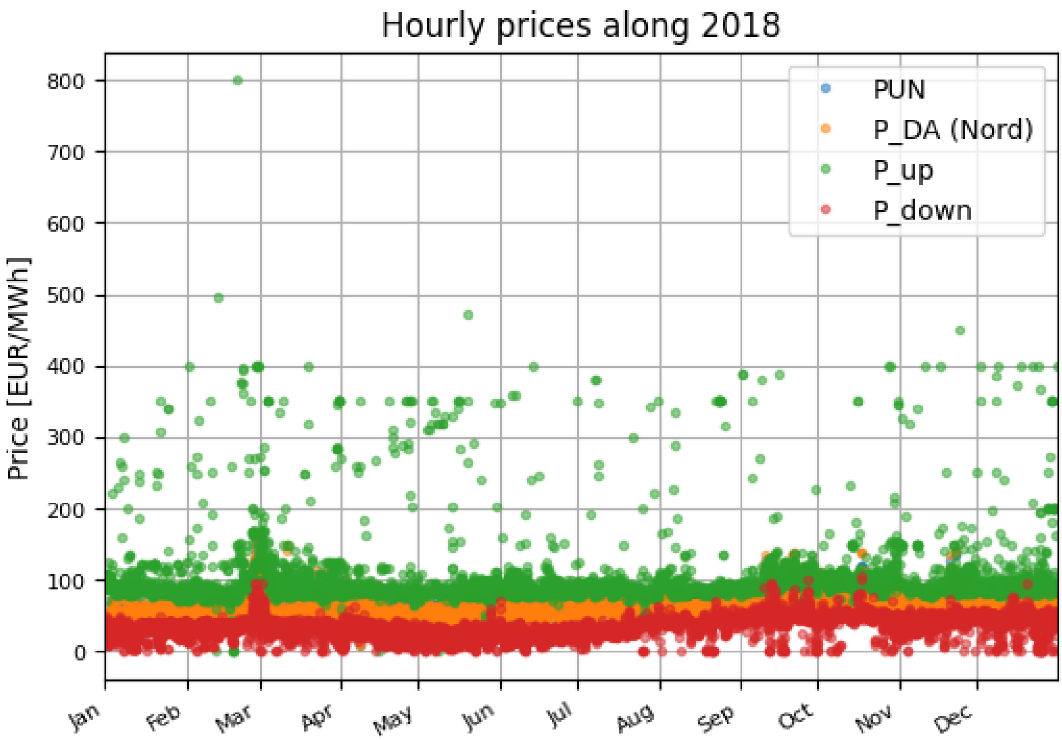


Figure A.24: Hourly market prices along 2018.

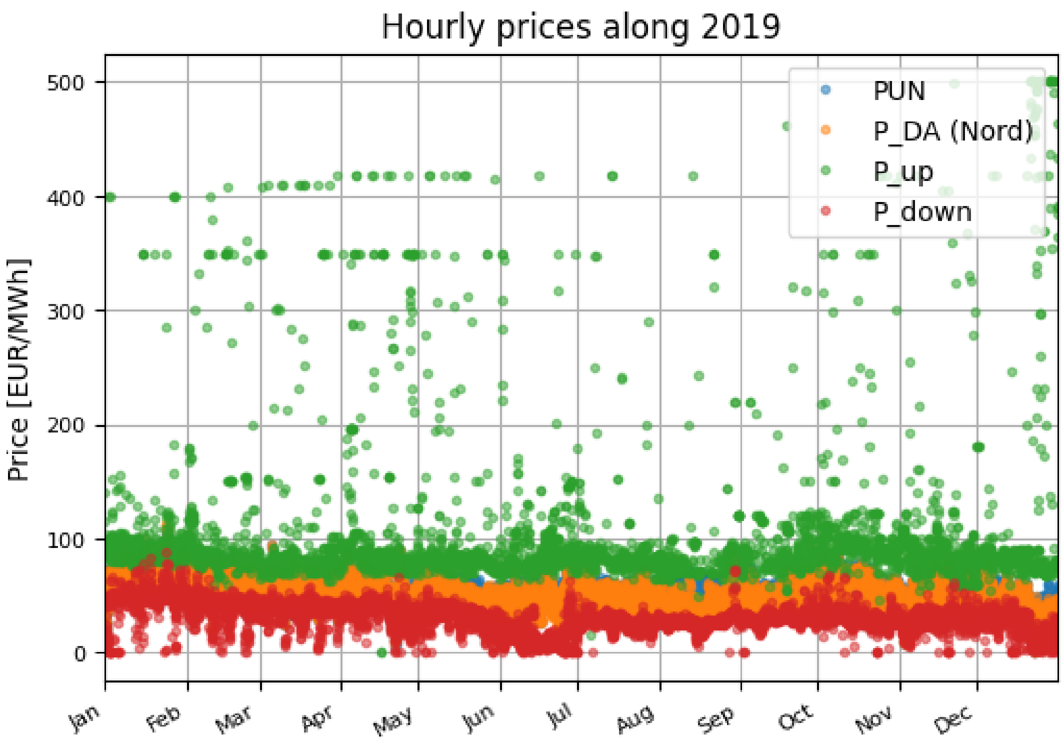


Figure A.25: Hourly market prices along 2019.

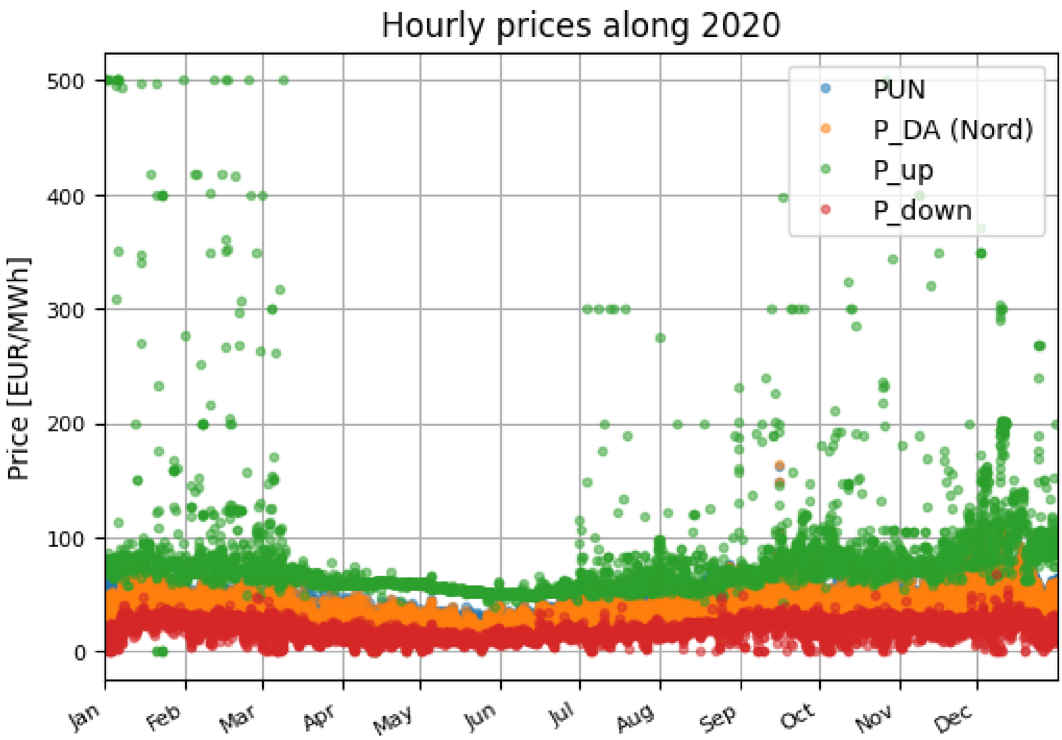


Figure A.26: Hourly market prices along 2020.

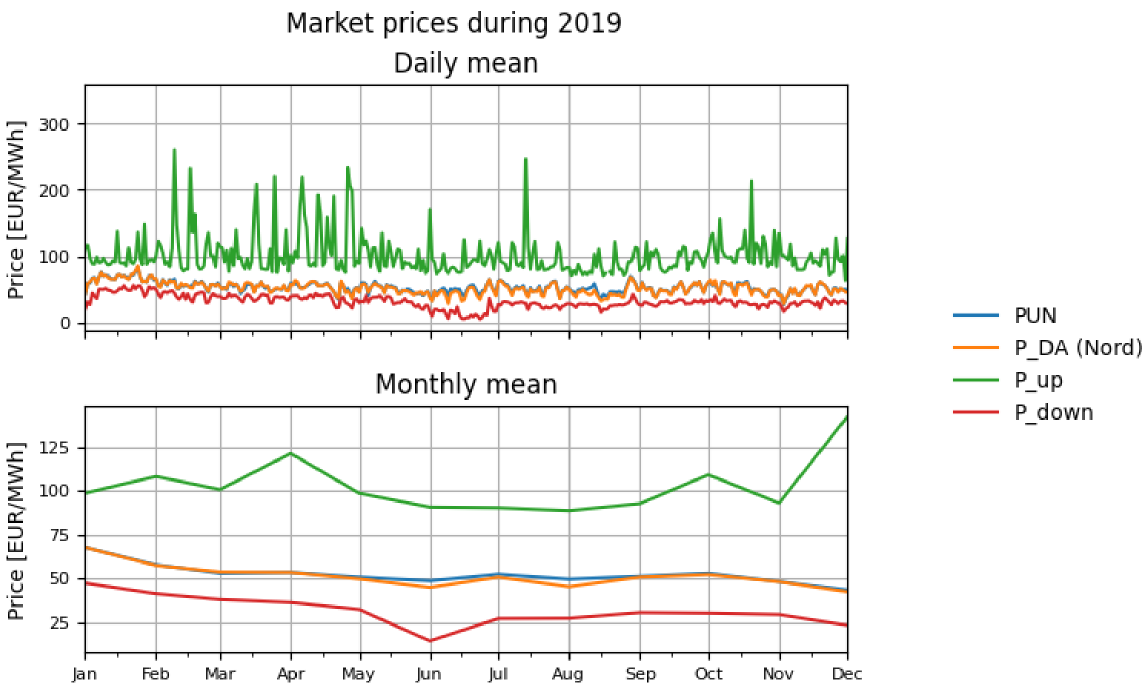


Figure A.27: Daily and monthly market prices mean along 2019.

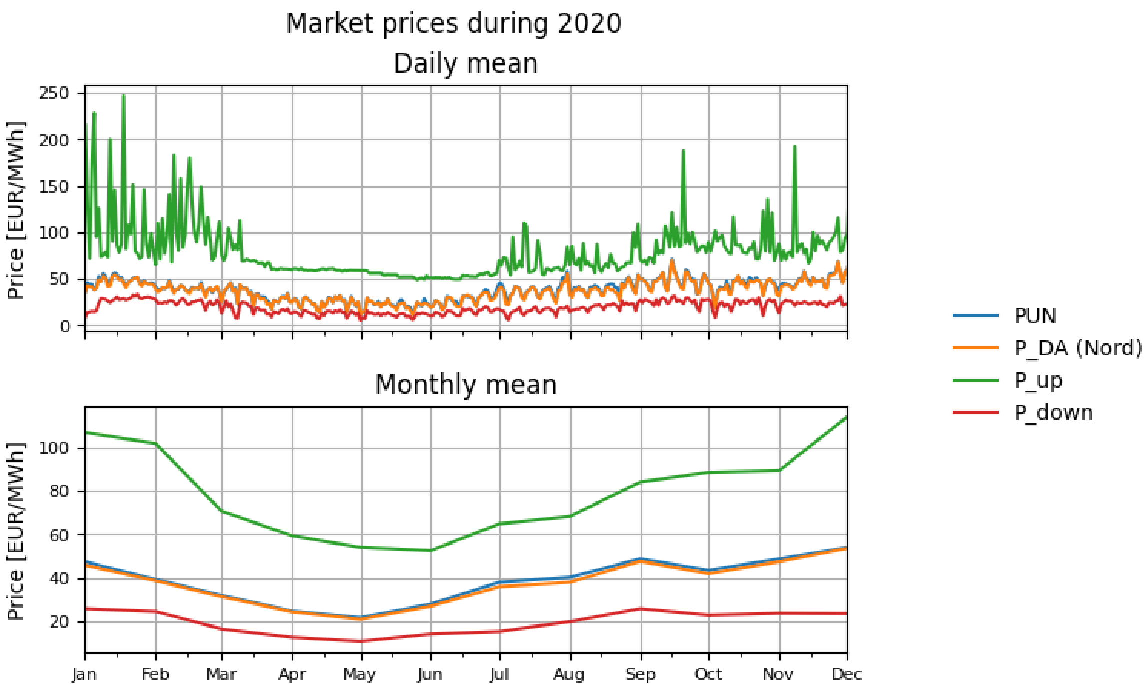


Figure A.28: Daily and monthly market prices mean along 2020.

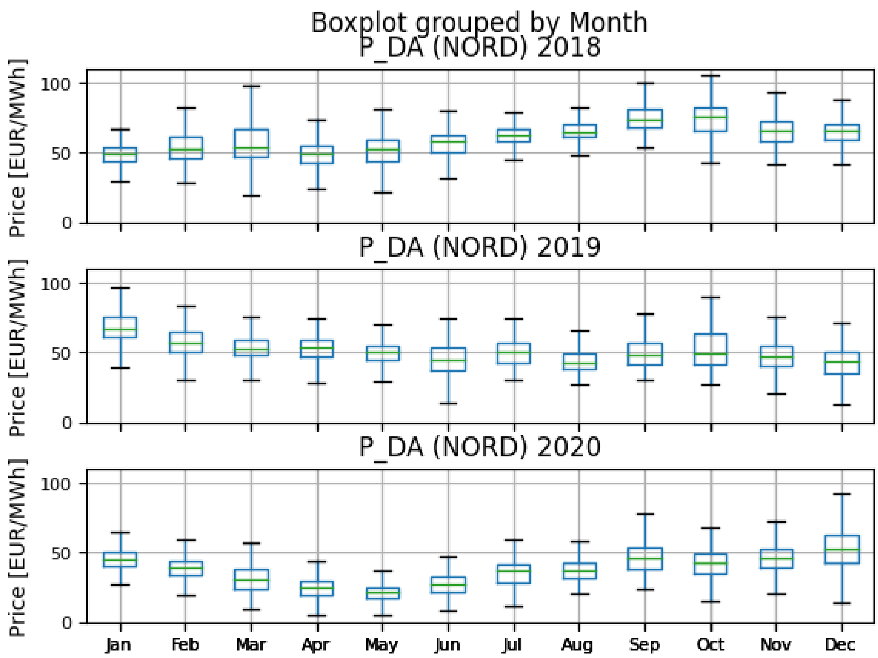
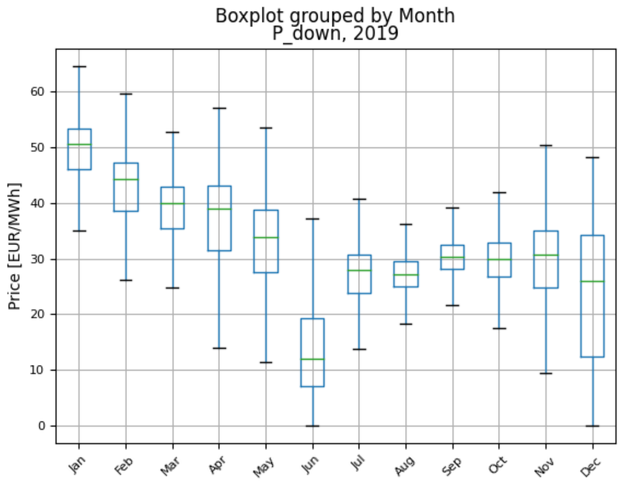
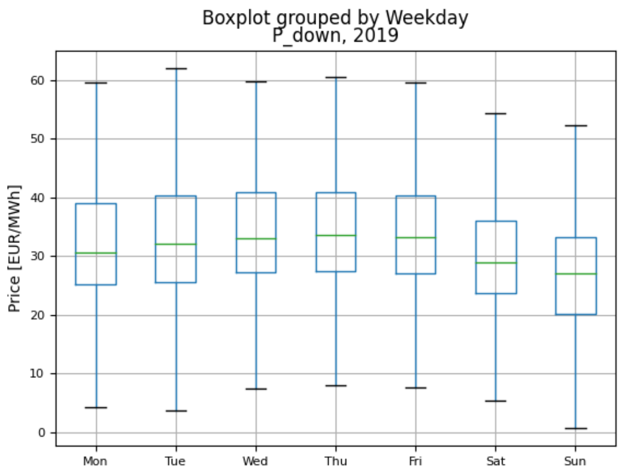


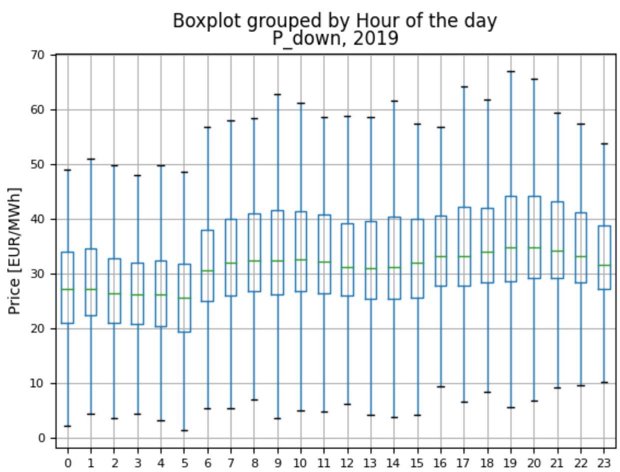
Figure A.29: P_{DA} grouped by month along 2018, 2019 and 2020.



(a) P_{down} *grouped by month*

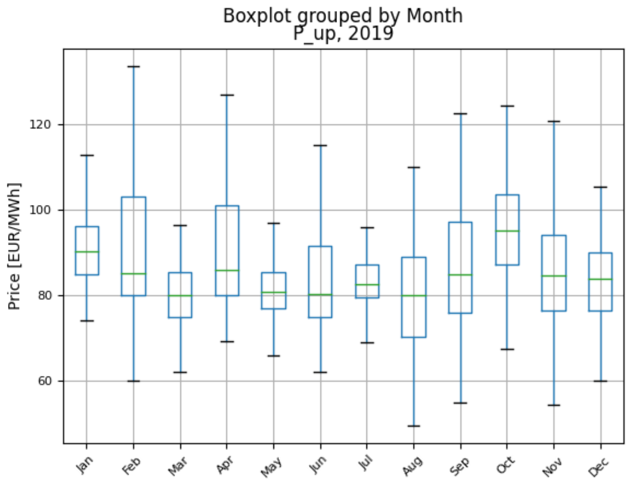


(b) P_{down} *grouped by day of week.*

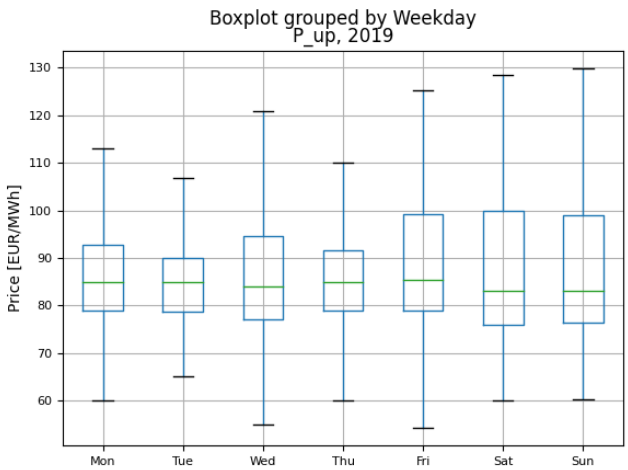


(c) P_{down} *grouped by hour.*

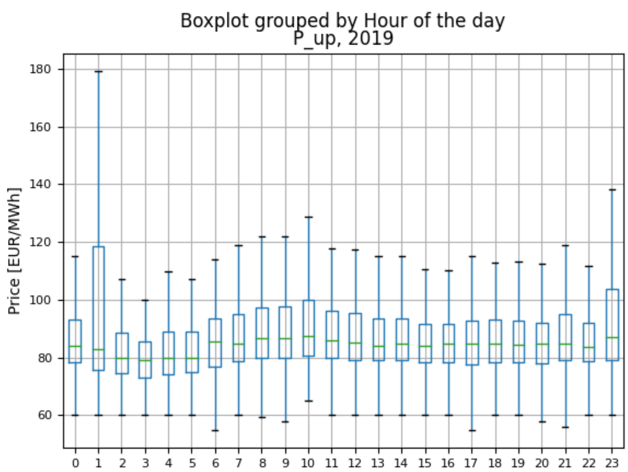
Figure A.30: P_{down} boxplots along 2019.



(a) *P_{up} grouped by month*

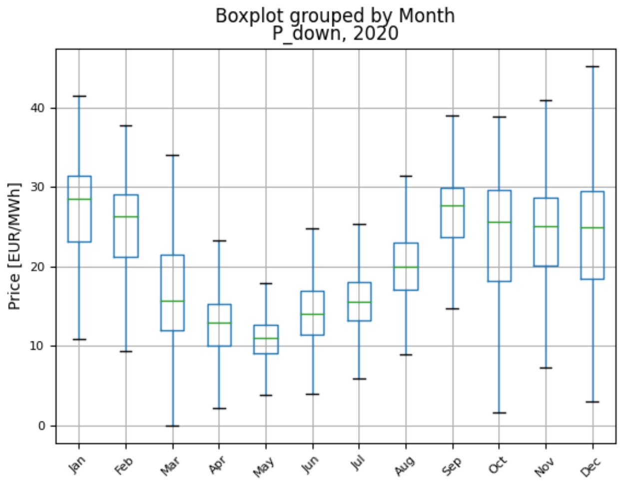


(b) *P_{up} grouped by day of week.*

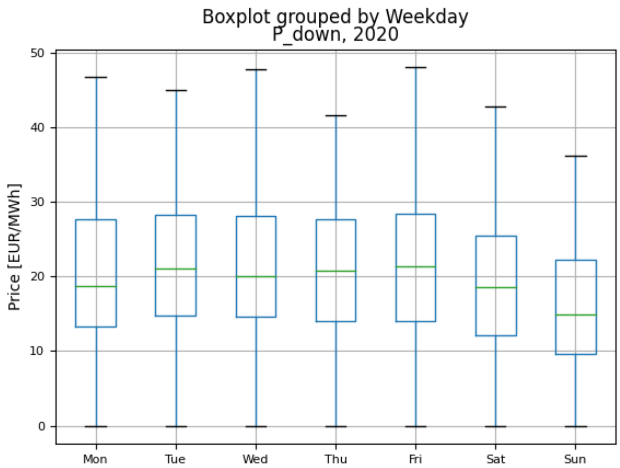


(c) *P_{up} grouped by hour.*

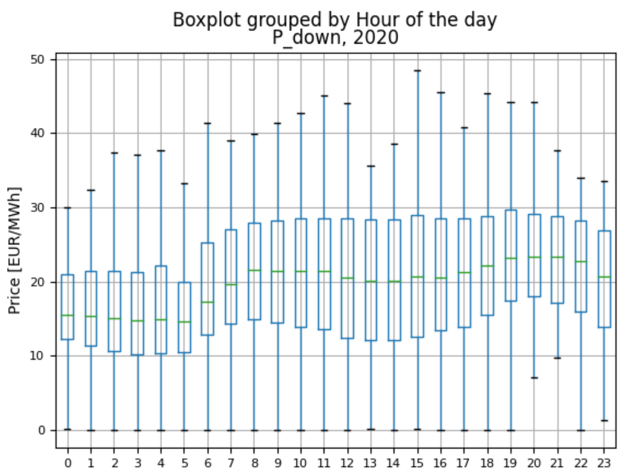
Figure A.31: P_{up} boxplots along 2019.



(a) P_{down} *grouped by month*

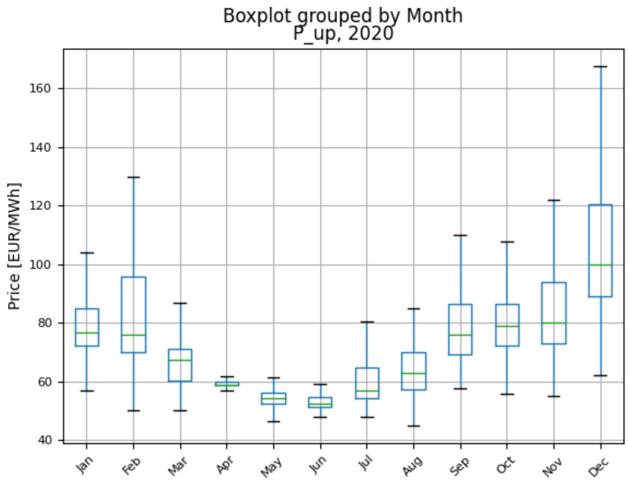


(b) P_{down} *grouped by day of week.*

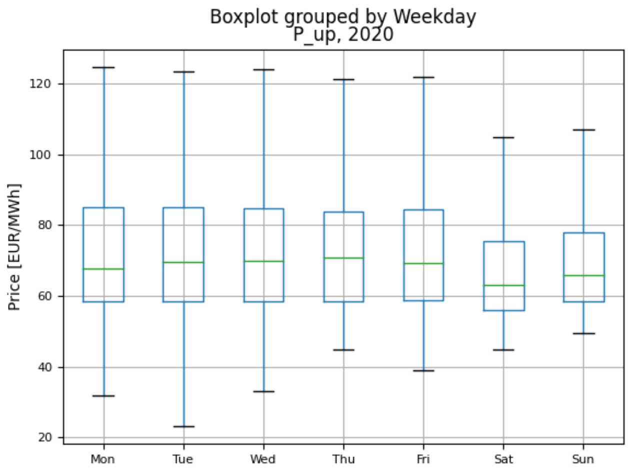


(c) P_{down} *grouped by hour.*

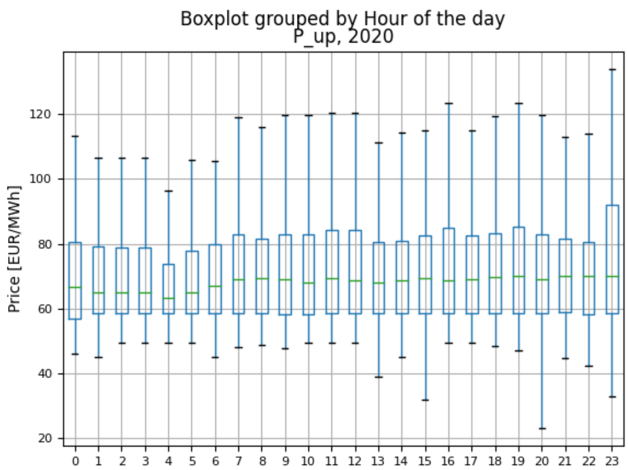
Figure A.32: P_{down} boxplots along 2020.



(a) *P_{up} grouped by month*



(b) *P_{up} grouped by day of week.*



(c) *P_{up} grouped by hour.*

Figure A.33: P_{up} boxplots along 2020.

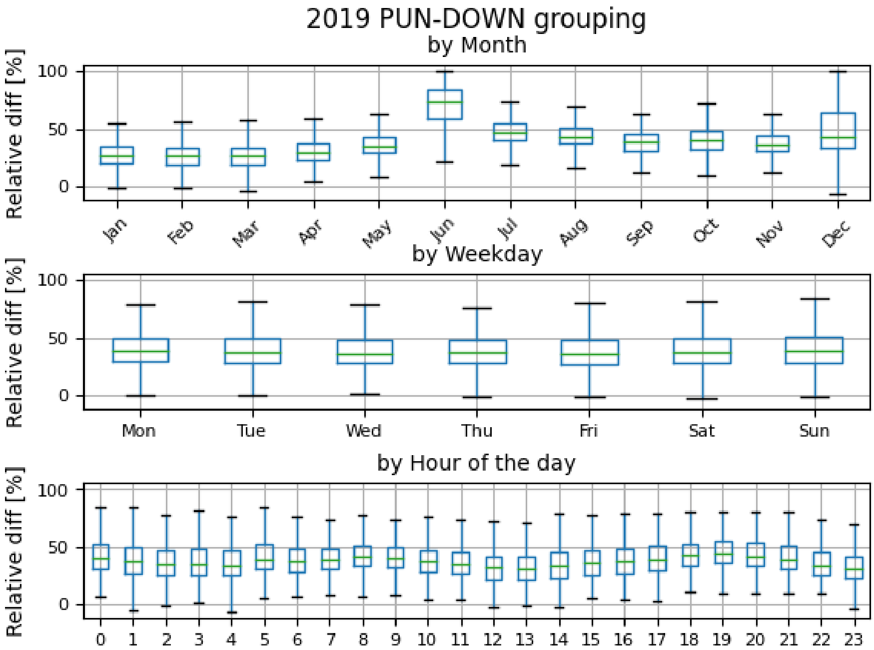


Figure A.34: Boxplots of $\triangle_{down}$ along 2019 grouped by month, day of week and hour of the day.

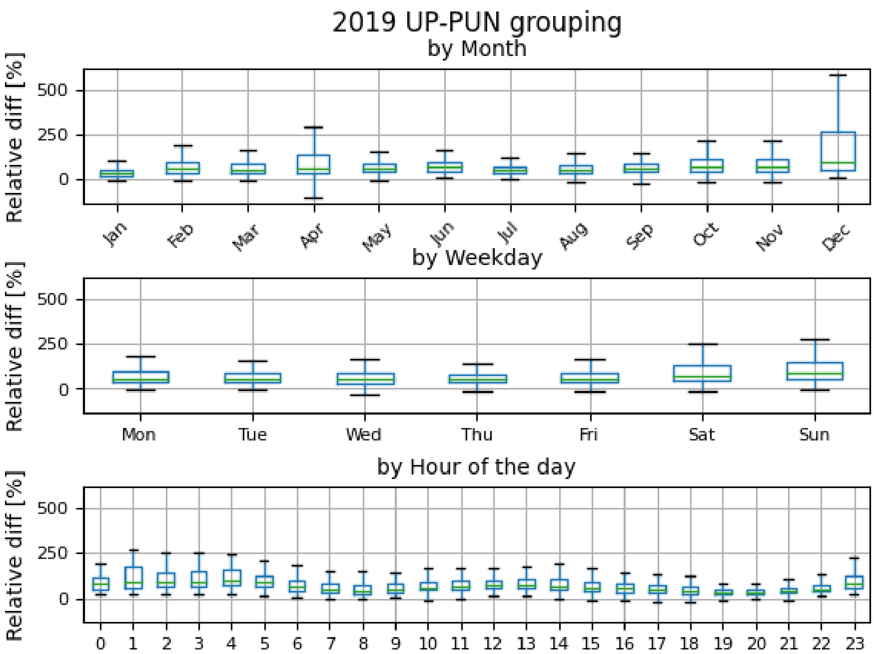


Figure A.35: Boxplots of $\triangle_{up}$ along 2019 grouped by month, day of week and hour of the day.

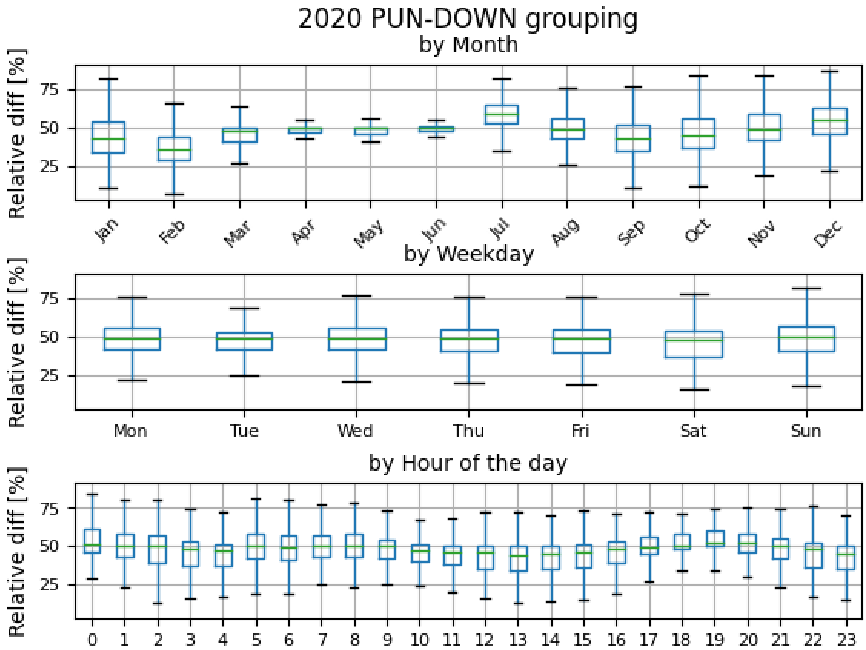


Figure A.36: Boxplots of $\triangle_{down}$ along 2020 grouped by month, day of week and hour of the day.

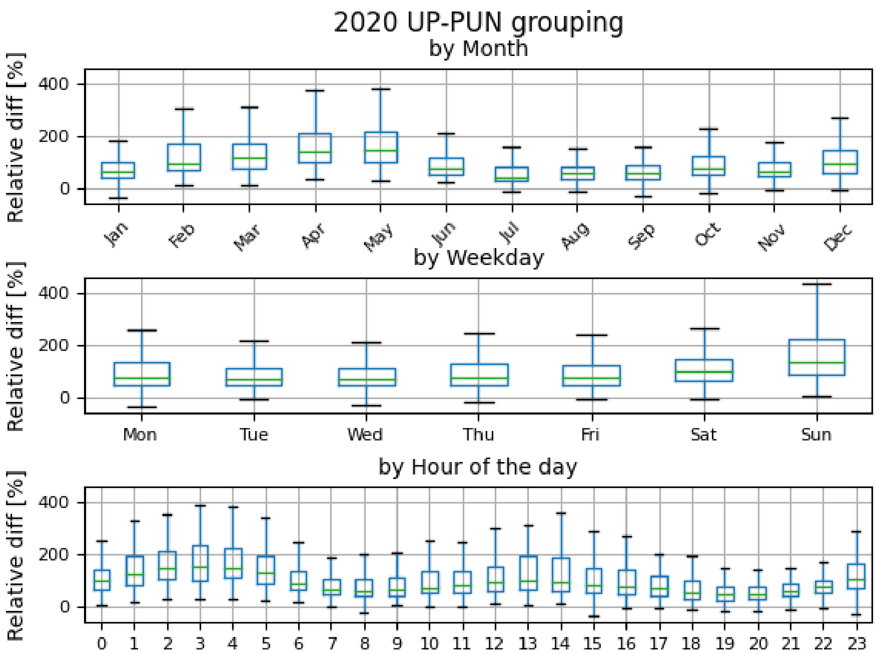


Figure A.37: Boxplots of $\triangle_{up}$ along 2020 grouped by month, day of week and hour of the day.

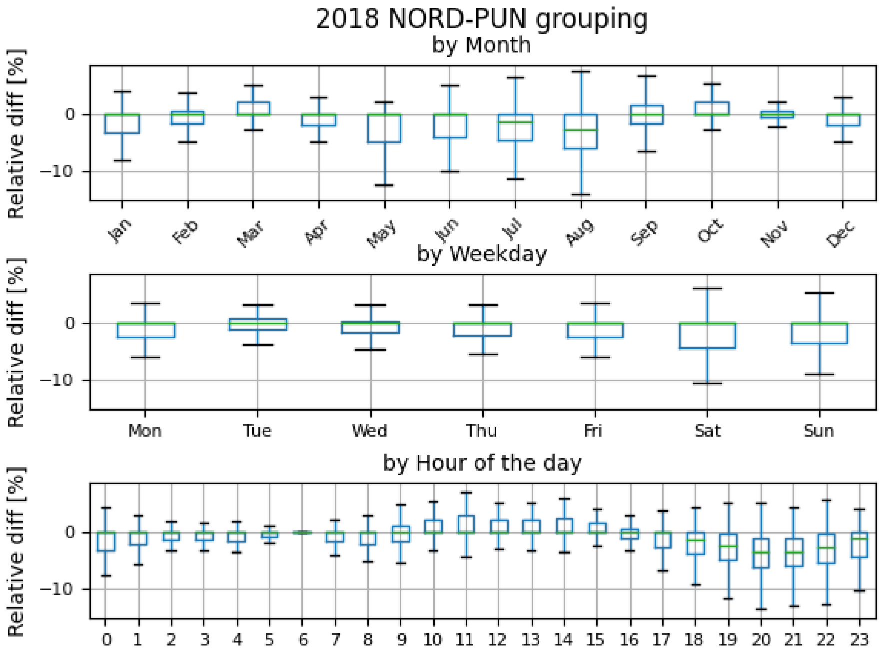


Figure A.38: Boxplots of $\triangle_{DA}$ along 2018 grouped by month, day of week and hour of the day.

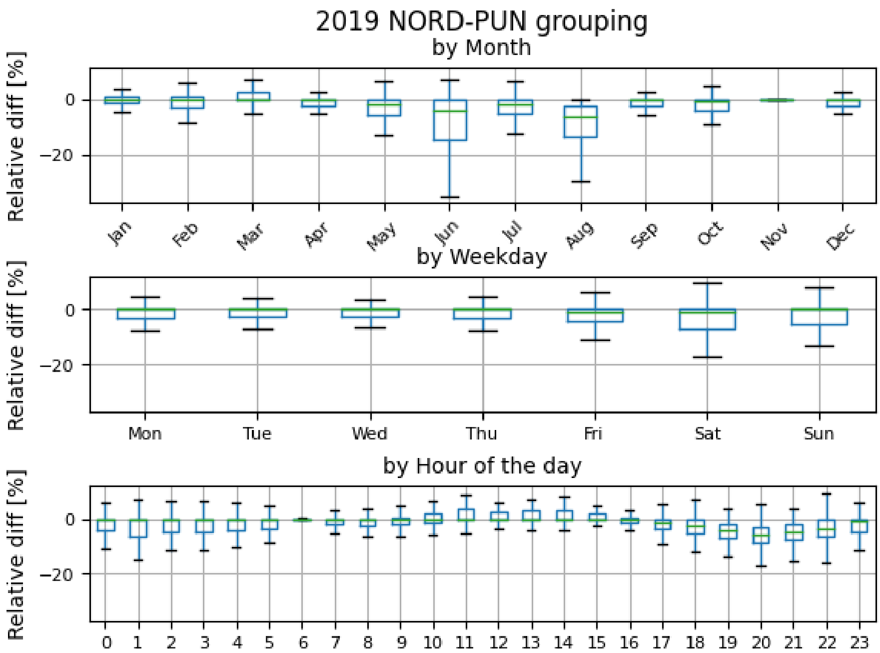


Figure A.39: Boxplots of $\triangle_{DA}$ along 2019 grouped by month, day of week and hour of the day.

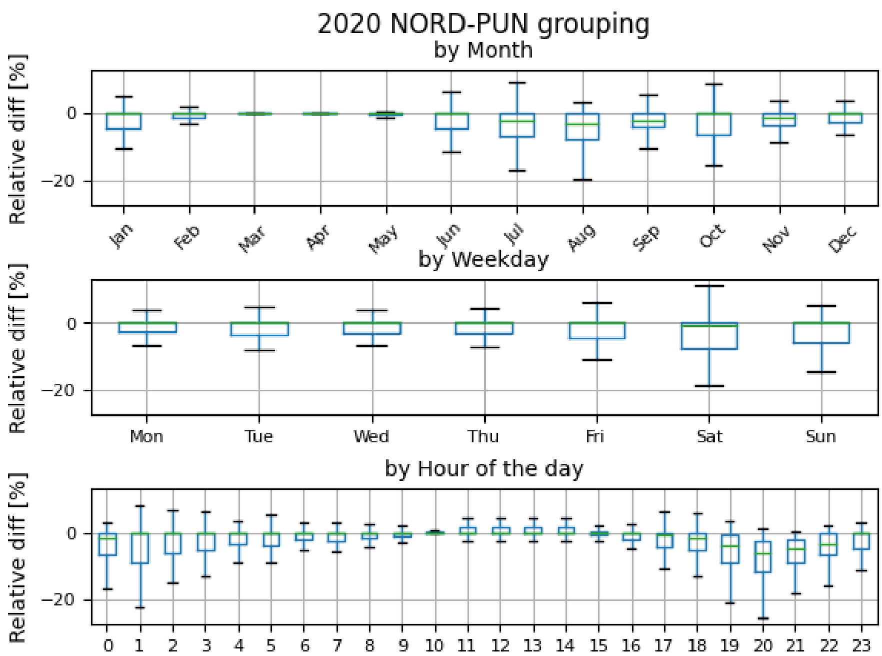


Figure A.40: Boxplots of $\triangle_{DA}$ along 2020 grouped by month, day of week and hour of the day.

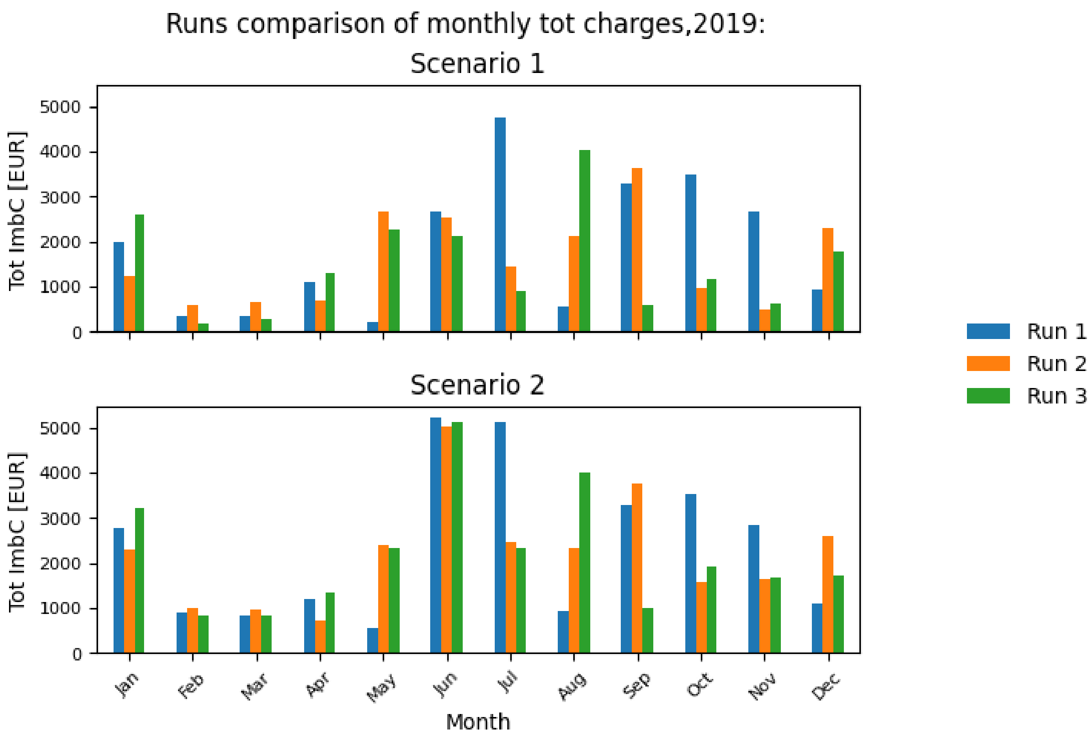


Figure A.41: Monthly tot $ImbC$: runs 1,2,3, 2019.

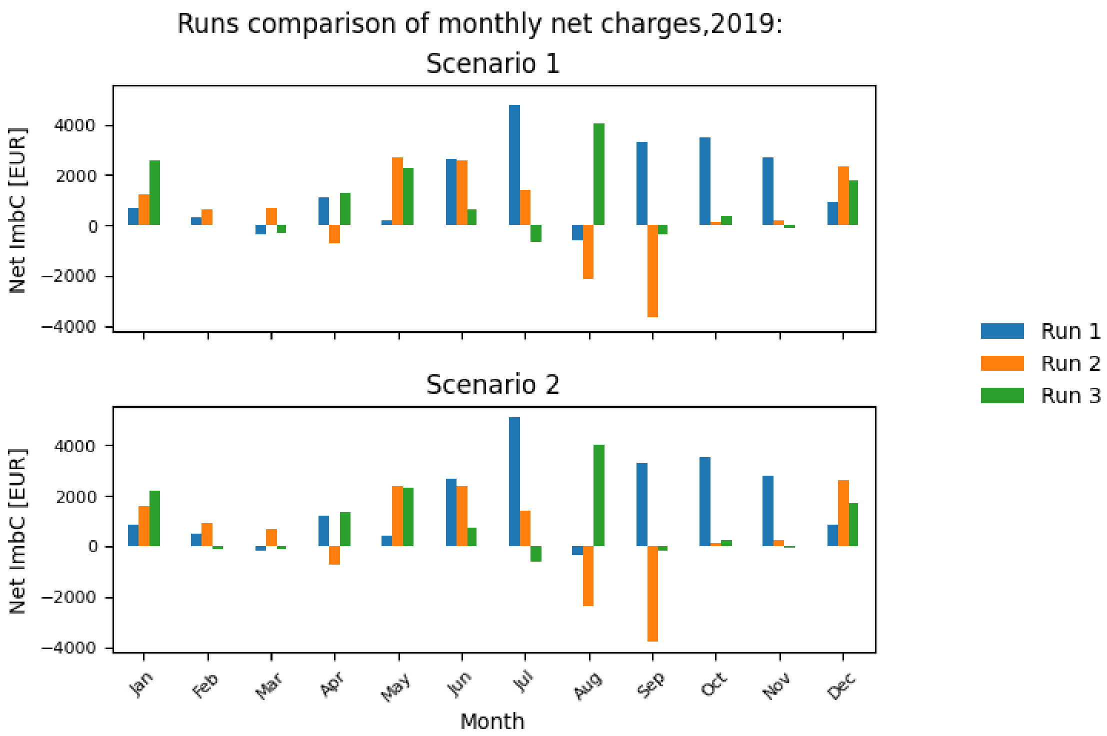


Figure A.42: Monthly net $ImbC$: runs 1,2,3, 2019.

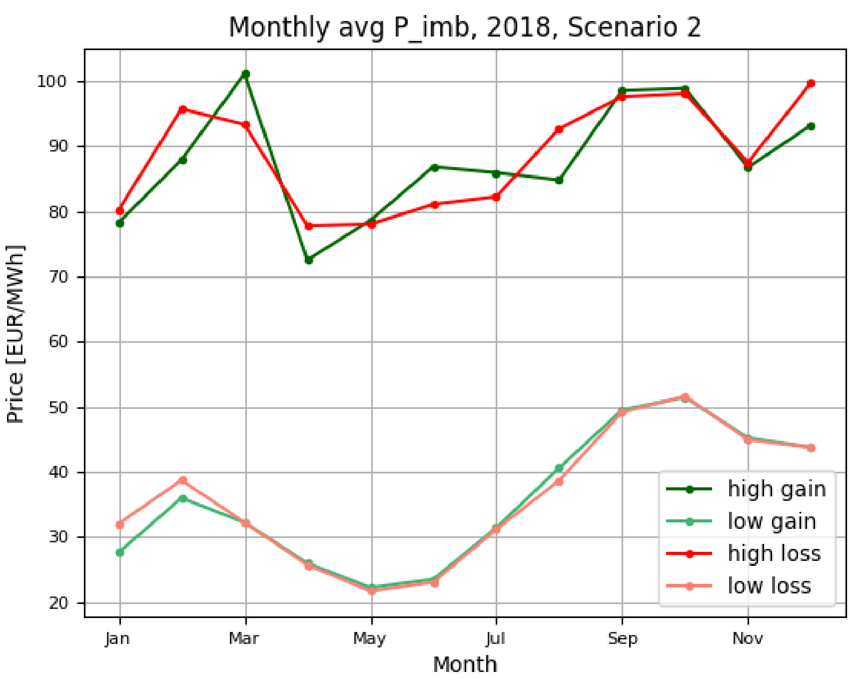


Figure A.43: Monthly average P_{imb} by payoffs sub-case: run 1, S2, 2018

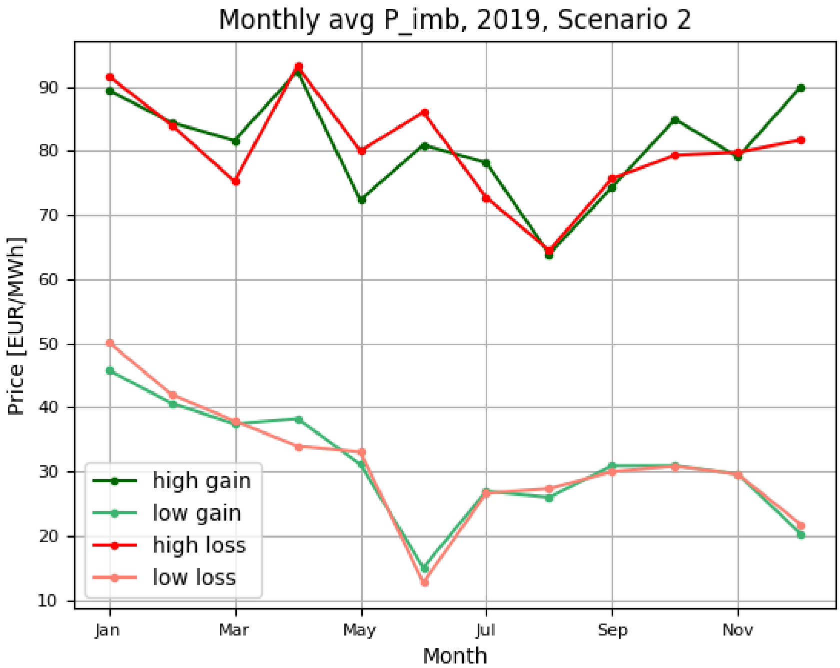


Figure A.44: Monthly average P_{imb} by payoffs sub-case: run 1, S2, 2019