UNIVERSITY OF PADUA

Department of Industrial Engineering DII

Master of Science in Energy Engineering

Opening the Ancillary Service Market:
New Opportunities for Energy Storage Systems in Italy

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Academic Year 2019/2020

ABSTRACT

The increasing share of non-programmable renewable energy sources and the decreasing share of programmable conventional plants is raising the volatility of the Italian energy market and the demand for ancillary services. The transition towards a mostly renewable energy scenario is needed to fulfill binding environmental targets of European energy policies of the Clean Energy Package, hence the Italian regulation is adapting to allow Distributed Energy Resources to really impact. The low system inertia of renewable generation and being renewable sources mostly unprogrammable (i.e. sun, wind) leads to the need for higher reserve margins. The pursuit of this aim requires a new a regulatory approach also in the Italian Electricity Market as already happens in other Countries. As of now, this effort is mostly limited to the pilot-project level. For example, the UVAM project enabled in 2019 the digital aggregation of small-scale plants to participate to the Ancillary Service Market. The minimum aggregated size is 1 MW, with no technology distinction. Battery storage can play an important role in this scenario with applications in peak shaving, load shifting and in the future smart grids, hedging the volatility introduced by renewable energy sources. As of today, the biggest obstacle is often represented by the initial cost and the uncertain profitability. Many studies treated technological improvements to facilitate the implementation of battery storages in the market, finding possible ways to guarantee a lifetime compatible to the fast cycling required by the market and the economic sustainability. Thus, no market-based simulation has been done and economical evaluation rarely went beyond probabilistic considerations. In this work a new approach is proposed, moving from a two-year dataset, a bidding strategy and the Italian balancing market are modeled. An accurate representation of market constraints and timeframes provide deterministic economic results of a battery storage bidding on either balancing market only or on both intraday energy market and services market, assessing the current structure of the UVAM project as well. Different market zones are analyzed separately, with a special focus on North and Centre-South. The result is a truthful picture of real economical possibilities of the technology and the validation of a different approach able to sustain and enhance more technical works, also related to different assets. The work reveals strongly diverging results for different market zones and the importance of a proper bidding strategy. Indeed, it is shown that monthly trends are more relevant than seasonal ones and the bidding strategy should be based on these findings. Eventually, a review of regulation's weaknesses is done and possible solutions aiming to increase the diffusion of new flexibility forms beyond pilot projects are proposed.

RIASSUNTO

Lo sbilanciamento nella produzione di energia elettrica, sempre più a favore di risorse rinnovabili non programmabili a scapito di risorse tradizionali programmabili, ha provocato negli ultimi anni un incremento nella volatilità di prezzi e fabbisogno di servizi di dispacciamento nel mercato elettrico italiano. Per soddisfare gli obiettivi vincolanti a livello europeo, previsti dal Clean Energy Package, è richiesta una maggior partecipazione di impianti alimentati da fonti rinnovabili, ma questo aumenta il margine di riserva utile a garantire la stabilità della rete, data la minor inerzia del sistema. A questo fine, si rendono necessari interventi normativi a supporto di nuove forme di flessibilità quali, a titolo di esempio, Demand Response e accumulo elettrochimico. Il primo passo nell'apertura del mercato elettrico italiano è stato mosso con la direttiva 300/2017/R/eel, che ha consentito la partecipazione al mercato dei servizi di dispacciamento anche a impianti considerati non rilevanti, ovvero con potenza installata minore di 10 MVA. La taglia minima è stata fissata a 1 MVA. Un'altra importante possibilità introdotta dalla stessa direttiva è l'aggregazione digitale di piccoli impianti al fine di raggiungere la soglia di 1 MW. Per favorire la partecipazione di questo tipo di impianti nel mercato elettrico, sono stati promossi alcuni progetti pilota con appositi regimi incentivanti. Il più rilevante (e con il maggior numero di adesioni) è il progetto UVAM. Il progetto pilota UVAM, lanciato nel 2018, consente a Unità Virtuali Aggregate Miste, ovvero contenenti sia unità di generazione che di consumo, di partecipare al mercato dei servizi ancillari come una singola unità, a patto che il perimetro di aggregazione rientri in una sola zona di mercato rilevante, in accordo col Codice di Rete, e che il punto di connessione con la rete sia unico. Il regime incentivante proposto è una quota annuale da erogarsi a condizione che la massima potenza dell'UVAM sia resa disponibile tra le 14 e le 20. Diversi studi trattano la fattibilità tecnica dell'integrazione di impianti di accumulo nella rete elettrica per fornire servizi ancillari, tuttavia non è presente nessuna rigorosa simulazione di mercato. Gli approcci utilizzati sinora si basano unicamente su analisi statistiche sui dati consuntivi del mercato, senza così considerare trend stagionali e oscillazioni orarie di prezzo. Qui è proposto un nuovo approccio. Utilizzando i dati ex-post del 2018 e 2019, vengono modellati il mercato elettrico italiano e diverse strategie di offerta. L'interazione tra batteria e mercato avviene rispettando i vincoli di mercato sulla base della strategia di offerta utilizzata e dipendente dalle condizioni tecniche della batteria. Un'accurata modellazione dei vincoli di mercato e dei vincoli tecnici della batteria consente di trarre importanti conclusioni sulle possibilità economiche di una batteria di accumulo, sia in configurazione stand-alone che all'interno del progetto UVAM. Tramite la creazione di

un tool MATLAB, si simulano le operazioni in tutte le zone di mercato, con particolare focus su Nord e Centro-Sud. Queste zone, a seguito di una dettagliata analisi statistica, si ritengono essere le più interessanti. Il Nord presenta i volumi di energia scambiata più alti, mentre al Centro-Sud si verificano i maggiori differenziali di prezzo tra offerte a salire (vendite di energia alla rete) e offerte a scendere (acquisti di enrgia dalla rete). Il risultato è la rigorosa valutazione delle reali potenzialità economiche dell'accumulo elettrochimico come supporto alla rete elettrica, delineando pattern locali e punti di forza e debolezze dell'attuale quadro normativo. La versatilità dell'approccio utilizzato rende il tool sviluppato adatto a future implementazioni anche con tecnologie diverse, in particolare in accoppiamento con impianti di generazione fotovoltaici o eolici.

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INTRODUCTION

The so-called Clean Energy Package (CEP) is the regulatory framework that sets environmental binding targets for European Union Member States, to be achieved by 2030. According to the last 2019 update, European targets for the period 2021-2030 are a 40% cut on greenhouse gas emissions from 1990 levels, the 32% of total energy to be produced from renewable sources and a 32.5% energy efficiency increase [1]. Italian targets are aligned to those just described and many efforts were done in the last decade to promote this transition. The recent possibility to digitally aggregate small-scale generators is an important asset to achieve the expected results, but an adaptive regulation is required. Renewable sources are now central in the energy framework for their established role as main drivers towards a sustainable future. However, their extensive use is introducing new challenges for the grid and regulators, in terms of (and non-exhaustive) power-flow control, protections and market architecture. Some solutions to technical problems were found in the past years, while many remain and prevent a complete integration of the renewable generation. A relevant barrier is represented by the economic feasibility yet to be proven for many of the new technologies, while the operating ones still need incentive schemes to be competitive. In this scenario it is becoming more and more important finding new business models for a complete market opening and to rethink the existing regulation. In the past, traditional power plants used to supply all of the needed energy on a fixed schedule. Now, with the increasing share of unprogrammable production, it no longer possible working in the same way. As traditional plants are no more the only generators in the grid, and Distributed Energy Resources are gaining a central role, a market rethinking for the adaptation to the new context is needed. This process started with the directive 300/2017/R/eel, which for the first time opened the electricity market to small generators, with a minimum power (even cumulative) of 1 MW. In this thesis a general overview is given about the current Italian Electricity Market architecture in Chapter 1, while upcoming changes, new business models at the Italian and European levels are presented in Chapter 2. In Chapter 3 an analysis over Ancillary Service Market data is conducted. Using results from the data analysis, the economic feasibility of a battery energy storage operating in the real-time balancing market is simulated in Chapter 4. It is modeled the 2019 Electricity market with zonal detail either with or without the incentive scheme provided by the UVAM pilot project. Insights from the simulations are meant to clarify current strengths and weaknesses of the specific technology treated as well as regulation necessary improvements. The result is the definition of a versatile approach to be used in further works for similar considerations on other technologies, in order to propose tailored regulation changes and targeted pilot projects.

CHAPTER 1
THE ITALIAN ELECTRICITY MARKET

The wholesale electricity market opened thanks to Legislative Decree no.76/16th March 1999. The so called *Decreto Bersani* laid the basis for the creation of the Italian Power Exchange (IPEX), in order to enhance competition and transparency of energy trades and to guarantee the economic and technical supply of ancillary services.
According to the Decree's art. 5, the central counterpart for IPEX is *Gestore dei Mercati Energetici S.p.A* (GME). GME must guarantee the security of energy trades and balancing demand and supply. GME is regulated through the *Testo Integrato della Disciplina del Mercato Elettrico* (TIDME), which was updated the 12th December 2019 from Italian Ministry of Economic Development and which is valid since the 1st January 2020. The following description of the electricity market's structure is extensively presented in TIDME [2]. GME is the central counterpart also for the Gas Market and the Environmental Markets, not presented in this work. IPEX is the place where demand and supply offers submitted by enabled market operators are matched and the market clearing price is determined. It is also the place where the Italian Transmission System Operator (TSO), Terna S.p.A., manages the Ancillary Service Market (ASM) for the provision of dispatching services. GME is the counterpart for commercial and physical programs definition and afterwards communication to Terna for dispatching. Market participation voluntary, trades can be concluded also Over the Counter (OTC), with compulsory communication of results for dispatching.
Italian electricity market (ME) is divided according to TIDME in *a)* Spot Market (*Mercato Elettrico a Pronti,* MPE) where the market is hourly cleared by matching demand and supply, *b)* Platform for Physical Delivery of Financial Contracts (*Consegna Derivati Energetici,* CDE) concluded on IDEX [1], *c)* Electricity Market with longer term and mandatory delivery (*Mercato Elettrico a Termine,* MTE), where energy blocks with timeframe longer than MPE can be traded.
Among these markets, this work focuses on MPE: this market section is opening and facing radical changes. Therefore, it offers new possibilities to different forms of energy flexibility

[1] IDEX (Italian Derivative Exchange) is part of the IDEM (Italian Derivative Market) managed by Borsa Italiana S.p.A. and it is the financial market where contracts underlying electricity spot prices are traded.

(i.e. storage systems). MPE is articulated, in accordance to the art. 21 of TIDME, in *a)* Day Ahead Market (*Mercato del Giorno Prima*, MGP) with a single gate closure at 12:00 of D-1 for selling and purchasing offers submission, where D stands for Delivery Day and H for Delivery Hour, *b)* Intraday Market (*Mercato Infragiornaliero,* MI) where operators can adjust their MGP programs by submitting new offers, *c)* Ancillary Services Market (*Mercato dei Servizi di Dispacciamento,* MSD) split in MSD ex-ante and Balancing Market (*Mercato di Bilanciamento,* MB) with different timeframe, with Terna as the central counterpart. MGP and MI are the energy markets in which demand and supply match. MGP refers to grid's need as of D-1, MI enables operators to update their position during D. MSD, instead, is used by Terna to procure energy for real-time services that maintain the equilibrium of injections and withdrawals during D.

1.1 How to participate

TIDME contains the information here presented. The electricity market is based on an online platform through which transactions take place. System security is based on online certificates. The applicant must respect all of TIDME technical conditions and the application must be done via an online form. GME communicates within fifteen calendar days whether or not the application is accepted (art. 14). In case of rejection, GME presents reasons for refusal or will require the operator to provide more information.

Terna S.p.A. and Acquirente Unico [2] are enabled markets operators. All the enabled operators are listed by GME on its website.

[2] Acquirente Unico (AU) is a not for profit public society created by GSE following art. 4 of Decreto Bersani that buys energy on ME and sells it to distributors (Enel, Acea, Hera, …) only covering its operating costs. Following this price Energy Authority (*Autorità di Regolazione per Energia Reti e Ambiente*, ARERA) fixes quarterly the final price for regulated consumer. These consumers are private consumers and SMEs under Maggior Tutela or Salvaguardia regulated regime. With the final energy market opening, now fixed for 2021, this operator and regulated regimes will be eliminated.

Figure 1.1 Virtual and geographical Italian market zones [3].

1.2 Market Zones

The Italian electricity market is divided in zones according to grid constraints, in order to increase the reliability of the whole system and to facilitate its management. Zones are determined using both geographical and virtual borders. Lines connecting different zones are called interconnectors. System stability is guaranteed by transit limits on the interconnectors.

In every zone, different exchange points are allowed to operate both on IPEX and IDEX, that must register their operations on the Energy Accounts Platform (*Piattaforma dei Conti Energia,* PCE). Physical programs, injections and withdrawals, and commercial programs, sells and purchases, are defined for all of these points to evaluate possible critical issues, grid congestions and to calculate the imbalances[3].

Traditionally, injection points coincide with modulable production unit, allowing Terna to optimize dispatching process. Withdrawal points can be single consumption units as well as multiple consumption units aggregated.

The grid is divided in zones in the following way, as shown in *Figure 1.1*:

i. six geographical zones: North, Central-North, South, Central-South, Sicily, Sardinia (that will be called NORD, CNORD, SUD, CSUD, SICI, SARD);

ii. eight foreign virtual zones: France, Switzerland, Austria, Slovenia, Greece, BSP, Corsica and Corsica AC;

[3] There is an imbalance every time that commercial and physical programs are different, representing a debit or a credit for market operator.

1.3 The Day-Ahead Market

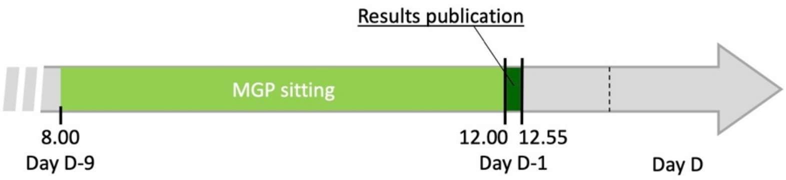

Figure 1.2 The Day-Ahead Market timeline: offers can be continuously presented when sittings are open. After the gate closure, demand and offers are matched and results are published as in the figure. Contracted energy must be delivered the following day [4].

The Day-Ahead Market (*Mercato del Giorno Prima,* MGP) is the energy market where energy is traded for the following day. It is the largest Italian electricity market with more than 250 TWh yearly traded. MGP is an energy only market, therefore only electricity operators and physical contracts with mandatory delivery are admitted. GME manages the online trading platform as the central counterpart and guarantees the observance of TIDME directives. Participation is optional and electricity operators can submit selling or buying offers according to the classification type of the node, either generating or load nodes.

Hereinafter D stands for delivery Day and H for delivery Hour. MGP opens at 8:00 on D-9 and the gate closure is at 12:00 on D-1. Results are communicated by 12:55 on D-1. Generally, in this market are matched offers of national and foreign producers, companies operating under the CIP6 deliberative, enabled customers, Terna, distributors, Acquirente Unico (AU), wholesalers and traders. MGP is based on auctions and gate closure, trading is not continuous. The bidding model is the implicit auction[4], resulting in equilibrium prices and quantity and physical programs for every hour of D. To facilitate operators' offers submission, at least an hour before the gate closure GME publishes Terna preliminary information and reference price for every zone and for every relevant period[5].

According to TIDME, operators may not to indicate prices and quantity, adapting to market results and needs, or indicate just price and quantity limits, for every relevant period (art. 27 and art. 28). For selling (purchasing) offers, the operator can indicate the minimum (maximum) unit price he is willing to accept for the maximum (minimum) energy indicated in the offer. Prices and quantities must be positive and must respect nodes constraints. Offers can be different for every relevant period and can be totally or partially accepted.

There are different possibilities for offers submission (art. 38):

[4] In an *implicit auction,* market participants bid at the same time for energy and transmission facilities in their own PEX, even if the energy is sold to a different PEX. In an *explicit auction*, market participants must bid separately for energy and for interconnectors use.

[5] The relevant period is market referring period, equal to an hour for MGP.

i. *simple*, a simple couple price-quantity is presented for the relevant period for the offer point;

ii. *multiple*, as a set of up to four simple offers for the same relevant period;

iii. *predefined*, either simple or multiple offers repeatedly presented in different days for the same relevant period.

Once presented, offers are validated by GME and accepted after the gate closure using the economic merit order. Selling (buying) offers are sorted by increasing (decreasing) price (art. 39) and supply (demand) curve is determined. In case of price equity, priority is given to predefined offers and to prior submissions. Among predefined offers, a casual mechanism (art. 34) attributes priority coefficients.

After gate closure every market zone is cleared, finding the equilibrium zonal unit price (Pz) in €/MWh. GME identifies accepted offers following TIDME art. 42 general criteria:

i. maximization of the net transactions value[6], respecting transit limit between geographic and/or virtual market zones;

ii. minimization of the total cost for energy supply for every geographic and/or virtual market zones, respecting transit limit between geographic and/or virtual market zones;

iii. buying offers are valued at PUN and selling offers are valued at zonal price;

iv. maximum price for selling offers is obtained by imposing *ii.* condition.

Without congestions, the Pz would be the same everywhere as market zones are fully connected. When a congestion between zones occurs, it prevents the definition of a national merit order, hence different zonal prices diverge. Under this situation, generators of a certain zone are activated, even if less economical than others. Given this consideration and being the Italian transmission grid strongly influenced by morphological factors, the Authority introduced *Prezzo Unico Nazionale* (PUN), in order not to force consumers to pay more just because of the geographical zone. PUN in €/MWh is calculated as the weighted average of zonal prices. These results are computed for D without considering physical constraints as the transit limit between zones, rather are based on the economic merit order only. At this point, GME communicates to every dispatching user in every node and to Terna the preliminary injection and withdrawal program. Preliminary programs unify results from energy auction and OTC contracts, registered on PCE: bilateral trades use transmission grid and contribute to PUN weighting. PCE programs are transmitted to MGP and concur to MGP result determination.

[6] The difference between total accepted buying offers and total accepted selling offers.

1.4 The Intraday Market

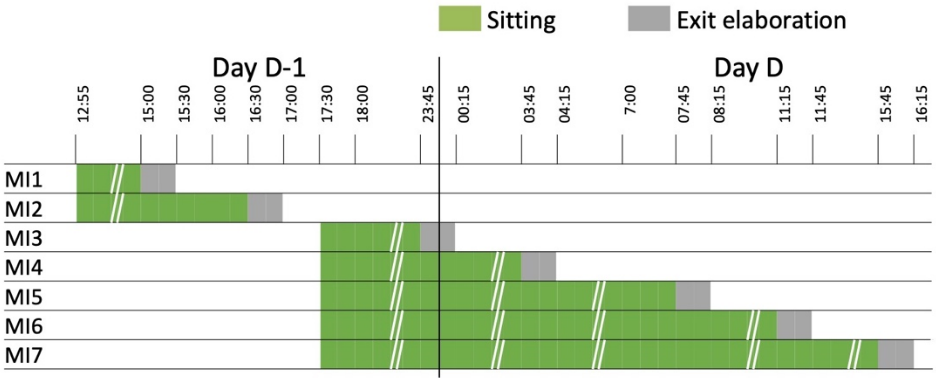

Figure 1.3 The Intraday Market timeframes. Sittings starts right after MGP closing and continue on D as operators can adjust their energy position according to arising contingencies [4].

The Intraday Market (*Mercato Infragiornaliero,* MI) substituted Adjustment Market in 2009 and allows electricity operators to adjust their market positions by submitting new offers. GME is the central counterpart and the market model adopted is the implicit auction. Rules are consistent to MGP ones for price determination, with the main difference that all of the offers are valued at Pz.

Another difference is that MI is operated in seven session, going from MI1 to MI7. Sitting opening, gate closure, results elaboration and presentation are presented in *Figure 1.3*. At the end of each session GME publishes relevant results:

i. valuation prices and quantities traded without considering transit limit, for every relevant period and for every market zone;

ii. supply and demand curves, for every relevant period and for every market zone.

Updated cumulative programs for every node are communicated and Terna calculates residual transmission capacity on interconnectors and evaluates possible congestions.

Market fairness is guaranteed by a so-salled non-arbitrage fee. For buying transactions, if the PUN on MGP is higher (lower) than the Pz on MI the operator must pay (be paid) the non-arbitrage compensation fee, equal to the difference between PUN and Pz for every MWh underlying the considered transaction. For selling transactions, if MGP PUN is lower (higher) than MI Pz the operator must pay (be paid) the non-arbitrage compensation fee, equal to the difference between Pz and PUN for every MWh underlying the considered transaction. Notably, even if the contracting scheme is closer to real-time, hence to the Ancillary Service Market described in the following, the remuneration scheme is based on the equilibrium price as it is on MGP.

1.5 The Ancillary Services Market

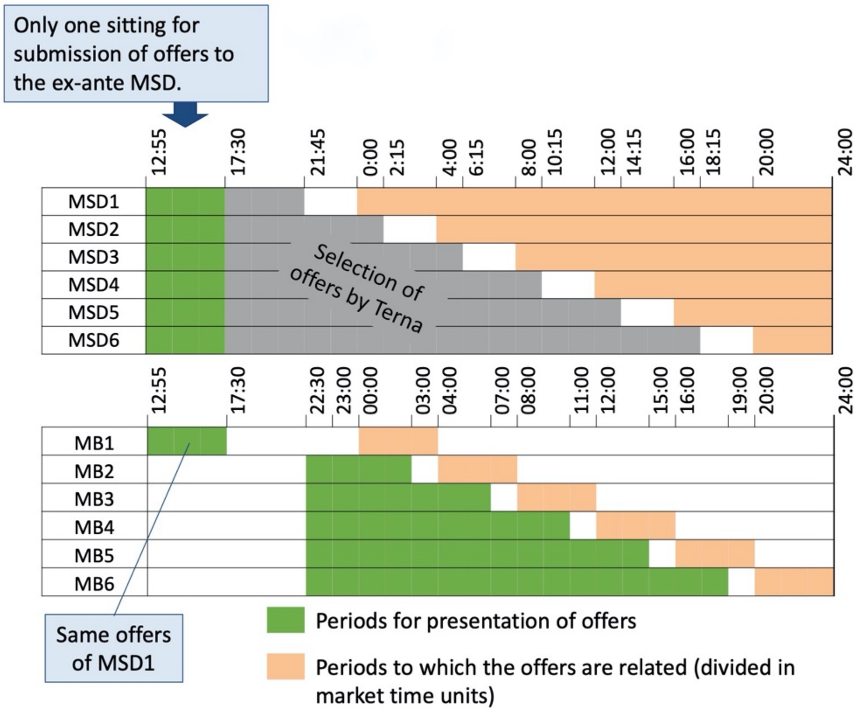

Figure 1.4 The Ancillary Services Market Timeframes. In the top, MSD ex-ante phases, in the bottom, MB ones [4].

In TIDME, the Ancillary Services Market (*Mercato dei Servizi di Dispacciamento,* MSD) is described as the channel used by Terna to gather the resources for dispatching services: congestion management, reserve margins provision, real time balancing, black start, load interruptibility and load shaving (art. 56). Therefore, Terna is the central counterpart and GME manages the information flow and publishes market results. Offers are remunerated pay-as-bid, if the offer is accepted the user receives (pays) from (to) Terna the unit price offered multiplied by the accepted quantity, whereas market clearing price[7] is used on MGP and MI.

ASM is split in MSD ex-ante and MB. MSD ex-ante (MSD[8]) takes places in six sessions but offers can only be submitted from 12:55 to 5:30 pm on D-1. Offers are accepted by Terna and results published by GME, starting from MSD1 at 9:45 pm on D-1 to MSD6 at 6:15 pm on D, every four hours. MSD timeline is clear in *Figure 1.4*. MSD is the programming phase of ASM, used by Terna to relieve congestions resulting from MGP and MI and to procur reserve margins, by accepting some offers and reserving some others for further acceptance on MB. On MB Terna accepts buying and selling offers mostly for Secondary Reserve and

[7] Every offer is valued at the equilibrium clearing price.

[8] This notation is used consistently to GME data.

real-time balancing. MB is articulated in six sessions: MB1 sittings are contemporary to MSD ex-ante ones and refer to a four-hour timeframe that goes from 12:00 pm to 4:00 am on D. All of the other sittings open at 22:30 on D-1 and closes respectively one hour before the activation block on D. Every sitting refers to a four-hour block on D, starting from 12:00 am. MSD ex-ante and MB function as pendant to MGP and MI. Indeed, MSD ex-ante bids for D are submitted on D-1 and selected during D, while MB offers are both selected and presented on D. The reason behind the split is that the procurement of reserve margins is done in a programming phase referring to MGP results, and progressively adapted to the ongoing negotiations on MI.
The operator bids on GME platform, Terna adjusts and selects needed products and overall results are eventually published by GME as:

i. daily total sold and purchased energy quantities for every market zone;
ii. daily mean selling and buying accepted prices, maximum accepted selling price and minimum accepted buying price for every market zone.

Moreover, GME publishes detailed results of ancillary services market for every bidding operator who submitted and offer and limited to those offers:

i. the awarded price and quantity, the relevant point of exchange[9];
ii. to the dispatching user (*Utente del Dispacciamento,* UdD) as defined by art.4 of deliberative 111/06, the final program and merit order;
iii. refused and eventually non-accepted offers.

A brief analysis of ARERA *Codice di Rete* [3] is used to highlight relevant aspects of the ASM regulation.

1.5.1 General Instructions

UdD must sign the dispatching contract with Terna for the the production unit (UP) managed. The UP is generally defined as a single power plant, while it is possible to aggregate different smaller plants. The UP is defined as *relevant*, if the total power of units is greater than 10 MVA, *non-relevant*, if the total power of the unit is smaller than 10 MVA, *virtual*, if different non-relevant UP owned by the same UdD are aggregated. In general:

i. in case on non-renewable resources, the total power of all sections is lower than 50 MVA;
ii. in case of renewable resources, the source must be the same for all plants;
iii. different plants must share the same grid connection point.

[9] Not the actual grid connection point, see 3.2.

Another important distinction is between enabled and non-enabled production unit. Minimal technical requirements for enabling a unit are presented in the following paragraph, according to the different dispatching resource. The relevant period is considered as the full hour for non-enabled UPs and the quarter of an hour for enabled UPs. UdDs must register relevant UPs and virtual UPs in *Registro delle Unità di Produzione* (RUP) by communicating UPs market and technical data.
Consumption units are never classified as relevant and their relevant period is the full hour.

1.5.2 Ancillary Service Market Resources

ASM resources must respect different technical requisites depending on the needed service. The main common aspect among different resources is the differentiation of possible offers according to the reserve margin variation they procure. Bids can be for *a scendere,* indicated as downward in this work, or *a salire,* indicated as upward products in the following, respectively purchases and sells from the operator to Terna. Information about technical requirements for all of the available services are available in *Table 1.1.* When reading the following table, it must be considered that some Italian services on ASM do not have an exact English translation. Therefore, some of the labels of different products were assigned by the author, leaving the original names in brackets.

Resources for Congestion Management

These resources are used to solve congestions in the programming phase, resulting from updated physical programs of MGP and of MI progression. Enabled UPs must be relevant, programmable and, alternatively:

i. if not hydropower, able to change their grid exchange of at least 10 MW in 15 minutes either upwards or downwards;

ii. if hydropower, having a minimum ratio of maximum daily producible energy on installed power of 4.

The power must be delivered within 15 minutes and the service must be maintained for 240 minutes (no time limits for hydropower) at least. Enabled units have the obligation to supply their full power once accepted, or to communicate possible issues to RUP, otherwise they are fined.

Table 1.1 Technical requisites for ancillary services enabling [6].

Service type	Codice di Rete technical requirements
Primary Reserve ***(Riserva Primaria)***	• ±1.5% of effective power band (10% in SICI and SARD) • half of the band within 15 seconds, whole band in 30 seconds • 15 minutes at least
Secondary Reserve ***(Riserva Secondaria)***	• ±15% of maximum power band • activation within 200 seconds • 120 minutes at least
Spinning Tertiary Reserve ***(Riserva Terziaria Rotante)***	• 10 MW at least • 50 MW/min ramp • activation within 15 minutes • 120 minutes at least
Slow Tertiary Reserve ***(Riserva Terziaria Pronta)***	• 10 MW at least • activation within 15 minutes • 120 minutes at least
Replacement Reserve ***(Riserva Terziaria Lenta)***	• 10 MW at least • activation within 120 minutes • No time limits
Balancing ***(Bilanciamento)***	• 3 MW at least • activation within 15 minutes • No time limits (240 minutes at least for hydropower)
Congestion Management **(*Risoliuzione di Congestioni)***	• 10 MW at least • activation within 15 minutes • no time limits (240 minutes at least for hydropower)
Interruptibility ***(Interrompibilità)***	• 1 MW at least • fast inteeruptibility: within 200 ms • slow interruptibility: within 5 s

Resources for Primary Reserve (FCR[10])

Primary Reserve is operated by all of the enabled generators connected to the European transmission grid that automatically respond in case of frequency drift. All generators with an installed power greater than 10 MVA are enabled and must participate to the service, with the exception of pumping units and geothermic plants since technically limited. Generators of every zone must be able to modify their grid exchange of at least ±1.5% (±10% for generators in Sicily and Sardinia) of their effective power. Half of the power must be supplied within 15 seconds from dispatching order reception, while the whole power band must be ready within 90 seconds and maintained for 15 minutes at least. Enabled units have the obligation to supply their full power once accepted, or to communicate possible issues to RUP, otherwise they are fined.

[10] Frequency Containment Reserve (FCR), is the reserve used in case of perturbation on the electricity system to contain frequency drift. This reserve is used before Frequency Restoration Reserve (FRR) which aim is bringing frequency back to its nominal value.

Resources for Secondary Reserve (aFRR[11])

Secondary Reserve aim is the compensation of differences between the energy need and the energy production at the national level, hence, to restore energy exchanges with virtual zones, eventually bringing frequency back to its nominal value and contributing to frequency restoration also at the European level. In addition to the requisites for FCR, plants must have at their disposal a device able to receive remote controls, ranging from 0 to 100% of the effective power, and automatic modulating the production. If a plant is composed by multiple UPs, it must be able to automatically split remote controls between different UPs. Generators must provide ±15% of their maximum power (for hydropower generators, the greatest between ±10MW and ±6% of effective power) within 200 seconds and continuously for 120 minutes at least. Enabled units have the obligation to supply their full power once accepted, or to communicate possible issues to RUP, otherwise they are fined.

Resources for Tertiary Reserve (mFRR)

These resources contribute to the creation of the reserve margin as a result of MSD ex-ante sitting. In addition to aFRR technical requirements, generators must start the production variation within 5 minutes from the dispatching order. mFRR contains three subcategories: Spinning mFRR (*Riserva Terziaria Pronta*), Slow mFRR (*Riserva Terziaria Rotante*) and RR (*Riserva Terziaria di Sostituzione*). Upward ramps must be exploited in 15 minutes for Spinning mFRR and Slow mFRR and in 120 minutes for RR. Upward ramps must be of at least 50 MW/min for Spinning mFRR. The service must be maintained for 120 minutes at least. Enabled units have the obligation to supply their full power once accepted, or to communicate possible issues to RUP, otherwise they are fined.

Resources for Balancing

These resources are accepted by Terna on MB to solve real-time congestions and for real-time balancing. Terna activates MSD's aFRR and mFRR accepted offers and at the same time accepts and activates new biddings from MB. Enabled operators submit offers for changing their previously defined physical program. Operators must be able to operate a ±3MW within 15 minutes from the reception of the dispatching order. Constraints here are softer than for aFRR and mFRR, in order to favor system's response. Available power must be ready within 15 minutes and the service must be maintained for 240 minutes (no time limits for hydropower) at least. Enabled units have the obligation to supply their full power once accepted, or to communicate possible issues to RUP, otherwise they are fined.

[11] Automatic Frequency Restoration Reserve (aFRR) indicates the Secondary Reserve, while manual Frequency Restoration (mFRR) Reserve indicates Tertiary Reserve.

Operators enabled to participate in the ancillary services market must reserve the mandatory minimum power band in case of needed supply by Terna. Technical requisites to be enabled and specific technical information distinguished by product are summed up in the table below.

1.5.3 Ancillary Services Market Offers

UdD of enabled UP for Primary Reserve, Secondary Reserve, Tertiary Reserve and Balancing Services have:

i. the obligation to submit predefined offers for programming phase;

ii. the possibility to submit non-predefined offers for both programming and real-time balancing phases.

If no non-predefined offers are presented for real-time balancing phase, offers from the same relevant period of programming phase will be taken into account [5].

Programming Phase Offers (MSD)

UdD must indicate the reference program for the offers, otherwise GME considers the updated cumulative program as the reference one. In case of non-predefined offers, UdD can submit:

i. Up to 3 couples of price-quantity upward (downward) offers, going from its physical program to its maximum (minimum) effective power, for all services except those explicitly mentioned below. This is allowed since 1st January 2010, when GME entitled the operator to present three different offers on MSD for its power band (four on MB), with different price and quantity. In terms of quantity, the third offer is meant to contain previous ones. In terms of price, it must be equal or increasing for upward offers, equal or decreasing for downward offers [7];

ii. 1 price for upward (downward) Secondary Reserve;

iii. 1 price for upward Minimum (*Minimo*) service. Minimum service is either an upward or downward offer, enabled UdD offers to increase or decrease their production from the resulting physical program to technical minimum power;

iv. 1 price for downward Switch-Off (*Spegnimento*) service. Switch-Off is a downward offer, enabled UdD offers to reduce production from the smaller between physical program and technical minimum power to switch-off;

v. 1 price for Switch-On fee (*Accensione*), if enabled. Switch-On is the fee required by enabled UdD for Start-Up its UP. Cap imposed;

vi. 1 price for Setup-Switch fee (*Cambio Assetto*), if enabled. Setup-Switch is the fee required by enabled UdD for switching its plant setup. Cap imposed [5].

If an enabled UdD submits both upward and downward offers with the same unit, selling prices must be higher than buying ones.

Balancing Phase Offers (MB)

Possibilities for balancing offers are the same as MSD. A minor difference is that while on MSD the operator can submit 3 different offers for every relevant period, on MB 4 offers are allowed. Furthermore, MB offers must improve economic conditions of MSD ones for the same relevant period.

Offers Adjustment

Presented offers are adjusted by Terna, in order not to create divergences between offers, updated cumulative program, reference program and technical limits. There are two subsequent adjustment types.

i. *Program adjustment*: Terna evens updated cumulative and reference programs inconsistencies. Generally, if the reference program is lower than the updated cumulative program, downward offers are reduced and upward offers are increased, in terms of quantity. Contrariwise, if reference program is higher than updated cumulative program, downward offers are increased and upward offers are reduced, in terms of quantity. Program adjustment starts from UdD perspective less convenient offers[12] and stops when programs difference is nil.

ii. *Technical adjustment*: Terna considers offers resulting from the first adjustment step and compare them to technical limits of the UP. Consequently, according to which technical limit is violated, either upper one or lower one, offers are adjusted and eventually used for the market results determination.

The logical approach of both the adjustments is described in a simplified way in *Figure 1.5,* for a certain relevant period. For the first approach the black dot represents the reference program while the black triangle is the cumulative program. Dashed lines are offer limits defined by operators offering for MSD. The up arrow stands for upward offers, down arrow for downward ones. If during MI sittings UdD position passes, for instance, from dot to triangle, Terna modifies operators offers accordingly, as shown by arrows' length change. For the second approach the logic is still the same. Offers are modified at a second step to respect technical limits indicated, in this case, by dashed lines.

[12] i.e. selling offers with lowest price and buying offers with highest price. Adjustment is a preservative criterium.

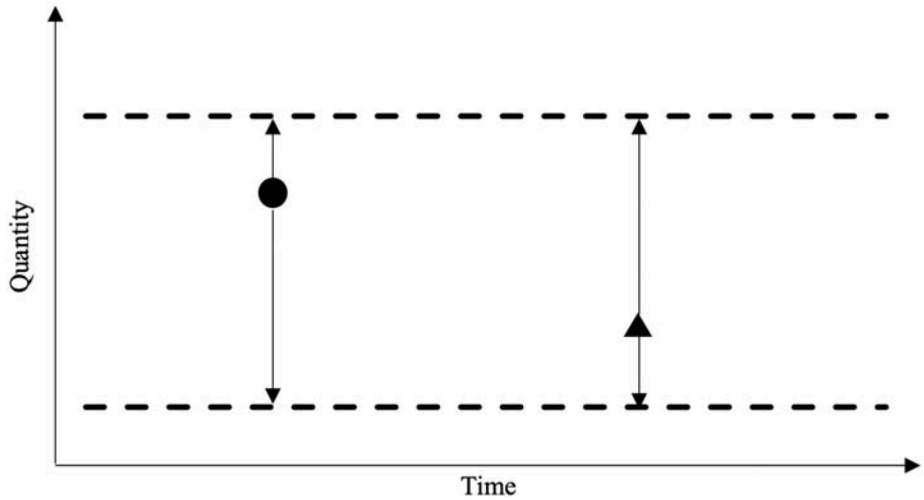

Figure 1.5 The logic of the adjustment process. The dot indicates the reference program and the triangle indicates the updated cumulative program.

Offers Selection and Remuneration

Terna selects offers using economical and power-flow criteria. The detailed algorithm lays beyond this thesis' aim of verifying the economic feasibility of participating to ASM with an energy storage system. Thus, the focus here is on how and when offers are remunerated. Since MSD and MB are pay-as-bid markets, accepted offers correspond to a cash-flow from Terna to UdD in case of upward offers, from UdD to Terna in case of downward offers. Cash-flow is equal to the unit price [€/MWh] submitted in the accepted offers multiplied by the accepted quantity[13].

On MSD Terna:

i. Accepts offers for mFRR and congestion management;
ii. Reserves offers for aFRR, Start-Up and Setup-Change fees;

On MB Terna:

i. Selects and activate resources for real-time balancing;
ii. Activates previously accepted offers;
iii. Accepts and activates previously reserved offers;
iv. Selects and activates additional resources for mFRR;
v. Accepts and remunerate Switching-On and Setup-Change offers;
vi. Activates emergency resources.

[13] In case of accepted fees offers the submitted price corresponds to the total transaction.

Interruptibility and load refusal services are activated in case of balancing impossibility. Until now, only the relevant services for this thesis have been analyzed. In *Table 1.2*, provision and remuneration criteria for different enabled resources are resumed.

Table 1.2 Enabled UP duty, competence market and remuneration [6].

Services type	Enabled Resources	Provision	Remuneration
Primary Reserve	Mandatory for relevant UP	Mandatory	Optional [8]
Secondary Reserve	Mandatory for relevant UP	MSD & MB	Pay-as-bid
Tertiary Reserve	Mandatory for relevant UP	MSD & MB	Pay-as-bid
Balancing	Mandatory for relevant UP	MSD & MB	Pay-as-bid
Congestion management	Mandatory for relevant UP	MSD & MB	Pay-as-bid
Voltage Regulation	Mandatory for relevant UP	Mandatory	None
Load Interruptibility	UC	Auctions	SMP[14] €/MW/year + Pay-as-bid €/MW for every interruption and power
Load refusal	Thermoelectric UPs, P>100Mw	Mandatory	None

[14] i.e. System Marginal Price, resulting from market clearing.

CHAPTER 2
REGULATION FRAMEWORK DEVELOPMENTS

In recent years, the European electricity markets are experiencing numerous changes due to the new challenges coming from environmental issues and energy policies adaptation. Main drivers are the integration of renewable energies services (RES) and the interconnection of national market, in order to hedge the risks coming from unprogrammable resources but also to increase the economic efficiency of the markets for all European citizens. Italian regulation framework is changing to support this transition and to adapt to European directives, such as the approach to real-time energy trades. Directives like 300/2017/R/eel aim to enlarge the number of resources participating to the market, admitting small generators and even consumption units (i.e. Demand Response, DR). This process is needed to support the electricity system in the progressive reduction of traditional high inertia thermal plants, that guarantee grid stability and provide ancillary services. Regulatory changes are the result of the joint work of Agency for the Cooperation of Energy Regulators (ACER) the main European regulatory authority, the European Commission and the European Network Transmission System Operator for electricity (ENTSO-e). The Commission defines long-term goals, ACER how to translate them into energy markets and ENTSO-e how to implement them. Rethinking electricity markets needs new interactions model between Transmission System Operators (TSOs) and Distributed System Operators (DSOs). In this chapter, the state of the art of TSO-DSO relations management is presented, then a brief analysis of European programs for markets integration and member-States measures for market opening is provided. After that, the Italian new regulation framework that applies to this thesis is presented in 2.3.

2.1 Energy Aggregators and TSO-DSO models

New ENTSO-E market platforms (described in 2.2) would facilitate the market integration, hence more efficient energy use. To push even more electricity market and energy provision efficiency, an evolution of regulatory framework is required. It is possible the identification of some main targets [9] of this evolution:

i. Allowing the pooling of resources, (i.e. aggregators) to increase smaller consumers and industrial customers market participation;

ii. Technology neutrality, any technology must have the chance to participate to energy and services market, including storage, if economically compatible;

iii. Neutral prequalification process and aggregation boundaries, reassessing prequalification requirements and clearly define geographical and competence boundaries for aggregators, according to up to date grid needs;

iv. Value-stacking: allowing multiple bids for multiple products For its own nature an aggregator is theoretically able, even with small capacity, to offer for multiple products in the same relevant period;

v. Streamlining of products, reducing and simplifying available energy products, with TSOs to cooperate in designing products and trading modes.

2.1.1 Energy Aggregators

Energy aggregators are defined in European BestRES project as "legal entities that aggregate the load or generation of various demand and/or generation units and aim at optimizing energy supply and consumption technically and/or economically" [10]. They are the connection point between upstream parties, TSOs, DSOs, BRPs[15] (described in 2.2), energy suppliers and downstream parties, industrial, commercial or residential prosumers. The directive 2018/2001 of the European Union [11] empowers the participation of end-users through the aggregator, enhancing their flexibility on energy provision, production, storage and sell. Aggregators will play a significant role after the complete market opening, both in energy and services market. Different small production units as well as DR resources, if aggregated in a Virtual Power Plant (VPP), are technically able to support energy provision and grid stability, with an increasing interest due to the fast RES penetration and related issues. VPPs are the digital aggregation of different types of both consumption and generation units, managed by a legal entity. The advantage of this kind of business model comes from the possibility to increase the flexibility of small units and hedge the risk of imbalances [12].

[15] i.e. Balance Responsible Parties, described in the foillowing.

There are four potential models for end-user aggregation, that mainly differ for the energy supply modes and BRPs number [13].

Aggregator supplier, is an aggregator that integrates energy supply and flexibility resources, with no need for bilateral contracts for imbalances settings. This is the lowest complex model.

Contractual aggregator, is a model in which the aggregator does not supply energy, but needs a separate BRP. To settle imbalances, bilateral contracts between the two BRPs are required.

Delegated aggregator, is similar to the previous model but simplified by the absence of the second BRP. There are no bilateral contracts to settle the imbalances rather a more extensive regulation for financial settling is needed.

Aggregator as a service provider, offering pure flexibility but not at its own risk as it is for the previous two models. In this case aggregators interacts with a third party who sells its flexibility.

The logical deduction of the described models is presented in Figure 2.1.

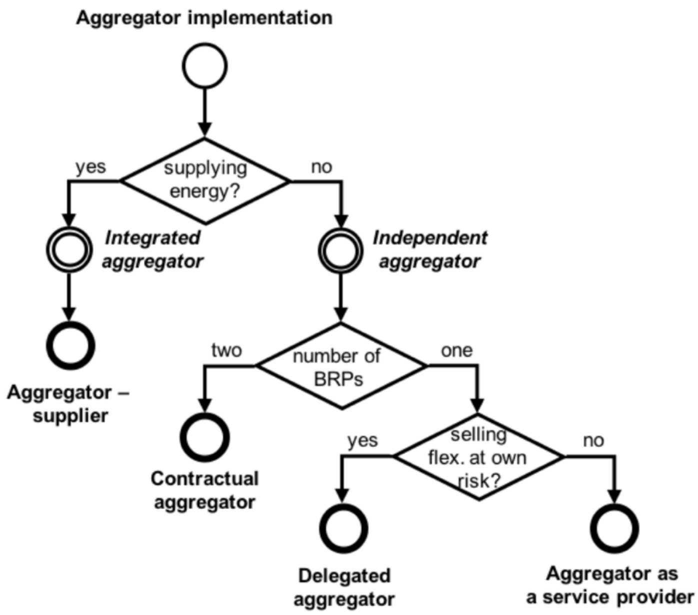

Figure 2.1 Flowchart representing different aggregator model and logical deduction [13].

2.1.2 TSO-DSO

The integration of aggregators for efficient use of small-scale energy resources and flexibility enhancement requires a renewed scheme for TSO-DSO interaction. TSOs are the entities entrusted to transport energy at the national level by using fixed infrastructure.

High cost coming from this activity often cause TSOs to be national natural monopolies (as for Terna). DSOs are described in the Directive (EU) 2019/944 of the European Parliament as responsible for the maintenance, operation and development of the distribution infrastructure in a given area. This is a broad topic currently discussed, here are some coordination schemes for ASM, from the 2017 SmartNet project report [14].

Centralized AS market model. A common market for AS is operated by TSO that decides when to directly activate resources, both at transmission and distribution level. TSO does not consider DSO constraints, while it is possible the installation of a prequalification system to guarantee that TSO choices does not cause congestion in DSO's grid.

DSO can still procure resources for local grid issues but using defined timeframes different from TSO ones and away from real-time.

Local ASM model. A separated local market is managed by the DSO. DSO clears the market and uses local flexibility and DER to solve local grid issues. Remaining resources are aggregated and offered to TSO's ASM, after checking compatibility with DSO constraints.

TSO still activates resources both at transmission and distribution level, but DSO owns the priority for the distribution level.

Shared balancing responsibility model. Two separate markets are respectively held by TSO and DSO. TSO manages the ASM for transmission level resources and it is responsible for transmission grid balancing. DSO manages a local market using resources for flexibility and congestion management. DSO's exceeding resources cannot be offered to the TSO's ASM and local clearing process comprehends DSO constraints. DSO respects a predefined schedule[16] based on historic data.

Common TSO-DSO AS market model. A common market is managed cooperatively by TSO and DSO. Under the *centralized variant*, DSO constraints are integrated in a single transmission and distribution level optimization process, for flexibility and congestions management. Under the *decentralized variant*, firstly a local DSO market is run without committing market participants. Result of this step are used for the combined optimization of the common market and final results are reported to all of the participants. In the centralized variant, a third party guided may guarantee system operations.

Integrated flexibility market model. There is no market separation. Bids are presented in series of auctions and accepted by the third party more willing to pay for the resource.

[16] i.e. a net injection or a net withdrawal, depending on the DSO.

2.2 European network codes and markets integration

ENTSO-e is the representative network for 36 TSO from 43 countries throughout Europe. This organization is the central counterpart for regulation directives, market design and system operation. The role of ENTSO-e is drafting network codes[17] following ACER guidelines. Latest codes for the electricity market are *i.* Capacity Allocation and Congestion Management (CACM), *ii.* Electricity Balancing, *iii.* Forward Capacity Allocation. *i.* and *ii.* regards respectively Day-Ahead and Intraday Markets and Ancillary Service Market and are discussed in this chapter. *iii.* is about the allocation of capacity on future timeframes and is not discussed here.

The progressive adoption of shared network codes would favor the market integration in the short term, for better use of energy and for grid reliability and sustainability enhancement. In this direction have been approved some projects that are short to go-live. These projects are: PICASSO, IGCC, TERRE, MARI on balancing market integration and XBID on cross-border intraday market interconnection.

2.2.1 CACM network code

CACM defines future developments and guidelines for day-ahead market and intraday market [15]. CACM day-ahead markets model is the implicit auction based on market coupling[18]. Organization is entrusted to Nominated Electricity Market Operators (NEMO) and national monopoly subjects that gather, organize and select offers according to the TSO methodologies for transit capacity calculation between market zones. The market is solved using the Euphemia algorithm [6] that aims to maximizes social surplus, daily and for every relevant period. CACM intraday market is based on continuous trading[19], opening at 3:00 pm on D-1 and with gate closure at H-1 [6] on D. Capacity is allocated with first-in first-served logic, while still remains the possibility of complementary implicit auctions for every market zone. For cross-border capacity allocation must be used a Flow-Based approach[20], while for national market zones Coordinated Net Transmission Capacity (CNTC[21]) is still permitted [15].

[17] i.e. a set of rules regarding electricity network and the grid.

[18] i.e. considering transit limit between geographical and virtual market zones.

[19] Now Italian MI is based on gate closure with seven sessions, changing in next years.

[20] i.e. a capacity calculation approach that evaluates simultaneously capacity allocation, transit capacity and the impact on critical grid elements.

[21] i.e. a capacity calculation approach that evaluates transmission capacity based on expected grid conditions. Less accurate than flow-based approach.

XBID platform

Cross-Border Intraday (XBID) is a platform that allows continuous trading for European intraday market [16]. This project improves market flexibility and efficiency. Operators can continuously adjust their day-ahead positions, following real-time dispatching issues. XBID allows market participants to benefit of international cashflows coming from national imbalances[22] adjustments. To promote this process, PXs and TSOs of 12 countries launched XBID, with go-live in 2018 in central Europe and for the fourth quarter of 2020 (the so called third wave) in Italy. Products supported are 15-minutes, 30-minutes, 60-minutes and hourly user defined blocks, with 24/7 delivery and already indicated gate closure.

2.2.2 Balancing Code

The Balancing Code [17] regards power exchanges between TSOs for the continuous balance of injections and withdrawals and frequency maintenance [18]. The idea is that balancing prices should give participants relevant market signals to operate closer to real-time. Real-time operations favor the unit commitment and hedge imbalances price volatility. A certain margin must be reserved before real-time to prevent market operators to only trade close to real-time risking the grid reliability. Balancing Code involves TSO and BSP and BRP.

Balancing Responsible Parties (BRPs) are the subjects responsible for injections and withdrawal programs execution, commercial and imbalances settlements. This role can be covered by the final customer, by the producer or by a delegated third party[23] and can correspond to the market operator.

Balancing Service Providers (BSPs) are the ancillary services providers, possibly corresponding to BRPs.

The market integration goes through standard products[24] trades. RR, mFRR, aFRR are the tradable products on international platforms (PICASSO, IGCC, TERRE, MARI), while specific local products are permitted. Another possibility for the TSO is the balancing capacity market.

International Balancing Platforms

PICASSO [19] is the Platform for International Coordination of Automated Frequency Restoration and Stable System Operation. This platform would allow the exchange of aFRR balancing energy, pursuing art. 21 of Commission Regulation (EU) 2017/2195 of

[22] i.e. divergences between physical and commercial programs due to different market sessions. Adjustment is difficult with gate closure mechanism since chances to change market position are low.

[23] e.g. AU is BRP for customers under 'Maggior Tutela' regime, GSE is BRP for units under incentive schemes like feed in tariff.

[24] Products differ from activation time, activation ramp and service length.

23 November 2017 [17]. The target of the project is the design and the operation of a platform for aFRR exchange based on TSO-TSO[25] model, to enhance the economic and technical efficiency always with the respect of safety limits. As of today, the consultancies go on with members, Italy included, and observers States of the project.

IGCC [20] is the International Grid Control Cooperation project that will become the future Imbalance Netting (IN) platform after ENTSO-E decision. Launched at first in 2010, IGCC includes now 24 countries and 27 TSOs. The basic principle that guides imbalance netting is to prevent the simultaneous activation of aFRR in opposite directions in member States. TSOs communicate their power-frequency signals to the optimization platform, that elaborates the input and delivers the correct signal to each IGCC member automatic controllers. Simultaneous activation of counter aFRR is avoided and energy use is more efficient at every optimization step. Italy is the latest member to become operational on the 12th February 2020 [21].

TERRE [22] is the Trans European Replacement Reserve Exchange project. This project shares targets and principles with PICASSO but underlies RR. TERRE is the most advanced project for balancing market integration following Balancing Code. The optimization algorithm and IT platform are almost ready to be given to member TSO for go-live. Italy is a member State.

MARI [23] is the Manually Activated Reserves Initiatives for the creation of an exchange platform for mFRR. As for all of the previous projects, product standardization and/or real-time conversion of national products would be determinant for a smooth implementation. Italy is a member State.

2.3 The Italian Framework

European directives, CEP and network projects (i.e. PICASSO, IGCC, TERRE, MARI) are incorporated in the Italian regulation framework to achieve binding environmental and efficiency targets. Italy entered IGCC on 12th February 2020 and it is an active member of the other projects, with ongoing regulation evolution to pursue CACM and EB target models. Moreover, a first opening to aggregators and VPPs came with the 300/2017/R/eel directive and following updates and the latest *Testo Integrato del Dispacciamento Elettrico* (TIDE) general guidelines.

2.3.1 The UVAM project

The 300/2017/R/eel directive [24] followed the ARERA 298/2016/R/eel consultation documents regarding the possibility to enable all of the relevant UPs, including RES for the

[25] i.e. dispatching model, other possibilities are later discussed in this chapter.

ASM. Moreover, in the consultation was proposed the participation even non-relevant UP, if virtually aggregated, and DR. VPPs are hereinafter called *Unità Virtuali Abilitate* (UVA). The directive led to the market opening for UVAs, distinguished in *i.* consumption only UVA-C, *ii.* production only UVA-P, *iii.* mixed UVAM, all managed by a BSP still coincident to BRP and referring to a single grid connection point. As of now, UVA-C and UVA-P are not applicable as they merged in the UVAM one. According to the directive, UVA's operations are not subject to dispatching fee payment and can incorporate storage systems[26][25]. Requisites for pilot project with a minimum installed aggregated power of 10 MVA are then described.

The UVAM Regulation

The 422/2018/R/eel directive actually opened for the first time to UVAM pilot projects first approval ARERA directive, is integrated by a Terna regulation document that contains enabling procedures, incentives and operating constraints. A UVAM can aggregate different resources: non relevant UPS, consumption units that are not under an AU contract, storage systems, relevant UPs non-mandatorily participating to ASM. Aggregation must happen within a defined perimeter, that must reflect grid's needs [26]. Minimum power depends on the services that UVAM is offering:

i. If offering both upwards and downward services, the minimum power is 1 MW;
ii. If offering only upwards services, the minimum power is 2 kW;
iii. If offering only downwards services, the minimum power is -2 kW.

UVAM can participate to both MSD and MB but can only provide congestion management services, tertiary reserve and real-time balancing. Technical requisites are those described in *Codice di Rete* for different services. UVAM enabling is confirmed by Terna after technical tests [26]. Once enabled, UVAM must bid on MSD and participate to offer selection.

UVAM offering process is described in UVAM regulation [26]. The BSP must present predefined offers and, furthermore, can submit multiple offers for enabled services. Every offer must contain price [€/MWh] and quantity [MW] for every bidding relevant period. For pilot projects, an incentive is awarded if the UVAM can guarantee either two or four hours of service at its full available power, between 2 and 8 pm. The maximum price for upward offers during the mandatory period must be 400 €/MWh. If no offer is submitted for the mandatory timeframe, predefined bids are used by Terna for the selection process. The incentive depends on the total installed UVAM power and is equal to 30000 €/MW/year if the UVAM guarantees four hours of service; 15000 €/MW/year if the UVAM guarantees

[26] According to deliberative 574/2014/R/eel, storage systems are equivalent to UPs [25].

only two hours of service. Financial settlement is operated monthly. For accepted offers, remuneration is pay-as-bid for a total amount equal to the bid price multiplied by the accepted quantity. Fines apply if dispatching orders are not respected.

2.3.2 Prospective TIDE Guidelines

On 23rd July 2019, ARERA published the new TIDE [6] consultation documents for stakeholders' review and subsequent approval. The aim is the implementation of market measures to fulfill 2030 CEP targets and to respect CACM and Balancing Codes. Most relevant for this work among TIDE directives are presented afterwards.
Exemplary the future change for gate closure, market clearing, transit capacity calculation and bidding criteria on MI, and general guidelines for ASM, according to CACM and Balancing Code.

Evolution of the Electricity Market Architecture

Currently existing Italian electricity market design aims to reflect physical constraints the more the specific market segment is close to real-time. This concept translates, on the one hand, in simplified grid constraints for MGP and MI, for a first approximated system dispatchment. On the other hand, since the ASM is used by TERNA to centrally gather ancillary services resources, must be strictly related to the grid's structure. The reference program used as a baseline in ASM is the one resulting from MGP and MI.
The CACM Code, moving intraday market gate closure to H-1, highlights the divergent trading nature of Italian and European electricity markets. While Italian markets are deeply connected to the actual physical programming, European trades are more financial based. The main issue is the geographical configuration of Italy, that forces physical programming to not be modified in order to guarantee grid safety and reliability. The possible solution is the separation of physical and commercial programming on IPEX. The separation would help removing the rigid markets sequence and would enable a responsive physical programming on ASM, according to real-time needs, with no commercial limitations. This measure would enhance the effectiveness of previously described directives and enlarge the number of admitted participants. The possibility of submitting offers directly linked to the physical programming would still be guaranteed.

Programming and Imbalances Settlements

BRPs and BSPs separation would empathize and improve effectiveness of the measures as well. Moreover, the same BRP, managing different UPs and aggregators, including DR and energy storage systems (ESS), could submit so-called portfolio offers within a predefined

perimeter[27]. Due to the different offers' valuation between demand and production on MGP and MI, at a first step portfolio offers should include either only demand or production units[28]. At a second step the removal of PUN, could deliver better price signals and allow the incorporation of both demand and production units in portfolio offers.
For UPs not enabled to ASM, BRP must define the program P, adjustable till H-1 and relevant for imbalances calculations.
For UPs enabled to ASM, the new architecture would lead to the following programming steps:

i. BRP defines the unit physical program **P** before MSD;
ii. BSP submits the offers;
iii. Terna adjusts, selects and remunerates offers for MSD;
iv. Program P becomes the binding program **PV** (Programma Vincolante), that must be respected by the BRP;
v. Terna can also indicate competence timeframes for BRP to further modify PV till H-1;
vi. PV becomes the binding modified program, **PVM** (Programma Vincolante Modificato);
vii. in real-time operation, the grid's needs in combination with respective MB trading eventually further change the program. This leads to **PVMC** (Programma Vincolante Modificato e Corretto), the binding modified and corrected program.

Terna would settle financial accounts with BRP, while BRP and BSP could independently define their respective contractual obligations. Given the proposed separation of commercial and physical programming, GME defines the commercial balance, for every i-hour, as:

$$\sum_{i,enabled}[PVM_i - (PV_i - P_i)] + \sum_{i,not\ enabled} P_i - PC \ ;$$

where PC is the commercial position. This formula distinguishes BRP trades on MGP/MI (PVM) and ancillary services accepted by Terna (PV_i-P_i). The resulting balance is valued using the imbalance price, as described by the current regulation framework [5]. GME should manage the platform for imbalances' operations.

[27] At most feeciding to market zone (suggested).
[28] i.e. PUN vs Pz.

Negative Prices

Nowadays offers' floor is fixed at 0 €/MWh. For some plants, switching-off/on the plant it may cost more than offering at a negative price, hence paying for injecting energy to the grid. Introducing negative prices would allow system cost reduction and better use of energy, possibly paired to enhanced by ESS.

The existing Start-Up fees[29], have accepted prices that are evaluated till ten times the actual technical cost of the operation.

On the other side, RES benefitting of incentives would gain clear market power by offering at a negative price but still obtaining a revenue due to the incentive. This issue could be solved by not applying the incentive during hours with the submission of negative prices. These hours should eventually extend the incentive timeframe [27].

UVAM First Results

UVAM pilot projects are currently operating only in ASM, in accordance to deliberative 300/2017/R/eel and 422/2018/R/eel. ARERA analyzed UVAM result in order to improve the effectiveness of the project and to propose adjustments to the current regulatory scheme. This analysis impacts on this work since the simulations of Chapter 4 are created not to use clear weaknesses of the current framework. One of the most evident is the chance for UVAM to offer at their cap price of 400 €/MWh for upward services, which is largely higher than average accepted price. Thereby, some UVAM benefit of the incentive scheme without actually providing a concrete service to the grid. Results of Chapter 4 provide insights of what may happen by removing this regulation defect and promoting a more efficient and integrated use of the UVAM project. From the ARERA analysis of UVAM results, emerges a first issue about aggregation perimeter. The problem lays in the divergence between UVAM perimeter, essentially coinciding to the belonging province, and actually dispatchment algorithm that uses a nodal approach. Moreover, it happens that in the same UVAM there are UPs belonging to different BRPs.

The analysis considers 128 UVAM under contract mostly (94) located in NORD, with 830.7 MW for upward services and 200.9 MW for downward services, managed by 24 BSPs. All of the UVAM are enabled for upward services, while only 28 of them for downward services. UVAM aggregate for the greatest part modulable consumption units, programmable production units (e.g. Combined cycles) and unprogrammable yet flexible production units (e.g. fluent-water hydropower).

[29] See 3.4.4.

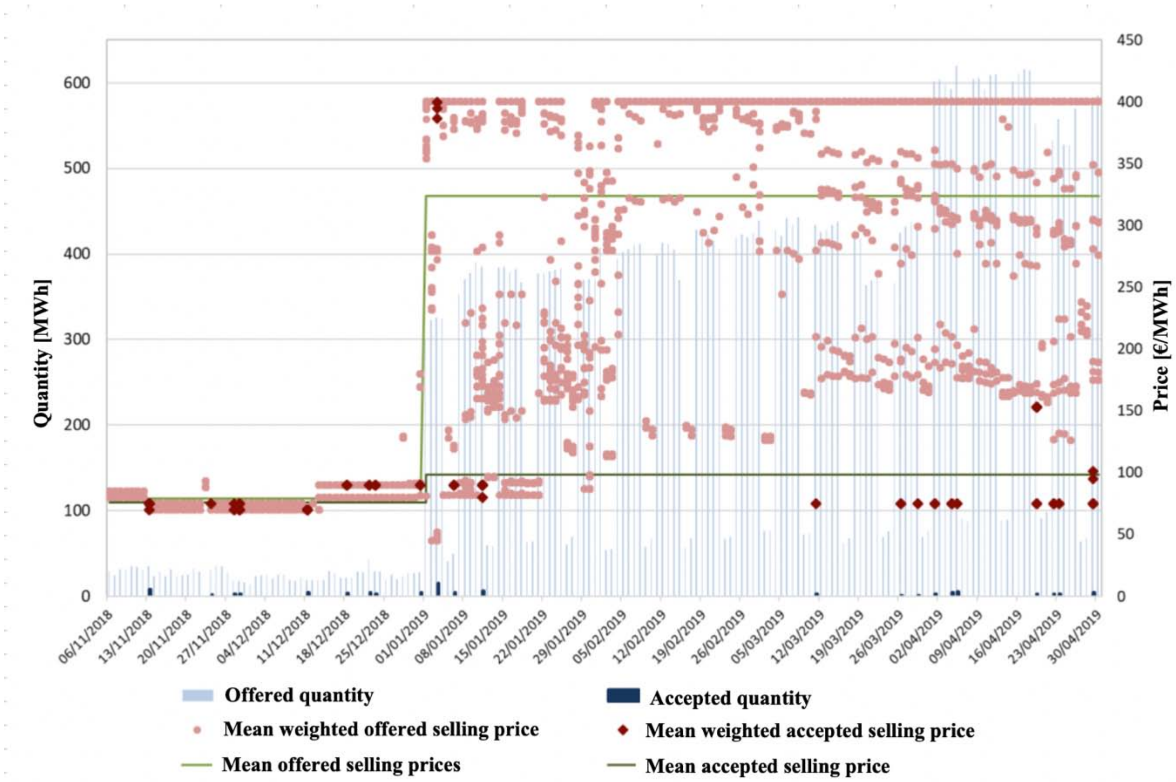

Figure 2.2 First UVAM results for upward offers. downward results are not presented as they are less significant [6].

From 1st November 2018 to 30th April 2019:

i. Generally, upward offers present high prices, with a weighted average of 80 €/MWh from 6th November to 31st December 2018 and of 324 €/MWh from 1st January to 30th April 2019;

ii. Terna never selected offers for downward services;

iii. Terna selected only 5% of submitted offers for upward services, with a good dispatching orders compliance of 81.5%;

iv. Selected offers were used only for real-time balancing, for a total of 708.33 MWh.

Ancillary Services provision and remuneration

For Primary Reserve, weekly discount auctions underlying a €/MW/week fix compensation and subsequent variable real-time remuneration are proposed. In alternative, the compensation could be fixed by regulation.

For Secondary Reserve, the current ASM provision is effective yet an approach similar to Primary Reserve scheme can be considered.
For Tertiary Reserve and Congestion Management the current provision process will not change.
Emergency Services will still be mandatory and free.
On bidding side, Block Offers are proposed. According to this method, the market player can submit offers for more than one relevant period, that must be completely accepted or refused. In addition, these offers can incorporate minimal acceptance required percentages or be linked-type, the acceptance (refusal) of a certain bid -children- is subordinated to the acceptance (refusal) of another one -parents-.
Regarding the remuneration criterium, a shift from pay-as-bid to system marginal price is possible. Indeed, with system marginal pricing the operator would offer its effective variable cost, while with pay-as-bid operators offer at a higher price to get close to the market equilibrium price. Adopting system marginal pricing would eventually increase market efficiency and transparency but would possibly penalize new technologies by lowering the average accepted price.

Pilot projects

Some additional pilot projects are under consultations, regarding only consumption units UVA belonging to the same BRP for the capacity market participation[30] (UCMC) and energy storage systems (ESS) to be used in power-frequency primary regulation [28].

2.4 Comparison of regulatory status quo in European balancing markets

SmartEn, with ENTSO-E cooperation, presented a study that pictures the current state of European balancing markets [9]. The study evaluates the present level of development of the access to balancing markets, measurements and prequalification process for ancillary services enabling, market segmentation and size, transparency and upcoming changes in European member States. All of the categories are rated from 1 to 5. Here are briefly presented the overall results, from the reported study.

2.4.1 European Countries Balancing Strengths and Weaknesses

France, Switzerland, Ireland, Finland and Belgium obtain the highest score of 4 out of 5, right behind there are Great Britain with 3.5 and Germany, Austria and the Netherlands with

[30] i.e. an auction market used to guarantee reserve margins in the long term. The main critical issue is the possible double remuneration of enabled players, both on capacity market and MSD.

3. Italy is rated 2.5 together with Denmark, while other Countries get a lower grade. Portugal, Spain, Estonia, Poland and the Italian bordering Slovenia gets only 1.
France has an almost open market that enables effective participation of DR and distributed energy resources (DER). FCR is procured, from July 2019, on daily basis auctions, on D-2, opened to DR and DER. 1 MW is the minimum bid, however the mix of DR and generation (e.g. Italian UVAM) is not permitted. aFRR is the less developed France ancillary service. Even if 1 MW offers are enabled, large generators, obliged by law to supply aFRR, can have indirect access to the market. Moreover, the pro-rata activation logic is an additional limit to DR and DER participation. Regarding mFRR, there are still barriers to the complete market opening due to the minimum power set to 10 MW and the provision done on a yearly tender. Overall France is doing very good, there is an active participation of new flexibility forms from residential to industrial sector, connected at any voltage level. These new resources are mostly used for mFRR and real-time balancing. The implementation of a European balancing platforms would improve current weaknesses and lack of transparency, especially for aFRR.
Finland is another example of efficient balancing market. Finland’s FCR is split in FCR for disturbances (FCR-D) and FCR for normal operations (FCR-N). FCR-D is procured by the TSO on yearly tenders to guarantee grid safety. The minimum bid size of 1 MW allows the active participation of aggregators and DR. For FCR-N, the minimum offer is 100 kW, allowing the access to small-scale and residential flexibility types, including water boilers and storages. aFRR is procured on hourly market with a minimum bid size of 5 MW. This market is opened but the 5 MW limit and low volumes prevent the entrance of DER and DR. mFRR as well is operated on hourly market with 5 MW minimum offer, but market volumes favor participation of untraditional flexibility that covers one third of the market. The main lack of Finnish system is the transparency: TSO does not publish real-time data except when reserve margin is lower than 150 MW. Enhancing communication, completely opening mFRR to aggregators lowering the participation limit to 1 MW and European platforms would allow Finland to do even better than now.
Another well performing Country is *Great Britain*. FCR has two main subcategories. The first is Firm Frequency Response (FRR), procured both on tenders and with specific contracts to fit the needs of different technologies. 1MW is required to participate, with aggregators partly allowed, to daily 4-hours blocks tenders. The second is Enhanced Frequency Response (EFR), providing a fast response -1 second- to be held for 15 minutes. 4 years of bilateral contracts are awarded through tenders. This product is perfect for ESS, allowing ESS BRPs to guarantee the return of the investments and to provide an efficient service. The success of the initiative is shown by the 200 MW under contract for EFR. aFRR is still pretty closed, due to the 25 MW limit, while mFRR regulation is too complex to

enlarge participants' number. Main problems for Great Britain are the prequalification process for FRR and the generally complexity of the framework scheme. For FRR participation, aggregators and DR are formally allowed but the tolerance of ± 0.01 Hz on service provision is a strict limit for their enabling. Main efforts are being made in the direction of simplifying regulation and products requisites, to smoothly enter European balancing platforms and to enlarge small-scale participation in balancing markets. This measure would allow to increase the tolerance band due to the expansion of available resources.

Italian FCR is currently a closed market. Operators must mandatorily provide the service, while the remuneration is possible only if advanced metering tools are installed for continuous data acquisition, not through the market. Technical limitations prevent aggregators and DR participation. Similarly happens for aFRR. Even though the service is procured through the market, the market is not opened to new flexibility providers. mFRR and real time markets are opened markets. The main Italian strength lays in the data communication transparency, through Terna and GME, and in the diffused changes that regulation is facing. The launch of new pilot projects, the consolidation and review of UVAM project and the planned possibility of opening other services' market would make Italy one of the most interesting Countries in the following years.

Low rated Countries main problem is the absence of a market for many of the available services and the lack of transparency in the procurement process. A radical change is needed and asked by EU after CACM and Balancing Codes introduction.

CHAPTER 3
ASM MARKET DATA ANALYSIS

After the overall description of Italian and European electricity markets, in this chapter market results published by GME are analyzed. The aim here is to understand bidding and market behaviors and related price differentials between upward and downward services on ASM to test, in Chapter 4, the profitability of ESS leveraging on them in the Italian grid. Except for 3.1, all of the considerations are done using a personal elaboration of 2018 and 2019 datasets. The first part of the chapter gives an overview on Italian electricity market trends over the last years, based on GME reports and Terna's data. After that, data gathering process and a first description of data structure is given. Whereupon, a statistical analysis is conducted. Some statistics are already present both on Terna and GME website but with less granularity. The main lack is the missing separation of different products. Monthly Terna reports, for instance, only differentiate Secondary Reserve (*Riserva Secondaria,* RS), while all of the other products are described as Other Services. For a proper evaluation but mostly for a truthful feasibility study in Chapter 4, an autonomous analysis must be conducted. The originality of this chapter lays in the creation of a set of MATLAB scripts for data analytics. Basic statistics concepts are used to understand general market trends with zonal detail, product differentiation and different timewise. At a first step, general price trends for upward and downward products are searched. At a second step, more granularity and result relevance are obtained by the separate analysis of every product, for every market zone with hourly detail. This process consent to narrow the results, finding criticalities and insights for UVAM non-tradeable products and accurate information over price differentials and possible market strategies for UVAM tradeable products. A further analysis circa total and hourly volumes is conducted, as well as an analysis over the most used UPs and belonging geographical areas. In this Chapter and in the following one, market zones are identified using the label used in GME's data.

3.1 A General Overview

Before going in deep with the ASM analysis, some relevant data are reported. According to GME 2018 Annual Report [29], in 2018[31] the Italian energy market volume was 295.56 TWh on MGP, increasing by 1.2% the 292.2 TWh result of 2017, and 25.38 TWh on MI with a slight increase of 0.1% compared to 2017 volume of 25.35 TWh. The gross domestic production, instead, decreased from 2017 level of 296 TWh to 290 TWh in 2018 [30]. Anyway, domestic production is following a growing trend from 2015 when it was 283 TWh. All times peak remains 2008 production, with 319 TWh, but must be considered the pre-crisis period and the lower energy efficiency at the time, that translated in higher energy consumption, 319 TWh in 2008 and 303 TWh in 2018, especially in the industrial sector.

Total installed power was 118 GW, following a decreasing trend from 2013 all times maximum of 128.6 GW. This resulted from the dismission of 14.5 GW of thermoelectric plants, which were unable to profitably adapt to market need for flexibility while keeping a high efficiency, not paired to a comparable increase of new power plants. Indeed, renewable energy plants installations met a growth of 4 GW, mostly Photovoltaic (PV) and Wind Power. Total RES installed power is 54.3 GW [31], the 46 % of total effective power, with more or less 20 GW of PV and 10 GW of wind power. The rest is almost hydropower, with a minimum part of geothermal and bioenergy power. RES produced 114 TWh in 2018, the 39.5% of total production, due for the 25% to PV and wind, with a big leap considering that the share was of only 1% in 2004 [30].

Another relevant trend is the growth of DER [30]: in 2017 plants with a power lower than 10 MVA were the 23% of the total, while in 2004 the same asset covered only 5%. In terms of energy, DER used to produce the 4.7% in 2004 and the 18% in 2017.

A first price information is given by the PUN; in 2019 the average PUN was 52.32 €/MWh similar to the 2018 result of 53.95 €/MWh and with a sensible decrease compared to the 2017 61.31 €/MWh. Total quantities exchanged on MGP were more or less the same in 2017, 2018 and 2019 but, the domestic production is increasing, resulting in a lower equilibrium price, on the average. The widespread of DER and small-scale plants contributed to this process on the one hand and increased the demand for ancillary services and related price differentials on the other hand. Traditional power plants dismission leads to some criticalities for dispatching. Flexibility is increasing, due to the adaptation of traditional fuel plants (e.g. CHP) and DER, but the now relevant share of RES, with uncertain physical programs profile strongly depending to weather conditions, causes the need for higher reserve margins. Moreover, during hours of the day characterized by and high irradiance, the increasing

[31] By the writing of this thesis the last available annual GME report is for 2018.

presence of PV power could represent a problem for the grid without storage systems, with generation exceeding demand and a poor modularity, forcing the controversial RES curtailment solution. The complexity of dispatchment management under aforementioned conditions, translates in a higher uplift unit fee, which is the cost associated to the provision of ancillary services and it increases as reserve margins increased. Reserve margins are now procured at a higher and more volatile price than it was in the past because of the current scenario and this affects the uplift fee. The fee reached its maximum of 0.92 c€/kWh in 2016 and was 0.65 c€/kWh in 2018, starting from 0.3 c€/kWh in 2009. Going deeper and analyzing quarterly data, the connection between unprogrammable resources and uplift fee is clear, since the fee is on the average 44% higher from April to September, when hydropower and PV produce the maximum.

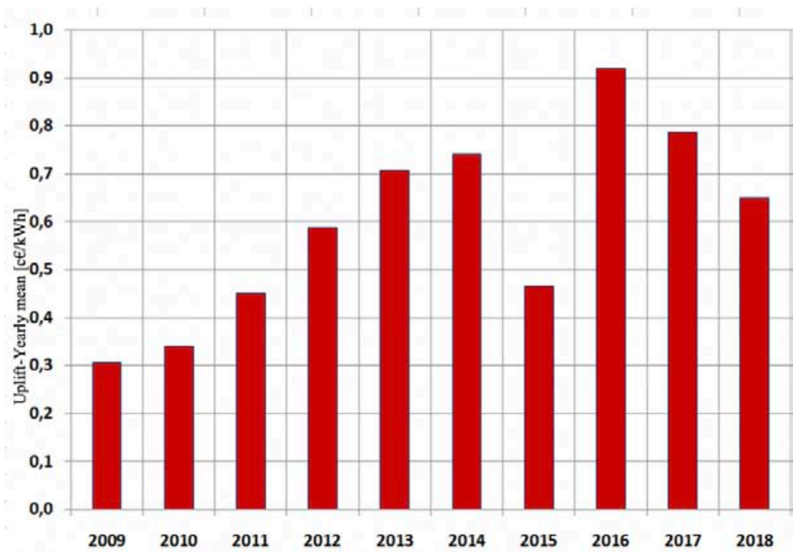

Figure 3.1 Yearly uplift trend [31].

3.2 Data Collection and Description

Before starting the analysis, data must be collected, organized and understood in each of their entries. Raw data can be downloaded from GME website [32] following the path: *GME website>Esiti dei mercati e statistiche>offerte pubbliche>MSD ex-ante* or *MB*. Data include a large amount of information about all of the offers submitted by the operators for every hour and for every product. Therefore, the download is only available one day at a time. With an express script, to be written on the Console of Google Chrome, the automation of the process is possible. After that, 365 .xml files per year (2018 and 2019) must be organized in readable way. The main issues are the high number of files and their total dimension. To simplify the analysis, 2018 and 2019 are treated separately. Is created an original C# program, that takes input files, elaborates them and gives output files. Daily files are used as inputs[32], while the program scrolls through files and creates different outputs for every market zone. The process is iterated, obtaining as a result quarterly files for every market zone excluded NORD, whose results are monthly. This distinction is necessary to allow MATLAB managing data with no issues. No information is lost in the process and at this point data are simpler to use. Then, .xml files are opened with Excel, for an easier access and to understand the logic of GME's data publishing. Some Excel columns are deleted since not necessary for this work. For each market zone, Excel files contains the following discussed entries.

- PURPOSE_CD: indicates the purpose of the offer and can either be 'BID' for downward offers or 'OFF' for upward offers.
- TYPE_CD: can be REG for current offers or STND for standard ones.
- STATUS_CD: is the state of the bid after market conclusion. ACC means that the offer is accepted and thus remunerated, REJ stands for rejected. If the offer does not respect regulation requisites, it is marked as unsuitable, INC, while if it is replaced by a new one, the label is REP. SUB stands for submitted and indicates that the offer is reserved on MSD for MB.
- PARTIAL_QTY_ACCEPTED_IN: it indicates whether or not, Y or N, the accepted quantity is lower than the offered one.
- OPERATORE: is the operator submitting the offer, e.g. ENEL PRODUZIONE SpA, ENGIE ITALIA SpA, etc.
- UNIT_REFERENCE_NO: identifies the UP through which the operator is submitting the offer.
- GRID_SUPPLY_POINT_NO: it is the relevant grid exchange point (PSR_). Generally, it is a set of primary cabins, belonging to the same market zone but not necessarily close to each other, within which it is indifferent where the injection (withdrawal) actually takes place, for dispatching optimization [33].
- INTERVAL_NO: it specifies the relevant period of the day and goes from 1, that indicates the hour between 12 am and 1 am, to 24 that indicates the hour between 11 pm and 12 am.
- BID_OFFER_DT: it is the date of the offer.
- SCOPE: it indicates the product the operator is bidding for, which are: *i.* RS, Secondary Reserve, *ii.* GR1, GR2, GR3, (GR4 only for MB) three (four) parts in which the operator can split its reserve band to supply Tertiary Reserve, Congestion

[32] The choice to use the C# one month at a time and, after that creating a trimestral file, is due to the RAM amount used by the program. To run the script for a month, 2 GB of free RAM are required. For completeness, NORD files must be processed month by month because of the big amount of total offers present.

Management and real-time balancing services, *iii.* ACC, is the fee required for Start-Up, *iv.* CA, is the fee required for Setup-Change, *v.* AS, indicates the Minimum offer.

- QUANTITY_NO: it is the quantity in MW (for one hour), as submitted in the offer by the operator or the quantity contained in the STND offer.
- ADJ_QUANTITY_NO: it is the quantity in MW (for one hour), as adjusted by Terna following the process described in 1.5.3.3.
- AWARDER_QUANTITY_NO: is the quantity in MW (for one hour), as eventually awarded by the market.
- ENERGY_PRICE_NO: it is the price in €/MWh, as submitted in the offer by the operator or contained in the STND offer.
- ADJ_ENERGY_PRICE_NO: it is the price in €/MWh, as adjusted by Terna, to respect offer constraints (e.g. UVAM upward cap as in 2.3.1.1).
- AWARDED_ENERGY_PRICE_NO: it is the price in €/MWh, as eventually awarded by the market and paid as bid.

About GR-offers, is important noticing that the quantity offered in GR2 incorporates the one offered in GR1, and so on, with an equal or higher (lower) price for upward (downward) offers, as shown in *Figure 3.3*. The operator is allowed to split its available capacity as it prefers, with no need to exactly divide it in three (four on MB) equal parts. In many cases, including the case study presented in Chapter 4, due the limited trading capacity, only the GR1 offer is presented.

A few contingencies lead to think that the offer submission process is still widely manual. This can be often seen in offers presented with quantity equal to zero. Those quantities are afterwards adjusted by Terna, to the minimum mandatory quantity[33] or to the STND offer. Terna's adjustment process appears instead as automatic and not related to grid needs, the adjustment is implemented, for current offers with quantities that do not respect bidding constraints, even if the offer is rejected or only partially accepted at the end of the market. Adjustment process interests less frequently offers' prices and it is limited to prices exceeding regulation limits. The example comes from the UVAM pilot projects; sometimes UVAM BRPs offer at a high price that can even reach VoLL[34], trying not to be selected but still benefitting of the incentive. However, during mandatory hours (from 2 to 8 pm) Terna adjusts the price to the mandatory upper limit of 400 €/MWh -still far from market prices- for upward offers. This behavior caused the reduction of overall relevance of the results of pilot projects, since UVAM are rarely selected.

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[33] According to technical requisite as described in 1.5

[34] i.e. Value of Lost Load, equal to 3000 €/MWh. It is the cap for market offers and expresses TSO's evaluation of 1 MWh not supplied.

The missing link between the specific of UPs and related PSR is clear for UVAMs. All of the UVAM offers for a certain market zone refer to the same PSR, still providing anyway a simplifying information for the analysis of UVAM trends. UVAM PSR zone by zone are: in NORD the PSR_295, in CNOR the PSR_297, in CSUD the PSR_299, in SUD the PSR_301, in SICI the PSR_314 and in SARD the PSR_305.

Figure 3.2 Splitting logic for upward offers. For downward offers the order of the arrows is inverted.

3.3 MSD Data Analysis

MSD is the programming phase of ancillary services market. Offer submission is done in a single sitting, while the selection takes place during the day, according to grid's needs and adjusting offers following criteria described in 1.5.3.3. From MSD it is possible finding offering behaviors patterns, resulting in different conclusions depending on the detail level. At first prices' extremes and their concentration is searched, afterwards a product differentiation is done. All the results from here on are obtained using specially created MATLAB scripts and using data formatted as Excel files, as described in the previous paragraph. The analysis starts from 2019 MSD overall price results. Later, the analysis takes into consideration different products on both MSD 2018 and 2019 dataset, resulting in worthy considerations over price distribution, total volumes and main market players, with a comparison between 2018 and 2019.

3.3.1 2019 MSD Prices

The analysis starts by considering at first global results with no product differentiation and daily detail. The purpose of this part is finding the statistical distribution of daily maximum accepted prices for upward services and daily minimum accepted prices for downwards services, for 2019. Here are considered only the extremes, since a more precise study would be useless, given the low granularity of this first dataset and the extended timeframe. This test is done for MSD only, since the market volume is larger than MB and gives more relevancy to this type of considerations. The MATLAB script used here has as input an Excel file containing 2019 MSD daily results, for every market zone. In the script it is possible to decide either if the search is for maximum accepted price for upward services or minimum accepted price for downward services. After that, the program elaborates Excel information through the simple statistic concept of Cumulative Distribution Function (CDF), for every market zone. In statistics, given a random variable X, $F_X(x)$ (i.e. CDF) is the probability that the random variable is equal or lower to a given specific value x of the variable. $F_X(x) = P[X \leq x]$ and $0 \leq F_X(x) \leq 1$.

Program's operation consists in taking all the offers that respect the decided criteria for every hour of the day and creating with them a price histogram. Price ranges have a width of 20 €/MWh from 0 to 500 €/MWh for sells and a width of 2 €/MWh from 0 to 40 €/MWh for purchases[35]. CDF is calculated from the histogram for every hour, and it equals 1 one there are 365 offers accepted at a price lower than the considered one. The opposite happens for downward offers. With this approach, it is important noticing that CDF equals to 1 from a certain point for a certain hour, only if at least one offer was accepted for that hour for every day of the year, otherwise maximum CDF value will be smaller than 1. With a simple approach, this script provides a first panoramic over price ranges and market solidity, by analyzing how distant from 1 are highest CDF values. Running the script, numerical results and 3D plots are obtained and described zone by zone in the following.

NORD

The first important thing is that for both upward and downward services, the CDF never reaches 1. This means that even in the largest Italian electricity market zone, due to the industrial presence in the North, not every day an offer is accepted on MSD. However, it must be considered that not all of the services in the market are accepted on MSD. Secondary Reserve, fees and sometimes also Tertiary Reserve are reserved on MSD for subsequent acceptance on MB. The maximum value for the CDF of upward services is 0.93 and fixed from the price range 40-60 €/MWh down, between 1 pm an 2 pm. High CDF values, greater than 0.88, are held between 11 am and 9 pm from the 60-80 €/MWh price range, with the exception of the time slot 4-6 pm, where for the same price range CDF is slightly minor.

[35] These price range division is the result of a trial and error process. Used division consent to highlight market trends in the best possible way.

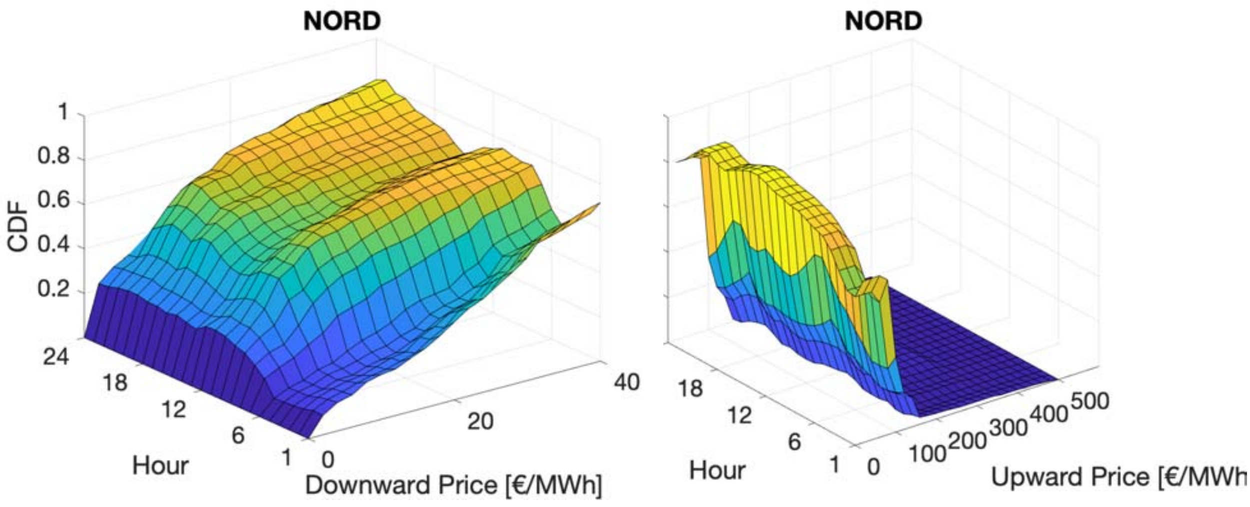

Figure 3.3 2019 NORD MSD CDF of extreme accepted offers.

However, the general trend is a moderate CDF increase for every relevant period, from 120-140 €/MWh price range and a steep increase from 80-100 €/MWh price range, passing from 0.3 to 0.7, in the central hours. This shows that highest daily accepted prices are mostly in this band.

The maximum value for the CDF of downward services is 0.83, in the 10 pm-12 am timeframe, between 40 and 42 €/MWh. Purchases' CDF is flatter than sells one, which means a more uniform distribution of daily lowest prices. In 2019, lowest price never was in the 0-2 €/MWh range and cumulated probability grows constantly with the price. Frequently, offers are accepted with a price far below the PUN, that for 2019 averaged at 52.32 €/MWh. On the average there is a considerable maximum price differential sells-purchases, that ranges between 38 and 60 €/MWh. NORD is not the market zone with highest differentials, but the one that guarantees the most solid base for Chapter 4 simulations. Found trends without great differences throughout the day, highlight what stated before, allowing the creation of a trustable business plan for new potential entries.

CNOR

Similar consideration can be done for CNOR. Even in CNOR the CDF never gets to 1 and both upward and downward cases follow the NORD model.

The highest of the CDF for upwards services is 0.66, in the 40-60 €/MWh price range for the 6-8 pm slot. From 8 am to 12 pm there is a step pattern in at 100-120 €/MWh, then a steep increase to achieve the highest values during 9-11 am and 7-9 pm intervals. In the first hours of the day, the CDF trend is comparable yet held on lower values, and never exceed 0.3.

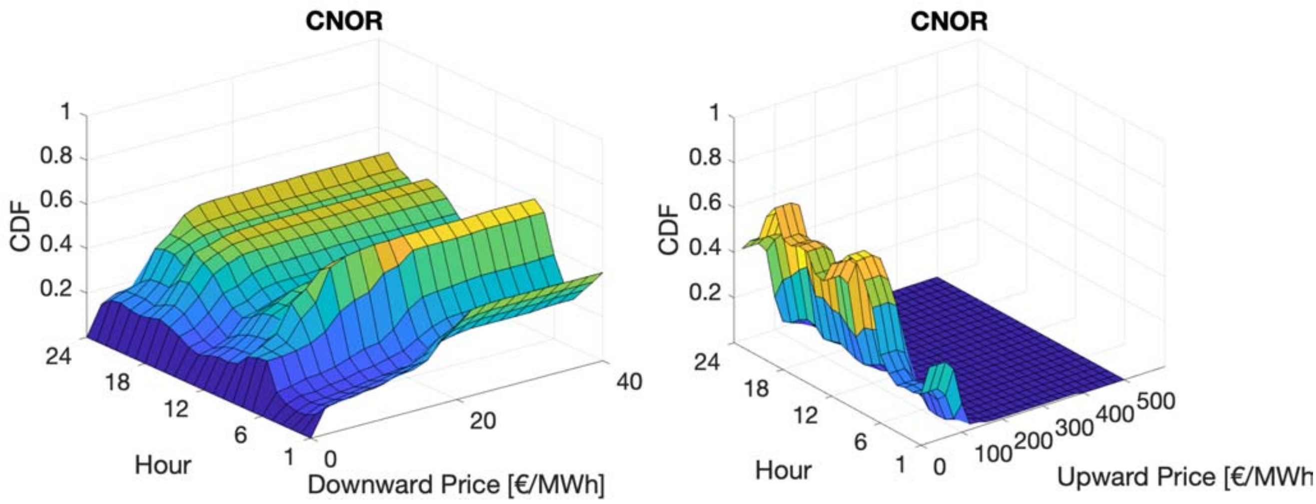

Figure 3.4 2019 CNOR MSD CDF of extreme accepted offers.

For purchases also, the trend is similar to NORD one. CDF grows more evenly, with a peak of 0.59 from 34-36 €/MWh between 7 am and 8 am, and close values in the adjacent time slots. Differently from upwards services, here the CDF has high values in the first hours of the day, then decreases during central hours and grows again from 5 pm to 11 pm.
The price differential is between 4 and 24 €/MWh, not only lower than NORD one but also based on a limited amount of data compared to NORD[36]. CNOR is similar to NORD in the general pattern, the problem is that reduced price differentials and market volumes[37], does not make this market zone as interesting as NORD.

CSUD

The CDF of CSUD has a different behavior compared to NORD and CNOR in terms of form, while as for the previous zones, it never hits 1.
Upward services CDF have a continuous increment, with slight differences among hours. The daily maximum accepted price can be found in almost all the price ranges, except for the last one, 480-500 €/MWh. The concentration of results grows quite uniformly, with a greater slope in higher price ranges. In the first hours, days without accepted offers are low, increasing the CDF maximum. From 12 am to 7 am, the cumulative probability remains close to values of 0.75-0.8 from 130-140 €/MWh and reaches its maximum of 0.85 in the 5-6 am slot. While the gradual increasing trend is maintained throughout the day, CDF values as well as the CDF slope, decrease from 7 am to 6 pm, to values of 0.60-0.65. During these hours, maximum CDF values are present starting from 60-80 €/MWh offers. There is

[36] Since CDF values are sensibly lower.
[37] This statement comes from ex-post consideration on more detailed market data, as presented in the following paragraphs.

another minor peak in 6-9 pm slot, similar to the first one but lower maximum values. The final hours of the day meet a general decrease of relevance, getting even to 0.35 as maximum CDF values.
On purchases side, the CDF curve is flat, with the first six hours not presenting a relevant number of data, getting to maximum value of 0.13. From 6 am on, curve's variations are limited for every hour from the price range of 18-20 €/MWh, with variations of less than 0.1, but mostly limited to 0.05, as the price goes on. This pattern is common, while CDF maximums range relevantly, from 0.27-0.33 to 0.40 from 10 pm to 12 am.
Price differential in most statistically relevant timeframes is 122-110 €/MWh, with the clarification that data validation is lower for downward services. CSUD is an interesting case study for the price differentials and for real time balancing needs, described in MB analysis. RES penetration, mostly PV, causes upward maximum prices to fall in the central hours of the day but introduces the need for more reserve margins during the other hours and the need for downward services, with competitive prices.

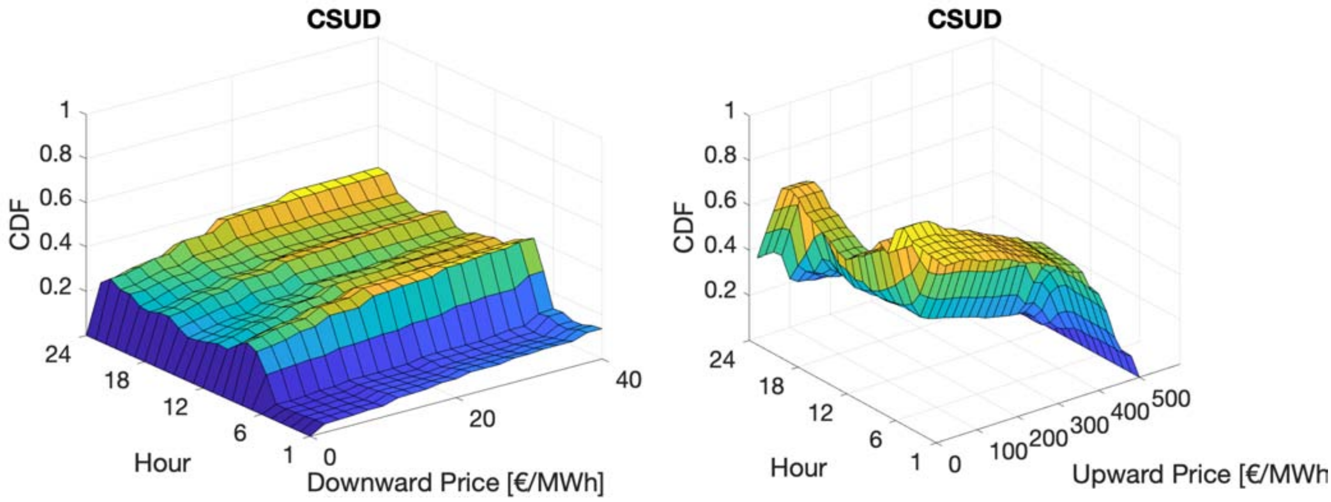

Figure 3.5 2019 CSUD MSD CDF of extreme accepted offers.

SUD
SUD result shows a singular situation: upward services CDF displays the highest values of all market zones, while there seems to be no need for downward services, as CDF maximum value is a 10^{-3} order of magnitude.
The sells' curve has step pattern and achieves its maximum from either 60-80 €/MWh or 80-100 €/MWh, so that this must be considered the most likely acceptance band. Maximum values are greater than 0.85 for every hour and even greater than 0.9 in many cases. Nothing accurate can be said over price differentials since purchases data are not relevant.

SUD relatively low upward prices can be justified by the great need for these services. It seems that the strong RES penetration cannot provide proper reserve margins, opening the field to traditional flexible plants.

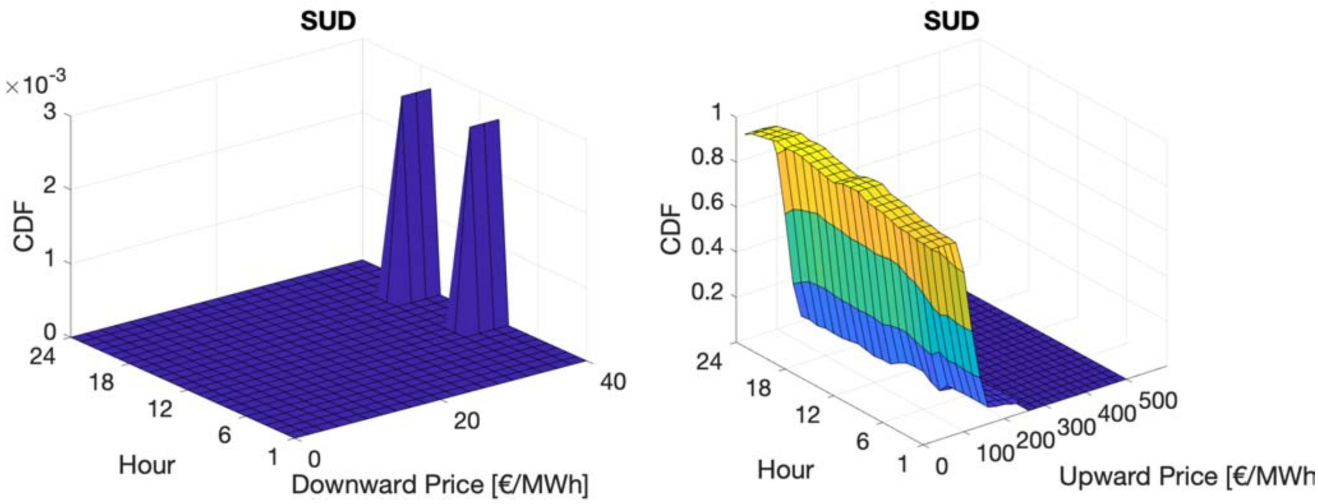

Figure 3.6 2019 SUD MSD CDF of extreme accepted offers.

SICI

SICI situation is similar to SUD's one, with a step pattern on sells' CDF that eventually reaches high values and no relevancy on purchases side. What happens here exactly follows SUD case also numerically.

SARD

SARD relevancy is scarce, since operated in islanding for ancillary services, using only essential plants and mandatory provisions.

From this first overlook, CSUD presents the more advantageous scenario in terms of price differentials, with a high concentration of downward offers around 0 €/MWh and upwards offers being often accepted over 400 €/MWh. NORD has lower differentials but more consistent values of CDF, which means for chances of trading even if with worse economic conditions. Trends of the other market zones follow either one CSUD or NORD patterns but definitely lower CDF values, which compromise for now, their relevance for the work.

3.3.2 MSD Volumes

After a first look at prices distribution, now the focus is on trade volumes on MSD (ex-ante only, without MB). Analyzing trade volumes allows to identify possible trends throughout the years, finding whether or not using energy storage systems could improve the current situation and lower system's costs. Given the scarce relevance of SUD, SICI, CNOR and SARD for the case study of Chapter 4, only NORD and CSUD are extensively discussed here. The analysis of volumes on MSD is conducted by comparing 2019 and 2018 traded quantity, from Excel files with hourly detail described in 3.2. The focus is on 2019, while 2018 is used as a comparison. Two MATLAB scripts, one per year, are created for this purpose. 2018 script starts and loads Excel files for the chosen zone. At first data are filtered by the script according to the purpose of the search, either for BID or OFF. Since the target is finding volumes of accepted offers, the script further filters Excel data and considers only ACC offers and the AWARDED_QUANTITY_NO column, since no analysis is conducted over the adjustment process that an offer goes through. At this point, the program separates different products with accepted offers on MSD, AS and GR[38], and calculates:

i. monthly accepted quantities for every product;

ii. total monthly accepted quantity on MSD.

Results are saved in a MATLAB array and converted in an Excel file for easier reading. The same process is operated for 2019 and results are eventually plotted in a single chart, for comparison. Total yearly quantities of every product and the cumulated volume are reported for each year. The algorithm automatically iterates for every zone and for both upward and downward services. NORD is the market zone with the highest volumes and even if the price differentials are lower than in other zones, the industrial network, the presence of metropolitan cities and the population density make NORD an interesting benchmark for business cases.

CSUD's volumes are lower than NORD ones, but the high RES presence, still on an increasing trend, and the critical grid's structure, offer now a big chance for thinking about innovative solutions and digitalization enhancement. For trade volumes values, specific tables are presented, figures instead aim to characterize the volume trend. For this reason scales vary a lot among different products.

[38] GR1, GR2, GR3 are considered as a single product since they are distinguished only due to the operators' possibility of dividing available capacity. In addition, data do not provide more accurate information circa the actual service GR offers are used for, making it useless considering them as three different products.

NORD

Downward overall MSD volume grew in 2019 to 5143 GWh while it was 4884 GWh in 2018. In detail, in 2019, AS passed from 347 to 417 GWh and GR went from 4537 to 4726 GWh. The difference is relatively more relevant for AS with an increase of 20% compared to the 4% of GR. At a first glance, total trends seem to be very different between 2019 and 2018. The reality is that 2018 shows a seasonal behavior well defined, with spring and summer months requiring more downward power, due to the seasonal RES predominance. The same is for 2019 but with an unexpected high spike in June and a low one in July. With product differentiation it is possible getting to the same considerations.

For upward product there was a demand inflexion going from 4124 GWh in 2018 to 3755 GWh in 2019. AS went from 2730 to 2314 with a 15% decrease while GR slightly grew by 1% from1394 to 1414 GWh. From monthly analysis some analogies are found with downward products. 2018 trend reflects predictable demand behavior, with more power required during fall due to the reduced renewable energy supply. In this aspect the two datasets are similar, except for the aforementioned June spike that is present also here. Different products follow the general trend. The presence of a general trend and possible singularities is an opportunity for storage systems. Indeed, an ESS could help facing these events without the need for high prices and overall cost increase for the TSO. Moreover, a relevant power is required for AS upward services. This means that traditional plants offer to move from their resulting position on energy market, under the technical minimum, to the technical minimum. It is true that this is an opportunity for flexible thermal plants to stay on the market but the stress on machineries forced to work at partial load and low efficiency is high. Assessing the economic feasibility of storage systems would drive future investments in the direction of limiting the operating range of flexible thermal plants to the maximum efficiency load. These plants could charge the storage system during partial load periods and use the energy to provide ancillary services and therefore to avoid frequent starts and stops. Actually, this could represent a possibility also for efficient coal plants at least for the transition period. The column '*similar trend?*' reports the result of the qualitative comparison between 2018 and 2019 trends that can be done by referring to the charts presented in the next page.

Table 3.1 NORD MSD volumes resuming table.

	Downward Volumes [GWh]				**Upward Volumes [GWh]**			
	2018	**2019**	**Variation [%]**	**Similar trend?**	**2018**	**2019**	**Variation [%]**	**Similar trend?**
GR	4537	4726	+4	Y	1394	1414	+1	Y
AS	347	417	+20	Y	2730	2314	-15	Y

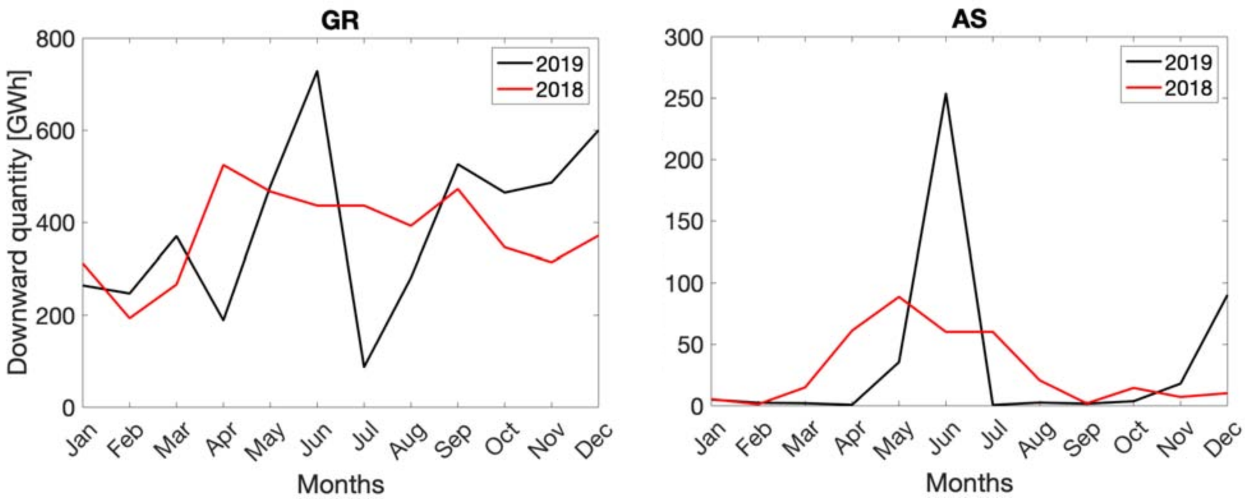

Figure 3.7 2018 and 2019 NORD MSD downward monthly volumes of GRs and AS.

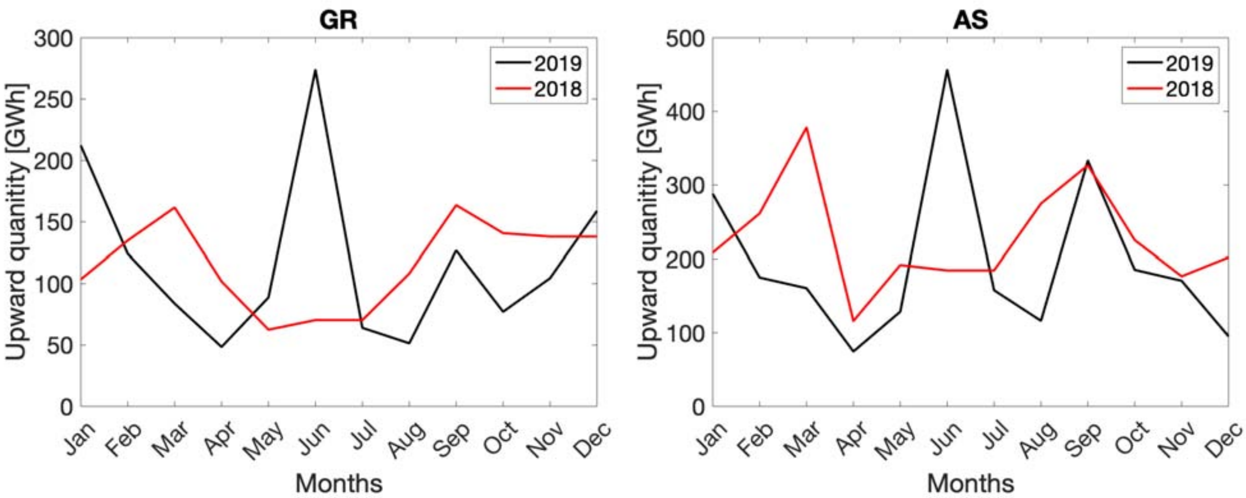

Figure 3.8 2018 and 2019 NORD MSD upward monthly volumes of GRs and AS.

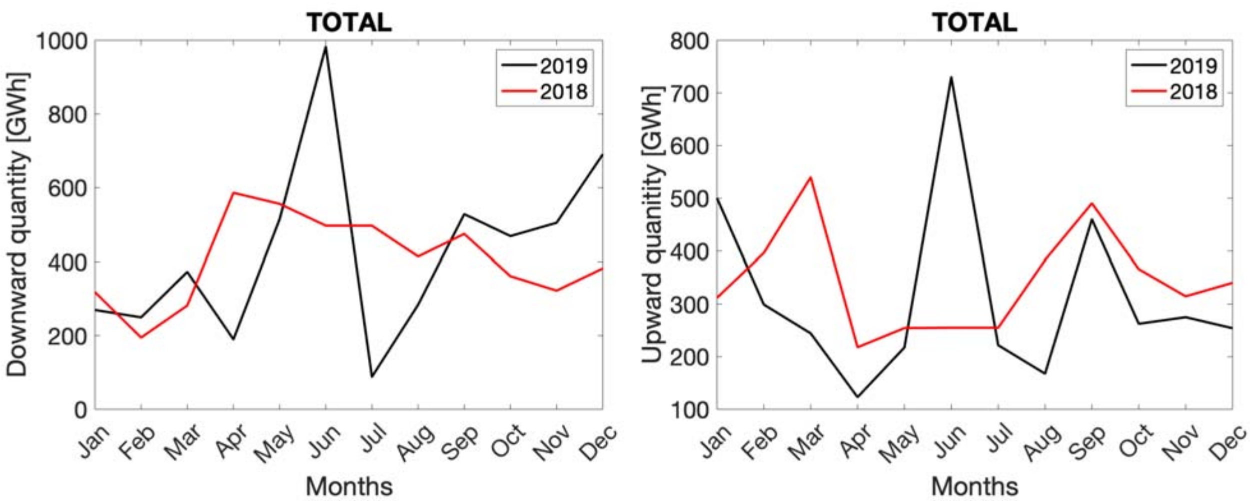

Figure 3.9 2018 and 2019 NORD MSD total downward (left) and upward (right) monthly volumes.

CSUD

Starting from downward volumes, CSUD meets a sensible increase in 2019, from 212.9 to 350.9 GWh. The relative growth is even more significant, with a 94% increase from 11.6 to 22.5 GWh for AS and a 63% increase from 201.3 to 328.4 GWh for GR. The general trend is a higher demand during summer because of the RES action, but in 2019 a general demand uplift during off peak periods happened. The idea is that the raising competitiveness of RES technologies is leading to a year-long use.

Upwards services demand grew from 1190 to 2286 GWh. AS demand more than doubled; with a 103% increase it passed from 1087 to 2209 GWh. On GR there was a limited inflexion in absolute terms, from 103 to 77 GWh. Except for GR trend, which is held on limited volumes and therefore highly volatile, other trends are perfectly aligned. Fall and winter peaks are followed by a smooth decrease in the central months, with RES full exploitation.

CSUD is the clear example of how increasing RES production can create new problems to the grid. If on the one hand the continuative production is necessary to achieve CEP targets, on the other hand it is necessary being able to handle any arising issue. From CSUD's volumes analysis, the increase of ancillary services demand is relevant throughout the year. The need for upward services, for instance, increases hand in hand with the penetration of renewable power. Possibilities for storage systems here can be found by following the same logic stated for NORD. The main difference here is the wider presence of renewable sources hence more interesting price differentials. If paired with cost effective ESS, renewable generation could grow even faster than it is doing now, accompanied by traditional plants equipped with ESS to limit load shifts during the transition.

Table 3.2 CSUD MSD volumes resuming table.

	Downward Volumes [GWh]				**Upward Volumes [GWh]**			
	2018	**2019**	**Variation [%]**	**Similar trend?**	**2018**	**2019**	**Variation [%]**	**Similar trend?**
GR	201.3	328.4	+63	Y	103	77	-21	Y
AS	11.6	22.5	+94	Y	1087	2209	+103	Y

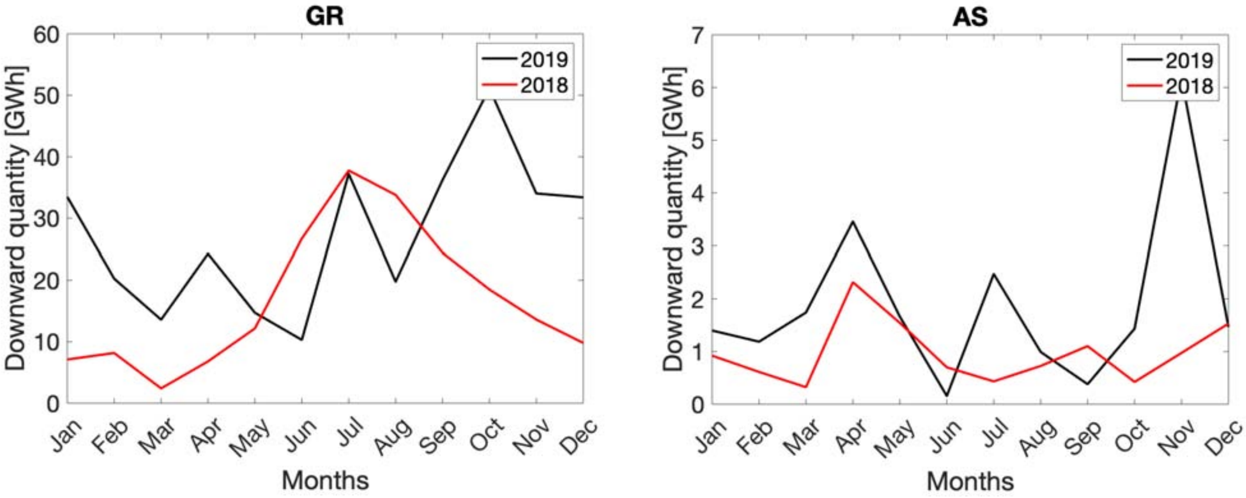

Figure 3.10 2018 and 2019 CSUD MSD downward monthly volumes of GRs and AS.

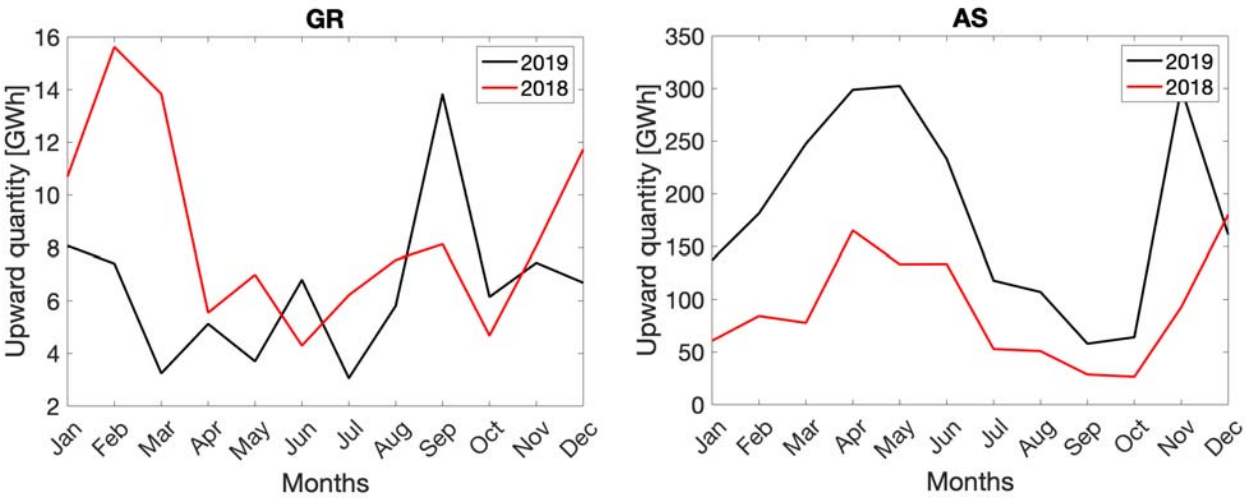

Figure 3.11 2018 and 2019 CSUD MSD upward monthly volumes of GRs and AS.

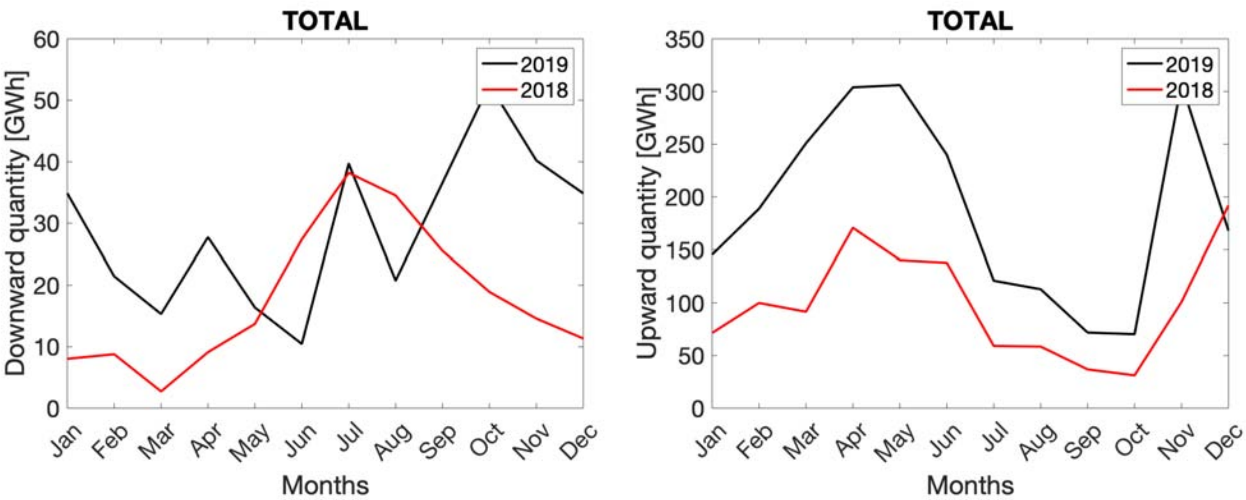

Figure 3.12 2018 and 2019 CSUD MSD total downward (left) and upward (right) monthly volumes.

3.3.3 MSD Hourly Results

A further analysis on MSD patterns is conducted with two more MATLAB scripts. The basic logic is similar to the previous one. For both 2018 and 2019, for every zone, the Excel file is loaded, only ACC offers considered and iteratively filtered by product and by offer's purpose. Here the granularity is increased, providing hourly results. For every hour of the year and for every product, are calculated:

i. the total accepted quantity;

ii. mean price weighted on accepted quantity.

Results are saved in an Excel file to facilitate the reading. For 2019 only, results are plotted with hourly detail, using black bars for quantity and red dots for prices. Hourly volume is obtained as the sum hour by hour of the awarded quantity of a certain product. The hourly mean weighted price is calculated by considering the awarded price and the awarded quantity as:

$$P_i{}^k = \frac{\sum_j \mathrm{AWARDED\_PRICE\_NO}_j{}^k \cdot \mathrm{AWARDED\_QUANTITY\_NO}_j{}^k}{\sum_j \mathrm{AWARDED\_QUANTITY\_NO}_j{}^k},$$

where i indicates the hour, j the single offer and k the market zone separately for every product. Resuming results of both datasets are eventually reported and discussed, for NORD and CSUD. Only 2019 GRs charts are presented, since they are functional to next Chapter's simulations. AS results are resumed in the tables.

NORD

Analyzing downward trends, at a first look is clear that for almost every hour there accepted offer for GR, while AS chart is more scattered. June's spike as described in 3.3.2 is observable by the presence in the month, both for AS and GR, of the day with the highest trade volume and of the highest density of volume bars. The high volumes traded in June causes prices to fall to values close to 0 €/MWh. Mean GR price results 30.8 € in 2019, with a 4% decrease from 2018 32.1 €/MWh, also thank to the June situation. For AS, instead, June spike is not enough to lower price under 2018 level of 8.2 €/MWh, and affected by generally sparse accepted offers, the mean price settles at 10.5 €/MWh.

For upward offers the pattern is very clear from the charts. There is a high-density zone for prices under 90 €/MWh, resulting in a mean price of 87.5 €/MWh for GR, lower than 2018 mean value of 97 €/MWh, and of 92.5 €/MWh for AS while it was 97.5 €/MWh in 2018. It is interesting how the bigger upward volume prevents price spikes in correspondence to quantity spikes, as it happens instead for downward services.

Mean price differential is 56.7 €/MWh in 2019 while it was 65.4 €/MWh in 2018 for GR, 82 €/MWh in 2019 and 89.3 €/MWh in 2018 for AS. Differentials reduction is sensible and a normal economic consequence of market players number increase, but still opening to new business opportunities. Current differentials and market dimension would justify the opening to the introduction of aggregators, including DR, storage systems and small-scale renewable energy plants.

Table 3.3 2019 and 2018 NORD MSD mean hourly prices.

	Downward Mean Price [€/MWh]		Upward Mean Price [€/MWh]	
	2018	2019	2018	2019
GR	35.5	31.2	98.2	95.6
AS	10.9	10.2	108.3	100.9

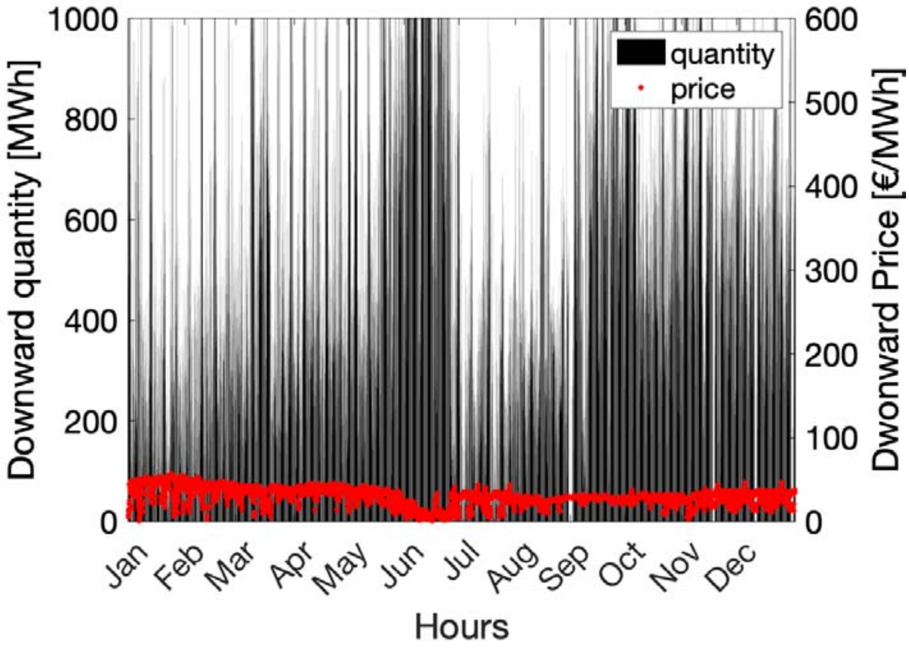

Figure 3.13 2019 MSD NORD GR downward hourly results.

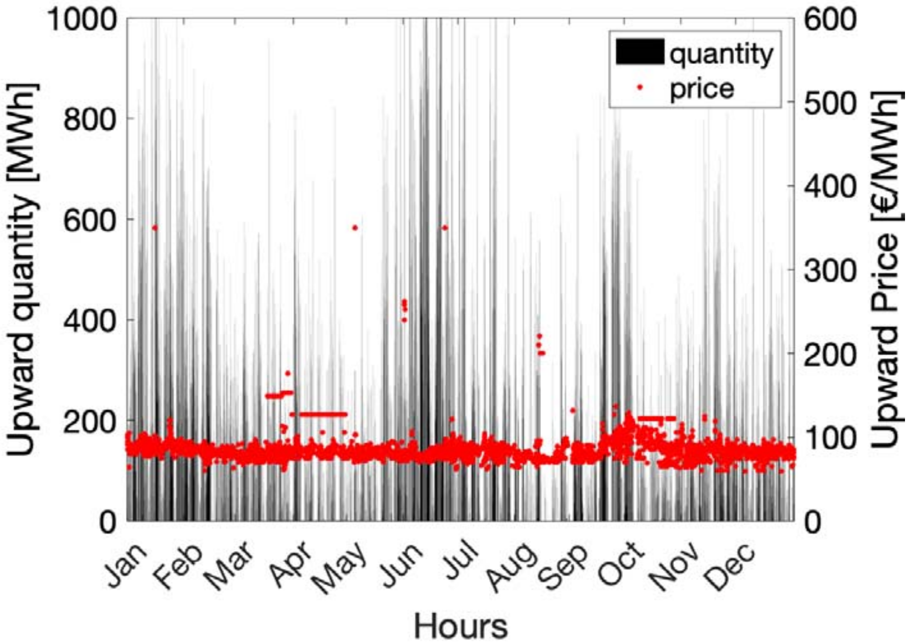

Figure 3.14 2019 MSD NORD GR upward hourly results.

CSUD

GR downward offers present a compact distribution around 30 €/MWh, resulting in a mean value of 32.5 €/MWh that was equal to 33 €/MWh in 2018. AS has a low relevance since based on low volumes, as can be expected from the sparse chart, 2019 mean price is 22.3 €/MWh and it was 3.5 €/MWh in 2018.

The opposite happens for upward offers, where GR mean price decrease for GR from 121 €/MWh in 2018 to 99.8 €/MWh in 2019 and AS price increases to 235.9 €/MWh from 2018 result of 173.3 €/MWh. Here results highlight a trend, due to large dimension of AS market.

Mean differentials are, respectively for AS and GR, 213.6 €/MWh and 67.3 €/MWh in 2019, 169.8 €/MWh and 87 €/MWh in 2018. Following the considerations done in the previous paragraph, the implementation of ESS can help during the transition towards renewable but can also be an investment choice as a stand-alone plant for the future, given the high differentials. As of today, the presence of AS that cannot be provided by ESS, represent a barrier for the entrance, but following the general pattern of traditional plant dismission, currently AS volumes may need to be provided by new forms of flexibility.

Table 3.4 2019 and 2018 CSUD MSD mean hourly prices.

	Downward Mean Price [€/MWh]		**Upward Mean Price [€/MWh]**	
	2018	**2019**	**2018**	**2019**
GR	35.5	31.2	98.2	95.6
AS	10.9	10.2	108.3	100.9

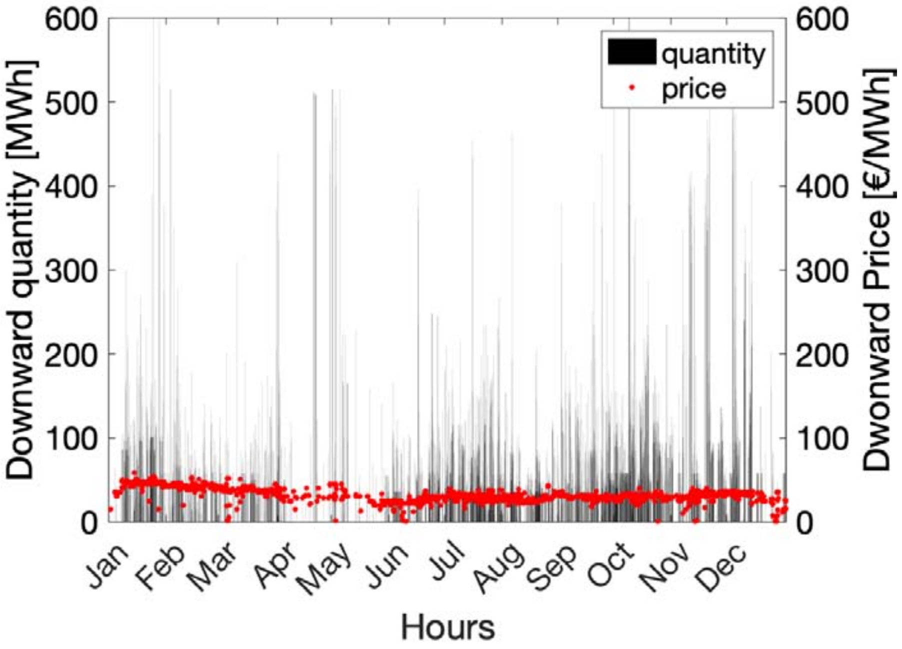

Figure 3.15 2019 MSD CSUD GR downward hourly results.

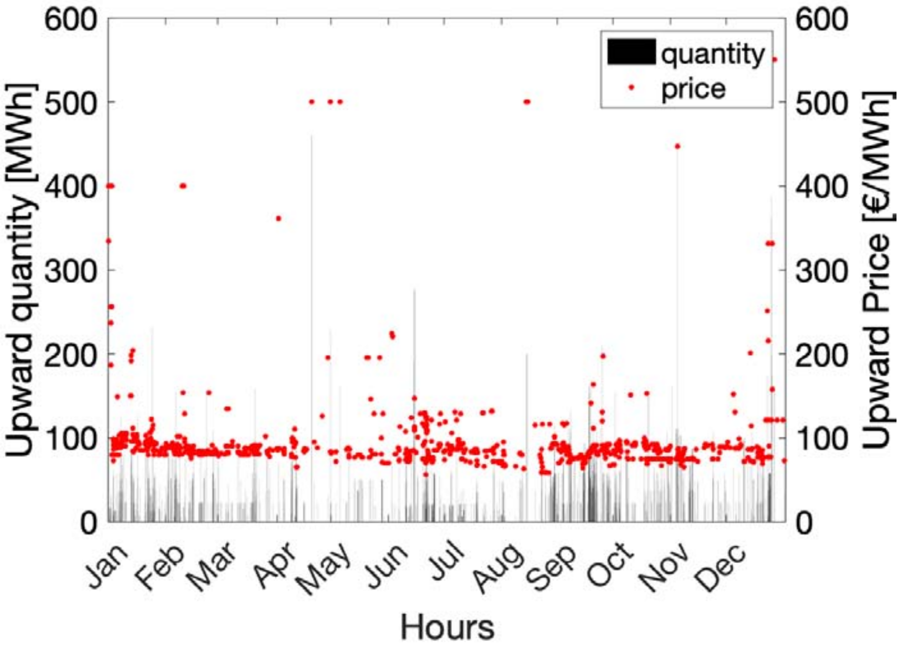

Figure 3.16 2019 MSD CSUD GR upward hourly results.

3.3.4 MSD Points of Exchange Analysis

Other insights that can be extrapolated from data are the busiest points of exchange (i.e. *Punti di Scambio Rilevanti*, PSR), the companies that operate in there and the UPs used. A MATLAB script is created for 2019 data only. Using the same filtering process already described, hourly accepted offers, either for upward or downward services, without product distinction and for every market zone, are gathered from the respective Excel file. After that, for every PSR is calculated:

i. the total quantity traded in 2019;
ii. its percentage weight on the total volume traded in the market zone;
iii. companies and most relevant UPs.

The market concentration level is evaluated. It is important to remember that PSR is not a geographical concept, but rather reflects the algorithm's logic of the grid optimizer. From this analysis it is possible understanding if and which companies dominate the market, but mostly which types of units are used and their locations. The exact location of UPs is found by additional web research, starting from UP names.

NORD

For easier reading, results are presented as tables and then discussed. The aim is to find which locations need the most ancillary services and either or not the intensive trade leads to prices' uplift. Anyway, it is possible finding most operating units and their locations, shaping an idea of where proposing targeted investments would possibly be advantageous.
There is a clear predominance of thermoelectric plants for the provision of ancillary services in NORD. For downward services more than 50% of total volumes is traded in two of the forty PSRs, while for up a concentration of 33.2 % is reached within the first two PSRs, out of the 43 totally operated. From this data, the greatest part of MSD is covered using combined cycles, often resulting from repowering of coal plants. In some cases -Turbigo plant for instance-, if the plant is composed by different sections, only the combined cycle one is active for flexibility need. Hence, as already said, as a first approach to ESS, a chance could be the use of storage to increase thermoelectric performance, and in the meantime promote aggregators participation. It is important saying that prices in the busiest nodes are exactly aligned to the mean trend of the region, hence it is deemed that offers selection reflects actual grid's needs.

Table 3.5 2019 NORD downward services most operating UPs.

PSR_	Relative Share [%]	UP Type	UP Location	Operator
283	36.5	Hydroelectric	Roncovalgrande (VA)	ENEL PRODUZIONE S.pA.
		Combined Cycle	Livorno Ferraris (VC)	EP PRODUZIONE S.p.A.
		Thermoelectric[39]	Ostiglia (MN)	EP PRODUZIONE S.p.A.
		Combined Cycle	Torviscosa (UD)	EDISON S.p.A.
100	14.2	Combined Cycle	Vado Ligure (SV)	TIRRENO POWER S.p.A.

Table 3.6 2019 NORD upward services most operating UPs.

PSR_	Relative Share [%]	UP Type	UP Location	Operator
283	24.2	Hydroelectric	Roncovalgrande (VA)	ENEL PRODUZIONE S.pA.
		Thermoelectric	Ostiglia (MN)	EP PRODUZIONE S.p.A.
		Combined Cycle	Turbigo (MI)	IREN ENERGIA S.p.A.
118	9	Thermoelectric (NG)	Sermide (MN)	A2A S.p.A.

CSUD

With the same aim of NORD analysis, are now presented CSUD results. Due to the higher RES presence CSUD has a high trades concentration for both upward and downward service within 2/3 PSR out of the 12 totally operating. The trend is clear: only flexible traditional plants are able to participate to MSD, with the only exception of Civitavecchia supercritical coal plant. Also for CSUD, the adoption of ESS if economically competitive, could be a chance to enhance flexibility performance and to pave the way for new forms of flexibility, given continuous RES increase. Like it is for NORD, the busiest plants' offers are perfectly aligned to zonal mean values and therefore no market distortion is procured by the local need for ancillary services.

[39] Mix of oil and Natural Gas (NG) used as fuel.

Table 3.7 2019 CSUD downward services most operating UPs.

PSR_	Relative Share [%]	UP Type	UP Location	Operator
287	38.6	Combined Cycle	Aprilia (LT)	SORGENIA S.pA.
		Combined Cycle	Sparanise (CE)	AXPO S.p.A.
		Combined Cycle	Napoli (NA)	TIRRENO POWER S.p.A.
		Combined Cycle	Taverola (CE)	SET S.p.A.
318	26.6	Thermoelectric (NG)	Gissi (CE)	A2A S.p.A.
56	26.6	Thermoelectric (CO)	Civitavecchia (RM)	TIRRENO POWER S.pA.

Table 3.8 2019 CSUD upward services most operating UPs.

PSR_	Relative Share [%]	UP Type	UP Location	Operator
287	23.7	Combined Cycle	Aprilia (LT)	SORGENIA S.pA.
		Combined Cycle	Sparanise (CE)	AXPO S.p.A.
		Combined Cycle	Napoli (NA)	TIRRENO POWER S.p.A.
		Combined Cycle	Taverola (CE)	SET S.p.A.
318	22.7	Thermoelectric (NG)	Gissi (CE)	A2A S.p.A.

3.4 MB Data Analysis

MB is the part of ancillary services market with sittings opened till one hour before the first delivery hour of a sitting's competence timeframe. In MB, offers for real-time balancing (GR) are selected and accepted and previously reserved Secondary Reserve (RS), and fees for Switching-On (ACC) and Changing the Setup (CA) of traditional fuels plants are eventually accepted, according to grid's needs. Here the relevant period is the quarter of an hour but, for simplicity, results will be reported with hourly detail[40]. MSD volumes are bigger than MB ones, but for the different nature of the two markets, differentials are bigger on MB. For this reason, the implementation of ESS would be more profitable if operating on MB, as simulated in Chapter 4 case study. The idea is that the need for responsive flexibility on MB is even higher than MSD one, favoring ESS adoption. The analysis is conducted starting from data gathered as described in 3.2, then they are processed through a set of MATLAB scripts similar to those used for MSD. Here it is not explicit the analysis over most active UPs, since those UPs are for the largest part the same as MSD. Rather, the fees situation is presented. The prices accepted for these products, that theoretically should just cover technical costs of traditional fuels plants, are proved to be far exceeding their purpose and to be following market logics [6]. For consistency, only NORD and CSUD results are here presented. As for MSD, only offers awarded by the market are considered, since no detailed analysis is conducted on the adjusting process.

3.4.1 2019 MB Prices

At first, the CDF for 2019 MB prices is searched by the implementation of the same methodology and criteria used for MSD: the CDF is plotted considering daily maximum accepted prices for upward products and minimum ones for downward products, if present. The only difference is that since MB is the market used for Chapter 4's simulations, product differentiation is applied even in this first step. Fees results are not presented in this paragraph, since CDF is not relevantly applicable on fees. Price discretization is done using 5 €/MWh partitions, for both downward and upward services[41]. All of the products are discussed while only GR offers charts are presented.

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[40] Mix of oil and Natural Gas (NG) used as fuel.

f hour but the reported values consider the full hour.

[41] The intervals width was decided, after trials with different choices, as the best alternative to highlight price trends.

NORD

Analyzing downward offers, the first relevant thing is the achievement of CDF values close to 1 (0.85 or higher) for every hour, meaning that at least one offer was daily accepted on MB, hence outlining a solid market. For RS and GR, the minimum price never fell in the 0-5 €/MWh interval, the CDF has a steep increase in the following interval and then a smoother slope. The CDF of GR overcomes 0.85 in the 25-35 €/MWh range in the first hours and in the 30-40 €/MWh range in the rest of the day, while for RS for every hour of the day 0.85 level is reached in the 20-30 €/MWh range. AS CDF, instead, get to 0.7 only for 10 pm slot and has a peaks and trough form. The greatest part of minimum accepted offers has a price lower than 15 €/MWh.

For upward services, only the CDF of GRs overcomes 0.85 for every time slot. Some daily maximums are present for prices even higher than 200 €/MWh yet for the greatest part they are at a price under 100 €/MWh. From 75-65 €/MWh the CDF is higher than 0.85 for every hour of the day. Similar considerations for RS trend, but 0.85 is exceeded only in 6-7 am and 1-6 pm slots. AS has a low acceptance rate that reflects in low CDF values, under 0.3 for most of the hours.

As of today, UVAMs are only enabled for GR products. Interesting differentials can be achieved on MB, also relying on market solidity, with daily accepted offers.

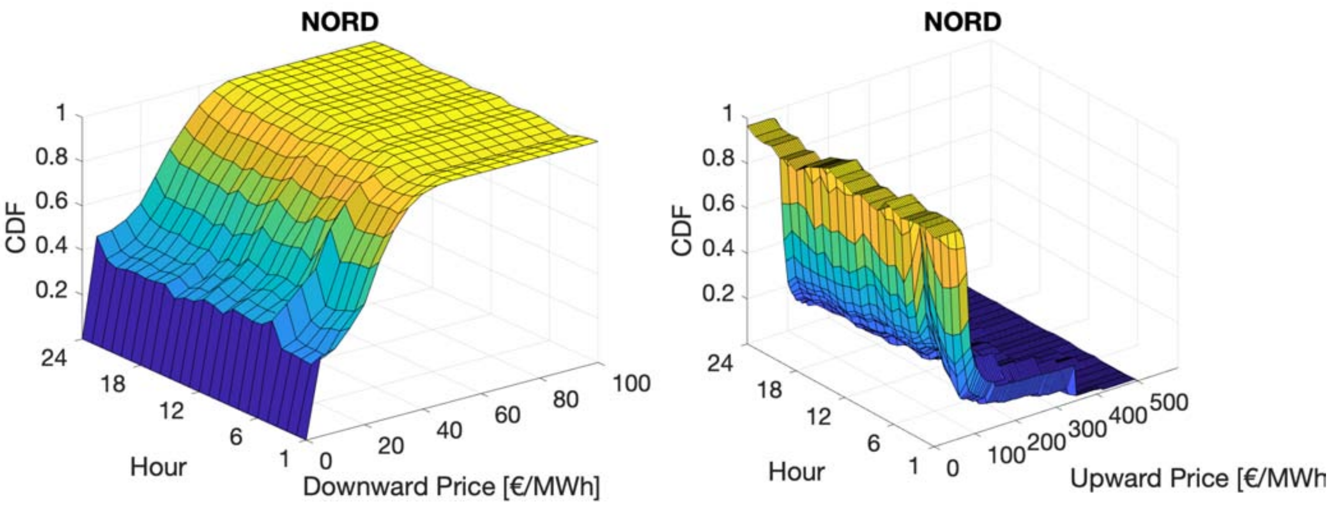

Figure 3.17 2019 NORD MB CDF for GR accepted downward (left) and upward (right).

CSUD

For downward GR, the CDF follows a trend similar to NORD one, with no minimums in the 0-5 €/MWh range, a steep increase in the following one and then a continuous gradual growth, achieving anyway lower values compared to NORD. From 30-40 €/MWh band, CDF's values are close to their maximums of 0.7-0.85. For 3-7 am slots, almost the whole CDF increase happens in the 5-10 €/MWh price range. RS follows the same path, with the difference that maximum CDF are reached in the first part of the day, 7-9 am, and in the last one, 7 pm-12 am, and never exceed 0.77. AS has a scarce relevance.

Upward CDF for GR product gets highest values in the first and final part of the day, but it is interesting that the maximum accepted offers are distributed throughout the whole price range, from 500 €/MWh down, and they are concentrated around 100 €/MWh. Differently, for RS, only for a limited set of hours the maximum is higher than 100 €/MWh, in the 6-9 am and 3 pm- 12 am slots. AS's CDF has a scarce relevance even for upward offers.

GR is required all day long due to the unpredictability of RES production, while upward GR has its peak during the off-peaks period of RES. The implementation of ESS would be possible thanks to this trend and therefore able to hedge possible issues coming from increasing RES penetration.

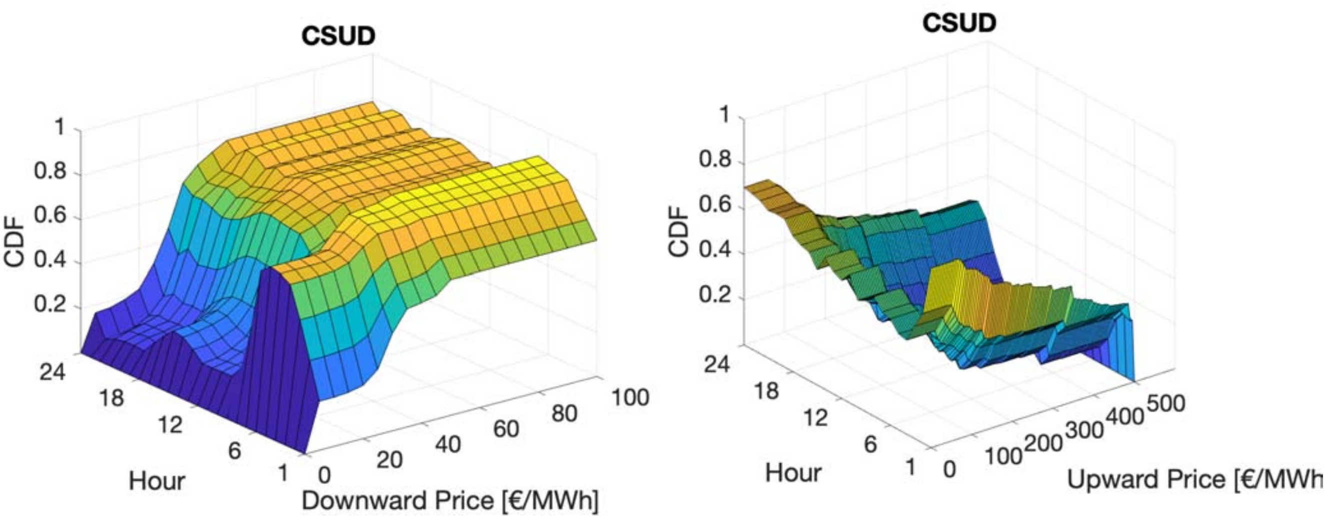

Figure 3.18 2019 CSUD MB CDF for GR accepted downward (left) and upward (right).

3.4.2 MB Volumes

Following the same logic as MSD, MB market volumes are now analyzed. The scripts used are analogue to those used for MSD, but here the GR offer has four variants. With no need to describe again the algorithm operated in MATLAB, the final result is:

i. monthly accepted quantities for every product.

Differently from MSD analysis, no plot is provided for total volumes, for the reason that going closer to real-time the focus must be more on single product's pattern. Once again, products are differentiated in AS, RS and GR, with the focus on GR offers, since they are the only that can be submitted by UVAMs. For fees' nature -they do not underly a quantity- they are not considered in this paragraph. A comparison is done, like it happened for MSD, with 2018 results. In this case are presented GR, RS and AS charts, to give grater relevance to volume trends and to find if there is an ongoing pattern between 2018 and 2019.

NORD

For 2019's downward services, the trend is a volume increase on MB compared to 2018. The interesting thing is that 2018 and 2019 follow the same pattern, but with higher volumes in 2019, for every product. GRs top peak is in June for 2018 and translated in July for 2019, while the lower peak is in October for 2018 and November for 2019. GRs volume increased in 2019 by the 28%, from 5086.3 to 6514 GWh. For RS top and lower peaks are inverted, with June lower peak. 2019 volume is 1472 GWh, with a 16% growth compared to the 1272.5 GWh of 2018. AS chart has the same trend as 2018 one, and it is similar in the form to 2019's MSD. The June peak is accentuated in 2019 and the total volume increases by the 53% passing from 64.7 to 98.9 GWh.

Differently from downward services, in 2019 there is a demand reduction for GR and RS upward services. The inflexion is respectively the 22% for GR, from 1157 to 892 GWh, the 7% for RS, from 824.6 to 770.3 GWh, while a small growth by the 8% from 204.7 to 221.5 GWh happens for AS. 2019 GRs' pattern is like 2018 one, with a summer peak, but held on lower volumes. Moreover, the 2018 November peak is absent. RS trend in 2019 is similar to the respective downward trend, with a lower peak in July, different from the 2018 peaks and trough trend. AS graphs are comparable, with 2019 demand increase justified by the high June peak.

Volumes analysis confirms MB market solidity and GR comparable trends suggest the possibility to use 2018 as a reference for possible case study to be applied to 2019 dataset. Described tendencies result from RES and DER integration considerations, while volumes inflexion in 2018 cannot be attributed to systemic effects, due to the limited timeframe.

Table 3.9 NORD MB volumes resuming table.

	Downward Volumes [GWh]				Upward Volumes [GWh]			
	2018	**2019**	**Variation [%]**	**Similar trend?**	**2018**	**2019**	**Variation [%]**	**Similar trend?**
GR	5086.4	6514	+28	Y	1157	892	-22	Y
RS	1272.5	1472	+16	Y	824.6	770.3	-7	Y
AS	64.7	98.9	+53	Y	204.7	221.5	+8	Y

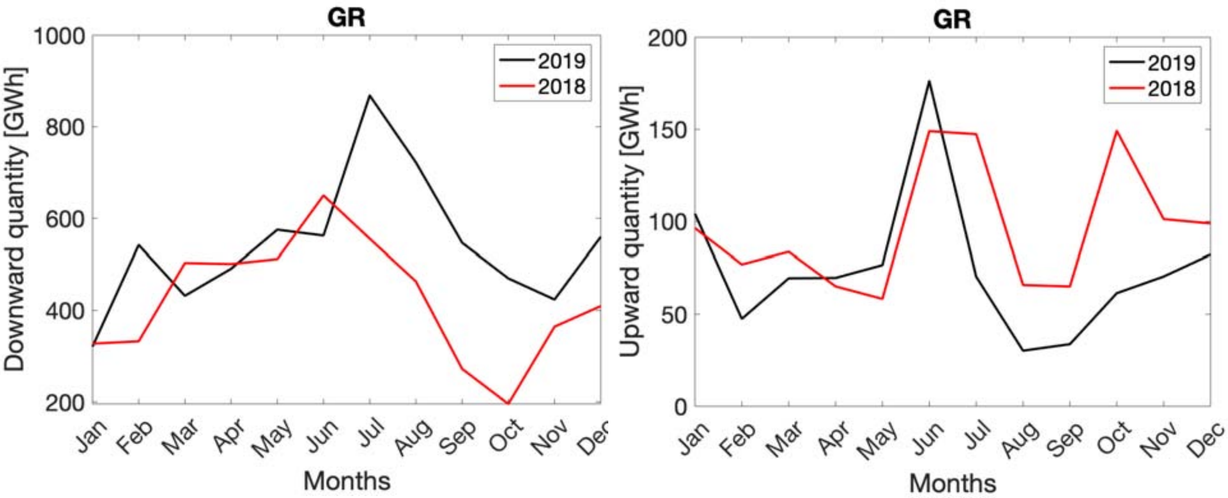

Figure 3.19 2019 and 2018 NORD MB downward (left) and upward (right) accepted GR volumes.

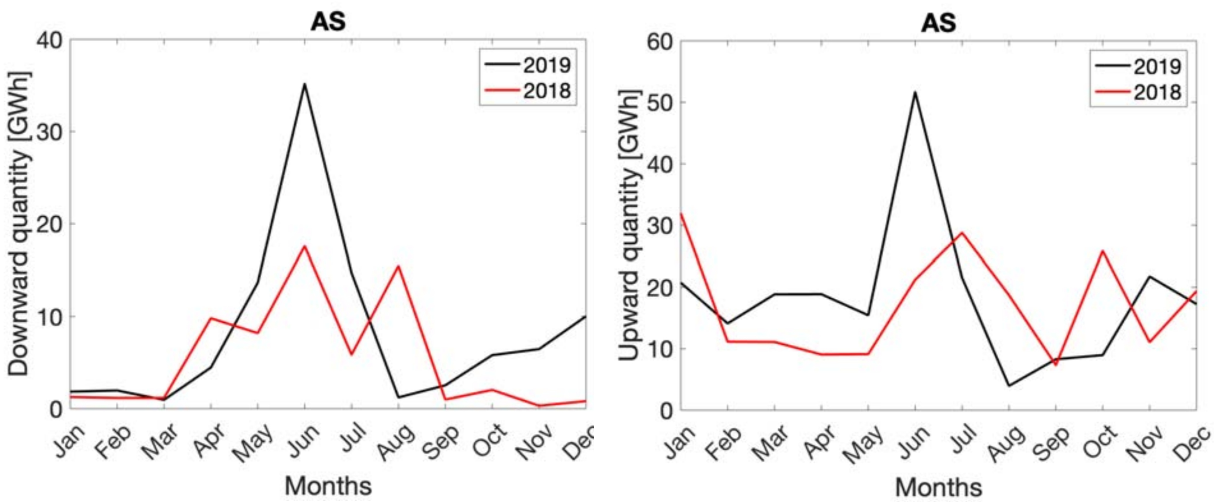

Figure 3.20 2019 and 2018 NORD MB downward (left) and upward (right) accepted RS volumes.

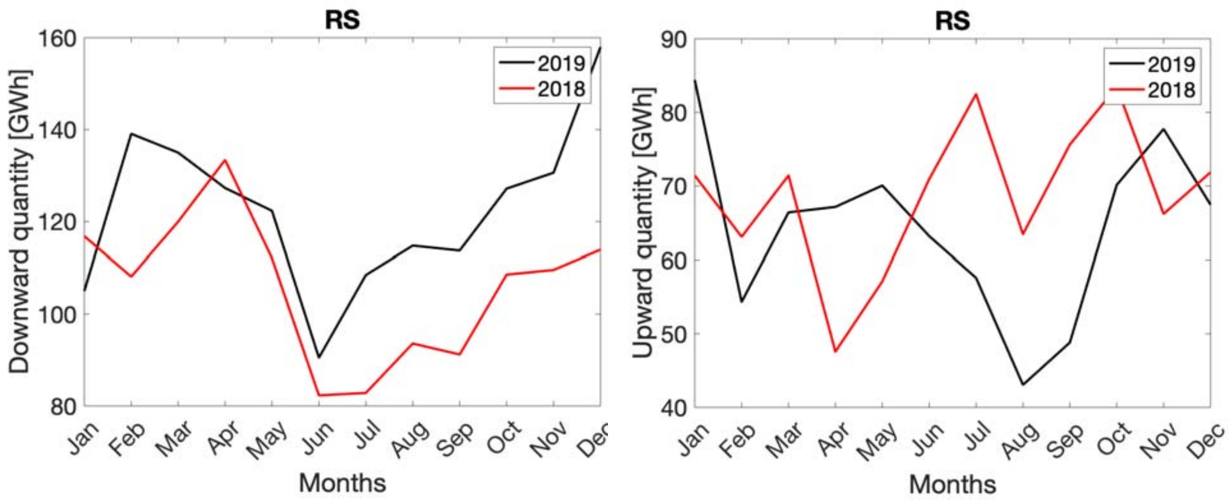

Figure 3.21 2019 and 2018 NORD MB downward (left) and upward (right) accepted AS volumes.

CSUD

Downward GR volume increases in 2019 by th 17%, from 1157 to 1351 GWh, maintaining 2018 trend characterized by the October top peak, when energy demand decreases after summer, but RES production is still high. Even for RS volume's trend is close to 2018 one with the top peak in September-October, but with sensibly higher results, passing from 67 to 126.1 GWh with an 88% increase. RS trends are comparable, but the volumes low, 4.3 GWh in 2018 and 6.4 GWh in 2019.

Even on upward side, 2018 trends are generally maintained, with a volume increase on every product. GR passes from 267.6 to 387.7 GWh with a 45% increase and the presence of two additional peaks in summer and fall, in addition to 2018 spring one. RS peaks are emphasized in 2019 and the volume grows by the 38%, from 44.4 to 61.5 GWh. AS meets the largest increase, the 138%, going from 91.9 to 218.5 GWh, with a different trend, that presents in 2019 some peaks compared to 2018 flatter curve.

From these results is possible seeing that MB is less likely than MSD to change trend from one years to the other. Moreover, patterns follow the theoretical behavior coming from the rising RES integration. The factors make MB a good benchmark from business cases simulations, also considering that, as for now, UVAM can only provide GR products.

Table 3.10 CSUD MB volumes resuming table.

	Downward Volumes [GWh]				Upward Volumes [GWh]			
	2018	2019	Variation [%]	Similar trend?	2018	2019	Variation [%]	Similar trend?
GR	1157	1351	+17	Y	267.6	387.7	+45	Y
RS	67	126.1	+88	Y	44.4	61.5	+38	Y
AS	4.3	6.4	+49	Y	91.9	218.5	+138	N

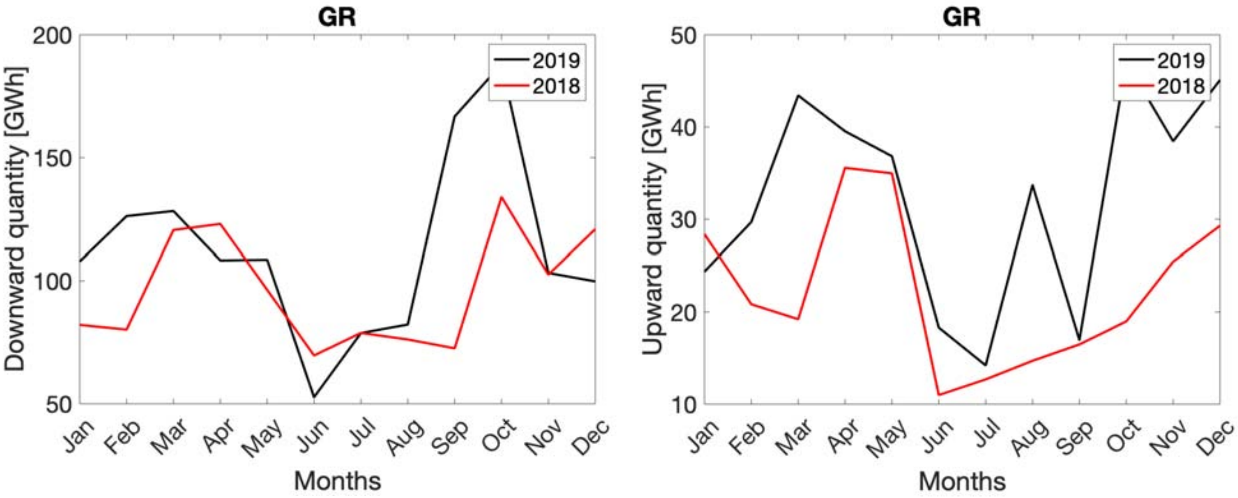

Figure 3.22 2019 and 2018 CSUD MB downward (left) and upward (right) accepted GR volumes.

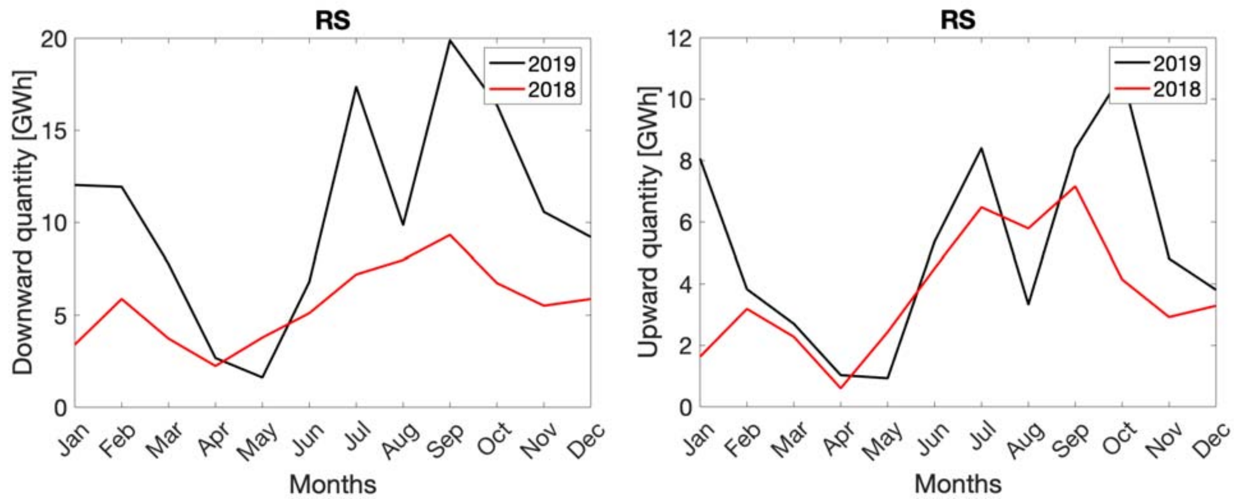

Figure 3.22 2019 and 2018 CSUD MB downward (left) and upward (right) accepted RS volumes.

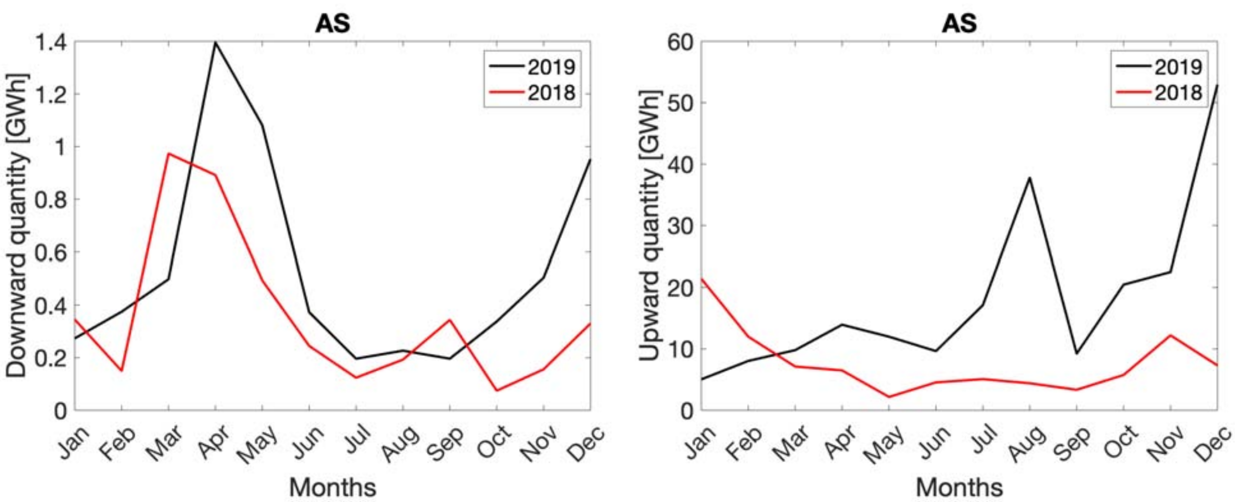

Figure 3.24 2019 and 2018 CSUD MB downward (left) and upward (right) accepted AS volumes.

3.4.3 MB Hourly Results

MSD's MATLAB scripts are adapted for the MB hourly analysis with product detail. Algorithm logic is the same described in 3.3.3, with Excel files as an input and the iterative change of product specification, offers' scope and market zone, the outputs are, for GR, RS, AS:

i. the total hourly accepted quantity for every product;

ii. hourly product's mean price weighted on accepted quantity.

Mean prices are calculated as:

$$P_i^{\,k} = \frac{\sum_j \mathrm{AWARDED\_PRICE\_NO}_j^{\,k} \cdot \mathrm{AWARDED\_QUANTITY\_NO}_j^{\,k}}{\sum_j \mathrm{AWARDED\_QUANTITY\_NO}_j^{\,k}},$$

for a certain product, for the i hour, using the j single offer in the k market zone.
The scripts are run for both 2018 and 2019 datasets, but the charts are presented only for 2019, using 2018 resuming data as a comparison on prices, given the already presented volume analysis. This analysis is important since it is the starting point for the core work of the thesis, the model developed in Chapter 4 moves from this analysis's considerations. Only 2019 GRs charts are presented, since they are functional to next Chapter's simulations. RS and AS results are resumed in the tables.

NORD

Considering downward products, the chart of GRs shows a high concentration around 2019's mean price of 31.2 €/MWh, lower than 2018 35.5 €/MWh, with the only exception of mid-June prices fall to values close to 0 €/MWh. RS prices as well, are concentrated close to the mean price of 24.6 €/MWh, similar to 2018 result of 24.1 €/MWh. AS chart, instead, has sparse chart, as predictable from total low volumes, with mean accepted price of 10.2 €/MWh, slightly lower than 2018 one, 10.9 €/MWh.
Upward mean prices, instead, decrease a little from 2018 to 2019, for all the products. GR chart displays a high concentration around the mean price of 95.6 €/MWh, lower than 2018 98.2 €/MWh, even if there are numerous accepted offers with a sensible higher price throughout all the year. RS daily prices are never far from the yearly mean of 93.6 €/MWh, which is under 2018's result of 110.9 €/MWh. Upward AS, like downward AS, presents a sparse chart, with most of the daily prices around the mean 100.9 €/MWh and a smaller set at 400 €/MWh. Anyway 2019 result is lower than 2018 108.3 €/MWh.

Table 3.11 2019 and 2018 NORD MB mean hourly prices.

	Downward Mean Price [€/MWh]		**Upward Mean Price [€/MWh]**	
	2018	**2019**	**2018**	**2019**
GR	35.5	31.2	98.2	95.6
RS	24.1	24.6	110.9	93.6
AS	10.9	10.2	108.3	100.9

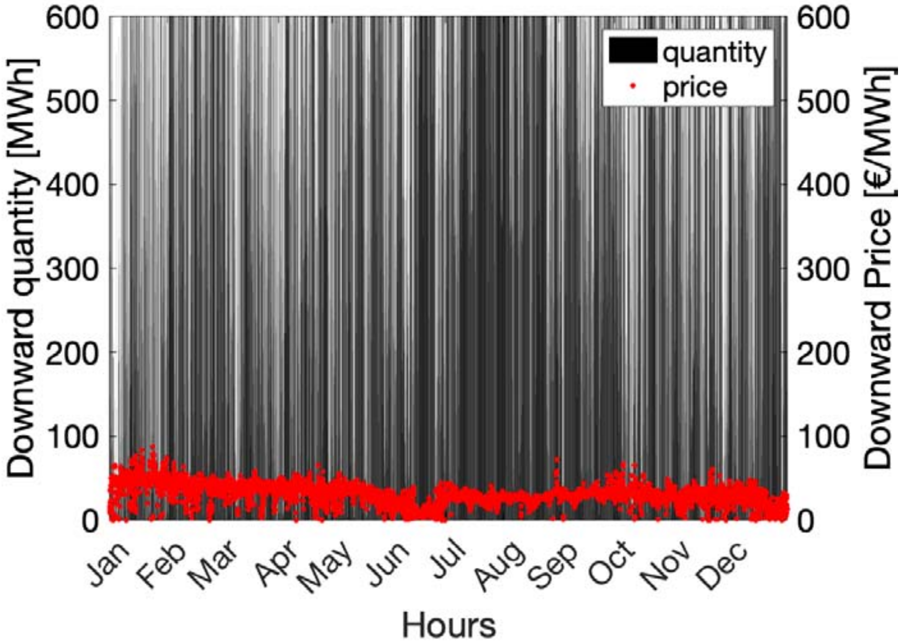

Figure 3.25 2019 MB NORD GR downward hourly results.

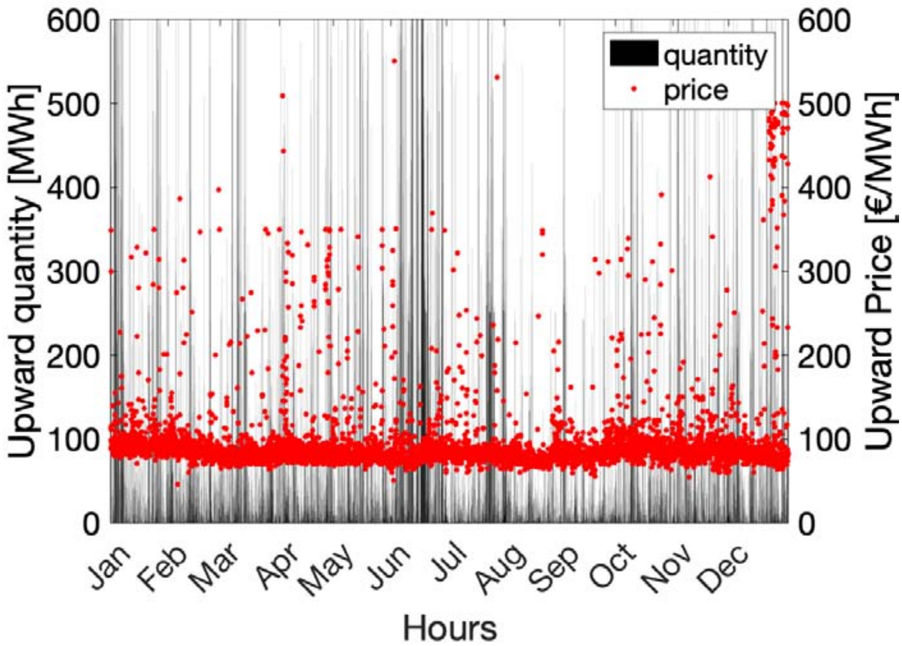

Figure 3.26 2019 MB NORD GR upward hourly results.

CSUD

Downward GR and RS accepted offers are close to the annual mean, with a certain number of days with a mean daily price of 0 €/MWh. 2019's annual mean price slightly increased compared to 2018 for both GR and RS, respectively passing from 21.2 to 23 €/MWh and from 27.4 to 27.7 €/MWh. AS offers are mostly accepted at 0 €/MWh, with a mean price of 1.7 €/MWh, the same result of 2018.

GR upward accepted offers present a strange pattern, there are two concentration zones around 100 €/MWh and 500 €/MWh with a relevant number of offers in the middle. The mean price is very high, 269.5 €/MWh, and close to the level of 2018. RS's results are for the greatest part in the annual mean zone, around 93.7 €/MWh, and under 2018 result of 114.6 €/MWh. AS presents a sparse configuration with annual mean of 231.6 €/MWh but low relevance because of the small volume.

Table 3.12 2019 and 2018 CSUD MB mean hourly prices.

	Downward Mean Price [€/MWh]		**Upward Mean Price [€/MWh]**	
	2018	**2019**	**2018**	**2019**
GR	21.2	23.0	266.4	269.5
RS	27.4	27.7	114.6	93.7
AS	1.7	1.7	268.0	231.6

This paragraph outlines how effective ESS could be for NORD and CSUD. NORD has interesting price differentials and a solid market, but traditional plants are still widely used to provide flexibility, working in off-design conditions for most of time, hence reducing their efficiency and requiring the intervention of non-flexible thermal plants for a costly fee[42]. ESS implementation would help working more often in design conditions and at the same time would favor RES implementation and DER empowering through UVAMs or other aggregation models. CSUD's MB has on the other hand high dispatching costs, due to RES causing real-time dispatching issues. Current renewable energy penetration already requires regulation's intervention to foster aggregators, in order to lower system's costs and hedge the volatility of reserve provision.

[42] See 3.4.4.

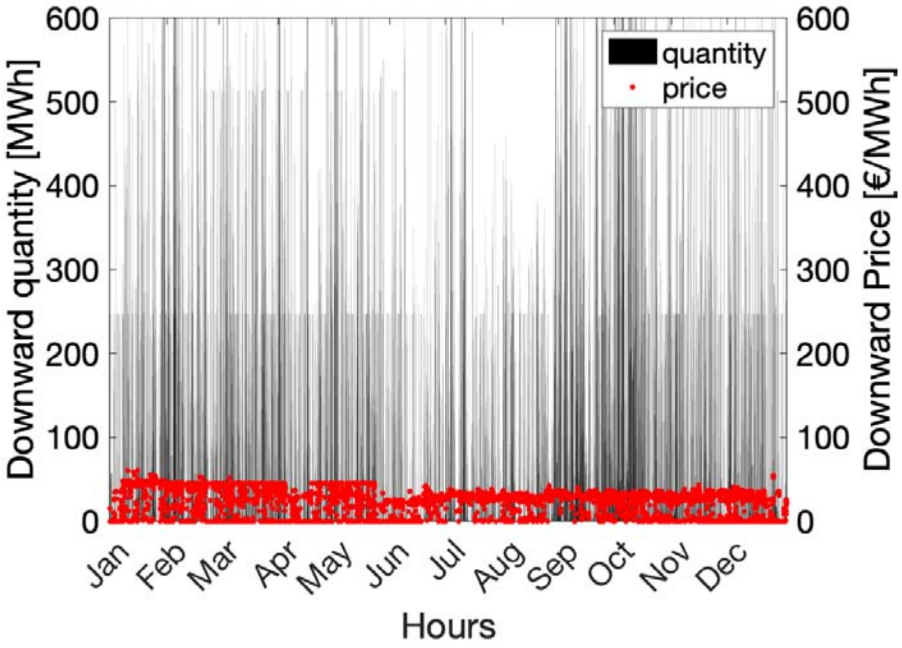

Figure 3.27 2019 MB CSUD GR downward hourly results.

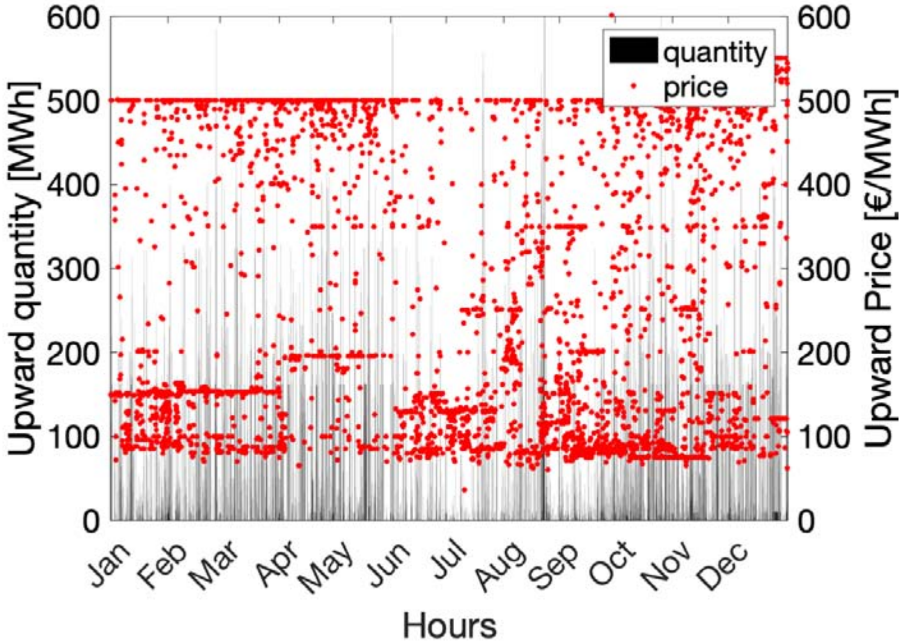

Figure 3.28 2019 MB CSUD GR upward hourly results.

3.4.4 Start-Up and Setup-Change Fees

As a conclusion for the MB analysis, the 2019's Start-Up and Setup-Change Fees are described. These fees are identified as upward products, although they are actually fees. These fees are required from thermoelectrical plants, mostly combined cycles, to complete the operation underlying the fee. These products do not comprehend any energy exchange, which is paid separately. As reported in TIDE, a Milan Polytechnic study over the mentioned fees [6], proposes a different methodology to fix offers cap, while the current one is based on previous year's offers. The aim of these products is covering extra costs deriving from the underlying operations on thermal plants, when they are called for ancillary services supply. The problem is that the current regulation allows the operator to base their offers on market considerations, rather than on technical costs. Analyzing actual cost of combined cycles[43] operations, the proposed cap is 24744€.

A MATLAB script is created. The algorithm is similar to those previously implemented for other products' analysis: Excel data are filtered, considering only accepted offers for ACC and CA, then the number of awarded fees and the mean price of non-zero ones are calculated. In NORD in 2019 were accepted 295 ACC fees and 215 CA fees, for a non-zero price. Both ACC and CA mean prices are much greater than 24744 €. Fees total cost, using mean prices of non-zero accepted offers reported in the Figure 3.29, is 50.8 m€, while using the Polytechnic proposed cap the total cost should be 12.6 m€. The 38.2 m€ difference could be used as the initial investment to lower costs of ESS and promote, by regulation, aggregators models.

A lower number of fees were accepted in CSUD in 2019: 74 ACC non-zero fees and 11 CA non-zero fees, for a total cost of 3.7 m€. The difference between this result and proposed cap scenario of 2.1 m€ total cost is 1.6 m€.

[43] This type of plant is the one requiring the fee most of the times.

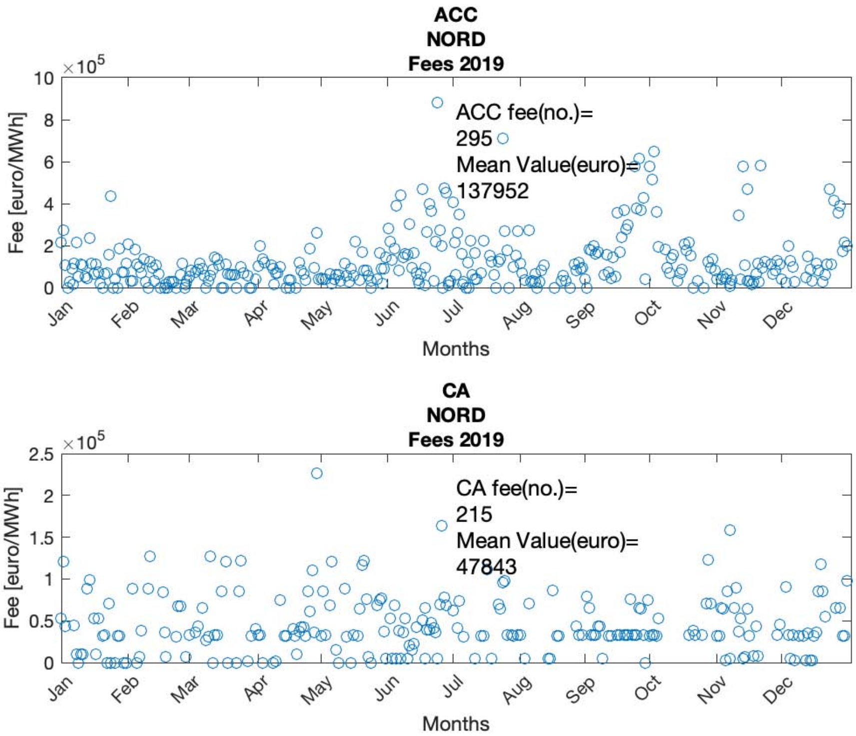

Figure 3.29 2019 NORD fees number and mean value of non-zero accepted fees.

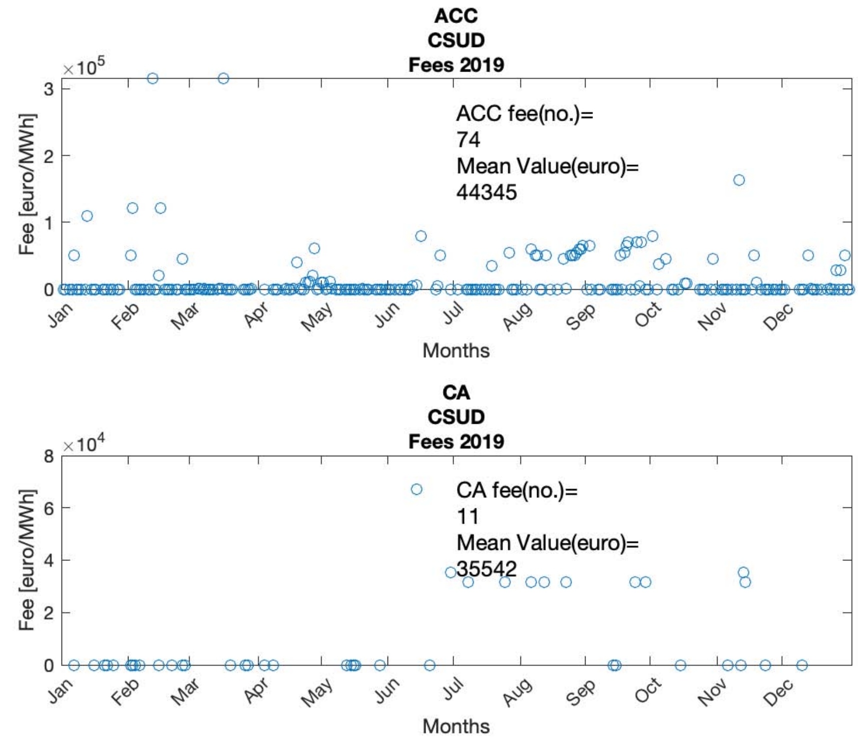

Figure 3.30 2019 CSUD fees number and mean value of non-zero accepted fees.

3.5 Final Considerations

This chapter exposes the results of the analysis of several different aspects of the Italian Ancillary Service Market. While all of the information presented are relevant to understand electricity service market dynamics, some points and patterns are fundamental for Chapter 4. The aim of this paragraph is to provide a clear overview of the environment in which the simulations of Chapter 4 are created. The focus is on MB in NORD and CSUD, as MSD is not used in the mentioned simulations and the simulations are run only in these market zones.

a) From CDF analysis, compared to CSUD, NORD has higher values of the curves for both upward and downward services, which means a better acceptance rate. On the other hand, CSUD accepted price are more advantageous;
b) From volumes analysis and with a particular focus on real-time balancing products (GR), NORD trend is basically the same in 2018 and 2019, with a characteristic peak in summer. Also, CSUD maintains the same trend in 2019 and presents two peaks in spring and autumn. 2019 NORD downward 6514 GWh traded are five times bigger than CSUD results. Upward volumes are lower, yet NORD with 892 GWh almost doubles CSUD trades.
c) The outcome of hourly results analysis puts together previous considerations. NORD volumes are sensibly higher, with well-defined price zones of acceptance around 31 €/MWh for downward services and 95 €/MWh for upward ones. CSUD price density for downward services is around 20 €/MWh, with a lower value than NORD one. Upward price have two zones with an concentration around 100 €/MWh and 500 €/MWh, and with a sparse distribution in between.

The general observation is that simulations like the ones proposed afterwards are useful to assess the effect of the different combinations of price differentials and market volumes (radically divergent in NORD and CSUD).

CHAPTER 4
BES BUSINESS CASE

In the final chapter of the thesis, data and considerations from Chapter 3 are used and the action of a 1.2 MW/ 3 MWh Battery Energy Storage (BES) in the Italian Ancillary Service Market is simulated. The difficulty of load balancing, deriving from fluctuations of load and RES generation variations, lays in the need for immediately ready power. As seen in Chapter 3, the influence of renewable plants is identifiable from market data, and the renewable installed power is expected to increase in the next years. As reported by Bloomberg New Energy Finance in Madrid COP25 conference preparatory reports [34], BES could have an important role in the support and enhancement of the renewable energy generation, hedging their non-programmability hence laying the basis for a more solid investment. Bloomberg starts from a base-case scenario for Spain, with wind and PV to generate the 51% of energy in 2030 and the 75% in 2050. In the best-case scenario, a BES price drop is deemed to enhance its diffusion in the stand-alone configuration, paired to renewable generation, or supporting gas turbines in working close to the design point and in fast-start, resulting in a 94% of zero-carbon generation and in a 13% reduction of gas back-up power. Similar considerations may apply to Italy, where wind and solar plants are becoming more and more competitive on the electricity market, especially in the Centre-South, thus the balancing problem is arising. As shown by Terna in the 2020-2024 Strategic Energy Plan [35], total sun and wind power increased by 1.1 GW in 2019, for a total of 31.4 GW, concentered for the 60% in the Centre, South and Islands. The contemporary dismission of thermal plants is lowering the inertia of the system, driving the need for investments to guarantee the stability of the grid. Being modulable, responsive and efficient[44] BES is presented among technical solution to the stated problem. Among the different types of batteries the most used technology (and later described) is Lithium-ion (Li-ion), employed in the 55% of the 1930 MW of storage systems installed in U.S. as of 2016, and in most of the projects worldwide [36].

[44] i.e. 70-95% for Li-ion batteries.

4.1 Goals and Scope

The main goal of this work is the development of a deterministic tool able to evaluate the economic potential of new forms of flexibility in the Italian ASM and to highlight current regulation barriers. In this thesis the focus is narrowed on BES, yet the method proposed can serve many cases, such as Demand Response, Power to Gas and others. First, a market model based on ex-post data is created, then different bidding strategy are proposed to simulate the operations of BES in the electricity market. Using a two years dataset, relative to 2018 and 2019, BES economic results from 1st January 2019 to 31st December 2019 is evaluated. The market aspect is the most relevant, that translates into deep and precise analysis of regulatory framework, incentive schemes and actual market phases, sittings and gate closure, to eventually propose the final model. Anyhow the technical aspect is considered: a set of technology specific constraints is implemented in addition to market depending ones. While market constraints depend on the regulatory framework, and must be changed only whether this framework changes, technology ones must be defined for every technology. Specific conditions here used are later explained in detail, without a detailed analysis over technical operations, but rather using operational limits from literature. This purpose is pursued with the definition of a MATLAB tool which comprehends a set of scripts and functions, created by the author. This tool is based on market data with hourly detail, published by the GME, for the simulation of the real market. The effort is to keep the model simple and opened for future improvements yet to guarantee the complete adherence to the actual market conditions and constraints. The MATLAB set of scripts eventually designed aims to provide a concrete baseline for further evaluations of UVAMs or, in general, aggregators supplying ancillary services.

4.2 Research Motivation

BES can support energy utilities at any level, from generation to consumption, with applications like peak shaving, congestion management, energy storage during low demand period for subsequent use, response to unexpected events and real-time balancing [37]. Moreover, it is widely discussed in this work and generally in literature, the chance of supporting renewable energy development using energy storage systems at industrial, commercial and residential level [37]. Finally, the use for transportation is well known, while technical and organizational aspects of using vehicles for active energy storage is currently object of study [38]. Anyway, there is a wide range of possible applications for BES, with the certainty of a rising attention towards BES as the price goes down. From 2019 BNEF Battery Price Survey [39], it results that the average cost of the battery pack only is now 156 $/kWh (value found in [39] by considering available price lists), with a 13% decrease from the 2018 value, and far below the 2010 cost of 1100 $/kWh. Moreover, it is forecasted that as the demand of BES may pass 2 TWh by 2024, BES price would fall under 100 $/kWh. The high cost of batteries used to represent a significant barrier for their diffused implementation, but with the described trend many BES-based projects are arising.

Some operating or ongoing relevant projects briefly discussed here, in addition to those presented by Zhang [36].

Tesla Hornsdale Power Reserve is the world's largest Li-ion BES to date. It is located in South Australia and the 70% of its power is used by SA government for grid stability services, while the 30% is managed by Neoen for commercial operations. The 100 MW/129 MWh Tesla Megapack was completed in November 2017 and works combined to a wind park of 309 MW. BES can ramp from 0 to 100 MW in 130 ms, under the required 200 ms needed for Primary Reserve [40]. The total investment was 50 USD million, and generated a 40 USD million savings in the first year. A list of large-scale storage facilities is planned in the next years. To support gas turbines operations[45] in *Moss Landing Gas Power Plant* in California for Pacific Gas and Electric Company (PG&E), a 183 MW/730 MWh by Tesla, a 300 MW/ 1.2 GWh by Vistra/Dynegy, a 75 MW/300 MWh by Hummingbird Energy Storage LLC and a 10 MW/40 MWh by Micronoc Inc. storage plants will be built. Other storage sites by AES Corporation are planned in California paired to PV generators, a 400 MWh one in Long Beach for the Alamitos Energy Center (AEC) and a 100 MW/400 MWh one in Oxnard for Strata Solar. In 2021, in Manatee County, Florida, after the installation of 30 millions of solar panels on site [41], Next Era is building the world's largest storage plant, sized 409 MW/900 MWh, meant to substitute by 2030 a 1650 MW gas power plant. These examples provide a proof of BES actually being a trend for worldwide investments as well as a widely established tool for RES supporting. Moreover, the growth of large-scale storage plants will drive the cost reduction of the asset, with benefits for smaller scale facilities as well. These opportunities represent a concrete scenario also in Italy (at a smaller scale) after the opening of the ASM. The participation of storage systems in Tertiary Reserve and real-time balancing provision is now allowed, with future possibility to provide Primary and Secondary Reserve as well [6].

[45] Using BES with gas turbines facilitates working at design point and allows fast-starts in under 10 minutes [40].

4.3 Approach

The procedure presented is applied to a UVAM connected to the Italian MV grid and operating in 2019, under the centralized dispatching system and Terna as the central counterpart. A market model is created for 2019 using ex-post data, enabling the obtainment of results based on facts rather than on forecasts. Then, a bidding strategy is proposed, either fixed and based on 2018 data or progressively elaborated during the 2019 simulation, recreating the real situation of a potential UVAM at the end of 2018. After that, the BES is characterized in the UVAM context, highlighting technical aspects useful for the modeling of market interactions. The core of the simulation is the definition of the interactions of BES and market models in two possible ways: leveraging the ASM only for providing upward and downward services versus a hybrid approach of bidding on the ASM in combination with the MI. Results are assessed for different market zone, focusing on NORD and CSUD. Eventually this study provides financing possibilities and an indicative benchmark for the gap of missing incentives, or still existent economic barriers to overcome, for an increased diffusion beyond pilot projects of EES in Italy, both at utility scale as well as at virtually aggregated small-scale level.

4.3.1 The Market Model

According to 4.3 and 3.4 considerations, MI and MB are the markets simulated in this work.

ASM Model

For the ASM market model, only MB is simulated. The decision is taken mainly because of market trends found in Chapter 3, that highlight a stronger volume correlation from year to year on MB rather than on MSD and the higher price differentials, that translate into more possibilities for the investment to payback. Additionally, the ARERA review of pilot projects review presented in TIDE, shows that as for now UVAM provided only real-time balancing services, which are accepted and activated on MB. The starting point for modeling is the result obtained from MATLAB scripts used in the hourly zonal MB analysis of Chapter 3 and saved as a set of Excel files. MB is articulated in 6 sessions, from MB1 to MB6. The offers accepted in each of them refer to a 4-hours timeframe, starting from midnight. Except for MB1, whose offers are selected from MSD submissions, the other session present the gate closure one hour before the starting of the respective block. The model proposed is based on accepted offers and is meant to represent MB only. For this reason, MB1 is approximated as functioning like other sessions, with no loss of reality adherence. Here only real-time balancing (GRs) information is considered, since all of the services that a UVAM can provide are under the name of GR products, with no differentiation. The small scale of the BES used does not allow to split its capacity in 4 different offers as permitted in MB, so that only GR1 offers are submitted. However, the considered Excel files report the hourly weighted average of all the GRs and the relative hourly total quantity. This is aligned with the aim of the work of testing potentialities of the technology also as a possible substitute for other units, and therefore able to reduce the number of offers accepted at GRs other than GR1. Another crucial point is the use of weighted average price instead of extremes ones. It is true that on MB the remuneration mechanism is pay-as-bid, so that theoretically offering even one c€ less than the highest accepted offer for upward services and one c€ more than the lowest accepted offer for downward services, would guarantee the acceptance. Nevertheless, MB has an important local component. It is possible, for instance, that Terna always accepts an offer less competitive than another only for geographical reasons, linked to nodal optimization of dispatchment. Moreover, the geographical acceptance logic and related prices is investigated in 3.3.4, where it is found that accepted price in the most critical nodes are exactly equal to the weighted mean price of the competence market zone. The main criticality is the insufficient nodal granularity of GME data, since to the indicated PSR belong different units that can be very far from each, preventing the legitimation of an unconservative approach. The used one, instead, is conservative since considers average values, resulting in a more realistic definition of the market. Additionally, the computational effort required for the conservative approach is bigger than how it would be for the other: extreme results are contained in single .xml files and need much less processing, but at the risk of producing misleading results. With these specifications, MB is hence modeled as an 8760 rows array, with the hourly weighted mean price and the hourly total quantity for GRs, differentiated between upward and downward services and for market zone

MI Model

MI is used in the scenario of a UVAM that contains a consumption unit and a programmable UP. Thank to this hypothesis, the dispatching fees occurring when purchasing or selling on MI are not considered in the economic assessment of BES, since considered as internal operations. In detail, purchases on MI are considered as the opportunity cost, missing revenue, for programmable UPs of not selling on the market and charging the battery instead. Sells on MI are considered as the extra revenue, the avoided cost, of supplying energy to the consumption unit instead of procuring that energy on the market. Both are valued at the MI price, since it represents the missing revenue/avoided cost. Daily data are downloaded from GME website following the path: *GME website>Esiti dei mercati e statistiche>download dati>MI* [42]. An .xml file per year and for each MI phase is obtained through a C# script, similar to the one used for ASM. MI is implemented as a continuous trading market, differently from current regulation (see 1.4) but justified by the upcoming change occurring in a short time of the XBID, with go-live in 2020 (third quarter for Italy) [6]. MI is modeled with hourly detail and price equal to Pz. This choice is justified by the TIDE disposition to always apply Pz to storage systems for both purchases and sells, in order to prevent clear and immediate arbitrage opportunities in market zones with a marked difference between Pz and PUN [6]. Relatively to the small-scale proposed BES, it is deemed that no controls are needed on available energy volumes, hence the access to MI is unconstrained on that side. Since different MI sessions can refer to the same timeframe, and prices for common time slots are updated as sittings proceed, prices from the latest activated MI session are used for the creation of a continuous MI. Using these prices, instead of the latest session still opened for every simulated hour, better fits in the perspective of a continuous trading market. Only MI phases from the 2nd to the 7th are considered, respectively referring to precise timeframes: MI2 covers the 1 to 4 timeframe, MI3 the 5 to 8 one, MI4 the 9 to 12 one, MI5 the 13 to 16 one, MI6 the 17 to 20 one and MI7 the 21 to 24 one. At the beginning the process is affected by missing data for all the MI sessions on the 31st March and on the 27th October. After a further research, it comes out that GME online platform experienced issues on those days. The problem is solved by attributing to those days the same values of the previous day. The solution is not invasive and does not diminish the effectiveness of the model. MI is completely defined by an 8760x3 array. The first column contains the date, the second one the hour of the day and the third one the Pz, different for every market zone.

In the MATLAB script, Excel files resulting from Chapter 3 are loaded and computed, creating the final market array merging with the MB one. The columns of the final array, which is different for every market zone, contain the day of the year, the hour of the day, the hourly mean accepted price and total quantity for GR products for MB and the hourly Pz for MI. Given the MB architecture, two supplementary columns are added to the market array, one indicates the progressive number of the four-hours block of the year, from 1 to 2190, and one identifying the number of the hour in every block, from 1 to 4. These indicators are used in the simulation.

4.3.2 The BES Model

BES is the player acting on the designed market model. The energy storage is supposed to participate in the UVAM project, with potentially other production and consumption units for a total power of 10 MW maximum. This aggregation is considered as the most likely one for a relevant introduction of energy storage in a DER context, always considering the potential use also as a support to large-scale thermal plants. The considered UVAM is not characterized in detail but justifies the non-application of dispatching fee on energy purchased and sold on MI. Economic considerations are done only for the BES and limited to the energy that can be provided by the storage. The 1.2 MW/ 3MWh BES's is comparable to some existing applications, such as the 1MW/2.4MWh Tesla Powerpacks installed by the New Zealand TSO Vector for grid's stability or by the Jackson Family Farm for peak shaving and DR [43]. Li-ion battery operates through the migration of lithium ions between electrodes. Generally, the positive electrode is lithium iron phosphate ($LiFePO_4$, LFP) while the negative one is made of lithium enriched graphite. When charging, lithium ions migrate from positive to negative electrode through the electrolyte and the direction is inverted when discharging. Li-ion batteries are currently the most common choice for renewable energy support, grid systems and micro grids [36]. The purpose of this thesis is not strictly technical but for completeness it is mentioned the ongoing study on Li-air batteries, that could improve the performance of Li-ion batteries in terms of energy density and specific energy, at a lower cost. The chemistry of these batteries is based on the oxidation of lithium metallic anode and the reduction of air oxygen on the cathode. Main issues concern the cathode design and the optimization of electrolyte composition [37].

BES Costs

The main barrier to extensive use of BES is the investment cost. As already reported, a BNEF study focuses on the cost decrease for the battery pack only, that after a continuous reduction averages at 156 $/KWh in 2019 [39]. This trend is forecasted to be maintained in the next years, but additional costs coming from development, inverter, control and safety systems, fees, taxes, must be considered. From 2019 U.S. National Renewable Energy Laboratory (NREL) report on utility scale storage cost progression, some comprehensive projections are done. The study references 25 publications that range from 2017 to 2019, pointing out how future price trends are scaled down as the publishing date is closer to 2019 [44]. This confirms BNEF considerations on future possible steep price decrease [34], [39]. NREL presents through a chart and a table, the expected storage prices from 2019 to 2050, starting from 2018 reference value of 380 $/kWh. To not create misunderstandings, Bloomberg values refer to the battery pack only, while NREL indicates the CAPEX costs. The 2020 forecast, equal to 297 $/kWh is used in this work, even if the business case refers to 2019. Anyway, the clue is the definition of the market model and possible interactions, the investment price can be changed anytime.

BES Lifetime and Efficiency

Other important parameters to be considered in the simulation are battery lifetime and efficiency. Battery lifetime is the central topic of many papers and each proposes different models for ageing and remaining lifetime calculation. Different approaches are used to calculate Remaining Useful Lifetime (RUL): *i.* Cycle Counting Models evaluate RUL essentially based on average depth of discharge, *ii.* Ah/Wh-throughput Counting Lifetime Models compare the value of the parameter Ah/Wh to the reference value for the battery, *iii.* Electrochemical Models is a reactions-based method that evaluate a large list of chemical parameters reaction, with an increase of detail level but also a complexity growth, *iv.* Equivalent Circuital Models base conclusions on the electrical modelling of the battery [45]. A different model is represented by the Accelerate Aging Model. According to this approach, the battery is tested under precise stress conditions in terms of State of Charge (SOC), temperature and charging/discharging speed [45]. This method better fits the case-study proposed, as the performance fade eventually found is the result of fast charging and discharging cycles that could potentially happen in the ASM. Performance fade under Accelerate Aging Model is presented below for different numbers of cycles and used afterwards [45]. The number of cycles considered is validated by the adoption in literature of similar values, with even higher values being adopted in works on the same topic [46]. The percentual losses reported in Table 4.1 refer to the situation at the end of the last considered cycle. However, no detailed model is implemented for cycle by cycle performance measurement and the approximation guarantees and additional safety margin.

Table 4.1 Capacity Fade (CF) and Power Capability Decrease (PCD) at 25ºC and 100% DOD for LFP [45].

Number of Cycles	CF [%]	PCD [%]
4000	14	4
6000	17.5	4.25
8000	20	4.75

On efficiency side, accurate characterization and models are published, with a detail level that exceeds the aim of this thesis. However, reasonable values for roundtrip performance equal to 0.85-0.9 are used in the simulations [44], [47].

BES Design

Designing BES is not meant here as the chemical component's choice, rather an economic reasoning considering cost and lifetime issues. The unit cost, lifetime and efficiency data previously derived and regulation constraints are here used. From UVAM regulation, the minimum size for a UVAM is equal to 1MW, and incentives are granted for the provision of the maximum power of the UVAM for at least two hours between 2 and 8 pm [26]. Hence, the minimum size of the battery is 1MW/2MWh. With the purpose of simulating a real case, losses are considered, using the cycle efficiency of 0.9, that considers charging, storing and discharging processes. With this considered, needed storage capacity increases and becomes 2.25 MWh [44], [47]. Ageing process affects the battery capacity and its maximum power, depending on the number of cycles. According the proposed correlation between the capacity and power fade and the number of cycles [45], starting from 1 MW/2.25 MWh and considering only 6000 and 8000 cycles alternatives, the total performance decrease, at the end of the last cycle would be:

Table 4.2 Capacity and Power fade for an LFO BES.

Total Cycles	Capacity Fade [MWh]	Power Fade [MW]
6000	0.39	0.00425
8000	0.45	0.00475

As it results from the table, the storage capacity must be increased, and raised to the rounded value of 3 MWh. A certain safety margin is guaranteed by this choice as the total loss is verified at the end of the last cycle. The hypothesis is that following an optimized charging and discharging protocol would hedge problems deriving from frequent uses [48] and hedge the risk of power mismatch that would eventually lead to penalties [47]. However, in the 8000 cycles scenario more contingencies, due to the extended stress on the battery, could increase the probability for these problems to occur. It is considered safer discussing only the 6000 cycles scenario. Power as well must be increased, also to consider possible control issues, not deeply analyzed here but still a potential problem in real operations [47]. Eventually, the size of the storage is 1.2 MW/3 MWh, with the power increased by a 20%. This indication is used to assess economic results of a hypothetical battery of the same size, which is very similar to 4.3.2 examples, but not referred to any specific commercial battery. A different cycle cost comes from different considered number of cycles. Simply by multiplying the unit cost of 270 €/kWh[46] by the 3 MWh capacity of the storage and dividing by the number of cycles, a cycle cost of 135 is obtained.

[46] Obtained converting 297$/kWh in euros with a 1.1 USD-EUR exchange rate, valid by 27th March 2019.

Table 4.3 Design parameters of the simulated BES.

Type	Mkt. relevant size	Lifetime	Roundtrip Efficiency	CF/PCD	Actual Size
Li-ion	1 MW/2 MWh	6000 cycles	0.85 %	17.5/4.5 %	1.2 MW/ 3 MWh

Cash-Flows Definition

The actual interaction between BES and the market is not described yet, but for better understanding, the cash-flows definitions used are presented. Costs comprehend energy purchases from the market, capital costs (CAPEX), losses. Energy purchases are valued pay-as-bid as prescribed by *Codice di Rete*. The cost on MB is obtained by multiplying the offered price from the strategy, if accepted, by the volume purchased, while if the purchase is on MI, the volume is multiplied by the PUN. The investment cost is depreciated throughout the whole life of the battery, by attributing to every cycle its own cost, not to affect the global considerations with the concentration of the investment at the beginning of 2019. The cost of losses is obtained through the multiplication of the energy lost in every cycle by the mean price of the downward market model. This choice is done since losing energy requires additional purchases needed to provide the desired output. Operational costs are assumed as already accounted in the investment cost. Revenues come from sells on the market, respectively valued pay-as-bid on MB and at the PUN on MI, and the UVAM incentive, when gained. The incentive for two hours granted with the cap price of 400 €/MWh is 15000 €/MW/year. Therefore, in this model the final incentive is 15000 €, since the additional power is just a safety margin.

Table 4.4 Design parameters of the simulated BES.

Revenues	Costs
Sells on MB/MI	Purchases on MB/MI
UVAM incentive	Losses and Ageing

Even if BES belongs to a UVAM, only economic results of the storage are assessed and the UVAM is used to justify the non-application of dispatching fee for MI trades. In the simulations that consider only MB, no incentive is accounted, the battery is not strictly linked to a UVAM but could possibly be a stand-alone plant. The aim is to verify the potentialities of the BES itself for further use, using a realistic environment.

4.3.3 Bidding Strategy Definition

The definition of a bidding strategy permits the simulation of BES's operations on the ASM. The strategy is based on MB data and consists in the definition of a characteristic week for each month for upward services and one for downward services. The definition of a bidding strategy is meant to simulate potential market behavior and to validate final results beyond a merely and ex-post analysis. In fact, strategies are based on historic data pretending not to know the actual outcome. For example, the July 2019 bidding strategy originates from historic data till, at maximum, June 2018. This way it is possible to extrapolate valid findings even without a complex predictive model.

For every hour of the week a reference price is defined. The idea of the characteristic week comes from an RSE and Milan Polytechnic publication. There a similar approach is used but the resulting week is not used as a bidding strategy, but rather as the starting point for the cash-flow calculation of the underlying project, DR in that case. The analysis of NORD offers is used for reference week determination, while statistical considerations of acceptance rate permit to scale reference values for cash-flow attribution [49]. In this work's simulations, instead, the reference week is the tool used by the hypothetical operator for the submission of standard offers for the 2019 MB.

Reference weeks are calculated in MATLAB, with different timewise to determine different strategies. Only real-time balancing offers are considered separately for every market zone, to create a strategy for upward services and one for downward services. Two strategies are proposed, hence respective results compared:

i. Fixed Strategy, a strategy based on only 2018 MB data. For example, the characteristic NORD January Monday will be defined using 2018 January data, defining prices for every hour of the day as the mean price weighted on quantity of accepted offers, for the same hour of all the January Mondays. The same procedure is iterated in the MATLAB script, resulting in an 84x24 array[47], with days in the rows and hours in the columns.

$$\mathrm{Ref}^{i}_{j,k\ \mathrm{fix}} = \frac{\sum_k \mathrm{AWARDED\_PRICE\_NO}^{i}_{j,k,n\ 2018} \cdot \mathrm{AWARDED\_QUANTITY\_NO}^{i}_{j,k,n\ 2018}}{\sum_k \mathrm{AWARDED\_QUANTITY\_NO}^{i}_{j,k,n\ 2018}}$$

Where i is the month, j is the day of the week (Monday, Tuesday, …), k is the hour of the day and n indicates the single presented offer.

[47] i.e. 7 characteristic days per month, for a total of 84 characteristic days.

ii. Adaptive Strategy, in which the strategy is adapted to market trends, by starting from the fixed strategy and modifying it as the year proceeds. Implemented in MATLAB, this second alternative simulates a possible bidding behavior by taking into consideration both data from the previous year and the ongoing one. This is achieved by referring for the i-2019month to the arithmetic mean of characteristic weeks of i-2018month and the (i-1)-2019month. January 2019 is the only month that will refer to January 2018 only, while February 2019 for example, will refer to February 2018 and to January 2019. This process does not weight respective quantities used for reference weeks calculation in 2018 and 2019, since that would mean considering global distributions over short term trends or vice versa, and no elements suggest the higher importance of either one of them at this stage.

$$Ref^{i}_{j,k\,adpt} = 0.5 \cdot Ref^{i}_{j,k\,fix} + 0.5 \cdot \frac{\sum_{\mathrm{k}} \mathrm{AWARDED\_PRICE\_NO}^{\mathrm{i-1}}_{\mathrm{j,k,n}\ 2019} \cdot \mathrm{AWARDED\_QUANTITY\_NO}^{\mathrm{i-1}}_{\mathrm{j,k,n}\ 2019}}{\sum_{\mathrm{k}} \mathrm{AWARDED\_QUANTITY\_NO}^{\mathrm{i-1}}_{\mathrm{j,k,n}\ 2019}}$$

Valid for the strategy from February to December 2019.

The first approach relies only on the price values and distribution and quantity trends similitude between two subsequent years, that reflect the actual grid's need on MB. The second one start from first one hypothesis and tries to adapt it to new possible trends that may emerge during the year. No strategy for MI offers is proposed since both purchases and sells are valued at PUN.

Benchmarking

To respect UVAM constraints, this simulation is run solely in the MB only case. In the use of realistic strategies arises the criticality of the possible trade-off between too low prices that guarantee acceptance but reduce cash-flows and too high prices which might increase individual cash-flows but decrease acceptance rate. To somehow evaluate the effect of such deviations a benchmark is set as a short-range price omniscient BES operator always bidding at the ideal price (i.e. the modeled one). The meaning of short-range omniscience is that the operator knows ideal prices of the three blocks at a time. This means that he may avoid bidding in a certain block, as the overall economic performance is better if bidding in the following one. These considerations are not allowed to the realistic player who does not know modeled prices and only bids according to historic data reasoning (as previously exposed). As it is described, this benchmark does not provide the best possible result, rather a suboptimal situation to be taken as a first approximation reference.

4.3.4 Market Interactions

In this paragraph is described the interaction between the UVAM and the market model, using the bidding strategy, and how eventually cash-flows are determined. The two types of bidding strategies are applied in two different scenarios:

i. Trading on MB only;

ii. Use of MI to always fulfill UVAM regulation requirements.

Information about BES sizing and the criteria of choices are provided in the following, as well as the description of market modelling and constraints applied to recreate a situation as close as possible to reality. The desired result is a truthful benchmark to find strengths and weaknesses of using BES in a UVAM, and a realistic model to be used for different technologies and further comparisons. The possibility not to prove the economic feasibility here is a way to discuss about incentive, regulation or technology itself lacks, in order to focus on possible improvement.

Simulations

The simulation model is described, presenting how market interactions happen and different control logics used. A MATLAB script is created, with inputs the defined strategies and operational constraints.

The program starts with inputs that define how the system is operated, the market and the strategy. The architecture is mostly composed by *for* and *if* nested cycles, that start from the 1st hour of 2019, then they verify hour by hour market and technical conditions and consequently update operating variables and cash-flows. The cycles stop at the 8760th hour of 2019. The idea is comparing hour by hour the strategy to the market model and according to a control logic determining cash-flows. The battery has a total capacity of 3 MWh but the energy actually traded is 2 MWh, the remaining capacity is used to consider losses and ageing and for a more accurate investment cost. The same is for the power, where power exceeding 1 MW is used to hedge ageing process and as a safety margin for power fluctuations, that could eventually lead to penalties for power mismatch between the dispatching orders and the effective power supply [47]. Following this, the trading unit decided for modelling is of 1MWh in case of offer acceptance. In MATLAB, the State of Charge (SOC) of the battery is indexed with a 3-levels variable, 0 for empty, 1 for half-charged, 2 for fully charged. It is important considering that this variable does not refer to the real SOC, that never goes to 0, but is used for script operations. Therefore, the DOD is lower than 100%, which is a caution hypothesis compared to the one used for CF and PCD calculation [45]. In the following the algorithm used is described, hence in Figure 4.1 a graphic representation is given.

Operational and Initializing Variables

Initializing variables, are the SOC set to 0, the number of cycles set to 0, the cost of the BES set to 270 €/kWh, the lifetime of either 6000 or 8000. At this point the script starts from the first hour of the 2019 market model. The Cash-flow array is initialized as an 8760x4 array of zeros. The columns represent in the order: the cost of energy, the revenues of energy, the cost of cycles and the cost of losses and are updated as described in the specific section.

Operational and logic conditions

A set of logic conditions is used for the simulation of BES trades. First of all, the basic logical condition is that the battery can only discharge when SOC=2, only charge when SOC=0, decide what to according to later described control logics when SOC=1, must charge before discharge and cannot charge and discharge at the same time. Then, to recreate MB structure and the operator's behavior, only one operation[48] can be completed by the battery in a 4-hours block. The operator can bid till one hour before the starting of the underlying block and it is aware of the SOC and of what is happening just in the running block, submitting offers bound to these constraints. When the simulation refers to UVAM incentive framework, the range of possible operations is different according to the number of the daily blocks, during blocks 4 and 5, from 1 pm to 8 pm, the precedence is given to 2-hours exchanges at the maximum effective power. In this case, the total service is 2 MWh either upward or downward according to the SOC. Otherwise if no incentive is accounted there is no difference between daily blocks. Even more granularity is imposed by checking the number of the hour in every block. During the first three hours of the block, depending on the SOC, 2-hours services are preferred, and in case of unavailability, only one hour is completed. This simulates the reality of case in which Terna can partially accepting an offer. Since it is not possible the acceptance of an offer submitted for a certain MB session, a half in the bidding session and a half in the following one, during the fourth hour of a block only one-hour products are accepted. When SOC=0 only downward quantity can be exchanged, with the preference for 2-hours service and if not possible, 1-hours service. Vice versa for upward quantity when SOC=2. When SOC=1, instead, the decision is taken according to economic considerations. The threshold price for the decision for either charging or discharging is set equal to the second quartile of the prices' CDF for respectively downward and upward 2019 market model data. This decision is not strictly linked to theoretical considerations but permits not to generate loops in the script. When the simulation refers to UVAM incentive framework, to fulfil the obligation during mandatory hours the SOC must

[48] Either upward or downward services.

be either 0 or 2 at the beginning of every regulated block. If by the third hour of the previous block SOC is equal to 0 or 2, no operation is allowed in the fourth hour. If by the third hour, the SOC is 1, MI, assumed to work on continuous trades, is used to move SOC to 0 or 2. The decision of either moving SOC to 0 or 2 by selling or purchasing on MI is done using as the decision point the mean 2019 MI price of 50.7 €/MWh. If MI were actually operated on continuous trades, an immediate bid could be submitted in the last hour before the gate closure of the MB sitting. Also, the eventuality not to complete any operation in the fourth hour simulates a possible operators' behavior of bidding on MB for only the first two hours in the third daily block, from 9am to 12pm, under the UVAM regulation. This happens only in simulations that arbitrating on MI through consumption units of the UVAM. For simulation using MB only, required conditions for the incentive cannot be granted, so that all of the constraints aiming to guarantee 2-hours services in 4th and 5th daily blocks are removed. If no offer is acceptable for a certain hour, for any reason at any step of the logic chain, the script moves to next hour, remaining in the same block. If no offer can be accepted within the block, the script moves to the next block. Variables are not updated in these two last cases.

Market Conditions

The set of so defined conditions establishes which operations could potentially be exploited, of course according to the SOC and the markets simulated. Once the previous requirements are met, the effective acceptance undergoes the hourly comparison between the bidding strategy and the market model. First of all, the quantity is checked. The available quantity is considered as the overall quantity eventually accepted by Terna for a certain service in a specific hour, as defined in the Market Model, 4.3.1. The hypothesis is that a trade can be completed only if it covers less than the 20% of the total demand of the specific service, hence the demand is higher than 40MWh for the 2-hours service or higher than 20MWh for the 1-hour service. Anyway, the precedence is given to 2-hours one. Then, the reference price is chosen from the strategy by a specifically designed function, depending on the strategy chosen either fixed or adaptive. The mechanism is the same, the function reads the date from the market model array and recognizes the respective day of the week, hence it selects the correct reference value from the strategy file. A complete battery cycle is considered completed when SOC moves from 0 to 2 and then back to 0. Therefore, a SOC variating by 1 is accounted as 0.25 cycles, while a SOC variating by 2 is accounted as. 0.5 cycles. For upward service, the offer is consider accepted on MB if the strategy price is equal or lower than the market model price. The SOC variable is increased by 1 or 2 according to the awarded offer, the cycles variable is increased by 0.5 or 0.25. The script moves to the Cash-flows part. Similarly, for downward service, the offer is considered accepted if the reference price is equal or higher than the market model price. The SOC is decreased according to the awarded quantity, the number of cycles is updated and the script moves to the Cash-flows part. If the use of MI is necessary, no price or quantity check is done, the variables are updated according to the operation completed, and the script moves to the Cash-flows part. If no offer is acceptable for a certain hour, for any reason at any step of the logic chain, the script moves to next hour, remaining in the same block. If no offer can be accepted within the block, the script moves to the next block. Variables are not updated in these two last cases.

Cash-flows Update

Since MB is a pay-as-bid market, cost and revenues deriving from energy expenses are accounted as the multiplication of the reference price and the awarded quantity, for either one or two hours according to the effective quantity exchanged that can be, indeed, 1 or 2 MWh. When an operation is completed on MI, the Cash-flows movement is equal to the quantity exchanged multiplied by the PUN. The cost related to the cycle progression is equal to the cost for a complete cycle multiplied by the portion actually completed. Moreover, the cost of losses is added. Given the average efficiency of 0.9, the cost is equal to the 10% of traded quantity valued at the mean price of downward services for 2019. Once Cash-flows array is updated, operational variables are updated and the script moves to the next daily block, since one offer has already been accepted in the running one. Once the last 2019 hour is simulated, the cash-flow array contains all of the revenues and the costs.

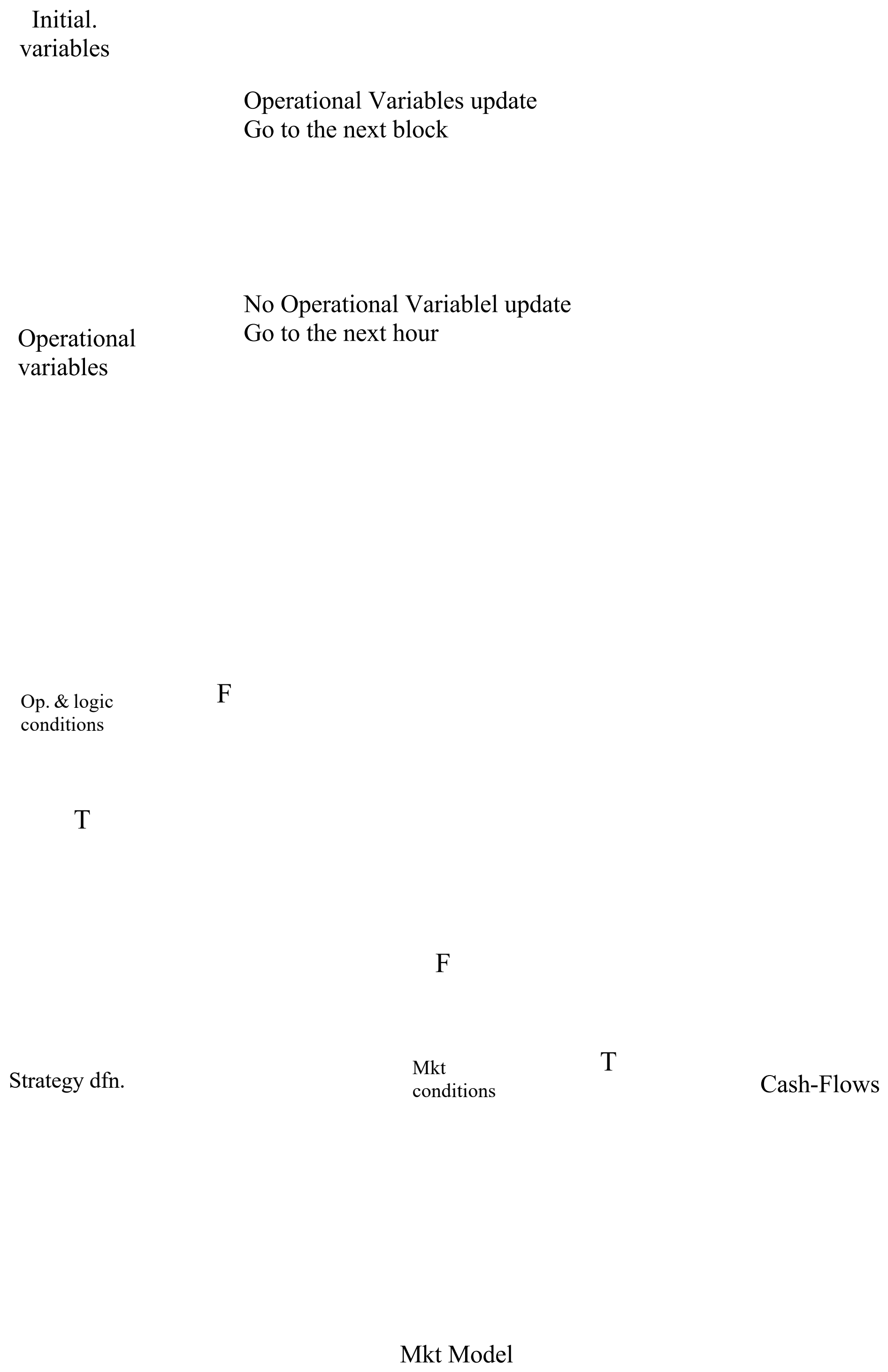

Figure 4.1 Simulations' flowchart. F stands for False; conditions of the block are not verified. T stands for True; conditions of the block are verified.

4.4 Results

From the Cash-flows array, total costs and revenues are calculated. When the UVAM framework is used, the incentive is an additional revenue. A sensitivity analysis is conducted, by the variation of the strategy and markets used. MI is used to guarantee the mandatory service in the UVAM regulation and eventually gaining the incentive. When MI is not used, no mandatory service is imposed, hence the unit can offer on MB by respecting market timeframes only[49]. This eventuality is used to evaluate the real effectiveness of current UVAM incentive policy and to propose possible developments. Economic results are assessed for 2019 only, so that also the investment cost is accounted by considering only the number of cycles completed in the year. This method allows a more truthful conclusion over the real performance of the battery itself. The following table is used for the NORD and CSUD results presentation.

Table 4.5 NORD and CSUD 2019 market simulations results for different strategies and different market usage, for an Li-ion battery with an expected lifetime of 6000 cycles.

UVAM CONFIGURATION

Market Zone	***Fixed-strategy***		***Adaptive-strategy***	
	Cycles	Cashflow [€]	Cycles	Cashflow [€]
NORD	496	(44089)	543	(43094)
CSUD	631	113370	653	118520

MB ONLY CONFIGURATION

Market Zone	***Fixed-strategy***		***Adaptive-strategy***	
	Cycles	Cashflow [€]	Cycles	Cashflow [€]
NORD	243	(6070)	298	(8095)
CSUD	383	148130	422	145070

MB ONLY CONFIGURATION

Market Zone	***Benchmark***	
	Cycles	Cashflow [€]
NORD	152	9160
CSUD	368	232890

[49] Under the current regulation for pilot projects [26], 1MW plants con operate, if enabled, without the necessity to respect mandatory timeframe, if they renounce

Under the aforementioned hypothesis, the results of the simulations follow similar patterns. A relevant note when reading the table is that although respecting UVAM constraints grants the 15000 € incentive, in the reported values the incentive is not applied in order to provide non-misleading insights. Evidently, CSUD benefits of price differentials described in Chapter 3, and the reduced volumes compared to NORD does not affect economic performance, with a Cashflow that overcomes 100000 € for all of the proposed cases. Positive cashflow indicates that energy revenues are higher than energy costs and costs associated to losses and the depreciation associated to relative ageing of the asset. Even if there is more available quantity in NORD, defining a competitive bidding strategy for CSUD is easier because of the reduced number of competitors. This is clear from the number of completed cycles which is always higher for CSUD. In both zones, benchmark results indicate how realistic bidding strategy are far from being optimized, with a more determinant influence in NORD, where the cashflows are positive only in the benchmarking situation. Except for CSUD in UVAM configuration, a better performance using the fixed strategy indicates that seasonal trends behind that strategy weigh more than monthly trends underlying the adaptive one. By comparing different configurations, the MB only solution has better economics. This is caused by the reduced price differentials that BES is sometimes forced to use in the UVAM configuration. Having to respect mandatory timeframes of the UVAM regulation, induces the BES to either complete a charging or discharging cycle before the mentioned daily block, by operating on MI, with less advantageous prices. This leads to an increased number of completed cycles which is not followed by an improvement of economic conditions as well. In fact, not only the BES is forced to work with thin differentials to guarantee the availability of contracted energy, but also it has not the provision guaranteed. It is true that on the regulatory level this opportunity cost is considered with the incentive scheme, but the incentive does not cover the actual cost that the operator faces. On the other hand, the benchmark strategy always results in the best cashflows with the lowest number of cycles completed. This is the proof that the ability of optimizing a bidding strategy to achieve better price differentials has a higher turnover than trying to total as many cycles as possible. This idea should drive future works.

CONCLUSIONS

In this thesis a new approach was developed to assess the energy storage systems economic feasibility and technology potentiality, respecting regulation constraints of the recently opened Italian ancillary service market. The main difference with commonly used probability-based approaches is that here the probability is used only to define a bidding strategy, while the effective economic result depends on the actual confrontation with the market. The accuracy of simulating the hourly market instead of considering only its overall results is deemed to provide more relevant results, as realistic conditions are recreated without just delimiting the theoretical potential. The difference is substantial, the method here adopted is more truthful to the market structure and actual market timeframes, hence it produces more reliable results. By the substitution of technology-specific constraints, the developed tool can be adapted to other technologies having a bidding strategy linked to the operating state. For the analyzed battery, the operating variable was the State Of Charge, characterized by three possible values. Exemplary, this easily applies to Demand Response, whose bidding strategy would depend on the hourly load and on the cost-effectiveness of the potential curtailment. Centre-South positive cashflow, which could have overcame 100000 € in 2019 according to the proposed model, should represent the starting point for battery storage systems diffusion for ancillary service provision. In fact, the profitability is promising and the investment would payback in around 10 years, which is compatible with an expected lifetime of 15 years with the average number of cycles yearly completed in the simulations. In addition, this guarantees a safety margin for unexpected events throughout the life cycle. Even current price trends do not justify a battery storage investment in North, forecasts predict a steep decrease in storage prices in the medium-long term with trends being adjusted downwards from year to year [39], [44]. In the short term a regulation review could help the process.

Some changes are proposed below.

i. *UVAM project review*: considering that the current incentive does not cover the profit loss deriving from the strict requirement of making available the maximum power during the mandatory timeframes (from 2 to 8 pm), the incentive should be reviewed. The profit loss should be evaluated and technology-specific regulation frameworks are desirable.

ii. *Start-up and Setup-change fee review*: as proposed by the Polytechnic of Milan, these fees should be capped and based on technical considerations rather than on market ones [6]. The expected systems cost reduction of 38 M€ for North and 1.6 M€ for Centre-South, could be exemplary used for financing new flexibility forms, through the UVAM project or similar.

iii. *Bidding structure and payment method*: in the simulations, it is assumed that the battery storage operator might offer for every hour of MB 4-hours blocks but only one offer can be accepted in every block. This architecture fits battery storage characteristics, it increases trading possibilities while reduces the risk of penalties deriving from mismatching. Contrary to TIDE hypothesis of using the equilibrium price in the ancillary services market as well, for an easier development of new form of flexibility the pay-as-bid remuneration should be maintained.

iv. *Opening the provision for new services*: a possible example is the chance given to BES to provide Primary Reserve with a dedicated product fitting storage's technical potentialities, the EFR, that requires an activation ramp of 1 minute and 15 minutes of service [9]. Even if new TIDE is opening to something similar, the concrete realization seems distant and the remuneration criteria are just sketched [6].

Future developments of this work should regard at first the extension of the dataset used for strategy elaboration, since it resulted that the best strategy is the one based on historic trends, therefore finding better bidding strategies and related determinant factors. Also, a more detailed statistical analysis could be used for forecasting the future market and not only using ex-post data. Moreover, the possibility of providing Primary Reserve through battery storage systems as well as the combination of storage and Photovoltaic or wind (enabling behind-the-meter charging) are interesting future developments.

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