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Comprehensive Evaluation of Electricity Market Design Elements for the Strategic Integration of Renewable Energies

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Abstract

One of the overarching challenges of the energy transition towards a decarbonized power system is balancing the power system with an increasing share of decentralized and inherently fluctuating resources. Such balancing is generally distinguished by two approaches: active and so-called passive balancing. On the one hand, active balancing implies the explicit activation of controllable resources, while passive balancing, on the other hand, describes the implicit approach around imbalance pricing schemes for both controllable and non-controllable resources. While both approaches potentially have the same effect, the academic debate about their effectiveness and side effects is vivid. Along with that, regulatory adoptions of imbalance pricing still vary notably among different European power systems.

The studies presented in this thesis aim to contribute to the debate on market design elements of balancing mechanisms to step up the successful integration of renewable and decentral energy resources (DERs) in power systems and connected markets. The study is based on the following triad: theoretical viewpoints as discussed in the academic discourse, regulatory framework developments as introduced at the European level, and empirical findings emerging from extensive numerical analyses of Italian market data.

A first set of studies investigates the implications of active balancing integration for DERs. The large-scale Italian UVAM project with more than 1,000 MW of new capacity from decentral assets added to the ancillary services market is critically reviewed. While the project's economic performance left space for improvement in the first 18 months of operation, subsequent case studies investigate the business opportunities that emerged for DERs under this framework. Analyzing active balancing provision from the perspective of a wind farm and a utility-scale battery energy storage unit quantifies the economic potential and highlights the challenges in terms of locational factors, adequate pricing strategies, and the implications of concurrent incentives.

A second set of studies focuses on market design elements for passive balancing integration instead. By comparing eight different imbalance pricing schemes with varying pricing rules and balancing products being considered, the comprehensive study confronts a broad spectrum of design elements as currently applied in Europe. An additional focus point concerns the sizing of imbalance pricing areas, a design element for which little empirical evidence has been provided so far. Findings suggest implementing local imbalance price areas to transmit a purposeful balancing incentive. Dynamic sizing further increases efficiency, whereas large macro-areas dilute local price signals significantly and impose unjustified burdens on individual

market participants. Welfare analysis of exemplary wind farm and PV operators underline the detrimental effects and complement the set of studies.

A last set of studies combines previous case studies and investigates the third approach of full balancing integration. Through value stacking of both active and passive balancing components, the interplay between different balancing integrations for DERs is highlighted. In a multi-period and multi-stage optimization of a virtually aggregated plant consisting of a PV and power-to-gas unit, the full flexibility potential with explicit and implicit service provisions is simulated. Findings suggest that value stacking can provide enhanced revenues of 40-100% compared to pure day-ahead market interactions but also highlight the complexity and resulting challenges of intertwined market operations. Furthermore, by enabling synergies behind the (virtual) meter, previously inelastic units merge with controllable complements and turn in sum price sensitive. Thus the opening for full balancing with combined active and passive balancing would demonstrably further boost the necessary integration of DERs.

Riassunto

Una delle sfide principali della transizione energetica verso un sistema energetico decarbonizzato è il bilanciamento con una quota crescente di risorse decentralizzate e intrinsecamente fluttuanti. Tale bilanciamento è generalmente distinto da due approcci: il bilanciamento attivo e il cosiddetto bilanciamento passivo. Da un lato, il bilanciamento attivo implica l'attivazione esplicita delle risorse controllabili, mentre il bilanciamento passivo prevede la risposta implicita di risorse controllabili e non controllabili a schemi di prezzo di sbilanciamento . Nonostante entrambi gli approcci abbiano potenzialmente lo stesso effetto, il dibattito accademico sulla loro efficacia e sugli effetti collaterali è vivace. Insieme a questo, le adozioni normative dei rispettivi schemi variano ancora notevolmente tra i diversi paesi europei.

Gli studi presentati in questa tesi mirano a contribuire al dibattito sugli elementi dei meccanismi di bilanciamento per accelerare l'integrazione delle risorse energetiche rinnovabili e decentralizzate (DER) nei sistemi elettrici e nei mercati connessi. Lo studio si basa sul seguente trittico: punti di vista teorici come discussi nel contesto accademico, sviluppi del quadro normativo introdotti a livello europeo, e risultati empirici che emergono da approfondite analisi numeriche di dati del mercato italiano.

Una prima serie di studi indaga le implicazioni dell'integrazione del bilanciamento attivo per le DER. Come primo passo, è stato esaminato il progetto italiano su larga scala UVAM con più di 1.000 MW di nuovi asset decentralizzati aggiunti al mercato dei servizi di dispacciamento. I casi di studio successivi indagano le opportunità di business emerse per le DER in questo contesto. Analizzando la fornitura di bilanciamento attivo dal punto di vista di un parco eolico e di una batteria di grande taglia, si quantifica il potenziale economico e si evidenziano le sfide in termini di fattori locali, strategie di prezzo adeguate e le implicazioni degli incentivi concomitanti.

Una seconda serie di studi si concentra invece sugli elementi per l'integrazione del bilanciamento passivo. Confrontando otto diversi schemi di prezzi di sbilanciamento con diverse regole di prezzo e prodotti, lo studio completo affronta un ampio spettro di elementi come attualmente applicati in Europa. Un ulteriore punto riguarda la formazione delle aree di prezzo di sbilanciamento, un elemento per il quale sono state fornite finora poche prove empiriche. I risultati suggeriscono l'implementazione di aree di prezzo di sbilanciamento locali per trasmettere un incentivo di bilanciamento efficace. Il dimensionamento dinamico aumenta ulteriormente l'efficienza, mentre le grandi macro-aree diluiscono i segnali di prezzo locali e impongono oneri ingiustificati ai singoli partecipanti di mercato.

Un'ultima serie di studi combina i casi di studio precedenti e indaga il terzo approccio dell'integrazione completa del bilanciamento. Attraverso il value stacking delle componenti di bilanciamento attivo e passivo, viene evidenziata l'interazione tra diversi schemi di bilanciamento per le DER. In un'ottimizzazione multiperiodo e multistadio di una centrale virtualmente aggregata composta da un'unità fotovoltaica e da un'unità power-to-gas, viene simulato il pieno potenziale di flessibilità con la fornitura di servizii espliciti ed impliciti. I risultati suggeriscono che il value stacking può fornire maggiori ricavi dal 40 al 100% rispetto alla pura partecipazione al mercato day-ahead, ma evidenziano anche la complessità e le conseguenti sfide delle operazioni tra mercati interconnessi. Inoltre, consentendo gli scambi dietro il contatore (virtuale), le unità precedentemente inelastiche sinergizzano con risorse controllabili e diventano quindi sensibili a segnali di prezzo. Pertanto, l'apertura al bilanciamento completo con il bilanciamento attivo e passivo combinato darebbe un ulteriore impulso alla necessaria integrazione delle DER.

Zusammenfassung

Eine der zentralen Herausforderungen der Energiewende hin zu einem dekarbonisierten Stromsystem ist es das System mit einem zunehmenden Anteil an dezentralen und inhärent fluktuierenden Ressourcen kontinuierlich in Balance zu halten. Um diesen Ausgleich zu erreichen werden im Allgemeinen zwei Ansätze unterschieden: der aktive und der sogenannte passive Ausgleich. Aktiver Ausgleich bedeutet einerseits die explizite Aktivierung steuerbarer Ressourcen, während passiver Ausgleich andererseits den impliziten Ansatz um Ausgleichspreissysteme, sowohl für steuerbare als auch für nicht steuerbare Ressourcen, beschreibt. Obwohl beide Ansätze potenziell die gleiche Wirkung haben, ist die akademische Debatte über ihre Wirksamkeit und Nebenwirkungen lebhaft und bisher uneindeutig. Ebenso variiert die Umsetzung von Ausgleichspreisen durch die Regulierungsbehörden in den verschiedenen europäischen Stromsystemen noch immer erheblich.

Die in dieser Arbeit vorgestellten Studien zielen darauf ab, einen Beitrag zur Debatte über verschiedene Elemente zur Marktgestaltung von Ausgleichsmechanismen zu leisten, und letztlich die erfolgreiche Integration erneuerbarer und dezentraler Energieressourcen (DERs) in Stromsysteme und verbundene Märkte zu fördern. Die Studie basiert auf dem folgendem Dreiklang: 1) Theoretische Gesichtspunkte, wie sie im akademischen Diskurs diskutiert werden, 2) Entwicklungen des regulatorischen Rahmens, wie sie auf europäischer Ebene eingeführt wurden, und 3) empirische Erkenntnisse, die sich aus umfangreichen numerischen Analysen italienischer Marktdaten ergeben.

Eine erste Reihe von Studien untersucht die Auswirkungen der Integration aktiver Ausgleichsenergie für DERs. Das italienische UVAM-Großprojekt, bei dem mehr als 1.000 MW an neuer Kapazität aus dezentralen Anlagen in den Markt für Systemdienstleistungen eingebracht wurden, wird kritisch untersucht. Während die wirtschaftliche Performance des Projekts in den ersten 18 Monaten des Betriebs noch Raum für Verbesserungen ließ, werden in den nachfolgenden Fallstudien die Geschäftsmöglichkeiten untersucht, die sich für DERs unter diesen Rahmenbedingungen ergeben haben. Die Analyse der aktiven Ausgleichsleistung aus der Perspektive eines Windparks und eines Batteriespeichers im industriellen Maßstab quantifiziert das wirtschaftliche Potenzial und zeigt die Herausforderungen in Bezug auf Standortfaktoren, angemessene Preisstrategien und die Auswirkungen von parallelen Fördermaßnahmen auf.

Eine zweite Reihe von Studien konzentriert sich stattdessen auf Marktgestaltungselemente für die Integration passiver Ausgleichsenergie. Durch den Vergleich von

acht verschiedenen Ausgleichsenergiepreissystemen mit unterschiedlichen Ansätzen zur Preisbildung wird in der umfassenden Studie ein breites Spektrum von Gestaltungselementen, wie sie derzeit in Europa angewandt werden, gegenübergestellt. Ein weiterer Schwerpunkt ist die Größe der Ausgleichsenergiegebiete, ein Gestaltungselement, für das es bisher nur wenige empirische Erkenntnisse gibt. Die Ergebnisse legen nahe, lokale Ausgleichspreiszonen zu implementieren, um einen zielgerichteten Ausgleichsanreiz zu vermitteln. Eine dynamische Dimensionierung erhöht die Effizienz weiter, während große Makrogebiete die lokalen Preissignale deutlich verwässern und einzelne Marktteilnehmer ungerechtfertigt belasten. Wertschöpfungsanalysen von beispielhaften Windpark- und PV-Betreibern unterstreichen die nachteiligen Effekte und ergänzen die Studienreihe.

Eine letzte Reihe von Studien kombiniert die vorangegangenen Fallstudien und untersucht den dritten Ansatz der vollständigen Integration. Durch eine Wertestapelung von aktiven und passiven Ausgleichskomponenten wird das Zusammenspiel zwischen verschiedenen Integrationsansätzen für DERs hervorgehoben. In einer mehrperiodischen und mehrstufigen Optimierung einer virtuell aggregierten Anlage, bestehend aus einem PV- und Power-to-Gas-Block, wird das volle Flexibilitätspotenzial mit expliziten und impliziten Leistungsvorgaben simuliert. Die Ergebnisse machen deutlich, dass so-genanntes Value Stacking im Vergleich zu reinen Day-Ahead-Marktinteraktionen zu höheren Erträgen von 40 bis 100% führen kann, zeigen aber auch die Komplexität und die sich daraus ergebenden Herausforderungen eines verflochtenen Marktbetriebs auf. Durch die Ermöglichung von Synergien hinter dem (virtuellen) Zähler verschmelzen außerdem zuvor unflexible Einheiten mit steuerbaren Anlagen und werden in der Summe preissensitiv. So würde die Öffnung für einen vollständigen Ausgleich mit kombiniertem aktivem und passivem Ausgleich die notwendige Integration von DERs nachweislich weiter fördern.

Foreword

This Thesis is written in the year when the University of Padua celebrates its 800th anniversary. Eight hundred years full of scientific achievements and associated social progress. Studying at this institution is an honor, a privilege that makes me humble and also a bit thoughtful in the face of this history.

In the 800 years since its founding, this institution has interacted with some of the most illustrious figures in history. Galileo Galilei, for example, was a professor here some 200 years ago, shared and deepened his knowledge during that time, and still shines as a bright star in the scientific firmament.

To become such a lighthouse nowadays, outshining everything, is most likely impossible. At best, this makes one humble, but perhaps, at times, it might make one also a little despondent. However, instead of despairing of perceived individual insignificance, I am convinced that we should rather rejoice in the fundamental brightness of these days, which certainly outshines that of earlier times. And precisely in this sense, I hope to contribute with this Thesis perhaps a small light, and may it be yet so tiny, so that the sky of our scientifically minted society may shine still a little brighter.

Padova in April 2022,

Jan Marc Schwidtal

Acknowledgements

The opportunity to have done this three-year doctorate fills me with great joy. It was an intensive, densely packed time. Not only have I had the opportunity to immerse myself in the topic of energy markets, but the doctorate has also brought me together with an incredible number of interesting people who have supported my work and inspired me along the way. Even though it is impossible to name all of them here, I would like to list at least the most significant ones.

First of all, Arturo Lorenzoni for the guidance but also the freedom he has given me as a supervisor to explore this topic and his network of valuable contacts that he has made available to add personal knowledge. The connections with the Florence School of Regulation (FSR) as well as with the International Energy Agency (IEA) that were established thanks to his mediation are, in retrospect, two of the most valuable connections that emerged from the PhD and that I hope will continue long after.

Second, Marco Agostini for his daily company in the lab and vigorous collaboration in all our joint projects. Without your expertise and translation skills of Italian regulation, I would not have gotten far. And not to mention your support in programming. On top of that, I will miss the excursions in local culture with Venetian dialect and Spritz at the end of the working day.

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Fourth, Roberto Turri, Fabio Bignucolo, and Massimiliano Coppo for integrating me so sincerely as a "foreign" PhD student into their research group in Padua and entrusting me with their original desk where they wrote their PhDs. I hope to have done justice to this historical piece of furniture; at least I have, literally, left my traces on the thoroughly interactive green surface.

Thanks also to the FSR as an institution for the in-depth courses and discussions I was allowed to attend, which raised my knowledge of European regulation to a new level each time, as well as the great network of energy professionals that resulted. Special thanks to Ilaria Conti for inviting me to the residential course on gas regulation, to Nicolò Rossetto for inviting me to the podcast on the Italian UVAM project, to Tim Schittekatte for kindly providing me with contacts in Madrid and Brussels.

Also, thanks to the IEA as an institution and in particular to UsersTCP with its Global Observatory on Peer-to-Peer, Community Self-Consumption, and Transactive Energy models for the opportunities they enable to young researchers. I have enjoyed collaborating in this international format and have found, in particular, two companions in Anna Gorbatcheva and Timothy Capper who were at similar points in their PhDs. Not only did your feedback help me through some of the mental lows of the PhD, but only together with you was it possible to conduct our study on local market and business models over such a long period of time and in such structured depth.

Sincere thanks to Jean-Michel Glachant and Christoph Burger as external reviewers for their time and input to improve this thesis. Likewise, to the Fondazione CARIPARO for providing the scholarship for foreign PhD students and the related financial opportunities to participate in courses, seminars, and conferences.

Last but definitely not least, very special gratitude goes to my family. To my parents who always believed in me and supported me throughout the whole time. My academic and professional path was without any doubt quite a long one, and yet it was never once questioned. To my brothers and grandparents, who always welcomed me at home with such open arms that it recharged all my energy reserves in what feels like seconds. My partner Carlotta, whose temperament and emotions always gave me that extra boost of energy that my German character would not have otherwise. Meeting you in Madrid and sharing the future since then was and is the personal highlight of this journey.

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Contents

1 Introduction

With the ratification of the Paris Climate Agreement, the European Union and its respective member states stipulated ambitious goals regarding emission reduction and energy generation [1]. The underlying increase of renewable energies in combination with increasing electrification of energy end-uses imposes a significant change of the electricity market structure with higher capacity and lower load factors, consumers becoming prosumers, and distinct subsidies and or penalties for individual energy resources [2–4]. Since this market development is still not naturally inherent but to a significant share guided by active policy interventions, the question arises: how could or should this transitional process be defined, shaped, and accompanied by regulations to reach the determined targets while keeping the societal costs as low as possible?

1.1 Background

One of the overarching challenges incorporated in this process is balancing the power system with an increasing share of decentralized and inherently fluctuating resources [5]. Such balancing is generally distinguished by two approaches: active and so-called passive balancing [6]. On the one hand, *active balancing* implies the explicit activation of controllable resources, while *passive balancing*, on the other hand, describes the implicit approach that circles around imbalance pricing schemes for both controllable and non-controllable resources [7]. Different imbalance pricing schemes set different incentives to balance or also not balance individual market positions [8]. If the incentives are set right, prompting market participants to deviate intentionally from their spot market position (or their forecasted load or generation profile) can indirectly balance the overall system [9].

While both approaches have thereby potentially the same effect, their underlying market design elements are clearly distinct and the academic debate especially about the effectiveness as well as side effects of passive balancing is vivid. Regulatory adoptions of imbalance pricing, for example, still vary notably among different power systems [10]. While in some European countries, such as the Netherlands, passive balancing is specifically desired, other countries such as Germany ban it. Different rules for specific resources or unit sizes, such as Italy with a specific scheme for small renewable plants, add to a variety of imbalance pricing schemes that are far from perfect or unified.

Also with regard to the active balancing approaches, notable differences at the European level persist [11]. Other than for the passive balancing approach, the academic position is less controversial, and also the regulatory approach at the overarching European level is more advanced with a comparably clear target model [12]. The remaining difference lies primarily in the extent to which individual countries have already adapted their market structures to this target model. One point of distinction remains thereby the market access barriers for decentral resources, be it in explicit form by excluding specific resource types such as non-programmable renewables or loads or in implicit form through minimum bid sizes and the permission for virtual aggregation or not.

1.2 Motivation, Research Questions and Overall Aim

The aim of the studies presented in this thesis is to contribute to the debate on market design elements of balancing mechanisms to step up the successful integration of Decentralized Energy Resources (DERs) and Renewable Energy Sources (RESs) in power systems and connected markets. The study is thereby based on the following triad: theoretical viewpoints as discussed in the academic discourse, regulatory framework developments as introduced at the European level, and empirical findings as emerging from extensive numerical analyses of Italian market data. Specific research questions are:

- What are the implications that individual aspects of enhanced balancing market access have with regard to the active balancing integration of DERs?
- What are the implications that different approaches of imbalance pricing have with regard to the passive balancing integration of DERs?
- What are the implications that the combination of active and passive balancing approaches has with regard to the overall balancing integration of DERs?

The focus shall be thereby twofold, investigating both individual (micro-economic) business as well as their wider (macro-economic) system implications of individual design elements by adopting a multiple case study approach [13]. After all, this research shall provide useful insight for two focus groups: On the one hand empirical findings to supports regulatory entities that might envisage future regulatory interventions and policy measures and, on the other hand, data-driven market insights for potential investing entities that might aim for a better understanding of emerging business opportunities under evolving regulatory frameworks.

1.3 Outline and Main Contributions

In the following, the structure of this thesis is outlined, and the main contributions of every chapter are summarized. The chosen scientific approach of this research project consists of two separate sections. A profound literature review in collaboration with international researchers sets the scene with academic viewpoints on transitioning energy ecosystems (Chapter 2). Upon this background analysis, the autonomous research work of Chapters 2 to 7 then represents the heart of the thesis on balancing integration of DERs. It utilizes empirical data from the Italian market to investigate the impact of individual regulatory design elements concerning active and passive balancing approaches and their interconnection. Figure 1.1 provides an overview of the structure, divided into eight chapters and an appendix. Appendix A lists all publications published within the scope of this thesis and Appendix B provides supplementary material.

Chapter 2 - Academic Viewpoints on Transitioning Energy Ecosystems Findings from a comprehensive literature review on transitioning energy ecosystems with their emerging local energy markets and business models provide the starting point to set the following empirical analysis into context. The structured review of academic viewpoints has been elaborated collaboratively with international researchers of the Global Observatory on Peer-to-Peer (P2P), Community Self-Consumption (CSC), and Transactive Energy (TE) models. In a first step, the analysis identifies and maps the main actor categories which academic authors envision in local energy markets. As aggregators are noticed as a central player to integrate Distributed Energy Resources (DERs), their Business Model (BM) as described in literature is analyzed in detail. In a second step the relations that characterize different ecosystem models are illustrated.

Chapter 3 - The Italian Framework Given the high availability of market and operational data from Italy, the following case studies are situated in an Italian context. This chapter introduces the Italian market framework and provides the methodology for the following analysis based on the empirical market data.

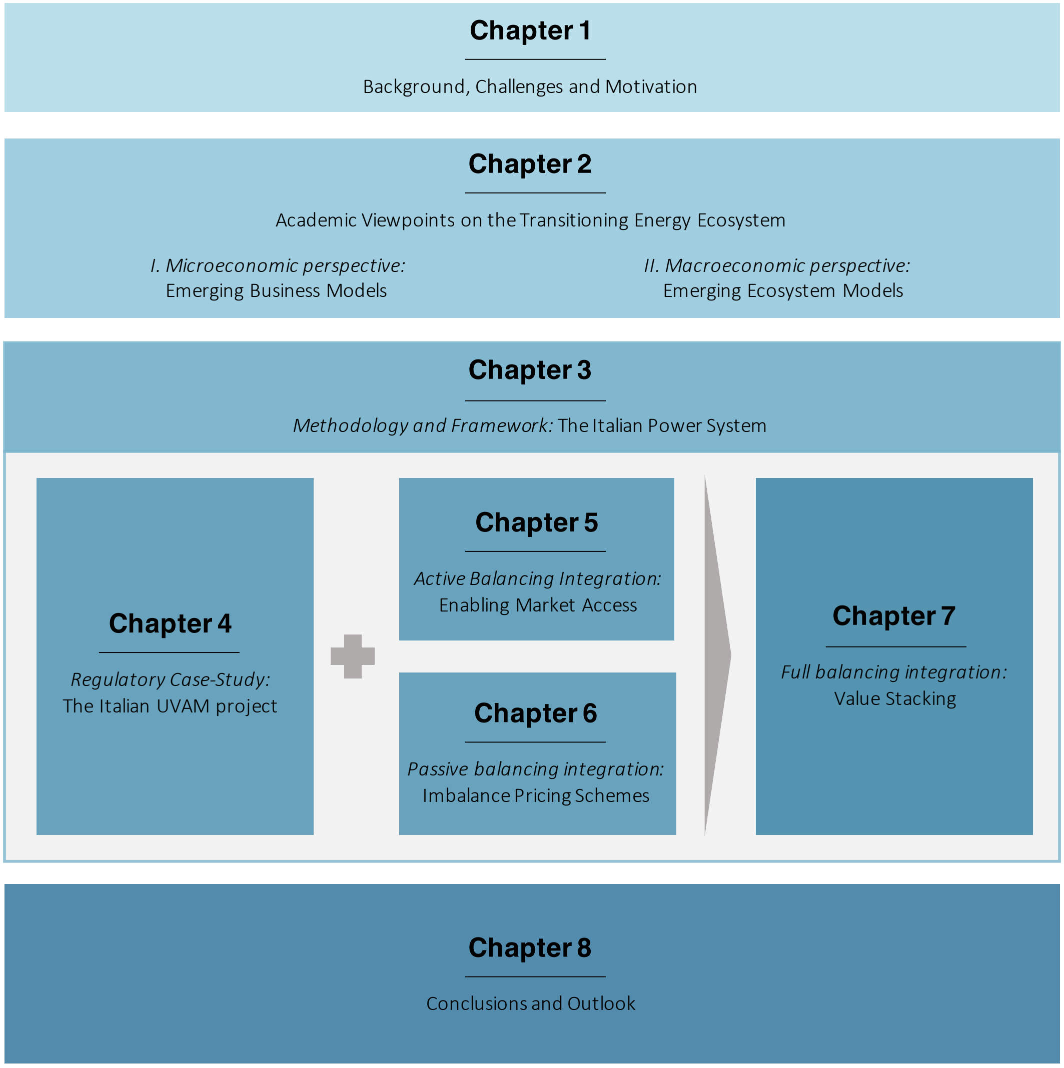

Figure 1.1: Overview of the logical structure of this thesis.

Chapter 4 - The Italian UVAM Project Utilizing the processed empirical market data, a first analysis focused on the performance of the Italian UVAM project. With more than 1,000 MW of new capacity from decentral assets added to the ancillary services market, the project represent a major regulatory case study. Based on in-depth data analysis, both individual units as well as the sum of the project's participants market integration is traced to understand: I) whether and how the new units actually participated in the market; II) what influences the individual design elements of the project's regulatory framework had; and III) how the units' behavior changed in the course of the project.

Chapter 5 - Enabling Market Access Upon the rather macroeconomic analysis of the UVAM project follows a first set of case studies to investigate the business opportunities that emerged for DERs under this framework. From the perspective of a wind farm and a utility-scale Battery Energy Storage System (BESS) the economic potential of active balancing integration is quantified and the challenges in terms of locational factors, adequate pricing strategies, as well as the implications of concurrent incentive schemes are highlighted.

Chapter 6 - Imbalance Pricing Schemes Switching from active to passive balancing, a second set of studies focuses on market design elements around imbalance pricing schemes. By comparing eight different pricing schemes with varying pricing rules and balancing products being considered, the comprehensive study confronts a broad spectrum of design elements as currently applied in Europe. An additional focus point concerns the sizing of imbalance pricing areas, a design element for which little empirical evidence has been provided so far. Welfare analysis of exemplary wind farm and PV operators complement the set of studies.

Chapter 7 - Value Stacking Eventually, a third case study line combines initial findings from the previous two chapters and analyzes the additional added value from full balancing integration. Through value stacking of both active and passive balancing components, the interplay between different balancing integrations for DERs is highlighted. In a multi-period and multi-stage optimization of a virtually aggregated plant consisting of a PV and power-to-gas unit, the full flexibility potential with explicit and implicit service provisions is simulated.

Chapter 8 - Conclusions The overall findings of this thesis are summarized in Chapter 8. Based on the empirical findings from the various studies and the confrontation with academic viewpoints as well as regulatory developments, updated policy recommendations for individual market design elements complement the thesis.

2 Setting the Scene: Academic Viewpoints on Transitioning Energy Ecosystems

This chapter contains collaborative material from

Jan Marc Schwidtal, Proadpran Piccini, Matteo Troncia, Ruzanna Chitchyan, Mehdi Montakhabi, Christina Francis, et al. *Emerging business models in local energy markets: A systematic review of Peer-to-Peer, Community Self-Consumption, and Transactive Energy models*. 2022. **Preprint**, cited as [14].

In order to provide a profound and comprehensive basis for the following analyses, this chapter aims to provide an overview of academic viewpoints on transitioning energy ecosystems. The presented findings have been elaborated collaboratively[1] with international researchers of the Global Observatory on P2P, CSC, and TE models, a task of Users' Technology Corporation Program of the International Energy Agency (IEA)[2].

2.1 Introduction

The ongoing energy transition is primarily influenced by the interplay between digitalization and the increasing prevalence of DERs. This fosters a far-reaching transformation of the power sector and the proliferation of potentially new Local Energy Market (LEM) models [15]. In this drive for innovation, the most widely discussed models in industry and academic literature are P2P, CSC, and TE [16–18]. All three models share common characteristics but differ in terms of size, operational

[1] Individual contributions to the collaborative research concerned the administration and conceptualization, methodology development, data investigation and validation, formal analysis, visualization, as well as the lead authorship in terms of writing and review for the joint manuscript [14]. For more information see also the respective manuscript's Credit Author Statement.

[2] More information on the Observatory's homepage under https://userstcp.org/task/peer-to-peer-energy-trading/

scale, and the primary purpose of their market activities [19]. Specifically, P2P refers to a concept of direct electricity exchange between local, same-level market participants that generally dispenses with central intermediaries of the conventional electricity value chain. CSC is based on a jointly acting community of actors in physical proximity and focuses rather on a range of environmental, economic, and social community benefits than sole financial profits. Finally, the concept of TE focuses on the dynamic interaction of both local and global power system actors, guided by value as a key indicator [14].

The power industry's transformation occurs at two levels, the system and the actor level. At the actor (i.e., the energy market participant) level, the proliferation of decentralized assets has, on the one hand, multiplied the number of potential market players [20]. On the other hand, the fragmentation of the field of participants has created the need for new actor types as facilitators or service providers and allowed a number of new digital technology businesses to enter the scene [21]. At the system (i.e., the energy ecosystem) level, the evolution was recognized as a new change from supply-centric to consumer-centric energy models [22]. Furthermore, the emergence of small-scale distributed power production creates opportunities for different market features and entails new types of collaboration among different market models [23].

Therefore, academic views on the ongoing transition of energy ecosystems are examined from these two opposing perspectives, i.e. at the system and actor level. Admittedly, academic models are often somewhat detached from reality or at least not directly comparable with current market models, not least because of the abstractions and simplifications that are often necessary. Nevertheless, it seems important to outline the implications of these central academic target models, as individual aspects can also be found in current regulatory innovations.

The main focus of this chapter is on the BMs implicitly integrated in academic literature and in particular on those that are found in all three market models and that take on central roles here. The aim is to extract a approximate understanding of how the value chains in emerging market models are linked, which actors take on which tasks and what the central elements of their academically envisioned BMs are. Specific research questions are therefore:

1. Who are the actors that dominate emerging local energy markets?
2. What are the market roles that academic authors envision for these actors?
3. How are the business models connected among each other in local ecosystems?

The remaining chapter is structured as follows. Section 2.2 describes the methodology that has been applied to structure the underlying literature review together with the other international researchers. Section 2.3 outlines then the identified actor profiles and their BMs, Section 2.4 describes how these businesses connect to ecosystems in different market models, and finally Section 2.5 summarizes the key findings.

2.2 Literature Review Methodology

The present study follows a systematic literature review methodology as reported by Kitchenham [24]. Therefore, the adopted methodology is composed of three key elements: search strategy and selection criteria, data extraction, and data analysis.

Data search and selection The objective of the search strategy is to identify and classify papers concerning peer-to-peer trading, transactive energy, a community of self-consumption in electricity markets. The search strategy adopted aims to cover the variety of terms that can be used to refer to the same concept. Given that the terms "peer to peer", "community/collective self-consumption", and "transactive electricity" are poorly defined, the study relied on the judgment of the paper authors to include papers that the authors claim are about peer-to-peer, self-consumption, or transactive energy. Therefore, for articles title, abstract, and keywords, the search string used in this work is:

> *("peer to peer" OR "peer-to-peer" OR P2P) OR ("self consumption" OR "self-consumption" OR CSC) OR (transactive OR TE) AND electricity* .

Only journal articles indexed in the Scopus and Web of Science digital libraries have been of interest for the literature review. These sources were chosen since they include the most widely referenced and indexed peer-reviewed publications on energy and market design topics.

Subsequently, the following inclusion criteria were used to identify the relevant publications from the mentioned digital libraries:

- *Publication Year:* All papers published in online repositories up till and including 25 March 2020;
- *Publication Type:* All peer-reviewed papers published in journals;
- *Content:* Papers that electricity trading over peer to peer, transactive energy, or self-consumption models.

- *Publication Language:* Only English language papers.

The term-based search yielded 1,346 titles from the two digital libraries in the first instance. Through checking for duplicates, 454 of these results were excluded in a second step. The remaining papers were reviewed for relevance against the inclusion criteria, resulting in the removal of another 747 papers. The remaining 145 were thoroughly examined using the methods outlined in the following two subsections. During a more thorough evaluation, a further ten previously considered relevant studies were determined to lack sufficient concentration on P2P, CSC, and TE models and thus also excluded. As a result, the data presented here is based on a corpus of 135 publications that have been examined.

Data extraction Data extraction and analysis have been carried out using a deductive approach to theme and code development, following the thematic analysis as proposed by [25]. Because this research was designed from the start to elicit a diversity of BMs, and the Business Model Canvas (BMC) framework gives a comprehensive breakdown of the elements from which a BM is created [26], the study takes a detective approach to the thematic analysis.

The BMC represents a commonly used tool by both academics and practitioners in the energy sector to describe, discuss, and analyze existing BMs [27–30]. It is subdivided into nine elements, representing the so-called building blocks for each BM as depicted in Figure 2.1. The building blocks are thereby not just a list of elements but form a structured framework that describes the interrelationships of the business model in its entirety.

Starting on the right-hand side, the *Customer Segments* describe the groups of individuals or organizations for which a company wants to create value. For each segment of them, the business has a central *Value Proposition* that consists of a bundle of products and services to create value for their customers. The value is then communicated and delivered through different *Channels* to the customers. *Customer Relationships* are the type of relationships a business develops and maintains with its customers.

On the left-hand side, the canvas captures the *Key Activities* a business needs to perform to create, deliver, and capture the proposed value. The *Key Resources* imply the indispensable assets that are necessary to do so. Cooperative agreements with other actors to leverage the BM are mapped under *Key Partners*.

Once the BMs infrastructure is defined through the upper building blocks, the financial structure is outlined on the one hand through the *Cost Structure* that specifies the costs incurred for operating it and the *Revenue Streams* that describes the income obtained from the different Value Propositions provided to customers.

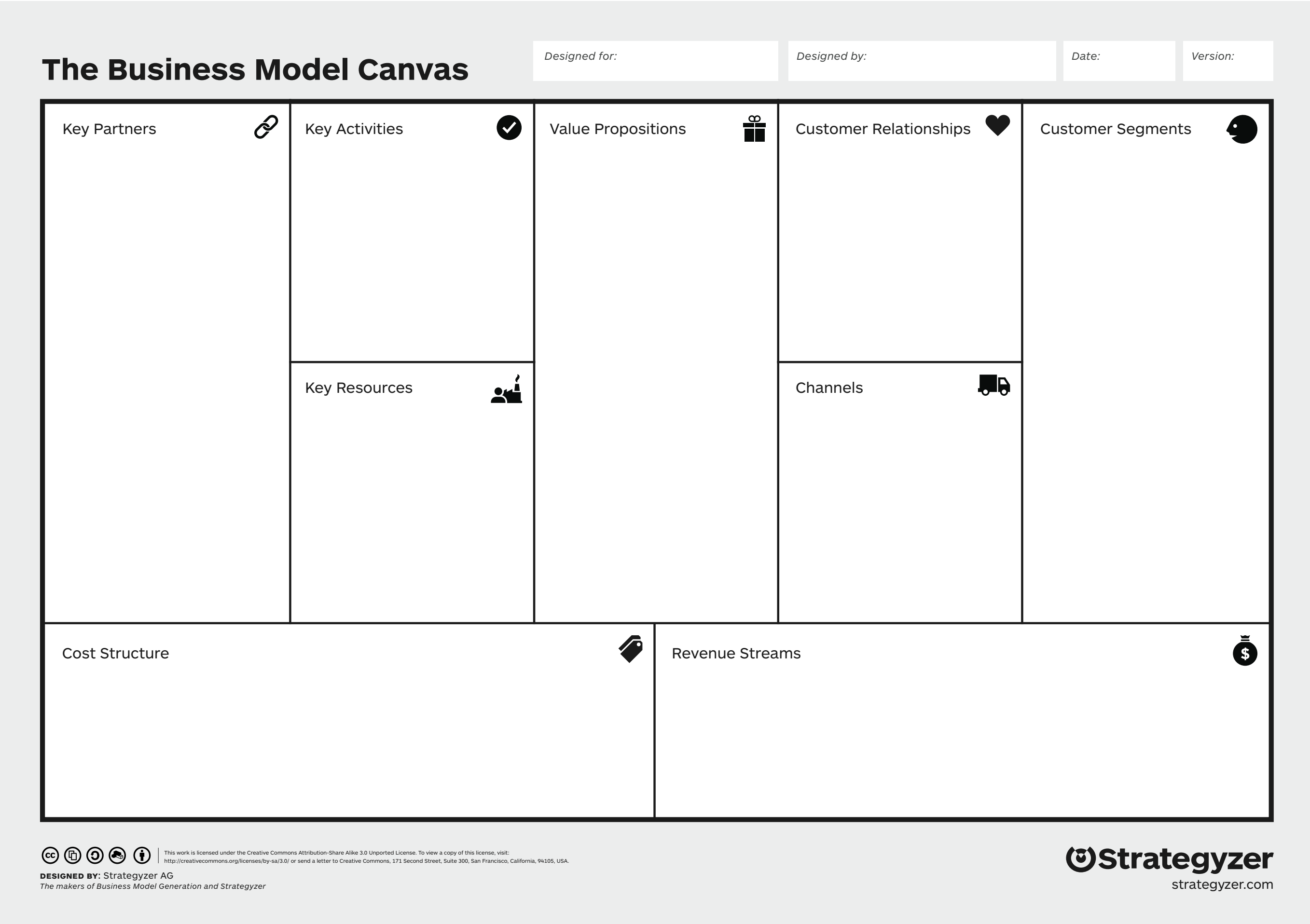

Figure 2.1: Template of the Business Model Canvas, reprinted with permission from [@31]

To create a better understanding of the distinctions between individual BMs, additional subcategories were introduced as follows:

- Channels were subdivided into channels for evaluating, purchasing, and delivering the value proposition-
- Key Resources were further subdivided into tangible, non-tangible, and human resources.
- Revenue Streams were distinguished between those based on static or dynamic variables.
- Cost Structures were differentiated between Capital Expenditures (CAPEXs) and Operational Expenditures (OPEXs).

For the following data extraction, the 135 publications were randomly divided among 14 researchers. Each researcher extracted data for the different BM elements of each identified active business on their own. If a document mentioned numerous active businesses, the data extraction method represented each business separately. The word "active business" denotes that the identified actor (e.g., organization, corporation, etc.) participates actively within the market addressed in the reviewed paper, and that the BMC elements for its operations are sufficiently outlined. Weekly meetings served to continuously monitor the correctness of extraction samples.

To ensure that the data extraction process had been undertaken consistently, an additional cross-review process was initiated upon completion of the individual data extraction. Therefore, the data extraction categories, i.e., BM elements, were assigned to independent researchers to validate the extracted data of each category for:

1. Completeness (i.e, no missing information);
2. Information type consistency with the BMC framework;
3. Relevance (i.e., the provided data informs the set category).

The BMC element review process did not check the accuracy of data extracted from the papers. However, where inconsistencies or missing data were detected, the initial researchers that performed the data extraction addressed the issue to finalize the data extraction. The full set of extracted raw data from all reviewed papers has been eventually made freely available at https://doi.org/10.48420/16930768.

Data analysis methodology The extracted data was subsequently analyzed in two stages: first, the identified BMs were clustered into generic actor types. Such was done by using the European Harmonized electricity market Role Model (HRM) model [32] as an additional framework to distinguish economic and managerial roles in electricity markets. The HRM is developed and maintained by the european forum for energy business Information eXchange ebIX, the European Federation of Energy Traders EFET and the European Network of Transmission System Operators for Electricity ENTSO-E. Building the actor analysis around the harmonized roles provides two major advantages. On the one hand, it facilitates the comparison of obtained findings with characteristics of currently existing actors in emerging pilot projects (being the fundamental second work-package of the IEA Global Observatory, starting soon). On the other hand, it provides clearer indications for other researchers that want to confront their findings with the presented results by following a structured methodology. To that regard, the regulation working group of the BRIDGE initiative reviewed for example the latest version of the HRM model and provided feedback along with potential modifications or add-ons from the perspective of European H2020 research projects [33].

Second, when the generic actor types were derived, the actor-specific BMs as envisioned and described by academic authors in literature were analyzed based on the associated set of data. Therefore, the BMC elements provided not only a structure for the initial data extraction but also for the following BM analysis.

2.3 Emerging Business Models

As a result of the extensive, structured literature review, this section presents first the identified macro actor-categories that are most discussed in LEM literature. Second, the BM of Aggregators as characterized by the sum of academic authors is presented in detail.

2.3.1 Macro Actor-Categories

The data extraction revealed the diversity of actor names currently used in the academic literature. Some terms are seemingly used synonymously for the same or at least very similar concepts, for example "Load-serving entity", "Retailer", and "Supplier". Other terms share a basic concept but describe specific variations of it, for example "Demand-Response Aggregator", "Load Aggregator", and "Microgrid

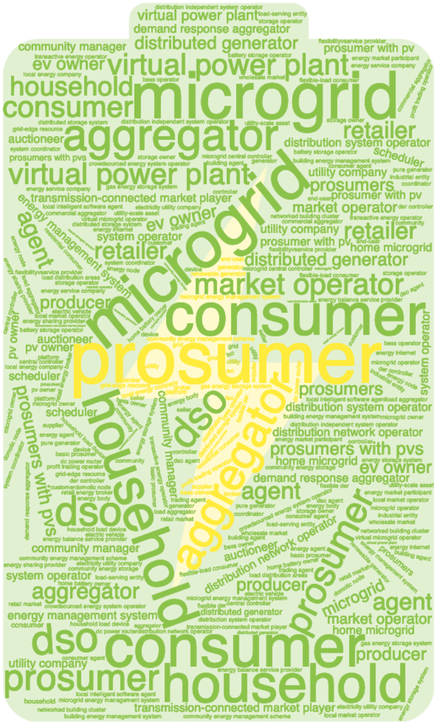

Figure 2.2: Word cloud of initial terms used in reviewed literature to describe active business in local energy markets.

Aggregator". In the 135 publications analyzed, a total of 225 active businesses were identified with 115 different terms. Figure 2.2 provides an overview of the terms mentioned and the frequency of their occurrence in the form of a word cloud.

While undertaking data extraction, it was observed that the actors and their underlying BMs, as discussed in the literature, correspond to a certain set of roles undertaken by market players within current electricity markets. This is not surprising as the businesses discussed in the literature are also intended to play various roles in the electricity market. The European HRM model served thus as a starting point for categorizing the BMs.

The HRM model In line with the HRM, an actor is defined as a party that participates in a business transaction. Each market consists of a set of roles that interact. In the HRM, the focus is on a distinction between the economic & managerial roles of businesses along the value chain of integrated energy market models. This is very much in line with the scope of this work and facilitates the subsequent BM analysis. For example, one value chain in the HRM for a single bidding zone (as a physical market) includes a “Market Operator” working through “Energy Traders”, “Energy Suppliers” attached to specific Accounting Points (or metering points) reaching to a “Party Connected to the Grid”, which can be either a “Producer” or “Consumer”. Other roles supplement this process.

Each actor exists in different variations, meaning it can consist of a different set of techno-economical roles as defined by the European methodology. The analysis defines for each actor a minimum set of roles that characterize this business as well as additional roles that this business might potentially embody on top of that. As an example, a Prosumer is in the most basic version the combination of the HRM roles of a producer and a consumer as well as a party connected to the grid. Potentially, the Prosumer could also manage the resources actively by itself, hence taking the so-called role of a resource provider. On the other hand, the management of the respective resources could be assumed also by a third party (e.g. an Aggregator). This way, the range of roles for each actor that was identified in the literature is defined as a min-max set of techno-economical roles based on the harmonized European methodology.

Having developed the generic categories, the BMs from the literature were mapped to the generic category types. For this, the information on business activities and interactions with the customers, as discussed in data extracted for each analyzed BM, was then compared to the set of definitions, thus placing each analyzed BM under a generic category.

Identified Macro-Actor categories Based on the identified businesses in the reviewed literature and the confrontation with the techno-economical roles of the HRM, nine macro actor-categories have been identified from a business and market interaction perspective. The actor categories are shortly presented and then further described and defined in the following section.

Overall, the nine macro-actor categories can be organized into three sets. A first set represents those actors with physical grid connections that are at the same time asset owners. These are:

- Prosumers;
- Pure Consumers;
- Pure Generators;
- Storage Operators.

A second set comprises facilitators and multipliers, which act either as intermediaries for market interactions of individual actors or groups of actors, or that provide a platform for direct interaction amongst actors. Namely, these are:

- Platform Operators ;
- Aggregators;
- Representatives.

A third set of actors are service providers and potential customers of asset owning actors. These are:

- Retailers;
- Grid Operators.

Figure 2.3 illustrates the dissemination of the identified macro actor-categories in the reviewed LEM literature. It can be seen that entities with a grid connection dominate the group of actors and make up about sixty percent of the total number of businesses described. Amongst these, Prosumers clearly prevail as the overall most described business. Besides Prosumers, Aggregators and Platform Operators, in general, represent two other widespread actors, underlining the prominence of facilitators in LEM models. The group of service providers with Retailers and Grid Operators, on the other hand, constitutes the group of actors that are least described in the literature. This, however, only relates to their participation in the LEMs as active businesses. As indicated in Section 2.4, their position as supportive partners and customers to other businesses is clearly more pronounced. A characterization of each actor type is provided in the following section.

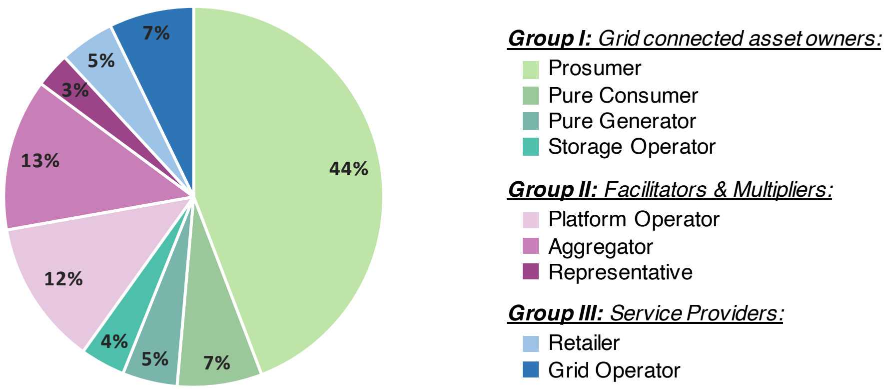

Figure 2.3: Dissemination of identified macro actor-categories in reviewed LEM literature. *(Adapted from [14])*

Note that the macro-actor categorization is non-exclusive as actors in literature can also take multiple roles in different contexts. A business labeled as a "microgrid operator" might act for example for a set of microgrid participants on the one hand as a Platform Operator to facilitate exchange energy amongst them, as well as an Aggregator on the other hand to enable coordinated ancillary services from them towards the Grid Operator. Also, additional combination, for example, taking on the role of a Retailer to supply the local participants with supplementary electricity from the spot market in case the microgrid's electricity generation is not self-sufficient, has been recorded in literature. While analyzing their described BMs, whether or not such combined roles might pose any legal and regulatory challenges has not been judged.

2.3.2 Actor Definitions

To characterize the macro actor-categories as clustered from the reviewed literature, in the following, a short profile of each actor type is outlined. This contains a short description of its key characteristics, the specific sets of HRM role combinations, and a selection of synonyms used in literature to label this role are presented in the following. These actor definitions create a sound basis upon which the associated business model findings can be structured and to which the empirical case studies in the following chapters can refer. Further detail on the individual HRM roles is provided in the Annex B.1.1.

The performed analysis used a simplified HRM version with a reduced set of roles for the clustering process, focusing on the most apparent ones to characterize businesses along the value chain in different markets. Minor roles with less visibility in academic literature, such as Balancing Responsible Partys (BRPs) or Balancing Service Providers (BSPs), are still stated for the sake of value chain completeness in the definitions parenthesis but did not actively interfere in the clustering process.

Prosumer

- *Characterization:* A Prosumer is an entity that is connected to the grid, and that injects and withdraws energy at the same grid connection point. It is characterized by a bidirectional electricity flow based on generating, consuming, and storing assets at its grid connection point and exists in various dimensions from electric vehicles to residential households, over commercial buildings up to microgrids interacting with other microgrids;
- *Minimum combination of HRM roles:* Party Connected to the Grid, Producer, Consumer;
- *Potential combination of HRM roles:* Party Connected to the Grid, Producer, Consumer, Resource Provider, Energy Supplier, Energy Trader (& BRP, CRP, BSP, PRP);

- *Synonyms as associated in literature:* Residential Prosumer, Commercial Prosumer, Electric Vehicle (EV)[3], Microgrid.

Pure Consumer

- *Characterization:* A Pure Consumer is an entity connected to the grid that possesses and potentially operates its own assets to consume electricity. Amongst such assets can also be storage assets, as long as they are only used to shift consumption and not re-inject electricity in the grid. A Pure Consumer is therefore characterized by a unidirectional, withdrawing electricity flow at its grid connection point;

- *Minimum combination of HRM roles:* Party Connected to the Grid, Consumer;

- *Potential combination of HRM roles:* Party Connected to the Grid, Consumer, Resource Provider, Energy Supplier, Energy Trader (& BRP, BSP, CRP);

- *Synonyms as associated in literature:* Consumer, Customer, End user, Electric Vehicle[4], Household.

Pure Generator

- *Characterization:* A Pure Generator is an entity connected to the grid that possesses and potentially operates its own assets to generate electricity. It is thereby characterized by a predominately unidirectional, injecting electricity flow at its grid connection point;

- *Minimum combination of HRM roles:* Party Connected to the Grid, Producer;

- *Potential combination of HRM roles:* Party Connected to the Grid, Producer, Resource Provider, Energy Supplier, Energy Trader (& BRP, BSP, PRP);

- *Synonyms as associated in literature:* Distributed Generators, Generators, Producer, Seller.

[3] EVs are associated to Prosumers as long as they are characterized by a bidirectional electricity flow, i.e. providing explicit flexibility services through a vehicle-to-grid scheme.

[4] EVs are associated to Pure Consumers as long as they are characterized by an exclusively unidirectional flow. Such might nonetheless contain an implicit flexibility provision through smart charging (load-shifting).

Storage Operator

- *Characterization:* A Storage Operator is an entity connected to the grid that possesses and operates its own assets to store electricity. It neither generates nor consumes energy (except minor process losses), but buys, keeps for a time, and then sells energy to the local market at different instances of time. It is thereby characterized by a bidirectional electricity flow at its grid connection point;
- *Combination of HRM roles:* Party Connected to the Grid, Resource Provider, Energy Supplier, Energy Trader (& BRP, BSP);
- *Synonyms as associated in literature:* BESS owner, BESS operator, Battery storage operator, Gas energy storage system.

Platform Operator

- *Characterization:* A Platform Operator is a single agent that operates a platform for energy trading. They are not connected to the grid and do not own any relevant generation or consumption assets, but facilitate the exchange amongst them. Such activity can encompass the mere provision of the platform, or also more active tasks such as market clearing and the subsequent billing. In some cases the energy platform will furthermore be responsible to supply the cleared energy to local participants and hence take over the role of a local supplier;
- *Minimum combination of HRM roles:* Market Information Aggregator, Data Provider;
- *Potential combination of HRM roles:* Market Information Aggregator, Data Provider, Billing Agent, Market Operator, Energy Supplier;
- *Synonyms as associated in literature:* Local Market Operator, Community manager, Coordinator, Crowdsourced Energy System Operator, Microgrid Operator, Transactive Energy Operator, Virtual Energy Company.

Aggregator

- *Characterization:* An Aggregator is a virtual entity, not physically connected to the grid, which acts on behalf of a variable group of parties connected to the grid (or their Representatives). Aggregators manage the combination of their clients' individual assets as one virtually aggregated asset, with various levels of activity on a potential plurality of markets. As such, they can represent in the simplest case one type of actor with one unidirectional offering (e.g., as a load Aggregator for a number of Pure Consumers) up to a diverse number of actors with a diverse portfolio of controllable and non-controllable assets with bidirectional needs and offerings on multiple markets (commodity and services) in more advanced cases;

- *Minimum combination of HRM roles:* Resource Provider, Resource Aggregator;
- *Potential combination of HRM roles:* Resource Provider, Resource Aggregator, Energy Supplier, Energy Trader (& BRP, BSP, CRP, PRP);
- *Synonyms as associated in literature:* Demand Response Aggregator, Load Aggregator, Micro Grid Energy Manager, Virtual Power Plant, Commercial Aggregator, Flexibility Service Provider.

Representative

- *Characterization:* A Representative is a virtual entity, not physically connected to the grid, which acts on behalf of a single party connected to the grid. Representatives manage (the potential combination of) their client's individual asset(s) towards a potential plurality of traders (such as Retailers or Aggregators) or market platforms with varying products or services depending on the clients' preferences and asset capabilities. Other than Aggregators, they always represent only one single client. Representative are in that sense somewhat of a personal small-scale, behind-the-meter Aggregator with a common example being home energy management systems;
- *Minimum combination of HRM roles:* Resource Provider *or* Energy Supplier, Energy Trader;
- *Potential combination of HRM roles:* Resource Provider, Energy Supplier, Energy Trader (& BRP, BSP, CRP, PRP);
- *Synonyms as associated in literature:* Agent, Broker, Building Energy Management System (BEMS), Home Energy Management System (HEMS), Domotic Node, Energy Node.

Retailer

- *Characterization:* A Retailer is usually a virtual entity, not physically connected to the grid, which does not own any physical assets. It hence neither generates nor consumes energy but buys and sells energy to the individual clients and in exchange with energy platforms. They often connect markets of different levels, e.g. the local market with an overarching wholesale market. In some exceptional cases, they also own generation assets and are hence an actual party connected to the grid, in parallel to their virtual trader and supplier role;

- *Minimum combination of HRM roles:* Energy Supplier, Energy Trader;
- *Potential combination of HRM roles:* Energy Supplier, Energy Trader, Resource Provider, Producer, Party connected to the grid;
- *Synonyms as associated in literature:* Local Energy Company, Load Serving Entity, Utility company, Supplier.

Grid Operator

- *Characterization:* A Grid Operator is an entity that manages, develops, and maintains the electricity or gas network for a specific territory. Such management can range from the mere infrastructure provision to rather passive management by only flagging potential resource scheduling issues up to active grid management with reserve provision and deployment;
- *Minimum combination of HRM roles:* System operator;
- *Potential combination of HRM roles:* System operator, Scheduling Area Responsible, LFC operator, Merit Order List Responsible, Reserve Allocator;
- *Synonyms as associated in literature:* Distribution Network Operator, Distribution System Operator, Distribution Independent System Operator, Independent System Operator, System Operator.

2.3.3 The Aggregator Business Model

Based on the identified macro actor-categories, the clustered business models for each actor as envisioned in academic literature were generated and analyzed. All actors have a very individual but equally important role in the ecosystem of LEMs, as shown in Section 2.4. Nonetheless, one actor stands out with particular importance for the further course of this thesis. Aggregators are not only the most cited facilitating actor across the reviewed LEM literature, but also central to many current developments in the European power sector. Chapter 4 discusses the side-effects of their first large-scale introduction in Italy and the case studies in chapters 5 and 7 are prepared from their perspective. The BM obtained from the literature review is thus presented in the following in detail, followed by a short discussion and comparisons to existing market roles. For more details on the BMs of the other macro-actors please refer to Schwidtal et al. [14].

Reviewing the academic perspective The corpus of 135 journal papers on LEMs comprised 29 publications that contained Aggregators actively interacting with one or more actors and the market. For each of these Aggregators, individual BM elements have been extracted by following the methodology as described in Section 2.2. This section outlines and discusses the clustered BM of an archetype Aggregator with exemplary references, the full list of references with more detail on individual elements is provided in Section B.1.2 in the Appendix.

Aggregators are relatively new players in the power system, aggregating various distributed generation and/or consumption units, to then act as a single entity on behalf of bundled customers and their assets. As distilled from the reviewed literature, Aggregators often engage in both EMs as well as ASMs and represent the nexus between large upstream actors and small, local downstream actors. This connection is particularly pronounced in models of TE markets (e.g., [34–36]). While it might appear surprising in the first place to find Aggregators also in P2P models, Aggregators are envisioned in some of tehse cases to become peers themselves and trade electricity with other peers (e.g., [37]). For CSC models, Aggregators' presence might be likewise surprising at first glance. However, in the two cases of such models with Aggregators, the latter take the role of a community manager that facilitates electricity exchange among local customers in a P2P fashion[5], and then, in a second step, connect them to upstream actors ([38, 39]).

In the reviewed literature, there are various types of Aggregators, operating with different scopes and a different focus in their BM. Load Aggregators as incorporated in the publications of Zhang et al. [40] and Liu et al. [41] focus on the optimization of the commercial position of a group of consuming parties, using potential flexibility from shiftable or interruptible loads only for internal optimization. DR Aggregators, such as incorporated in the publications of Feng et al. [42] and Siano et al. [43], leverage the same load flexibility also for flexibility services towards external customers. Some BMs also conceive the internal electricity exchange (be it as active trading or as passive sharing) between consumption and generation units as a core activity, in resulting Community Aggregators such as in Long et al. [38] and Cali and Cakir [44]. Unlike pure community managers (that would be classified as Platform Operators), Community Aggregators use the internal resources of DERs also to offer flexibility services to external customers or markets. The further difference between Community Aggregators and Microgrid Aggregators is again fluid; the latter are usually characterized by an even more pronounced spatial proximity (or separation) of the DERs and usually also control them completely through direct

[5]Note that market models are non-exclusive. While most reviewed papers state only one of three LEM models, few papers combine models of P2P & TE or P2P & CSC.

control signals such as implemented by Wu et al. [45] and Moslehi and Kumar [46]. VPP Aggregators finally form the most general Aggregator version in which a broad spectrum of DERs with and without spatial proximity are aggregated to offer an equally broad spectrum of products and services to internal and external customers. Examples for such are provided by Qiu et al. [47, 48].

Even though Aggregators may have thus different characteristics in different markets, they share some overlapping key characteristics in the BMs. Figure 2.4 illustrates the clustered BMC as envisioned by academic authors in 29 publications that contain Aggregators across all LEMs.

Customer segments of Aggregators comprise two distinct sets of customers, downstream and upstream actors. Downstream customers[6] are mainly Prosumers with DERs [34–36, 38, 44–47, 49–53] and Pure Consumers [37, 38, 40, 42, 43, 46, 48, 51, 54, 55], both with potentially controllable assets such as BESSs or EVs and non-controllable assets such as PV or loads. Small-scale Pure Generators [37, 41, 46, 48, 51, 54] and Storage Operators [37, 48, 51, 54] complement the set of downstream customers. The Aggregator's central *Value Proposition* towards these customers consists in optimized asset operation that enables reduced consumption costs for consuming parties [34, 40, 42–48, 50–53, 55] and increased sales revenues for generating parties [38, 44, 46–48, 51]. Additional value propositions concern the reduction of imbalance costs, especially for fluctuating iRES generation units [45, 47, 48, 53, 55] as well as the enabling of new revenue streams from ancillary service provision (for consuming units, these are usually translated into reduced consumption costs and not kept as a separate revenue stream) [36, 49, 55].

Upstream customers[7], on the other hand, are mainly Grid Operators [34–36, 39, 41, 43, 46, 49, 52–54], both at transmission and distribution levels. Local or national marketplaces of Platforms Operators [41, 46, 52, 54], Retailers [42, 44], or also actors that appear as peers such as other Aggregators [37, 41, 51], individual large-scale generation or consumption units [46], and Microgrid Operators as a type of large-scale Prosumer [40] complement the set of customers. The core Value Proposition that Aggregators gear towards these customers consists of flexibility services from sources that previously were not involved. These services can come with a locational component to react to network constraints, e.g., at the distribution grid level [34–36, 39, 41, 43, 46, 50, 52], or also without such to balance portfolios or wider (transmission level) network areas [41, 42, 46, 49–53]. A secondary value

[6] Downstream refers to customers located below the Aggregator in the value chain and within the direct sphere of influence of the virtual aggregate.

[7] Upstream refers to customers that are above the Aggregator in the value chain and at the same time outside the direct sphere of influence of the virtual aggregate.

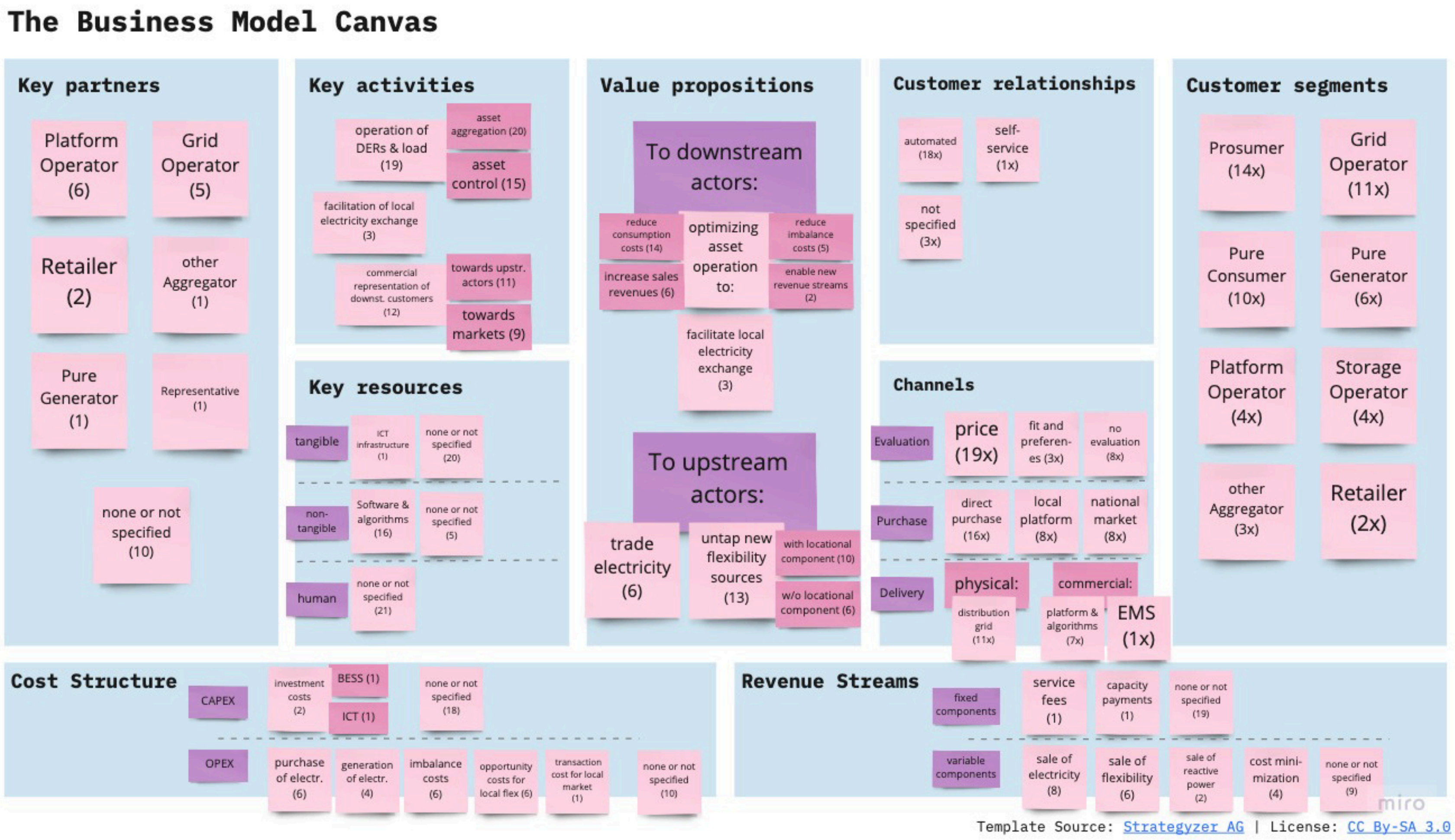

Figure 2.4: The comprehensive Business Model Canvas of Aggregators as illustrated in LEM literature. *(Adapted from [14])*

proposition consists in being a counterpart for electricity trading [37, 40, 41, 44, 46, 52, 54], be it bilaterally or through marketplaces.

Generally, Aggregators maintain *Relationships* with customers through automated services [34–38, 40, 41, 44–48, 50–55]. Sales *Channels* for downstream customers to purchase Aggregator services are predominately based on direct interactions with the actor, either through direct interactions that include the exchange of offers and bids [35, 36, 39, 45, 50, 52] or through long-term sign-ups [34, 38, 43, 46, 48, 51, 55]. For upstream customers, instead, platform-based solution dominate, based in similar proportions on local platforms [34, 37, 40, 41, 46, 51, 53] or connection to national balancing and wholesale market platforms [46–50, 53, 54]. Most customers evaluate the value from Aggregators by considering financial aspects, such as the costs or potential revenues of the offered services [35–37, 40–55]. Certain customers might consider additional factors such as individual preferences for EV charging [50] or the technical fit of flexibility offers [35, 39, 55]. In some cases, small-scale downstream customers also do not evaluate the individual value proposition continuously once signed up [34, 38, 39, 43, 46, 48, 51, 55]. The physical delivery follows then through the local electricity networks [35, 37, 39–41, 47–49, 51–53], while commercial delivery is associated with the sales channel and either through a local P2P or TE platform and its market algorithm [39, 40, 44, 46, 50, 51, 53], or the direct interaction with the Aggregator or [34–36, 49, 55] a Representative [45].

Aggregators create value propositions through their key activities, which rely on key resources and key partners as described below:

- *Key activities* of Aggregators are to bundle and manage a portfolio of downstream customers' DERs and loads [34, 35, 37–40, 42–55], in most cases also with active optimization and (more or less direct) control of their customer's assets [35, 37–40, 42, 47–55]. In a second step, they then interact with upstream actors [34, 35, 37, 39, 40, 42–45, 51, 53] or markets [43, 45–49, 51, 54, 55] as commercial representatives of their aggregated customers.
- Key resources of Aggregators' BMs are non-tangible assets, specifically a central Energy Management System (EMS) with respective software and algorithms to forecast, optimize, and perform market interaction [34, 35, 37, 39, 40, 42, 44–50, 53] as well as Information & Communication Technologies (ICTs) to interact with connected clients and their assets [37, 39, 45–49, 53].
- Key partners for Aggregators include various actors in the electricity system, depending on the types and activities Aggregators involve in. Particularly prominent are (local) Grid Operators that guarantee the provision of local

flexibility (especially when they are not a customer themselves) [37, 40, 50, 52, 55] or Platform Operators that enable the exchange of local flexibility (especially when the Aggregator does not run its own local platform) [34, 40, 43, 50, 51, 53]. If so intended, Retailers [49, 55] or large-scale Pure Generators [55] can supplement this to supply electricity to the Aggregators' customers.

The financial structures on which Aggregator BMs are based are discussed only superficially in the literature. Although generally described in the literature as cost-driven BM, i.e. convincing through prices rather than personalized value creation, the *Cost Structure* described refers primarily to costs associated with retailer activities. Overall, nine publications state electricity purchase costs from upstream markets or actors [40, 46, 48, 50, 53, 55] or VPP-internal generation costs [47, 48, 51, 54]. This is followed by imbalance costs for whenever the VPP portfolio might not be balanced [47, 48, 50, 51, 53, 55]. Opportunity costs for flexibility provision by the Aggregator's customers are mentioned in only six out of thirty Aggregator-related publications [39, 47–49, 54, 55], transaction costs for local energy trading even only once [51]. On the income side, the primary reported *Revenue Stream* stems from the electricity sales, either to downstream actors [37, 46–48, 51, 52, 55] or to upstream actors and markets [37, 46, 48, 51, 52, 54, 55]. Only after that follow cash-flows from the sale of flexibility [39, 46, 49, 53–55] or other ancillary services such as reactive power to upstream actors and markets [46, 54]. Indirect revenue streams in terms of cost reductions for own imbalance costs [48, 53] or for customers in terms of electricity procurement costs [47, 48, 50] complete the set.

Discussion of Business Model Elements With the clustering of the comprehensive BMC for Agggregators in LEM literature, several points of note emerged which are discussed in the following.

Certain BM aspects of Aggregators are relatively clearly presented in the literature and are naturally the focus of interest for academic authors. The first point to name here are the customer segments, separated for upstream and downstream actors, and the associated value propositions towards them. Also the touchpoints between the actor and its customers in terms of evaluation and purchase channels are straightforward and often sufficiently transparent. Together with the mostly rather implicitly stated partnerships, a reasonably vivid ecosystem emerges, in which Aggregators operate. Naturally, also the key activities with which Aggregators operate their BM are outlined and hence do not constitute a gap in literature.

While the questions of "what" are therefore reasonably outlined, the "how" of the BM remains however often hidden. Comprehensible for concise academic publications, which often do not primarily revolve around the actor model of the Aggregators themselves, the key resources represent a first underspecified BM element. Although it is often described as an "asset-light" BM, the complete absence of material resources seems implausible. Only in one case is ICT infrastructure specified as such a resource [44]. Also non-tangible resources do not compensate the lack of clarity, with only 16 out of 29 papers providing any detail on this aspect. Even then remains the provided information often superficial, rarely providing more profound information for example on the EMS with communication and or forecasting abilities [45, 56], the portfolio optimization algorithm [57] or the applied blockchain technology for financial transactions [37, 44]. Potential human resources for the BM operation are at no time specified.

A second underspecified area of the Aggreagtors BM in the reviewed literature concerns their financial structure. Cost structures and revenue streams are often only rudimentary described and, if at all, focus primarily on the "tangible" commodity business in which Aggregators are involved if supplying downstream customers also with energy. The financial implications of flexibility provision remain surprisingly often unspecified, only six out of thirty publications state associated costs and revenues. And even these contain still margin for further investigation, with flexibility remunerations being only for half of the cases based on actual dynamic market prices [53–55]. Investment costs and fixed operational expenditures such as maintenance remain basically completely unspecified.

An additional, notable weakness of the revenue streams as illustrated in the reviewed set of LEM literature is the fact that for most of the papers, the actual contractual agreement between DER owners and Aggregator remains unclear, especially who pays what and how much individual activities are rewarded (see Liu et al. [51] and Mohy-ud-din et al. [54] exemplary). This is the case for flexibility-related payments, but also electricity (commodity) related payments or overarching tasks such as local platform operation. One of the few examples where revenue sharing is explicitly addressed is the paper of Good et al. [55], analyzing the case of a Retailer-Aggregator to manage a community district in France. Besides the sharing of variable revenue streams from sales of electricity and or flexibility services, the paper is also the only one that mentions a fixed service fee that the Aggregator is paid for its operation.

Comparison to existing market roles Comparing the emerged actor characteristics with its BM from literature with actual European market roles, a set of common profiles emerges. First of all a somewhat pure Aggregator archetype that acts as a VPP operator to provide flexibility from customers decentralized assets. Such Aggregators are labeled in the industrial context as "*Independent Aggregators*" [58] and, in European market terminology, would equal the combination of HRM roles of a Resource Provider, Resource Aggregator and BSP. Examples for this constellation can be found in Morstyn et al. [36] and Brown et al. [49]. A more integrated and more common archetype in literature adds to this the commercialization of locally generated electricity as well as the supply of electricity to local consumers[8]. Aggregators combine thereby their flexibility provider role with the one of a Retailer, forming a category of Aggregators that is called in the industrial context an "*Integrated Aggregator*" [58]. They add thereby the HRM roles of an Energy Trader and Energy Supplier. Examples of this combined archetype can be found in literature in Moslehi and Kumar [46] and Qiu et al. [48] (further references are [40, 47, 50, 51, 53–55]). Another combination that is not mutually exclusive in the literature with the previous combination is to add the role of a local market operator [37–40, 44]. In harmonized European terminology, this would add at least the four roles of a Market Operator, Market Information Aggregator, Data Provider, and Billing Agent. Last but not least, few cases in literature combine the Aggregator BM with the role of a local Grid Operator incorporated in a microgrid [45, 46] or a subsidiary of a DSO [52]. Besides adding at least the HRM role of a System Operator, such fully integrated actors combine then usually also the role of a Retailer [45] or Platform Provider [46].

Comparison to first industrial implementations Comparing the emerged actor characteristics further with first industrial implementations in the European context complements the evidence gaps in the literature. With regard to Key Resources, an exemplary outline of five Aggregator BMs of the EU-funded BestRES project consortium confirms the central importance of non-tangible resources around technical and economic optimization algorithms [30]. The hardware part that complements these software resources to effectuate monitoring and control of involved energy resources appears instead only in parts to be an internal resource, but often rather a solution provided by dedicated partnerships of respective resource providers. Human resources instead also occur in this BM overview less frequently but are mentioned for market knowledge, product development, and sales experience [59].

With regard to the BMs' financial structure, the USEF Foundation, as a network of leading players in the smart energy industry, highlighted the difference between implicit demand response (i.e., leveraging locally on different electricity prices) and explicit demand response (i.e., actively offering flexibility to upstream markets) [60]. This leads to different services offered by different Aggregators to their customers and translates to different revenue streams, respectively. Therefore,

[8] BMs that added only the commercialization of generated electricity but not the supply of electricity to consumers have explicitly not been identified in literature

the BestRES project reports volume-based energy and (flexibility) service remunerations as well as capacity-based availability and/or activation remunerations as a basis for the Aggregators' revenue streams. Monthly or annual subscription fees complement the reported revenue streams [30]. On the cost side, the most important component mentioned is the (usually variable) cost associated with the remuneration of DER providers plus additional energy sourcing (in the case of an Aggregator-Supplier). Fixed costs are mentioned for staff and offices plus necessary technology development, such as platforms or other software solutions. The latter is partially also outsourced to partner companies, substituting the internal costs with external, contractual costs [59].

While a variety of Aggregator BMs are ready for implementation in different European markets, remaining barriers for Aggregator BM appear first of all legal and regulatory barriers that prevent the implementation of BMs in certain markets. In the second place, economic issues connected to regulatory barriers often prevent the extension of existing BMs towards additional value propositions [61]. The investigation of these real-world application barriers, as well as an updated confrontation of academic viewpoints with key characteristics of actual industrial implementations, represent the key focus of the second phase of the IEA Global Observatory on P2P, CSC, and TE models that will start shortly after the presumed publication of this thesis. Key findings and associated publications will be made available on the observatory's webpage https://userstcp.org/task/peer-to-peer-energy-trading/.

2.4 Emerging Ecosystem Models

Beyond the individual BM studies, the structured literature review provided also the opportunity to analyze the emerging ecosystems that are formed among actors in the different LEM models. As a first point of note, it emerged that the presence of individual actor categories varied significantly between the three analysed market types. Figure 2.5 provides an overview of the distribution of the individual actors presence. The overlap of the bars is related to the fact that some papers are associated to more than one energy model and hence count for two bars. Note also that the three models are represented to different degrees in the literature. Out of the 135 analyzed papers, 77 were associated with P2P models, 58 with TE models and 9 with CSC models.

The split for the three LEM models unveils which actor is most prominent in which model type. Prosumers, for example, are an actor type that is found relatively evenly in all three LEM models (i.e., with similar shares with which the models are also

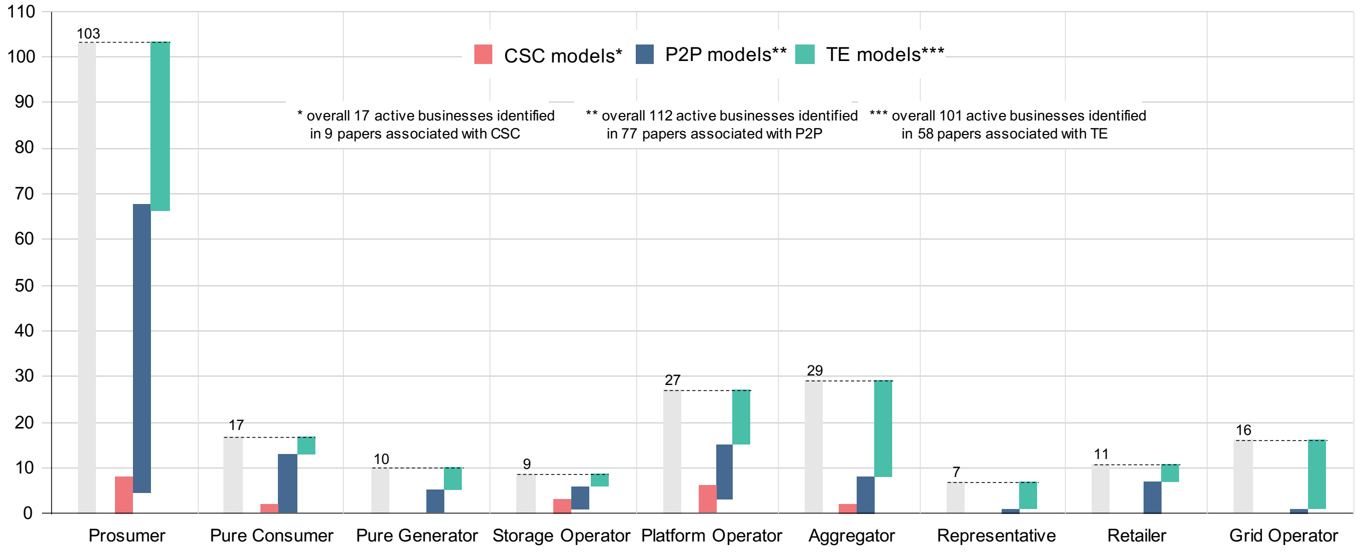

Figure 2.5: Presence of identified macro actor-categories in P2P, CSC, TE models of reviewed LEM literature.

present in literature). Pure Consumers instead are most present in P2P models, Platform Operators comparably wide spread in CSC models, and Aggregators and Grid Operators are clearly prevailing in TE models.

Another point of note concerns the finding that not all markets contain the full range of actor categories. Especially CSC models operate with a reduced set of actors, not mentioning Pure Generators, Representatives, Retailers and Grid Operators as active businesses in the reviewed literature. Moreover, P2P models appear to circle most of all around the asset owning actors with grid connection, i.e., Prosumers, Pure Consumers and Pure Generators. TE models instead are the ones with the prominent presence of facilitating and service providing actors such as Aggregators, Representatives and Grid Operators as active businesses.

Finally, table 2.1 provides the associated literature references for the individual actors' presence. Note that a single paper can be associated not only to more than one LEM model (respective references are highlighted with an "*") but also contain multiple actors. The wide range of Prosumers gave furthermore the opportunity to study them more in detail and they were hence further split in four subcategories. These four subcategories of Prosumer are: Prosumers that interact directly with other Prosumers *(peer-peer)*, Prosumers that interact with a group of other Prosumers *(peer-group)*, Prosumers that interact with one or multiple markets *(peer-market)*, or Prosumers that interact with the support of dedicated individual EMSs *(peer-EMS)*. More detailed characteristics along with dedicated BM analyses for these four Prosumer subcategories are described in [14].

Table 2.1: Presence of identified macro actor-categories in reviewed LEM literature. (Adapted from [14])

	P2P	CSC	TE
Prosumer	[44, 45, 49, 62–115] [38, 39, 116–119]*	[49, 120–122] [38, 39, 116, 117]*	[35, 36, 46, 50–53, 57, 123–149] [118, 119]*
Prosumer peer-peer	[44, 49, 62, 65, 66, 71–73, 75–77, 79, 84, 86, 87, 89, 90, 93, 95, 96, 98, 99, 106, 107] [118, 119]*	-	[124, 125, 127, 133] [118, 119]*
Prosumer peer-group	[66, 74, 78, 80, 86] [38, 39, 117]*	[49, 120–122] [38, 39, 117]*	[35, 53, 135, 140]
Prosumer peer-market	[49, 64, 67, 82, 83, 91, 92, 100, 101, 103–105, 108, 114, 115] [116]*	[116]*	[50, 51, 126, 129, 130, 134, 142, 143]
Prosumer peer-EMS	[45, 68, 70, 80, 81, 85, 88, 110–112]	-	[46, 128, 131, 136, 138, 145, 146]
Pure Consumer	[73, 88, 91, 94, 105, 106, 137, 150–154] [38, 39]*	[38, 39]*	[41, 155, 156]
Pure Generator	[90, 150, 153, 157, 158]	-	[41, 48, 137, 159, 160]
Storage Operator	[63, 67, 103] [39, 116]*	[161] [39, 116]*	[48, 160, 162]
Platform Operator	[49, 66, 82, 96, 102, 163–166] [38, 39, 116]*	[49, 120, 121] [38, 39, 116]*	[34, 41, 53, 55, 57, 135, 137, 139, 141, 145, 156, 167]
Aggregator	[37, 40, 44, 45, 49, 92] [38, 39]*	[38, 39]*	[34–36, 41–43, 46–48, 50–57, 132, 133, 137, 155]
Representative	[102]	-	[52, 145, 149, 159, 168, 169]
Retailer	[49, 71, 90, 104, 151, 154]	-	[42, 55, 135, 167, 170]
Grid Operator	[67]	-	[34–36, 41, 43, 52, 53, 57, 123, 132, 162, 167, 171–173]

[ ]* entry refers to a paper that contains more than one energy market model

Besided the simple presence of actor-categories in the different LEM models, a second interesting point of analysis are the networks of relationships that actors form within these models. The two BMC building blocks "Customer Segments" and "Key Partners" provide a practical approach to this. The following sections present thus an overview of actor relations that emerged in the three LEM models. For more technical aspects of the market functioning within these three LEM models, please refer to the second joint publication that investigated archetypal market designs and auction mechanisms within the same set of literature [19].

2.4.1 Actor Relations in Peer-to-Peer Models

As noted previously, P2P models are dominated by Prosumers and dispose also a notable presence of Pure Consumers as active businesses. The overall ecosystem that these market models usually form are however much more complex as indicated by the overall actor relations illustrated in Figure 2.6. Arrows in magenta imply thereby relations that are based on mentions as customers, blue arrow instead relations as key partners. The thickness of the arrows corresponds to the frequency of mentions, which are also quantified by numbering at the tip of individual arrows.

A first observation concerns the fact that Pure Consumers are not only quite present in general, but especially a key customers for many other business. Moreover, Prosumers appear to be the not only the most cited active business but overall also the most important customer to other Prosumers in P2P models.

A second observation concerns the set of facilitating actors, such as Platform Operators and Aggregators. While Platform Operators, for example, do not stand out as particularly significant customers to other actors, they appear instead as central partners for many other businesses. This finding might be somewhat surprising since P2P models are often interpreted as a way to precisely overcome the necessity for such central roles. However, current literature appears to still see a notable necessity for them. Besides Grid Operators, another business that is assigned a notable partner role in P2P ecosystems are Retailers. This happens most of time as a so-called "supplier of last resort" for any points in time in which the local market among peers might not be self-sufficient.

All in all, the total number of customer and partner relationships extracted from this analysis shows that the P2P model is characterized by the interaction between five main kinds of actors (with other actors taking more minor roles):

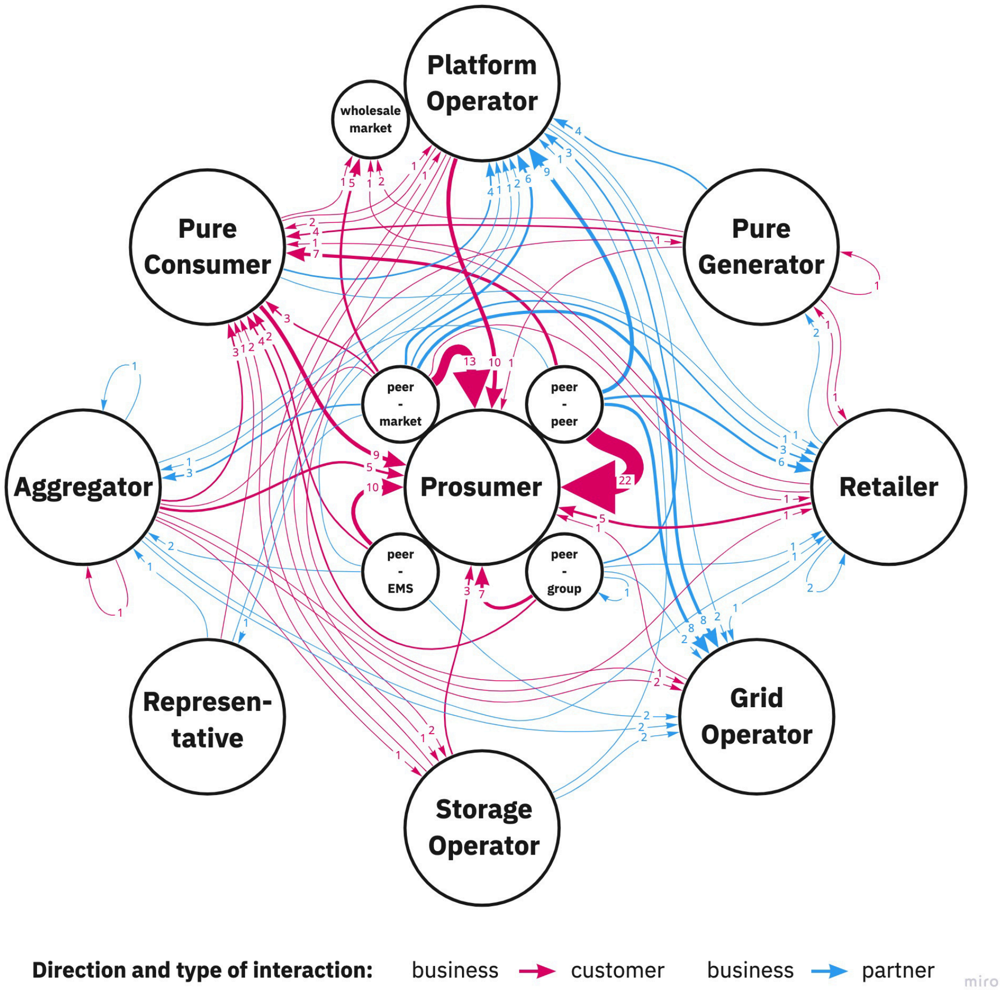

Figure 2.6: Business relations of main actors in P2P ecosystems as reviewed in literature. *(Adapted from [14])*

- Prosumers (87 mentions) acting as a sellers to most other actors and as especially as the central customers to their peer Prosumers;
- Pure Consumers (29 mentions), who serve as customers to the full set of other market actors;
- Platform Operators (33 mentions), who are close partners with Prosumers as well as with all other active actors.
- Grid Operators (30 mentions), who have a strong partnership with Prosumers and also collaborate with the wider set of market participants.
- Retailers (18 mentions), who, again, have strong partnerships with Prosumers plus a broader market engagement.

2.4.2 Actor Relations in Transactive Energy Models

TE models are not only characterized by a more prominent presence of facilitating actors such as Aggregators and Grid Operators, but present also overall the most extended ecosystem that involves the full set of actors as illustrated in Figure 2.7.

Compared to P2P models, Pure Generators and Storage Operators are comparably more involved in TE models. For Representatives this is even the only LEM model where they have a reasonable presence. While still being the most cited actors, the focus on Prosumers is however somewhat reduced. Instead, TE models bring three actors into their focus: Aggregators, Grid Operators and Retailer.

Aggregators become not only a partner to many businesses, but maintain customer relationships with basically all actor categories. As emerged also from the comprehensive BMC in the previous section, the main customers for them are Prosumers and Pure Consumers on the downstream side of the value chain and Grid Operators for upstream services. Grid Operators turn in TE models in general into a notably more active business, not only as a partner to others but especially as a customer for services from a multitude of actors. Platform Operators maintain their crucial role as a facilitating partner.

The total number of customer and partner relationships extracted from the analysis shows that the TE model is eventually mainly characterized by interactions between six categories of actors (with other actors taking more minor roles):

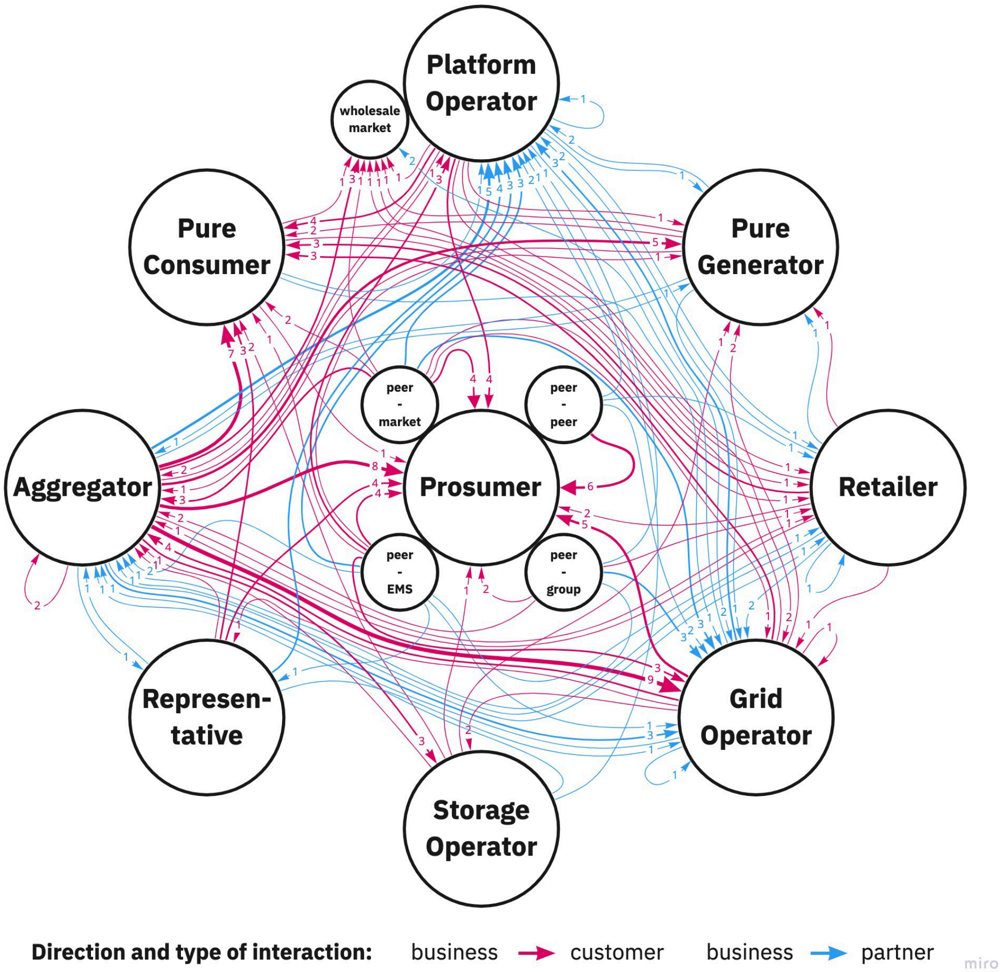

Figure 2.7: Business relations of main actors in TE ecosystems as reviewed in literature. *(Adapted from [14])*

- Prosumers (41 mentions) continuing to act as customers to their peer Prosumers, but most notably also to Aggregators, Grid Operators and other market actors;
- Pure Consumers (27 mentions) who serve as customers to all market participants, but particularly to Aggregators;
- Pure Generators (13 mentions) who are a principal customers to Aggregators but also sell and purchase from and to other market actors.
- Aggregators (17 mentions as a customer, 8 as a business partner) and Grid Operators (17 customer mentions and 20 partner mentions) who are mutually integral customers and key business partners to each other, and also serve the broader market.
- Platform Operators (32 mentions), that serve with partnerships across entire set of market actors.

2.4.3 Actor Relations in Community Self-Consumption Models

While CSC models are the overall least quoted LEM model in literature, the still display a very unique ecosystem as illustrated in Figure 2.8. Operating with a limited set of actors, this model clearly sets the focus on actor relations of Prosumers and Pure Consumers. Platform Operators represent the central facilitator to enable this ecosystem, especially for markets that use a passive energy sharing strategy instead of active energy trading. Storage Operators complement the involved set of active participants as an actor to enhance self-sufficiency of the ecosystem.

While Pure Generators and Representative are not present at all in the reviewed literature set, Retailers and Grid Operators still have a passive role. They are not mentioned as actively engaging businesses in the CSC models, but serve as business partners and customers respectively. Aggregators play also a minor role and are mentioned only with single customer relationships to the core actors.

The total number of customer and partner relationships extracted from the presented analysis demonstrates that CSC models are characterized by the interaction between three main kinds of actors:

- Prosumers (16 mentions) who mainly serve as key customer to their peer-group Prosumers and Platform Operators;

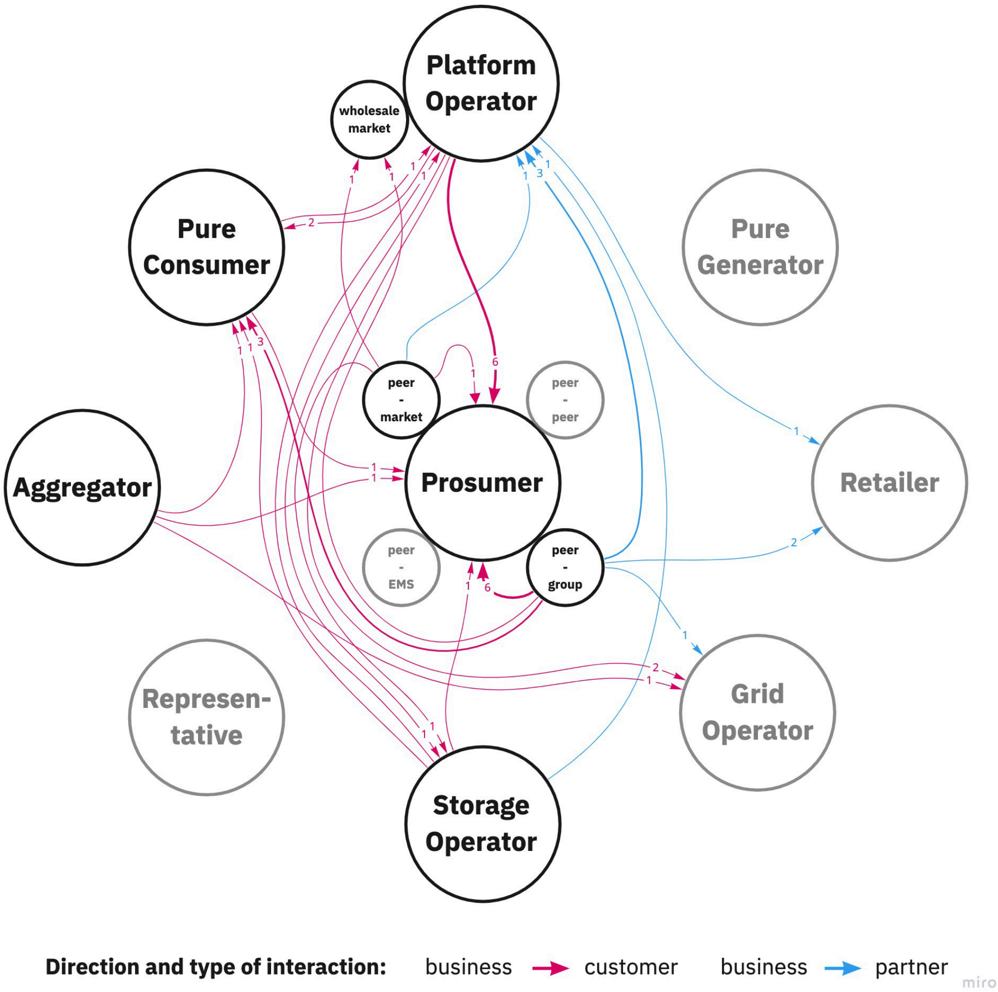

Figure 2.8: Business relations of main actors in CSC ecosystems as reviewed in literature. *(Adapted from [14])*

- Pure Consumers (7 mentions) who are also customers to their peer-group Prosumers or the Platform Operator;

- Platform Operators (7 mentions) who partner with Prosumers and Storage Operators and facilitate their business relations.

To summarize, although a formal delimitation between the different LEM models is still missing, aggregated findings from the structured literature review converge on the characterizations that:

- *CSC models* operate (groups of) peer Prosumers and Pure Consumers acting as costumers to each other and in partnership with a Platform Operator. Overall this model appears to focus on a "many-support-many" context that is designed to function in a comparably limited ecosystem.

- *P2P models* operate as (groups of) peer Prosumers and Pure Consumers acting as costumers to each other and in partnership with Platform Operators, Grid Operators, and Retailers. Overall this model appears to function in a "one-supports-one" context with a clear focus on end-users while maintain a wide ecosystem involved.

- *TE models* operate as (groups of) Prosumers, Pure Consumers, and Pure Generators acting as costumers to Aggregators and Grid Operators, and in partnership with Platform Operators, Grid Operators, and Aggregators. Overall this model appears to focus on a "many-support-one" context with a particular wide ecosystem being involved.

2.5 Summary and Implications for Empirical Case-Studies

Based on a structured literature review that was jointly performed with international researchers of the IEA's Global Observatory on Peer-to-Peer, Community Self-Consumption and Transactive Energy Models, a significant corpus of over 130 academic contributions has been analyzed in depth to shed light on business models and business relations in emerging local energy markets. Local energy markets are attracting more and more attention in academic literature since they are seen as a critical component of the current energy transformation.

In a first step active business in these market models have been identified and clustered to actors with common sets of market roles. As a result, nine macro actor-categories were formed. Prosumers are by the far the most frequently mentioned actors and lead the group of grid-connected actors consisting of Pure Consumer, Pure Generator and Storage Operator. Platform Operators, Aggregators and Representatives form a second group of actors that engage as facilitators and multipliers for the grid-connected actors. Grid Operators and Retailers complete the overall set of actors as service providers in literature on local energy markets. The individual actor models are described and further outlined based on harmonized European market roles.

In a second step the actor relations that characterize different local energy ecosystems are mapped based on extensive analysis of individual actors' business model elements. It can be seen that all three models examined place the Prosumers at the centre of their activities, but that the design beyond this differs significantly. While community self-consumption models operate with a reduce set of actors around Prosumers, Pure Consumers, and Platform Operators, Peer-to-Peer models extend the ecosystem with relations across all actors and especially Grid Operators and Retailers supporting as partners. Transactive Energy models eventually involve Grid Operators even more actively also a customers to other actors and Aggregators taking a central role for service facilitation.

Due to the central role of Aggregators also for the following case studies on the balancing integration of decentral energy resources, the academic viewpoints on their business model has been outlined more in detail. Two elements of their business models appeared thereby particularly underspecified, namely the key resources to operate and the financial structure on which the business model is founded. Especially the latter provides therefore an interesting starting point for the following case studies. The most cited operational costs and revenue streams of Aggregators in literature focus on a rather classical retailer business, which is rather a complement than central core of their value proposition. Opportunity costs for flexibility provision and associated revenue streams remain for the most part unspecified or based on static assumptions. From a financial point of view, the reported Aggregator information in academic literature provide hence no evidence for a viable business case. The following case studies will integrate here by providing empirical insights to try quantify the potential dimensions of these variable financial aspects.

3 Framework and Methodology for Applied Case Study

This chapter provides the framework and following background methodology that serves as the foundation for the subsequent empirical case studies. First, the Italian market framework with its energy and ancillary service markets structure is introduced. In the following, the specific characteristics of market participation are outlined and how they changed during the last three years. A special focus provides then an overview on how the COVID-19 pandemic has affected the Italian electricity market. Finally, after explaining the overall market framework with its characteristic key figures, the supporting methodology used to prepare the empirical data for use in the following case studies is elaborated.

3.1 The Italian Market Framework

The Italian electricity market has been liberalized in the first instance following the approval of the Legislative Decree 79/99, the so-called *Bersani Decree*, that was part of a process to implement the European Directive 96/92/EC concerning common internal market rules throughout the European Union. This decree, which defined the beginning of the structural reform in the Italian electricity sector, responded to the need, on the one hand, to promote competition and, on the other, to maximize the transparency and efficiency of natural monopolies. In line with free-market conditions, the activities of production, transmission, distribution, and sale of energy have been split into separate corporate entities (so-called unbundling process). Among these entities, two entities are of particular relevance for the following study. On the one hand, the nominated electricity market operator GME (Italian acronym for *Gestore del Mercato Elettrico*) and, on the other hand, Terna that is the Italian Transmission System Operator (TSO).

The narrow and arduous geography of the Italian peninsula has challenged the development of the transmission network. In addition, a large part of the electricity consumption takes place in the industrial and more densely populated north, while many renewable generation plants are located predominantly in the sunny and windy

Figure 3.1: Schematic representation of the Italian bidding zones as of 2019.

south. This leads to congestions and security concerns in the Italian power system up to this day, especially in the southern area. In order to overcome these issues, the Italian market framework is tailored to the technical needs of the network, establishing strict rules and with a TSO that pro-actively operates in a central dispatch regime.

Bidding Zones The Italian electricity market framework is based on multiple bidding zones according to the grid's constraint. In 2019 these amounted to six zones: North, Centre-North, Centre-South, South, Sardinia, and Sicily. Figure 3.1 provides a schematic representation of the bidding zone layout. Specific network constraints give rise to additional "poles of limited production", i.e., an area in which the (conventional) generation capacity exceeds the transmission capacity. From a market perspective, poles of limited production act as an individual bidding zone but without internal local load. In 2019 there was one such pole, called Rossano, that was located in the bidding zone South[1]. In line with other empirical studies on Italy, this study focuses solely on the full bidding zones and assumes accordingly that the limited production pole does not impact transmission between the other bidding zones [8, 174–176].

The largest Italian bidding zone is thereby North, being in terms of load bigger than the sum of the remaining five southern zones. It is also the best-connected zone with international couplings to France, Switzerland, Austria, and Slovenia and the national connection to the contiguous bidding zone Centre-North. Table 3.1

[1] With the latest revision of the Italian bidding zone framework in January 2021, Rossano merged with the southern half of the bidding zone South into a new, seventh, bidding zone Calabria.

Table 3.1: Overview of selected characteristics of different Italian bidding zones in 2019.

		North	Centre-North	Centre-South	Sardinia	Sicily	South
Installed PV capacity *(Jan. 2019)*	[GW]	8,960	2,376	2,901	785	1,392	3720
Avg. hourly PV generation *(all 2019)*	[MWh]	803	269	376	71	167	486
Installed onshore wind cap. *(Jan. 2019)*	[GW]	122	145	1,794	1,073	1,887	5,320
Avg. hourly wind generation *(all 2019)*	[MWh]	10	35	399	230	377	1,188
Avg. hourly load *(all 2019)*	[MWh]	82,346	15,558	21,770	4,132	8,749	13,414
Connected national bidding zones	-	Centre-North	North, Centre-South, Sardinia *(through Corsica)*	Centre-North, Sardinia, Centre-South	Centre-North *(through Corsica)*, Centre-South	South	Centre-South, Sicily
Connected international bidding zones	-	France, Switzerland, Austria, Slovenia	Corsica (France)	Montenegro	Corsica (France)	Malta	Greece

Note: *self-calculated values based on [177] for iRES capacities and based on [@178] for generation and load data.*

summarizes a selection of key characteristics from the Italian bidding zones in 2019 as utilized in the further course of the study.

Among the Southern bidding zones, two zones are of particular interest for this study: Centre-South and Sicily. Both share a similar average presence of PV generation with approximately 2% with regard to their local load, in line with the overall average in all zones of southern Italy. Onshore wind as the other major intermittent Renewable Energy Source (iRES) type is more present in Sicily than in Centre-South, aligning with 4% and 2% just around the average of 3% for southern Italy. In this sense, the two zones provide a reasonably representative sample and are used in the following for individual case studies on specific Southern effects.

Centre-South represents thereby the largest southern Italian bidding zones in terms of average load and also the overall most connected zone, linking to three national and one international bidding zone. Nonetheless, Centre-South suffers from notable internal congestions from one particular local area that is too big to give rise to another limited production pole yet too small to form another independent bidding zone [175]. This circumstance often turns it into a key driver of price developments in southern Italy and makes it therefore a reasonable focus of potential case studies around regional effects.

Sicily instead is a comparably small bidding zone and poorly connected due to its island location, linking only to the national bidding zone South and the internationally to Malta (although the latter connection is predominantly used in the direction of export). This detaches its price developments often from the rest of southern Italy and makes it therefore another valuable focus for potential case studies. Moreover, the compact island location with its relatively uniform conditions makes Sicily the preferred object of study when it comes to breaking down zonal forecasts and forecast errors for renewable energies to individual plant sizes [179].

Trading Venues The bidding zone structure is then incorporated into the Italian electricity market. The main trading venues of interest for this study are:

- *Mercato del Giorno Prima (MGP)*, the Day-Ahead Market (DAM) with exchange of hourly energy blocks for the following day;
- *Mercato Infragiornaliero (MI)*, the Intra-Day Market (IDM) for further adjustment of energy profiles during the day of delivery;
- *Mercato dei Servizi del Dispacciamento (MSD)*, the Ancillary Services Market (ASM) through which the TSO procures resources to manage the transmission network.

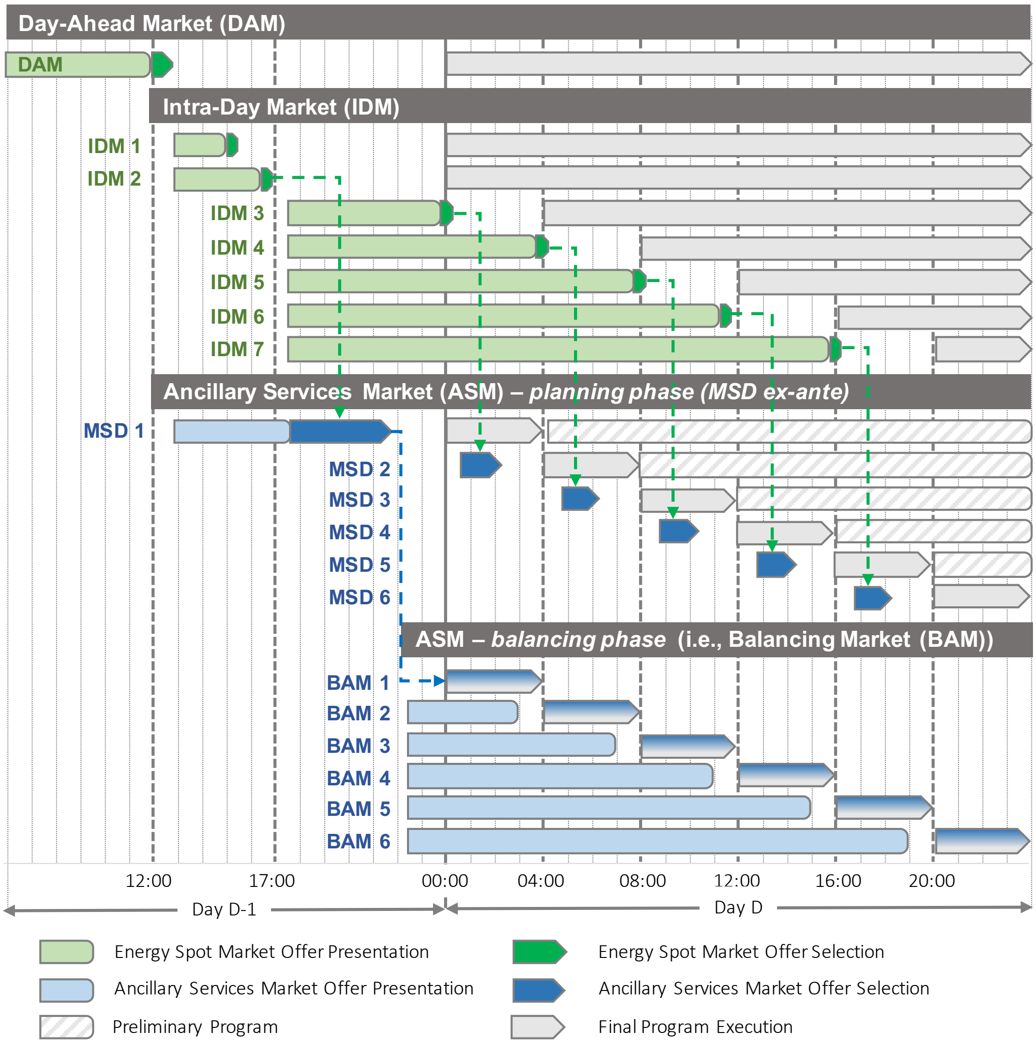

Figure 3.2: Sequences of the Italian electricity markets as of 2019.

While DAM and IDM represent thus the two most relevant spot Energy Markets (EMs), the Italian ASM is also further subdivided into two separate markets. First takes place a programming phase called *MSD ex-ante* and then subsequently a Balancing Market (BAM) for intraday trading of power reserves called *MB*. While the gate closure of the MSD ex-ante is on day D-1, the one of the MB is one hour before the beginning of the full hour to which individual products refer. MB activation occurs then in real-time. The two ASMs reflect thereby a similar structure as the spot markets with DAM and IDM. For the further course of the thesis, the acronym ASM from here on always refers to the combination of both markets, while BAM exclusively refers to the Italian BM. Figure 3.2 provides an overview of the market sequences and their interconnections. Detailed characteristics of the different types of electricity markets are discussed in the following.

Table 3.2: Average zonal day-ahead market prices $\varnothing p_{DAM,z}$ in Italian bidding zones in 2019.

	North	Centre-N.	Centre-S.	Sardinia	Sicily	South
$\varnothing p_{DAM,z}$ $[\frac{€}{MWh}]$	51.25	52.23	52.28	51.80	62.77	50.89

Note: *Self-elaborated based on GME data [@181].*

3.1.1 Spot Energy Markets

In general, Italy is an auction-based central dispatch system with the market operator GME being the central counterparty for both EMs. DAM and IDM are therefore cleared for each bidding zone by matching demand and supply. The first market to clear is the DAM that clears in a single session at 12 pm on day D-1. Cross-zonal transmission capacity is allocated implicitly through the auctions and, based on the DAM clearing results, a first injection and withdrawal schedule for each offering point is generated. In the event of congestion at the interconnection between two bidding zones, the market is split and zonal prices vary. Supply offers are always remunerated at this zonal price (pay-as-cleared), whereas demand bids are valued at a single purchase price that is the weighted average of all zonal prices, the so-called PUN (Italian acronym for *Prezzo Unico Nazionale*) [180].

Table 3.2 provides an overview of the average DAM clearing prices for 2019 in the six physical bidding zones. It shows that, eventually, the average DAM prices are in the range of 51 to 52 €/MWh for five out of six of the physical bidding zones. Only Sicily has a notably higher DAM price, being on average more than 10 €/MWh above the one of the other zones. Such is mainly based on the limited interconnection of the island of Sicily with the Italian mainland in combination with the limited liquidity of the local bidding zone.

The DAM is followed by the IDM that was based until mid-2021 on seven different sessions of implicit auctions with hourly products and a gate-closure latest four hours before delivery, as illustrated in Figure 3.2. Also the auctions of the IDM apply a merit-order based pay-as-cleared approach for hourly energy blocks, taking into consideration the updated transmission limits. The IDM is hence managed with the same rules as the DAM and gives the market agents the option to adjust their commercial position. While the overall importance of the IDM in terms of exchanged volumes is slightly growing over the years, its exchanged volumes amount currently to approximately 10% of the DAM volumes (26.4 TWh versus 295.8 TWh in 2019). Therefore, the DAM remains the EM of reference in Italy. IDM prices follow the DAM price and average between 52 and 58 €/MWh for the different sessions. The later sessions with shorter time to delivery show both a higher level of price and volatility [182].

In September 2021, Italy adhered then to the European Single Intraday Coupling project (SIDC, previously known as XBID) and adapted its IDM structure accordingly. In this context, the auction sessions were reduced to three, and continuous bidding sessions were introduced in parallel. In line with the European framework conditions, several innovations were introduced along with the continuous bidding sessions. On the one hand, the gate closure was anticipated to be one hour before delivery. On the other hand, negative prices were introduced for the first time by lowering the IDM floor from 0 €/MWh to -500 €/MWh. The price cap instead remains (same as for the DAM) at the Italian Value Of Lost Load (VOLL) of 3,000 €/MWh. Furthermore, accounting is now for the first time possible at portfolio level, although this remains so far limited to the continuous bidding sessions of the IDM [183].

3.1.2 Ancillary Service Markets

For the Italian ASMs, the TSO Terna acts as the single buyer to cover itself proactively with the necessary resources to ensure reliable and efficient power system functioning. Apart from the partial use of some own network resources, e.g. for reactive power provision, Terna fulfills its operational tasks entirely with the help of these markets. No separate long-term reserve capacity procurements or similar are undertaken and remunerations are generally only based on activation (energy-only) on a pay-as-bid basis[2].

The main traded products on the ASMs that are of relevance to this study are secondary reserve (called Frequency Restoration Reserve (FRR) in ENTSO-E terminology) and tertiary reserve (called Replacement Reserve (RR) in ENTSO-E terminology), always distinguished for upward and downward direction. The latter product is, in the Italian context, eventually a multi-purpose product and labeled with the acronym "*OS*" (Other Services, "*altri servizi*" in Italian), one of the Italian ancillary service products. The TSO utilizes this product not only for frequency control but also for congestion management and balancing purposes. Primary reserve (called Frequency Containment Reserve (FCR) in ENTSO-E terminology) is potentially remunerated but obligatory for all so-called "qualified" units (see explanation further below) and hence not actively traded or procured.

[2]However, Italy did introduce a capacity mechanism in 2019 that contains capacity auctions with first delivery in 2022. Auction winners are obliged to bid with their respectively assigned capacity in the energy-only markets, i.e., spot EMs and ASMs. While doing so, a price cap applies and, besides this limitation, reserve procurement continues to be fully market-based.

For the sake of completeness, additional ASM products that are of less interest to the scope of this research and hence not further considered in this thesis are tokens for the start-up, shutdown, or switch of assets.

MSD ex-ante is the first of the two ASMs and has the main purpose of relieving congestions as emerged from DAM (through product OS) and procuring reserve margins (through both products, OS and FRR) on a scheduled basis. The latter happens by reserving respective offers and then eventually activating them through the BAM. While the gate-closure for offer presentation of the MSD ex-ante is on day D-1, the selection of individual offers by the TSO occurs in individual selection sessions up to 1:45h before delivery with the clearing results of DAM and IDM as input data (see green dashed arrows in Figure 3.2). The product granularity that the MSD ex-ante disposes is hourly and the clearing is generally also based on a merit order. However, this should not be taken literally as in particular re-dispatch measures for congestion management evaluate activations on nodal level. Therefore, there is no fully equivalent activation on bidding zone level, but the merit order applies at most from a nodal perspective. Table 3.3 provides an overview of the average price and hourly quantities of accepted OS offerings on the MSD ex-ante in 2019, divided for activation direction and bidding zone.

After the planning phase MSD ex-ante follows in the Italian ASMs the BAM, called MB, for real-time balancing. As input to the first session of BAM offer selections serve the reserved and forwarded bids from the last MSD ex-ante session (see blue dashed arrow in Figure 3.2). Furthermore, individual operators may update and resubmit their previous offers in the following BAM sessions, but only on improved terms. The gate-closure for offer presentation is then one hour before the delivery of the respective session starts, offer selection and activation occurs instead in real-time.

Compared to the MSD ex-ante, the previously hourly product segments are further refined in the BAM with quarter-hourly resolution. Activated product categories are predominantly FRR and OS, both separated in upward and downward directions. As congestions that emerged from the energy markets were already managed through the MSD ex-ante, the BAM activations of the multi-purpose product OS are mainly associated with balancing purposes. Eventually, the offers and bids accepted in the BAM determine individual units' final injection or withdrawal schedule. Table 3.4 provides an overview of the average price and hourly quantities of accepted FRR and OS offerings on the BAM in 2019, divided for activation direction and bidding zone.

Overall, it shows that ASM prices are significantly more heterogeneous than EM prices for the various bidding zones. Concerning the prices for the product OS, a significant price spread across zones emerges, especially in upward direction. The

Table 3.3: Average ancillary service market (MSD ex-ante) clearing prices $\varnothing p_{ASM}$ and hourly quantities $\varnothing q_{ASM}$ for the product category OS in 2019.

		North	Centre-North	Centre-South	Sardinia	Sicily	South	Marco-South*
$\varnothing p_{ASM,OS\downarrow}$	$[\frac{€}{MWh}]$	29.69	39.93	31.19	46.11	21.37	27.45	30.23
$\varnothing p_{ASM,OS\uparrow}$	$[\frac{€}{MWh}]$	95.50	125.45	229.31	69.84	124.11	111.65	140.37
$\varnothing q_{ASM,OS\downarrow}$	[MWh]	643.15	28.60	39.80	1.17	5.68	46.41	208.53
$\varnothing q_{ASM,OS\uparrow}$	[MWh]	460.48	24.06	261.68	146.89	239.09	398.65	1,103.60

* Macro-South refers to the sum of all physical bidding zones except North, plus the pole of limited production Rossano. More information on macro-zones in Chapter 6y

Note: *Self-elaborated based on GME data [@181]*.

Table 3.4: Average balancing market clearing prices $\varnothing p_{BAM}$ and hourly quantities $\varnothing q_{BAM}$ for the two product categories FRR and OS in 2019.

		North	Centre-North	Centre-South	Sardinia	Sicily	South	Marco-South*
FRR								
$\varnothing p_{BAM,FRR\downarrow}$	$[\frac{€}{MWh}]$	26.44	21.85	35.79	58.81	38.76	45.07	31.55
$\varnothing p_{BAM,FRR\uparrow}$	$[\frac{€}{MWh}]$	93.56	87.27	93.65	86.70	126.68	88.05	88.48
$\varnothing q_{BAM,FRR\downarrow}$	[MWh]	173.61	10.07	14.40	0.68	3.11	20.46	58.63
$\varnothing q_{BAM,FRR\uparrow}$	[MWh]	87.94	6.17	7.02	0.36	1.33	8.98	29.14
OS								
$\varnothing p_{BAM,OS\downarrow}$	$[\frac{€}{MWh}]$	31.39	30.84	22.25	37.51	27.02	31.69	23.35
$\varnothing p_{BAM,OS\uparrow}$	$[\frac{€}{MWh}]$	96.17	85.31	226.32	103.65	132.43	117.35	171.11
$\varnothing q_{BAM,OS\downarrow}$	[MWh]	759.70	31.08	154.93	30.44	27.90	74.19	477.22
$\varnothing q_{BAM,OS\uparrow}$	[MWh]	127.10	6.17	69.20	18.55	46.08	58.23	215.10

* Macro-South refers to the sum of all physical bidding zones except North, plus the pole of limited production Rossano. More information on macro-zones in Chapter 6.

Note: *Self-elaborated based on GME data [@181]*.

by far highest OS in upward direction is registered in Centre-South with around 229 €/MWh on the MSD ex-ante and 226 €/MWh on the BAM. The lowest upward price instead is registered with around 70 €/MWh on the MSD ex-ante in Sardinia and 85 €/MWh on the BAM in Centre-North. Also the accepted quantity varies significantly among the different bidding zones, ranging on the MSD ex-ante from on average 460 MWh per hour in North to 24 MWh per hour in Centre-North. Results for the downward direction vary as well, although to a much smaller extent. The maximum price spread amounts here on the MSD ex-ante to 25 €/MWh with the highest average price being 46 €/MWh in Sardinia and the lowest average price being 21 €/MWh in Sicily.

A particular point of note concerns the ratio of accepted quantities. On the MSD ex-ante quasi all bidding zones result with, on average, distinctly more upward than downward quantities. Only the bidding zone North (and Centre-North to a smaller extent) results in the opposite. On the BAM, instead, all bidding zones register on average more OS quantities in the downward than the upward direction. Sicily constitutes the only zone with an opposed ratio. Why this pattern of predominantly upward OS in the planning phase and predominantly downward OS in the balancing phase emerges remains unclear. Possible reasons could lie in the TSO's operational preferences, however, they require more extensive research for a deeper understanding. Eventually, the overall OS quantities appear comparably balanced upward and downward across both ASMs and all zones for 2019 (on average 1,905 MWh per hour in upward direction and 2,088 MWh per hour in downward direction).

The second product category, FRR, records overall considerably smaller quantities than OS, especially in southern bidding zones low. Downstream volumes are on average twice the upstream volumes (232 MWh per hour versus 117 MWh per hour) and thus amount to approximately 10% and 5% of the average OS volume, respectively. Together with the lower volumes, the average prices over the year are also more contained. The price-spread from different zones amounts only to roughly 40 €/MWh in the upward direction (126.68 €/MWh in Sicily versus 86.70 €/MWh in Sardinia) and to 37 €/MWh in the downward direction (58.81 €/MWh in Sardinia versus 21.85 €/MWh in Centre-North).

Besides its proprietary trading venues, Italy adheres to multiple European projects that emerged from the EB GL for the joint provision and or operation of power reserves. Specifically, these projects are PICASSO[3] for aFRR provision, MARI[4] for mFRR provision, TERRE[5] for RR provision, and IGCC[6] for imbalance netting across TSOs. At the time of writing, the IGCC initiative as well as the platform of TERRE are operational and actively integrated into the Italian system operation (national go-lives were in January 2020 and January 2021, respectively). The Italian go-live for the other two initiatives is expected for summer 2022 instead.

3.1.3 Characteristics of market participation

As a central dispatch system, Italy does not operate market participation at portfolio level but for a significant share of assets per individual offer point[7]. Therefore, the Italian system distinguishes the following two non-exclusive categories of generation and consumption units:

- *Relevant and non-relevant units*, i.e., units that are of independent relevance or not to the operation of the transmission system[8].
- *Qualified and non-qualified units*, i.e., if individual units are qualified to participate in the Italian ASMs.

In general, all units with a total power of the associated generation groups not less than 10 MVA are classified as relevant. Consumption units are all considered non-relevant. Apart from the derogations as under to the UVAM pilot project (further explained in Chapter 4), qualified units are generally always relevant units whose output is programmable. Participation in the ASMs is restricted to but also mandatory for qualified units. If individual operators do not offer in line with their technical capabilities, the Italian TSO can "adjust" their non-existent or incorrect offers and actively dispatch the units accordingly [184]. Overall, the strict bidding requirements make the Italian ASM still one the most demanding in Europe for conventional generators and one of the most hostile to DERs and Demand Response (DR).

[3] Acronym for: Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation. More information on the ENTSO-E homepage under https://www.entsoe.eu/network_codes/eb/picasso/.

[4] Acronym for: Manually Activated Reserves Initiative. More information on the ENTSO-E homepage under https://www.entsoe.eu/network_codes/eb/mari/.

[5] Acronym for: Trans European Replacement Reserve Exchange. More information on the ENTSO-E homepage under https://www.entsoe.eu/network_codes/eb/terre/.

[6] Acronym for: International Grid Control Cooperation. More information on the ENTSO-E homepage under https://www.entsoe.eu/network_codes/eb/imbalance-netting/.

[7] An offering point represents the physical grid connection for injection or withdrawal of individual units.

[8] Relevant is not to be confused with essential in this context. A subset of the relevant units is the so-called essential units, which are vital for the operation of the transmission network.

For the EMs instead, participation in both DAM and IDM is voluntary and possible for all agents that are pre-qualified by GME [180, 185]. Being physical markets, single transactions still have to be associated with an individual offer point. For relevant units, this is the physical grid connection point, non-relevant generation units as well as consumption units form instead aggregated offer points per operator and typology at zonal level.

Balancing responsibility is assigned accordingly per offer point. This means that the injection or withdrawal schedule has to be balanced per individual unit for relevant units. Only for non-relevant units, the balancing responsibility is aggregated at zonal level. The imbalance settlement period for all qualified units is 15 minutes (given that they can access the BAM with respective settlement periods) and 60 minutes for all non-qualified units. Applied imbalance pricing schemes vary for different classes of units from single to dual and special compensation schemes with diverse tolerance margins for iRES, for more information see Chapter 6. Finally, the imbalance price in Italy is published in a preliminary version 30 minutes after delivery and the day after in the final version [186].

3.2 Special focus: The impact of COVID-19 on Italian electricity markets

The COVID-19 pandemic that swept across Europe, starting in the early part of 2020, had not only a substantial impact on economic and social systems but left its mark also on the Italian power system. Especially April 2020 was characterized by a complete lockdown of the country and its economy, resulting in notable impacts as discussed in the following.

Compared to the same month of the previous year, the overall electricity demand dropped across Italy by -17% and the non-renewable generation dropped even more by -24%. Instead, the renewable energy share at net generation rose from 40% to 49%. The lower demand in combination with an increased renewable share drove the PUN (i.e., the average national DAM price) down by -54% from 53.40 €/MWh in April 2019 to 24.80 €/MWh in April 2020. The overall value traded on the DAM dropped even by -62% [187]. Table 3.5 presents the detailed development of local DAM prices for the different bidding zones in Italy.

In line with that, also the BAM experienced significant differences in exchanged volumes and prices, although not only in decreasing direction. Upward BAM product

Table 3.5: Development of average day-ahead market prices $\varnothing p_z$ for the different Italian bidding zones during the COVID-19 pandemic, comparing April 2020 (full lockdown) to the corresponding month in the previous year.

			North	Centre-North	Centre-South	Sardinia	Sicily	South
April 2019	$\varnothing p_z$	$[\frac{€}{MWh}]$	53.32	53.32	51.37	49.51	63.50	50.51
April 2020	$\varnothing p_z$	$[\frac{€}{MWh}]$	24.46	24.78	25.21	24.52	26.13	25.17

Note: *Self-elaborated values based on GME data [@181].*

Table 3.6: Development of average balancing market prices $\varnothing p_{BAM}$ in upward and downward direction for the different Italian bidding zones during the COVID-19 pandemic, comparing April 2020 (full lockdown) to the corresponding month in the previous year.

			North	Centre-North	Centre-South	Sardinia	Sicily	South
April 2019	$\varnothing p_{BAM\downarrow}$	$[\frac{€}{MWh}]$	35.64	33.63	17.15	41.56	35.85	27.80
	$\varnothing p_{BAM\uparrow}$	$[\frac{€}{MWh}]$	103.50	101.83	320.19	88.88	138.80	141.17
April 2020	$\varnothing p_{BAM\downarrow}$	$[\frac{€}{MWh}]$	7.07	5.56	2.57	29.93	7.85	9.18
	$\varnothing p_{BAM\uparrow}$	$[\frac{€}{MWh}]$	91.24	71.28	297.65	83.14	101.03	85.47

Note: *Self-elaborated based on GME data [@181].*

volumes increased in April 2020 across all bidding zones by 66% compared to April 2019, whereas downward volumes remained overall nearly constant with only -1%. The average prices across all bidding zones and BAM products instead dropped for both product directions, resulting overall to be on average -3% lower for upward balancing products and -78% lower for downward balancing products [187].

Another remarkable observation is the flattening of the intraday price level, which is expressed in a strongly reduced spread between prices in the peak and off-peak hours. While in April 2019 the price difference between accepted upward offers at 04:00 and 16:00 amounted on average to 108 €/MWh, the same spread reduced to on average 23 €/MWh in April 2020. The reduction is not only reflected in the convergence of the weighted average prices, but also in a significant reduction in the variance of the individual accepted offers. Table 3.6 provides a detailed breakdown for the price development of the specific product category "*OS*" that is mainly used in the following analyses of this theses.

With conventional generators being traditionally the price-makers in merit-order based electricity market structures such as the Italian one, the strongly decreased prices in DAM and also BAM reflect the struggle of conventional generators to stay in a market under changing conditions and increasing renewable share. On the other hand, given the detailed level of available market data, the time of the COVID-19 pandemic again provides the interesting opportunity for sensitivity studies on an increasingly price-competitive system with conventional participants fighting for shrinking market share. This might be interesting for potential forward-looking scenarios and is illustrated, for example, in Chapter 6.4.4 for the analysis of different imbalance pricing schemes.

3.3 Methodology for empirical data utilization

While significant parts of the presented research project are based on empirical data from Italy, such is only available in a raw format and needs excessive pre-processing before being able to be used for the individual analyses. This section explains the data availability, its extraction, and subsequent pre-processing.

3.3.1 Data Availability

The utilized data for this research project is entirely publicly available. Forecast and generation data for aggregated iRES types are available with hourly granularity at bidding zone level through the transparency platform of European Network of Transmission System Operators for Electricity (ENTSO-E) [@178]. System imbalances and imbalance prices, including specific adjustment components, are available with hourly and quarter-hourly granularity at macro-zonal level through the respective online portal of the Italian TSO Terna [@188]. Finally, market and operational data from the Italian electricity system are available with hourly granularity for the DAM, IDM, and MSD ex-ante and with quarter-hourly granularity for the BAM, always at bidding zone level through the Italian market operator GME [@181].

3.3.2 Data Extraction and Pre-Processing

In order to be effectively usable, the raw market data must first be extracted and pre-processed. For this purpose, a structured data preparation methodology with five steps is applied as outlined in Figure 3.3. The data preparation will be shown using BAM data as an example since this data is particularly complex. However, the preparation of other ASM data or EM data works just as well, except that individual steps can be skipped.

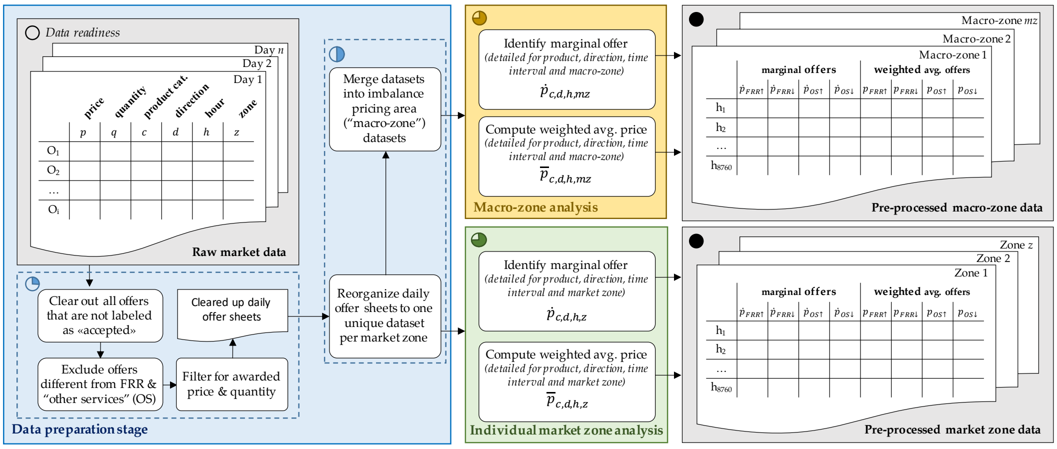

Figure 3.3: Flowchart of empirical market data pre-processing

In the first step, the respective data is downloaded from the market platform. The raw data is available at single market transactions, aggregated in daily offer sheets. Each data point of an individual offer O_i consists of an offered quantity q_i for price p_i and four additionally characterizing parameters: the product category $c = \{FRR, OS\}$, the direction of the product's offering $d = \{up(\uparrow), down(\downarrow)\}$, the time interval (hour) to which the offer refers $h = \{1, 2, \ldots, H\}$ (where H represents the total number of intervals in the considered period) as well as the spatial assignment to either a market zone $z = \{north, cnorth, csouth, sardinia, sicily, south\}$ or a macro-zone[9] $mz = \{macro-north, macro-south\}$.

In the second step of data preparation, rejected, replaced, and revoked offers are cleared out, maintaining only accepted offers. Such offers are then limited to offers of the two product categories of interest, FRR and OS, and filtered for awarded price and quantity. Additional offers from the European exchange platform TERRE have been excluded since they did not count in the imbalance price calculations of the examined timeframe of 2019 and 2020.

The cleared-up daily offer sheets are then reorganized in the third step into a set of individual datasets per market zone for the timeframe to be analyzed, representing the basis for the individual market zone level analysis. For the macro-zone level analysis, the datasets of all market zones except North are further merged, constituting the final dataset of the macro-zone South. For North, instead, the market zone equals the macro-zone and no further adaptations are necessary.

Once the reorganized zonal datasets are obtained, it is possible to analyze the datasets in a fourth step and to compute the final pre-processed datasets that contain

[9] The concept of macro-zones is an aggregate of multiple bidding zones and is used in the Italian context for imbalance price calculations. More information are provided in Chapter 6.

necessary input prices for the subsequent imbalance price analyses. Therefore, the marginal prices $\dot{p}_{c,h,z}$ of all accepted offers are identified, detailed for each product category, direction, time interval, and geographic zone.

$$\dot{p}_{c,h,z,\uparrow} = \max(p_{c,h,z,\uparrow,o}) \quad \forall o \epsilon \{O_1, O_2, \dots, O_i\}$$
$$\dot{p}_{c,h,z,\downarrow} = \min(p_{c,h,z,\downarrow,o}) \quad \forall o \epsilon \{O_1, O_2, \dots, O_i\}$$

Given that the BM has a quarter-hourly resolution whereas the relevant time interval for the analysis of this work is the full hour, hourly marginal prices are derived as the arithmetic mean value of the quarter-hourly values for which accepted offers exist.

$$\dot{p}_{c,d,h,z} = \frac{1}{qh} \cdot \sum_{j=1}^{qh} \dot{p}_{c,d,h,z,j} \quad , \text{ with } qh \ \epsilon \{1, \dots, 4\}.$$

Furthermore, the weighted average price $\overline{p}_{d,p,z,h}$ of all accepted offers $o \ \epsilon O_1, O_2, \dots, O_i$ is calculated for each product and zone, again further detailed for hourly time interval and direction, as

$$\overline{p}_{d,p,z,h} = \frac{\sum_o (p_{c,d,h,z} \cdot q_{c,d,h,z})}{\sum_o q_{c,d,h,z}}.$$

The resulting hourly marginal and weighted average prices for each product category and direction are then saved in a fifth and last step in separate datasets for each zone.

3.3.3 Data Utilization

The ASM datasets obtained are then used for the following analyses. In particular, Chapter 4 uses the weighted average OS prices from MSD ex-ante and BAM at zonal level to identify the offering behavior of individual units and clusters of units on the Italian ASMs. Chapter 6 uses the weighted average as well as marginal prices of OS and FRR from the BAM at zonal and macro-zonal levels to calculate imbalance prices based on different European calculation schemes. Chapter 5 uses the weighted average prices of OS from the BAM at zonal level to simulate potential business opportunities of DERs through newly gained ASM access. Finally, Chapter 7 uses the weighted average prices of OS and FRR from the BAM at zonal and macro-zonal levels to simulate the co-optimization of a fully integrated DER unit that faces both active balancing opportunities on ASMs as well as passive balancing opportunities through imbalance pricing schemes.

Case studies that contain a simulation of active market interaction from DERs, such as in Chapter 5 and 7, require one more boundary condition. Given that Italian ASMs clear on a pay-as-bid basis, there is no one clearing price at which respective offers are evaluated and, on the contrary, also no single value that could serve as an immediate benchmark to evaluate the potential success of additional offers. Therefore, this study uses the weighted average price of effectively registered accepted offers as the acceptance benchmark for additional offers from simulated units.

The processed version of the empirical market data from Italy thus provides a valuable basis for a wide variety of case studies on the balancing integration of DERs. Additional input data as forecast errors and generation profiles complement the case studies' groundwork.

4 Regulatory Case-Study: the Italian UVAM project

This chapter includes material from

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4.1 Introduction

In the transitioning energy ecosystem, the share of iRES is relentlessly increasing at the expense of a decreasing share of fossil-fueled generation. With the progressively changing asset base of the power system, the associated ASMs are challenged by two issues. First, ASMs have been primarily driven by conventional, fossil-fuel-based power plants. The more these power plants are squeezed out of the (spot energy) markets, the less ancillary services they can provide [190, 191]. Second, the more the power system is based on non-programmable and intermittent resources, the more flexibility measures are needed to guarantee the continuous match of demand and supply [192, 193]. With the energy transition proceeding and the needed measures not (yet) in place, ASMs are already noting a growing scarcity. As an example, the reserve capacity margin at peak load decreased in Italy from 25 GW in 2012 to 7 GW in 2017 [194]. In line with the increasing scarcity, the costs for addressing the balancing needs skyrocketed. According to ENTSO-E, the contracted balancing reserves increased by 21% from 2016 to 2017 and the expenses for remedial actions of congestion management increased by 25% from 2015 to 2017, summing up to 1.27 billion € at the European level [195].

A changing generation portfolio, rising demand for ancillary services, and a growing scarcity of appropriate conventional capacity for ASMs necessitate new sources of flexibility to assure future-proof resource adequacy and security of supply [196]. The energy transition's triad of decarbonization, decentralization, and digitization makes it possible to harness the previously untapped potential from local resources to provide ancillary services [197]. To enable the service provision from such small and decentralized resources and to leverage their flexibility potential, European legislation fosters the concept of end-user aggregation through the Clean Energy Package (CEP) [1]. In such an aggregation, several small units are integrated into one large unit of a so-called Virtual Power Plant (VPP) [198]. As illustrated in Chapter 2, aggregation into a VPP can be performed at multiple levels, be it through Aggregators at the system level, through a microgrid at the local distribution level, or through an EMS at the individual user level. The newly gained dimension of the aggregate enables in all cases to participate in markets, be it EMs or ASMs, that individual resources would not be able to access. This provides a two-fold gain. On the one hand are additional revenue streams unlocked for operators of such DERs. On the other hand access is provided for grid operators to resources that can provide additional and most of all local ancillary services. Virtual aggregation represents therefore an essential building block for a successful energy transition with increased integration of DERs [58].

After the official introduction by the CEP on the European level, the concept of virtual aggregation is currently being transposed step by step at the level of the individual Member States into specific market designs. One of the largest initiatives to serve this purpose is the Italian large-scale pilot project UVAM (Unità Virtuali Abilitate Miste, i.e., virtually aggregated mixed units) that is fully operational since January 2019. While the pool of new players that enter the market is notably heterogeneous and different from incumbent players, creating an even playing field for the aggregated units is accordingly complex. Individual market design elements can have thereby a potentially decisive impact and lead to positive or negative market developments [199]. Therefore, this research aims to critically review and map the Italian UVAM project for the first year and a half in full operation. Based on empirical data, the weaknesses and strengths of individual market design elements are analyzed with regard to the market interactions of both individual units as well as the project as a whole. Specific research questions are:

- How has the fixed capacity payment worked as an incentive to mobilize the virtual aggregation of DERs?
- To what extent did the offer requirements trigger active ASM integration of individual DERs?

- How successful was the DERs market participation, and which business opportunities emerged or were even leveraged?

By covering a period of 18 months of project operation from January 2019 to June 2020, the analysis contributes to understanding the challenges and benefits of virtual aggregation, providing decision-makers in both regulatory and investing environments with valuable insights to evaluate the flexibility potential of distributed resources.

The further course of the chapter is structured as follows. Section 4.2 provides background information on the European and Italian regulatory framework that shaped the UVAM project. Section 4.3 describes the methodology that was applied to analyze the project. Section 4.4 outlines the results in the form of individual units' market participation and the ASM participation of the project as a whole. The emerging implications of specific market design elements as found in this analysis are then discussed in Section 4.5 before Section 4.6 concludes with policy recommendations.

4.2 Background

As the UVAM project was driven by regulatory innovation, this section briefly outlines the evolution of the European and Italian regulatory frameworks that led to the project's genesis.

4.2.1 The European Framework

The UVAM project is part of a broader paradigm shift at the European level towards the propagation of distributed resources and their respective market integration. As one of the fundamental steps of the new European energy regulation framework, the CEP (also called the "Third Energy Package" or the "Winter Package" [200]) was presented by the European Council in 2018 and approved by the European Parliament in early 2019. Out of the eight legislative texts, three legislative documents are of specific interest for the concept of (end-user) aggregation and flexibility provision from DERs. These are the Renewable Energy Directive 2018/2001 [201], the Electricity Regulation 2019/943 [202], and the Electricity Directive 2019/944 [203].

The new framework entitles final consumers inter alia to:

1. act as active consumers (2019/944, Article 15.1) and, more specifically, to become renewable self-consumers (2018/2001, Article 21);
2. to virtually aggregate (2019/944, Article 13);
3. to sell self-generated electricity and to participate in flexibility schemes (2019/944, Article 15.2).

Aggregation is thereby defined at the European level as "a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market" [203]. Based on this definition, not only generation but demand is entitled to aggregate and participate in all EMs, providing a considerable added potential from DR that is estimated between 50 to 100 GW in Europe [204–206]. In addition, Member States are required to ensure that system operators consider DR through aggregation in a non-discriminatory manner when procuring flexibility (2019/944, Article 17).

Another provision of the CEP targets the use of flexibility in distribution networks. Specifically, Article 32 of Directive 2019/944 states that member states shall provide the necessary regulatory framework and dedicated incentives for such. This implies necessarily the provision of flexibility from DERs, given that traditional ancillary services are connected at the central transmission level and thus, by definition, unable to deliver specific local services at the distribution level. In contrast to their previously rather passive role, this represents a paradigm shift for DSOs and evolves them into active system operators (in line with academic suggestions as elucidated in Chapter 2.3). As such, they would have to engage actively with service provision from external actors, either through still to be established LEMs or through the already existing central ASMs. In the latter case, the national ASMs would have to integrate the decentral flexibility resources by preserving their locational information so DSOs could procure services applicable to their specific local needs [207].

Different market designs for local flexibility markets are currently being piloted in different European Member States. To set the UVAM project in context to similar European initiatives, the following two subsections provide first an overview of some of the main pilot projects related to decentralized flexibility across Europe and reflect then in a second step on general policy decisions implemented in individual European markets.

Pilot Projects in the European Context Multiple projects have been established across Europe to investigate the concept of end-user aggregation along with the active integration of DERs in the power system operation. Such projects emerged both at distribution as well as transmission level and respectively with an intended impact rather at the national (or even cross-border) level or at the local level. Among the most renowned projects with a local scope are:

- *Dominoes*, establishing a reference architecture for a scalable LEM [208];
- *Enera*, developing a local platform for TSOs to purchase flexibility, especially to avoid iRES curtailment [207];
- *GoFlex*, a market platform with modular building blocks for the effective use of flexibility at distribution level [209]
- *InterFlex*, exploring a set of solutions for DSOs to address contingencies in distribution grids with high a renewable share [210, 211];
- *NODES*, adapting Nordic marketplaces for trading of decentralized flexibility [207];
- *Piclo Flex*, a dedicated DSO platform to tender specific locational flexibility capacity needs, aiming to provide a competitive solution to grid reinforcement [207].

Similar projects with a rather national or even cross-border scope are:

- *EU-SysFlex*, envisioning a common marketplace for joint provision of ancillary services by TSOs and DSOs [212];
- *CoordiNet*, providing coordination schemes for TSOs and DSOs to procure grid services from the same pool of resources [213, 214];
- *GOPACS*, enabling the local electricity market to include bids with a a locational tag from distributed resources [207];
- *FutureFlow*, establishing a regional cross-border platform for ancillary services of DERs [215].

The scope of the AS products that the projects contain varies thereby along with the scale of the individual projects. Most DSO-related projects focus on specific locational products such as voltage support, distributed congestion management, or the increase of the local network's hosting capacity through peak shaving. The larger, TSO-related projects instead focus on enabling and integrating distributed resources to provide ancillary services at the national level, such as frequency control or general congestion management. Besides enabling distributed agents for existing products, some projects adapt the currently traded products or create even specifically new products. The project GOPACS uses for example a standard product definition similar to intraday energy blocks but with an additional locational tag [207]. Other projects define no standard product to provide either flexibility providers (as in NODES) or flexibility consumers (as in Piclo Flex) the possibility to tailor bids and offers to their needs and abilities [207]. Besides the product aspects, another defining characteristic for the projects is their platform focus. Some of them focus on facilitating structures, e.g., to overcome possible problems related to the TSO-DSO coordination [211, 212, 215], others aim at creating a new trading platform that integrates into an existent market or also updating the existent markets themselves [207, 208]. Table 4.1 provides a comparative (though non-exhaustive) overview of key aspects of the listed projects. More extensive details on the UVAM project follow in Section 4.2.2.

All these projects are united in the aim to create an inclusive framework that connects a wide field of stakeholders from Grid Operators, over Aggregators to Prosumers and other DER operators, and to enable new business opportunities for the individual actors. However, given the complexity arising from a large number of different actors as well as the complexity to adhere to the existing regulatory frameworks, in most cases the initiatives are applied as limited pilot projects instead of integrated projects into national markets. In this respect, the UVAM project is special in that, unlike most other projects, it aims at full integration into national markets.

For the sake of completeness, it should be noted that in addition to the projects dealing with DERs and market integration of Aggregators, several other European projects are exploring the underlying technologies that enable distributed flexibility, such as DA/RE, DELTA, and the inteGRIDy project, to name a few [@227–@229].

Market Reforms in the European Context Apart from testing individual use cases through pilot projects, the European market designs are further evolved to better integrate the flexibility and ancillary services of DERs. This includes bringing markets closer to real-time trading, enabling shorter product durations, accepting smaller bid sizes, and increasingly allowing bids from virtually aggregated units of load and generation. A selection of noteworthy market reforms in the major European markets is outlined in the following.

One of the first countries to introduce amendments based on the publication of the CEP was France, moving the procurement of FRR to a daily basis from the previous weekly basis in July 2019. Notable is also the comparably small product resolution for the automatic Frequency Restoration Reserve (aFRR) of only 30 min. And while the minimum bid size for FCR and aFRR is already at 1 MW, as of now only the manual Frequency Restoration Reserve (mFRR) remains at 10 MW. Another French key factor in enabling effective DR and Distributed Generation (DG) participation is

Table 4.1: Key facts on selected European pilot projects for flexibility integration from DERs (not exhaustive). *(Reprinted with permission from [189])*

Project	Countries of application	Scope	Participants	User products
CoordiNet [@216]	(GRC, ESP, SWE)	National	Grid Operator (TSO & DSO), Retailer, Aggregator	TSO: DSO:
Dominoes [@217]	(FIN, PRT)	Local	Grid Operator (DSO), Aggregator, Prosumer	DSO: local agents:
Enera [@218]	(GER)	Local	Grid Operator (TSO & DSO), Aggregator, Platform Operator	TSO: DSO:
EU-SysFlex [@219]	(EST, FIN, FRA, GER, IRE, ITA, PRT)	National (+ cross-border)	Grid Operator (TSO & DSO), Retailer, Aggregator	TSO: DSO:
FutureFlow [@220]	(AUT, HUN, ROU, SVN)	National (+ cross-border)	Grid Operator (TSO), Retailer, Aggregator	TSO:
GoFlex [@221]	(CYP, GER, CHE)	Local	Grid Operator (DSO), Retailer, Aggregator, Prosumer	DSO: local agents:
GOPACS [@222]	(NLD	National	Grid Operator (TSO & DSO), Retailer, Aggregator, Platform Operator	TSO: DSO: local agents:
InterFlex [@223]	(CZE, FRA, GER, NLD, SWE)	Local	Grid Operator (DSO), Retailer, Aggregator	DSO:
NODES [@224]	(GER, NOR, GBR, SWE)	Local	Grid Operator (TSO & DSO), Retailer, Aggregator, Platform Operator	TSO: DSO: local agents:
Piclo Flex [@225]	(GBR)	Local	Grid Operator (DSO), Aggregator	DSO:
UVAM [@226]	(ITA)	National	Grid Operator (TSO), Aggregator	TSO:

the allowance of non-symmetrical[1] aFRR and mFRR bids. A remaining shortcoming is that DR is practically excluded from aFRR provision as it is obligatory for large-scale generators. Also the min bid size of 10 MW for mFRR still represents a significant obstacle for distributed units. Virtual aggregation of smaller units to participate in the ASM is allowed, however, mixed aggregation of demand and generation units in the same pool is not allowed [11, 230].

Similar to France, also Germany gradually reduced its timeframes for AS products, though still relying on a capacity tendering approach (instead of an energy-only approach as, for example, Italy). FCR (called "Primärreglreserve" in Geman) tendering changed first from weekly to daily resolution in July 2019 and then further to four-hour products in July 2020. In line with that, mFRR products (called "Minutenreserve") are tendered daily with a four-hour resolution. aFRR (called "Sekundärregelleistung") instead remains with 24h resolution. The minimum bid size has been reduced to 1 MW for FCR and 5 MW for aFRR and mFRR. The latter is further reduced to 1 MW under special conditions [231]. In general, only the products category of FCR is still symmetrical and virtual aggregation of generation and demand is allowed. Furthermore notably is that all balancing services are open to all types of market participants and technologies, as long as the general technical requirements are fulfilled [232]. BESS are therefore mainly active in FCR, and also first iRES units (e.g., wind turbines) participate in negative mFRR [11, 233].

Although future developments continue to be the subject of macro-political muscle-flexing, another market with yet comparably advanced adoptions of CEP provisions is Great Britain. Previously criticized for its comparably complex product and market structure, the TSO National Grid started modifying balancing product categories to streamline and standardize them [11]. So-called "firm frequency response" (as the FCR equivalent) is still tendered on a monthly basis but started weekly tendering trials in June 2019. Furthermore, the procurement of the product category called “Fast Reserve” (as the aFRR equivalent) was suspended in January 2020. Its monthly tendering did not comply with CEP regulations, and National Grid considered the switch to day-ahead procurement as unsuitable [234]. On the contrary, the procurement of the "short-term operating reserve" STOR (as the equivalent to mFRR) was modified and moved to a comparably shorter timeframe closer to real-time, i.e., on a 24 h basis at day-ahead [235]. While virtual aggregation is allowed for specific product categories such as mFRR, the minimum bid sizes for FCR and mFRR are 1 MW and 3 MW, respectively [11, 230].

[1] non-symmetrical means in this context to allow separate bids in upward and downward direction.

In Spain, providing FCR services is mandatory yet not remunerated for large generators. On the contrary, aFRR and mFRR are contracted with a market-based approach on a day-ahead basis [11, 230]. The minimum bid size for the respective products has been reduced starting from previously 10 MW in 2019 to 1 MW. iRES are already eligible to provide aFRR, mFRR, and RR [236], DR joined the provision of RR in early 2021. Aggregation of generation and demand is similarly allowed since early 2021, however, only for the same technology [214].

Similar to Spain, the Italian market used to be a relatively closed market concerning balancing services that shares the same core characteristics of a central dispatching system with a strongly proactive TSO. In fact, the Italian market was considered one of the least opened ASMs in Europe in 2018, effectively not allowing any DER participation in the ASMs for capacities below 10 MW [11]. However, significant market design changes have been introduced over the last year, overturning the situation significantly. While the general Italian market framework is outlined in Section 3.1, the following section recaps the emergence of the nation-wide framework for the participation of Aggregators and (subordinated) Prosumers with DERs in the ASM and how this project integrated into the general market framework.

4.2.2 The Italian Framework

While before 2017, DR and DG units smaller than 10 MW were fundamentally excluded from any ASM participation, the CEP triggered the Italian National Regulatory Authority (NRA) ARERA to initiate a redesign of the market framework. In the first resolution in 2017, the Italian TSO Terna was asked to outline potential innovative pilot projects for the market integration of DERs [237]. The main objective of these projects was to gather, first of all, valuable insights about individual market design elements and, along with practical experience, serving then as the basis for subsequent comprehensive market reforms. Eventually, these reforms shall aim to involve DG and DR in the ASM without compromising the principle of technological neutrality. With this being said, the insights from the large-scale Italian pilot project do not only provide valuable input for the upcoming Italian market reforms but can serve at the same time as points of reference for policy-makers around the world.

The first of the proposed projects to be implemented was the so-called *UVAC* project (Unità Virtuali Abilitate di Consumo, i.e., enabled virtual consumption units) in June 2017 [238]. Through the project, individual consumption units could aggregate into clusters. The minimum bidding size for virtual unit's of this project was reduced from the previous 10 MW to 1 MW, thus allowing smaller-sized operators' participation. Note also that individual units of the aggregate can be even smaller than that. The product for which the aggregated units could compete in the market was the Italian multi-purpose product "OS", with specific use cases for tertiary reserve and balancing services.

Few months later, in November 2017, launched the second project under the name *UVAP* (Unità Virtuali Abilitate di Produzione, i.e., enabled virtual production units) [239]. This project complemented the first one by allowing for aggregation of generation units to provide the same services such as UVACs plus congestion management service (always through the same product category OS).

One year later, in November 2018, the UVAC and UVAP projects converged in the project *UVAM* (Unità Virtuali Abilitate Miste, i.e., mixed enabled virtual units) [240]. This third and final project aims to enable ASM participation also for mixed aggregates of consumption and generation units as well as storage systems. For simplicity, such virtual units are from now on always called “UVAMs”. “UVAM project” is used instead to refer to the project as a whole.

The aggregation perimeter of individual UVAMs is defined by the TSO on a provincial or regional basis, considering only the physical characteristics of the electricity grid at transmission level. At the time of writing, Terna subdivided Italy into 18 geographic zones in which UVAMs can aggregate, each zone being a sub-zone of one of the electricity market bidding zones [241].

Each UVAM is operated by a single BSP, which participates with the virtual unit in the ASM. However, for participation in the EMs, individual consumption or production units within the virtual aggregate remain to BRPs. Therefore, in line with European regulation, BRP and BSP may or may not coincide for a virtually aggregated unit [242]. Thus, while only one BSP will operate each such virtual unit on the ASM, potentially multiple BRPs might manage the EM operation of individual units that belong to the aggregate. In the beginning, BSPs needed the permission of every BRP for individual units to join the virtual aggregate. In combination with initial difficulties concerning the management and remuneration of individual units, this was heavily criticized by participants [243]. In response to this criticism, the permission ruling has been overturned by the regulator, with BSPs now simply notifying BRPs about individual units' participation [244].

The minimum scalable capacity that UVAMs must entail as of now (in both upward and or downward direction) is 1 MW. This minimum size results from a continuous reform process to enable the participation of smaller-sized operators, starting from

10 MW in 2017 and having reached 1 MW as of today. Further reduction of the minimum capacity to 0.2 MW is currently under discussion [245]. They are thus eligible to provide the same services through the product category OS as UVAPs previously: mFRR, RR, balancing services, and services for congestion management. The activation needs to occur then in line with the products specifications within 15 min and is monitored in intervals of 60 or 4 s depending on the individual units' size.

UVAM units are generally distinguished as contracted and non-contracted units. The distinction is based on the remuneration mechanisms. All UVAMs are eligible to participate in the ASM and thus receive the standard remuneration on a pay-as-bid basis for all successful market offers. Moreover, UVAMs can compete through an additional (temporary) tender mechanism to become a contracted capacity if they consist of at least 50% of programmable capacity, be it on the generation or consumption side. Being a contracted UVAM provides a fixed capacity payment in exchange for offer obligations on the ASM. The idea behind the one-off payment is that it can be used to offset possible investment costs, such as implementing necessary ICT resources. Implied bidding requirements consist then of mandatory offers with the full capacity of each UVAM in the upward direction for at least 2 or 4 consecutive hours during presumed peak hours, i.e., daily between 14:00 and 20:00 Monday through Friday. The commitment's duration eventually determines the price cap of the capacity auctions. Non-contracted UVAMs, instead, are free to place as many or few offers as they like on the ASM. The resulting payments for operators are thus defined as:

- a *variable activation payment*, equal to the price offered by the UVAM operator on the ASM (with a price cap of 400 €/MWh in upward direction for contracted units);

- a *fixed availability (capacity) payment* for successfully contracted UVAMs. The payment is set in a pay-as-bid downward auction with a price cap placed at either 15,000 €/MW/year or 30,000 €/MW/year depending on the time commitment.

UVAM contracts are awarded through multiple auctions, starting with one auction with annual duration products, followed by three interim auctions with "multi-month" products for remaining capacity, and finally 12 monthly auctions in case additional capacity should be available (or have been revoked in the meantime). The TSO's total contractual capacity amounts to 1,000 MW, making it one of the most ambitious projects of ancillary services provision from DER in Europe.

4.3 Methodology

To investigate and eventually map the operational behavior of UVAM units, preprocessed empirical market data as explained in Chapter 3.3 is used. A unique plant identifier distinguishes offers of individual units, yet UVAM units are not explicitly indicated. In a preliminary data-analysis, as further described in the related publication [189], it emerged that the plant identifiers of UVAM units start with "UP_MD...". Applying this as an additional filter for the market data eventually provides the registered offers and transactions of individual UVAM units.

Using then the respective daily data sets from the 1st of November 2018 until the 31st of June 2020 provides an overview of the UVAM market integration for the first one and a half years of full project's operation plus two initial months in which individual aggregates could already qualify as UVAMs and act on the ASM although no contracted capacity payment was yet available. Additional data for an analysis on the capacity assignments would be available on the TSO's website [@226] and is also presented in [189]. The following analysis on the UVAMs market integration is subdivided into two steps.

First, individual participants' market integration is investigated, identifying common bidding strategies and the development of operators' behavior throughout the project. To do so, individual offers are clustered on an hourly basis for typical price and or quantity patterns and subsequently cross-compared. Such is done separately for the amount of offers in each year and in upward and downward directions[2].

Second, the global market integration of the project as a whole with all its virtually aggregated units is analyzed and benchmarked to average market behavior. To do so, the UVAM offers are summed up on an hourly basis in terms of overall offered quantity and the associated weighted average price. Such is mapped against the average market clearing price (i.e., the weighted average price of all accepted offers of the same product category), again separately for upward and downward direction.

[2]Strictly speaking, offers in downward direction would be "bids" instead of "offers". However, for the sake of simplicity, the term offer is used for both typologies and transactions are distinguished through the parallel statement of the direction.

4.4 Results

This section presents the results from the in-depth data analysis of the UVAM project's market integration, first on an individual participants basis and subsequently for the project as a whole.

4.4.1 Individual Unit's Market Integration

The actively registered UVAM capacity grew steadily over the course of the project, starting from around 100 MW in December 2018 to 1,040 MW in December 2019 and slightly further to 1,070 MW in June 2020 [189]. Most of this capacity is directly related to contracted capacities, with assigned contracts from the first round of auctions in January 2019 summing up to 400 MW and then steadily growing up to nearly 1,000 MW in December 2019. The first auction in January 2020 confirmed the operators' preference for the additional fixed remuneration despite the connected offer obligations, assigning 99% of the annual capacity right away [@226].

The close connection of all UVAM participants through the contractual obligations ultimately also affected the individual units' market integration, with surprisingly clear patterns emerging. By mapping the hourly offers of each unit, several shared bidding characteristics came to light. Figure 4.1 illustrates the presented ASM offers of four exemplary aggregated units during a representative week in June 2019 in upward direction (chart above) and downward direction (chart below). Bars represent thereby the offered quantity (referring to the left axis) and dots the offered price of each individual offer (referring to the right axis).

Clear patterns emerge that are repeated in relation to specific times or days of the week. Some units such as UVAM 1 and 2 (green- and yellow-colored in the figure) offer, for example, a constant quantity of upward services at all times. Other UVAMs, like UVAMs 3 and 4 (blue and red-colored respectively in the figure), offer their contracted quantity only during obligatory hours and an insignificant quantity during other hours. Moreover, while all UVAMs offer the compulsory upward services, few UVAMs offer the optional downward services. Such happens then usually alternating to upward offers during the respective non-obligatory hours (see UVAM 3 as an example).

Also, clear strategies patterns are noticeable regarding the offered price of UVAM units. Some UVAMs offer their upward services at somewhat competitive prices close to the weighted average market price (black line in the figure) around 90

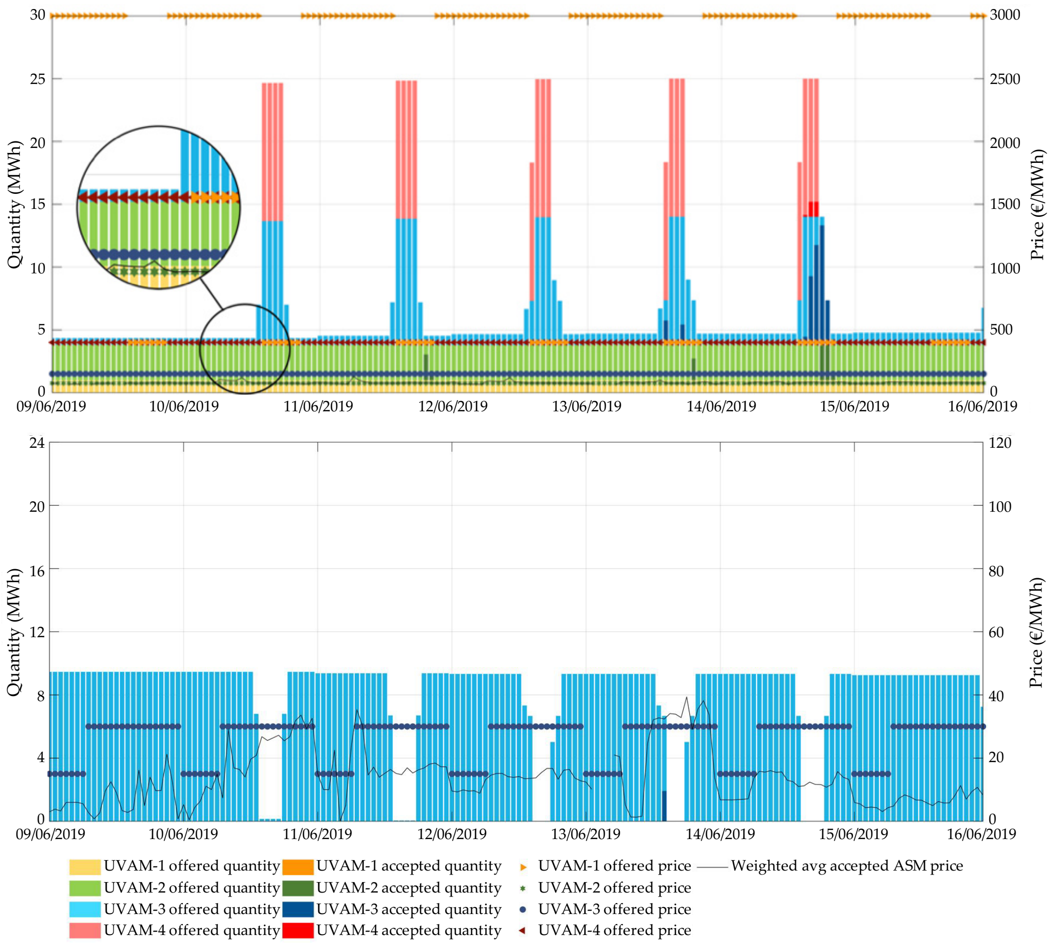


Figure 4.1: Exemplary illustration of hourly offers by individual UVAM units in upward direction (chart *above*) and downward direction (chart *below*). *(Reprinted with permission from [189])*

to 120 €/MWh, such as UVAMs 2 and 3 in the example. Other units offer far beyond that. UVAM 4, for example, offers consistently at a price of 400 €/MWh, regardless of whether the price cap applies to the hour in question or not. Even worse, UVAM 1 offers at 400 €/MWh during obligatory hours and at the overall market price cap of 3000 €/MWh (i.e., the Italian VOLL).

Based on the analyzed UVAM behavior as illustrated in Figure 4.1, four fundamental bidding strategies are identified. Out of these, a set of more complex bidding strategies can be combined that coincides eventually with a large number of UVAM offers. Specifically, the four fundamental strategies are:

- *Strategy I:* offering significant quantity only during obligatory hours (from 14:00 to 20:00) and minor quantities otherwise (see UVAM 3 & 4);
- *Strategy II:* offering, whenever offering, a constant quantity of upward services throughout the year (see UVAM 1 & 2);
- *Strategy III:* offering, whenever offering, at constant price throughout the year (see UVAM 2, 3 & 4);
- *Strategy IV:* offering, during certain time intervals, upward services at VOLL price (see UVAM 1).

The bidding strategy analysis covers only upward services since downward services represent only a fraction of the overall offered quantity. Specifically, no UVAM unit offered only downward services in 2020, and only 16 out of 208 active UVAM units offered both upward and downward services. As the UVAM incentive scheme does not include any obligations concerning downward services, no clear strategies are detectable in the analyzed data set. Instead, combining the four named fundamental upward bidding strategies provides a very representative picture of the individual participation patterns of UVAM units as outlined in Table 4.2.

The left-hand side of the table shows thereby the four fundamental bidding strategies and, at the bottom, the share of UVAM participants that adhered (non-exclusively) to them throughout the analyzed period from November 2018 to June 2020. While, for example, in the first two months of the project only 13.4% offered their quantity exclusively during the obligatory hours, this share increased to 70.9% for 2019 and eventually reached 88.3% for the first six months of 2020. Likewise, the share of participants that include the patterns of Strategy II & III increased over the course of the project's duration, whereas the relative share of UVAMs that offer certain hours at VOLL decreased from 4.9% to a nearly negligible share of 0.8%.

Table 4.2: Distribution of identified bidding strategies by individual UVAM units in 2018, 2019, and 2020. *(Reprinted with permission from [189])*

	Strategies I	Strategies II	Strategies III	Strategies IV	2018 (MW)	2018 (%)	2019 (MW)	2019 (%)	2020 (MW)	2020 (%)
Strategy combination	●	○	○	○	0.0	0.0%	248.5	23.9%	74.2	6.9%
Strategy combination	●	●	○	○	0.0	0.0%	143.4	13.8%	72.8	6.8%
Strategy combination	●	○	●	○	2.8	2.7%	87.4	8.4%	121.8	11.4%
Strategy combination	●	●	●	○	10.9	10.7%	258.1	24.8%	677.2	63.2%
Strategy combination	○	●	○	○	0.0	0.0%	0.0	0.0%	8.8	0.8%
Strategy combination	○	●	●	○	4.9	4.8%	1.6	0.2%	2.0	0.2%
Strategy combination	○	●	○	●	0.0	0.0%	7.0	0.7%	0.0	0.0%
Strategy combination	○	●	●	●	5.0	4.9%	0.0	0.0%	0.0	0.0%
Strategy combination	○	○	●	○	18.3	18.0%	28.5	2.7%	25.8	2.4%
Strategy combination	○	○	○	●	0.0	0.0%	29.9	2.9%	8.1	0.8%
Strategy combination	○	○	○	○	59.8	58.8%	235.7	22.7%	81.2	7.6%
Year 2018	13.4%	20.4%	41.2%	4.9%	101.72	100%	1039.99	100%	1071.77	100%
Year 2019	70.9%	39.4%	36.1%	3.5%						
Year 2020	88.3%	71.0%	77.1%	0.8%						

Even more insights emerge by combining the four fundamental strategies. The table's right-hand side reports the relative share of UVAMs that follow exclusively a specific combination of strategies. While for example in 2018 few strategy patterns were fully pronounced, and 58.8% of the participants did not follow a specific combination of strategies (last row with only white circles), this number decreased to 7.6% for the observed six months in 2020. Said differently, the other identified combinations of bidding strategies cover the behavior of 92.4% of the active UVAMs.

Due to the increasing dominance of the fundamental strategy I (i.e., offering significant quantity only during obligatory hours), the combinations that contain this strategy prevail over the overall strategy patterns. Along with the introduction of the capacity scheme in 2019, UVAMs tended to adopt different combinations around this strategy. The most prominent combination was thereby in 2019 with 24.8% (or 258 MW of summarized UVAM capacity) to offer only during obligatory hours but with constant price and constant quantity. The share of UVAM units that adopted this strategy increased even further in 2020 to 63.2% or 677 MW, making it the by far dominating bidding strategy. So, what was intended as a minimum participation requirement with a price cap eventually turned into a baseline with a strike price.

Overall, it is also more than remarkable to see how strongly the requirements apparently influence the participating Aggregators. With all bidding behaviors containing Strategy I being clearly influenced by the project's incentive scheme, only 29.2% of the actively participating UVAM capacity in 2019 chose to offer beyond these minimum requirements. In 2020 the share dropped even further

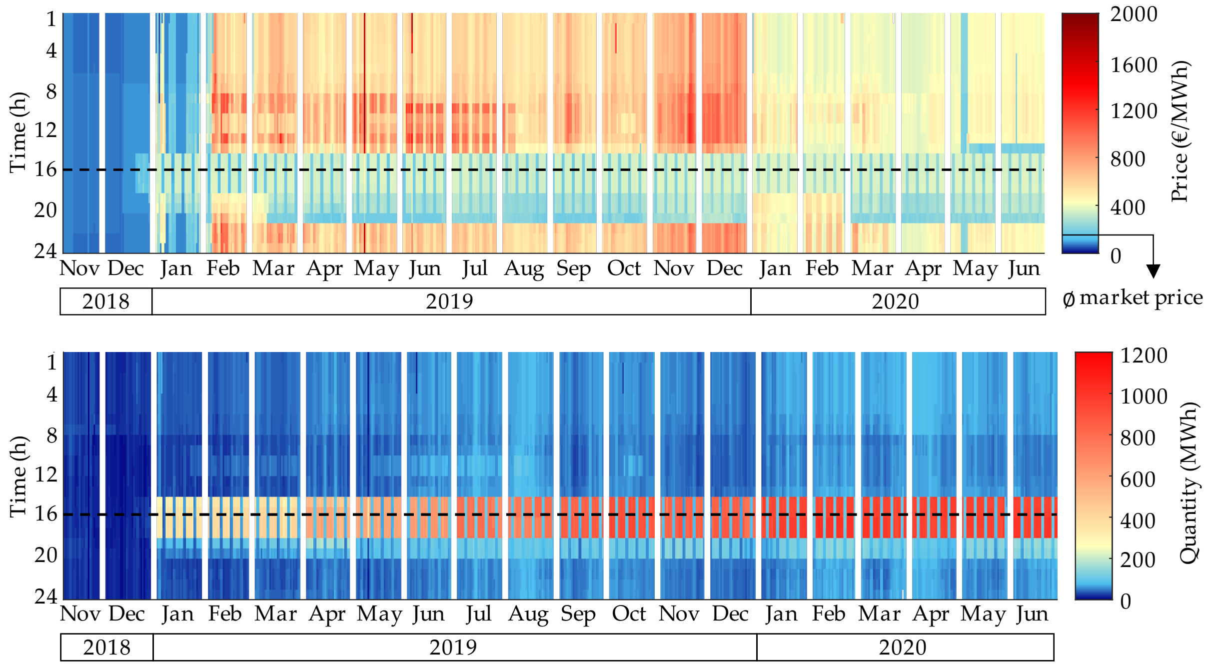


Figure 4.2: Heatmap of summarized hourly offers by UVAM units in upward direction in terms of the weighted average price (chart *above*) and the summed quantity (chart *below*). *(Reprinted with permission from [189])*

to only 11.8% demonstrating a genuine bidding behavior that can be described as unaffected by the incentive scheme.

4.4.2 Project's Market Integration

Following the analysis of individual units' market participation, the following section outlines the market integration of the project as a whole.

Qualitative Comparison To illustrate the overall project's performance from a system perspective, the two heatmaps of Figure 4.2 report the weighted average price and the overall quantity of upward offers that were made from the sum of UVAM units from November 2018 to June 2020. As previously, the reported results of the analysis focus on upward offers. Nonetheless, the analysis also contained results for the downward bids as reported in Appendix B.2.

Through the visualization of UVAM offers, the previous findings from individual bidding strategies become more tangible. Following the development on the lower heatmap outlining the offered quantity, it becomes clearly visible how the offers are concentrated to the mandatory period from 14:00 to 20:00 (reflecting the fundamental Strategy I). Clearly visible also how weekend days distinguish from weekdays through the absence of offerings as well as how the overall capacity associated with the project increases over time.

Also the average offered price as illustrated in the upper heatmap reflects the previously identified bidding strategies and, in particular, the imposed price cap of 400 €/MWh during obligatory hours. In fact, the total average price for hourly upward offers from UVAMs at 16:00 on weekdays in 2019 is 361 €/MWh, instead, outside the obligatory timeframe at 04:00 on weekdays it is 570 €/MWh. The higher average price outside the obligatory is mainly driven by individual UVAMs offering at a very high price up to the VOLL (reflecting the fundamental Strategy IV) and, also due to generally reduced quantity in these hours, covering thereby the nonetheless existent more price-competitive offers of other UVAMs. This divergence also expresses in a notably higher standard deviation of the price of upward UVAM offers of around 1,150 €/MWh at 04:00 on weekdays versus 110 €/MWh at 16:00 on weekdays.

With the turn of the year 2019/2020, not only was the contracted UVAM capacity redistributed among the participants, but also the high-priced offers close to the VOLL disappeared (see Table 4.2, with the share of Strategy IV dropping from 3.5% to 0.8%) and the effective average price of the other UVAMs was revealed. The continuity of repetitive bidding patterns, which is still clearly visible, illustrates the further increase in the share of the fundamental Strategies II and III.

Another price difference that is related to the rigid offer requirements becomes visible by comparing the weighted average price of UVAM offers at 16:00 on weekdays and days of weekends. As the offering requirement obliges UVAMs only to offer on working days, those UVAMs that offer only the bare minimum requirement (i.e., combinations that include the fundamental Strategy I) disappear, and only those with a more genuine bidding strategy remain. As a matter of fact, the offers of the remaining units turn out to be significantly more competitive with a weighted average price of 214 €/MWh for offerings at 16:00 on days of weekends. These types of more competitive offers also continue during the compulsory hours on weekdays, but are then outnumbered by the minimal requirement offers around 400 €/MWh.

To benchmark prices and quantities of UVAMs with accepted offers of other (non-UVAM) operators, Figure 4.3 provides comparable heatmaps for the overall accepted OS offers on the Italian ASMs (MSD ex-ante + BAM). First of all, it emerges that the clearing price of the product category under discussion is with on average 90-120 €/MWh significantly lower than recorded average UVAM offers. However, most notably, it appears that the highest clearing prices occur in the off-peak hours in the late evening after 20:00 as well as in the early morning hours up

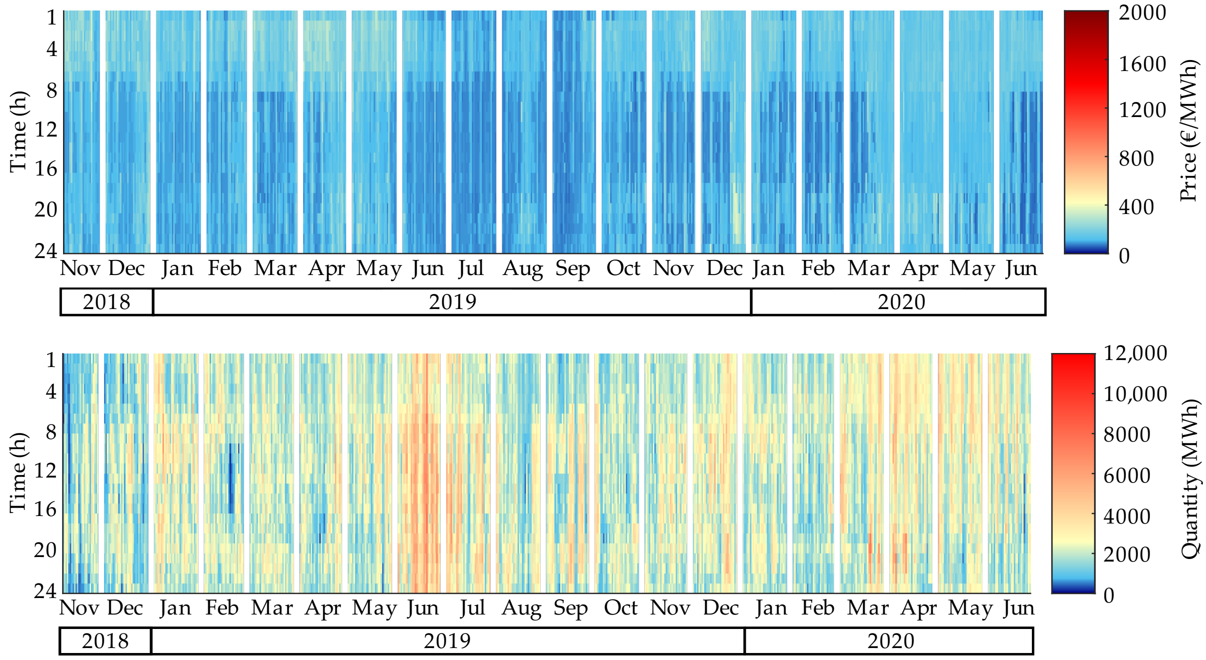


Figure 4.3: Heatmap of summarized awarded offers in upward direction on the Italian ASMs in terms of the weighted average price (chart *above*) and the summed quantity (chart *below*). *(Reprinted with permission from [189])*

to 08:00. Moreover, no sizeable cluster of accepted quantity (or system need) appears during the obligatory UVAM period from 14:00 to 20:00, making the choice of project parameters somewhat disputable.

Quantitative Comparison After the qualitative comparison of the UVAM projects' competitiveness through heatmaps, respective offers are compared in a second step on a more quantitative basis. Therefore, Figure 4.4 illustrates the price distribution of submitted and accepted UVAM offers compared to the price distribution of overall accepted upward and downward quantity within the Italian ASMs for the analyzed period of 18 months. Offers are grouped in price intervals of 10 €/MWh and, as previously, only ancillary service product OS that UVAMs are eligible for is considered. For the sake of conciseness, the different diagrams illustrate results up to 400 €/MWh. Although few offers with prices above this threshold exist, the depicted range contains 96% of all submitted UVAM offers and 100% of all eventually accepted UVAM offers.

As expected from the previous qualitative findings, upward bids of UVAM offers are not evenly spread above all price ranges but are highly concentrated in a few clusters. As visible through the blue-toned bars in Figure 4.4(a), the vast majority falls in the sole interval of 390–400 €/MWh. A second though considerably smaller

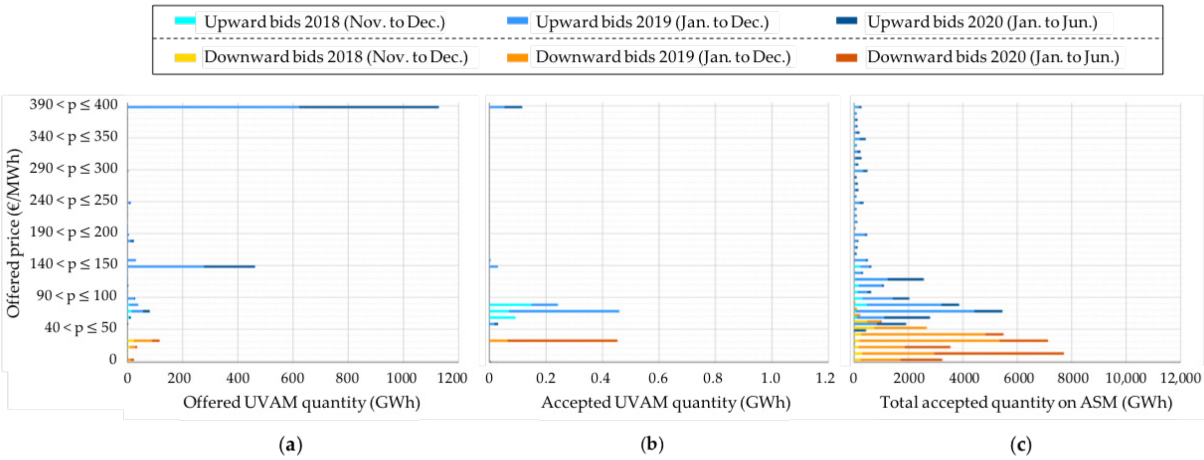


Figure 4.4: Price ranges of offered and awarded UVAM offers compared to overall market clearing results. *(a)* Submitted UVAM offers; *(b)* Accepted UVAM offers; *(c)* Overall market results. *(Reprinted with permission from [189])*

cluster is identified from 140–160 €/MWh and a third even smaller cluster emerges around the broader price range of 70–100 €/MWh.

By comparing the submitted with the actually accepted UVAM quantities (Figure 4.4(b)), it shows that the vast majority of accepted upward offers falls in the range of the third, low-price cluster from 60–90 €/MWh. Only minor UVAM quantities were accepted beyond that range. So eventually, the majority of accepted UVAM offers stems from out of the smallest, though most cost-competitive cluster of submitted offers. Note also the by a three order of magnitudes reduced scale on the x-axis.

Unsurprisingly, the identified distribution of accepted UVAM offers is in line with the distribution of overall accepted offers on the Italian ASM (4.4(c)). The center of gravity for overall accepted upward offers across all bidding zones on Italian ASMs is centered around 70–80 €/MWh, slightly skewing towards higher prices. Taking together all UVAM upward offers, the Italian TSO has accepted only 985 MWh during the first 18 months since the project's initiation. This represented around 0.05% of the submitted UVAM offers and provided them in this direction a market share of 0.003% for the product category OS on the ASMs.

The second product direction, downward offers, are much less frequently submitted by UVAMs and show a smaller price spread with a sole cluster of offers in the low-price ranges around 20–30 €/MWh (see yellow-toned bars in Figure 4.4). As this price cluster is well in line with the overall price range of accepted downward offers on the ASM, these offers can be considered comparably competitive. Overall, around 530 MWh of downward services from UVAMs have been purchased by the Italian TSO during the first 18 months since the project's initiation.This represents roughly 0.3% of the submitted downward UVAM offers and provided them therefore a market share of 0.002% for the product category OS in this direction on the ASMs.

Special Focus: COVID-19 Implications As described in detail in Chapter 3.2, the pandemic situation in 2020 left its mark on the Italian power system. While conventional power generators were increasingly being squeezed out of the market and the overall demand for ancillary services was rising with increasing shares of iRES in the system, the UVAM project had only been fully operational. As a significant share of UVAMs is as of now related to industrial plants with conventional, co-generative power units [246], the nationwide lockdown of society and economy proved the project's first baptism of fire.

However, despite the challenging circumstances, the COVID pandemic does not seem to have had a detrimental impact on UVAM bids. The aggregated units not only increased their offered quantity along with the contracted capacity, but also maintained their offer constant or even slightly improved outside the obligatory timeframe. As visible in Figure 4.2, the offered upward quantity by UVAMs increased in line with the contracted capacity from April 2019 to April 2020 by 59%. Moreover, from January 2020 (as the last unaffected month pre-COVID) to April 2020, the submitted offers increased slightly by 5%, although basically no new capacity had been contracted in the meantime. Moving from offered capacity to prices, it shows that the average UVAM prices during the obligatory hours remained at a high level between 350–370 €/MWh. The average UVAM price outside these hours reduced instead from its previously even higher level, not only compared to the previous year but also on a monthly basis to an average of around 390 €/MWh in April 2020. This price is of course still well above the long-term average price of the market, and since other participants reduced their offer prices even further during the pandemic, no upward UVAM offers were activated in the end.

For downward services instead, the picture is somewhat different. Also here, UVAM operators maintained a relatively constant quantity of offers, albeit at a low level. As the offered prices for this ancillary service were already competitive and kept constant, the UVAMs eventually benefited from the increased market demand. This triggered an increased activation of downward services from UVAMs, and eventually, 85% of all accepted downward offers from UVAMs are situated within the five months from February to June 2020. Although not focusing specifically on this product direction, this UVAM services turned out most valuable (in line with its competitiveness) for the system during the time of the highest pandemic challenges. Figure 4.5 summarizes the accepted upward and downward quantities by UVAMs during the first 18 months of operation.

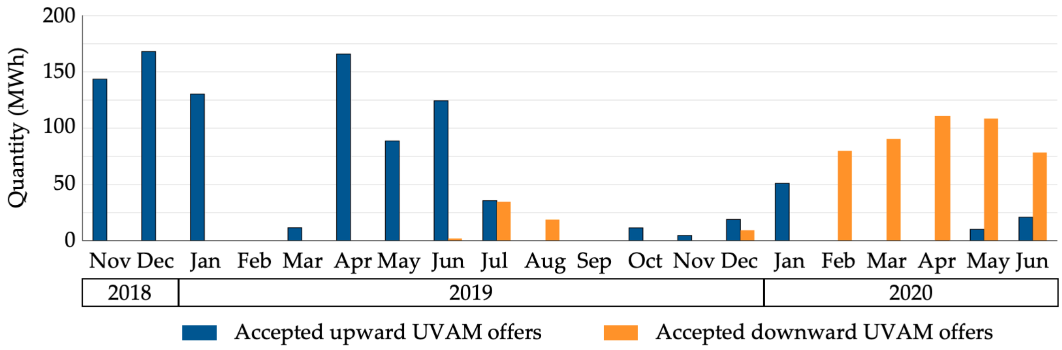


Figure 4.5: Monthly distribution of accepted upward and downward offers from UVAMs. *(Reprinted with permission from [189])*

4.5 Discussion

When evaluating the UVAM project based on its first 18 months of operation, it appears at first glance that the project seems to have activated and integrated into the market a massive potential of ultimately more than one gigawatt of decentralized flexibility. At closer examination, however, the positive picture is becoming somewhat flawed.

As noted previously, it appears that the minimum bidding requirements linked to the capacity payments turned into an operation baseline for UVAM operators. In fact, a continuously growing share of operators offered upward quantity of their controllable assets only during the four obligatory hours. During the first six months of 2020, this share summed up to more than 88% of all participating UVAM units.

Also the price cap for upward offers results eventually rather as a fixed strike price. 77% of all UVAM operators offered during the first six months of 2020 at an always constant price, and the weighted average price of UVAM offers during the contracted hours resulted in being 360 €/MWh. The only reason the price in these hours is not exactly at the price cap of 400 €/MWh is that a minority of UVAM operators also offer in the 150 €/MWh range. The literal aversion of some operators to being accepted is also reflected in the prices outside the core time, which are on average even higher and driven by some offers that go up until to the Italian VOLL of 3000 €/MWh.

So, overall, most UVAMs do only the bare minimum concerning market participation, and only a minority of operators participate with a genuine bidding strategy that would include price-competitive offers beyond the four obligatory hours. The rate of accepted offers is correspondingly low, and it remains debatable as to how successful the market integration can thus effectively be considered.

The fact that the majority of Aggregators refrain from offering at prices that are even remotely competitive is somewhat surprising. Even if the premium from the capacity scheme already represents an income, they are thus foregoing the second, potentially much greater business opportunity to sell in a new market at significantly higher prices than has been possible so far in the commodity markets. A deeper understanding of why most Italian Aggregators waive the opportunity to sell the power of their assets as an active service remains subject to further investigation, but two possible options seem conceivable. On the one hand, the internal benefits of the energy usage might be very high (also considering that a majority of UVAMs are actually co-generating units), creating high opportunity costs for schedule changes and thus eventually justifying the high offer prices. Or, on the other hand, hitherto unknown external obstacles make it difficult for operators to participate actively and tempt them to make uncompetitive offers rather than risk being activated and then having to deliver. In any case, it appears that the currently adopted bidding strategies for most of the Aggregators are unrelated to actual market incentives with the highest prices occurring in evening or early morning hours, but purely guided by the project's auction scheme.

Two points besides the general market integration of individual units and the project as a whole attracted additional attention. First, it emerged that only one operator accounts for 85% of all accepted upward offers from UVAMs and even for 100% of downward offers. Specifically, this Aggregator is a subsidiary of the previous Italian incumbent operator. Moreover, only 11 out of the 27 UVAM operators placed at least one successful offer that has been accepted by the TSO, underlining how ambivalent different operators' participation is.

The second note concerns the TSO acceptance behavior. Eventually, it appears that the TSO never accepted any UVAM offer during the period of study on the programming phase of the ASMs (MSD ex-ante) but only on the BAM. This implies that the TSO actually uses the virtual units only in its real-time operation for balancing purposes, but, at least as of now, not for pro-active congestion management. Whether the preference for other orders is driven by merit-order or individual operational preference of the TSO remains, again, subject to further investigation.

4.6 Summary and Policy Recommendations

Based on empirical data of the first 18 months of operations, this chapter analyzes the first active balancing integration of distributed energy resources in Italy. The pilot project UVAM enabled Aggregators to access the Italian ancillary services market with virtually aggregated assets and was conceived as a regulatory case study to generate insights for subsequent market reforms. At the same time, it also surfaced the actual business opportunities that such new actors can leverage in Italy, with all its pros and cons.

As a first positive observation, the project was able to enable around 1,000 MW of new capacity from distributed energy resources and to integrate it into the ancillary services market. This entire capacity was previously not entitled to participate in active balancing mechanisms, hence only being able on spot energy market but not contributing to any ancillary services markets. Therefore, it appears that the fixed capacity payment from the auctions was able to fulfill its purpose and to mobilize the virtual aggregation of distributed energy resources on a significant scale.

However, concerning the market participation and integration of these newly aggregated units, the pilot produced rather debatable results. The rigid offer requirements, which were intended as minimum requirements for those units benefiting from capacity payment, ultimately turned out to be interpreted rather as a bidding guideline for Aggregators. The market integration resulted thereby eventually considerably inactive with a majority of operators offering only four hours per day at prices far above the average market-clearing prices. The project failed in that sense its purpose of experimenting with the interactive ancillary services market integration of distributed energy resources. Therefore, the directly connected regulatory implications are to either lower the imposed price cap and hence "force" the Aggregators into a more interactive market integration, or to investigate and remove potential external barriers that prevent operators from competitive bidding.

In fact, during the first 18 months of the project's operation, considerable few Aggregators actually leveraged the potential business opportunity of ASM participation. Even though the TSO seems to prefer to use the capacity of the virtual aggregated units almost exclusively for real-time balancing purposes and not for ex-ante congestion solutions, this does not detract from the business case as the average clearing prices on the balancing market are nonetheless more than twice as high as the average clearing prices on the energy markets. Moreover, even though this was not the initial focus of the pilot project, downward services also provide a substantial opportunity that the TSO apparently values, especially in times of high renewable generation.

With regard to specific policy recommendations, four major conclusions can be drawn:

1. Allowing smaller bid sizes and the virtual aggregation of generation and consumption units of even smaller sizes can untap an impressive potential of new flexibility resources.

2. The combination of fixed incentives through capacity payments with rigid offer requirements requires careful judgment. For the case of the evaluate Italian project, it triggered insufficiently active market participation of individual units.

3. The pure business case of balancing services provision from DERs might, at least in the current Italian setup, not be sufficiently attractive for in-depth DER activation. To enhance the business case, possible remaining obstacles related to the existing product offerings would need to be further explored and addressed, or the eligible product portfolio expanded accordingly.

4. A potential (re-)design of a project framework for active DER integration might want to focus also more specifically on downward services. Such provided particularly valuable during times of high RES share and absence of other traditional service providers.

5 Active Balancing Integration: Enabling Market Access

This chapter includes material from

Jan Marc Schwidtal, Matteo Bernardi, Marco Agostini, Fabio Bignucolo, and Arturo Lorenzoni. "Balancing Services Provision from Wind Turbines: An Italian Case Study". In: *UPEC 2020 - 2020 55th International Universities Power Engineering Conference, Proceedings* (2020). DOI: 10.1109/UPEC49904.2020.9209819. **Peer-Reviewed Conference Paper**, cited as [247]

Jan Marc Schwidtal, Federico Zeffin, Fabio Bignucolo, Arturo Lorenzoni, and Marco Agostini. "Opening the ancillary service market: New market opportunities for energy storage systems in Italy". In: *International Conference on the European Energy Market, EEM* 2020-September.Im (2020). DOI: 10.1109/EEM49802.2020.9221871. **Peer-Reviewed Conference Paper**, cited as [248].

5.1 Introduction

Based on the presentation of the UVAM project and the related integration of DERs into the Italian ASM as presented in the previous chapter, this chapter analyses the resulting business opportunities that emerged for DER operators. Two types of DERs are of particular interest. Firstly, iRES units, as these assets are the core of the energy transition and already available in large numbers. Secondly, energy storage units, which have not only seen considerably lower investment costs and are thus becoming continuously more widespread, but which are also representing a renowned complement to iRES units as non-producing units. The analysis presented in this chapter therefore illustrates the business opportunities of active balancing integration for two separate units: a wind farm representing iRES units and a stationary utility-scale BESS unit representing energy storage units.

Concerning the active balancing integration of iRES and wind power in particular, Chaves-Avila and Hakvoort [10] provided a study of the BAM design at European level. The study highlighted how the participation of iRES and wind power in particular can improve systems efficiency but also that the market design represent a key factor for successful iRES balancing integration. While iRES are generally advantaged on EMs with granted priority dispatch and marginal generation costs close to zero, on BAMs and ASMs in general their situation is somewhat different. iRES obtain no prioritization here, rather the contrary with strict technical requirements often favoring large-scale programmable units and hence excluding small-scale non-programmable units such that iRES typically are.

More country specific, Martín-Martínez et al. [249] investigate the market design changes in the Spanish BAM and the following contribution of wind power in 2016 and 2017. Edmunds et al. [250] followed up on this and compared the market access situation for wind power in Great Britain and Spain. For Italy on the other hand, this topic is still little investigated, despite the significant presence of more than 10 GW installed wind capacity and the market opening in 2018. So far, only the technical feasibility of ancillary service provision from wind turbines and its compliance with Italian standards has been examined [251].

With storage units such as BESS, ASM access is not per se as restricted as with iRES, but specific market and product design features such as the minimum delivery period and the time between gate closure and delivery restrict operation. Different studies investigated therefore the business opportunities for BESS units based on currently regulatory frameworks in different European countries such as the Netherlands [252], Germany [253] or the Nordics [254].

Concerning the Italian markets, the research branch of the national market operator provided an initial probabilistic analysis to approximate economic opportunities for BESS by outlining the magnitude and price level of markets [255]. However, by averaging over weekly, monthly, or even annual time horizons, precisely those temporal price variations battery operations aim at are omitted. As the units also do not provide their own baseline but their operation is completely dependent on possible price differences of the different markets, accurate evaluations of economic opportunities are necessary to close the gap between theoretical possibilities and concrete applications. In this sense, a string of studies from Benini et al. based its analysis on an ex-post analysis of empirical ASM data from one Italian bidding zone with hourly resolution [256–258].

The case study as presented in this chapter build on the present studies from literature by extending the analysis of business opportunities from newly gained ASM access for DERs across all bidding zones. Furthermore, the study integrates for both DER types, Wind and BESS, the intertwined operation on EMs and ASMs. Outlining the possible benefits in a first step through a benchmarking best-case scenario, these theoretical findings are then contrasted with different bidding strategies that are nearer to practice. Specific research questions are therefore:

- How attractive are the business opportunities from active balancing market integration for iRES and BESS units in Italy?
- Are business opportunities evenly distributed across Italy or are there regional differences?
- What are remaining economic barriers within the current regulatory framework that prevent successful exploitation of the potential business opportunity?

The remaining chapter is structured as follows. Section 5.2 outlines the applied methodology for the twofold case study on wind and BESS opportunities. Section 5.3 presents the case study results, first for the wind farm with a special focus on different bidding strategies, second for the BESS with a special focus on bidding zones differences. Overarching findings for the active balancing integration of DERs are discussed in Section 5.4 before Section 5.5 concludes.

5.2 Methodology

The two case studies build on the updated regulatory framework for DERs in Italy as emerged with the UVAM framework as described in Section 4.2.2. In both cases the study is run as an ex-post analysis, utilizing empirical market data from Italy with initial pre-processing as outlined in Section 3.3.

5.2.1 Wind farm modelling approach

To simulate the potential participation of iRES in Italian ASMs, the case of a Sicilian wind farm is simulated. Given due to availability of on-site generation data, the analysed timeframe is the year 2018 with hourly data. The investigated wind farm consists of 11 turbines and has an overall capacity of 22 MW. For better comparability, results are however scaled to a 10 MW plant. It is assumed that individual turbines can not be modulate their power linearly, but only switch off or run. While modern wind turbines are capable of modulating their output, this

Table 5.1: Nomenclature of pricing scenario for active balancing offers from wind farm.

Scenario No.	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Pricing strategy	Omniscient	Minimum	Minimum	Wgt. average	Wgt. average	Maximum	Maximum
Reference period	-	Day before	Week before	Day before	Week before	Day before	Week before

deliberately conservative choice is made to include older farms, as it is these that are operated without incentives and are therefore of particular interest for the analysis. The simulated wind farm, from which the generation data is obtained, is incentivized in the form of a guaranteed minimum price of 89 €/MWh. No investment costs were assumed as the active balancing integration would represent an add-on to the remaining business case of EM operation, likewise operational costs are assumed to be negligible and covered by the EM operation.

The aim of the case study is to simulate the parallel operation of the wind farm on EMs and ASMs. The reference EM is in this case the DAM market on which all generation is sold. On the ASM side instead, both markets of MSD ex-ante and BAM are included. The considered ASM product is the one UVAMs are eligible for, i.e., "OS". In a first approximation perfect generation forecast is assumed, the implications of forecast errors are then studied in detail in the following Chapter 6 and combined with active balancing integration in Chapter 7. The analysis of business opportunities from active balancing integration is then divided into four steps.

First, the available hourly capacity for active balancing is determined. Since the service offered must correspond to at least 1 MW and must potentially be kept constant for two hours according to the product requirements, smaller quantities and quantities that fluctuate in shorter timeframes cannot be offered.

Secondly, the bidding price for the hourly services is determined. With ASMs being remunerated on a pay-as-bid basis, the right bidding price is crucial for economic success. The case of omniscient, always perfect pricing provides the ideal though purely hypothetical benchmarking scenario. Perfect pricing implies hereby to offer at the most convenient price that is still accepted. The benchmarking scenario is then complemented by six realistic pricing scenarios which are based on previous prices. Simple pricing schemes based on the minimum, maximum, or weighted average price of verified transactions from the day before or the same day one week earlier are used as summarized in Table 5.1. The purpose is thereby to simulate potentially realistic economic behavior of the wind park at limited computational costs, rather than to determine an optimal pricing strategy.

In a third step, the available hourly quantity is offered in two separate analyses either entirely as upward or downward balancing service. For upward services the wind farm has to reduce its baseline on EMs beforehand to be able to then increase generation, for downward services instead the full generation is integrated in the EM baseline with potential reductions starting from here. The wind farm's modulation capacity is in both cases offered first in the MSD ex-ante and, in case of non-acceptance, forwarded with improved price to the subsequent DAM.

In a fourth and last step, the potential acceptance of the wind farms offers are evaluated. With the actual market outcome being available (although being assumed to be unknown at the moment of offering), the potential success is evaluated based on the criterion if the wind farm's offering was better than the weighted average price of the individual market clearing per hour and product category in the bidding zone Sicily.

5.2.2 BESS modelling approach

Other than for the wind farm, the BESS case study represent a scenario of a DER asset that is dedicated to active balancing and without a underlying base-scenario of EM operation. CAPEX and OPEX are accordingly important and fully considered. Based on an extensive literature review of Cole and Frazier [259], investment costs are assumed to be 270 €/kWh and depreciated on a straight-line basis over the battery's lifetime. Following the characteristics of other utility-scale Li-ion BESS systems such as the Tesla Hornsdale Power Reserve, the average roundtrip efficiency of the storage system is assumed to be 0.85 [259, 260]. Associated power losses represent thereby the major OPEX of the plant. With regard to the battery's aging process, the Accelerated Aging Model as presented by Stroe et al. [261] is applied with an assumed lifetime of overall 6,000 cycles. This results in a power capability descrease of 4.25% and a capacity fade of 17.5% over the assets lifetime [262]. In order to fulfill the minimum requirements of DERs under the UVAM framework, the simulated plant dimensions result therefore to be 1.2 MW / 3 MWh.

The aim of the case study is to simulate then the BESS operation in a first step as a stand-alone unit. Combined operation of storage or conversion units with iRES units are presented in the following Chapter 7. As the wind farm, the BESS unit combines EM and ASM operation. As short-term markets fit best to the characteristics of BESS operation with high cyclicity but limited capacity, the IDM and BAM are the two markets of choice. the considered ASM product is as previously the Italian "OS", used on the BAM for balancing purposes and tertiary reserve. The IDM is thereby assumed to operate already as introduced through Single Intraday Coupling (SIDC) with continuous bidding and gate closure of one hour before delivery (see Chapter 3.1.1 for more details). Utilized data comprises the year 2019. The analysis of business opportunities from active balancing integration for a BESS unit is then further as follows.

First, available capacity is determined. Other than for the wind farm the starting point is here not a potential EM baseline but the battery's State of Charge (SoC). Three levels are thereby compared, 0 for an empty battery, 1 as half-charged, and 2 for a fully charged battery. Depending on its SoC, the battery can then offer either a one or two-hour service.

In a second step, it is evaluated on an hourly basis whether it would be more opportune to offer either upward or downward services on the BAM or to interact with the IDM. The evaluation is thereby based on the internal SoC and an external price forecast, which is assumed to be perfect. For more details on the intertwined EM and ASM interaction please consult [248].

As for the wind farm, the potential success of individual BESS offer is evaluated in a last step. In order to highlight the differences between the various Italian bidding zones, this case study is conducted in parallel for all six physical zones (see Section 3.1 for more details). As previously, the evaluation criteria for BAM offers is thereby the weighted average clearing price per hour and product category. In case that in an individual bidding zones no quantity at all should be accepted, also the BESS's offer is considered as not accepted.

5.2.3 Business opportunity evaluation

Based on the potential quantity, price and success of individual ASM offerings, the overall business opportunities for active balancing service provision is evaluated. The evaluation is thereby based on the potentially generated cash-flows from the ex-post analysis of the empirical market data.

For the wind farm, the benchmark is thereby the pure EM operation. Distinguishing for an incentivized or an unincentivized unit, the added value of ASM participation is subsequently evaluated compared to the current status-quo of asset operation.

For the BESS unit instead the benchmark is the potential recovery of investment costs. The comparison is therefor based on the potential revenues from a business case that is based on the new regulatory framework versus the upfront costs depreciated over the sum of the individual charging-discharging-cycles.

5.3 Results

This section outlines first the results for the emerging business opportunities for a wind farm with active balancing integration along with implications of different pricing strategies. Subsequently the for a BESS unit are presented along with an analysis of the variations of business opportunities in the different Italian bidding zones.

5.3.1 Opportunities for a Wind Farm

As mentioned previously, the first step of the wind farms offering is to calculate the available quality. Starting from a total generation of 21,717 MWh in 2018 for the 10 MW plant, all quantity that is smaller than the minimum bid size and not long lasting enough can not be offered. The potential offer quantity for the plant reduces thereby to 19,455 MWh.

In the second step, the desired offer price for each hour is calculated. With ideal, omniscient pricing this price amounts on average to 117.16 €/MWh for upward offers of the wind farm in Sicily and 25.36 €/MWh for downward offers. Note that these two prices are not the "pure" average market clearing price, but the average of those hours in which the wind farm has available quantity to offer. Different pricing strategies lead naturally to different offer prices. For example, setting the offer price at the minimum accepted price of the same hour on the previous day (Scenario 1) results in an average price of 105.23 €/MWh, taking the same hour of the same day in the previous week (Scenario 2) results instead in an average price of 90.73 €/MWh. Taking a more aggressive bidding approach that reference not the lowest still accepted bidding price but the average (Scenario 3) or even the highest still accepted bidding price (Scenario 5) results logically in higher prices of 115.16 €/MWh and 120.98 €/MWh, respectively. Whether or not these offers might be successful depends then not only on the actual price of competitors for the hour to come but most of all also on the actual system demand for services.

Crossing wind park availability with the system's (market) demand determines therefore the maximum capacity which can be sold, independent of the actual pricing. This is especially relevant for small bidding zones with comparatively limited (internal) balancing demand such as Sicily. Figure 5.1 illustrates for one exemplary week the match of potential wind farm offers and system demand. The available wind farm capcity is thereby represented by the black bars, the system demand that has been met through the two consecutive market MSD ex-ante and BAM are represented by the blue areas for upward balancing demand and red areas

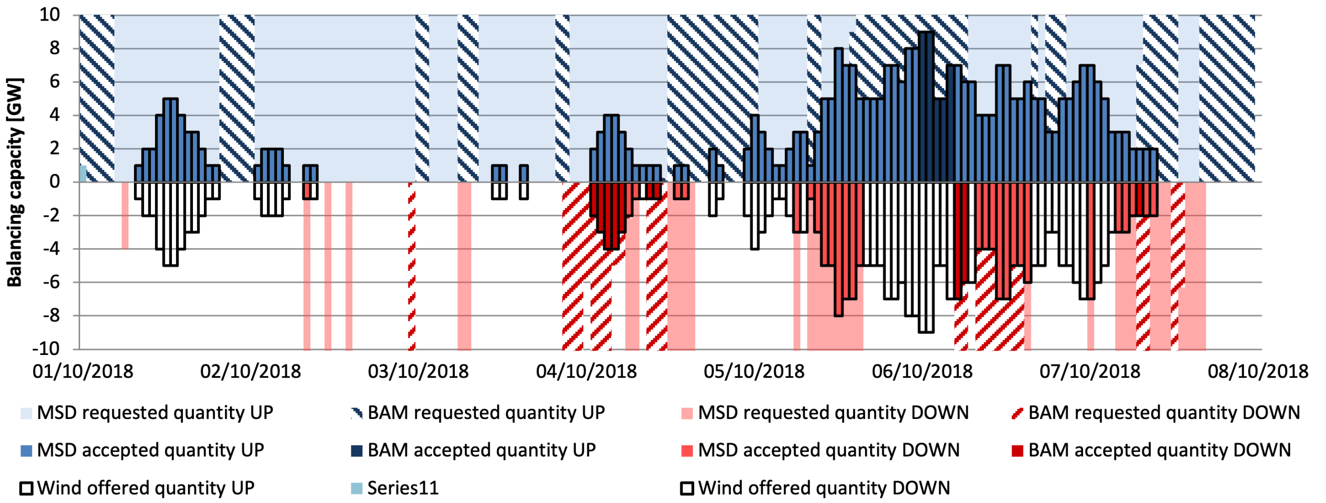


Figure 5.1: Availability of balancing offers from wind farm versus market requests and resulting potential acceptances for a representative week in October 2018. *(Adapted from [247])*

for downward balancing demand. Overlaps of demand and potential supply are highlighted by the darker coloured areas. As the bidding zone of Sicily has a notably higher demand for upward balancing (just most other Italian bidding zones as well, see Section 3.1.2 for more detail) the wind farm potentially meets notably more upward than downward demand. Overall, from the initial 19,455 MWh that could be offered on the ASMs, only 16,907 MWh (87%) meet upward demand and with 3,257 MWh a fraction of only 17% meet downward demand.

Whether these offers would then actually be accepted depends primarily on the price offered compared to the market price of the respective hour. In the hypothetical case of optimal pricing, as assumed in price scenario 0, all available quantity of the wind farm corresponding to market demand would be sold for the best acceptable price of each hour, i.e. under the applied acceptance criterion the weighted average market price. For the compared other pricing scenarios with more realistic pricing, the potentially accepted quantity is reduced accordingly. This results in a direct trade-off between low prices that lead to much accepted quantity but also low revenue per service provided and higher offer prices that increase relative revenue but sell less quantity overall. Compared to the 16,907 MWh of upward services that result in an potential ASM casflow of 1,980 k€ under ideal pricing, maximum pricing on the day-before basis (Scenario 5) leads to only 5,666 MWh with an ASM casflow of 685 k€. Instead, minimum pricing on the day-before basis (Scenario 1) leads to an potential acceptance of 16,370 MWh with an ASM cashflow of 1,723 k€. Even the lowest prices compared to the reference period do not guarantee a complete sale, as

Table 5.2: Comparison of the results of potential upward or downward balancing offers of a wind farm in Sicily in 2018. *(Adapted from [247])*

Pricing Scenario	Incentive	*Upward Balancing* Accepted quantity	Avg. acc. price	Cashflow ASM	Cashflow DAM	Relative Revenue	*Downward Balancing* Accepted quantity	Avg. acc. price	Cashflow ASM	Cashflow DAM	Relative Revenue
	y/n	[MWh]	[€/MWh]	[€]	[€]	[€]	[MWh]	[€/MWh]	[€]	[€]	[€]
Scenario O	yes	16,907	117.16	1,980,890	- 1,830,147	150,738	3,257	25.36	- 82,580	- 65,401	- 147,981
	no	16,907	117.16	1,980,890	- 1,223,836	757,054	3,257	25.36	- 82,580	- 14,640	- 97,220
Scenario 1	yes	16,370	105.23	1,722,700	- 1,830,147	- 107,401	1,800	22.67	- 40,820	- 39,983	- 80,802
	no	16,370	105.23	1,722,700	- 1,223,836	498,865	1,800	22.67	- 40,820	- 7,448	- 48,267
Scenario 2	yes	16,792	90.73	1,523,499	- 1,830,147	- 306,649	1,155	10.45	- 12,077	- 29,181	- 41,258
	no	16,792	90.73	1,523,499	- 1,223,836	299,663	1,155	10.45	- 12,077	- 4,285	- 16,362
Scenario 3	yes	10,599	115.16	1,220,554	- 1,830,147	- 609,593	2,067	31.65	- 65,435	- 42,949	- 108,385
	no	10,599	115.16	1,220,554	- 1,223,836	- 3,281	2,067	31.65	- 65,435	- 9,043	- 74,478
Scenario 4	yes	9,280	118.52	1,220,554	- 1,830,147	- 730,304	2,339	35.26	- 82,484	- 49,661	- 132,146
	no	9,280	118.52	1,220,554	- 1,223,836	- 123,993	2,339	35.26	- 82,484	- 10,078	- 92,563
Scenario 5	yes	5,666	120.98	685,471	- 1,830,147	- 1,144,675	3,049	38.86	- 118,474	- 61,149	- 179,623
	no	5,666	120.98	685,471	- 1,223,836	- 538,364	3,049	38.86	- 118,474	- 13,571	- 132,045
Scenario 6	yes	900	152.32	137,154	- 1,830,147	- 1,692,993	3,202	75.01	- 240,188	- 64,624	- 304,812
	no	900	152.32	137,154	- 1,223,836	- 1,086,681	3,202	75.01	- 240,188	- 14,188	- 254,375

the offers from other suppliers for the coming hour may be lower again regardless of this, or the respective system requirements may be lower overall.

Another point of note with regard to pricing scenarios concerns the presence of potential EM related incentives for the involved DER or iRES unit. With the current Italian regulatory framework, and many other European frameworks too, the iRES incentive only counts for sales that benefit the EM market and is forfeited if the energy is used elsewhere. This also applies to possible offers on ASMs. The financial value that these balancing services have to outbid to offer an interesting business option is thus much higher. Or, said differently, the opportunity costs for active balancing integration rise accordingly. While the amount that needs to be retained for upward services remains the same regardless of the incentive, the costs this incurs are significantly different. In the extreme case of retaining all potential wind capacity to offer it on the ASM, this quantity sums up to a value of 1,224 k€ on the DAM. However, if at the same time the wind farm benefits from the incentive the value of withheld energy rises to 1,830 k€ in 2018 (+49%).

The sum of ASM cashflows from potentially provided balancing services and the opportunity costs from missed sales on the DAM results in the overall relative revenue that the active balancing integration might provide for the wind farm. Table 5.2 summarized the results for the different scenarios. Under ideal pricing upward balancing can yield a potential added value for a 10 MW wind farm of 757 k€ in 2018 or even still 151 k€ if benefiting from a incentive of 89 €/MWh as in the investigated case. In relative terms compared to the installed capacity, this implies a relative profit of 75.7 k€/MW_{cap} or 15.1 k€/MW_{cap}, respectively. More realistic pricing, however, quickly erodes this hypothetical added value. Only pricing based on the minimum price of previous market sessions results in positive added value in the range of 300 k€ to 498 k€, while the other analysed scenarios lead to negative outcomes.

Instead, downward balancing offers lead to continuously negative revenues, but this was not to be expected otherwise due to the market design. The price floor at 0 €/MWh prevent any ASM outcome that would lead to a positive cashflow for a market participant that operates a plant with basically zero marginal costs. In addition to the losses on the ASM, there are also losses on the DAM if, as assumed, the turbines can only be shut down as a whole and not modulated individually.

Also for the downward balancing offers, the different simulated pricing strategies lead to different results in terms of accepted quantity and associated cashflows. With the payment direction being inverse, i.e., from the market participant to the TSO, also the probability for acceptance is inversed with higher prices coming first

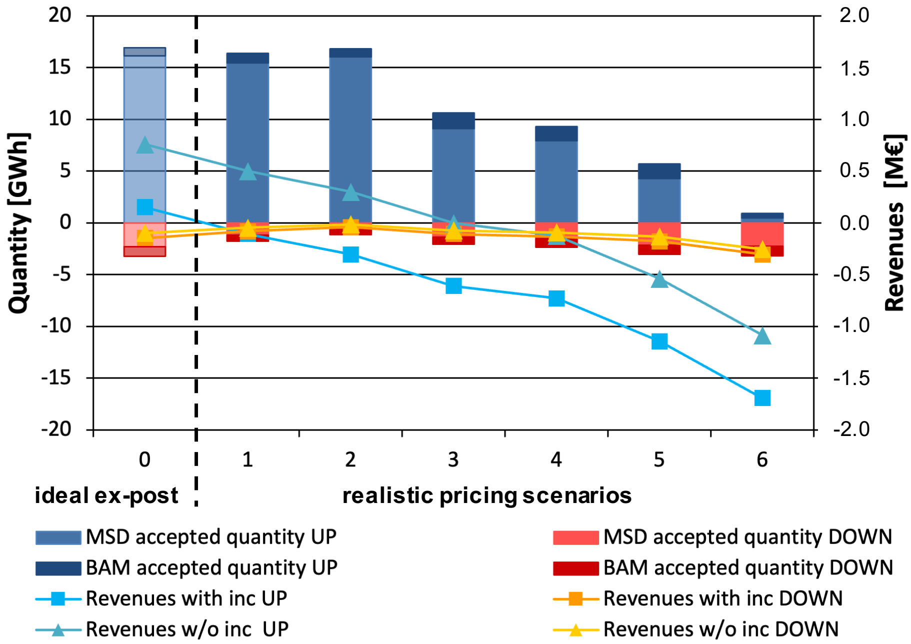
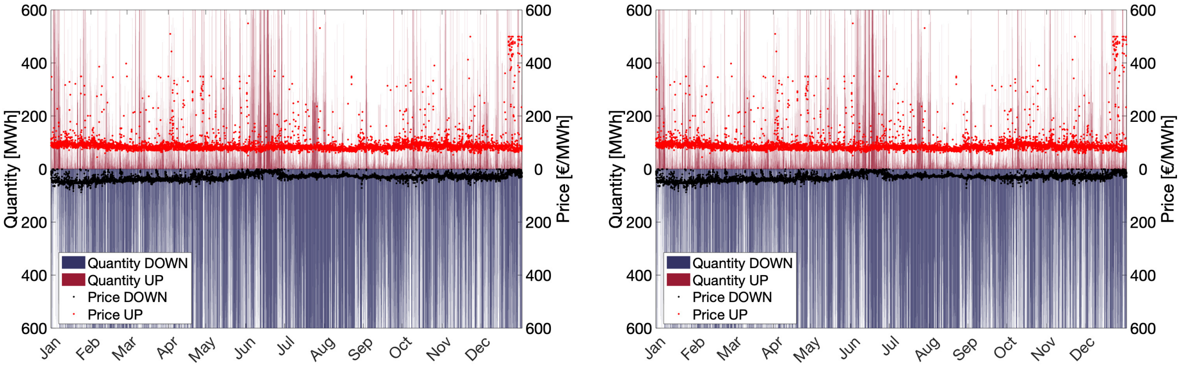


Figure 5.2: Summary of results in terms of potentially accepted quantities and additional revenues from active balancing services for a wind farm with different pricing strategies. *(Adapted from [247])*

on a merit-order basis. Price scenarios that build on the highest price of accepted offers from a reference period lead accordingly to higher accepted quantities within the case study. Scenario 5 leads in this case to 3,202 MWh of accepted quantity, being reasonably close to the quantity as under ideal pricing (Scenario 0) with 3,257 MWh. Minimum pricing as under Scenario 1 reduced this potential balancing provision to 1,800 MWh. The cashflows from ASM develop accordingly and rise from -82 k€ under Scenario 1 to -118 k€ under Scenario 5.

Other than for the upward services, the DAM cashflow is not constant across all scenarios but associated to the accepted quantity of balancing services. As turbines do not need to shut down beforehand but only upon service activation the potentially unsold power generation is reasonably more contained. Nonetheless, the cashflow is also for this service provision always negative and results together with the negative ASM cashflow in an by definition overal negative relative revenue from downward balancing. To summarize, Figure 5.2 provides a visual comparison of the results from the different pricing strategies within the market zone of Sicily.



(a) Nord

(b) Centre-South

Figure 5.3: Individual prices of accepted upward and downward offers along with hourly quantities on the balancing market in 2019 for the Italian bidding zones North and Centre-South. *(Reprinted with permission from [248])*

5.3.2 Opportunities for a Battery Energy Storage System

The most crucial factor that determines the value of business opportunities for BESS units is the price-spread during different instances of time on which they can leverage their alternating operation. This is independent of the mode of operation of BESS, whether they only aim to exploit price differences on EMs or also provide active balancing services. Apart from possible fixed compensations such as capacities payments or similar, all that matters is the difference between input (charging) and output (discharging) price. For the assumed BESS characteristics of this case study, the necessary price-spread to offset the wear of the battery (i.e., to recover the depreciated investment costs) amounts to roughly 40 €/MWh, in line with similar studies [263, 264]. Only business opportunities that comprise a (recurring) price differential above this threshold will potentially provide a viable business case for BESS operators.

Figure 5.3 represent the individual prices of accepted upward and downward offers (black and red dots in figure, respectively) along with hourly quantities on the balancing market in 2019 for the Italian bidding zones North and Centre-South. As it is visible, both zones dispose a potential price gap of more than 40 €/MWh between upward and downward balancing services, although with different characteristics. For the North, the price distributions of awarded offers prove to be very compact, ranging from 25-35 €/MWh for downward offers and from 70-100 €/MWh for upward offers, with few outliers from accepted bids to higher prices. Instead, the price distribution in Centre-South is notably more scattered. For downward offers the average price is still around 30 €/MWh, the range of accepted offers lasts though more widespread from 0-50 €/MWh. Prices of accepted upward offers are even further dispersed with two clusters emerging in the wider area of around 100 €/MWh and at 500 €/MWh. Additional accepted offers between the two clusters complement the picture.

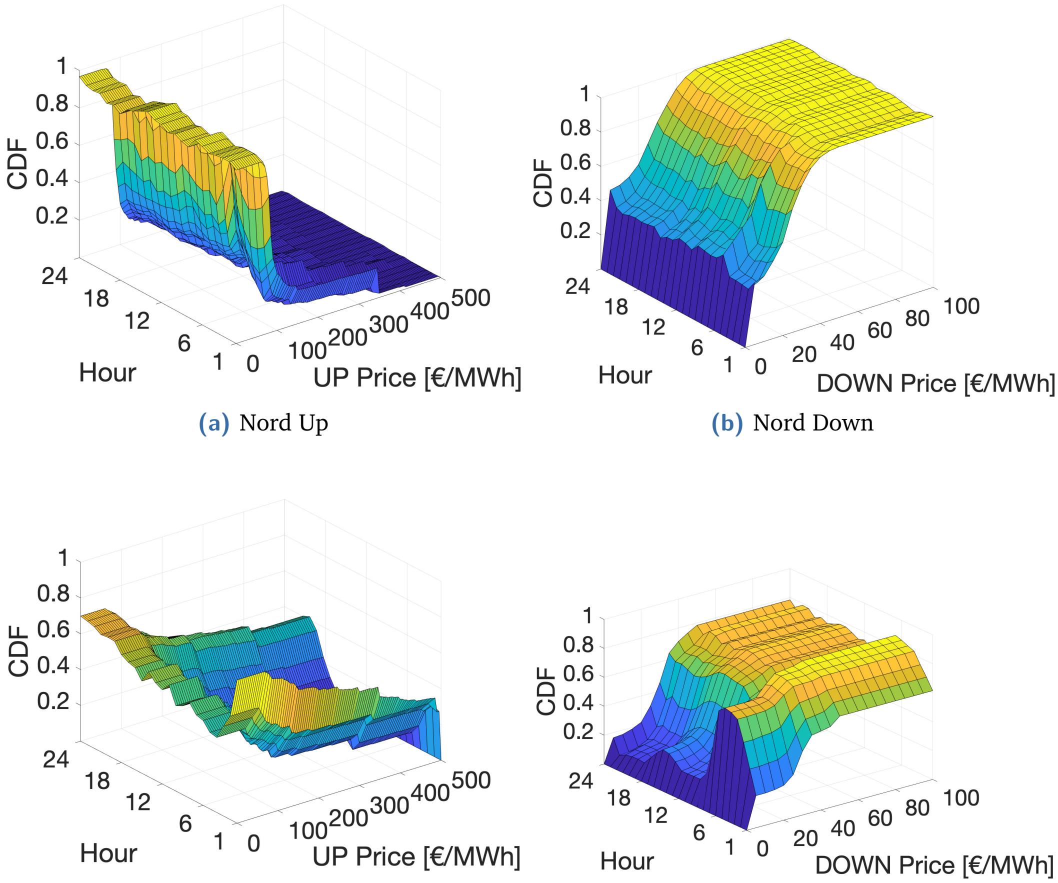
However, the mere price difference is only part of the objective function. In particular, the key issue is the regular occurrence of such a price difference and sufficient time in between to adjust its market position in accordance with the regulatory framework[1]. Variances or standard deviations of prices (as reported in Chapter 3.1.2) provide information about the general price fluctuation, but lack precisely this temporal measure.

Most ideal for efficient BESS operation are dedicated hourly patterns that repeat on a daily basis. Figure 5.4 displays the Cumulative Distribution Functions (CDFs) for clearing prices of accepted upward and downward services in 2019 in the bidding zones North and Centre-South. The bidding zone North demonstrates thereby no notable variations across the day, the distribution of both upward and downward bids results practically independent of the time of day. In Central-South, on the other hand, the night hours are distinguished from the rest of the day by a significantly higher proportion of markedly priced offers that can potentially be accepted. For upward offers the hours from approximately 19:00 to 03:00 demonstrate an increased probability for high prices up to 500 €/MWh, for downward offers the hours from 02:00 to 07:00 contain a notably increased probability for low prices between 0 to 20 €/MWh.

Given the average EM prices of around 50 €/MWh in all Italian bidding zones, it is the high upward balancing offers in particular that make a viable business case possible. The classic target constellation that results from this for the BESS operation is the provision of a higher-priced upward service that is then completed by cheap recharging on the EM. Downward services optionally enable even cheaper recharging, but the spread between downward and EM price is usually too low to obtain an independent business case.

Based on the beforementioned market characteristics, the analysis of the BESS-market interaction leads to similarly varying results for the diverse bidding zones. Table 5.3 summarizes the resulting cashflows from the BESS operation with active balancing integration. Note that the presented cashflows are all based on perfect pricing strategies for simplified comparison with other case studies in

[1]The previous Italian market design made such a business case virtually impossible due to its prohibitively long time lags between gate closure and delivery. Before the introduction of SDIC, this time span was 4 hours for the IDM and together with the 4-hour BAM sessions and the extra hour between gate closure and delivery, the fastest battery cycle that included balancing services was practically limited to 9 hours.



(a) Nord Up **(b)** Nord Down **(c)** Centre-South Up **(d)** Centre-South Down

Figure 5.4: Cumulative distribution functions for acceptance prices of upward and downward offers in the Italian bidding zones North and Centre-South on the balancing market in 2019. *(Reprinted with permission from [248])*

Table 5.3: Comparison of the cashflows from active balancing service provisions of a battery energy storage system in the different Italian bidding zones in 2019. *(Adapted from [247])*

Bidding zone		North	C.-North	C.-South	South	Sardinia	Sicily
No. of cycles		152	0	368	4	2	53
Market Revenue	[€]	29,680	175	282,570	1,446	740	13,409
BESS wear	[€]	- 20,520	0	- 49,680	- 540	- 270	- 7,155
Balancing Profit	[€]	9,160	175	232,890	906	470	6,254

Chapter 5.3.1 or Chapter 7. Possible scenarios with additional, more realistically designed prices can be found in [248].

The Centre-South bidding zone is proving to be by far the most interesting case study with a potential profit of over 230,000 € in 2019. Compare to the installed BESS capacity, this results in a relative profit of around 76,700 €/MW_{cap}/a. Thanks to the particularly high price of the accepted upward offers and the resulting high price difference, both the number of cycles and the revenues generated from balancing provision are correspondingly high. The North bidding zone, on the other hand, also has a sufficient price difference and, with 175 cycles, enables about half as many as Centre-South. However, the price difference is often only slightly greater than the respective battery usage costs and results in a correspondingly thin economic margin to operate on. The potential profit from balancing service provision even under ideal pricing is barely positive and with only 9,160 € considerably low. Even worse, the other four bidding zones have either an insufficient price difference (e.g. Sardinia) or too many hours in which no balancing offers (e.g. Sicily) are accepted and the business case is therefore non-existent here. For more information on individual bidding zone statistics please see Chapter 3.1.

5.4 Discussion

Based on the two case studies of business opportunities from active balancing integration, several points for general discussion emerge.

Bidding Strategies As of now, DERs operate for the most part only on EMs where the pay-as-cleared pricing approach makes bidding strategies straightforward, especially for iRES units with zero marginal costs. The potential integration into active balancing provision with a pay-as-bid approach on ASMs requires however more sophisticated bidding strategies which are everything else but straightforward. This is getting further complicated as the empirical market results suggest that the (Italian) TSO does not only accept on a merit-order basis. While this is reasonable for the MSD ex-ante in which congestions are resolved with not only price-dependent but also location-dependent product offerings, for balancing services on the BAM this is less obvious. In any case the ability to apply an appropriate bidding strategy turns out to be a crucial capability for DER operators that embark in active balancing provision.

Incentivized versus Non-Incentivized Plants The case study on the active balancing integration of a wind farm revealed what a price driver the currently existing feed-in incentives for iRES are in this context. The guaranteed high purchase prices on EMs create artificially high opportunity costs for participating units and make balancing provision almost always a loss-making business at the current prevailing market prices in Italy. While continuing to pay the incentives would give an unfair advantage over other (non-iRES) balancing providers, it seems to make more sense to focus on non-incentivized plants from the outset. With a steadily increasing number of such plants dropping out of the respective incentive programs in the coming years, the potential of additional flexibility providers is nevertheless sufficiently large. However, when draft potential market design changes, it has to be taken into account that the participating units will thus be the relatively old ones and not necessarily the newest and most modern ones that have just been built.

Upward versus Downward Balancing from iRES A third, crucial point to highlight is the significant difference of the implications between upward and downward balancing services for DERs. For stand-alone iRES units, downward services appear not reasonable as the existent price-floor of 0 €/MWh on ASMs prevents positive cashflows for units that have basically zero operational costs. To render downward services potentially interesting also for iRES units, the market design would have to be modified by removing the artificial price floor. the The only conceivable loophole with the existent regulatory framework instead would be to effectively use the not fed-in energy behind the meter, e.g. by combining it with a storage unit or another possible load that makes valuable usage of the extra energy. Such combined scenarios are further analyzed in Chapter 7.

The corresponding disadvantage for iRES upward services comes from the need to create a margin by turning down units beforehand. In case of non-acceptance for these services their potential power generation is lost and remains unsold while not having any gains from potentially saved variable operating (i.e., fuel) costs. A good price and market demand analysis in advance is therefore even more important to maximize the probability of acceptance. On the other hand, non-acceptance of downward services results only in the lack of potential "behind-the-meter energy" with its respective valorization but causes no direct losses on cash flows from the EM.

Locational Difference Italy with its six physical bidding zones gave the opportunity to investigate the impact of locational differences for the viability of business cases that base on active balancing integration. The results from the case study underline how different the economic conditions in the various bidding zones apparently are. While some zones have a high demand for balancing services, the supply there is also correspondingly abundant and average prices are comparatively low. What is desirable from a system perspective makes it difficult for the integration of new and, at least initially, relatively expensive flexibility providers to compete. Other zones have particularly pronounced price peaks and at the same time sufficiently high demand to represent a thoroughly interesting business case. Still other zones have neither pronounced high prices nor high demand and thus do not represent a pronounced business case. In sum, the choice of location is fundamental to the business case of active balancing provision from DERs in Italy.

Different Types of DERs The separate study of the two DER typologies of a wind farm and a BESS plant brought to light their fundamentally different operating characteristics and the necessary framework conditions. While the operation of a BESS unit results to be highly dependent on distinct market conditions with recurring price differentials, the advantage, on the other hand, lies in the independence from other external factors such as wind availability. Instead, the BESS has the possibility to operate with an independent baseline purely guided by market conditions. The wind farm (and likewise other iRES facilities), on the other hand, can look at upward and or downward services independently and pursue the business case of interest for each case.

5.5 Summary and Policy Recommendations

In summary, the presented case studies of this chapter investigated the emerging business opportunities for DERs from active balancing integration. The Italian UVAM project provided therefore an interesting testbed framework, which has been studied from the perspective of an flexibility provider that operates either a wind farm or a BESS unit.

Especially upward balancing services prove to be an attractive business opportunity for DER operators, adding value compared to the sole operation on energy market. For iRES units, this is considered an individual business case that yielded in the case study with ideal pricing strategies up to 75,700 €/MW_{cap} of extra revenue for a wind farm in Sicily. For BESS operators upward offers can also potentially be combined with alternating downward services to further enhance the value creation. Under ideal pricing the extra annual revenue amounted here to a similar value of 76,700 €/MW_{cap}. In this sense, the further opening of ASMs to DERs seems to be a valuable policy instrument that not only provides further balancing resources to the system itself, but that can also represent a potentially interesting business case for DER operators.

Instead, downward compensation turns out to be less attractive in its own right. Especially from the perspective of operators of assets without significant operating costs, the abolition of the price floor of 0 €/MWh on the ASM would be necessary to effectively enable downward balancing provision from iRES. Behind-the-meter usage of the reduced energy injection might provide a second option to facilitate this service provision. Such is further investigated in Chapter 7.

A crucial determination factor for viability of business opportunities from active balancing integration of iRES is furthermore whether or not the unit at issue benefits from an incentive that guarantees feed-in prices. The presence of the latter drives opportunity costs of service provision significantly and reduces the previously outlined business case significantly. On the other hand, with more and more iRES dropping out of the incentive schemes in the coming year, market designs for the flexibility provision from DERs and iRES in particular should account particularly for these rather old assets.

Two further points of not concern the geographic location of assets in terms of the bidding zone they are associated to and the pricing strategy through which they interact with the ASM. The presented case study has clearly shown that the deviations between the different bidding zones in Italy are significant. Four out of six zones have too low prices or demand to currently represent an interesting business case for BESS, one zone has sufficient liquidity but the price difference is at least for this DER type too low to make profit. The sixth zone, on the other hand, has a substantial price differential and a correspondingly large potential. To leverage this, DERs need a sophisticated pricing strategy and sufficiently good forecasting capabilities. Diverse scenarios have shown that the potential profit of a DER can quickly turn from a significant positive value to a negative one if prices are based on disadvantageous reference points. At the same time, it is fundamental to correctly assess the market demand and to have the corresponding transparency. The focus here is on the Italian network operator to enhance this, as up to now, activation has obviously not been exclusively based on merit order and the effective market situation is correspondingly difficult to assess.

6 Passive Balancing Integration: Imbalance Pricing Schemes

This chapter includes material from

Jan Marc Schwidtal, José Pablo Chaves-Ávila, and Arturo Lorenzoni. "Driving balancing responsibility: why imbalance pricing methodologies and balancing area sizing matter for renewables". IIT-21-142WP. Madrid, 2021. **Working Paper**, cited as [265].

6.1 Introduction

With the aim to further decarbonize the electricity system, renewable energy sources (RES) are on the rise and continuously increasing their share of generating capacity. Intermittent renewable energy sources (iRES) such as wind and solar are taking thereby a central role, being the two resources with the highest growth-share among renewables and having overtaken fossil fuels in terms of capacity additions for the first time on a global scale in 2017 [266]. The fact that such increasingly outcompete fossil fuels, with global weighted average auction and power purchase agreement prices dropping as low as USD 0.043/kWh for onshore wind and USD 0.039/kWh for solar PV plants to be commissioned in 2021 [267], underlines that this growth trend is likely to continue if not accelerate. The massive deployment of iRES remains, however, not without implications for the power system and its operation, but requires dedicated actions [5]. Wind with its significant generation fluctuation over time and solar generation being characterized by both a diurnal as well as a seasonal pattern result in limited predictability and non-controllable variability of iRES. While spatial diversity can mitigate some of the variability, the common belief in literature is that iRES such as wind will generally increase the need and costs for balancing [179, 268–271]. One of the few studies that indicate other developments is by Hirth and Ziegenhagen [7] and describes the so-called "German paradox" in which the balancing needs reduced by 50% from 2008 to 2014 and balancing costs decreased by 15% despite the installed wind and solar capacity tripled. Furthermore, Gianfreda et al. [272] showed for the bidding zone North in Italy that balancing quantities decreased but balancing costs increased with higher iRES penetration. While the authors interpret this as a signal for market power in the specific Italian case, it appears that iRES do not necessarily require more balancing but, at least over time, there might be other factors that overcompensate the iRES expansion and reduce balancing requirements instead [7].

Balancing mechanisms build in general on the three pillars of *balancing responsibility*, *balancing service provision* and *imbalance settlement* to tackle the challenge of unforeseen fluctuations [273]. In the European setting, iRES are nowadays usually integrated into the first and last of these three but mostly not in the second one though. Individual pilot projects remain the sole exception [11, 207, 274]. As long as iRES remain prevented from the second pillar and respective active balancing participation, the third pillar with its design element of imbalance pricing mechanisms remains the main leverage to give an accurate balancing incentive to such market participants. This might potentially also include the option of so-called *passive balancing*, which, if properly incentivized, implies indirect support of the overall system's balance by purposely deviations from individual spot market schedules [275].

While the recent European Guideline on electricity transmission System Operation (SO GL) and European Guideline on Electricity Balancing (EB GL) set the new general framework how to regulate balancing in the European context [242, 276], there is still no fully harmonized European approach but ample scope for individual countries interpretations (see Section 6.3.2 for further details). For example, Italy and a significant number of other European countries distinguish as of now strongly between conventional and non-conventional units with regard to both balancing service provision (i.e., active balancing contribution) as well as imbalance settlement (i.e., potential passive balancing contributions). However, as the differences start to vanish with increasing forecast and respective adaption abilities for iRES on short-term market, as well as increasing technical abilities to provide system services and the uprising integration of DERs and iRES in balancing markets through beforementioned pilot projects and market framework changes, also the classification for imbalance settlements is likely to change.

The related research question is how to price the balancing demand most efficiently and fairly in a system with increasing iRES contribution. This is especially important in the sense not only to distribute costs but to use Imbalance Price (IP)-schemes as an efficient tool to incentivize an inherent system imbalance reduction [7]. This study contributes to this by shedding light on the implications of different IP-schemes to support policymakers to further integrate RES in all system operations and put them on an equal footing with conventional units. A particular focus lies thereby on the underlying design element of imbalance areas, an aspect to which comparably little attention has been paid so far in the academic discussion. Detailed contributions are:

- An enhanced comparison of imbalanced pricing schemes based on a single empirical dataset. Overall eight different schemes as discussed in the literature and as currently applied in Europe are confronted;

- An evaluation of the specific design element of imbalance area sizing with three different sizing approaches and their respective impact on incentives for BRPs;

- An illustrative case-study how the general theoretical findings translate into concrete incentives of imbalance costs or even revenue for iRES units based.

- Findings for forward-looking scenarios by the comparison of implications from different system conditions with a higher share of RES and lower consumption, such as experienced during the COVID-19 pandemic;

The study connects thereby to the future research as proposed by Clò and Fumagalli [8] to explore the welfare effect of pricing schemes on BRPs' balancing costs as well as to Hirth and Ziegenhagen [7] which note that the literature on the impact of the size of the IP-area is still comparably scarce.

The remainder of this chapter is structured as follows. Section 6.2 provides the background to this study with a literature review on academic positions for IP-schemes, contemporary regulatory developments to this regard in the European context, and the mathematical formulations of the discussed pricing schemes. Section 6.3 describes the applied methodology with individual input data, the case study outline, and identified limitations. Section 6.4 presents and discusses the results of the four consecutive case studies, which focus on: I.) different IP-schemes; II.) different IP-area sizings; III.) the perspective of individual iRES plants and how IPs impact their welfare; IV.) the impact of varying system conditions experienced during the COVID-19 pandemic. Opportunities for further research are eventually outlined in Section 6.5 before Section 6.6 summarizes the key findings with related policy recommendations.

6.2 Background

This background section provides an overview of literature standpoints on passive balancing integration through imbalance pricing and places this work in the context of other publications on the Italian balancing scheme. In the following, different IP-schemes as commonly applied in the European context are presented with their calculation methods.

6.2.1 Literature Review on Imbalance Pricing

Electricity for balancing purposes on dedicated markets is, as of now, usually more expensive than on the wholesale market (e.g., [187]). Although Barth et al. [277] argue that this has not necessarily to be the case, for the time being such a surcharge can be interpreted in two ways. On the one hand, it is a flexibility premium for market participants to actively change their schedules on short notice. On the other hand, it can be an expression of higher concentration in BAMs and respective exertion of market power by individual participants [272]. Given the remunerative differences of the two markets and that iRES already assume balancing responsibility at large on spot markets while still experiencing limited accessibility to BAMs, it is of vital importance which characteristics the settlement scheme contains that they face for their passive (im-)balance contribution.

Pricing Basis The first characteristic that distinguishes different imbalances settlement schemes is whether the price is based solely on the last activated balancing energy bid, so-called *marginal pricing*, or on the *average* cost of balancing. This discussion is strongly linked to the underlying settlement rule for balancing energy. While at least for balancing energy that is remunerated on a pay-as-bid basis (as it is the case for example in Italy), average prices might be more adequate from a cost allocation fairness point of view, the general opinion of academic literature considers marginal prices as more efficient by resulting in an accentuated incentive [7, 275].

Pricing Scheme The second characteristic that distinguishes imbalance settlement schemes is whether the resulting IP depends only on the imbalance direction of the overall imbalance area or also on the BRP's imbalance direction. In the first case, this results in the so-called *Single Pricing* for BRPs versus the so-called *Dual Pricing* in the second case. Mathematical definitions for the two pricing schemes follow in Chapter 6.2.4. In general, Single Pricing is often considered as the generally more efficient scheme for both single actors and the market as a whole, mainly since it allows for passive balancing and thereby integrates units into the system's balancing process that are otherwise excluded as they have no direct BAM access [275, 277, 278]. Furthermore, Möller et al. [279] find that the passive balancing from Single Pricing actively contributes to the smoothening of hourly steps from electricity market trading.

However, to effectively enable these benefits from passive balancing, timely publication of the IP as well as the legal ability for BRPs to respond to the price signal are the two fundamental prerequisites [7]. The effectiveness of passive balancing depends moreover on the non-existence of internal congestions. To avoid adverse price signals from such, Chaves Ávila et al. [9] propose in line with Jokic et al. [280] zonal Single Pricing instead of nationwide Single Pricing, i.e., the downsizing of the IP-area, as an alternative to the otherwise also possible Dual Pricing. Contrary to passive balancing, Clò and Fumagalli [8] argue that BRPs should only have the incentive to balance their own position (and hence no passive system balancing). They also argue that passive balancing would intentionally shift economic transactions from the more liquid and competitive DAM to a concentrated and more volatile BAM.

In line with that, Germany does not allow BRPs to deviate from their schedule purposely and hence to balance passively. Nonetheless, it applies a single price based imbalance scheme that would potentially enable to do so, and, although the actual IP and imbalance direction are published only about one month after market clearing, Möller et al. [279] and Just and Weber [281] show that such can be theoretically forecasted and that a respective arbitrage potential between the spot market and the balancing mechanism exists. Eicke et al. [6] then eventually demonstrate that German BRPs do leverage this implicit opportunity. Based on their results, they interpret the process of system balancing, after all, not as a response to an exogenous shock but as an active market mechanism. One central conclusion here is that, even with the conservative approach to legally prohibit purposely deviations, there will always be participants that try to do so. In that sense, it appears adequate rather to design a proper incentive scheme right away.

If a market might dispose only of scarce balancing resources, Veen et al. [278] recommend Dual Pricing over the otherwise preferred Single Pricing. In line with that Brijs et al. [282] and Vandezande [283] note that such a scheme will disincentivize BRPs from speculating on imbalance directions. Italy offers, therefore, an interesting case study by switching from Single to Dual Pricing in 2016. Based on empirical evidence, Clò and Fumagalli [8] show that, before the reform, the system's imbalance was significantly higher than the TSO's forecast error and that it significantly decreased afterwards. This suggests that the intentional imbalance of market participants decreased significantly with Dual Pricing. Furthermore, it supports the argument that this scheme facilitates TSOs to forecast imbalances and pro-actively manage the system (assuming that pro-active system management of TSOs would be preferable). While Clò and Fumagalli acknowledge the relevance of passive balancing for participants that are not allowed to participate in BAMs, according to them, passive balancing should at least be disabled as soon as these participants could participate in BAMs (and hence balance actively) and Dual Pricing being therefore applied to them as well. This is especially relevant under the impression that the UVAM pilot project enabled this access for DERs just recently on a national level in Italy [189].

A considerable side effect occurs if Dual Pricing exists in combination with balancing responsibility at a portfolio level. Just and Weber [281] highlight the possible benefits for large players in Dual Pricing due to imbalance netting, while Single Pricing results in no difference if combined with balancing on an individual unit or portfolio basis. Moreover, Vandezande et al. [271] elucidate that Dual Pricing is more than cost-recovering for TSO and, even if these extra gains are redistributed through lower transmission tariffs, such results in a transfer of money from inflexible users (e.g., iRES operators) to average users. Saguan [284] and Vandezande [283] even argue that the asymmetric penalties of Dual Pricing lead to the negative side effect of distorted BRP preferences, inclining them to take a long position.

While sound positive and negative arguments can thus be found for both Single and Dual pricing, regulators might be inclined to implement separate imbalance settlements for separate purposes, e.g., generation and load. Vandezande et al. [271] argue, however, that the implementation of such separate imbalance settlements, like implemented in the Nordics or also in Italy, has its merits but does not sufficiently counteract the negative side-effects of asymmetric penalties from Dual Pricing. Also, as sometimes implemented especially for iRES units, tolerance margins in pricing schemes should be avoided according to Chaves Ávila et al. [275] since they might eventually represent a penalization instead of the intended economic support.

Balancing Areas Besides the calculation scheme, also the sizing of the geographical area used as the basis for the (im-)balance calculation is contested. Such is significant not only in terms of balancing reserve sizing but also for the definition of the BAM, whose clearing price counts towards the final IP. In the international context, this is usually referred to in simplified terms as the *balancing area*. In European terminology, however, multiple areas must be thereby differentiated. Going from big to small, balancing reserves are dimensioned on the level of *Load-Frequency Control (LFC) blocks*[1]

[1] A LFC block is defined by the SO GL as "*a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC blocks, consisting of one or more LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control*" (Art. 3(18)) [276].

and activated on the level of *LFC areas*[2] [285]. IPs are calculated at the level of *IP-area* and individual BRP's imbalances are eventually calculated at the *imbalance area*.

In general, larger balancing areas (i.e., LFC areas in the European context) with sufficient transmission capacity require less active system balancing through operating reserves since they reduce the net variability and uncertainty of iRES [286–288]. From a system operator's point of view, a to some extent similar effect can also be achieved if balance activities are coordinated among control areas, such as through the European TSO initiative on imbalance netting IGCC [289]. From a BRP's point of view, the imbalance netting effect works, however, only if the balancing responsibility can be handled at a portfolio level and the resulting imbalance areas are sufficiently large.

A shortcoming of too large IP-areas in combination with single pricing is that such can set adverse incentives that aggravate local imbalances in the context of internal congestions. Such is identified by Chaves Ávila et al. [9] in their study of the German electricity market, demonstrating the interdependence and necessary coordination of IP-schemes and IP-area sizing. In line with the common position in literature to favor the smallest possible IP-areas in order to achieve the highest locational incentive efficiency [290–292], Chaves Ávila et al. recommend ideally a nodal system or a zonal IP as a compromise for implementation reasons. The right sizing of the respective zones as IP-areas remains though admittedly difficult to assess [292].

6.2.2 Academic Contributions on Italian Balancing Schemes

Besides the general academic discussion on theoretical considerations of imbalance pricing, some authors contributed to this with reflections from the Italian perspective. Similar as Möller et al. [279] and Just and Weber [281] for Germany, Lisi and Edoli [174] demonstrate that also in Italy, the zonal imbalance sign is potentially forecastable. And, although legally not allowed, non-qualified units which act under a single pricing scheme could potentially exploit opportunities from purposeful deviations (or passive balancing) as Pierro et al. [293] proved exemplarily for PV plants. In a similar case study, Brunetto and Tina [179] provides a balancing cost assessment for a wind farm based on empirical data from Sicily. The analysis of this study further integrates here by deriving the welfare impact of updated IP-schemes as currently applied in Europe, for both a PV and wind plant, based on a common set of data.

[2] A LFC area is defined by the SO GL as "*a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC Areas, operated by one or more TSOs fulfilling the obligations of load- frequency control*" (Art. 3(12)) [276].

With regard to prices on the Italian balancing market, Caporin et al. [175] show the existence of long-run relationships between Italian day-ahead and balancing prices. The prices tend to converge over time for all continental zones except for Central-South, which "calls for careful assessment of the behavior of power producers in this zone." In line with that, Gianfreda et al. [272] elaborate on the market power in the Italian balancing markets under increasing iRES impact and find that thermal units are recovering in balancing sessions their profits lost on the DAM. According to the authors, this would be especially the case in off-peak hours, when competition from hydro and water pumping is low. The analysis of this study adds to this discussion by providing insights from a specific period with different system conditions such as higher iRES share and lower load.

The Italian IP-area design has also been criticized by academic authors such as Oggioni and Lanfranconi [180]. Their main criticism is that IPs are computed based on static zones (i.e., the two macro-zones) while the TSO buys and sells energy in the BM at varying prices in different network nodes. Evidence from empirical data suggests, in fact, that the activation of reserves within the two macro-zones might not follow a typical merit order, not least certainly also because of the use of a multi-purpose product for balancing and congestion management. However, the static (macro-)IP-areas do not take into account the network lines that are effectively constrained in real-time. Similar to other academic authors suggested in general in the previous section, this would call for nodal pricing according to Oggioni and Lanfranconi. In a recent consultation paper, the Italian NRA, ARERA, proposes the introduction of dynamic IP-areas instead, as currently applied for example also in Norway [294]. Such would be based on the bidding zones and aggregate if no congestions are present between the zones. The analysis of this study integrates here by providing additional empirical evidence in support of the IP-area criticism.

6.2.3 Contemporary Regulatory Developments

Besides the vivid academic discussion, two major decisions shaped the context in which European regulators implement national balancing frameworks. First of all, the European Commission stipulated with the EB GL as regulation 2017/2195 [276] among other things that: iRES shall neither bear nor receive any discriminatory requirements but compete on a level playing field with other market participants (see Article 3(1) respectively); all DERs, including also RES and demand-side response, shall be allowed to become active balancing providers (Article 18(4)); all European TSOs shall develop a proposal to harmonize imbalance settlement with single pricing as the default scheme whereas dual pricing has to be justified and approved by the NRA (Article 52(2)); and the imbalance area shall equal the scheduling area[3], except in the case of a central dispatching model where the imbalance area may constitute a part of the scheduling area (Article 54(2)).

Considering the all TSOs proposal, the European Union Agency for the Cooperation of Energy Regulators (ACER) decided then the imbalance settlement harmonization methodology [295]. One key aspect concerned the definition of IP-areas that shall equal bidding zones, except in the case of a central dispatching model where the IP-area may constitute a part of the bidding zone (Article 1(2)). For the most part, this will imply that imbalance areas equal IP-areas which equal bidding zones[4]. Furthermore, their decision confirmed single pricing as the default and dual pricing only as an exception upon approval (Article 7(1)). With regard to the IP basis, Article 9(1-4) specifies furthermore that both average and marginal pricing are allowed and that the product basis for such might include the entire range from secondary to tertiary reserves as well as dedicated balancing products or the prices from an integrated scheduling process. Additional components such as specific scarcity, incentive, or cost-neutrality elements are also allowed.

Overall, these two regulatory decisions of the European Commission and ACER set a clear framework while still leaving sufficient space for individual interpretations. The presented analysis provides empirical evidence concerning as elaborated in Chapter 6.4 to support the discussion among academics and policymakers on the recent decisions.

Finally, Table 6.1 provides an overview of the compared IP-schemes, for which types of BRPs they apply in Italy, as well as a selection of other European countries that also apply such types of configurations according to a survey of European grid operators [230]. Additional components such as scarcity mark-ups, incentive elements, or spot market couplings might further modify the configurations in their actual application.

6.2.4 Mathematical Formulations of Imbalance Pricing Schemes

To price the imbalances of BRPs, multiple schemes exist and, despite efforts to harmonize, the European reality still comprises a variety of implemented schemes.

[3]For the most part, the scheduling area equals the bidding zone for electricity markets, i.e., a single TSO operates the bidding zone, or otherwise the multiple TSOs decide to operate a common scheduling process for the joint bidding zone (as in Germany). Only in case multiple TSOs should operate on one bidding zone and not agree on a common scheduling process one bidding zone might be split into multiple scheduling areas, see SO GL Art. 110 (2).

[4]This is true as long as the scheduling area equals the bidding zone. Only central dispatch models have the exception that the TSO might decide for smaller imbalance areas or imbalance price areas.

Table 6.1: Compared imbalance pricing schemes with current application in Italy and Europe

IP-scheme *category*	*configuration*	**Application field in Italy**	**Other European countries where applied**
Single Pricing	average	consumption BRPs; non-qualified generation BRPs; iRES generation BRPs (optional)	
Single Pricing	marginal		(DNK)
Single Pricing	average incl. FRR	ARERA's proposal for all generation and consumption BRPs	(FRA) & EU target model
Single Pricing	marginal incl. FRR		(NOR, NLD, BEL, IRL)
Dual Pricing	average		(ESP)
Dual Pricing	marginal	qualified generation BRPs	(DNK)
Italian compensation scheme		iRES generation BRPs (default)	
German IP-scheme			(GER)

This section introduces the mathematical formulations of the most relevant types of IP-schemes as also further compared in this analysis.

Single Pricing The first IP category is the so-called Single Pricing where the IP p_{imb} solely depends on the imbalance direction of the underlying price area. In case the IP-area needs to activate predominantly downward balancing offers, it is called being long and has a positive imbalance sign. The IP is defined in this case as the lower of downward balancing price $p_{BAM\downarrow}$ and DAM price p_{DAM}. If it needs to activate predominantly upward balancing offers, on the contrary, it is called short and the IP is defined as the greater of upward balancing price $p_{BAM\uparrow}$ and DAM price p_{DAM}[5]. Table 6.2 summarizes the definition of IP calculations under Single Pricing.

Dual Pricing The second category of IP distinguishes not only for the imbalance direction of the system but also of the individual BRP. In case the BRP's imbalance $q_{imb,i}$ has opposed signs to the system's imbalance $q_{imb,z}$, the IP p_{imb} is set to the price of the DAM p_{DAM}. Instead, if the BRP's imbalance has the same directional

[5] The DAM price is here generally the reference price. However, in individual implementations this could be also the IDM price or a mix of both.

Table 6.2: Imbalance prices under Single Pricing

	BRP long	BRP short
Imbalance price area long	$p_{imb} = \min(p_{DAM}; p_{BAM\downarrow})$	$p_{imb} = -\min(p_{DAM}; p_{BAM\downarrow})$
Imbalance price area short	$p_{imb} = \max(p_{DAM}; p_{BAM\uparrow})$	$p_{imb} = -\max(p_{DAM}; p_{BAM\uparrow})$

sign as the system, the IP results from both BAM and DAM price as under Single Pricing. Dual Pricing is thereby eliminating potential positive pay-offs from BRPs' imbalances in case they would relieve the system's imbalance, while maintaining the negative payments in case of aggravating imbalances. The resulting IP calculations for Dual Pricing are listed in Table 6.3.

Table 6.3: Imbalance prices under Dual Pricing

	BRP long	BRP short
Imbalance price area long	$p_{imb} = \min(p_{DAM}; p_{BAM\downarrow})$	$p_{imb} = -p_{DAM}$
Imbalance price area short	$p_{imb} = p_{DAM}$	$p_{imb} = -\max(p_{DAM}; p_{BAM\uparrow})$

Additional pricing factors Besides the general framework of Single or Dual Pricing, two additional factors distinguish the configuration of these IP-schemes. First, the BAM prices p_{BAM} that feed into the schemes can be defined in two ways. On the one hand, the price can be defined as the *marginal* one of the last accepted offer, or, on the other hand, as the weighted *average* of all accepted offers in that direction.

The second distinguishing factor is which BAM products are applied to derive the price. In Italy, secondary reserve (so-called FRR in European terminology) has been excluded since 2016 from the IP calculation, which is instead exclusively based on a product called "other services" (i.e., "altri servizi" in Italian) that is used for balancing, congestion management and tertiary reserve. A distinction of the actual activation purpose is not possible since, unlike in some other European countries, no tag is associated with the acceptance purpose [296].

As a workaround, the IP calculation in Italy is solely based on accepted offers of this product on the BAM. Accepted offers of the same product on earlier sessions of the ASM (i.e., "MSD ex-ante" in Italian) are not considered. This is based on the simplified assumption that congestion management and tertiary reserve provisions will happen beforehand, whereas the real-time activations on the BAM will mainly be for balancing purposes. The reasoning to exclude FRR, on the other hand, was that its dynamic activation would not necessarily correlate to the hourly or quarter-hourly imbalances of market participants [297]. Although being currently discussed to be re-included for Single Pricing average in line with European regulations, for the time being, it remains excluded [294]. This results for both Single and Dual Pricing in four potential configurations, based on marginal or average prices and with or without secondary reserve products. For the sake of simplicity, these configurations are called from here on “marginal” and “average”, and configurations that include FRR are explicitly labeled. In contrast, all other schemes are only based on the specific balancing product as defined by current Italian regulations.

Italian iRES pricing scheme Besides the two simple implementations of Single and Dual Pricing, additional variations of these imbalance frameworks exist. Italy, for example, has a dedicated compensation scheme for iRES that consists of a variation of Single Pricing with tolerance bands. As long as the imbalance remains within this tolerance band of the scheduled energy injection, the BRP only pays (receives) the DAM price p_{DAM} for being short (long) and pays or receives the compensation price p_{com}. The compensation price is thereby independent of its own imbalance direction but calculated based on the overall imbalance of all participating BRPs (or better: iRES units). Although Italy generally applies individual unit balancing responsibility due to its central-dispatch system, this scheme effectively converts it into a "portfolio" balancing responsibility that all iRES share at the bidding zone level. In detail, the compensation price is calculated as

$$p_{com} = \frac{\sum_{i\epsilon z}\left[(p_{imb,nq}) - p_{DAM}) \cdot (\min(|q_{imb}|; |\alpha * q_{pro}|) \cdot (q_{imb}/|q_{imb}|))_i\right]}{\sum_{i\epsilon z}\min(|q_{imb}|; |\alpha * q_{pro}|)_i}$$

where $p_{imb,nq}$ stands for the regular IP that non-qualified units face (i.e., single pricing average under current regulation), and the subscript i comprises all those non-qualified units that adhere to the compensation scheme of the individual bidding zone z. α, on the contrary, is the percentage of the tolerance band attributed to individual resources. As for 2019, this was defined in case of relevant units as 49% for wind, 31% for PV, 8% for run-of-the-river hydro and 1.5% for all other relevant iRES plants. For non-relevant iRES units applies an 8% tolerance band independent of the actual resource since such units do not bear individual balancing responsibility but at an aggregated market zonal level. For imbalances outside the tolerance band, Single Pricing average is applied in all cases. Table 6.4 summarizes the resulting IPs from the compensation scheme for BRPs’ imbalances remaining within the tolerance band. Note that the compensation price p_{com} can also be negative. According to the already previously named consultation paper of ARERA, this scheme might be abolished since all units should act on an even playing field, independent of their technology [294].

Table 6.4: Imbalance prices under Italian iRES comnpensation scheme (within tolerance band)

	BRP long	BRP short
Imbalance price area long	$p_{imb} = p_{com} + p_{DAM}$	$p_{imb} = p_{com} - p_{DAM}$
Imbalance price area short	$p_{imb} = p_{com} + p_{DAM}$	$p_{imb} = p_{com} - p_{DAM}$

German IP-scheme Another particular IP-scheme that is based on Single Pricing but in a more complex version with a unique twist is the German IP-scheme. The *basis of this scheme* is that the IP is calculated as the difference of costs and revenues incurred by the TSOs from their balancing activities in each imbalance settlement period. This price is then adjusted by additional measures such as a price cap linked to accepted balancing offers, a spot market price coupling, and a scarcity surcharge as described in the following. Costs and revenues in Germany are incurred mainly from the activation of secondary reserve, which is why in this analysis for the Italian case study, not only the costs and revenues of the usual Italian balancing product were summed, but likewise of the activated secondary reserve. Following the sign convention of this analysis that short positions are counted negative and long positions as positive, the first step of the *Ausgleichs Energie Preis*, i.e., the German imbalance price (AEP) is hence calculated as

$$p_{AEP,1} = \frac{\sum costs_z - \sum revenues_z}{-\sum q_{imb,z}}.$$

Note that in the German imbalance convention, signs are opposed and hence the denominator is defined initially without the additional minus. The following adjustment steps maintain the convention of this analysis and appear therefore with adverse signs of imbalance directions compared to German definitions.

The second calculation step consists of an *IP cap* to the highest price of any accepted balancing bid or offer since, in case of small overall system imbalances, the small denominator would drive the resulting price inadequately high. Therefore, it results that

$$p_{AEP,2} = \begin{cases} (-1) \cdot \min(|p_{AEP,1}|; |\max(p_{BAM})|), & \text{if } p_{AEP,1} < 0 \\ \min(|p_{AEP,1}|; |\max(p_{BAM})|), & \text{if } p_{AEP,1} \geq 0. \end{cases}$$

To avoid further inappropriately high IPs for very small net imbalances, an *additional price cap* has been introduced for the range of $\sum q_{imb,z} = -125\,\text{MWh}$

to $\sum q_{imb,z} = 125\,\text{MWh}$. The cap is linear increasing with the net imbalance and linked to the price of the respective hourly product on the (spot) IDM p_{IDM}. The adjusted price results to be

$$p_{AEP,20} = \begin{cases} (-1) \cdot \min\left(|p_{AEP,2}|; \left|p_{IDM} - 100\,\frac{€}{\text{MWh}} - 150\,\frac{€}{\text{MWh}} \cdot |\frac{\sum q_{imb,z}}{125\,\text{MWh}}|\right|\right), \\ \qquad \text{if } p_{AEP,1} < 0 \text{ } \mathit{and} \text{ } -125 \geq \sum q_{imb,z} \geq 125 \\ \min\left(|p_{AEP,2}|; \left|p_{IDM} - 100\,\frac{€}{\text{MWh}} - 150\,\frac{€}{\text{MWh}} \cdot |\frac{\sum q_{imb,z}}{125\,\text{MWh}}|\right|\right), \\ \qquad \text{if } p_{AEP,1} \geq 0 \text{ } \mathit{and} \text{ } -125 \geq \sum q_{imb,z} \geq 125 \\ \qquad \text{else, } p_{AEP,2}. \end{cases}$$

The fourth step of the calculation consists of a *price comparison to the spot market price* for the respective hour. The aim is to ensure a minimum price-spread of 25% or at least 10€/MWh as long as a minimum volume of 500 MWh has been traded for the respective spot market session. For very small imbalances up to 125 MWh the minimum price-spread increases linearly, defined as:

$$\triangle p = \max\left(10\,\frac{€}{\text{MWh}} \cdot \frac{\min(125\,\text{MWh}; |\sum q_{imb,z}|)}{125\,\text{MWh}}; \right. \\ \left. |\sum q_{imb,z}| \cdot \frac{\min(125\,\text{MWh}; |\sum q_{imb,z}|) \cdot 0.25}{125\,\text{MWh}}\right).$$

The resulting adapted IPs results as:

$$p_{AEP,3} = \begin{cases} \min(p_{AEP,20}; p_{IDM} - \triangle p) & \text{if } \sum q_{imb,z} > 0 \text{ } \mathit{and} \text{ } Q_{IDM} \geq 500\,\text{MW} \\ \max(p_{AEP,20}; p_{IDM} + \triangle p) & \text{if } \sum q_{imb,z} < 0 \text{ } \mathit{and} \text{ } Q_{IDM} \geq 500\,\text{MW} \\ & \text{else, } p_{AEP,20}. \end{cases}$$

In a last step, a *scarcity component* is added in case that more than 80% of the contracted upward reserves $Q_{res\uparrow}$ or downward reserves $Q_{res\downarrow}$ would be activated (so-called 80%-criterion). The price is thereby increased or decreased by either 50% or at least 100€/MWh, respectively. The final adapted price results as:

$$p_{AEP} = p_{AEP,4} = \begin{cases} p_{AEP,3} - \max(100\,\frac{€}{MWh}; 0.5 \cdot |p_{AEP,3}|) & \text{if } \sum q_{imb,z} < -0.8 \cdot Q_{res\downarrow} \\ p_{AEP,3} + \max(100\,\frac{€}{MWh}; 0.5 \cdot |p_{AEP,3}|) & \text{if } \sum q_{imb,z} < -0.8 \cdot Q_{res\uparrow} \\ \text{else, } p_{AEP,3}. \end{cases}$$

The final adapted price p_{AEP} is then used as the actual IP p_{imb} for BRPs. The presented version of this IP-scheme is the one that was valid in 2020 during the time of this work's analysis. In August 2021, the calculation step of the scarcity component with $p_{AEP,4}$ has been further revised to follow a function of second-order [298]. As for the Italian iRES compensation scheme, the IP sign is eventually not directly linked to the imbalance direction of the IP-area, and the resulting IP can also take negative values for long BRPs. Other than the Italian scheme, however, the German also distinguishes specifically for the BRPs imbalance direction. The summarized IP conventions for short or long BRPs are presented in Table 6.5.

Table 6.5: Imbalance prices under German imbalance pricing scheme

	BRP long	BRP short
Imbalance price area long	$p_{imb} = p_{AEP}$	$p_{imb} = -p_{AEP}$
Imbalance price area short	$p_{imb} = p_{AEP}$	$p_{imb} = -p_{AEP}$

BRP imbalance pay-offs Based on the derived IPs, BRPs' imbalances are valued. The overall pay-offs BRPs face are based on the sum of cash flow a BRP has to pay (or receives) in connection with an imbalance. Similar to active balancing reserve provision, such relate not only to the direct Imbalance Fees (IFs) but also to previously obtained (or missed) cash flows on the spot market [7]. The Imbalance Pay-Offs (IPOs) are especially relevant for the analysis of BRPs that deviate intentionally, where they can be interpreted as the inverse of imbalance opportunity costs. Said differently, pay-offs represent the driver for potential imbalances of conscious BRPs [8].

As an example, if a BRP i results to have a negative imbalance $q_{imb,i}$ (i.e., a short position on the spot market), its imbalance is valuated at the IP. But the BRP also received the wholesale market price previously (e.g., the DAM price) for the very same undelivered energy. Hence, the overall IPO $P_{IPO,i}$ results to be the combination of IPs and DAM prices[6] multiplied by the actual BRPs imbalance. Note that IPOs can result in a cost and hence be negative but also a profit and hence be positive. Table 6.6 summarizes the resulting cash flows for BRPs with imbalances under the different IP-schemes.

[6] As previously, the DAM price is used here as the general reference price. Individual implementations might consider however also the IDM price or a mix of both.

Table 6.6: Resulting pay-offs for BRPs' imbalances

	BRP long	BRP short
Imbalance price area long	$P_{IPO,i} = \lvert q_{imb,i} \rvert \cdot (p_{imb} - p_{DAM})$	$P_{IPO,i} = \lvert q_{imb,i} \rvert \cdot (p_{imb} + p_{DAM})$
Imbalance price area short	$P_{IPO,i} = \lvert q_{imb,i} \rvert \cdot (p_{imb} - p_{DAM})$	$P_{IPO,i} = \lvert q_{imb,i} \rvert \cdot (p_{imb} + p_{DAM})$

6.3 Methodology

This section describes first the input data for the following case studies on passive balancing integration of DERs, then secondly the case-study framework in which they were applied and, thirdly, the methodological limitations that apply.

6.3.1 Input Data

The analysis is fully built on publicly available market and operational data from the Italian electricity system, available through the Italian market operator GME [@181], the Italian TSO Terna [@188] and the European transparency platform of ENTSO-E [@178].

BAM data [@181] is pre-processed according to the general methodology as described in Chapter 3 to obtain the hourly average and marginal prices per product category and bidding zone. The BAM data is further denoted as $\bar{p}_{BAM,c,d,z}$ for weighted average prices and $\dot{p}_{BAM,c,d,z}$ for marginal prices. The subscripts express thereby the following characteristics: the category of products $c = \{FRR, OS\}$, the direction of the product's offering $d = \{up(\uparrow), down(\downarrow)\}$, as well as the spatial assignment to either a bidding zone $z = \{north, cnorth, csouth, south, sardinia, sicily\}$ or a macro-zone $mz = \{north, south\}$. In the case of macro-zone calculations, the marginal price of the macro-zone consists of the marginal price of the marginal prices of the individual bidding zones. Instead, the average price consists of the weighted average price of the respective weighted average bidding zone prices. In the case of calculations that also include FRR, the prices of the two products, FRR and OS, are similarly combined as the marginal of the marginal and the weighted average of the weighted average price, respectively.

DAM data requires no pre-processing as it is already available in the correct format, displaying the hourly DAM prices per bidding zone $p_{DAM,z}$ [@181]. The same applies to the price for the Italian iRES compensation scheme $p_{com,z}$ [@188].

The forecast error of a hypothetical iRES plant in the case-study ϵ_{iRES} is calculated as the difference of the day-ahead forecast q_{for} for PV and onshore wind versus the respective actual generation q_{act}. Both input data are available on an hourly basis at the bidding zone level for each resource [@178]. The few hours for which the ENTSO-E dataset contains no day-ahead forecast are excluded from the imbalance error calculation.

6.3.2 Case Study Outline

In order to provide a comprehensive study of passive balancing integration of DERs, a four-part case study is performed. First, different IP-schemes are compared. Second, the differences for different IP-area sizing are investigated. In the third part, the implications of IP-schemes in terms of IFs for individual iRES plants are demonstrated. Finally, previous findings are confronted with results from a system under peculiar conditions during the COVID-19 pandemic. The study is carried out with data of the Italian electricity system with its reasonable data availability, however, due to its general character derives general findings with applicability to other systems as well.

Case Study I: Varying imbalance pricing schemes For the first part of the comparative analysis, eight different configurations of IP-schemes as currently applied in Europe and as presented in Table 6.1 are compared. The framework of this part of the case study analysis is the entire year of 2019 with an hourly resolution for the macro-zone North. This zone is particularly suitable to compare different IP-schemes since it is, on the one hand, a distinctively liquid bidding zone with comparably low market power of single actors. On the other hand, balancing area and bidding zone coincide, so potential effects of interzonal congestions as for the macro-zone South can be excluded. The *Single Pricing average* scheme, as currently applied in Italy for small and non-qualified generators, is the most basic IP-scheme and therefore used as the benchmarking IP-scheme. The second IP-scheme *Single Pricing marginal* is then used to compare the effect of marginal pricing versus average pricing on both aggravating as well as relieving BRPs. With the integration of the *Single Pricing configuration including FRR*, a comparison to the target IP-scheme of European regulation is provided. To highlight potential peculiarities of FRR, both configurations of average and marginal Single Pricing are implemented. *Dual Pricing* finally completes the comparison of standard IP-schemes as discussed in the academic discourse. It provides thereby also the interesting opportunity to confront the balancing implications of new units such as virtual aggregates of DERs that are increasingly equated to large conventional units by entering ancillary service markets, but which are as of now not equated in terms of imbalance settlement by being under different IP-schemes as Single Pricing. Besides the standard IP-schemes, two more particular schemes are integrated. On the one hand, the *Italian compensation scheme* to compare a specific scheme for iRES and on the other hand the *German IP-scheme* to compare a scheme that aims for financial neutrality of TSOs. The results of this analysis are discussed in Chapter 6.4.1.

The schemes are then applied as introduced in Chapter 6.2.4 and IPs are calculated separately for the four case scenarios of an either long or short BRP in combination with an IP-area that would be consistently long or short for the entire period of study. This theoretical consideration provides a generic IP analysis, independent of the effectively fluctuating imbalance directions of BRPs and the IP-area.

IPs are based on the BAM for all settlement periods in which accepted BAM offers exist and otherwise on the DAM price. For the *Italian iRES compensation scheme*, the analysis is conducted for imbalance within the tolerance margins to show the specific effects of this scheme. If effects beyond that would be of interest, the resulting price could simply be combined with any other IP-scheme on a proportional basis of imbalances beyond and within the tolerance band. Furthermore, the *German IP-scheme* is slightly modified. Without loss of generality, the last step of the IP calculation adding a scarcity component is skipped with $p_{AEP} = p_{AEP,3}$ given that Italy performs no capacity procurement of balancing reserves and scarcity information of Italian reserves are hence unavailable. In addition, given that the dominating spot market in Italy is the DAM instead of the IDM and also considering that all current Italian IP-schemes relate to DAM price, the spot market coupling in $p_{AEP,20}$ and $p_{AEP,3}$ is conducted by using DAM prices. Other input data is used as described in the previous section 6.3.1 of this chapter.

Case Study II: Varying imbalance price area sizing In the second part of the analysis, the design element of IP-area sizing is investigated by decomposing the current IP-area of Macro-South in its actual bidding zones as potential local IP-areas. As previously, the analysis is purely based on accepted BAM offers and DAM prices. Therefore, the specific input data for the IP calculation are the activated BAM offers per bidding zone versus per aggregated macro-zone. The applied scheme for this comparative analysis is *Single Pricing average* and the time-frame remains the entire year of 2019.

In a first step, the split of Macro-South into local IP-areas is undertaken on a static basis, treating each of the five bidding zones as a completely independent IP-area with respective IPs being purely based on accepted BAM offers within the respective bidding zone. Unless otherwise specified, local IP-area from here on always implies static local IP-area. In a second step, the bidding zones are dynamically re-connected for IP calculation in the absence of congestion, similar to the Norwegian IP-area model [299]. Similar to different bidding zones in spot markets, contiguous bidding zones act thereby as one IP-area with a joint IP calculation as long as no congestion between bidding zones occurs. With the latter's presence, bidding zones split instead into dynamic IP-areas of the size of the remaining non-congested group of bidding zones. The smallest possible IP-area results therefore to be the single bidding zone, the largest possible IP-area the current macro-IP-area. In a first approximation, diverging DAM prices are used as a measure for congestion between bidding zones. Furthermore, congestions are assumed to impede the activation of balancing products in both directions, resulting in a complete split of respective bidding zones in separate IP-areas. The effects of dynamic IP-area sizing are exemplary demonstrated for Sicily's bidding zone, a particularly small and poorly connected bidding zone in Italy.

By splitting one IP-area into smaller areas, the analysis provides a first indication of how the implications for BRPs might change if exposed to smaller IP-areas that reflect local market characteristics more accurately. Such insights are specifically valuable against the backdrop of the already cited EU regulation requiring IP-areas to be equal to or smaller than individual bidding zones, which is currently not the case in Italy.

Case Study III: From imbalance prices to imbalance fees Following the research gap suggestion by Clò and Fumagalli [8], the third part of the analysis looks into economic implications of IP-schemes. As an extension of the previous two parts, the implications of different regulatory frameworks from the perspective of a single iRES plant are derived. In contrast to the theoretical consideration in the previous sections, no intentional and consistent BRP or IP-area imbalances are assumed, but the actual iRES forecast error and (macro-) IP-area imbalance direction according to the TSOs database are used. The unit of analysis are thereby two 10 MW plants of PV and onshore wind, respectively. According to Italian regulation, such units are just on the edge of being so-called "*significant*" units (see section 3.1.3 for more information) and, under the recent pilot project UVAM, could also enter a "*qualified*" aggregate for ASM participation. Depending on its characterization and the underlying regulatory framework, the units face different IP-schemes accordingly.

The analysis follows the idea from the worst-case IP framework that an iRES unit might face nowadays to the EU target IP model. In the first place, the IFs for the year 2019 under *Dual Pricing marginal* are calculated. This IP-scheme would apply in case iRES units would be treated as conventional generation units as proposed by Pierro et al. [293], given that they reached grid parity. This is compared to the resulting IFs as under the *Italian iRES compensation scheme*, which applies as the default IP-scheme to the majority of Italian iRES plants nowadays. Next, results for the second (optional) IP-scheme for iRES in Italy, *Single Pricing average*, are presented. To extend the perspective to future-oriented scenarios, the resulting

IFs are then outlined for a year of operation under *Single Pricing average incl. FRR* as the EU target IP model and finally also in combination with local IP-area sizing. In a first approximation and for better comparison, the IP-area imbalance direction is kept equal to the aggregated macro IP-area.

Case Study IV: Varying system conditions: COVID-19 impact To conclude the case studies on passive balancing integration of DERs, finally the sensitivity of the findings from the previous case studies are investigated with regard to varying system conditions. The impact of the COVID-19 pandemic provides for this objective a viable study opportunity, with a system characterized by reduced electricity consumption and a significantly increased share of iRES in electricity generation as further described in Chapter 3.2. A second motivation behind the particular focus on the period impacted by the COVID-19 pandemic is that such an analysis provides insights that might be of interest as a basis for future discussions on IP-schemes in systems with generally increased iRES shares.

Resuming the approach of the first three case-study sections, initially different IP-schemes are compared based on one bidding zone, followed by the comparison of the impact of different IP-area sizings based on one IP-scheme. As previously, the benchmarking bidding zone for the first part is thereby the *North* whereas the benchmarking IP-scheme for the second part is *Single Pricing average* and the third part is analyzed for a PV plant in Sicily. The underlying comparison period is April 2020, the only month in which a full lockdown was applied to all of Italy. Due to the reduced time period, results of April 2020 are compared to April 2019 only. While this reduced unit of analysis comes along with limitations for the direct comparability of the results with those of other analyses (see explanations in the following limitations section), the aim of this case study is not to repeat the entire previous analyses but to evaluate the sensitivity of their main findings towards changing system conditions.

6.3.3 Limitations

While undertaking this study, several potential limitations to the study validity have been identified and mitigated, as discussed below.

Empirical data limitations One limitation of the presented is the fact that empirical data are used. These data are based on many variables and influences whose origins or correlations are neither fully traceable nor controllable.

To minimize a possible validity risk of the study, several principles are followed. On the one hand, the analyses are carried out with data sets as large and general as possible to avoid singular effects. Even if the data are available on the basis of individual market transactions, IPs are calculated on an annual basis, for example, to avoid seasonal or individual weekday effects. Furthermore, analyses are performed for the largest possible and best-connected bidding zones and abstracted as far as possible by, for example, calculating and considering IPs independently of IP-area directions.

Nevertheless, the generalizability and transferability of individual results to other application scenarios are naturally limited. Individual results should not be considered absolute, and direct comparisons or extrapolations of individual results should be avoided. What the study can provide is an analysis of basic effects for the Italian system. These findings can then be used as reference points for discussions on systems with similar frameworks or conditions.

Public data limitations A second limitation of the presented work is based on the publicly available dataset of the market operator GME. The individually accepted offers contained in this dataset represent the basis for the IPs as also published separately by the Italian TSO Terna. The published IPs are at the macro-zonal level and a result of the currently applied IP-schemes. This work uses the GME dataset to rebuild the IPs of the existent Italian IP-schemes, but also to analyze additional IP-schemes and IP-area configurations.

When comparing the resulting prices of currently applied IP-schemes from this work with the ones published by the Italian TSO Terna, it appears that the numbers differ to a certain extent. While the overall differences are minor and in the range of one-digit percentages, they do become more pronounced for specific cases in which the market and IP-area Macro-North is short. The GME dataset prices are, in this case, on average 19% higher than for the Terna dataset when applying the scheme Single Pricing average.

Tracing the differences down, it appears that for a number of hours for which the Terna dataset presents no IP (which would imply no accepted balancing offers), the GME dataset instead contains accepted upward balancing offers. As hours of no accepted BM offer use by default the comparably lower DAM price as the IP, this results in the reduced IPs from the application of the TSOs dataset.

In order to mitigate a potential threat to the validity of the study, Terna has been consulted. It appears that the reason for this discrepancy is that individual BAM transactions can be contested ex-post by BSPs. In case of successful contestation, the IP publication of Terna is adjusted accordingly, whereas the published BAM dataset of GME remains untouched without being updated. Despite this difference, the generality of the essential findings from this analysis remains unrestricted since the differently affected macro-zones North and South are not directly compared. Individual IP-schemes are always compared on the same single dataset. Likewise, the comparison of IP-area configurations is limited to the macro-zone South with low dataset discrepancies and reasonably negligible implications of potentially ex-post adjustments being randomly distributed amongst the underlying bidding zones. For more detailed information on the dataset deviations see Appendix B.3.

Cross-zonal balancing uncertainties Static IP-areas as used in a part of this analysis have the side-effect that some BAM offers will be activated in zones different than the one that actually created the balancing need. As long as the activation purpose of single offers remains undisclosed (as it is the case in Italy), such cross-zonal balancing activations will remain undetected and potentially distort the results for individual zones. Dynamic IP-areas in their studied implementation mitigate this issue, except for potential unilateral balancing activation across congested bidding zones and BAM offers from outside the studied bidding zones (e.g., offers from other international markets or joint platforms such as the European platforms TERRE[7] and MARI[8]).

To further mitigate this potential threat to the study's validity, direct comparisons of IPs in absolute numbers across bidding zones should be avoided, especially with static IP-area sizing. On the contrary, the results as obtained in Chapter 6.4.2 should be interpreted instead as an indication of how IPs might change by changing IP-area sizings or, at most, which imbalance areas might contain specifically high or low priced balancing reserves.

6.4 Results and Discussion

The results of the four case studies are presented and discussed one by one in the following section. Such is always followed by a short recap with interim takeaways before Section 6.5 presents the identified opportunities for future research, and overall conclusions are finally drawn in Section 6.6.

[7]TERRE stands for Trans European Replacement Reserves Exchange and is the joint European platform for the exchange of RR.

[8]MARI stands for Manually Activated Reserves Initiative and is the joint European platform for the exchange of mFRR

6.4.1 Different Imbalance Pricing Schemes

To compare different IP-schemes based on empirical data from Italy, their average prices and their standard deviations are calculated and benchmarked to the most "standard" scheme *Single Pricing average*.

The calculated results distinguish the cases of an either long or short BRP in combination with an IP-area that would be consistently long or short for the entire period of study. The four case scenarios are represented by the four double-rows of Table 6.7. The brightness of each cell's color denotes the deviation of individual IP-schemes towards the benchmarking IP-scheme. Negative prices indicate a payment from BRP to TSO and positive prices from TSO to BRP. Note that the German IP-scheme does not explicitly distinguish IPs for long or short IP-areas, but only for long or short BRPs.

Therefore, average IPs and their standard deviation for only two case scenarios are distinguished. Calculations for effective IPs and resulting costs for BRPs with varying, positive and negative, imbalances that operate on an IP-area with varying imbalances are presented in Chapter 6.4.3.

For the bidding zone North, the average IP in 2019 under the benchmarking Single Pricing average scheme results +-31.41 €/MWh for a consistently long IP-area (and a long or short BRP, respectively) and +-94.62 €/MWh for a consistently short IP-area. Along with the increased IP, also the standard deviation for a short IP-area (i.e., where predominantly upward balancing reserves need to be activated) is notably increased with 69.89 €/MWh compared to 12.41 €/MWh for a long IP-area (i.e., where predominantly downward balancing reserves need to be activated).

Figure 6.1 provides an illustrative calculation example of how these IPs transform into potential IPOs for BRPs. With the average DAM price in the bidding zone being 51.25 €/MWh for 2019, the average pay-off in a consistently long IP-area emerges to be -19.84 €/MWh for a long BRP and +19.84 €/MWh for a short BRP, respectively (point (1.) in the figure). In a consistently short IP-area instead, the average pay-off amounts to +43.37 €/MWh for a long BRP and -43.37 €/MWh for a short BRP (point (2.) in the figure).

Assuming that the IP-area would have a balanced imbalance sign, i.e., effectively be 50% of time short and 50% of time long, the average IPO for a consistently long BRP results +11.76 €/MWh and for a consistently short BRP -11.76 €/MWh instead (point (3.) in the figure). For a BRP that would intentionally deviate from its spot market schedule (be it to "passively" balance the system or simply

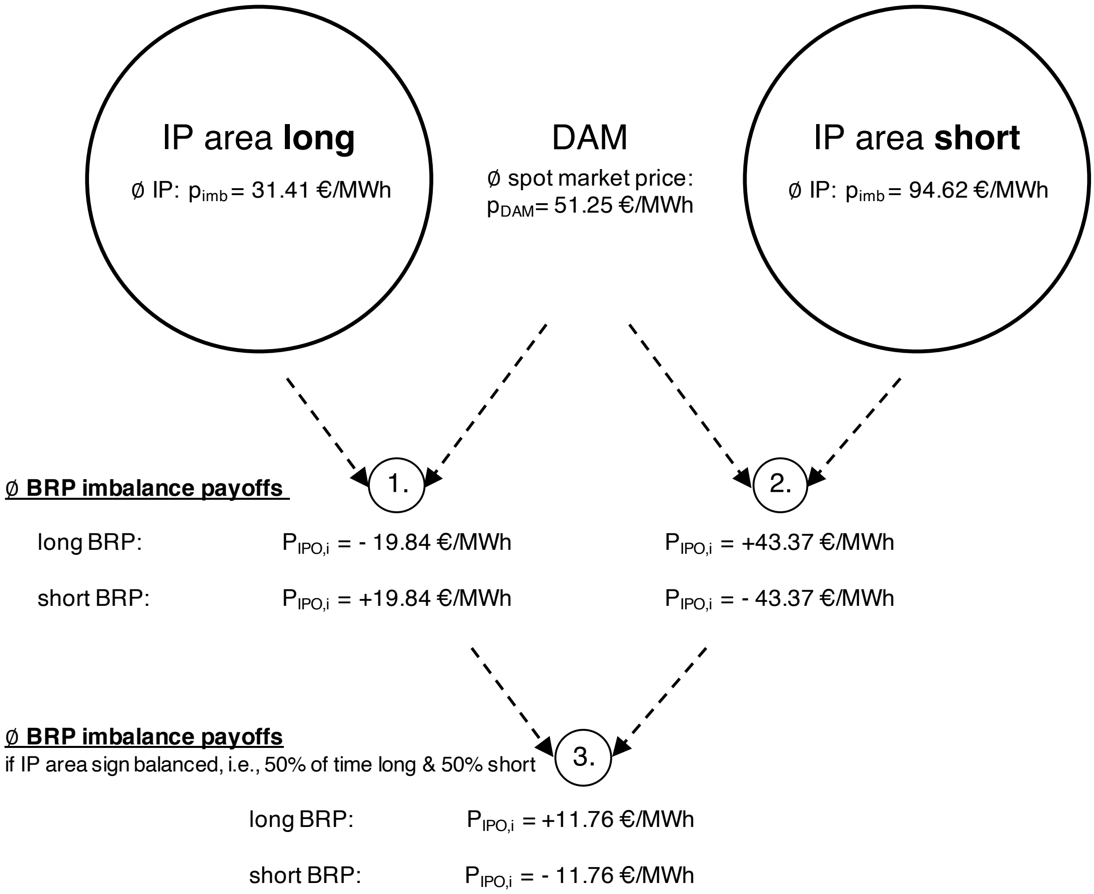


Figure 6.1: Illustrative calculation example for the average imbalance pay-off (IPO) of a BRP under Single Pricing average with values of the bidding zone North in 2019.

Table 6.7: Comparison of average imbalance prices $\varnothing p_{imb}$ and their standard deviations $\sigma(p_{imb})$ for eight different imbalance pricing schemes, applied to the bidding zone North for 2019

			Single Pricing		**Single Pricing incl. FRR**		**Dual Pricing**		**Italian iRES comp. scheme**	**GER IP scheme**
			average	marginal	average	marginal	average	marginal	-	-
Area + BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	31.41	13.97 (- 56%)	29.77 (- 5%)	5.89 (- 81%)	31.41 (+0%)	13.97 (- 56%)	50.28 (+60%)	21.72 (- 31%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	12.41	15.85 (+28%)	10.45 (- 16%)	9.42 (- 24%)	12.41 (+0%)	15.85 (+28%)	18.27 (+47%)	61.83 (+389%)
Area - BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	94.62	147.27 (+56%)	95.18 (+1%)	166.02 (+75%)	51.25 (- 46%)	51.25 (- 46%)	50.28 (- 47%)	21.72 (- 77%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	69.68	239.33 (+243%)	51.78 (- 26%)	237.10 (+240%)	12.91 (- 81%)	12.91 (- 81%)	18.27 (- 74%)	61.83 (- 11%)
Area + BRP -	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	-31.41	-13.97 (- 56%	-29.77 (- 5%)	-5.89 (- 81%)	-51.25 (+63%)	-51.25 (+63%)	-52.22 (+66%)	-21.72 (- 31%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	12.41	15.85 (+28%)	10.45 (- 16%)	9.42 (- 24%)	12.91 (+4%)	12.91 (+4%)	18.85 (+52%)	61.83 (+398%)
Area - BRP -	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	-94.62	-147.27 (+56%)	-95.18 (+1%)	-166.02 (+75%)	-94.62 (+0%)	-147.27 (+56%)	-52.22 (- 45%)	-21.72 (- 77%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	69.68	239.33 (+243%)	51.78 (- 26%)	237.10 (+240%)	69.68 (+0%)	239.33 (+243%)	18.85 (- 73%)	61.83 (- 11%)

Note: *Percentages describe the deviations of results for individual imbalance price schemes from the results for the benchmarking* Single Pricing average. *Cell colors relate to percentages for increased comparability.*

to optimize its individual financial position), this resulting average price difference of IP and DAM price would constitute an incentive to rather take a long position and to leverage the financial opportunity.

By analyzing zonal imbalance data from the TSO in detail, however, it emerges that the bidding zone results effectively to be long for 66% of the time [@188]. This somewhat counterbalances the effect of unbalanced IPs, reducing the remaining average gain to 1.65 €/MWh for long BRPs[9]. The third case study in Section 6.4.3 further investigates the effective incentives and related IFs for BRPs with actual system imbalances and iRES plant imbalances. For the sake of comparability and in order to maintain the theoretical approach of the IP comparison independent from the zonal imbalance direction, the following comparisons will continue to refer to the assumption of an overall balanced IP-area that is 50% of the time long and 50% short.

Average vs. marginal schemes Compared to implementations based on average prices, marginal pricing intensifies IPs by decreasing (increasing) them for long (short) IP-areas. For the case study of the bidding zone North in 2019, the intensifying effect is remarkably uniform in both directions for long and short IP-areas. Under Single Pricing (with the currently used balancing product categories in Italy), the IP amplification of marginal pricing compared to average pricing results to be 56%. For the European target model that would consider FRR as well, this amplification increases further to 81% lower prices for long or 75% higher prices for short IP-areas. Marginal schemes generate thereby a significantly stronger price signal to balance individual BRP portfolios.

Considering FRR or not Single Pricing in its envisioned European implementation results in a wider pool of BAM transactions that are considered for IP calculation. For the Italian bidding zone North in 2019, this implies a shift of balancing incentives compared to the current implementation. By also considering FRR activation for imbalance pricing, the average IP BRPs pay or receive reduces for a long IP-area and increases the IP for a short IP-area. While under average pricing, the impact of including FRR activation remains with 1-5% notably modest, under marginal pricing, the impact becomes more pronounced and rises to an additional 20-25%. This is especially interesting against the backdrop that Italy currently has both a marginal (Dual Pricing) and an average (Single Pricing) scheme in place and, at the same time, recently started to evaluate the option to consider FRR as well for

[9] Why the zone has an inclination towards being long remains uncertain and subject to further investigation. Potential reasons might be structural congestions, operative preferences of the proactive (i.e., central-dispatching) TSO, or also a majority of BRPs already trying to passively balance and hence actively leveraging on the general imbalance incentives by being long on purpose.

its IP calculations. Depending on the implementation, the inclusion of FRRs would thus impact the incentives of BRPs to a greater or lesser extent.

Furthermore, the product category of FRR appears to have a different market equilibrium point in upward and downward direction than the standard balancing product OS. By including FRR, the average IP decrease for a long IP-area North turns out more pronounced than the IP increase for a short IP-area North. All other things being equal, this would slightly shift the incentive for BRPs under Single Pricing to stay less long. Shifts of market equilibrium points for other bidding zones might differ additionally.

Dual Pricing vs. Single Pricing Inherent to Dual Pricing, this scheme reduces the positive incentives from relieving imbalances compared to Single Pricing while maintaining those for BRPs with aggravating imbalances. The reduction of the positive incentive from the application of the DAM price instead of respective balancing energy prices results to be on average around 50% for the bidding zone North in 2019 (46% lower IP that long BRPs receive in short IP-areas and 63% higher IPs that short BRPs pay in long IP-areas).

The consequentially negative pay-offs for BRPs under Dual Pricing remove any incentive to deviate intentionally and generate a unilateral cash-flow from the BRPs to the TSO. Considerations for pro-active BRPs involve only loss avoidance by the tendency to convert forecast uncertainties rather into market positions of one direction than the other. For the example of an IP-area North with an on average balanced imbalance sign, the IPO for consistently long BRPs results to be -9.92 €/MWh and -21.68 €/MWh for consistently short BRPs in 2019 (applying the same calculation scheme as in Figure 6.1). Converting potential forecast uncertainty in a rather long market position reduces the imbalance cost risks for BRPs by around half. In this sense, Dual Pricing continuous to impose the tendency for BRPs to maintain rather a long market position, even if only for the unavoidable minimum of the forecast uncertainty.

Special imbalance pricing schemes Other than Dual Pricing, the German IP-scheme represents from the TSO's perspective a dedicated cost-neutral IP-scheme. While the first six compared IP-schemes differ for each of the four case scenarios of long or short IP-areas and BRPs, the German IP-scheme results in one price that the BRP pays (receives) if it is short (long). Applying the scheme to Italian market data, the resulting average IP of +-21.72 €/MWh appears significantly lower than the IPs from other schemes if considered across the four case scenarios.

Similarly, the Italian compensation scheme for iRES contains one single price p_{comp} that is not directly linked to the individual BRP's imbalance or the IP-area sign. However, as the final IP p_{imb} contains also the spot market price p_{DAM} which the BRP pays (receives) for being short (long), the IP eventually varies slightly for short or long BRPS. As the IPOs cancel out the DAM from the IPs, the resulting IPOs for BRPs are balanced like a Single Pricing scheme and fundamentally solely based on the compensation component p_{comp} with an average of -0.97 €/MWh for the bidding zone North in 2019. With the overall lowest IPOs among the eight compared IP-schemes, the Italian iRES scheme fulfills its purpose of a compensation scheme with damped imbalance (opportunity) costs for individual iRES units. This is, of course, only true as long as individual imbalance remains within the respective tolerance bands.

Imbalance price fluctuations Besides the comparison of average prices, a look at the standard deviations of IPs from different schemes provides further details on price behavior. By their very nature, marginal price schemes lead not only to an amplified average price but also to increased price fluctuations as visible through respectively increased standard deviations. Interestingly, marginal prices contain significantly higher standard deviations for short IP-areas, i.e., if upward balancing reserves need to be activated. While this appears logical due to the imposed price floor of 0 €/MWh and the respectively limited price fluctuations for downward offers, it implies at the same time a strongly unbalanced IP risk for exposed BRPs without the capability to forecast IP-area signs. Furthermore, standard deviations for schemes that consider FRR result reduced, indicating a more liquid market for FRR than for the current standard balancing product OS.

Although having an overall reduced average IP, the German IP-scheme results in a relatively high standard deviation compared to average Single Pricing schemes, especially for long IP-areas. The Italian iRES compensation scheme, in contrast, has an overall significantly reduced standard deviation and thus dampens imbalance risks not only in terms of resulting average prices but also in terms of price fluctuations. Although the standard deviation for long IP-areas increases compared to the benchmarked scheme, this effect is fairly small in absolute numbers and outweighed by the reduced fluctuations in short IP-areas.

Imbalance price distributions Besides the numeric comparison of average prices and standard deviations, the analysis of the underlying price distributions with CDFs provides the third perspective to contrast the different IP-schemes. Figure 6.2 illustrates the distribution of IPs in the bidding zone North in 2019 for the first case scenario with a short IP-area and a long BRP.

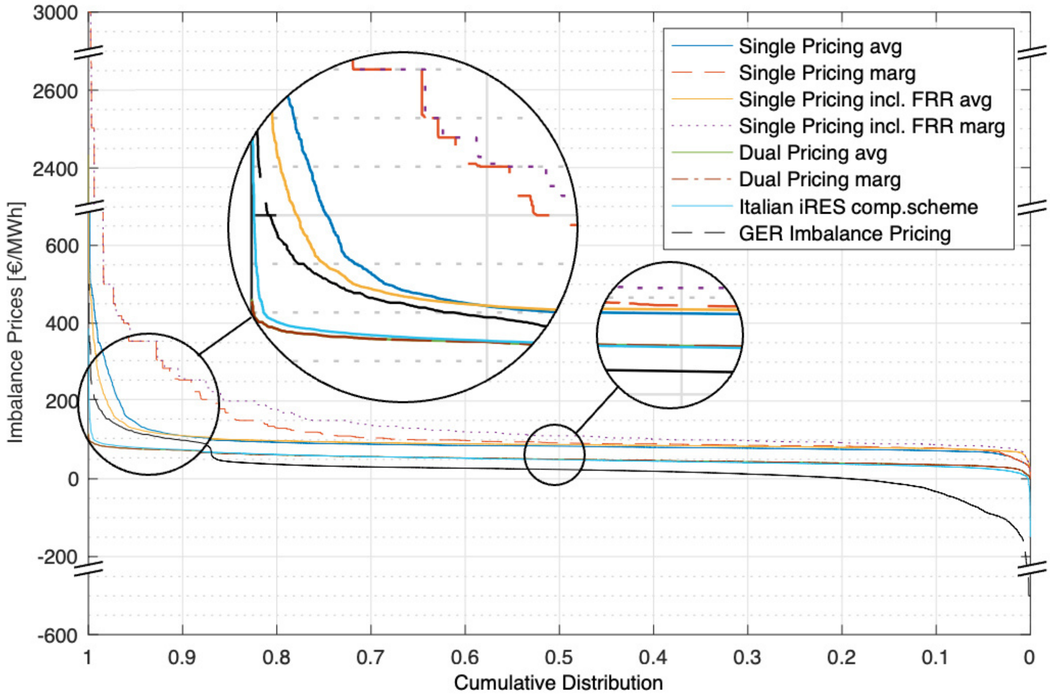


Figure 6.2: Cumulative distribution function of compared imbalance pricing schemes for 2019 in the bidding zone North. *Case scenario:* short imbalance price area and long BRP.

Comparing average and marginal schemes (dark blue line and dashed orange line in the figure), it emerges that notable differences in the shape of the curve occur quasi exclusively for the comparably high price range. While for both implementations a cumulative probability of 0.7 contains an IP of roughly up to 90 €/MWh (see smaller zoom), a cumulative probability of 0.95 contains for average implementations still an IP of approximately 140 €/MWh whereas for marginal implementations this value increases to 350 €/MWh (see larger zoom). The highest registered IP for the average implementation is 2430 €/MWh, for the marginal implementation it is the Italian VOLL of 3,000 €/MWh, representing at the same time the imposed price cap for DAM and BAM. Said differently, while marginal pricing increases the overall average price, the probability of notably higher prices is limited, and, for the example of the bidding zone North in 2019, it amounts in the upward direction to only about a quarter of the time.

Comparing the inclusion of FRR, the CDF illustrates how Single Pricing average with FRR (yellow line) has a slightly increased average IP compared to Single Pricing average without FRR (blue line) with an at the same time reduced standard deviation. For roughly 90% of the time, the inclusion of FRR slightly increases the IP, visible by the yellow line that extends slightly above the blue one. On the other hand, the probability of high prices in the range of 120-400 €/MWh is reduced with the two curves inverting their course. Single Pricing average with FRR has therefore fewer price spikes or, put differently, the more liquid FRR product category damps the IPs distribution in the high price range while slightly increasing the overall average price.

In a potential marginal implementation, naturally, FRR can not damp the distribution as the marginal offer of the combination of all product categories counts. However, at the same time, it also adds little to nothing on high price areas but, instead, amplifies the resulting average price with more probability of IPs on middle price areas in the range from 70-270 €/MWh (compare orange dashed line with purple dotted line). Put differently, the addition of FRR in a marginal implementation does not add more high price spikes but raises resulting IPs instead in a medium price range.

Dual Pricing represents in this CDF the distribution of the DAM price in the bidding zone North, as aggravating imbalances are valued at this price (in both, average and marginal implementations). Closely located to that, the Italian iRES compensation scheme (light blue line) shows a very balanced distribution with a quasi-linear and horizontal distribution that follows the DAM in the range of 40-90 €/MWh. Only for a few observations with probabilities of less than 1% prices diverge to more extreme values over 100 €/MWh on the upper side and negative values on the lower side.

On the same note, for the German IP-scheme (black line) negative IPs occur with a cumulative probability of roughly 20%. The negative prices imply that a long BRP with excess energy has to pay for its imbalance and, as the distribution for short BRPs remains the same and only the sign is reversed, a short BRP would receive in the same time a payment for its shortage. While this is somewhat logical for systems that also contain negative prices on the spot market, such as the German one, it is less straightforward for systems where this is not the case, such as the Italian one. Clearly visible is also the jump in price by 40 €/MWh at roughly 0.87 of the cumulative distribution of the German IP-scheme, triggered by the stepwise calculation mode and specifically the price comparison to the spot market price.

To complement the CDF characterization, figure 6.3 illustrates the distribution of IPs in the bidding zone North in 2019 for the second case scenario with a long IP-area and a long BRP. Note that Single Pricing and Dual Pricing overlap in this case scenario for their respective average and marginal implementations. Clearly visible is also here the amplifying effect of marginal implementations. Due to the relatively closer proximity to the market price limit, in this case being the price floor of the Italian DAM and BAM, marginal implementations lead for the case scenario of a consistently long IP-area North in 2019 to the notably increased cumulative probability of IPs with the value of 0 €/MWh of nearly 0.5 for Single and Dual Pricing marginal as well as 0.65 for Single Pricing incl. FRR marginal. In the average implementations, the cumulative probability for the same IP amounts to 0.01 without and basically 0.00 with FRR. Furthermore visible is the original independence of IPs under the Italian iRES compensation scheme and the German IP-scheme from the IP-area's imbalance direction, maintaining the same cumulative distribution of IPs.

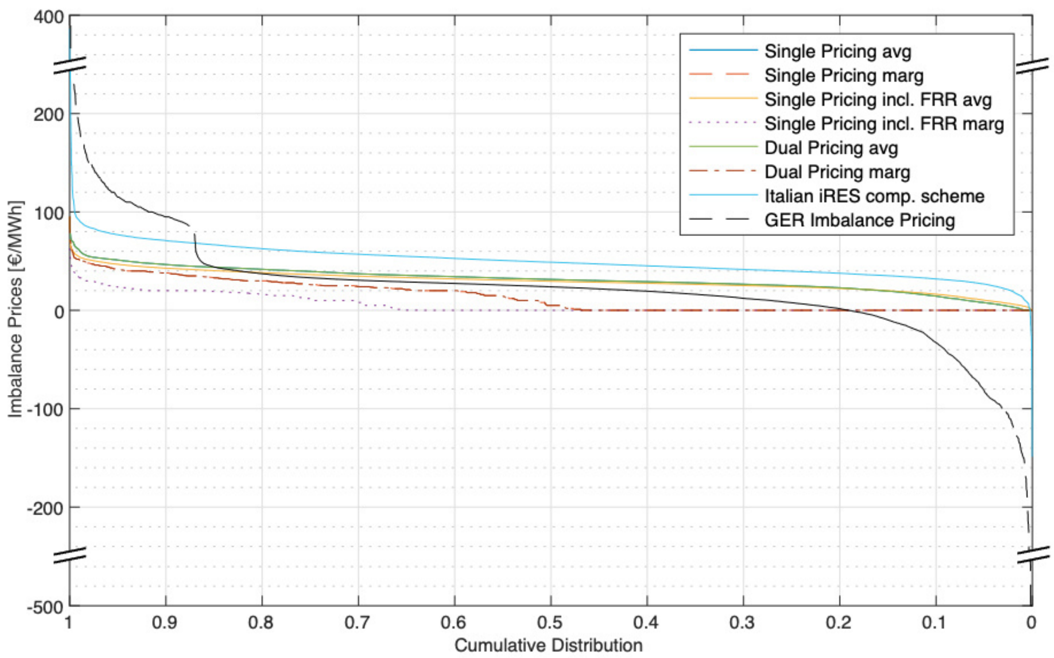


Figure 6.3: Cumulative Distribution Function of compared imbalance pricing schemes for 2019 in the bidding zone North. *Case scenario:* long imbalance price area and long BRP.

The third and fourth case scenario's CDFs are equal to the first two for all Single Pricing schemes (including the German scheme), except that the signs of the prices are reversed. For Dual Pricing, the two case scenarios for short BRPs follow the calculation rule whereas the third case scenario (IP-area long, BRP short) is identical to the second but with negative signs, the fourth instead equals the fourth of Single Pricing, which is the second case scenario of Single Pricing with negative signs. Differences in the Italian iRES compensation scheme's distribution for short BRPs are negligible, and the distribution follows the same shape as for long BRPs.

Interim Takeaways As a first bottom-line recap from the comparison of different IP-schemes, it appears that IPs are generally not evenly balanced. The overall higher price spread from the DAM prices to upward balancing prices than downward balancing prices generates a balancing incentive that would incline BRPs in an equally balanced IP-area to take a long position. Such is somewhat counterbalanced by the overall IP-area inclination to be long, representing however a fundamental distortion of the Italian IP setup.

Comparing average versus marginal price implementations of IP-schemes, it emerges, first of all, that marginal pricing amplifies the IPs in Italy by 50 to 80% depending on the considered product categories. This effect is visible for both upward and downward IPs, with a specifically pronounced impact for times of already lower liquidity (or higher scarcity). In that sense, it appears that marginal pricing does not notably vary prices over the full course of time but is rather limited to certain times in which high prices get even higher. For the case study of the bidding zone North in 2019, the cumulative probability of this effect amounted to around 25%. Therefore, marginal pricing turns out to be a design element with a certain scarcity pricing effect yet leaving the price for the majority of time rather unchanged.

Single Pricing in its envisioned European implementation widens the pool of BAM transactions that count towards imbalance pricing (overall +29% for the Italian bidding zone North) and results in a potential shift of the IP equilibrium. Compared to the current Italian implementation that considers only one product used for balancing and RR, the consideration of FRR results in average pricing implementations in a very moderate IP amplification, damping even high price moments from the other product category. For marginal implementations instead, the amplification is more pronounced and, at least for the Italian data, relates to an IP increase in the medium-price range, triggering overall a slight shift of BRPs incentive to stay less long.

Compared to Single Pricing, Dual Pricing reduces the positive incentives from relieving imbalances while maintaining those for BRPs with aggravating imbalances. Nonetheless, the uneven price-spread of Italian IPs preserves the effect that particularly short BRPs are penalized also under Dual Pricing. The Italian iRES compensation scheme instead reduces not only positive but also negative balancing incentives for all participating plants whose imbalance remains within the predefined tolerance bands. Overall, this results in the most balanced IP-scheme with a price close to DAM price and with a very small standard deviation. This is mainly due to the special feature that its calculation applies somewhat of an integrated portfolio balancing approach, whereas otherwise individual unit balancing responsibility is applied in Italy. The German IP-scheme represents, last but not least, an IP-scheme that applies a consistent cost-neutral approach for the TSO. While resulting in the overall lowest average IP, its multiple correction factors eventually result in a stepwise calculation that partly leads to price jumps and, most notably, implicitly contains negative prices for BRPs' imbalances.

6.4.2 Different Imbalance Price Areas

To analyze the impact of IP-area sizing, the Italian IP-area Macro-South is decomposed in its five bidding zones as local IP-areas. Such is done initially on a static basis, treating each bidding zone as a completely independent IP-area with respective IPs being purely based on accepted BAM offers within the respective bidding zone. Unless otherwise specified, local IP-area from here on always means static local IP-area. In a second step, the bidding zones are dynamically re-connected for IP calculation in the absence of congestion, similar to the Norwegian IP-area-model (see Section 6.3.2 for more information). Such IP-areas are from here on always labeled as dynamic local IP-areas.

Static local IP-areas To demonstrate the effect of a simple, static split of IP-areas, Table 6.8 reports the average IPs and their respective standard deviations under the benchmarking IP-scheme *Single Pricing average* by applying the local bidding zones as static IP-areas compared to the aggregated IP-area Macro-South. The table contains the first two case scenarios for IPs (IP-area long / BRP long and IP-area short / BRP long), the third and fourth case scenario equal the first two with inverted signs. Cell colors express the deviation of individual bidding zone results with local IP-areas from the initial results for the aggregated IP-area.

As might be expected in the implementation with a macro-IP-area, all bidding zones under an aggregated IP-area Macro-South result to have a similar average IP around 23 €/MWh for consistently long IP-areas and around 168 €/MWh for a consistently short IP-area. Small deviations are only based on the influence of zonal DAM prices for the few hours that no BAM offers are present at the macro-zonal level. Such is the case for approximately 2% of the hours in 2019 in the downward direction and 3% in the upward direction.

In the disaggregated implementation with local IP-areas, results differ appreciably for individual bidding zones, and two observations emerge. First, the IP under long IP-areas increases for all bidding zones, although with different intensity from 20-120%. The initially somewhat perplexing fact that prices are rising in all individually considered zones is related to the fact that smaller (local) IP-areas activate less balancing energy than larger (aggregated) IP-areas. As a result, a higher percentage of hours happen without any BAM activation within the IP-area. For Centre-South by itself, this amounts to 22% and for Sicily even to 72% of the hours in 2019 in downward direction. For the implementation of a static split, the calculation of local downward IPs are based on the DAM for a corresponding share of hours, representing one of the limitations of static IP-areas as discussed in Section 6.3.3. Table 6.9 reports

Table 6.8: Comparison of calculated average imbalance prices $\varnothing p_{imb}$ and respective standard deviations $\sigma(p_{imb})$ under Single Pricing average in 2019 for the bidding zones of the imbalance price area Macro-South with aggregated and disaggregated imbalance price areas.

	Imbalance price area:			Centre-North	Centre-South	Sardinia	Sicily	South
Area + BRP +	*(Aggregated) Macro-South*	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	23.54	23.58	23.43	23.61	23.36
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	15.61	15.68	15.75	17.12	15.73
	Local bidding zone	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	40.59 (+72%)	28.53 (+21%)	45.25 (+93%)	51.72 (+119%)	37.38 (+60%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	17.69 (+13%)	19.13 (+22%)	17.47 (+11%)	30.91 (+81%)	17.83 (+13%)
Area - BRP +	*(Aggregated) Macro-South*	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	167.77	167.71	167.70	169.55	167.63
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	125.69	125.74	125.74	124.69	125.82
	Local bidding zone	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	63.54 (-62%)	191.21 (+14%)	65.42 (-61%)	94.08 (-45%)	93.12 (-44%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	37.96 (-70%)	177.23 (+41%)	31.62 (-75%)	52.47 (-58%)	92.36 (-27%)

Note: *Percentages describe the deviations of disaggreagted imbalance price areas from the results for aggregated ones. Cell colors relate to percentages for enhanced comparability.*

Table 6.9: Percentage of hours for which no balancing energy has been activated $\%_{noBAM}$ in upward and downward direction for the two product categories FRR and OS in 2019.

		North	Macro-South	Centre-North	Centre-South	Sardinia	Sicily	South
no $BAM_{FRR}\downarrow$	[%]	6%	9%	38%	45%	97%	67%	49%
no $BAM_{FRR}\uparrow$	[%]	21%	22%	47%	54%	98%	74%	37%
no $BAM_{FRR}\downarrow\uparrow$	[%]	0%	4%	34%	42%	95%	64%	33%
no $BAM_{OS}\downarrow$	[%]	1%	2%	49%	22%	66%	72%	40%
no $BAM_{OS}\uparrow$	[%]	4%	3%	71%	35%	72%	53%	36%
no $BAM_{OS}\downarrow\uparrow$	[%]	0%	0%	42%	10%	48%	40%	20%
no $BAM_{OS,FRR}\downarrow\uparrow$	[%]	0%	0%	18%	5%	47%	26%	9%

the percentages of hours for which no upward or downward balancing activation is registered for the different bidding zones of Macro-South on the BAM. In the second place, besides the effect of the absence of BAM offers, the differences in the intensity of IPs relate to varying average prices of activated balancing energy in the individual bidding zones. These are reported in Table 3.4. The lowest average price in the southern bidding zones is thereby noted for Centre-South with 22.25 €/MWh, whereas the highest is registered for Sardinia with 37.51 €/MWh.

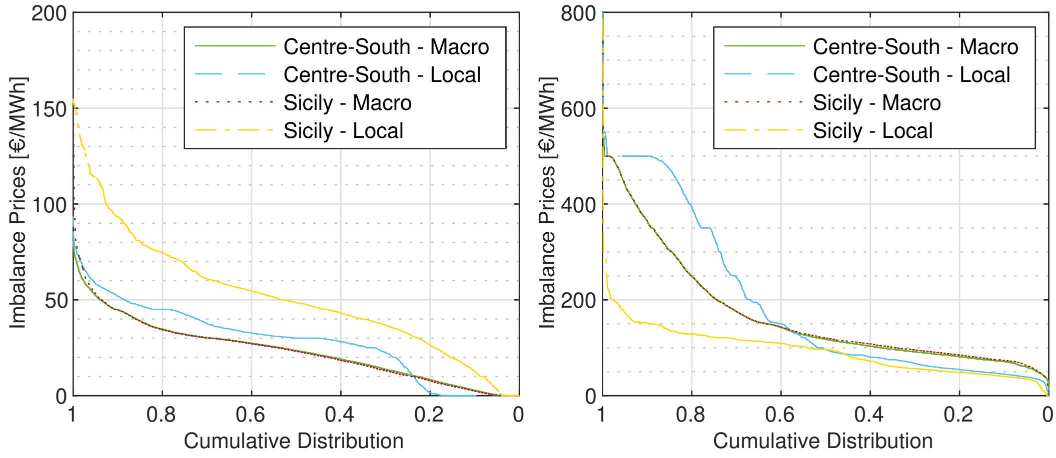
The second significant observation of local IP-areas concerns the IPs under short IP-areas. The prices decrease for all bidding zones by roughly 40-60% except for the bidding zone Centre-South where the average IP increases by 14%. The decrease for the majority of local IP-areas is, on the one hand, related to lower individual average BAM prices for upward balancing than for the aggregated macro-zone (e.g., 132.43 €/MWh in Sicily versus 171.11 €/MWh in Macro-South, see 3.4 for all other zones). On the other hand, this decrease relates as before also to an increased number of hours for which no (upward) balancing energy has been activated within the respective zones, resulting to be for example 53% for Sicily. The reason for the increase of the IP in Centre-South, in contrast, is purely related to the significantly higher upward balancing prices in this bidding zone, being with 226.32 €/MWh on average more than 100 €/MWh more expensive than the second most expensive bidding zone Sicily. This massively increased BAM prices also outweigh the effect of hours for which no BAM offers in upward direction are accepted, still summing up to 35% in 2019 for Centre-South.

More pronounced prices together with potentially higher price volatility as for a short IP-area Centre-South are thereby an expression of the natural downside of small IP-areas (as long as they are static): a smaller (and less liquid) market area from which activated resources count towards the IP calculation, which can result in more extreme prices for local BRPs. Larger, aggregated IP-areas instead base their price on a wider pool of balancing transactions and spread the risk of individually accepted high price offers over a larger group of overall accepted offers and eventually over a larger group of BRPs that share the resulting costs (or revenues). However, it should be noted that the emerging prices in this analysis are based on actually accepted offers in Centre-South despite being aggregated to the Macro-South IP-area. In that sense, these resources were apparently required by the system at this precise location, although neighboring bidding zones might have offered balancing resources at lower prices. Decomposing the IP-area Macro-South into smaller IP-areas would thereby unveil the otherwise hidden balancing costs at this location and provide a respectively strong price incentive for local BRPs to reduce the imbalance.

The resulting IPOs for BRPs shift along with the change of IPs from aggregated to static local IP-areas. Following the exemplary calculation approach of Figure 6.1 for Sicily in 2019 with an average zonal DAM price of 62.77 €/MWh, a long BRP in this bidding zone would lose on average 39.16 €/MWh if the aggregated Macro-South IP-area would always be long or gain on average 106.78 €/MWh if the same IP-area would always be short. Assuming again that the imbalance sign of IP-area would eventually be balanced, the remaining pay-off for a positive imbalance (i.e., a long position) in this constellation is a notable gain of 33.81 €/MWh. Instead, if the macro IP-area would be split in static IP-areas at bidding zone level, for a long BRP the loss in an always long IP-area Sicily would reduce to 11.05 €/MWh and the gain in an always short Sicilian IP-area would drop to 31.31 €/MWh. Assuming again that the local IP-area would eventually be half of the time long and half of the time short, the overall IPO of an always long BRP would change to a reduced gain of 10.13 €/MWh. The split of the aggregated IP-area Macro-South in static, local IP-areas would hence imply a significantly changed balancing incentive for the bidding zone Sicily, resulting comparably less inclined towards a long position. Similar calculations for the impact of IP-area sizing changes on BRPs IPOs in other bidding zones lead to similar results. Only for Centre-South, with its further increasing IP under a short IP-area, the overall IPO for an always long BRP develops in the opposite direction from a gain of 43.36 €/MWh to a gain of 57.59 €/MWh.

To complement the analysis of the impact of IP-area sizing, Figure 6.4 illustrates the corresponding CDFs of Single Pricing average IPs in the two exemplary bidding zones, Centre-South and Sicily. The green and red lines represent the CDFs for the two bidding zones under the common, aggregated IP-area Macro-South, whereas the blue and yellow lines represent the CDFs for the individual bidding zones as local IP-areas, respectively.

For the case scenario of consistently long IP-areas (sub-figure (a)), the resulting IP distribution functions for local IP-areas differ from the curve of the joint macro-IP-area for the entire observation period. For both zones, the average price increases as shown by the enlarged area under the two curves compared to the overlapping curves of the macro-IP-area. Centre-South basis the overall IP increase in its local treatment on raised probabilities for prices above 10 €/MWh despite exhibiting a cumulative probability of 20% for IPs of 0 €/MWh. Sicily, on the other hand, has in its local implementation generally increased IPs and reports a maximum IP of 153 €/MWh. The presence of remarkably high prices, resulting in a cumulative probability of 20% above 75 €/MWh and of 10% above the highest IP of Centre-South with 94 €/MWh, is thereby the result of an exceptionally high local DAM price in Sicily that enables for some hours also exceptionally high down-



(a) Area + / BRP + **(b)** Area - / BRP +

Figure 6.4: Cumulative Distribution Functions of imbalance prices in the bidding zones Centre-South and Sicily with the imbalance price area being either the aggregated area Macro-South or the local bidding zone. *Case scenarios:* Single Pricing average in 2019 with (a) a long imbalance price area and a long BRP and (b) a short imbalance price area and a long BRP.

ward balancing prices. The combination of both gives finally reason to the overall highest average IP among local IP-areas in this direction.

Focusing on the case scenario with a short IP-area (sub-figure (b)), the two local implementations share a relatively common price distribution up to approximately 100 €/MWh, accumulating a probability of roughly 50% for both local IP-areas, For prices above this value, the macro-IP-area disaggregation also disaggregates the two CDFs. Whereas the potential IP in a local Sicilian IP-area is characterized by low prices that remain overall below 200 €/MWh for 98% of the time, Centre-South demonstrates a cumulative probability for IPs above 200 €/MWh of 0.3 and for approximately 10% of the time the price reaches even the mark of 500 €/MWh.

The split of the aggregated IP-area varies thereby not only the average IP to send different locational balance incentives but also decouples the IP risk for BRPs in the individual bidding zones. For Sicily, the risk of high prices is evenly distributed with a comparably linear distribution of IPs, whereas for Centre-South, the risk of high prices is rather unevenly distributed with a significantly increased probability of prices for half of the time. This becomes especially relevant if BRPs have unevenly distributed abilities to forecast zonal imbalances, favoring (the usually larger incumbent) BRPs that dispose of this ability and hence can protect themselves or even leverage the high prices accordingly.

The impact of smaller IP-area sizing can be interpreted in two ways. If one assumes that BRPs actively respond to IPs (i.e., deviate strategically or, said differently, balance passively), one perspective is that the decomposition of large IP-areas shifts incentives for BRPs and provides a locational incentive to better balance portfolios or individual units in areas where the electricity system faces high balancing prices, such as in Centre-South. The diverging local IPs would generate an even stronger incentive for BRPs in this bidding zone to stay long and allow the system accordingly to require less activation of upward balancing energy. At the same time, the very same split of IP-areas would reduce the potential incentive for local BRPs in Sicily to deviate accordingly. The aggregated IP-area Macro-South mixes these two incentives and results overall in a mid-level incentive.

The other perspective is that if the IP is not a price to leverage on but a cost to potentially pay, i.e., if it is not an incentive to deviate strategically (also as BRPs are not allowed to do so), then the aggregation or disaggregation of IP-areas exposes BRPs to different IP risks. By aggregating all BRPs in one macro-zone, all BRPs are exposed to the same price risk. BRPs in Sicily are thereby somewhat penalized by being exposed to higher prices than their actual bidding zone would generate individually. BRPs in Centre-South, on the contrary, are somewhat advantaged since part of their individual bidding zone risk is redistributed to BRPs from other zones.

A major weakness of static local IP-areas remain the increased percentage of hours in which no BAM transaction are registered that influence the IP, and the latter would be based instead on the DAM price. For Sicily, the percentage of hours in which in 2019 no BAM transaction for the currently used balancing product category was registered, neither in upward nor downward direction, amounts for example to 40%. Two potential measures could counteract this weakness. On the one hand, the consideration of FRR as a second product category for IP calculation would provide additional BAM transactions that count towards the IP and, for the example of Sicily, reduce the percentage of DAM-based IPs to 26%. Another potential measure could be the introduction of an alternative IP calculation for these hours based on the value of avoided activation of balancing energy (as envisioned by the EB GL). However, such calculation methodology does not yet exist in Italy and would require additional implementation effort[10].

Dynamic local IP-areas Extending the case scenario of local IP-area sizing by dynamic local IP-areas finally applies a somewhat hybrid scheme that, by default,

[10] Given the quasi non-existence of hours without any activated balancing offers in the macro-zones, the implementation of such is currently also of little relevance in Italy. For potential local zones, however, the situation is different. See Table 6.9 for a detailed breakdown.

tackles some of the limitations of static zones such as cross-zonal balancing activation and the related excessive influence of the DAM price on IPs. For the bidding zone Sicily, as a particularly small and poorly connected bidding zone in Italy, the hours in which the bidding zones connection to other Italian bidding zones resulted congested (with regard to the DAM clearing) summed up to 3,967 hours in 2019, equivalent to roughly 45% of the time. At the same time, the small size of the zone in combination with effectively occurring cross-zonal balancing activation limits the share of hours in which locally accepted BAM offers exist and hence can serve as the basis for IP calculations. For the local bidding zone, these hours sum up to only 28% of time in downward direction and 47% in upward direction. Said differently, the static IP-area Sicily would base its IP for 72% on the DAM price if it would be consistently long and for 53% if consistently short. This represents a significant weakening of the potential balancing incentive for local BRPs.

Dynamic IP-area sizing counteracts this by extending the IP-area to one or more contiguous bidding zones for 55% of the time in 2019. For 3,292 hours or roughly 38% of the time in 2019 no congestion at all is registered in the entire area of Macro-South and the dynamic IP-area sizing expands therefore to the full aggregated area. Figure 6.5 provides a schematic representation of the dynamic IP-area sizing from the perspective of the bidding zone Sicily. Percentages represent the share of hours in which no congestion occurs from Sicily until the respective bidding zone, and the dynamic IP-area would be extended to this point. The share of hours in which the IP would merely be based on the DAM reduces along with that to 35% in downward direction and to 24% in upward direction. Compared to static sizing, dynamic IP-area sizing maintains thereby a significantly stronger, BAM-based balancing incentive for BRPs.

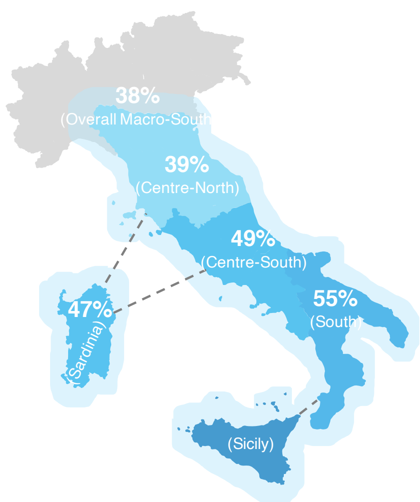
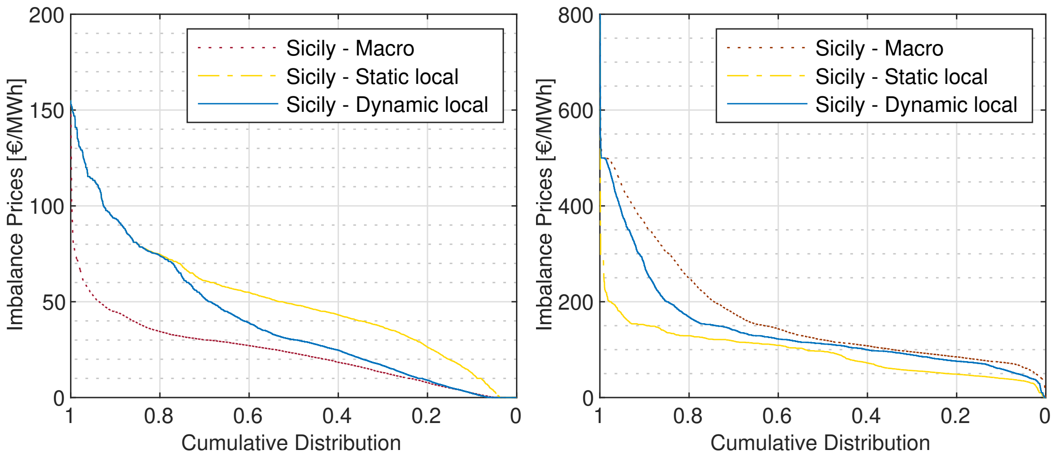


Figure 6.5: Schematic representation of the extension of the dynamic imbalance price area sizing in terms of time from the perspective of the bidding zone Sicily.

The IP distribution for a dynamic local IP-area appears thereby as a hybrid between the aggregated macro-IP-area and the static local IP-area. Figure 6.6 illustrates the CDFs of IPs in the bidding zone Sicily for the three compared IP-area sizing options: the aggregated IP-area Macro-South (dotted red line) as well as the bidding zone Sicily as a static local IP-area (dashed yellow line) and a dynamic local IP-area (full blue line).



(a) Area + / BRP +   (b) Area - / BRP +

Figure 6.6: Cumulative Distribution Functions of imbalance prices in the bidding zone Sicily with the imbalance price area being the aggregated area Macro-South, the static local bidding zone or the local bidding zone dynamically connected with other bidding zones in absence of congestion. *Case scenarios:* Single Pricing average in 2019 with (a) a long imbalance price area and a long BRP and (b) a short imbalance price area and a long BRP.

For the case of a consistently long IP-area (sub-figure (a)), the probability of IPs in the high-price range above 70 €/MWh resembles for the dynamic and static IP-areas; below that, the price distribution of the dynamic zone approaches that of the macro zone. For the case of a consistently short IP-area (sub-figure (b)), the CDF of the dynamic local IP-area follows the distribution of the macro IP-area in the lower price range before separating somewhat more clearly from 120 €/MWh onward, following then a middling price distribution between the ones of the macro and the static local IP-area.

As mentioned before, the dynamic coupling to other zones prevents a larger impact of the DAM price compared to the static implementation. This is visible in the CDF diagrams by the reduced probability of IPs in the range around 40-50 €/MWh[11]. While the DAM price in Sicily is basically on average close to

[11] For the consistently long IP-area in sub-figure (a) it might appear on the first sight that cumulative probability of prices in the range of 40-50 €/MWh would be increased for the dynamic implementation compared to the static one. Note though that the cumulative probability for this price range is

63 €/MWh, this differs considerably for periods with and without congestion. Considering only the congested hours, the price reaches on average 82 €/MWh, while for hours without congestion it is 47 €/MWh. Precisely this price range around the DAM price in non-congested hours is replaced in the dynamic implementation by BAM prices from other bidding zones.

On the other hand, the coupling with other bidding zones increases the number of available BAM transactions for IP calculations even in the hours when BAM offers were accepted in Sicily itself. Given the on average lower BAM downward prices and higher upward prices of other bidding zones, the impact of the other zones BAM offers translates in the presented case study in a respectively shifted price distribution. Compared to static sizing, the probability for very low prices increases for a consistently long IP-area Sicily under dynamic sizing, and the probability for comparably high prices for the case of a consistently short IP-area Sicily increases.

Nonetheless, some specific local effects remain also by applying dynamic IP-area sizing. The most prominent example is the occurrence of IPs above 70 €/MWh with a cumulative probability of 20% for a consistently long IP-area Sicily (sub-figure (a)). The overlapping CDFs of static and dynamic IP-area sizing point to the fact that these prices are apparently not influenced by the neighboring bidding zones of Sicily. This might either be the case because Sicily is dominating the IP for these hours on the extended local IP-area (improbable for an IP-scheme with average implementation, more probable for marginal implementations) or because these IPs occur in hours where the connection to other zones is congested and dynamic IP-area sizing does hence not influence. In both cases, the prices reflect a specific, local need of the Sicilian bidding zone and represent hence also a valuable locational price signal. Finally, Table 6.10 summarizes the overall average IPs in Sicily under the three IP-area sizings, once again underlining the hybrid outcome of a dynamic implementation.

Interim Takeaways All in all, aggregated macro-zones as IP-areas result little efficient as they dilute specific local incentives from individual bidding zones and expose BRPs from unaffected bidding zones in return to unnecessary high price risks. Bidding zones as static local IP-areas are better in this respect as they generate more accurate local price signals and are also comparably easy to implement. Two negative aspects remain, however. On the one hand, small zones have by default less balancing market transactions and potentially result in an increased number of hours

the difference of the two individual cumulative probabilities, i.e., for the dynamic implementation approximately 0.7-0.6 = 0.1 and for the static implementation 0.55-0.35 = 0.2. The cumulative probability of IPs in the price range from 40-50 €/MWh is therewith twice as high for the static implementation than for the dynamic implementation.

Table 6.10: Comparison of average imbalance prices $\varnothing p_{imb}$ and respective standard deviations $\sigma(p_{imb})$ under Single Pricing average for the bidding zone Sicily with an aggregated, statically disaggregated and dynamically disaggregated imbalance price area.

			Sicily		
			Aggregated - Macro-South	*Static* - local bidding zone	*Dynamic* - local bidding zone
Area + BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	23.61	51.72 (+119%)	40.64 (+72%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	17.12	30.91 (+81%)	35.46 (+107%)
Area - BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	169.55	94.08 (- 45%)	140.14 (- 17%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	124.69	52.47 (- 58%)	102.95 (- 17%)

Percentages describe the deviations of results for local IP-areas compared to the aggregated IP-area. Cell colors relate to percentages for increased comparability.

the IP would be based only on the DAM and result in a comparably reduced balancing incentive. The introduction of an alternative IP calculation for these hours based on the value of avoided activation of balancing energy could remedy the weakness, as well as in the Italian case the consideration of FRR as a second product category for IP calculation. A proposed Key Performance Indicator (KPI) to evaluate the adequateness of static zones to this regard would hence be the percentage of hours for which no balancing market transactions are registered in upward and downward direction at the local IP-area level. The second potential issue of static local IP-areas concerns cross-zonal activation of balancing services (assuming that the system's operation continues to take place at a higher macro-level). Such activations would then be misallocated to the IP calculation in the zone of activation instead of the potential other zone(s) that actually caused the activation. Activation tags that specify the allocation of each BAM transaction could remedy this issue, though a possible introduction of such seems unlikely given the difficulties with BAM transparency that already exist today (see public data limitations in Section 6.3.3 for example).

Dynamic IP-area sizing counteracts both limitations of static IP-area sizing instead by extending the IP-area to one or more contiguous bidding zones as long as the connection remains unobstructed. The percentage of hours without balancing market integration reduces thereby for the case-study of Sicily in 2019 by about half and, compared to static sizing, dynamic IP-area sizing maintains thereby a significantly stronger, balancing market-based, price incentive for BRPs. The price distribution results eventually somewhat hybrid between the one of the aggregated macro-zonal and the static local implementation. A negative aspect of dynamic IP-area sizing is the potentially more complex implementation with a less straightforward calculation methodology. On the other hand, such might be somewhat beneficial as one of the major reasons behind the Italian aggregation approach was limiting the zonal imbalance sign predictability and reducing BRP arbitrage opportunities, respectively. At the same time, dynamic sizing would be in sync with the effective system operation and set (passive) balancing incentives most in line with actual (active) balancing activation, making it therefore eventually the preferable IP-area sizing scheme.

6.4.3 From Imbalance Prices to Imbalance Fees

To illustrate the practical implications of IPs on iRES and their system integration, this case study moves on to analyze the passage from IPs to IFs for two exemplary iRES plants.

iRES operational parameters Figure 6.7 illustrates exemplarily the distribution of hourly IPs (sub-figure (b)) that a consistently long or short unit would actually face in Sicily under *Dual Pricing marginal* in 2019 by incorporating the (macro-)zonal imbalance direction of the bidding zone. Combining this then with the hourly distribution of the forecast error of a 10 MW PV plant (sub-figure (a)) or a 10 MW Wind plant (sub-figure (c)) results in the actual hourly IFs as illustrated by the sub-figures (d) and (e) respectively. Negative IFs imply thereby a cost, i.e., a payment from the iRES unit (or its BRP) to the system operator, and a positive IF implies an income, i.e., a payment from the system operator to the iRES unit.

The annual IFs for a 10 MW PV plant in Sicily that emerge from this case-study sum up to -53,447 € in 2019, if Dual Pricing marginal would apply. With the summed (absolute) day-ahead forecast error of 1,648 MWh, the resulting overall average IP that the PV plant actually faces per MWh of imbalance amounts to -32.43 €/MWh_{imb} under Dual Pricing marginal. For better comparability to literature data, the annual IFs are also related to the annually generated electricity of the plant. According to TSO data, a 10 MW PV plant in Sicily effectively generated on average 10,392 MWh of electricity in 2019, resulting in a relative IF of -5.14 €/MWh_{gen}.

For a 10 MW Wind plant instead, the annual IFs amount to -157,940 € under the same IP-scheme. With the summed absolute forecast error of 3,451 MWh, the resulting overall average IP that the wind plant actually faces under Dual Pricing marginal amounts to -45.77 €/MWh_{imb}. In this case, the annual IFs compare to an average of 17,507 MWh of effectively generated electricity and results in a relative IF of -9.02 €/MWh_{gen}. While the overall average forecast errors are comparably well-balanced and nearly cancel out for both the PV and Wind plant (+0.055 MWh and +0.062 MWh, respectively), the two relative IFs differ on

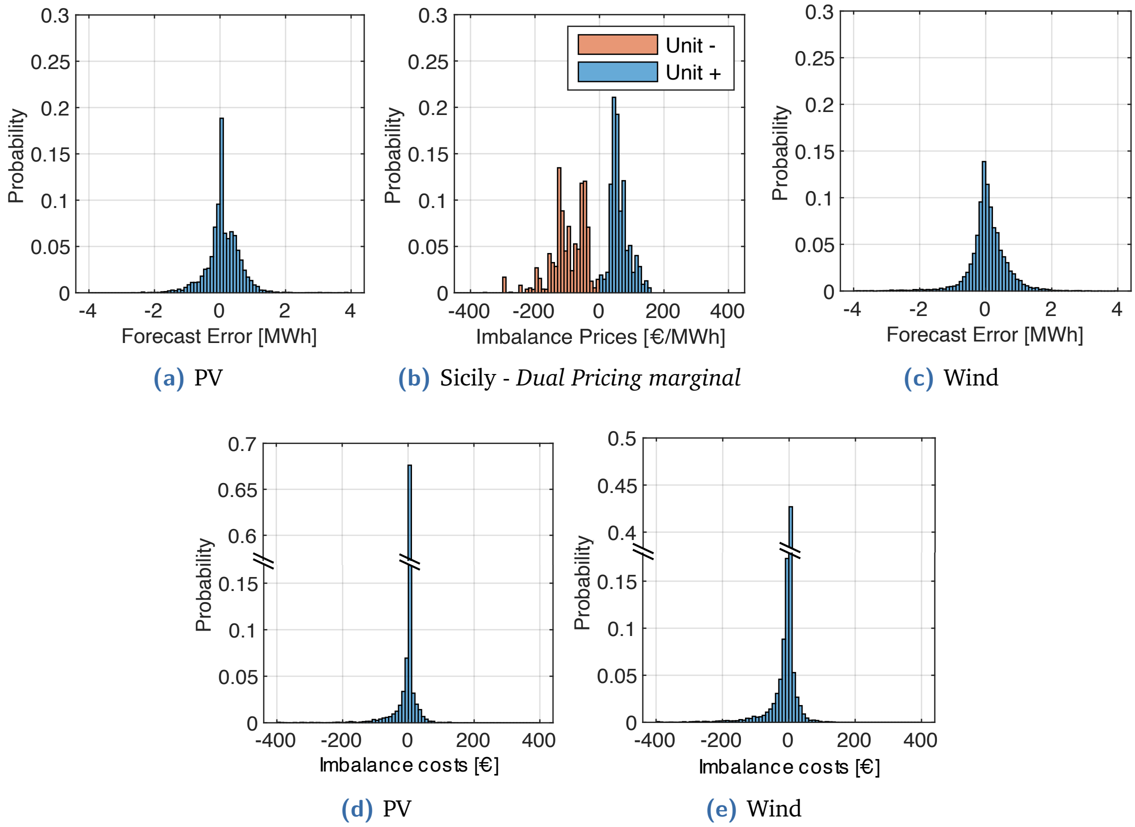
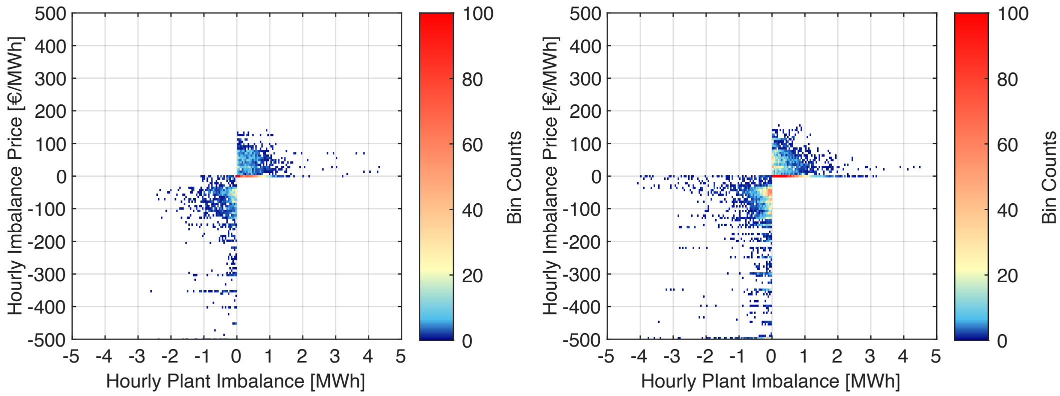


Figure 6.7: Probability distributions of the (a) hourly forecast errors for a 10 MW PV plant and (c) hourly forecast errors for a 10 MW Wind plant, which, in combination with the (b) hourly imbalance prices in the bidding zone Sicily, lead to corresponding (d) hourly imbalance fees for the PV plant and (e) hourly imbalance fees for the Wind plant. *Case scenario:* Dual Pricing marginal in the imbalance price area Macro-South in 2019.

the one hand due to different magnitudes of the forecast errors with absolute average hourly forecast errors of 0.198 MWh and 0.394 MWh, respectively. However, this is only one of two distinguishing features.

Imbalance prices for Wind and Solar A second relevant point represents the fact that PV and Wind imbalances occur in different hours and encounter different IPs, respectively. Figure 6.8 displays the observed IPs in relation to individual plant imbalances (i.e., forecast errors) under Dual Pricing marginal. As it emerges, the Wind plant demonstrates not only a wider dispersion of positive and negative imbalances errors, but also encounters more often extreme prices. Given the characteristics of Dual Pricing, this results in especially high negative prices for negative plant imbalances.

Different IP-schemes naturally lead to different price distributions and intensities (and not only to different average prices) that are encountered even if the plant's



(a) 10 MW PV plant **(b)** 10 MW Wind plant

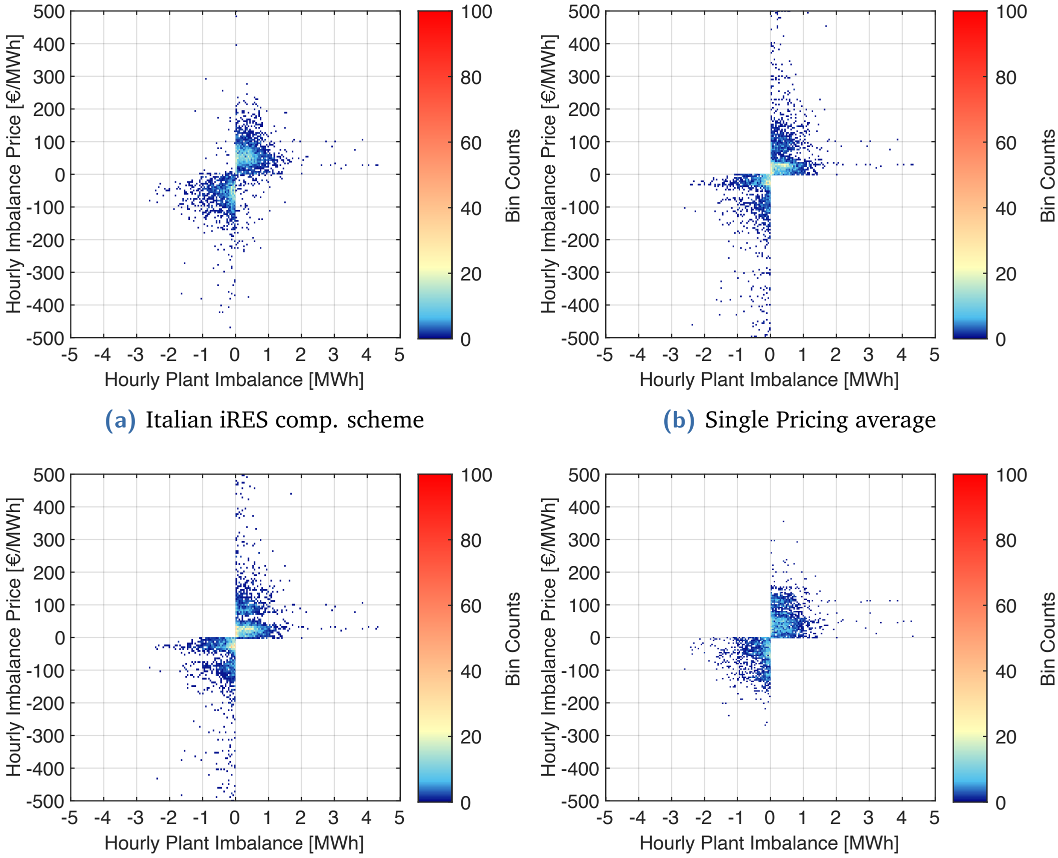
Figure 6.8: Hourly imbalance prices versus hourly plant imbalances for a representative 10 MW PV plant and a representative 10 MW Wind plant in the bidding zone Sicily. *Case scenario:* Dual Pricing marginal in the imbalance price area Macro-South in 2019 .

imbalance remains the same, as further illustrated by Figure 6.9 for the PV plant under different IP-schemes. The corresponding figures for the Wind plant are reported in Figure B.3 in the Appendix.

Other than Dual Pricing, *Single Pricing* schemes lead inherently to a more balanced distribution of price-imbalance observations. Although the empirical distribution is not entirely symmetric due to uneven forecast errors and zonal imbalances, high positive prices are roughly as often encountered as high negative prices. However, the gravity center of observations is clearly located in low price ranges, e.g., for Singly Pricing average between 10-40 €/MWh (see sub-figure (b)).

Integrating *FRR* into the IP-scheme enlarges the pool of BAM transactions on which the final IP is based. As noted previously, FRR has a different market equilibrium than the other Italian balancing product OS. By slightly increasing the overall BAM price for upward balancing and slightly reducing the price for downward balancing, the consideration of FRR eventually results in a slightly more pronounced cut between the two observation clouds of 0-60 €/MWh and observations in the range of 80 €/MWh and above (see sub-figure (c)). The latter observation cloud is thereby dominated by IPs that are based on upward balancing transactions, the first observation cloud instead is dominated by IPs that are based on downward balancing transactions or the DAM price in case no BAM transaction has been registered.

Most interestingly, the same IP-scheme in combination with the (static) *local IP-area* Sicily instead of the aggregated IP-area Macro-South leads to a significantly more compact price distribution that the iRES unit encounters during the case-study period (see sub-figure (d)). This is mainly attributed to the fact that high-price-observations



(a) Italian iRES comp. scheme

(b) Single Pricing average

(c) Single Pricing incl. FRR average

(d) Single Pricing incl. FRR average - *local IP-area*

Figure 6.9: Hourly imbalance prices versus hourly plant imbalances under different imbalance pricing schemes for a representative 10 MW PV plant in the bidding zone Sicily. *Case scenario:* 2019 with (a) to (c) Macro-South as the underlying aggregated imbalance price area and (d) Sicily as the local imbalance price area.

in the aggregated IP-area version relate to other bidding zones, specifically the bidding zone Centre-South (see Chapter 6.4.2 for more details). From a Sicilian point of view, the IP-area aggregation does hence not balance IPs but intensifies them. By separating the IP-areas, these high-price outliers are removed for plants in Sicily, and the overall price distribution becomes more compact. At the same time, the gravity center of price observations slightly expands from the previous range of 20-40 €/MWh and distributes now across the range of 10-70 €/MWh.

The Italian *iRES compensation scheme* leads to a similarly compact distribution of encountered prices. Notable however, it also contains negative prices for individual positive plant imbalances and, in a few cases, positive prices for negative imbalances (see sub-figure (a)).

Overall, the intensity and distribution of IPs relate to the encountered price risk. The shape of the observation clouds in Figure 6.9 can be interpreted therefore as a graphical measure for BRPs' IP risk exposure. The more compact the observation clouds, the more contained is the risk and the easier it is estimable or manageable from a BRP's point of view. The more balanced the observation cloud in positive and negative price direction, the more balanced are the incentives for a BRP to take a pro-active position in passively balancing the system. Different IP-schemes naturally lead to different price distributions and intensities (and not only to different average prices) that are encountered even if the plant's imbalance remains the same, as further illustrated by Figure 6.9 for the PV plant under different IP-schemes.

Imbalance fees for Wind and Solar Finally, the resulting relative IFs of the compared IP-schemes for both the PV plant as well as the Wind plant are summarized in Table 6.11. The first observation that attracts attention is that wind turbines seem to face fundamentally more punitive (i.e., more negative) IFs. As noted previously, one reason for this is the twice as high average forecast error of Wind. More importantly, it manifests though that the Wind plant faces more penalizing IPs. Such is especially visible under Single Pricing where the PV obtains overall an on average positive IF whereas the Wind plant faces overall an on average negative IF. Why the Wind plant faces more penalizing IPs remains thereby subject to further investigation. Potential explanations for this phenomenon might be that imbalances from Wind are more often aggravating to the system's imbalance direction than PV imbalances or happen in less opportune hours with higher system balancing prices. However, these are only hypotheses that require further in-depth analyses.

Table 6.11: Comparison of relative imbalance fees per generated MWh $\varnothing P_{Imb}$ for a 10 MW PV plant and a 10 MW wind plant under different imbalance pricing schemes. *Case scenario:* 2019 in bidding zone Sicily.

			Dual Pricing marginal	**Italian iRES comp. scheme**	**Single Pricing** average	**Single Pricing incl. FRR** average	**Single Pricing incl. FRR** average *local IP-area*
PV	$\varnothing P_{Imb,PV}$	$[\frac{€}{MWh_{gen}}]$	- 5.14	1.91	1.31	1.42	2.36
Wind	$\varnothing P_{Imb,Wind}$	$[\frac{€}{MWh_{gen}}]$	- 9.02	0.36	- 0.58	- 0.53	0.66

Comparing the resulting average IF across the different IP-schemes, it emerges that the results deviate notably for the different IP-schemes with a trend of most negative to most positive costs going from the current "worst-case" scenario for an Italian BRP to the desired future scenario of European regulation. *Dual Pricing marginal* results as the only IP-scheme in negative average IFs for both PV and wind. *Single Pricing average* implies already a clearly positive IF for PV and a significantly less negative IF for Wind. Taking into consideration also FRR in this scheme shifts the IFs towards slightly further positive values, and the application of a local IP-area instead of the aggregated zone Macro-South culminates in a positive IF of 2.36 €/MWh_{gen} for a PV plant and 0.66 €/MWh_{gen} for a wind plant.

Literature findings in comparison estimate IFs for Wind and PV in model-based studies in the range of -6 to 0 €/MWh_{gen} [7]. Empirical studies instead report for the most part a wider range from -13 to 0 €/MWh_{gen} [268, 270, 300]. More specifically, the European Wind Energy Association (EWEA) reports IFs in a range of -4 to -1 €/MWh_{gen} for wind power in Italy in 2015 [301]. At that time, imbalances of Italian iRES plants were evaluated through a Single Pricing average scheme. Pierro et al. [293] find that a PV unit in Italy would have faced in 2015 average IFs in the range of -5 to +5 k€/MWp depending on the geographic location of the plants. By applying the average annual generation from this analysis, this translates to an IF range of -4.8 to +4 €/MWh_{gen}. Moreover, Antonanzas et al. [302] find that a PV unit on the Iberian market under Dual Pricing average -3.3 to -2.6 k€/MWp, translating to -3.2 to -2.5 €/MWh_{gen}.

The prices found in this study are consistent with the literature values in that dual pricing leads to consistently negative values and wind plants being exposed in general to a larger extent to negative IPs and respective IFs.

Imbalance pay-offs for Wind and Solar Especially from the perspective of conscious BRP's imbalances (as the concept of passive balancing implies), IFs alone do not capture the full picture yet. With a positive average forecast error, the plant would have on average a long spot market position. Therefore, the final pay-offs from imbalance result in -76,544 € as the sum of the aforementioned IFs minus another 23,097 € from foregone DAM sales. To set the resulting IPOs into context, the overall revenue the plants could generate if selling their generation without imbalances on the DAM amount to 574,890 € for the PV plant and 964,920 € for the Wind plant. Overall, the relative pay-offs for imbalances of the PV plant in Sicily under Dual Pricing marginal result to -7.37 €/MWh_{gen}. Table 6.12 reports the resulting average IPOs of the different IP-schemes for both the PV plant as well as the Wind plant.

Basically for all compared IP-schemes and for both PV and Wind, the resulting pay-offs from imbalance show negative values, indicating an overall financial loss for respective BRPs caused by the imbalances. Only for *Single Pricing incl. FRR average* in combination with the bidding zone Sicily as the local IP-area, the value remains just positive for a PV plant.

Table 6.12: Comparison of relative pay-offs from imbalance per generated MWh $\varnothing P_{IPO}$ for a 10 MW PV plant and a 10 MW wind plant under different imbalance pricing schemes. *Case scenario:* 2019 in bidding zone Sicily.

			Dual Pricing marginal	**Italian iRES comp. scheme**	**Single Pricing** average	**Single Pricing incl. FRR** average	**Single Pricing incl. FRR** average *local IP-area*
PV	$\varnothing P_{IPO,PV}$	$[\frac{€}{MWh_{gen}}]$	- 7.37	- 0.31	- 0.91	- 0.81	0.13
Wind	$\varnothing P_{IPO,Wind}$	$[\frac{€}{MWh_{gen}}]$	- 11.33	- 1.95	- 2.89	- 2.84	- 1.65

At first glance, the negative pay-offs may seem surprising, given both plants' overall slightly positive forecast error that leads on average to a long market position, which emerged from the previous case-study section as desirable for the southern bidding zones. However, this was only true under the premise that the IP-area would be long for half of the time and short for the other half of the time. For the studied period 2019, Macro-South is on the contrary for more than 70% of the time long[12]. The predominant inclination of the IP-area to be long counterbalances thereby the incentives from long and short BRPs' IP differences, and effectively causes the pay-offs to turn negative.

Relative (im-)balance impact on iRES income Comparing the average pay-offs from imbalances in a last step to the overall iRES revenues describes the order of magnitude of the impact that imbalances effectively have on BRPs (or plant owners) business case. Assuming that the iRES plants do not receive any subsidy like fixed feed-in tariffs but purely sell their generated energy on the DAM, the respective average sales prices that the PV and Wind plant face throughout their generation in 2019 are 55.32 €/MWh and 55.12 €/MWh, respectively. The impact that IPOs under different IP-schemes develop varies therefore from a revenue reduction of -13% and -21% for *Dual Pricing marginal* to -2% and -5% for *Single Pricing average* and eventually a +-0% -3% for the dedicated *iRES compensation scheme* for a PV and Wind plant, respectively. This strong diversion from basically no impact to strongly significant negative impacts clearly underlines the significance of an adequate IP-scheme for iRES to steer their further system integration.

Interim Takeaways In summary, as it emerged from this analysis, different IP-schemes translate into different IFs that iRES units have to face and eventually result as well in similarly different IPOs. To evaluate the intensity of the different schemes and their impact on individual iRES units' welfare, two values have to be distinguished.

[12]Why the zone has an inclination towards been long remains as previously for the other macro-zone North uncertain and subject to further investigation.

If the forecast error of the iRES units is considered to be inherent and given, i.e., not subject to financial optimization, the unit of analysis are the resulting imbalance fees. Confronting under this premise the impact of different IP-schemes, it emerges from the case-study calculations that Dual Pricing generally results in consistently negative IFs. Instead, Single Pricing has a less detrimental welfare effect for BRPs and even results for a PV unit in Sicily in a positive average IF in 2019. This implies that imbalances of a PV unit in Sicily result for an associated BRP on average as a remuneration and instead of a cost.

The effect of local IP-area sizing further shifts the financial results for involved BRPs and, for the case of a Sicilian PV BRP, a local IP-area improves the financial result related to imbalances by 66%, raising the average IF from +1.42 €/MWh_{gen} to +2.36 €/MWh_{gen}. For BRPs in other local zones instead (that are the drivers behind the macro-zonally seen higher prices), the financial outcome would conversely worsen accordingly. Therefore, Local IP-area sizing has a significant impact on the welfare of involved BRPs, be it from iRES units or also other generation and consumption units.

Comparing the welfare impact of imbalances on BRPs of Wind farms versus PV plants, it emerges that wind farms have apparently not only a higher forecast error but also face less opportune IPs. This results in generally more negative IFs compared to PVs, ranging from approximately 2 to 4 €/MWh_{gen} more negative average IFs in Sicily in 2019.

If the forecast error is instead assumed to be subject to financial optimization or also if potential intentional imbalances are assumed, i.e., that individual BRPs actively try to leverage positive imbalance pay-offs and "passively" balance the system, then the unit of analysis are the resulting IPOs that factor also the economic value of the imbalance on the DAM in. As it emerges from the case study, basically all IPOs for iRES BRPs based on the underlying forecast errors are negative. This means that by simply following the average forecast, the overall imbalances eventually lead to a negative financial result. Intentional deviating BRPs would have to assume therefore a different and smarter "imbalance strategy" to leverage the financial opportunities from passive balancing and turn the individual imbalances into a positive pay-off. By default, such is only possible under Single Pricing schemes. The currently still applied compensation scheme for smaller Italian iRES units proves beneficial for connected iRES units in the sense that it exposes individual units to the overall lowest IP risk (under constant IP-area sizing) and results in overall positive IFs. However, the reduced effect of individual balancing responsibility also results in a reduced incentive to actively improve the individual forecast accuracy, which might be considered negatively from a system's perspective.

6.4.4 Different System Conditions - The COVID-19 Impact

This last case study compares the impact of different system conditions on the theoretical findings from the first two sections, i.e., IPs under different pricing schemes and different IP-area sizings. Note that the unit of analysis is now one month instead of one year as previously. Direct cross-comparison with the other case studies is therefore limited.

Impact on previous findings for imbalance price schemes Comparing the IPs for the six "standard" IP-schemes from April 2020 to April 2019, it appears that average IPs and their standard deviations drop basically across all compared IP-schemes as presented in Table 6.13. However, the intensity of price drops for consistently long IP-areas and consistently short IP-areas vary notably. IPs vary thereby along with the registered prices of BAM transactions as presented in Table 3.6 under the changed system conditions and shift also the BRPs' balancing incentives. The direction of this sift depends thereby on the intensity of IP drops compared to the drop of the DAM price (see Table 3.5 for details on DAM price developments).

For the benchmarking *Single Pricing average* scheme, this reduction amounts to an on average 80% lower IP in a consistently long IP-area and a 13% lower IP under a short IP-area. Standard deviations of respective IPs reduce in the same direction although slightly less intense by 55% and 47%, respectively. The reason for the disproportionately falling downward prices can be found in the likewise falling DAM prices and the associated opportunity costs for downward balancing prices (see Hirth and Ziegenhagen [7] for details on opportunity costs for balancing provision). Such a stronger reduction of downwards prices in long IP-areas (both in percentage in absolute numbers) would generally shift the theoretical equilibrium for pro-active BRPs' positions[13] towards a more balanced and less long position. However, the reduced average DAM price of only 24.46 €/MWh in April 2020 (compared to 53.32 €/MWh in April 2019) eventually thwarts such a shift and, under the assumption of an overall balanced IP-area sign, further increases the potential incentive to assume an even longer position by 52% or 8.13 €/MWh (gaining on average 23.83 €/MWh with a long position in April 2020 versus 15.70 €/MWh in April 2019). Also for BRPs that do not interpret IPs as a price signal for pro-active

[13] i.e., BRPs with an ambition to engage in passive balancing and pro-actively deviate their market position

Table 6.13: Comparison of calculated average imbalance prices $\varnothing p_{imb}$ and their standard deviations $\sigma(p_{imb})$ in April 2019 (benchmark - no Covid) to April 2020 (Covid - full lockdown) for six different imbalance pricing schemes, applied to the bidding zone North.

			Single Pricing		**Single Pricing incl. FRR**		**Dual Pricing**	
			average	marginal	average	marginal	average	marginal
April 2019								
Area + BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	35.86	16.93 (- 53%)	33.49 (- 7%)	7.87 (- 78%)	35.86 (+0%)	16.93 (- 53%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	9.94	17.79 (+79%)	7.62 (- 23%)	10.87 (+9%)	9.94 (+0%)	17.79 (+79%)
Area - BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	102.19	163.91 (+60%)	98.24 (- 4%)	175.07 (+71%)	53.32 (- 48%)	53.32 (- 48%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	66.29	322.28(+486%)	40.51 (- 39%)	319.97(+483%)	12.10 (- 82%)	12.10 (- 82%)
April 2020								
Area + BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	**7.25** (- 80%)	**1.81** (- 75%) (- 89%)	**6.52** (- 10%) (- 81%)	**0.73** (- 90%) (- 91%)	**7.25** (+0%) (- 80%)	**1.81** (- 75%) (- 89%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	**4.47** (- 55%)	**3.77** (- 16%) (- 79%)	**3.57** (- 20%) (- 53%)	**2.44** (- 45%) (- 78%)	**4.47** (+0%) (- 55%)	**3.77** (- 16%) (- 79%)
Area - BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	**89.34** (- 13%)	**131.05** (+47%) (- 20%)	**92.36** (+3%) (- 6%)	**152.24** (+70%) (- 13%)	**24.46** (- 73%) (- 54%)	**24.46** (- 73%) (- 54%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	**34.89** (- 47%)	**93.50** (+270%) (- 71%)	**26.34** (- 25%) (- 35%)	**90.19** (+258%) (- 72%)	**8.80** (- 75%) (- 27%)	**8.80** (- 75%) (- 27%)

Note: *Percentages below individual values describe the deviations of results for April 2020 from the results for April 2019. Cell colors relate to these 2019-2020 comparison percentages for increased comparability. Percentages on the right-hand side of individual values describe the deviations for individual imbalance price schemes from the benchmarking* Single Pricing average.

adjustments of the individual market position, this shift still entails a respectively increased price risk for their imbalances although overall market prices dropped.

As can be expected, the IPs under the marginal implementation of the very same scheme drop even more with -89% and -20%, respectively. Other than for the average implementation, however, the price decrease in absolute numbers is more pronounced on the side of short IP-areas than for long IP-areas (-32.86 €/MWh versus -15.12 €/MWh, respectively). The price spread between positive and negative IPs decreases thereby for marginal schemes with the changed system conditions. In combination with the reduced DAM price, this leads, on the one hand, still to an increased incentive for BRPs to stay long (gaining on average 41.97 €/MWh in April 2020 versus 37,10 €/MWh in April 2019). On the other hand, this incentive increase is interestingly though to a lesser extent than the increase for the average IP implementation (plus 13% or 4.87 €/MWh only).

Also under FRR consideration, IPs drop with the changed system conditions, the consideration of this product category in the IP calculation shift BRPs' balance incentives though as in the general IP-schemes comparison of Section 6.4.1 slightly towards long positions. Particularly, FRR damps the reduction of IPs for consistently short IP-areas (3% higher price than no FRR and reduction from April 2020 to April 2019 by only -6% versus -13% without FRR). Such happens as the system with less load and more iRES generation values upward FRR apparently comparably higher than other upward balancing products. As before, this effect is also again significantly more pronounced for marginal implementation.

Dual Pricing continues to reduce positive incentives for BRPs with imbalances that are relieving from a system's imbalance perspective while maintaining the negative incentives for BRPs with aggravating imbalances. As the DAM price drops in absolute numbers similarly strong as the IP for long IP-areas with its underlying downward BAM offers (-28.61 €/MWh and -28.86 €/MWh, respectively), whereas the IP for short IP-areas with its underlying upward BAM offers dropped in absolute numbers only by less than half (-12.85 €/MWh), also the Dual Pricing scheme eventually penalizes short BRPs even more than already previously and pushes BRPs to rather favor an exposure towards a long than towards a short position.

In summary, the changed system conditions cause IPs to drop consistently across all compared IP-schemes. The drop is for the largest Italian bidding zone North thereby stronger on the downward balancing side of IPs for long IP-areas than on the upward balancing side of IPs for short IP-areas. As the DAM price reduction in absolute numbers is roughly in the same dimension, such results in an increased shift of the incentive for BRPs to balance their market position with a tendency for long positions. If the Italian market did not dispose of a price floor at 0 €/MWh, downward prices might have dropped in April 2020 even further. In fact, the marginal downward IP touches the price floor in the IP-area North for more than 50% of the hours in this month. If this artificial floor had not limited the prices, the disparity of BRP incentives to stay long might have been contained by resulting in more balanced IPs that actually reflect the market equilibrium.

Instead of lifting the price floor, the Italian regulator reacted to the IP development with a temporary but inverted measure: the floor of downward IPs (for non-qualified generation or consumption units) was raised to 50% of zonal DAM prices, whereas the upward IPs were capped at the larger of either 150% of the zonal DAM price or the marginal cost of an open-cycle gas turbine (to be calculated by the TSO each week, resulting eventually around 50-60 €/MWh) [303]. This way, the balancing incentive for be BRPs was restored and evened out around the DAM price. Notably, for BRPs in IP-areas that usually are prone to particularly high upward balancing prices and respective IPs, this temporary measure ultimately led to even more balanced prices than outside of COIVD-19 times.

Impact on previous findings for imbalance price area sizing Shifting the scope from individual IPs to IP-area sizing and the area of analysis from North to South, the changing system conditions also impacted the effects of a potential split of the aggregated IP-area Macro-South into IP-areas at the bidding zone level. Table 6.14 reports therefore the IPs under Single Pricing average in the two exemplary bidding zones Centre-South and Sicily with aggregated and static local IP-area sizing.

First of all, it remains to note that under a joint Macro-South IP-area, the IPs for both southern bidding zones develop for a consistently long IP-area with changed system conditions similar to the bidding zone North. Downward prices decrease in April 2020 by nearly 70% and eventually amount to 7.14 €/MWh and 7.16 €/MWh, respectively. Upward prices decrease by around 10% percentage-wise nearly as much for the bidding zone North, however, the price in absolute numbers remains with 188.78 €/MWh and 188.85 €/MWh remarkably high.

If the IP is calculated separately for the two bidding zones, it clearly emerges where the high upward price for the IP-area Macro-South originates. Sicily on its own, with the local bidding zone acting as the IP-area, would face in April 2020 an upward IP of 63.20 €/MWh only based on proprietary BAM transactions, another 33% lower than its individual value for April 2019. Centre-South, on the contrary, generates an individual upward IP of 234.29 €/MWh for April 2020, even raising

Table 6.14: Comparison of average imbalance prices $\varnothing p_{imb}$ and respective standard deviations $\sigma(p_{imb})$ under Single Pricing average in April 2019 (benchmark - no Covid) to April 2020 (Covid - full lockdown) for two bidding zones of the imbalance price area Macro-South with aggregated and statically disaggregated imbalance price areas.

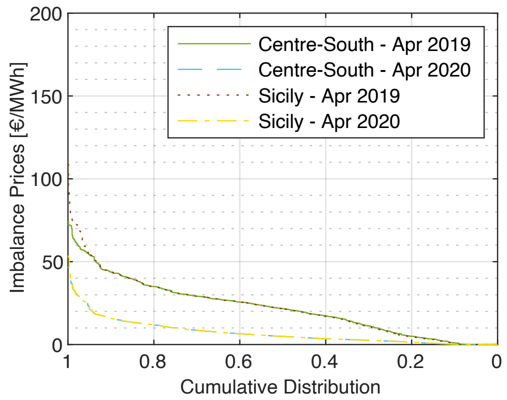
				Centre-South		Sicily	
	Imbalance price area:			April 2019	April 2020	April 2019	April 2020
Area + BRP +	*(Aggregated) Macro-South*	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	22.20	7.14 (- 68%)	22.49	7.16 (- 68%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	16.39	7.52 (- 54%)	17.73	7.62 (- 57%)
	Local bidding zone	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	26.17	8.55 (- 67%)	50.66	18.41 (- 64%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	21.15	12.24 (- 42%)	25.55	13.42 (- 48%)
Area - BRP +	*(Aggregated) Macro-South*	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	207.86	188.78 (- 9%)	209.44	188.85 (- 10%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	145.27	117.79 (- 19%)	144.06	117.71 (- 18%)
	Local bidding zone	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	219.21	234.29 (+7%)	93.66	63.20 (- 33%)
		$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	185.10	180.80 (- 2%)	51.71	54.19 (+6%)

Percentages describe the deviations of results for April 2020 from the results for April 2019. Cell colors relate to percentages for increased comparability.

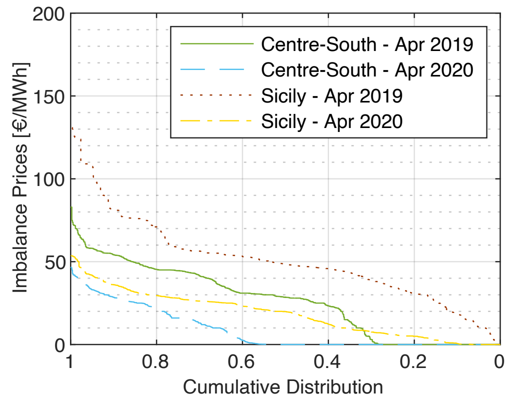
the individual value from April 2019 by another 7%. This means that the price-spread of the local IP-area values increased by another 36% from 125.55 €/MWh in April 2019 to 171.09 €/MWh in April 2020.

Following the previous calculation examples, the potential balancing incentive of BRPs is thereby even further shifted. Assuming a balanced IP-area imbalance direction, it remains as also in the previous analysis an incentive for BRPs to maintain a rather long position, however, with significantly varied magnitude. Under a joint IP-area Macro-South, BRPs in both bidding zones would gain with such an inclination on average around 72 €/MWh in April 2020. Splitting the aggregated IP-area splits the potential incentive instead to 96.21 €/MWh for a BRP in Centre-South and to 14.67 €/MWh for a BRP in Sicily. This massive amplification of the IP-induced balancing incentives underlines the increasing significance of local IP-areas under system conditions with an increased iRES generation share to provide accurate balancing incentives. On the contrary, an aggregated macro-zone such as Macro-South tends to dilute respective signals severely.

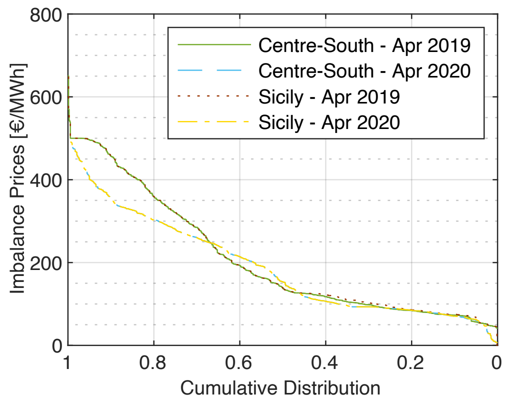
To further demonstrate where the differences in IPs emerge in the two bidding zones under aggregated and local IP-area sizing, Figure 6.10 presents the corresponding CDFs in April 2019 and April 2020.



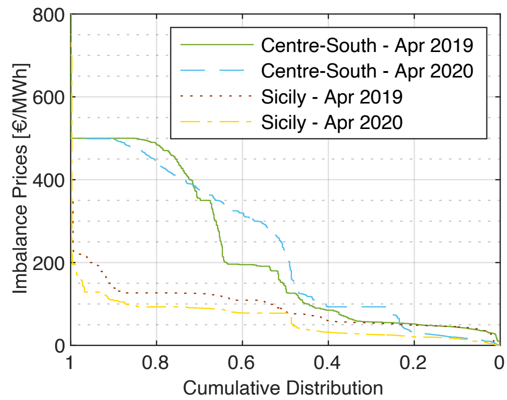
(a) Macro-South IP-area: Area + / BRP +



(b) Local bidding zone IP-areas: Area + / BRP +



(c) Macro-South IP-area: Area - / BRP +



(d) Local bidding zone IP-areas: Area - / BRP +

Figure 6.10: Cumulative Distribution Function of imbalance prices in the bidding zones Centre-South and Sicily in April 2019 versus April 2020, with the imbalance price area being the aggregated area Macro-South ((a) & (c)) or the imbalance price area being the local bidding zone ((b) & (d)). *Case scenario:* Single Pricing average.

In the aggregated IP-area configuration, CDFs for Centre-South and Sicily basically do not distinguish but overlap consistently (solid green line with red dotted line for April 2019 and blue dashed line with yellow dash-dotted line for April 2020) also under changed system conditions as visible in sub-figures (a) and (c), respectively. For a long IP-area (sub-figure (a)), the impact of COVID-19 with its changing system conditions manifests as a quasi-uniform percentage shift of the curve across the entire cumulative distribution. For a short macro-IP-area (sub-figure (c)) instead, the impact of COVID-19 on IPs in April 2020 affects mainly the probability of prices above 120 €/MWh. By changing concavity and adding an additional inflection point around 200 €/MWh, the CDF for April 2020 demonstrates a slightly increased probability for IPs in the range from 200 to 350 €/MWh. It reveals thereby a second cluster of comparably more probable IPs, adding to the previous one in the low range from 50 to 120 €/MWh while removing the cluster at 500 €/MWh. Apart from that, the impact of COVID-19 is comparably low in line with the modest overall IP reduction of 10%.

In the local IP-area configuration as envisioned by the European regulatory framework, the COVID-19 impact distinguishes the shapes of the CDFs for Centre-South and Sicily even further as visible in sub-figures (b) and (d), respectively. The respective local IP-area CDFs remain entirely detached for a long IP-area (sub-figure (b)). The local IP-area Centre-South registers thereby in April 2020 an even more pronounced probability of cumulatively 60% for IPs at the price floor of 0 €/MWh, compared to 30% in April 2019 (blue dashed line versus green full line). Sicily instead continues to record little to no probability for these prices (yellow dash-dotted line). For a short IP-area (sub-figure (d)), the intensification of distinctions continues. First of all, the split between the two local IP-area CDFs extends, and only for a cumulative probability of roughly 20% the two curves overlap in the low price range around 25 €/MWh. Besides this price cluster, Centre-South develops two more clusters of probable IPs, one around 100 €/MWh with a cumulative probability of roughly 10% and one at 500 €/MWh with again a cumulative probability of roughly 10%. In between these two falls an additional high-price section with more variable prices in the range of approximately 250-500 €/MWh that accumulates 40% of probability. Instead, a local IP-area Sicily is characterized in this direction by only IP clusters. On the one hand, an extension of the shared cluster with Centre-South from 25-40 €/MWh with a cumulative probability of roughly 50%. This cluster is linked to the DAM price for the hours of no internal BAM transactions (see more details in the paragraph below). The second cluster is registered in the range from approximately 75-100 €/MWh with a cumulative probability of 40%, representing the majority of internal BAM upward transactions.

Besides the hours of missing internal BAM transactions, the zones show a fundamentally different price distribution that leads to well-distinct IP characteristics. This shows again the difference it would make to consider the different zones separately and that this also applies particularly in transitory times as for example with the changed system conditions of COVID-19. While macro IP-areas continue to distort and dilute balancing incentives, local IP-areas would send a significantly more pronounced price signal based on local conditions and not expose BRPs to unwarranted risk other than that in their area of (indirect) influence.

In this context, it is interesting to take one more time a look at the percentage of hours without BAM transactions in Table 6.15. Notably, the percentage decreased both for local and aggregated IP-areas from April 2019 to April 2020. For the

Table 6.15: Percentage of hours for which no balancing energy in respective direction has been activated $\%_{noBAM}$ for the aggregated imbalance price area Macro-South and the two subordinated bidding zones Centre-South and Sicily in April 2019 (benchmark - no Covid) and April 2020 (Covid - full lockdown).

		Macro-South		Centre-South		Sicily	
		April 2019	April 2020	April 2019	April 2020	April 2019	April 2020
no BAM ↓	[%]	1%	1%	27%	24%	70%	55%
no BAM ↑	[%]	6%	2%	37%	23%	58%	49%
no BAM ↓↑	[%]	0%	0%	8%	6%	46%	30%

upward direction, this is straightforward as the overall BAM trading volume has increased (see Chapter 3.2. For the downward direction, on the other hand, less so, as it remained overall more or less constant, or even decreased by -19 and -15% for the two zones Centre-South and Sicily, respectively. Apparently, the activated amount of balancing energy was activated more evenly, resulting in an overall reduced percentage of hours without BAM transactions. If this percentage is taken as a KPI for the adequacy of static, local zones, it means that such fit even better under the changed system conditions than before.

Interim Takeaways Changing system conditions as under COVID-19 impacted not only DAM and BAM prices but also IPs significantly. Basically all IPs dropped across all IP-schemes and shifted BRPs' balancing incentives. For the system with a higher iRES share and less load it resulted that especially the average IP for long IP-areas (due to the underlying opportunity costs for downward balancing provision) dropped by up to 80%. IPs for short IP-areas dropped as well, but to a lesser extent of 13% on average. Together with the DAM price drop of 54% from 53.32 €/MWh in April 2019 to 24.46 €/MWh in April 2020, this shifted the theoretical equilibrium for pro-active BRPs' positions towards an even longer imbalance position. Along with the amplification of the balancing incentive, also the price risk for imbalances of fully passive BRPs increased accordingly.

The shift of the incentive towards even longer market positions resulted, among other things, from the fact that the downward BAM price often hit the artificial price floor of Italy. For the investigated month of April 2020, this was the case for more than 50% of the time in the largest bidding zone North and even for roughly 60% of time in the second largest bidding zone Centre-South. A possible introduction of negative prices would give the downward prices in future cases the possibility of decreasing further and reaching an effective market equilibrium, which would also result in correspondingly more balanced BRP incentives.

Regarding IP-area sizing, the changing system conditions under COVID-19 amplified the price spread for local IP-area implementations between the two southern bidding zones Centre-South and Sicily by another 36%. This additional amplification of the IPs also shifted the potential balancing incentives of individual BRPs further and underlined thereby the even more increased difference that local IP-areas could make under system conditions with an increased iRES generation share to provide accurate balancing incentives. Furthermore, static local IP-areas might even be more adequate under such conditions than previously, given that one of their weak points in terms of hours with no local BAM transactions, reduced for the analyzed period.

6.5 Opportunities for Further Research

While the presented study of imbalance pricing for passive balancing integration covers a wide range of aspects, five fields for further research have been identified in line with the different case studies that were undertaken.

1. Utilize empirical market data from other countries to cross-validate individual findings for the investigated IP-schemes, e.g., that FRR damps the overall IP distribution or that marginal pricing increases only for a limited amount of time.

2. Advance the investigation of dynamic IP-area sizing to include a differentiation for congestion directions. Along with that, IP-area splitting based on real-time congestions from effective power flows would further refine the analysis.

3. Calculate local IP-area imbalance signs to extend the case study on individual iRES plant impacts (or on portfolios of such) also with fully local imbalances instead of macro-zonal imbalance directions.

4. Extend the welfare analysis from imbalance pricings to the perspective of a TSO, i.e., reverse the BRPs micro-economic perspective and investigated the macro-economic effect that different IP-schemes have on the overall system's imbalance cash-flows.

5. Use a simulation based methodology to investigate the effect of imbalance pricing on bidding incentives and on the overall system imbalance .

6.6 Summary and Policy Recommendations

This chapter presents a comprehensive study of imbalance pricing for passive balancing integration through multiple case studies based on empirical market data from Italy. With a special focus on imbalance pricing schemes and imbalance price area sizing, eight different imbalance pricing schemes are compared along with three different modes of imbalance price area sizing. Among these are the currently most discussed versions at the European level, as well as particular implementations from Italy, Germany, and Norway.

Imbalance Pricing Schemes As a first finding on pricing rules, it proved that marginal pricing naturally amplifies prices, but only for a limited share of time. Marginal pricing emerged thereby as a sort of scarcity pricing which, on the one hand, left imbalance prices for the most part fundamentally unchanged but, on the other hand, amplified imbalance prices especially in times of already amplified prices even further. The meaningfulness of marginal or average pricing thus clearly depends on the aim of the (im-)balancing incentive that is intended to be set. Average pricing generates a balancing incentive for BRPs that is based on overall balancing market dynamics and, if desired, marginal pricing can add a scarcity pricing element that is also driven by balancing market characteristics.

A second finding concerns the consideration of additional product categories for imbalance pricing. In general, such enlarges the pool of balancing market transactions that count towards the imbalance price calculation and can hence influence the resulting IP and its underlying balancing incentive. For the specific case of the inclusion of secondary reserve, which Italy for example is not (yet) considering, the analysis demonstrated that results differ notably for average and marginal implementations. In average implementations, secondary reserve appears to amplify resulting imbalance prices only to a small extent in the medium-price range, whereas high-price moments are rather damped. For marginal pricing implementation instead, it develops a more pronounced effect yet raising prices again more in the medium-price range while adding little to nothing to high-price moments. Therefore, the inclusion of secondary reserve in imbalance price calculations appears favorable as it cuts off some of the high-price peaks from the current implementation and generates a more equitable balancing signal, especially in the average implementation. This is especially true under the impression that Italy's only balancing product to date is a multi-purpose product and hence also being used for other tasks, such as congestion management. Consequently, the use of this product, especially during high-price phases, might not always be exclusively related to balancing purposes. The addition of secondary reserve might temper such effects and, all in all, appears a reasonable step towards the continued harmonization of the imbalance pricing approach at the European level.

Dual Pricing as the second fundamental imbalance pricing scheme next to Single Pricing proves to entail the highest economic impact on BRPs, especially for those of intermittent renewables with an inherent forecast error. If the forecast error of renewables is considered in this regard as inherent and given, the dedicated Italian compensation scheme for intermittent renewables with its portfolio balancing approach damps the overall welfare losses the most and might hence be most adequate. However, it is questionable if this is still desirable for an increasing number of more integrated and advanced renewable units, for which the forecast error still can not be evaded but reasonably be subject to minimization.

Imbalance Price Area sizing With regard to imbalance price area sizing, the analysis outlined how significant macro-zones dilute local price signals and how inefficient they are therefore to deliver a purposeful balancing incentive. Static local imbalance price areas are better in this respect because they generate clearer local price signals while being easy to implement. Also from an economic perspective, the risk of high prices is allocated more adequately to BRPs that are in actual proximity to the price-driving imbalances, whereas other BRPs further away are relieved accordingly. The example of a Sicilian BRP responsible for a PV plant shows that a split of the currently still aggregated imbalance price area Macro-South to local imbalance price areas at bidding zone level would improve its financial result for 2019 related to imbalances by 66% on average. Other BRPs in zones that cause specific high-price moments, such as Centre-South, would be correspondingly more burdened and thus stimulated to resolve the system imbalance locally.

Nonetheless, static imbalance price areas entail two weak points. On the one hand, cross-zonal balancing transactions would potentially be misallocated if not equipped with activation tags to allocate them to the respective imbalance price area that required them, be it entirely or in parts. On the other hand, linked with the first issue is a non-negligible number of hours in which the local balancing market does not register any transactions and the imbalance price would dispose of a notably lower balancing signal solely based on the DAM price.

Dynamic imbalance price area sizing, as implemented for example in Norway, counteracts both these limitations of static imbalance price area sizing by extending the imbalance price area to one or more contiguous bidding zones as long as the connection remains unobstructed. The IP distribution results thereby eventually somewhat hybrid with a more pronounced, balancing-market-based price incentive for BRPs compared to the static imbalance price areas while maintaining specific local signals in case of limitations in the transmission capacity. All in all, this makes it therefore the preferable and most adapted imbalance price area sizing.

Changing System Conditions The impact of COVID-19 gave the opportunity to study the behavior of imbalance pricing schemes under changing system conditions, characterized by less load and an increased renewable generation share. To a certain extent, this combination thus also provides a basis for the discussion on future scenarios for the transitioning energy ecosystem, in which conventional generators are fighting for a continuously shrinking market share. The core finding is that imbalance prices dropped under the changing system conditions across all schemes, especially downward prices due to the underlying opportunity costs for balancing provision. Eventually, the downward imbalance price for long imbalance price areas touched the Italian price floor of 0 €/MWh for more than 50% of time in different imbalance price areas (aggregated North or static local South). Being limited to decrease further, the subsequent imbalance price resulted finally distorted and generated a balancing incentive beyond the market (and system) equilibrium. The removal of the price floor in spot and balancing markets appears therefore worth consideration, especially in view of future systems with even higher renewable shares. Last but not least, COVID-19 also amplified the difference that imbalance price area splitting would make, underlining thus once more how sensible it would be to move away from aggregated macro zones to adapted local zones.

Considerations on Imbalance Pricing Schemes Adequacy for DERs After having compared different design elements around imbalance pricing, the question emerges which imbalance pricing scheme would eventually be the most adequate for distributed and renewable energy resources in particular. Given that imbalances from forecast errors remain inevitable for renewables, a dedicated scheme such as the Italian compensation scheme for adhering small renewable units in the sense that it exposes individual units to the overall lowest imbalance price risk. However, the reduced effect of individual balancing responsibility results also in a reduced incentive to actively improve the individual forecast accuracy, which might be considered negatively from a system's perspective.

Single Pricing, as currently applied for larger renewable units, provides a stronger price signal, which, by its very nature, is still balanced for units with equally positive and negative imbalances[14]. Pro-active BRPs will be able to interpret the opportunities of Single Pricing also as a valuable incentive to improve forecasting accuracy and leverage potential financial benefits through passive balancing. In that

[14] This is true as long as the price-spread between upward and downward balancing prices compared to the day-ahead spot market price is balanced in line with the overall zonal imbalance direction. See Section 6.4.1 for more details.

sense, it appears to be an adequate scheme for larger renewable units in case of individual balancing responsibilities as in Italy, or for smaller renewable units in case portfolio approaches for balancing responsibilities are applied.

A different case arises when renewable units are combined into a virtual power plant and thus potentially also managed in a joint portfolio with controllable units. At the moment, the regulatory approach in Italy stipulates that each unit maintains thereby the scheme that it would adhere to individually, e.g., Single Pricing. However, as a virtual power plant also turns previously non-controllable renewable units into part of an overall price-responsive aggregate, in principle, Dual Pricing would be conceivable to put these units on an even footing with other controllable units in Italy. If Single Pricing would continue to apply, cost-conscious plant operators (as a combination of BSP & BRP) would probably turn this into an effectively "positive" Dual Pricing scheme, in the sense that they would be able to leverage the positive payments but avoid the negative ones (see Chapter 7 for an illustrative case-study). On the other hand, Dual Pricing entails the most detrimental welfare effect for BRPs. To what extent either the punitive nature of Dual Pricing for maximum individual balancing or the incentive of Single Pricing as an integration aid towards the system as a whole would then be preferable, is left to the discretion of regulators under careful consideration of individual system conditions.

One last consideration concerns the imbalance price area sizing in combination with the emergence of virtual power plants. A fundamental principle to this regard is that the virtual power plant's catchment area must not be larger than an imbalance price area in order not to gain an imbalance price arbitrage advantage across different imbalance price areas. Italy follows this principle by designating 15 aggregation zones that are subordinated to the six bidding zones. Therefore, local sizing would not be an obstacle but, on the contrary, an additional incentive for renewables to join a virtual power plant and thus, from their individual perspective, to leverage additional benefits from potentially even higher local price signals. On the other hand, from a system's perspective, this would be an additional catalyst to eventually leverage the full potential of the continuously growing asset base at the local level, turning previous sources of uncertainty into price-responsive balancing providers.

7 Full Balancing Integration: Value Stacking

This chapter includes material from

Jan Marc Schwidtal, Marco Agostini, Massimiliano Coppo, Fabio Bignucolo, and Arturo Lorenzoni. “Integrating Distributed Energy: Value Stacking for PV with Power-to-Gas”. In: *International Conference on Applied Energy 2021*. 2021. **Conference Paper**, cited as [304].

7.1 Introduction

As outlined in the previous Chapters, the integration of DERs and iRES is a key element of the ongoing energy transition. The term "integration" is thereby often used in two contexts. On the one hand, in the direct integration of individual units into existing markets by lowering potential entry barriers or facilitating the overcoming of such barriers. Virtual aggregation of individual units to so-called VPPs is therefore a key facilitator for DERs to enter markets they previously could not enter and to enable *explicit flexibility* provision from DERs. On the other hand, integration is used in a more indirect context of incorporating DERs more effectively into auxiliary schemes that are not direct market schemes but that have a similar effect. Examples for such schemes are imbalance pricing schemes or the facilitation of behind-the-meter activities that enable *implicit flexibility* provision from DERs [305].

Yet only the combination of both concepts will realize the full potential of DERs and create a win-win situation on a macro- and micro-economic level for both system and individual plant operators [306]. Therefore, the analysis presented in this chapter examines the business case of a VPP that creates local synergies by aggregating a programmable and a non-programmable DER, i.e., a solar Photovoltaic (PV) plant and a Power-to-Gas (P2G) plant. Such an aggregated entity can capture internal benefits, such as reducing imbalances and corresponding payments or maximizing the valorization of low-cost generation. On the other hand, it can generate external benefits by offering a wider variety of products and services to the system than each entity could offer individually. The resulting concept of providing multiple services simultaneously from a single flexible unit is called value stacking [307], revenue stacking [308], or benefit stacking [309].

As of now, VPPs in literature for which the implications of value stacking have been analyzed usually consist of a PV unit in combination with a BESS unit [310–312]. However, the flexibility of such VPPs is limited by the inherent capacity constraints of BESS with the corresponding operational limitation as described in chapter 5.3.2. It operates in a kind of "closed" flexibility cycle, i.e. all services provided in one direction are limited in time and must sooner or later be accompanied by a similar service in the opposite direction before they can be provided again [313]. VPPs with P2G units instead offer a wider range of flexibility and operate in a somewhat "open" flexibility cycle, meaning that any service can be provided without specific time constraints as long as the baseline is right [314].

The aim of this chapter is to outline the flexibility abilities such a virtual aggregate disposes, especially if operated on a full flexibility scale that incorporates both explicit and implicit applications. In doing so, it combines aspects of the previous two chapters by examining a unit that is integrated with both active balancing services and passive balancing schemes. For the further course of the thesis, this concept will be referred to as full balancing integration. Specific research questions addressed in this chapter are:

- What is the added value of full balancing integration for exemplary DER units?
- Which of the potential products and markets a VPP can leverage on provides interesting business cases?
- How do individual market design elements from active and passive balancing influence the business case of a fully integrated DER unit?

The remaining chapter is structured as follows. Section 7.2 introduces the key characteristics of the modeled VPP and the simulation approach that has been applied. Section 7.3 outlines and discusses the results from value stacking for the combined PV and P2G unit. Section 7.4 discusses the findings on full balancing integration in the light of the previous findings on active and passive balancing before 7.5 finally concludes and outlines associated policy recommendations.

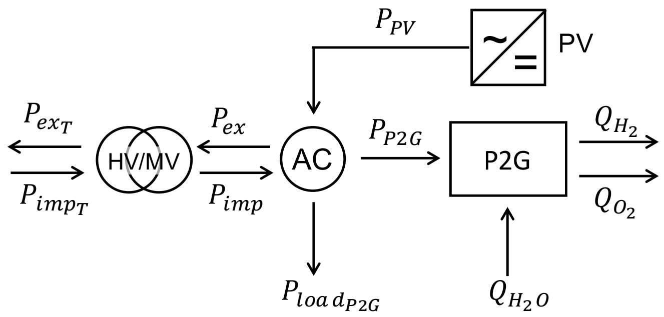


Figure 7.1: Schematic representation of the modeled VPP. *(Reprinted with permission from [265])*

7.2 Methodology

The modeled VPP consists of a 20 MW_{peak} PV unit and a 6.2 MW_{peak} P2G unit connected at medium voltage level. The model considers combined operation on the DAM, the IDM, and BAM in the Italian market zone of Sicily. To comply with current Italian regulations for virtual aggregation, it is assumed that the two units share the same primary substation. However, without loss of generality, the two units could be also be located at two different grid connection points. A schematic representation of the modeled VPP is shown in Figure 7.1.

Input Data Following the general methodological approach as outlined in Chapter 3.3, operational data for the PV pant is extrapolated from the day-ahead forecast and actual PV generation of the market zone of Sicily as provided by [@178]. For the additional intra-day froecast error a randomized perturbation of 5% is applied, in line with other academic approaches [315]. For the P2G plant, operational characteristics of a plant with identical dimensions as in the Mainz Energy Park is used [@316]. The corresponding P2G model input parameters are reported in Table 7.1.

Table 7.1: Characteristics of modeled P2G unit. *(Reprinted with permission from [265])*

Model parameter	Value	Reference
Rated power	3.75 MW	[@316]
Peak power	6.20 MW	[@316]
Min power	1.00 MW	[@316]
Efficiency* at rated power	55%	[317]
Efficiency* at peak power	49%	[317]
Efficiency* at min power	65 %	[317]
Standby consumption	0.001 MW / MW_{rated}	[317]
Demineralized water consumption	9 kg / kg_{H2}	[318]
Demineralized water costs	0.0007 €/kg	[318]

* with regard to the lower heating value, including all auxiliaries.

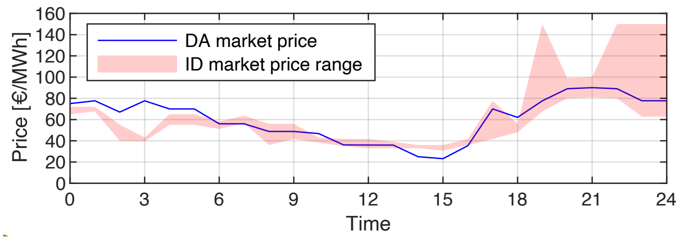
While the regulatory framework for P2G units in Italy is not yet fully developed, it is assumed that such a unit will be able use the behind-the-meter energy from the PV unit or to directly purchase electricity from the spot EM. Furthermore, it is assumed that the P2G unit will pay grid charges for purchased electricity as other medium voltage connected large consumers in Italy, while being exempted from additional taxes or levies for not being an electricity end-user (similar as BESS in Italy). Respective grid charges amounted to 15.77 €/MWh in 2019 [319]. As for the previous BESS case study it is thereby assumed that the IDM would have been already in continuous trading with a respective gate closure one hour before delivery. It disposes therefore not of a single clearing price, but of a range of prices per hour which are obtained from the different IDM sessions.

ASM interaction is modeled with the BAM as it is the only market with convenient gate-closure for dynamic value stacking. For better comparability with the previous case studies, empirical market data from the year 2019 is used and generally pre-processed as described in Chapter 3.3. IPs that the VPP would face for remaining real-time imbalances are calculated based on the approaches in Chapter 6. In particular, the two standard IP-schemes Single Pricing average and Dual Pricing average are applied. The resulting market prices with which the VPP interacts are presented for an exemplary day in July 2019 in Figure 7.2.

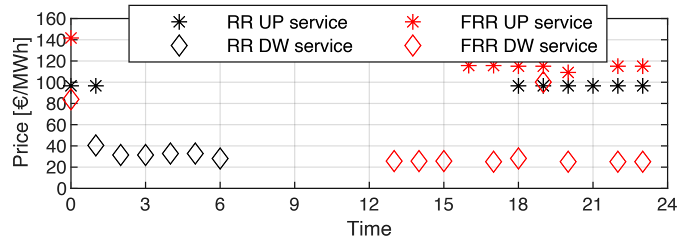
On the Hydrogen (H2) side, no spot market exists, which is why a fixed sales price of 4 €/kg_{H2} is assumed in line with the average of other renewable H2 projects in Europe [320].

Model Calculation The VPP and its operation are modeled in Matlab using YALMIP and Gurobi as a solver for multi-stage and multi-period optimization. The simulation is performed with an hourly resolution for four sample days, one day each during the week and weekends in summer and winter. The service orchestration of the VPPs follows the sequences of the market sessions, and the operational decisions are guided solely by market conditions through price signals. Since this analysis focuses on the benefits of value stacking rather than optimal forecasting techniques, perfect market price forecasting is assumed, consistent with the approaches in 5. The optimization objective is to minimize operating costs and maximize revenues for each time period by interacting with multiple markets with different services and products.

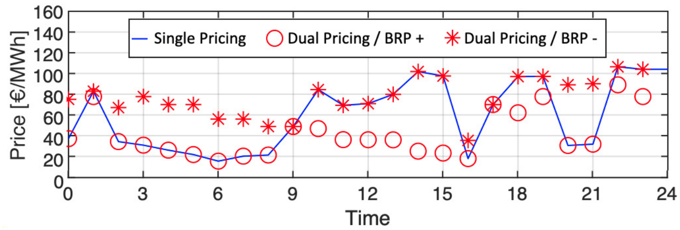
Based on the day-ahead forecast of PV and DAM prices as input parameters, the first optimization decision is to either sell the PV generation to the DAM or consume it through the P2G unit, which converts it to H2. In addition, the P2G unit can also directly purchase electricity from the grid when market prices are favorable.



(a) Spot Energy Market Prices



(b) Ancillary Services Market Prices



(c) Imbalance Prices

Figure 7.2: Market prices on one exemplary day (07.07.2019) in the Italian bidding zone of Sicily. (a) Spot Energy Market Prices, (b) Ancillary Services Market Prices, (c) Imbalance Prices. *(Adapted from [304])*

In the following, the day-ahead forecast error is taken into account and the PV profile is updated. In addition, the VPP is confronted with new prices from the hourly IDM sessions. Therefore, the model optimizes the operation by compensating for the forecast error by either adjusting the P2G profile or buying/selling the energy difference to/from the IDM and possibly further adjusting the P2G profile depending on market conditions.

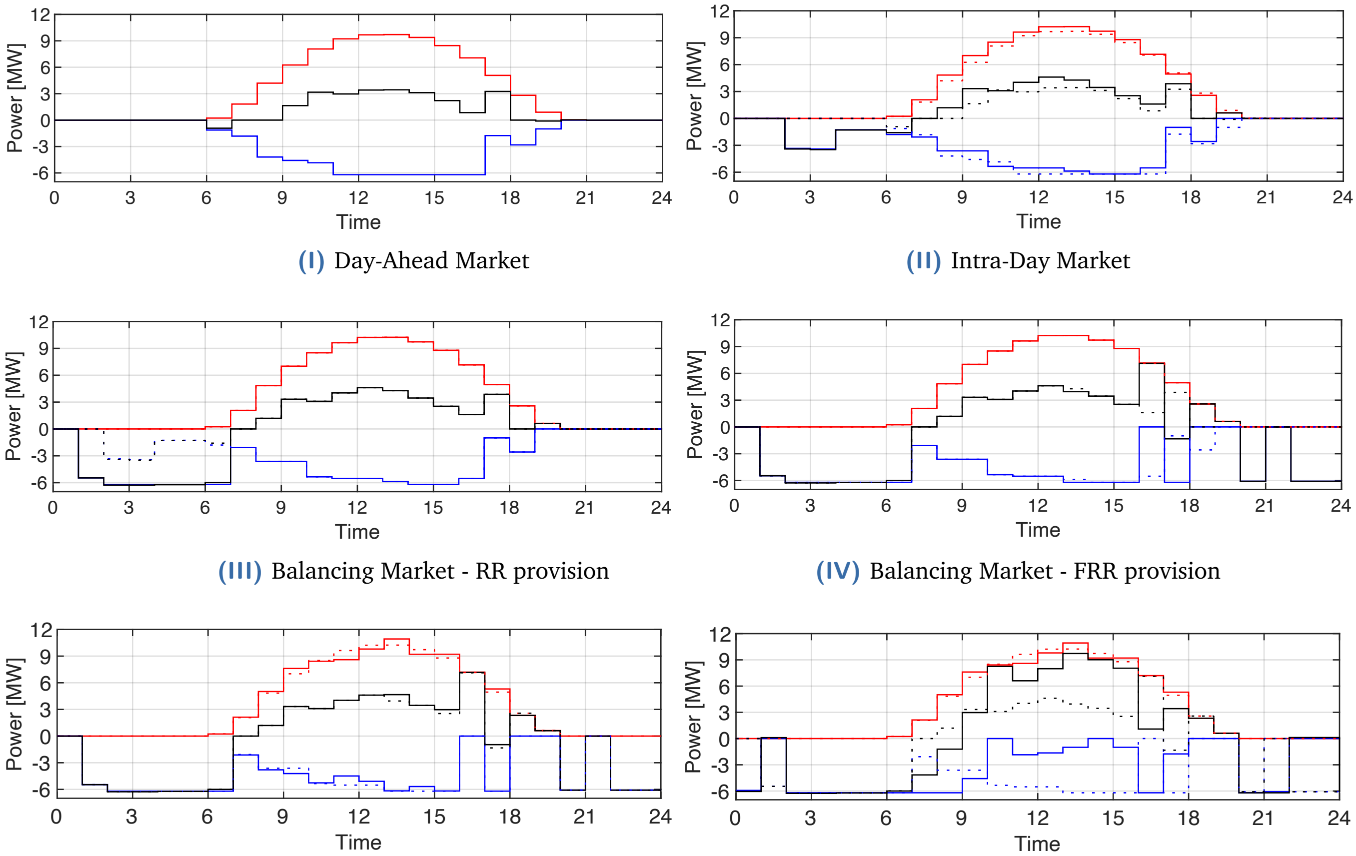
At the end of the energy market sessions, the VPP may decide to offer balancing services at the BAM, starting from its adjusted baseline. The adjusted baseline is the resulting grid exchange profile at the substation, which is the sum of the PV and P2G profiles of all previous energy market operations. In the first step, RR is offered in either the upward or downward direction. As before, a perfect price forecast and full offer acceptance is assumed, in a first approximation for individual offers based on the weighted average price of the actual accepted offers at the market zone level. In a second step, the VPP may offer additional compensation in the form of the faster FRR.

When the last market session closes one hour before delivery, the VPP no longer has the opportunity to correct its market position. Nevertheless, it is confronted with an additional forecast error that distorts the profile from the intra-day forecast in real-time. Assuming that the IPs are predictable (see Chapter 6.2.1 for details), the VPP is left with the option of adjusting the P2G operation or accepting the imbalance prices. Two scenarios are distinguished. In the first scenario, the operation is in compliance with the current Italian regulatory framework, which does not allow intentional deviations. In this case, the VPP can only decide to use the P2G to bring the overall profile of the network exchange back in line with the settled market position, but not beyond. In the second scenario, the VPP will instead use the P2G unit to respond to the predicted IPs as if it were a regular market price and adjust the overall exchange profile accordingly without further constraints. In combination with a Single Pricing IP-scheme, this would be the passive balancing approach as used for example in the Netherlands.

7.3 Results

With a H2 sales price of 4 €/kg_{H2}, the marginal price at which the P2G plant comes on line is a spot market price of 78.00 €/MWh. Below this price, the VPP will begin to consume the PV generation by the P2G plant, and above this price, it will tend to sell to the grid. Since the efficiency of the P2G plant decreases as the load increases, the price must fall below 58.20 €/MWh until the P2G plant consumes the PV generation at full (peak) capacity. Given the additional grid charges for the consumed electricity, the spot market price must fall even further below the 62.23 €/MWh price before the VPP begins to buy electricity from the grid for H2 generation whenever PV generation should not be available.

For the exemplary summer weekend day on 07.07.2019, VPP operation on the DAM results in absorption of PV generation by P2G units that varies with PV availability and DAM prices, as shown in Figure 7.3 (I). The red line represents thereby the profile of the PV unit (P_{PV} in Figure 7.1), the blue line the profile of the P2G unit (P_{P2G} in Figure 7.1) and the black line the overall VPP exchange profile with the grid ($P_{exT/impT}$ in Figure 7.1). Only from 06:00 to 07:00, the VPP will import electricity from the grid because market prices are sufficiently low. At the same time, PV generation is still not sufficient to meet the minimum operating demand of 1 MW for the P2G unit alone. On the contrary, during the night hours when PV generation is not available, DAM prices are too high to operate the P2G unit with imports from the grid. It is also worth noting the decrease in P2G consumption



(I) Day-Ahead Market

(II) Intra-Day Market

(III) Balancing Market - RR provision

(IV) Balancing Market - FRR provision

(V) - (a) - Real-time Imbalance Adjustment

(VI) - (b) - Real-time Passive Balancing

Figure 7.3: Operational profiles of VPP through five market phases one exemplary day (07.07.2019) with PV (red line), P2G (blue line), and grid exchange (black line). Dotted lines imply the old profile from the previous market stage. *(Extended from [304])*

with a corresponding increase in PV export to the grid during the high price hour of 17:00 to 18:00. This transforms the otherwise inelastic PV generation implicitly into a price-responsive unit thanks to aggregated P2G flexibility. This is beneficial for the operation of the overall system as well as for the operation of the individual plants. The PV plant alone would generate revenues of 1,645 € on that day if it sold all of its generation to the spot market. Conversely, the P2G plant would earn 240 € if it generated H2 only from electricity not generated by the PV plant but purchased on the DAM and imported via the grid. In combined VPP operation, the total revenue increases to 2,055 €, as shown in Table 7.2. Since the cash flow of the aggregate is higher than the simple sum of the two individual revenues, the added value of aggregation becomes visible here for the first time.

With the adjustments to the day-ahead PV forecast error in the subsequent time step, the optimization modifies the P2G profile with respect to the new IDM prices.

Table 7.2: Operational results for each of the five operation modes with active and passive balancing integrations of the VPP on four exemplary days in 2019. *(Adapted from [304])*

	Energy Market Operations			*Active Balancing*		*Passive Balancing*		
	DAM:	**IDM:**		**BAM:**		**IP:**		**Total:**
	baseline	**day-ahead adjustment**		**RR provision**	**FRR provision**	**real-time adjustment**		**value stacking**
	VPP combined	*PV only*	*added value VPP*	*added value VPP*	*added value VPP*	*PV only*	*added value VPP*	*VPP combined*
Weekday Winter (02.01.2019)	2,055 €	- 25 € (- 1%)	+53 € (+3%)	+676 € (+33%)	+416 € (+20%)	- 9 € (-1%)	+8 € (+1%)	3,173 € (+54%)
Weekend Winter (06.01.2019)	2,402 €	+191 € (+8%)	+130 € (+5%)	+1,761 € (+73%)	+436 € (+18%)	+43 € (+2%)	+31 € (+1%)	4,993 € (+108%)
Weekday Summer (03.07.2019)	5,575 €	+809 € (+14%)	+156 € (+3%)	+395 € (+7%)	+2,239 € (+40%)	+10 € (+0%)	+43 € (+1%)	9,227 € (+65%)
Weekend Summer (07.07.2019)	4,592 €	+131 € (+3%)	+175 € (+4%)	+496 € (+11%)	+1,165 € (+25%)	- 30 € (- 1%)	+86 € (+2%)	6,615 € (+44%)

As shown in Figure 7.3 (II), for example, additional PV generation is absorbed by the P2G unit from 10:00-11:00, while from 08:00-10:00 additional PV generation is sold to the spot market instead. The dashed lines in the figure represent the respective profiles from the previous DAM session, while the solid lines represent the updated profile from the IDM operation. Since the IDM has higher prices than the DAM in the two hours from 08:00-10:00, the P2G plant actually reduces its consumption and the VPP increases its total export to the grid. In addition, the comparatively lower IDM prices in the early morning hours drive the VPP to import a significant amount of energy through the P2G plant outside the hours of PV generation. While the updated forecast would slightly improve the EM result for a stand-alone PV system by 3%, the IDM optimization for the combined system with P2G increases the total revenue on that day by another 4%.

In the third stage, BM operation with RR provision is introduced. The possibility of obtaining additional energy in a very favorable price range of 25-40 €/MWh leads the VPP to increase the absorption from the grid in the early morning hours through downward services (see Figure 7.3 (III)). Upward services are not possible during these hours, even if demanded by the market, because the VPP's baseline is zero and no energy export is possible without PV generation. Revenues are increased by an additional 11% by the RR services offered compared to the DAM operation.

Integrating additional FRR services in the fourth optimization step mainly changes the VPP grid exchange profile for the evening hours (see Figure 7.3 (IV). These are hours when the market either does not demand RR services or FRR prices are more convenient than those for RR services. In hours where the VPP has a sufficiently substantial P2G load, such as for example from 16:00-17:00 or 18:00-19:00, upward services provision results economically convenient. Hours with lower P2G load instead, such as, for instance, from 17:00-18:00, are prone to DW services despite the conveniently high UP prices per MWh. FRR services add thereby an additional 25% of revenues.

In the fifth and last step of the value stacking optimization, the VPP is confronted with another perturbation resulting from the intra-day PV forecast error. If facing IPs based on a single pricing average scheme, as currently applied in Italy for DERS, this would result in a negative cash flow of 30 €/MWh. By internally using the implicit flexibility of the P2G unit, the VPP eventually manages to offset the negative payments and turn the cash flow from the real-time adjustments into a positive amount of 86 €/MWh. Ultimately, the total revenues from the sum of the individual market interactions for the VPP add up to 6,615 € on 07.07.2019. Compared to the initial baseline of 4,592 € on this day, value stacking results in additional revenue of 44% for the entire VPP. On the other three simulated days, the additional gains from EM operations combined with active and passive balancing are even higher, as shown in table 7.2. In this context, the contributions of the different markets depend on the underlying forecast errors, the demand for balancing services, and the respective prices of each day.

Given the importance of passive balancing schemes for DERs that are currently not yet enable to active balancing (be it Italian DERs that do not adhere to the UVAM project or other DERs in the European context where the ASM is generally not yet opened to DERs), the presented case study ran different scenarios for the last optimization step. If the VPP would not face for the last optimization step IPs that are based on a Single Pricing scheme but a Dual Pricing scheme (as currently applicable for programmable units in Italy that operate on the ASM), the cash flow from real-time adjustments would deteriorate accordingly. Even under utilization of the P2G's flexibility, the cashflow for the 07.07.2019 remains negative with -7 €.

If the the VPP would instead continue to face a Single Pricing scheme and interpret the IPs as active market signals to leverage on (i.e., to deviate intentionally), the real-time deviations would be similarly pronounced as from previous balancing market interactions (see Figure 7.3 (VI)). Given the high IPs during day hours as illustrated in Figure 7.2, resulting in this case from a short IP-area and accordingly accepted upward balancing offers on the BAM, the VPP contributes by re-injecting a significant amount of the PV generation and providing a passive upward balancing to the grid. Such is highly remunerated and would result in this case in a cash flow from imbalance fees of 2,301 €. The total revenue from VPP operation would amount thereby to 8,859 €, nearly doubling the initial baseline and generating an added value of 93%.

7.4 Discussion

The stacking of different products and services analyzed in the case study raises the question of whether some of these offer special value and thus should receive special attention for further integration of DERs. Based on the limited case study with four exemplary days, no clear preference emerges as to which product would be most beneficial.

Generally, however, it remains to be noted that the IDM does not have an excessively large price jump to the DAM, it appears though to be particularly valuable when the inaccuracy of the forecast values of iRES plants is considerable. Furthermore, the activities on DAM and the following IDM show effectively how much a

VPP converts a previously rigid resource such as PV into a highly price-responsive unit. In this sense, aggregators not only enable the active balancing integration of DERs with explicit flexibility provision, but also independently enable a significant activation of implicit flexibility potential.

Otherwise, the combination of both RR and FRR seems to be useful as the business opportunities complement each other in different hours. This is especially important for bidding zones where there are a considerable number of hours in which a product may not be in demand, as it is the case for the studied Sicily. For the limited case study with the four exemplary days, the additional possibility to provide FRR added between 20-40% of extra added value to the business case, more than the sole provision of RR. With reference to the original UVAM framework, the additional provision of FRR thus appears to represent an interesting extension. In addition, the case study shows that combining an iRES system with a behind-the-meter consumption or storage option eventually makes downward balancing also attractive for a (combined) iRES unit.

With regard to real-time imbalances caused by short-term forecast errors that can no longer be absorbed by any market, it is shown how VPPs can still absorb these imbalances. Depending on the underlying IP-scheme and the forecasting capabilities or transparency of the IPs, additional large balancing potentials can be realized if VPP operators interpret the prices as a market signal and apply passive balancing.

A fundamentally important point for the provision of both active and passive balancing services is the underlying baseline of the aggregated unit. For example, if the VPP is to provide downward balancing services, it must have sufficient downward margin in advance and the P2G unit must not already be running at full capacity[1]. Conversely, for the economic provision of upward balancing services, the P2G unit must already be running in advance and have a corresponding baseline from which it can consume less electricity or feed in more electricity. This results in a complex interaction of the different market operations. The version presented in this case study works market by market without prejudice. For example, no intentional and possibly unprofitable baselines are built on EMs in order to be able to offer high-priced balancing services. Such combined optimization processes would be all the more interesting from an economic point of view and are therefore subject of future research.

[1] Potentially the PV could of course still be curtailed, but this is the least economic approach, especially as long as no negative downward balancing prices exist in Italy. See Chapter 5.3.1 for more details.

7.5 Summary and Policy Recommendations

In this chapter, the simulated operation of an aggregated unit of PV and power-to-gas using a multi-period and multi-stage optimization approach is presented to assess the value of providing multiple services from distributed energy resources. The case study is based on empirical market data from Italy and operating parameters of an existing power-to-gas plant. The combined operation of multiple DERs in virtual aggregates proves to be highly favorable and offers numerous advantages.

For DER operators, the integration of their assets into a VPP that operates with value stacking provides at least 44% of potentially added revenues compared to sole day-ahead market operations. The complex operational interdependencies between the different service offerings call for in-depth optimization and provide also margin for future research.

From a system operators perspective, the joint operation of programmable and non-programmable units under a single VPP generates the added value to turn previously inelastic units price sensitive. Even without active balancing integration, only through pure EM operation, this already results in a tangible implicit flexibility potential. With regard to inevitable real-time imbalances, the combined operation in a VPP enables DER operators to minimize the risk of imbalance fees and provides system operators with a more balanced asset portfolio connected to their grid. The potential opening for passive balancing would demonstrably further boost the responsiveness of DERs.

Last but not least, the separate analysis of multi-product offerings showed that there is currently no one product that would be most valuable from a flexibility providers perspective. Instead each product adds its very own value in an often complementary way. In that sense the full opening of ASMs with the full set of products to distributed flexibility providers appears most reasonably. While the opening for a single product such as through the Italian UVAM project opened already a new business opportunity for DERs, the addition of FRR would enhance the business case of individual units. Average results suggest that the added value might be in a similar range as the originally enabled provision of RR and hence double the economic appeal.

8 Conclusions

With the energy transition aiming to decarbonize the energy sector, its transformation process is accompanied by a continued decentralization and digitalization of involved assets and respective actors. And while the decentralization sets more and more end-users in the center of attention, facilitating actors such as aggregators appear to be the crucial connection point to drive the transition to success. By aggregating, optimizing and centrally controlling the distributed assets, the aggregator and other actors of its kind connect and integrate decentral energy assets to rather central market frameworks. The ecosystem of customers, markets and partners to be linked by this player are clearly described in the literature. As outlined in Chapter 2 they consist mainly of downstream customers in the form of prosumers and consumers on the one hand, and grid operators and platform operators with higher level markets on the other hand. Platform providers and retailers complement the set of partners in case aggregators enter additional segments of the value chain. Also the value proposition towards their customers is clearly outlined in academic literature in that customers should on the one (donwstream) hand be able to reduce possible consumption costs plus access new revenue streams, whereas on the other (upstream) hand customers gain access to new flexibility resources for local or system-wide services. However, the financial structures that are supposed to enable this business model are less clear and remain rather abstract to superficial in the academic literature.

To emancipate from governmental subsidies and take the energy transition to the next level, a viable and inherently market-based business case for actors who drive renewable and distributed energy assets, such as aggregators, is key. The studies presented in this thesis address the identified evidence gap in the literature in this regard, providing empirical evidence from Italy on potential economic implications of different market design elements that aim for increased balancing integration of distributed and renewable energy resources. Therefore, full balancing integration of such distributed energy assets, with active and passive contributions, represents an interesting approach. This is true not only from a technical point to guarantee the stability of a system with continuously less large-scale programmable (i.e., conventional) assets but also as the provision of balancing services presents the always more central business case for the remaining conventional assets.

Implications of Active Balancing Integration - Chapter 4 & 5 The Italian large-scale pilot project UVAM provided a first case study for active balancing integration of distributed energy resources (DERS) by integrating more than 1,000 MW of new capacity into the Italian Ancillary Service Markets. While at first glance this appears to be a successful development, more detailed investigations have shown that this is only superficially valid.

Eventually, it manifests that the project's framework alone might not have provided sufficient stimulus for market participants. While the overall DER capacity was on the paper integrated into the market, in the end the market engagement the DERs was characterized as strongly inactive and, in the end, little to no flexibility offer has ever been accepted. On the one hand, the business case for tertiary reserve (RR) provision alone may not be strong enough to overcome internal opportunity costs. Based on simple case studies, it appears that adding additional secondary reserve (FRR) provision would virtually double the economic opportunities for DERs and could therefore possibly provide the additional stimulus. On the other hand, the fixed capacity payment was probably just too tempting to just meet the minimum requirements and cash in. Maintaining such payments therefore seems questionable, or should at least be linked to changes in the framework conditions in order to avoid such repeated undesirable developments in the future.

Ironically, downward balancing bids in particular proved valuable during the difficult times of COVID-19, when renewables accounted for a higher share and conventional generators struggled to stay in the market, even though the project was not specifically designed to do so. One lesson learned from this should be to consider both balancing directions equally and to adjust the design parameters of the project or future markets accordingly. However, this unexpected service provision from UVAM units was most likely related to small conventional units as downward balancing proves not viable for renewable energy units that feature literally zero marginal costs. Removing the currently still existent price floor of 0 €/MWh on ancillary services markets would strengthen this business case, especially under the impression that the market price touched this barrier for a significant amount of hours during the COVID-19 pandemic due to high shares of renewables as they are also to be expected in future times with ongoing energy transition.

Feed-in tariffs and other support schemes related to energy market operations emerge as a generally detrimental factor for the business case of active balancing integration of renewable units, raising opportunity costs for flexibility provision significantly. Instead of focusing on the plants with incentives, however, it seems more appropriate to focus on the rapidly increasing number of potentially older plants that will soon fall out of the corresponding subsidy programs. To be feasible for such older plants, the market design elements must be adapted accordingly.

A last point of note concerns locational factors. Italy with its six physical bidding zones disposes of different market characteristics and economic conditions into which DERs are potentially integrated. Conducting several case studies in different bidding zones has shown how different the business case for actively balancing DERs turns out in this case. While the North represents a zone with a comparably liquid ancillary service market that has high demand but also considerably low prices, other zones are characterized either by staggeringly high prices or by remarkably low demand. The choice of the right location is thus crucial for the potential success of each business case.

Implications of Passive Balancing Integration - Chapter 6 Passive balancing can be conceived in two different ways. Either as an instrument to enforce minimum deviations of individual units or market participants, or as an instrument to integrate also those units and participants into an interactive system balance approach that are not (yet) included in active balancing approaches via markets. Depending on which philosophy one follows, the following findings have different implications.

Dual Pricing represents the design of choice for those who follow the first philosophy, punishing all individual imbalance no matter whether these are on average beneficial or detrimental to the overall system's balance. Single Pricing instead has its appeal especially for the second group of thought. While also additional components as further described in the following influence the welfare of concerned market participants, the difference between these two fundamental schemes provides a first benchmark. For the example of a single PV plant in Sicily, the application of a Dual Pricing based scheme would impact its annual balance sheet with imbalance payments of around 13% of its electricity sales on the day-ahead market, a Single Pricing based scheme instead would impact with only 2%.

A second design element that impacts the implications of passive balancing integration is the pricing basis. While the European target imbalance pricing schemes basis its calculation for example on (weighted) average balancing prices, marginal pricing that accounts only for the last accepted offer are also comparably widespread in Europe. In general, marginal pricing amplifies resulting imbalance prices, but only for a limited proportion of time. It represents thus a type of scarcity component which, for the bidding zone North in Italy, would amplify prices for roughly one quarter of time.

A third design elements concerns the passive balancing integration is the basis of products that the imbalance price calculation is based on. Italy, which as of now does not consider FRR, would face different scenario with the addition of FRR depending on the underlying pricing rule. With average pricing implementations FRR would have little to no effect, at most damping high prices. With marginal pricing this is naturally different, resulting in raised imbalance prices especially in medium-price range. The integration or not of other product categories can thus not be considered independently of the surrounding circumstances.

A fourth and last design element that was investigated is the the sizing of imbalance pricing areas. Italy adopts here as of now again a special role with macro areas that span across multiple bidding zones. On the other hand the fact to dispose multiple bidding zones provides also the opportunity to study and consequentially implement more local imbalance price areas. The performed studies showed that the current macro-areas dilute local price signals significantly and they are thus inefficient to transmit a purposeful balancing incentive. Local imbalance price areas are better on that regard, especially if implemented in a dynamic sizing fashion such as also in Norway. For the Italian case this would lead to more precise price signals for DERs to adjust their market position. Case studies for a Sicilian PV operator that is located in a comparably overpaying zone showed for example that the financial result from imbalance fees improves in this case by 66%, other operators in zones that underpay would deter accordingly. Imbalance pricing area sizing has therefore a significant impact on the welfare of involved market participants, be it from renewable units or also other generation and consumption units.

Implications of Full Balancing Integration - Chapter 7 Combining case studies from the previous two areas of focus constituted the final framework for a case study on full balancing integration with value stacking. While previous studies analyzed individual elements at a time, this study highlighted the interplay between different balancing integrations for DERs.

In general, the combined operation of multiple DERs in virtual aggregates proves to be highly favorable and offers numerous advantages for both individual DERs as well as for system operators. The performed case study shows that the integration of DERs into a VPP that performs value stacking with multiple energy markets, balancing markets, as well as real-time imbalance adjustments provides between 40-100% of potentially added revenues compared to sole day-ahead market operations.

While no one product or balancing service emerged in the case study as the clearly most valuable, it proved instead that each product adds its very own value in an often complementary way. Therefore, the full opening of ASMs to allow distributed flexibility providers to leverage on the full set of products appears most reasonably. Full balancing integration with value stacking of multiple services and products further extends the potential business opportunity from an individual DER operators' perspective and might be therefore the right step ahead to improve balancing performances' after the UVAM project.

From a system operators perspective, the joint operation of programmable and non-programmable units under a single VPP generates not only new opportunities for active balancing, but provides also a secondary no less important added value. By enabling synergies behind the (virtual) meter, previously inelastic units merge with controllable complements and turn in sum price sensitive. The extent to which this happens exceeds the elasticity that the controllable unit would display on its own. Even without active balancing integration, only through pure EM operation, this already results in a tangible implicit flexibility potential.

Concerning inevitable real-time imbalances, the combined operation in a VPP enables DER operators to minimize the risk of imbalance fees and provides system operators with a more balanced asset portfolio connected to their grid. By allowing for intentional deviation from market positions and providing the necessary transparency for adequate evaluation of the overall system's imbalance, the VPP could furthermore provide a proven additional flexibility potential. This would not only supply valuable short-term capacity to system operators but would also significantly extend the VPP's business case for DER integration. Thus the potential opening for full balancing with combined active and passive balancing would demonstrably further boost the responsiveness of DERs.

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List of Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
AEP	*Ausgleichs Energie Preis*, i.e., the German imbalance price
aFRR	automatic Frequency Restoration Reserve
ARERA	*Autorità di Regolazione per Energia Reti e Ambiente* i.e., the Italian regulatory authority
ASM	Ancillary Services Market
BAM	Balancing Market
BESS	Battery Energy Storage System
BM	Business Model
BMC	Business Model Canvas
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CAPEX	Capital Expenditure
CDF	Cumulative Distribution Function
CEP	Clean Energy Package
CSC	Community Self-Consumption
CRP	Consumption Responsible Party
DAM	Day-Ahead Market
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
EB GL	European Guideline on Electricity Balancing
EM	Energy Market
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
GME	*Gestore dei Mercati Energetici*, i.e., the Italian energy market operator
H2	Hydrogen
HRM	Harmonized electricity market Role Model
ICT	Information & Communication Technology

IDM	Intra-Day Market
IEA	International Energy Agency
IF	Imbalance Fee
IP	Imbalance Price
IPO	Imbalance Pay-Off
iRES	intermittent Renewable Energy Source
KPI	Key Performance Indicator
LEM	Local Energy Market
LFC	Load-Frequency Control
MB	*Mercato del Bilanciamento*, i.e., the Italian Balancing Market
mFRR	manual Frequency Restoration Reserve
MSD	*Mercato dei Servici di Dispacciamento*, i.e., the Italian Ancillary Services Market
NRA	National Regulatory Authority
OPEX	Operational Expenditure
OS	Other Services ("*altri servizi*" in Italian), one of the Italian ancillary service products
P2G	Power-to-Gas
P2P	Peer-to-Peer
PV	Photovoltaic
PRP	Production Responsible Party
RR	Replacement Reserve
SIDC	Single Intraday Coupling
SoC	State of Charge
SO GL	European Guideline on electricity transmission System Operation
TE	Transactive Energy
Terna	*Trasmissione Elettricità Rete Nazionale*, i.e., the Italian TSO
TSO	Transmission System Operator
UVAM	UVAM (Unità Virtuali Abilitate Miste, i.e., virtually aggregated mixed units)
VOLL	Value Of Lost Load
VPP	Virtual Power Plant

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Main Publications:

- Jan Marc Schwidtal, Marco Agostini, Fabio Bignucolo, Massimiliano Coppo, Patrizia Garengo, and Arturo Lorenzoni. "Integration of Flexibility from Distributed Energy Resources: Mapping the Innovative Italian Pilot Project UVAM". in: *Energies* 14.7 (2021). DOI: 10.3390/en14071910. **Peer-reviewed**, cited as [189].
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Supplementary Material B

B.1 Supplementary Material of Chapter 2

B.1.1 HRM role definitions

The following list are the definitions that ENTSO-E provides for the specific market functionalities. They are part of a wider set of definitions from their the Harmonized electricity Market Roles (HRM) [32].

- *Balancing Responsible Party:* A Balance Responsible Party is responsible for its imbalances, meaning the difference between the energy volume physically injected to or withdrawn from the system and the final nominated energy volume, including any imbalance adjustment within a given imbalance settlement period. Note: Based on "Regulation (EU) 2017/2195". Additional information: Responsibility for imbalances (balance responsibility) requires a contract proving financial security with the Imbalance Settlement Responsible of the Scheduling Area entitling the party to operate in the market.

- *Balancing Service Provider:* A party with reserve-providing units or reserve-providing groups able to provide balancing services to one or more LFC Operators. Additional Information: Based on Based on "Regulation (EU) 2017/2195".

- *Billing Agent:* The party responsible for invoicing a concerned party.

- *Consumer:* A party that consumes electricity. Additional Information: This is a type of “Party connected to the grid”.

- *Consumption Responsible Party (CRP):* A Consumption Responsible Party is responsible for its imbalances, meaning the difference between the energy volume physically withdrawn from the system and the final nominated energy volume, including any imbalance adjustment within a given imbalance settlement period. Additional information: This is a type of Balance Responsible Party.

- *Data Provider:* A party that has a mandate to provide information to other parties in the energy market.

- *Energy Supplier:* An Energy Supplier supplies electricity to or takes electricity from a "Party connected to the grid" at an accounting point.

- *Energy Trader:* A party that is selling or buying energy.

- *LFC Operator:* Responsible for the Load Frequency Control (LFC) for its LFC Area or LFC Block. Additional information: This role is typically performed by a TSO.

- *Market Information Aggregator:* A party that provides market related information that has been compiled from the figures supplied by different actors in the market. This information may also be published or distributed for general use. Additional Information: This usually is an energy/power exchange or platform. The definition is based on the "Regulation (EU) 2019/943".

- *Merit Order List Responsible:* Responsible for the management of the available tenders for all Acquiring LFC Operators to establish the order of the reserve capacity that can be activated.

- *Party Connected to the Grid:* A party that contracts for the right to consume or produce electricity at an Accounting Point

- *Producer:* A party that generates electricity. Additional information: This is a type of "Party connected to the grid". The definition is based on the "Directive (EU) 2019/944".

- *Production Responsible Party (PRP):* A Production Responsible Party is responsible for its imbalances, meaning the difference between the energy volume physically injected to the system and the final nominated energy volume, including any imbalance adjustment within a given imbalance settlement period. Additional information: This is a type of Balance Responsible Party.

- *Reserve Allocator:* Informs the market of reserve requirements, receives bids against requirements and in compliance with the prequalification criteria, determines which bids meet the requirements and assigns bids.

- *Resource Aggregator:* A party that aggregates resources for usage by a service provider for energy market services. Note: In the current version, the only service provider in HRM is the Balancing Service Provider.

- *Resource Provider:* A role that manages a resource and provides production / consumption schedules for it, if required.
- *Scheduling Area Responsible:* A party responsible for the coordination of nominated volumes within a scheduling area. Additional information: This role is typically performed by a TSO.
- *System Operator:* A party responsible for operating, ensuring the maintenance of and, if necessary, developing the system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of transmission of electricity. Additional information: The definition is based on "Directive 2009/72/EC".

B.1.2 Extended information on Aggregator Business Model

Table B.1: Detailed business model elements with references of reviewed Aggregators in local energy markets. *(Adapted from [14])*

	Aggregator		
	P2P	**CSC**	**TE**
Value proposition	*For upstream customers* 1. untapping new flexibility [49], [39]* • with locational component to react to network constraints, e.g., for congestions [39]* • without locational component to balance portfolios or network areas [49] 2. trading electricity [37, 44] • at convenient rates (buy above wholesale, sell below wholesale price) [37] • at regular market rates [44] *For downstream customers* 1. virtual aggregation and central dispatch [40, 44, 45, 49], [38]* • for supply of (deficit) electricity with reduced procurement costs [40, 44, 45] • for purchase of (surplus) electricity with enhanced revenues [44] [38]* • to reduce imbalance costs [45] • to enable additional revenues from utilization of assets' flexibility [49] 2. facilitate electricity exchange amongst customers [44] [38, 39]*	*For upstream customers* 1. untapping new flexibility with locational component to react to network constraints, e.g., for congestions [39]* *For downstream customers* 1. virtual aggregation and central dispatch for purchase of (surplus) electricity with enhanced revenues [38]* 2. facilitate electricity exchange amongst customers [38, 39]*	*For upstream customers* 1. untapping new flexibility [34–36, 41–43, 46, 50–53] • with locational component to react to network constraints, e.g., for congestions [34–36, 41, 43, 46, 50, 52] • without locational component to balance portfolios or network areas [41, 46, 50–53] • for optimal electricity procurement on upstream markets [42] 2. trading electricity [40, 41, 46, 52, 54] *For downstream customers* 1. virtual aggregation and central dispatch [34, 36, 42, 43, 46–48, 50–53, 55] • for supply of (deficit) electricity with reduced procurement costs [34, 42, 43, 46–48, 50–53, 55] • for purchase of (surplus) electricity with enhanced revenues [46–48, 51] • to reduce imbalance costs [47, 48, 53, 55] • to enable additional revenues [36, 55] – from capacity market participation [55] • while guaranteeing individual preferences [50, 52] 2. No specific value proposition to downstream customers [35, 41]
Customer segments	*Upstream (& peers):* • Grid operator [49], [39]* • microgrid as (large-scale) Prosumer [40] • Aggregator [37] • Retailer [44]	*Upstream (& peers):* • Grid Operator [39]* *Downstream:* • Prosumer (residential) [38]* • Pure Consumer (EVs) [38]*	*Upstream (& peers):* • Grid Operator [34–36, 41, 43, 46, 52–54] • Aggregator [41, 51] • Retailer [42] • (large-scale) Pure Generator [46]

Aggregator			
	P2P	**CSC**	**TE**
Customer segments *(cont'd)*	*Downstream:* • Prosumer [44, 45, 49], [38]* – EVs [45] – residential prosumers [44, 49], [38]* • Pure Consumer [37, 40], [38]* – Loads [37, 40] – EVs [38]* • Pure Generator [37] • Storage Operator [37]		*Upstream (& peers) (cont'd):* • Platform Operator [41, 46, 52, 54] – wholesale market [41, 52, 54] – nested market at next higher voltage level [46] *Downstream:* • Prosumer [34–36, 46, 47, 50–53] – residential prosumer [35, 52, 53] – EVs [34, 50, 53] • Pure Consumer [42, 43, 46, 48, 51, 54, 55] • Pure Generator [41, 48, 51, 54] • Storage Operator [48, 51, 54]
Customer relationships	• Automated [37, 40, 44, 45], [38]* • Not specified [49], [39]*	• Automated [38]* • Not specified [39]*	• Automated [34–36, 41, 46–48, 50–55] • self-service [55] • Not specified [43]
Channels	*For upstream customers:* **Evaluation:** • Bid and ask prices [37, 40] • Price merit order (for a grid operator) [49] • Technical fit [39]* • Not specified [44, 45, 49], [38]* **Purchase:** • direct interaction (bargaining / bid exchange) [39]* • local platform [37, 40] • national (balancing market) platform [49] **Delivery:** • Market algorithm [44] • Distribution grid [37, 40, 49], [39]* • Balancing market [49] • Not specified [38]* *For downstream customers:* **Evaluation:** • Price [44, 45] • None or not specified [37, 40, 49], [38, 39]*	*For upstream customers:* **Evaluation:** • None or not specified [38, 39]* **Purchase:** • direct interaction (bargaining / bid exchange) [39]* **Delivery:** • Power network [39]* • Not specified [38]* *For downstream customers:* **Evaluation:** • None or not specified [38, 39]* **Purchase:** • direct interaction [38, 39]* – bargaining / bid exchange [39]* – long-term sign-up [38]* **Delivery:** • Power network [39]* • Not specified [38]*	*For upstream customers:* **Evaluation:** • Price [35, 41, 42, 46, 51, 53] • Constraints of DERs [35] • Cost [54] • Not specified [34] **Purchase:** • direct interaction (bargaining / bid exchange) [35, 36, 42, 52] • local platform [34, 41, 46, 51, 53] • national (wholesale & balancing market) platform [46–48, 50, 53, 54] **Delivery:** • Distribution grid [35, 41, 51–53] • Wholesale markets [53, 54] • TE platform [55] • Not specified [42] *For downstream customers:* **Evaluation:** • Preference for charging EVs [50] • Revenue generation [47, 55] • Benefits from aggregator's services [48]

	Aggregator		
	P2P	**CSC**	**TE**
Channels *(cont'd)*	**Purchase:** • direct interaction [45], [38, 39]* – bargaining / bid exchange [45] [39]* – through representative (EMS) [45] – long-term sign-up [38]* • local platform [44] • unclear sign-up [37, 40, 49] **Delivery:** • Market algorithm [44] • Representative (HEMS) [45] • Distribution grid [37, 40, 49], [39]* • Not specified [38]*		**Evaluation *(cont'd)*:** • Price [43] • Types of services [55] • None or not specified [34, 51, 52] **Purchase:** • direct interaction [34–36, 43, 46, 48, 50–52, 55] – continuous bargaining / bid exchange [35, 36, 50, 52] – long-term sign-up [34, 43, 46, 48, 51, 55] • unclear sign-up [41, 42, 47, 53] **Delivery:** • TE platform [34, 35, 50, 51, 55] • Specific systems/networks - Bus network [47] - A nested system [46] • Distribution grid [48] • Not specified [42]
Revenue streams	*From upstream customers* **fixed Revenues:** • None or not specified [37, 40, 44, 45, 49] [38, 39]* **variable Revenues:** • Sale of electricity [37] • Revenue from accepted bids and offers for flexibility [49] [39]* • None or not specified [40, 44, 45] [38]* *From downstream customers* **fixed Revenues:** • None or not specified [37, 40, 44, 45, 49] [38, 39]* **variable Revenues:** • None or not specified [37, 40, 44, 45, 49] [38, 39]*	*From upstream customers* **fixed Revenues:** • None or not specified [38, 39]* **variable Revenues:** • Revenue from accepted bids and offers for flexibility [39]* • None or not specified [38]* *From downstream customers* **fixed Revenues:** • None or not specified [38, 39]* **variable Revenues:** • None or not specified [38, 39]*	*From upstream customers* **fixed Revenues:** • Capacity payments for flexibility provision [55] • None or not specified [34, 35, 42, 43, 46, 48, 51–54] **variable Revenues:** • Sale of electricity [46, 48, 51, 52, 54, 55] • Sale of flexibility [46, 53–55] • Sale of ancillary services (reactive power) [46, 54] • Revenue from cost minimisation [48, 53] *From downstream customers* **fixed Revenues:** • Services fees [55] • None or not specified [34, 35, 42, 43, 46–48, 50–52] **variable Revenues:** • Sale of electricity to Prosumers [46–48, 51, 52, 55] • Revenue from cost minimisation [47, 48, 50] • None or not specified [34, 35, 42, 43]

	Aggregator		
	P2P	**CSC**	**TE**
Key partners	• Grid operator [37, 40] • Platform Operator [40] • Aggregator [45] • Retailers [49] • None or not specified [44] [38, 39]*	• None or not specified [38, 39]*	• Grid Operator [50, 52, 55] – DSO [50, 55] – TSO [52, 55] • Platform Operator [34, 43, 50, 51, 53] – TE platform operator [34] – Market operator [43, 50, 51] • Pure Generator [55] • Representative (commercial agent) [55] • Retailer (Utility and retailer) [55] • Not specified [35, 36, 41, 42, 46–48]
Key resources	**tangible:** • Smart devices [44] • None or not specified [37, 40, 45, 49], [38, 39]* **non-tangible:** • ICT and software to manage and communicate with customers and operate relevant activities [37, 40, 44, 45, 49], [39]* • None or not specified [38]* **human:** • None or not specified [37, 40, 44, 45, 49], [38, 39]*	**tangible:** • None or not specified [38, 39]* **non-tangible:** • software to manage bids and control individual flex [39]* • None or not specified [38]* **human:** • None or not specified [38, 39]*	**tangible:** • None or not specified [34–36, 42, 43, 46–48, 50–55] **non-tangible:** • ICT and software for: – Demand response forecast [42] – Aggregating and managing DERs [34, 41, 46, 48] – Optimisation [35, 50, 55] – Generation and loads forecast [46, 48] – Interaction with the market [46, 55] • None or not specified [36, 47, 52–54] **human:** • None or not specified [34–36, 42, 43, 47, 48, 50, 51, 53–55]
Key activities	*For upstream customers* • Facilitate service provision through: – aggregating individual flexibility [49] [39]* – controlling the performance of individual flexibility providers [39]*	*For upstream customers* • Facilitate service provision through: – aggregating individual flexibility [39]* – controlling the performance of individual flexibility providers [39]*	*For upstream customers* • Facilitate service provision through: – Submit DR [42] – Submit requirements and bids from EVs [34, 53] – Communicate with DSO [35] • Optimisation [35]

	Aggregator		
	P2P	**CSC**	**TE**

Key activities *(cont'd)*	*For upstream customers (cont'd)*
	• Facilitate energy trading through:
	  – aggregation of individual consumption/generation profiles [37, 44]
	For downstream customers
	• Aggregate and actively manage assets of customers [37, 40, 49] [38]*
	  – Shifting load to off-peak periods [40]
	  – Control, schedule and reschedule DERs for optimized production [37, 49] [38]*
	• Operate local market and facilitate exchange amongst customers [44] [38, 39]*
	• Forward external flexibility needs to customers [39]*
	• Interact with other local market participants on behalf of customers to buy/sell supplemental/surplus electricity [37, 40, 45]
	• Participate in the wholesale market (bidding) on behalf of aggregated customers [45]
		For downstream customers
		• Aggregate and actively manage assets of customers [38]*
		  – Control, schedule and reschedule DERs for optimized production [38]*
		• Operate local market and facilitate exchange amongst customers [38, 39]*
		• Forward external flexibility needs to customers [39]*
			For downstream customers
			• Aggregate and and actively manage assets of customers:
			  – Manage DR [42, 48]
			  – Manage DERs and submit bids to the market [43, 46–48, 51, 54, 55]
			  – Manage EVs and submit bids to DSO and TE operator [34, 50, 53]
			  – Optimisation of DERs [35, 47, 48, 51]
			• Participate in the wholesale market (bidding) on behalf of aggregated customers [43, 54]
			• Trade electricity on behalf of prosumers [47, 51]
			• Communicate with DERs [35]

Cost structure	**CAPEX:** • none or not specified [37, 40, 44, 45, 49], [38, 39]* **OPEX:** • opportunity costs for local flexibility provision [49] [39]* *(cost equals revenue received [39]*)* • purchase of electricity (variable component + grid costs) [40] • none or not specified [37, 44, 45] [38]*	**CAPEX:** • none or not specified [38, 39]* **OPEX:** • opportunity costs for local flexibility provision (equals revenue received for flexibility) [39]* • none or not specified [38]*	**CAPEX:** • BESS investment cost [47] • ICT [55] • none or not specified [34–37, 42, 43, 45, 46, 48, 50–54] **OPEX:** • purchase costs for electricity from upstream (wholesale) market [46, 48, 50, 53, 55] • generation (fuel) costs for local (internal) electricity [47, 48, 51, 54] • opportunity costs for local flexibility provision (e.g., load shifting) [47, 48, 54, 55] • imbalance costs [47, 48, 50, 51, 53, 55] • transaction costs for local electricity [51] • none or not specified [34–37, 41–43, 45, 52]

[ ]* entry refers to a paper that contains more than one energy market model

B.2 Supplementary Material of Chapter 4

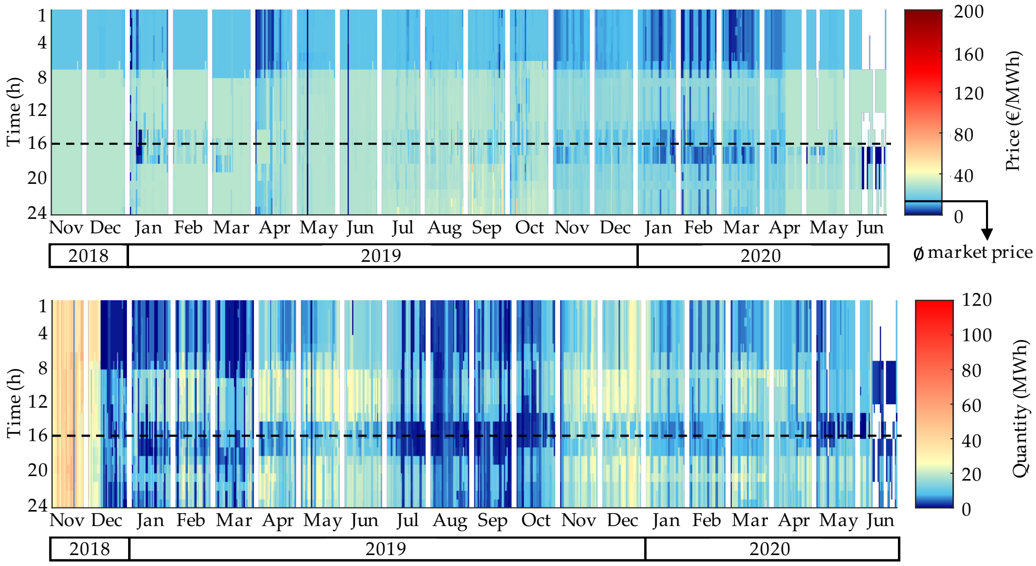


Figure B.1: Heatmap of summarized hourly offers by UVAM units in downward direction in terms of the weighted average price (chart *above*) and the summed quantity (chart *below*). *(Reprinted with permission from [189])*

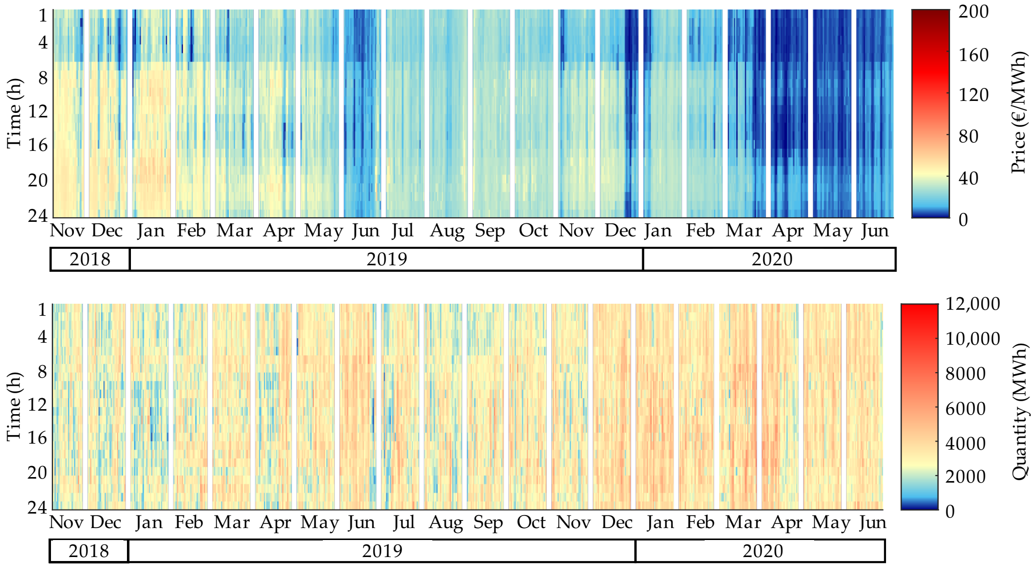
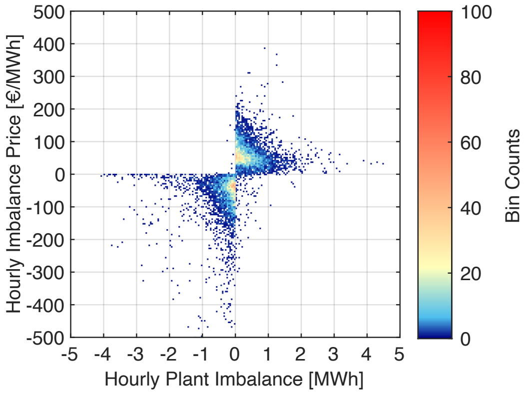
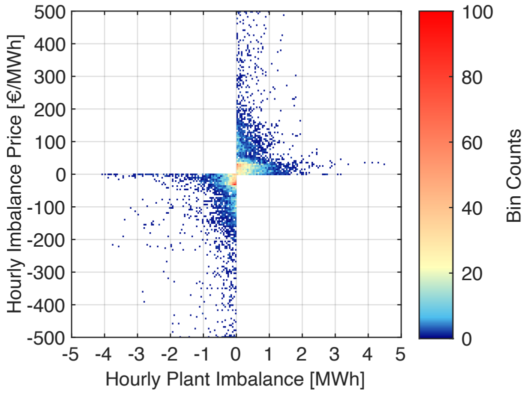


Figure B.2: Heatmap of summarized awarded offers in downward direction on the Italian ASMs in terms of the weighted average price (chart *above*) and the summed quantity (chart *below*). *(Reprinted with permission from [189])*

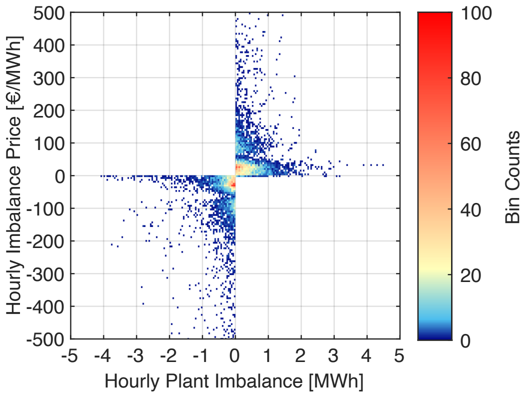
B.3 Supplementary Material of Chapter 6



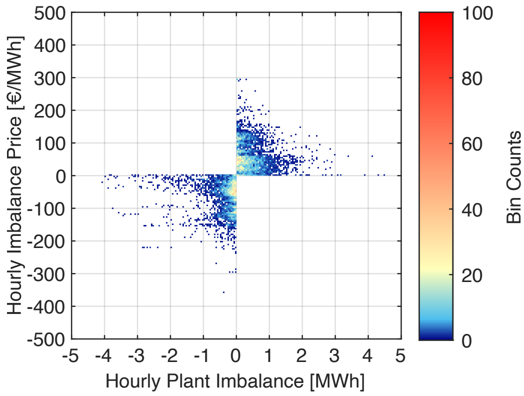
(a) Italian iRES comp. scheme



(b) Single Pricing average



(c) Single Pricing incl. FRR average



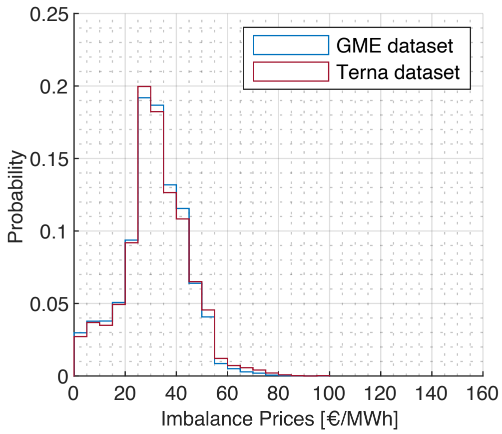
(d) Single Pricing incl. FRR average - *local IPA*

Figure B.3: Hourly imbalance prices versus hourly plant imbalances under different imbalance pricing schemes for a representative 10 MW Wind plant in the bidding zone Sicily. *Case scenario:* 2019 with (a) to (c) Macro-South as the underlying aggregated imbalance pricing area and (d) Sicily as the local imbalance pricing area.

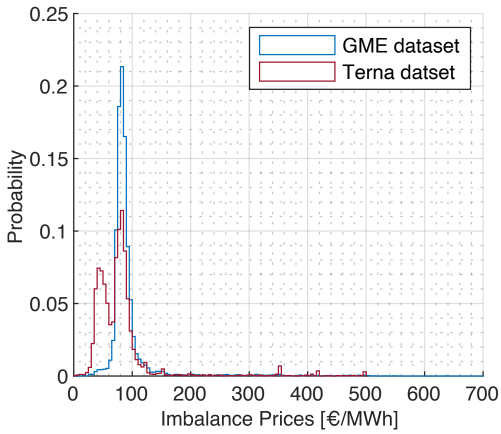
Table B.2: Calculated average imbalance prices $\varnothing p_{imb}$ and respective standard deviations $\sigma(p_{imb})$ based on the datasets of the Italian market operator (GME) and the Italian TSO's (Terna) for 2019 in the bidding zones North and Sicily under Single Pricing average.

Bidding zone:			**North**			**Sicily**		
Imbalance price area:			North			Macro-South		
Dataset:			Terna dataset	GME dataset		Terna dataset	GME dataset	
Area + BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	30.03	31.41	(- 2%)	24.48	23.61	(- 4%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	12.96	12.41	(- 4%)	18.34	17.12	(- 7%)
Area - BRP +	$\varnothing p_{imb}$	$[\frac{€}{MWh}]$	79.43	94.62	(+19%)	159.42	169.55	(+6%)
	$\sigma(p_{imb})$	$[\frac{€}{MWh}]$	57.50	69.68	(+21%)	124.47	124.69	(+0%)

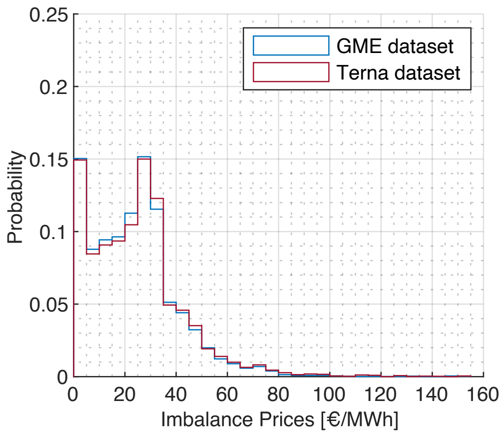
Note: *Percentages describe the deviations of the imbalance price from the GME dataset compared to Terna's dataset.*



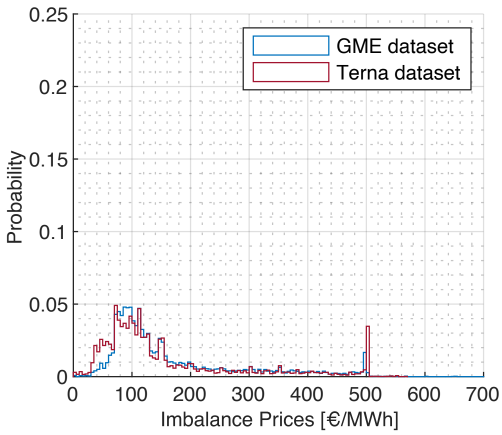
(a) Bidding zone North: Area + / BRP +



(b) Bidding zone North: Area - / BRP +



(c) Bidding zone Sicily: Area + / BRP +



(d) Bidding zone Sicily: Area - / BRP +

Figure B.4: Comparison of imbalance price as emerging from the Italian market operator's (GME) dataset and the Italian TSO's (Terna) dataset for 2019 in the bidding zone North ((a) & (b)) and Sicily (with IPA Macro-South) ((c) & (d)). *Case scenario:* Single Pricing average.

Colophon

This thesis was typeset with $\LaTeX\,2_\varepsilon$. It uses the *Clean Thesis* style developed by Ricardo Langner. The design of the *Clean Thesis* style is inspired by user guide documents from Apple Inc.

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