POLITECNICO DI MILANO

School of Industrial Engineering and Information

Master of Science in Electrical Engineering

TSO-DSO Coordination Schemes for Flexibility Markets

Master Thesis

Javier José González Ruiz

ID: 915159

Supervisor: Prof. Cristian Bovo

Co-supervisor: Prof. Valentin Ilea

Academic year 2020/2021

Contents

Contents 2

Figures 6

Tables 12

Acknowledgements 14

1 Abstract – Sommario 15

2 Introduction 17

2.1 Outline of the Thesis 20

3 Context 21

3.1 Global warming and RES 21

3.2 Distributed Energy Resources 25

3.3 The Clean Energy Package 29

3.3.1 Ensuring the internal market level playing field 31

3.3.2 Adapting to the decentralization of the power system 32

3.3.3 Empowering customers and citizens 33

3.4 European Ancillary Services and Balancing markets 33

3.5 The Italian market reforms 37

3.6 TSO-DSO coordination in the Clean Energy Package 42

4 TSO-DSO coordination 45

4.1 Distributed Energy Resources and flexibility services 45

4.2 TSO-DSO coordination in the literature 48

4.3 SmartNet project 53

4.3.1 Models for TSO-DSO coordination 54

4.3.2 Simulation platform 56

4.3.3 Objective function of the market model 59

4.3.4 Results and policy recommendations 60

4.4 Other European projects 61

4.4.1 EUSysFlex ... 61

4.4.2 Interflex ... 64

4.4.3 COORDINET ... 66

4.4.4 OSMOSE Project ... 67

5 Bidding structure and Aggregation ... 70

5.1 Bidding in European balancing energy platforms ... 71

5.2 The Italian experience with aggregation: UVAM pilot projects and Electricity Dispatching Reform ... 72

5.3 European Union founded projects: SmartNet and INTERRFACE ... 76

5.4 Bids and market designs in the literature ... 79

5.5 Load shifting: EV, energy storage and other resources ... 81

5.6 DSO's proprietary energy storage systems ... 84

5.7 Literature review summary ... 85

5.8 Proposal for aggregation and bid modelling ... 86

6 Network model for power flow and Optimal power flow problems ... 95

6.1 Distribution Network models ... 95

6.1.1 Branch formulation ... 96

6.1.2 Polar power flow formulation ... 100

6.1.3 Current injection formulation ... 106

6.1.4 Method Comparison ... 108

6.2 Numerical comparison ... 110

6.3 Chapter conclusions ... 122

7 Market models for TSO-DSO Coordination ... 124

7.1 Flexibility Market Structure ... 124

7.2 TSO-DSO Coordination schemes ... 125

7.2.1 Scheme 1: Flexibility market at the transmission level, incomplete information 125

7.2.2 Scheme 2: Flexibility market at the transmission level, complete information 126

7.2.3 Scheme 3: Flexibility market at the transmission level, DSO applies acceptance criteria to bids 127

7.2.4 Scheme 4: Flexibility market at the distribution level 128

7.2.5 Scheme 5: Flexibility market at the distribution level, TSO imposes PQ profile at the HV/MV interface 128

7.2.6 Scheme 6: Flexibility market at the distribution level, DSO aggregates and submits bids to TSO 129

7.3 Mathematical and market formulation 130

7.3.1 Scheme 3 131

7.3.2 Scheme 4 132

7.3.3 Scheme 5 138

7.3.4 Scheme 6 139

8 Iterative optimization algorithm 143

8.1 Step (3): Optimization algorithm and bid selection 146

8.2 Step (4): Stopping criterion 146

8.3 Step (6): Updating system state 148

8.4 Numerical convergence issues 151

8.4.1 Reactive power management 152

8.4.2 ESS management 153

8.4.3 Modelling relevant constraints 153

9 Simulation results 154

9.1 Proof-of-concept model 154

9.1.1 Scheme 4 163

9.1.2 Scheme 5 170

9.1.3 Scheme 6 173

9.2 TESTOPF – 96 periods 176

9.2.1 Scheme 4 182
9.2.2 Scheme 5 183
9.2.3 Scheme 6 185
9.3 Rete81 – 96 periods 188
9.3.1 Scheme 4 191
9.3.2 Scheme 5 194
9.3.3 Scheme 6 196
9.4 Results Discussion 199
10 Conclusions and future work 201
10.1 Simulation platform 201
10.2 Regulatory framework 202
10.3 Future work 203
11 Bibliography 205
12 Appendix 213
12.1 Network characteristics 213
12.2 Results from Network testing scenarios 218
12.3 Numerical versus analytical sensitivity matrices 223
12.4 Automatic network generation tool 226
12.5 Information and Additional simulation results 232

Figures

Figure 3-1. Globally averaged combined land and ocean surface temperature anomalies and Global anthropogenic CO_2 emissions, adapted from [4] 22
Figure 3-2. GHG emission pathways 2000-2100: all AR5 scenarios [4] 22
Figure 3-3. Global greenhouse gas emissions under different scenarios and the emissions gap in 2030, median estimate and 10^{th} to 90^{th} percentile range [5] 23
Figure 3-4. Increase in global mitigation costs due to either limited availability of specific technologies or delays in additional mitigation relative to cost-effective scenarios [4] 24
Figure 3-5. Global electricity generation changes in Stated policies (STEPS) and Sustainable development (SDS) Scenarios [7] 24
Figure 3-6. Centralized and Distributed renewable energy resources [8] 25
Figure 3-7. Global weighted-average LCOE and price learning curve trends for solar PV, CSP, onshore and offshore wind, 2010-2021/2023 [9] 25
Figure 3-8. Energy installation costs central estimate for battery technologies, 2016-2030 [10] 26
Figure 3-9. Expected penetration of solar and battery capacity in the Australian electrical system [11] 27
Figure 3-10. Electric vehicle retrospective and prospective trends, adapted from [14] 28
Figure 3-11. Interaction of frequency related services during an under-frequency event [22]34
Figure 3-12. Schedule for implementation of European market platforms [23] 35
Figure 3-13. Italian Market sequences proposed by 322/2019/R/eel [25] 38
Figure 3-14. Definition of commercial positions and Energy programs in the Italian market reform 39
Figure 3-15. Aggregation schemes in the market reform [25] 41
Figure 4-1. Innovation in ancillary services [32] 47
Figure 4-2. Dispatching models for TSO-DSO coordination. Adapted from [29] 49
Figure 4-3. Hierarchical coordination mechanism [35] 50
Figure 4-4. Conceptual representation of market and grid operation phases with respect to congestion management [36] 50
Figure 4-5. Representation of explicit/implicit capacity allocation by the DSO [36] 51
Figure 4-6. PQ charts of distribution network [37] 52
Figure 4-7. TSO-DSO coordination schemes. Adapted from [40] 54
Figure 4-8. Block representation of SNP simulation platform [43] 58

Figure 4-9. Minimization of activation costs in the SNP [43] 59
Figure 4-10.Curve-crossing illustration for the maximization of the social welfare [43] 60
Figure 4-11. Activation mechanisms for DSO needs in InterFlex [51] 65
Figure 4-12. Business cases tested in Dutch and French networks [50] 66
Figure 4-13. Work-plan OSMOSE Project [54] 67
Figure 4-14. Market designs considerations [55] 69
Figure 5-1. Standard products for Balancing energy [58] 71
Figure 5-2. Bid characteristic for UVAC projects [60] 74
Figure 5-3. Baseline for UVAM projects [26] 74
Figure 5-4. Standard bids Smart-Net project [43] 77
Figure 5-5.Graphical representation of various P-Q limit definition: a) fixed power factor, b) triangular limit, c) rectangular limit and d) circular limit [43] 78
Figure 5-6. Structure of the aggregation model [31] 80
Figure 5-7. Energy variation profile for aggregated DER and upward cost curve. Adapted from [31] 81
Figure 5-8. Pumped storage capabilities for load shifting, [68] 82
Figure 5-9. Residential load profiles for uncontrolled EV charging on the left, off-peak charging on the center and smart charging on the right. Adapted from [69] 83
Figure 5-10. Trade-off between model accuracy and complexity in different modelling alternatives [71] 84
Figure 5-11. Alternative 1 for Reactive power management 89
Figure 5-12. Alternative 2 for Reactive power management 90
Figure 5-13. Alternative 3 for Reactive power management 91
Figure 6-1. Simplified network diagram. Adapted from [72] 95
Figure 6-2. PI transmission line model [77] 104
Figure 6-3.Initial voltage and current profile, TESTOPF network 110
Figure 6-4.Initial voltage and current profile, RETE81 network 111
Figure 6-5. Voltage error, scenario 1 – TESTOPF 114
Figure 6-6. Current error, scenario 1 – TESTOPF 114
Figure 6-7. Slack error, scenario 1 – TESTOPF 115
Figure 6-8. Voltage error, scenario 4 – TESTOPF 116
Figure 6-9. Current error, scenario 4 – TESTOPF 116
Figure 6-10. Slack error, scenario 4 – TESTOPF 117

Figure 6-11. Voltage error, scenario 1 – RETE81 118
Figure 6-12. Current error, scenario 1 – RETE81 119
Figure 6-13. Slack error, scenario 1– RETE81 120
Figure 6-14. Voltage error, scenario 4 – RETE81 120
Figure 6-15. Current error, scenario 4 – RETE81 121
Figure 6-16. Slack error, scenario 4– RETE81 121
Figure 7-1. Flexibility Market structure 124
Figure 7-2. Scheme 1: Flexibility market at the transmission level, incomplete information .125
Figure 7-3. Scheme 2: Flexibility market at the transmission level, complete information 126
Figure 7-4. Scheme 3: Flexibility market at the transmission level, DSO applies acceptance criteria to bids 127
Figure 7-5. Scheme 4: Flexibility market at the distribution level 128
Figure 7-6. Scheme 5: Flexibility market at the distribution level, TSO imposes PQ profile at the HV/MV interface 129
Figure 7-7. Scheme 6: Flexibility market at the distribution level, DSO aggregates and submits bids to TSO 130
Figure 7-8. Aggregated supply curve for TSO-DSO coordination 139
Figure 7-9. Calculation of supply curve for TSO/DSO coordination Scheme 6 140
Figure 7-10. Expected results of aggregated supply algorithm 142
Figure 8-1. Iterative optimization algorithm 146
Figure 9-1. Cumulative load profile, proof-of-concept model 156
Figure 9-2. Cumulative aggregators profile, proof-of-concept model 157
Figure 9-3. Active network constraints, proof-of-concept model 158
Figure 9-4. Active branches constraints (red) and aggregators' location (green), proof-of-concept model 158
Figure 9-5. Cumulative flexibility from continuous bids, proof-of-concept model 161
Figure 9-6. Summary, Scheme 4, proof-of-concept model 164
Figure 9-7. ESS power variations, Scheme 4, proof-of-concept model 164
Figure 9-8. Evolution absolute error, Scheme 4, proof-of-concept model 165
Figure 9-9. Final errors, Scheme 4, proof-of-concept model 165
Figure 9-10. Summary, Scheme 4 – limit charging/discharging ESS, proof-of-concept model 166

Figure 9-11. Final errors, Scheme 4, proof-of-concept model – limit charging/discharging ESS 166
Figure 9-12. State of Charge, Scheme 4, proof-of-concept model....169
Figure 9-13. Slack power, Scheme 4, proof-of-concept model....169
Figure 9-14. Slack power, Scheme 5-1, proof-of-concept model 170
Figure 9-15. Summary, Scheme 5-1, proof-of-concept model....170
Figure 9-16. Accepted Resources, Scheme 5-1, proof-of-concept model....171
Figure 9-17. Slack power, Scheme 5-2, proof-of-concept model 172
Figure 9-18. Summary, Scheme 5-2, proof-of-concept model....172
Figure 9-19. Accepted Resources, Scheme 5-2, proof-of-concept model....172
Figure 9-20. Slack power, Maximum profile Scheme 6, proof-of-concept model....173
Figure 9-21. Summary, Maximum profile Scheme 6, proof-of-concept model....174
Figure 9-22. Summary, Minimum cost – Maximum profile Scheme 6, proof-of-concept model 174
Figure 9-23. Summary, Minimum profile Scheme 6, proof-of-concept model 175
Figure 9-24. Slack power, Maximum profile Scheme 6, proof-of-concept model....175
Figure 9-25. Feasible profiles and cost, Scheme 6, proof-of-concept model....176
Figure 9-26. Cumulative Non-flexibility resources profile, TESTOPF-96....177
Figure 9-27. Cumulative Flexibility resources profile, TESTOPF-96 178
Figure 9-28. Active network constraints, TESTOPF-96....179
Figure 9-29. Active branches constraints (red) and aggregators' location (green), TESTOPF – 96 179
Figure 9-30. Cumulative flexibility from continuous bids, TESTOPF – 96 180
Figure 9-31. Cumulative flexibility from step bids, TESTOPF – 96....181
Figure 9-32. Summary, Scheme 4, TESTOPF – 96 182
Figure 9-33. Final errors, Scheme 4, TESTOPF – 96....182
Figure 9-34. Accepted Resources, Scheme 4, TESTOPF – 96 183
Figure 9-35. Slack powers, Scheme 4, TESTOPF – 96....183
Figure 9-36. Slack power, Scheme 5-1, TESTOPF – 96....184
Figure 9-37. Accepted resources, Scheme 5-1, TESTOPF – 96....184
Figure 9-38. Slack power, Scheme 5-2, TESTOPF – 96....185
Figure 9-39. Accepted resources, Scheme 5-2, TESTOPF – 96....185
Figure 9-40. Cost and minimum power profile for periods 69-96, Scheme 6, TESTOPF – 96.186

Figure 9-41. Cost and maximum power profile for periods 27-65, Scheme 6, TESTOPF – 96 187
Figure 9-42. Cost and minimum power profile for periods 27-65, Scheme 6, TESTOPF – 96.187
Figure 9-43. Cumulative non-flexibility resources profile, RETE81....188
Figure 9-44. Cumulative Flexibility resources profile, RETE81 189
Figure 9-45. Active network constraints, RETE81....189
Figure 9-46. Cumulative flexibility from continuous bids, RETE81 190
Figure 9-47. Cumulative flexibility from step bids, RETE81....190
Figure 9-48. Summary, Scheme 4 – Oscillations, RETE81....191
Figure 9-49. Objective function and maximum relative error, Scheme 4 – Oscillations, RETE81 192
Figure 9-50. Summary, Scheme 4, RETE81 193
Figure 9-51. Objective function and maximum relative error, Scheme 4 – Oscillations, RETE81 193
Figure 9-52. Slack powers, Scheme 4, RETE81....194
Figure 9-53. Accepted resources, Scheme 4, RETE81 194
Figure 9-54. Slack powers, Scheme 5 – 1, RETE81 195
Figure 9-55. Accepted resources, Scheme 5 – 1, RETE81....195
Figure 9-56. Slack powers, Scheme 5 – 2, RETE81 196
Figure 9-57. Accepted resources, Scheme 5 – 2, RETE81....196
Figure 9-58. Two-hour step bids periods 46-53, Scheme 6, RETE81 197
Figure 9-59. Two-hour step bids periods 6-13, Scheme 6, RETE81....198
Figure 9-60. Two-hour step bids periods 75-82, Scheme 6, RETE81 198
Figure 12-1. Voltage error, scenario 2 – TESTOPF....218
Figure 12-2. Current error, scenario 2 – TESTOPF....219
Figure 12-3. Slack error, scenario 2 – TESTOPF 219
Figure 12-4. Voltage error, scenario 3 – TESTOPF....220
Figure 12-5. Current error, scenario 3 – TESTOPF....220
Figure 12-6. Slack error, scenario 3 – TESTOPF 220
Figure 12-7. Voltage error, scenario 2 – RETE81 221
Figure 12-8. Current error, scenario 2 – RETE81....221
Figure 12-9. Slack error, scenario 2– RETE81 221
Figure 12-10. Voltage error, scenario 3 – RETE81 222
Figure 12-11. Current error, scenario 3 – RETE81....222

Figure 12-12. Slack error, scenario 3– RETE81....222
Figure 12-13. Relative error in voltage sensitivities – TESTOPF....225
Figure 12-14. Relative error in current sensitivity matrices – TESTOPF....225
Figure 12-15. Relative error in voltage sensitivity matrices – RETE81....226
Figure 12-16. Relative error in current sensitivity matrices – RETE81....226
Figure 12-17. Load profiles [80] – [1], [69] – [2] and [81] – [3] in per unit....227
Figure 12-18. Average monthly generation profiles – January to March....228
Figure 12-19. Day-ahead prices, XM and GME....232
Figure 12-20. Maximum profile, Accepted Resources, Scheme 6, proof-of-concept model....232
Figure 12-21. Maximum profile – minimum cost, Accepted Resources, Scheme 6, proof-of-concept model....233
Figure 12-22. Minimum profile, Accepted Resources, Scheme 6, proof-of-concept model....233
Figure 12-23. Summary, Scheme 5-1, TESTOPF – 96....233
Figure 12-24. Summary, Scheme 5-2, TESTOPF – 96....234
Figure 12-25. Accepted resources, Scheme 6, minimum power between periods 69-96, TESTOPF – 96....234
Figure 12-26. Accepted resources, Scheme 6, maximum power between periods 27-65, TESTOPF – 96....234
Figure 12-27. Accepted resources, Scheme 6, Minimum power between periods 27-65, TESTOPF – 96....235
Figure 12-28. Accepted resources, Scheme 6, Minimum power between periods 35-60, RETE81....236

Tables

Table 3-1. Summary of technical scarcities, adapted from [15,16] 29
Table 3-2. New designation of Frequency related services [21,22] 34
Table 3-3. European Platforms for Ancillary Services [23] 35
Table 3-4. Roles of entities in new electricity balancing markets [21] 36
Table 3-5. Single price algorithm for imbalance settlement 40
Table 3-6. Resources allowed (A.) and not allowed (N.A.) to participate in the MSD in its current version (C.) and in the reform [25] 40
Table 3-7. Changes in procurement and remuneration of ancillary services [25] 42
Table 4-1. Dispatching Resources from DG and RES. Adapted from [29] 46
Table 4-2. TSO-DSO Coordination proposal. Adapted from [36] 51
Table 4-3. Aggregation models Smart Net Project. Adapted from [42] 57
Table 4-4. Basket generic system services [16] 63
Table 4-5. EUSysFLEX TSO-DSO Coordination schemes, Adapted from [49] 64
Table 5-1. Italian aggregation pilot projects [26] 73
Table 5-2. Aggregation in consultation document 322/2019/R/eel 75
Table 5-3. Summary of reactive power management alternatives 92
Table 6-1. Network notation 95
Table 6-2. Comparison power flow algorithms for distribution networks 108
Table 6-3. Testing scenarios – TESTOPF network 113
Table 6-4. Testing scenarios RETE81 network 118
Table 7-1. Summary coordination schemes 131
Table 7-2. TSO Prioritization list, Coordination Scheme 3 132
Table 7-3. DSO Prioritization list, Coordination Scheme 3 132
Table 7-4. Variables and parameters, Upward and Downward Continuous Bids 134
Table 7-5. Constraints, Upward and Downward continuous bids 135
Table 7-6. Variables and parameters, Upward and Downward Step Bids 135
Table 7-7. Constraints, Upward and Downward step bids 136
Table 7-8. Variables and parameters, ESS bids 136
Table 7-9. Constraints, ESS bids 137
Table 8-1. Network equations, linearization approach 143
Table 8-2. Variables and Parameters, Auxiliary continuous bids 148
Table 8-3. Constraints, Auxiliary continuous bids 148

Table 8-4. Numerical example, Auxiliary continuous bids....150
Table 8-5. Auxiliary variables and parameters, steps and ESS bids....150
Table 9-1. Base load, proof-of-concept model....155
Table 9-2. Load profiles, proof-of-concept model....156
Table 9-3. Aggregator information, proof-of-concept model....157
Table 9-4. Solar profile, proof-of-concept model....157
Table 9-5. Previous market section price, proof-of-concept model....159
Table 9-6. Continuous upward bids for periods 2-3, proof-of-concept model....160
Table 9-7. Continuous downward bids for periods 5-6, proof-of-concept model....160
Table 9-8. Upward Step bids, proof-of-concept model....161
Table 9-9. Downward Step bids, proof-of-concept model....162
Table 9-10. BESS, proof of concept model....162
Table 9-11. Continuous bid selected, Scheme 4, proof-of-concept model....167
Table 9-12. Step bid selected, Scheme 4, proof-of-concept model....168
Table 9-13. ESS selected variables, Scheme 4, proof-of-concept model....168
Table 9-14. Non-flexibility resources, TESTOPF – 96....177
Table 9-15. Flexibility Resources, TESTOPF-96....178
Table 9-16. Step bid characteristics, TESTOPF-96....180
Table 9-17. BESS, TESTOPF – 96....181
Table 12-1. Branch TESTOPF (base 100MVA)....213
Table 12-2. Generation TESTOPF (base 100MVA) – Slack node 1....213
Table 12-3. Bus TESTOPF (base 100MVA)....213
Table 12-4. Branch TESTOPF (base 2.5MVA)....213
Table 12-5. Bus TESTOPF (base 2.5MVA)....214
Table 12-6. Bus TEST81 (base 100MVA)....215
Table 12-7. Branch TEST81 (base 100MVA)....216
Table 12-8. Generation TEST81 (base 100MVA) – slack node 81....218
Table 12-9. Load profile description [80] – [1], [69] – [2] and [81] – [3]....227
Table 12-10. Geographical information for PV profiles....228
Table 12-11. Load flexibility quantities....229
Table 12-12. PV flexibility quantities....230
Table 12-13. Flexibility Resources, RETE81....235
Table 12-14. Step bid characteristics, RETE81....235

Acknowledgements

A mi familia, Fabiola, Javier y Alejandra, por su compañía y apoyo durante toda la maestría. También a aquellos de los cuales me despedí para siempre sin saber antes de emprender esta nueva aventura.

To professors Cristian Bovo and Valentin Ilea for their attention and patience while developing this thesis.

To Italy, for making me feel at home even during the hardest time.

And to all of those who I met during this special journey.

1 Abstract – Sommario

Given the regulatory guidelines provided by the Clean Energy Package for All Europeans regarding Transmission System Operators (TSO) and Distribution System Operators (DSO) coordination in flexibility markets, a simulation platform is developed to implement, evaluate, and compare coordination schemes.

The model implemented uses an iterative process based on a first order linear network approximation to solve the flexibility markets. Distributed Energy Resources are represented by continuous and step bids, while Energy Storage Systems owned and operated by DSOs are also included.

A tool with simplified aggregation strategies is implemented to generate testing cases in distribution networks. Results show that in several coordination schemes the DSO would effectively take the role of a high-level aggregator, and as a result guarantying the appropriate incentives in the regulatory framework is a vital condition for the coordination strategy to contribute to an efficient and effective use of flexibility resources.

Further work is required to develop a more realistic and complete simulation platform that appropriately represents the expected behavior of agents participating in the coordination schemes, and their implications in global social welfare.

A partire delle linee guida fornite dal Clean Energy Package for All Europeans relative al coordinamento dei gestori dei sistemi di trasmissione (TSO) e dei gestori dei sistemi di distribuzione (DSO), è stata sviluppata una piattaforma di simulazione per implementare, valutare e confrontare gli schemi di coordinamento tra TSO e DSO.

La rete elettrica e i vincoli che la caratterizzano sono gestiti mediante un processo iterativo basato su un'approssimazione lineare del primo ordine di tali vincoli. Tale modello di rete è poi stato introdotto in un modello per la gestione dei mercati della flessibilità. Le risorse energetiche distribuite sono state rappresentate da offerte continue e differenziate; inoltre, sono stati inclusi i sistemi di accumulo di energia gestiti dai DSO.

Sempre in tale lavoro di tesi, è stato implementato uno strumento che genera diverse strategie di aggregazione semplificate con l'obiettivo di generare opportuni scenari test da applicarsi a differenti modelli di rete di distribuzione che sono utilizzati per studiare le caratteristiche dei

modelli proposti. I risultati mostrano che, per quanto riguarda gli schemi di coordinamento TSO-DSO, il DSO assume il ruolo di aggregatore ad un livello superiore. Ciò implica la necessità di opportuni incentivi da prevedere nel quadro normativo affinché la strategia di coordinamento contribuisca ad un uso efficiente della flessibilità.

Gli sviluppi futuri del lavoro possono orientarsi nella messa a punto di una piattaforma di simulazione più realistica e completa che rappresenti adeguatamente il comportamento atteso degli agenti che partecipano ai mercati della flessibilità e le sue implicazioni per il benessere sociale globale.

2 Introduction

The evolution of electricity systems in the following years will be the result of several drivers. First and foremost, global warming. This phenomenon is undoubtedly the most important challenge humanity will face this century, as it is the biggest barrier to achieve sustainable development and even threatens the basic structure of our society. An electricity and hydrogen-based economy, with an energy sector completely reliant on renewable and flexible energy resources, might be the only technologically and politically viable solutions to overcome what seems to be an unsurmountable obstacle for us all.

From a technical standpoint, the transformation of electricity systems to meet increasing demands for clean energy sources concentrates on one key concept: the efficient system integration of RES and DER. Initially, due to environmental commitments both at the national and international levels, and later economic and technological developments, shares of renewable and variable energy technologies in the generation mix have increased dramatically in the last two decades. The same trend is started to be seen in the penetration of Distributed Energy Resources in electricity networks, mainly solar photovoltaic generators but also electric vehicles, energy storage systems and new demand response programs. In this scenario, and if emission targets for the energy sector are to be met, electrical systems must be flexible enough to effectively use these new clean energy resources while avoiding security and operative constraints that need to be satisfied by conventional and more pollutant technologies.

The flexibility that networks ought to achieve for the efficient system integration of DER and RES is not only a technical challenge. A vast majority of electricity systems, both in developed and developing countries, are liberalized and follow market structures. In this context, competitive (large scale generation, retailing, DER) and regulated (transmission and distribution) activities interact following a predefined set of rules and market interactions, where agents and firms maximize their welfare actively responding to incentives. Therefore, the desired flexibility requirements cannot be forced into market players, but instead it should be the result of incentives coming from proper market design.

Fortunately, electricity systems and markets have dealt with flexibility issues for decades, due to special characteristics of electricity as a commodity. To start, electricity cannot be stored in large scales at efficient prices. Pumped storage hydro plants and other energy storage systems have been used but are in no means predominant. This constraint forces supply and electricity demand to be always matched. Moreover, electricity is transported through complex networks that must comply with physical laws (Kirchhoff circuit laws and thermal capacity of individual elements, just to name a few). Finally, electricity demand has been comparatively inelastic, with the main reasons being limited in information access, now solved with the deployment of smart metering infrastructure, and lack of effective and efficient substitutes. These electricity attributes inevitably created a demand for flexibility, that historically has been met with ancillary services, recently procured through dedicated market sections.

Ancillary services are energy and power products with special characteristics that help to balance and operate electricity systems while they move energy from generating resources to retail consumers [1]. Balancing the system means matching supply and demand while maintaining a system frequency, while operative problems refer mainly to the alleviation of technical constraints mainly in transmission systems. Markets have been designed to procure these services efficiently and competitively, examples being the Regulation and Reserves markets in PJM and the Ancillary and Balancing markets sections in Italy.

Although ancillary services markets have been in place for years, their application framework is mainly concentrated in frequency related services and congestion management at the transmission level. However, the impacts of the increased penetration of DER and RES might change the requirements and scope of ancillary services markets in the short and mid-term. To start, to balance large shares of variable resources the demand for frequency related ancillary services is expected to increase. Furthermore, requirements for congestion management services will rise, not only because of the DER and RES penetration, but because networks are operated closer to their technical limits. The efficient use of existing infrastructure is a principle already applied to transmission systems but that has not been properly implemented at the distribution level.

In response to this context, the Clean Energy for all Europeans package[1] proposed the guidelines to extend ancillary services markets to resources located in distribution networks. The fit and forget approach, where distribution networks are designed for peak conditions and are not monitored nor operated like transmission systems are, should be replaced for more efficient planning and operation methodologies. In this new smart grid paradigm, DER and their aggregated capabilities are an opportunity to solve network constraints, thus delaying

[1] The Clean Energy Package is composed of Four Directives and Regulations: I.) Energy Performance in Buildings Directive (2018/844), II.) Renewable Energy Directive (2018/2001), III.) Energy Efficiency Directive (2018/2022), IV.) Governance of the Energy Union Regulation (2018/1999), V.) Electricity Regulation (2019/943), VI.) Electricity Directive (2019/944), VII.) Risk preparedness Regulation (2019/941) and VII.) ACER Regulation (2019/942).

investments, reducing total costs incurred by final customers and maximizing social welfare. However, in addition to technical requirements, properly designed ancillary services markets are key to use the flexibility of DER connected to any voltage level.

One of the key aspects of ancillary services market design for future electricity systems is the coordination of TSOs and DSOs. Until now, resources capable of providing ancillary services were connected at the transmission level, thus markets only required the involvement of the TSO. With DER mainly located in distribution networks, the DSO engagement is more and more necessary. Nonetheless, the way in which the DSO participates in the ancillary services market is still an open question, which will be studied along this document.

This thesis, with its main objective of developing a simulation platform to implement, evaluate and compare market schemes for the procurement of ancillary services at the distribution level, and the necessary TSO-DSO coordination strategies, will attempt to help current efforts of academia and research projects to better understand interactions present in a new market design. A better comprehension of the problem is necessary before the real implementation takes place in years to come.

To address and better understand this problematic, a simulation platform to evaluate and compare coordination schemes between TSOs and DSOs is developed. To achieve this objective, several requirements are needed in the model. To start, going above and beyond the *Fit and Forget* approach for distribution network planning implies that a more detailed operation of its assets from the DSO side. This translates to an appropriate network representation, incorporating its electrical constraints. Second, the model should incorporate DER penetration and aggregation technics, in the context of new regulatory and technological developments. Finally, the coordination schemes between need to be implemented both from a conceptual and market structures, understanding the roles of involved entities in the process and the economic outcomes. The three main steps of this simulation framework composed the core of this thesis.

The results obtained in this thesis are limited and do not provide the definitive answer to the TSO-DSO coordination problem. Instead, they provide initial insights into what are the challenges and obstacles that should be overcome to achieve an effective and efficient interaction in flexibility markets from the future. In short, a more complete analysis must include, among other parts: I.) the complete aggregation rules for DER participating in the market, II.) possible differentiation of flexibility products to procure, III.) an agent-based modelling of market participants, to better understand their interactions and the possibilities to exert market power in the coordination schemes, IV.) TSO-TSO coordination schemes, and their implications downstream.

2.1 Outline of the Thesis

In **Section 3** the general context in which this thesis is being developed is presented, given special emphasis to the relation between DER, network assets and flexibility requirements during the energy transition.

Section 4 deepens on the topic of TSO-DSO Coordination for flexibility markets recently presented in the Clean Energy Package for all Europeans and presents how the problem has and is being treated by research projects and academia.

In **Section 5** methods in which DER are modelled and aggregated are discussed, with the objective of proposing a simplified approach valid for the simulation framework being developed.

Section 6 presents distribution network models commonly used in the literature, evaluating and comparing them to later include it into the optimization model used to implement the flexibility market and the coordination schemes.

In **Section 7** six TSO-DSO coordination strategies are presented both theoretically and mathematically. Further detailed is provided for those coordination strategies that can be simulated in the developed framework.

Section 8 discusses the iterative algorithm that is being used to solve the flexibility markets using a linear sensitivity approach as the network modelled. In addition, special attention is given to numerical problems found during the development and testing of the proposed solution.

Section 9 presents and discusses the simulation results of three coordination schemes, emphasizing numerical challenges found in the solution process when necessary.

Finally, **Section** 10 discusses the thesis' conclusions, and future work.

3 Context

The following section introduce in greater detail the most important parts of the context presented in the introduction, mainly deepening on three areas: I.) climate change, II.) technological and market trends in electricity systems and III.) the current regulatory framework and its perspectives.

In these orders of ideas, Section 3.1 presents the challenge of global warming, and the necessity of RES and the electrification of the economy to overcome it. Section 3.2 presents an overview of DER, a special category that of assets that includes RES and other technologies expected to penetrate distribution networks. Section 3.3 summarizes main aspects of the recently presented guidelines for the reform and development of European Electricity markets and the energy sector, contained in the Clean Energy Package for all Europeans. Sections 3.4 and 3.5 present an overview of European and Italian ancillary services markets, respectively. Finally, section 3.6 highlights main aspects of the TSO-DSO coordination requirements of the Clean Energy Package,

3.1 Global warming and RES

Thanks to economic, technological, and cultural developments after the industrial revolution, humanity and its relationship with its environment changed drastically. To start, human population has increased from around 1 billion people in the 19th century, to 2.5 billion in the middle of the twentieth century to finally 7.3 billion in 2015 [2]. Primary energy consumption has followed a similar trend, as 5.6 TWh were consumed in 1800, 28.5 TWh in 1950 and 173 TWh in 2019 [3]. This energy has been mainly obtained from fossil fuels, sources that are still dominant today, when 83% of primary energy consumed in 2019 comes from oil, coal and natural gas [3].

One of the indirect effects of the increase in population and energy consumption, that undoubtedly has also brought welfare and improved life conditions for many, is a dramatical rise in Greenhouse Gasses (GHG) emissions, mainly CO_2, to the atmosphere. Because of the greenhouse effect, global temperatures have also increased, as shown in Figure 3-1 [4] .

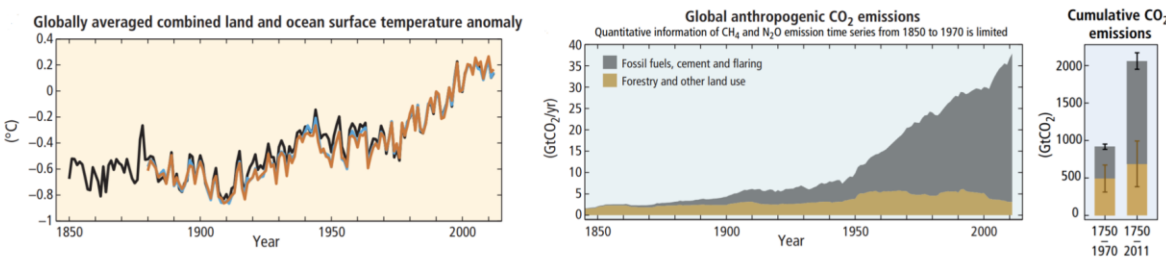

Figure 3-1. Globally averaged combined land and ocean surface temperature anomalies and Global anthropogenic CO_2 emissions, adapted from [4]

Although the effects of global warming are already tangible and critical for the world population nowadays, if the trends described earlier continue during the next decades its impact on life on earth would be dreadful. Stated policy scenarios, those in which current policies and trend are applied for the complete horizon maintaining the status quo, show that average global temperature in the years 2081 to 2100 could be between 2.6 to 8.5 °C higher than today's [4]. Even though a deeper understanding of global warming dynamics are needed to quantify the effects of such a change in temperature, scientific consensus is clear that a greenhouse phenomenon at such scale will lead to dramatic and irreversible consequences for human society and life on earth [4].

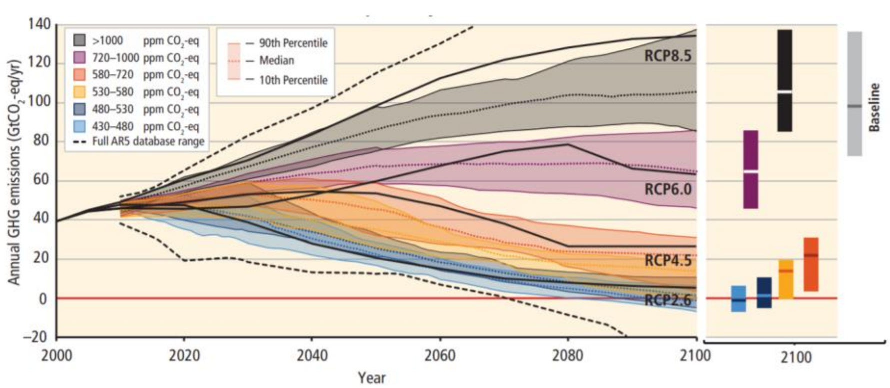

Figure 3-2. GHG emission pathways 2000-2100: all AR5 scenarios [4]

Global warming has been deeply studied and understood by academia, and mitigation of climate change is now one of the major drivers of energy policy worldwide. In the context of facing a problem that seems unsurmountable, appearing to be the greatest challenge humanity will face in the twenty first century, continuous and worldwide collaborative efforts are needed to avoid scenarios with temperature increases beyond 2 °C worldwide. This was the main goal of the Paris Agreement, accord that, as Figure 3-3 demonstrates, fell short of its original target.

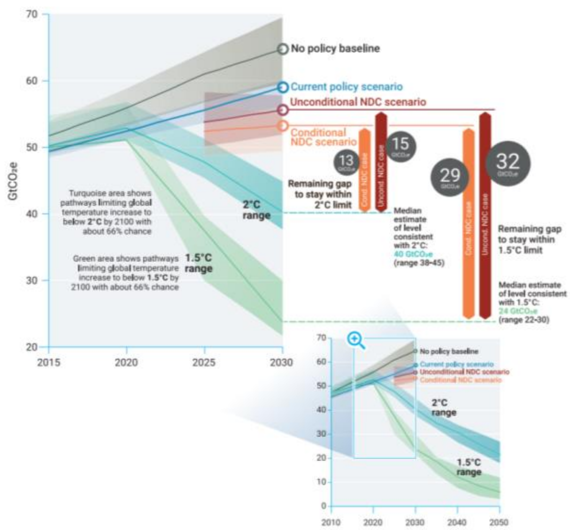

Figure 3-3. Global greenhouse gas emissions under different scenarios and the emissions gap in 2030, median estimate and 10th to 90th percentile range [5]

As discussed before, much greater ambition is required to achieve the still feasible objective of limiting temperature increments in the 1.5 to 2 °C range. The magnitude of the ambition in society that is needed to mitigate global warming is illustrated by the 2020 pandemic. While this thesis has been developed and written, a global pandemic caused by the virus COVID19 has forced countries around the world to enforce lockdowns, reducing among other things industrial activity, consumption of commodities and very limited air travel. Even under these circumstances, Greenhouse gas concentrations in the atmosphere are at high record levels and continue to increase. Moreover, emissions are heading in the direction of pre-pandemic levels following a temporary decline caused by the lockdown and the economic slowdown [6].

In the transformation of society required to overcome global warming, the energy sector will play a main role both for its current emissions, and the mitigation capabilities at its disposal. As Figure 3-4 shows, the availability of clean energy resources (Carbon Capture and Sequestration CCS, and nuclear, solar, wind and bioenergy) drastically reduces mitigation costs in all scenarios, in addition to increasing the probability of a feasible energy transition [4].

	Mitigation cost increases in scenarios with limited availability of technologies [d] [% increase in total discounted [e] mitigation costs (2015–2100) relative to default technology assumptions]				Mitigation cost increases due to delayed additional mitigation until 2030 [% increase in mitigation costs relative to immediate mitigation]	
2100 concentrations (ppm CO_2-eq)	no CCS	nuclear phase out	limited solar/wind	limited bioenergy	medium term costs (2030–2050)	long term costs (2050–2100)
450 (430 to 480)	138% (29 to 297%) 4	7% (4 to 18%) 8	6% (2 to 29%) 8	64% (44 to 78%) 8	44% (2 to 78%) 29	37% (16 to 82%) 29
500 (480 to 530)	not available (n.a.)	n.a.	n.a.	n.a.		
550 (530 to 580)	39% (18 to 78%) 11	13% (2 to 23%) 10	8% (5 to 15%) 10	18% (4 to 66%) 12	15% (3 to 32%)	16% (5 to 24%)
580 to 650	n.a.	n.a.	n.a.	n.a.		

Symbol legend—fraction of models successful in producing scenarios (numbers indicate the number of successful models)

: all models successful

: between 80 and 100% of models successful

: between 50 and 80% of models successful

: less than 50% of models successful

Figure 3-4. Increase in global mitigation costs due to either limited availability of specific technologies or delays in additional mitigation relative to cost-effective scenarios [4]

The results of the changing paradigm in the energy sector during the energy transition will be driven by the electrification of the economy. In this new system, electricity produced by renewable and other low carbon energy sources will be dominant, replacing fossil fuels for a cleaner energy vector [7].

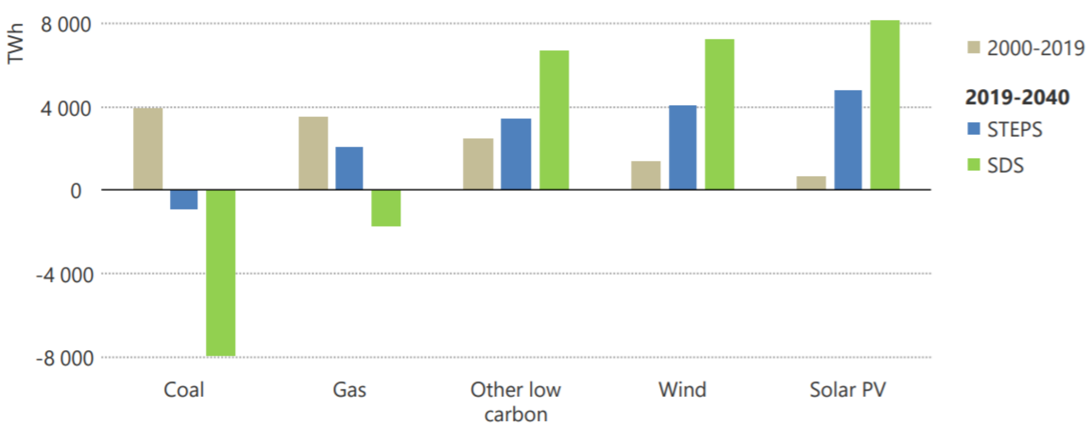

Figure 3-5. Global electricity generation changes in Stated policies (STEPS) and Sustainable development (SDS) Scenarios [7]

This thesis is developed in the context of global warming, and energy policy driven by the necessity of assuring the efficient integration of large shares of renewable energy sources shown Figure 3-5 into today's power system.

3.2 Distributed Energy Resources

Distributed Energy Resources (DER) are electricity producing resources or controllable loads connected to distribution networks. These resources, illustrated in Figure 3-6, include flexible demand, distributed generation, energy storage systems, advanced power electronics and control devices [8]. In the last category, Electric Vehicles and their charging stations are the most representative, but it also includes residential, commercial, and industrial inverter-base applications.

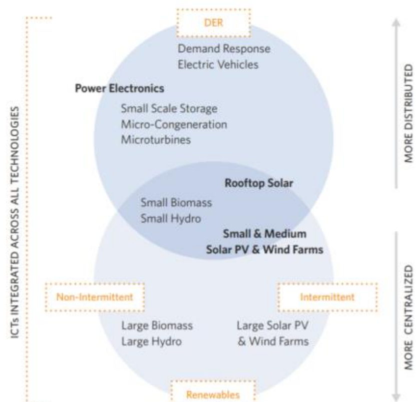

Figure 3-6. Centralized and Distributed renewable energy resources [8]

The penetration of DER in electric systems has increased dramatically in the last decade, in part due to advancements on the political, regulatory, and environmental framework briefly described in Section 3, but also due to reduced costs and increased production capacities for distributed energy technologies [8]. These trends, as shown in Figure 3-7 for solar and wind generation technologies and Figure 3-8 for battery energy storage systems, are deaccelerating but will remain in the short-term [9].

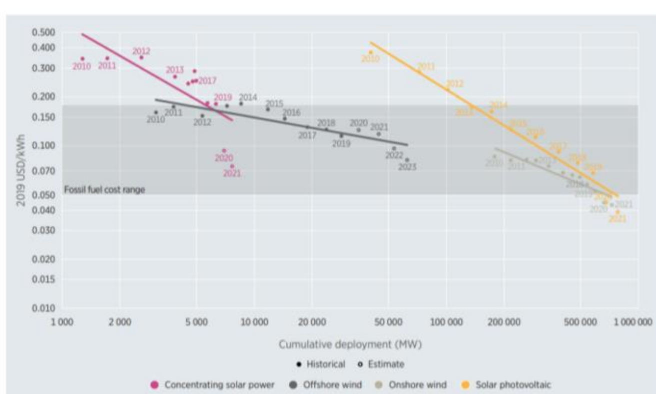

Figure 3-7. Global weighted-average LCOE and price learning curve trends for solar PV, CSP, onshore and offshore wind, 2010-2021/2023 [9]

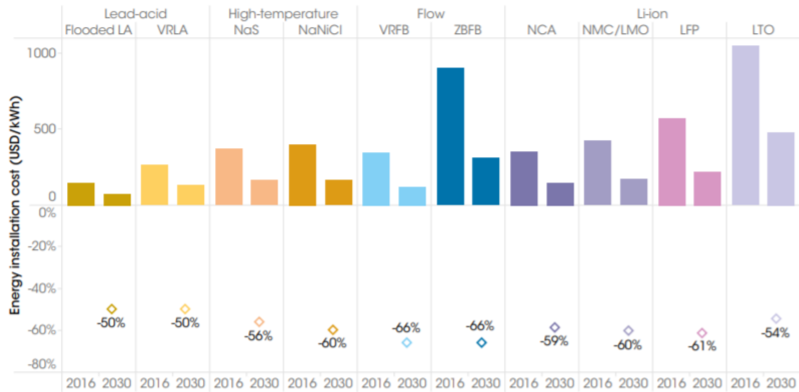

Figure 3-8. Energy installation costs central estimate for battery technologies[2], 2016-2030 [10]

As shown in 3.1 the Energy Transition towards renewable energies is already on their way, studies found in the literature and carried out by institution normally do not normally differentiate penetration of renewable energy resources between utility and distributed categories, as they are normally carried out in a country by country, or state by state, basis. For illustration purposes, Figure 3-9 presents the main results of forecasts analyzing the penetration of renewable energy sources, and DER, in Australian networks [11]. In addition to the expected accelerated integration of renewables and energy storage systems, the

[2] Technologies LA: Lead-acid, VRLA: valve-regulated lead acid, NaS: sodium sulphur, NaNiCL: sodium nickel chloride, VFRB: vanadium redox Flow battery, ZBFB: zinc bromine Flow battery, NCA: nickel cobalt aluminum, NMC/LMO: nickel manganese cobalt, LFP: lithium-ion phosphate, LTO: lithium titanate.

penetration is mainly due to resources of relatively low scale, likely to be connected to distribution networks.

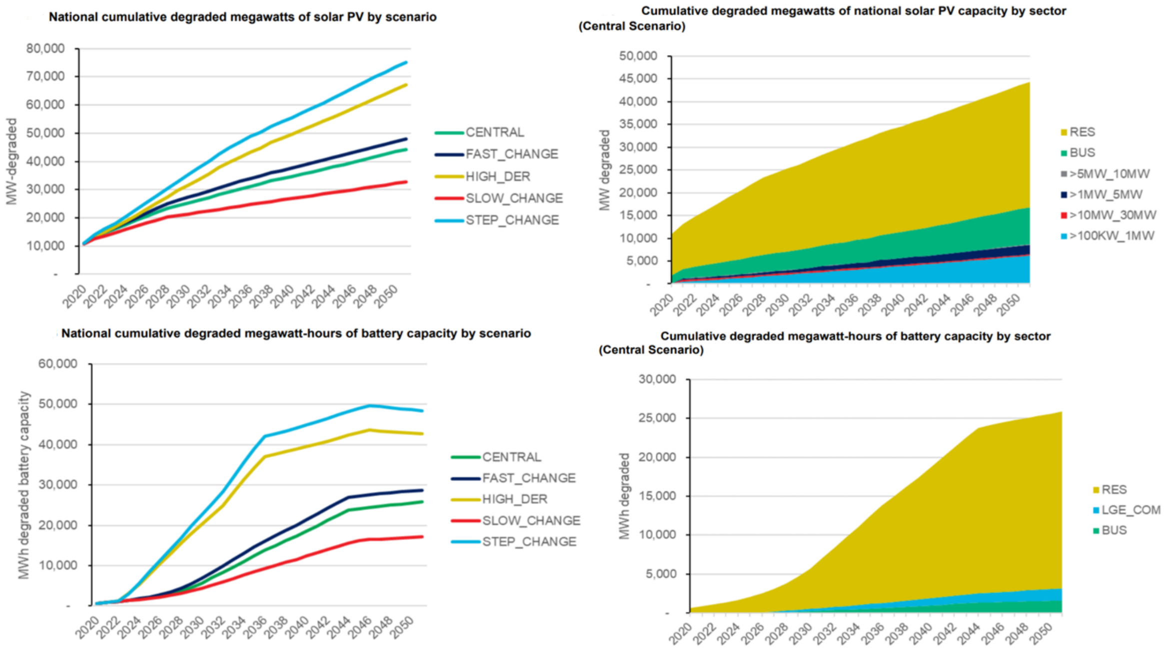

Figure 3-9. Expected penetration of solar and battery capacity in the Australian electrical system[3] [11]

In the context of Distributed Energy Resources, electric vehicles (EV), and the broader movements towards electric mobility, deserves special attention. In addition to the previous trends that push towards the deployment of DER, electric mobility has also local incentives due to the effects on public health caused by Internal Combustion Engines, especially when the technology is used in public transportation [12]. Moreover, the car industry has divested resources to the development and manufacturing of electric vehicles, with 450 new models expected to be launched by 2022 and TESLA being the highest valued car firm in the world, even during the global pandemic [13]. As a result of these condition, the share of electric

[3] Scenarios vary from the most aggressive and fastest adoption of renewable energy sources through a radical change in the energy sector (STEP_CHANGE), to the slowest integration (SLOW_CHANGE). Moreover, a scenario that models penetration mainly through distributed renewable energy resources is also included (HIGH_DER).

vehicles in the transportation sector is expected to increase dramatically, as illustrated in Figure 3-10 [14].

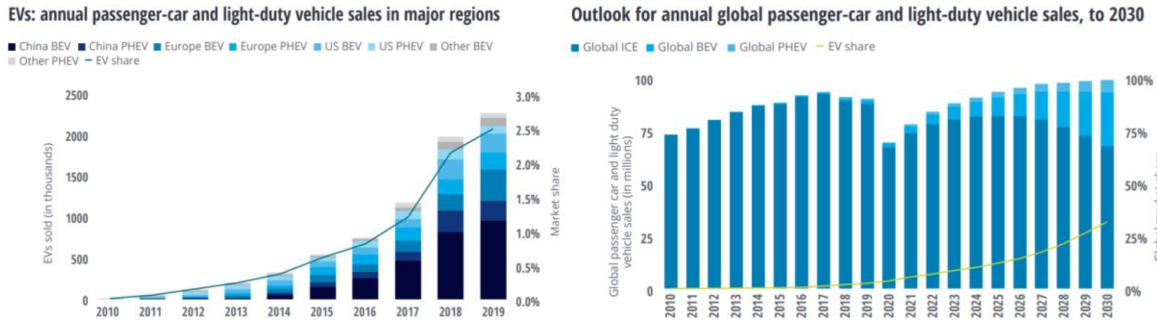

Figure 3-10. Electric vehicle retrospective and prospective trends, adapted from [14]

Electric mobility has three characteristics of interest, when compared to other DER. First, it is the expected massification of electric vehicles that, assuming using patterns remain similar, will behave as distributed energy resources. Moreover, electric vehicles are loads with considerable consumption[4], posing risks to distribution networks not sized or operated properly. Last but not least, electric vehicle and their charging station, through appropriate market schemes and regulatory incentives can provide and receive different energy services from the network, exchanges that are referred to as Vehicle to Grid (V2G) and Grid to Vehicle (G2V) services [8].

A future energy system with high RES and DER shares might raise adequacy, reliability and operative concerns [8]. Focusing on the latter, Table 3-1 presents a summary of operative scarcities that arise in electrical systems with high shares of variable energy sources.

[4] TESLA Model 3 has an average consumption of 14.9 kWh/100km [82]. Assuming a fairly conservative estimate of 10,000 km driven per year, a single Model 3 would consume 1.5 MWh yearly.

Table 3-1. Summary of technical scarcities, adapted from [15,16]

Scarcity in system services	Associated issues	Reason for the scarcity
Lack of frequency control	• Inertia • Reserves • Ramping	Reduced amounts of synchronous generation on the system providing inertia and reserve capability means that frequency can vary more quickly in case of power equilibrium incidents and can be less manageable
Lack of voltage control	• Short circuit power • Steady state voltage control • Dynamic voltage control	• Less synchronous generation available to provide reactive power support • Reduced short circuit power due to the replacement of synchronous machines and the limited capacity of converters in terms of short-circuit current injection • Voltage variation effects due to connection of RES in the distribution system
Rotor angle instability	• Small signal stability • Transient stability	• Less synchronous generation to maintain inertia and stability. Reduction in synchronizing torque deteriorates stability margin • Reduction of transient stability margins due to the displacement of conventional plant • Introduction of new power oscillation modes • Reduced damping of existing power oscillations
Congestion	• Network hosting capacity • RES curtailment • Capacity allocation	• Increase in distance between generation and load, and generation variability • Increased feed-in power and bidirectional power flows noted in distribution networks
Need for system restoration	• Black-start capability • Network reconfiguration • Load restoration	• Less black start capable plants on the grid • Current restoration strategy mainly refers to large synchronous generation
Reduction in System adequacy	• Uncertainty of RES generation • System interdependencies	Reduction in load factors and decommissioning of conventional generation driven by penetration of renewable

3.3 The Clean Energy Package

The Clean Energy Package for all Europeans is a set of energy policy guidelines published by the European Commission, with the main objective of updating the political and regulatory framework to enable the Energy Transition required to achieve the commitments signed by the union in the Paris Agreement during the COP 21 [17]. The set of eight legislative proposals were published for discussion of third parties in 2016, approved by the European Commission in 2019 to be later pass into laws by the individual countries before 2021.

The Clean Energy Package addresses the Energy Transition in the European Union from five dimensions: I.) energy security, II.) internal energy market, III.) energy efficiency, IV.) decarbonization of the economy and V.) research, innovation, and competitiveness [18]. In addition, the Clean Energy Package is developed through five main elements [18]:

1. Energy Efficiency First: new energy efficiency target of 32.5% lower primary energy consumption with respect to 2007 PRIMES scenarios, in addition to the new energy performance of building directives to maximize the energy saving potential of smarter and greener buildings;
2. More Renewables: new target of at least 32% in renewable energy in gross final energy consumption by 2030, with specific provisions to foster public and private investment.
3. A better governance of the Energy Union: new energy rulebook under which each Member State drafts National Energy and Climate Plans (NECPs) for 2021-2030 setting out how to achieve their energy union targets, and the 2030 targets on energy efficiency and renewable energy;
4. More rights for consumers: new rules to make it easier for individuals to produce, store or sell their own energy, and strengthen consumer rights with more transparency on bills, and greater choice flexibility;
5. A smarter and more efficient electricity market: new laws that will increase security of supply by helping integrate renewables into the grid and manage risks, improving cross-border cooperation.

These targets have been strengthen by the commitment of the Union to achieve carbon neutrality by 2050, path that requires cutting GHG emissions by at least 55% by 2030 with respect to 1990 levels, an increase of at least 40% with respect to the previous goals [19,20].

Among the eight legislative acts that form the Clean Energy Package, the Directive on common rules for the internal market in electricity (e-Directive) and the Regulation on the internal market for electricity (e-Regulation) are especially relevant electricity market designs. Following the framework proposed in [17][5], the following sections present three integral parts of the legislative acts of interests: I.) ensuring the internal market level playing field, II.)

[5] Sections 3.3.1, 3.3.2 and 3.3.3 summarized the analysis of the Clean Energy Package presented in [83] and [17].

Adapting to the decentralization of the power system and III.) Empowering customers and citizens.

3.3.1 Ensuring the internal market level playing field

To achieve the objective of ensuring a level playing field in the internal market design, the Clean Energy Package establishes four key measures: I.) the phasing out of public intervention in setting electricity prices, II.) the methodologies for calculating and determining network tariffs, II.) the limitation of the use of capacity mechanisms, and IV.) the interlinkage of the Clean Energy Package guidelines with network codes [17].

Regarding public intervention in electricity tariffs, the Clean Energy Package requires Member States to adopt appropriate measures to promote effective competition among electricity suppliers, which shall be able to set electricity supply prices freely. In terms of intervention, Member States can establish protective measures to protect the energy-poor or vulnerable household customers. In addition, it is possible for Member States to impose public interventions to allow for a transitional period to promote effective retail competition.

In terms of network tariffs, the Clean Energy Package states that tariffs shall be cost-reflective, send appropriate signals on the short and long-term to support overall system efficiency and guide efficient investments. Moreover, network tariffs shall not discriminate against distributed energy resources and aggregation, in addition to being cost-reflective regarding the use of the network by grid connected users. Furthermore, distribution tariff methodologies shall provide incentives to DSOs for cost-efficient operation and development of their networks, including the procurement of required services. Finally, tariff design should facilitate innovation and ease unlocking flexibility potential in electricity systems.

With respect to capacity mechanisms, the Clean Energy Package reinforces security of supply and resource adequacy as fundamental pillars for the decarbonization and electrification of the economy. However, imperfect capacity mechanisms could hinder the penetration of new services and resources, affecting cross-border trade and distorting investment signals. As a result, the Clean Energy Package limits the use of capacity mechanisms to address adequacy deficiencies and prioritizes market reforms to solve the issue. When capacity mechanisms are used as a last resource, the Clean Energy Package imposes measures to avoid discrimination against emerging business, their impact on climate goals and cross-border trade distortion.

Finally, regarding the relationship of the Clean Energy Package with respect to network codes, the legislative acts consider balancing responsibilities, system operation regional governance, bidding zones and calculation of interconnectors' capacity methodologies already defined in previous guidelines and regulatory decisions. Section 5 details the regulatory guidelines on balancing responsibilities defined in REG 2017/2195.

3.3.2 Adapting to the decentralization of the power system

The Clean Energy Package redefines and adapts the function, roles and responsibilities of the DSOs in the ongoing decentralization of the power systems. This revision includes both traditional or current practices, like the planning and management of distribution networks, and limits for the role of DSOs in emerging businesses, as EV charging facilities and energy storage systems.

In terms of network planning, the Clean Energy Package establish that DSOs shall publish network development plans for distribution systems to: I.) support the integration of renewable energy resources, II.) provide system users adequate information regarding network upgrades or expansions., III.) provide transparency on the medium and long-term flexibility services needed, IV.) evaluate and compare the use of distributed energy resources to delay network investments, and V.) be coordinated with relevant users and the TSOs.

Moreover, to ensure a cost-efficient, secure, and reliable development and operation of networks, the Clean Energy Package establishes that DSOs and TSOSs shall cooperate in planning and operation functions, in addition to exchanging necessary information regarding performance of generation assets, demand side response, the daily operation of their networks and the long-term planning of network investments.

Regarding the procurement of flexibility services, the Clean Energy Package shall establish the regulatory framework to provide incentives for DSOs to procure flexibility services, including congestion management, to improve efficiencies in the operation and development of distribution system. The procurements process must allow the participation of all market participants and establish standard products at least at the national level. As before, TSOs and DSOs should coordinate the procurement of flexibility services to ensure the optimal utilization of resources, guarantee a secure and efficient operation of the system and to facilitate market development. This context is especially relevant for this thesis, and as a result the topic is broaden in Sections 3.6 and 0.

For EV charging facilities and Energy Storage Systems, the Clean Energy Package gives third parties priority for their ownership, development, management, and operation. Exceptions might be granted by the regulatory authority, given that no other agents are interested in such investments.

Last, DSOs shall maintain a neutral role with respect to data management, guaranteeing non-discriminatory practices, in addition to clear and equal access to data. These considerations are especially relevant for vertically integrated DSOs to not impose entry barriers for new agents, products and services.

3.3.3 Empowering customers and citizens

The Clean Energy Package also establishes a set of guidelines to empower customers and citizens in the context of the Energy Transition and the development of smart grids. Among these measures are rights for active customers regarding: I.) self-consumption, II.) smart metering, III.) data access and management, and IV.) dynamic pricing. In addition to the liberalization and increased competition between retailers, new customer intermediaries, aggregators, and citizen energy communities, are defined. The figure of the aggregators, in conjunction with the balancing responsibilities, are discussed in Section 4.

From an economic standpoint, a market is a set of rules or structure that allows the exchange of products and services. Market participants, representing the supply and demand of products and services, try to maximize their individual profits or welfare. A perfect market, infinitive number of competitors and complete information, results in the maximization of the social welfare. Ancillary services markets are just a special case of energy markets, they themselves being a category of the broader definition stated before. In this Section, after previous Sections have presented the building blocks of what consists the market model to evaluate TSO-DSO coordination schemes for ancillary services procurement, some final details of the market structure are discussed and proposed.

3.4 European Ancillary Services and Balancing markets

In the context of RES and DER integration, European markets, and especially ancillary services markets, are being revised and reformed. In this context, the European Council published the Regulation 2017/2195 on Electricity Balancing markets [21]. This section summarizes the relevant aspects of the reform, even when they mostly apply to frequency related services at the transmission level, which are not the main scope of this project.

To start, the regulation and subsequent decisions defined a new naming scheme for frequency related services. These modifications are shown in Table 3-2, in addition to some characteristics of the related services. Their interactions in an example case of an under-frequency event are shown in Figure 3-11, where the sequence starts with the automatic activation of the Frequency Containment reserves and finalizes with the manual activation of the replacement reserves.

Table 3-2. New designation of Frequency related services [21,22]

Previous name in ENTSO-E	Designation in Regulation 2017/2195	Activation Method	Time domain of the response
Primary control reserve	Frequency Containment Reserve (FCR)	Automatic	Up to 30 seconds
Secondary control reserve	Automatic Frequency Restoration Reserve (aFRR)	Automatic	Up to 5-7.5 minutes
Fast tertiary control reserve	Manual Frequency Restoration Reserve (mFRR)	Manual	Up to 12.5 minutes
Slow tertiary control reserve	Replacement reserves (RR)	Manual	30 minutes

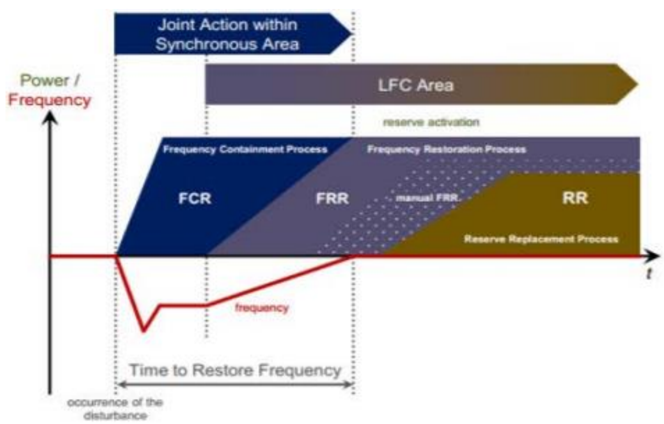

Figure 3-11. Interaction of frequency related services during an under-frequency event [22]

Each one of these products are to be procured in Cross-European markets and platform, currently under development. These platforms, that follow from the principles of Regulation 2017/2195, will be in charge of the frequency services highlighted in Table 3-3, and expected to be developed according to the schedule shown in Figure 3-12.

Table 3-3. European Platforms for Ancillary Services [23]

Balancing service	Platform
Replacement reserves	Trans European Replacement Reserves Exchange (TERRE)
Manual Frequency Restoration Reserves	Manually Activated Reserves Initiative (MARI)
Automatic Frequency Restoration Reserves	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)
Imbalance Netting	International Grid Control Cooperation (IGCC)

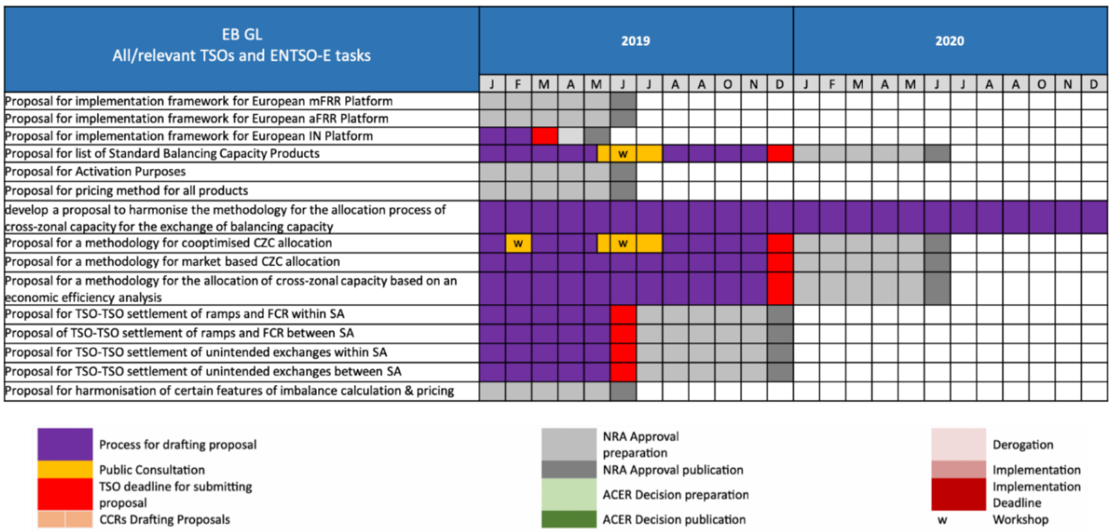

Figure 3-12. Schedule for implementation of European market platforms [23]

Moreover, the Regulation provides the definition of the Balancing Service Providers (BSP) and Balancing Responsible Parties (BRP). According to Regulation 2017/2195 Balancing Service Provider is "*a market participant with reserve-providing participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs*" and Balancing Responsible party is "*a market participant or its chosen representative responsible for its imbalances".* In simple terms the BSP in the new market structure will correspond to the aggregator, and BRP will be the representative of the resources, production, consumption, or mixed units, capable of providing Balancing Services to the TSOs. In this new framework for electricity balancing markets, the most important roles of the TSO, the BSP and the DSO are defined as shown in Table 3-4.

Table 3-4. Roles of entities in new electricity balancing markets [21]

Entity	Roles
TSO	Each TSO shall be responsible for procuring balancing services from BSP in order to ensure operational security
	Each TSO shall apply a self-dispatching model for determining generation and consumption schedules, or notify about the application of a central dispatching model (subject to approval)
BSP	A BSP shall qualify for providing bids for balancing energy or capacity, which are activated or procured by the connecting TSO.
	Each BSP shall submit to the connecting TSO its balancing capacity bids that affect one or more BRP.
	Each BSP has the possibility to submit and update ids bids (capacity or standard bids) before the gate closure time
	Units providing the service must belong to the same scheduling area
BRP	In real time, each BRP shall strive to balance or help the power system to be balance.
	Each BRP shall be financially responsible for the imbalances to be settle with the connecting TSO
	Prior to the intraday cross-zonal gate closure time, each BRP may change the schedules required to calculate its position.
	After the intraday cross-zonal gate closure time, each BRP may change the internal commercial schedules required to calculate its position.

Among the most important principles that Cross European market platforms should follow are [24]:

- The main objectives of the European platforms for the exchange of balancing energy are: I.) fostering effective competition, non-discrimination and transparency in balancing markets II.) enhancing efficiency of balancing at European and national levels, III.) integrating balancing markets and promoting the exchange of services, while maintaining operational security and IV.) facilitating the participation of demand response and renewable energy sources;
- The use of standard products, that shall be developed as part of the proposals for the implementation frameworks for European platforms, and with similar characteristics to the ones described in Figure 5-1. Nonetheless, TSOs may develop a proposal for specific products;
- The balancing energy gate closure time shall be harmonized for standard products at the union level at least for replacement reserves, frequency restoration reserves with manual activation and frequency restoration reserves with automatic activation and shall: I.) be as close as possible to real time, II.) not be before the intraday cross-zonal gate closure time and III.) ensure sufficient time for the necessary balancing processes;
- There should be cooperation between TSOs and DSOs in the following terms: I.) TSOs, DSOs, BSP and BRP shall cooperation in order to ensure efficient and effective balancing, II.) each

DSO shall provide all necessary information in order to perform the imbalance settlement to the connecting TSO and III.) TSO and DSOs in its control area may jointly elaborate a methodology for allocating costs resulting from actions of DSOs, considering the BRP involved;

- The activation of balancing energy shall use a cost-effective methodology based on a common merit order list. It is also recommended to implement the maximization of social welfare as the objective in the market;
- The pricing of balancing energy shall be based on marginal pricing and define how the activation of balancing energy bids activated for purposes other than balancing affects the balancing energy.

3.5 The Italian market reforms

Responding to the Clean Energy Package for all Europeans, the Italian market is undergoing a broad revision and evolution through the reform of the TIDE (*Testo Integrato Dispacciamento Elettrico).* This reform has been expressed in the consultation document 322/2019/R/eel published by the Italian regulatory authority ARERA, and having three main objectives: i.) responding to an evolving electricity system, including the penetration of new technologies, agents and services, ii.) integrating the Italian markets into European ones and iii.) achieving the 2030 European targets regarding greenhouse gasses emissions, energy poverty and development [25]. A brief summary of the main changes to ancillary and balancing market changes, including their interaction with other market sequences, is presented in the following[6].

The first, and most important structural change to the Italian markets comes from the change in which existing market sequences interact with each other. The proposed interaction between the Day-Ahead market (DAM), Intra-day market (IM), Ancillary Services market (ASM) and Balancing market (BM) is shown in Figure 3-13.

[6] The summary presented in this chapter takes inspiration and structure from the Lecture "Italian Electricity Dispatching Reform", Topic 5 in the chapter of Current and prospective dispatching from the class of Regulation of electric power systems, by professors Michelle Benini and Maurizio Delfanti.

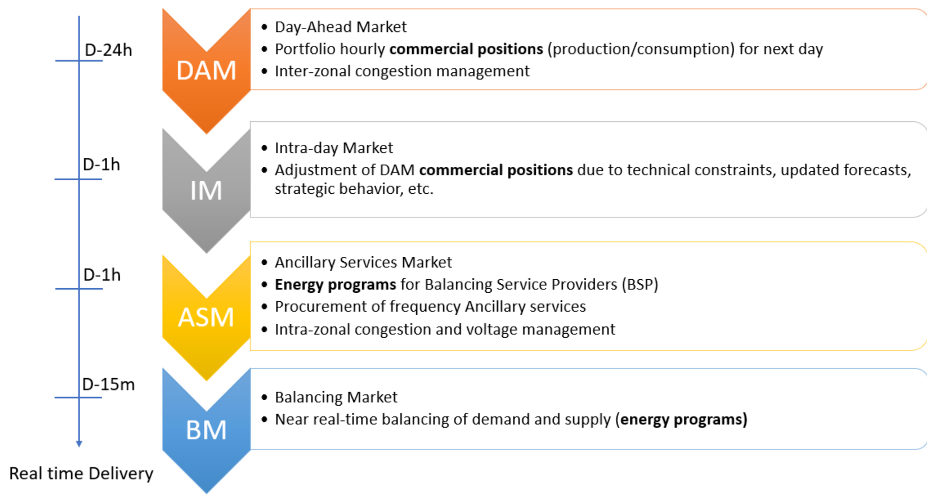

Figure 3-13. Italian Market sequences proposed by 322/2019/R/eel [25]

Two concepts are relevant for market interactions: commercial positions and energy programs. Both commercial and energy programs are energy positions that are later settle according to different market rules. The DAM and IM defined the commercial positions of the agents' portfolios while the energy programs of BSP are the result of both the ASM and the BM:

- **Commercial positions:** In the DAM, one day before delivery, commercial positions (production/consumption) are defined managing inter-zonal congestion. In the IM, one hour before dispatch after the integration with the XBID cross European market, the commercial positions are updated considering portfolio's technical constraints, updated forecast for variable resources, fuel availability and strategic behavior;
- **Energy programs:** The definition of the Energy Programs in the ASM and BM depends on whether the resources are enabled for participation:
  - For units not enabled to participate in the MSD, the BSP define the injection and withdrawal programs one hour before delivery. Because the BSP does not participate in any market sequences, the energy programs cannot be modified before delivery;
  - For units enabled to participate in the MSD, the following sequence is taken: I.) Initial programs (IP) and the related bids, prices and quantities, are defined by the BSP as an input to the ASM, respecting technical constraints of the aggregated units II.) TERNA, the Italian TSO, minimizes total system's cost to accept bids. Once bids are selected, they are commercially settled in this market, III.) accepted bids form the binding program (BP), that should be respected by BRP, IV.) TERNA sets,

beforehand, an interval in which BSP may modify binding programs. Within that range, binding programs could become modified binding programs (MBP), V.) Modified binding programs can be altered one last time if it is presented to the balance markets. If bids are accepted by TERNA, they become modified and corrected binding programs (MCBP).

The definition of energy programs for units enabled to participate in the MSD, and the relation with commercial positions is summarized in Figure 3-14.

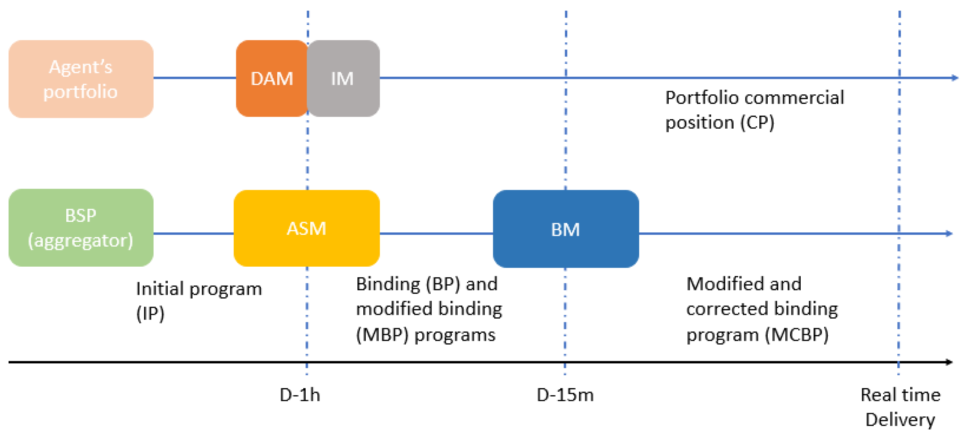

Figure 3-14. Definition of commercial positions and Energy programs in the Italian market reform

Following the definition of commercial positions and energy programs, a possible difference might emerge between the two energy values. As a result, the market operator calculates for each hour and each portfolio a final commercial settlement. The energy for this settlement is defined as CS and determined according to Equation (3-1). The CS energy is paid following the single price algorithm for imbalances, as shown in Table 3-5[7]. The imbalance settlement for units enabled to participate in the ASM, as explained earlier, depends on modified and corrected binding programs. The remuneration price depends on the average upward/downward price in the ASM and on the DAM price.

$$CS = \sum_{Enabled} [MBP - (BP - IP)] + \sum_{Not\ enabled} [IP] - CP \tag{3-1}$$

[7] Given a generation notation, a positive plant imbalance occurs when the output of an aggregator is higher than initially defined. A positive zonal imbalance arises when the total power in a given market zone is higher than initially expected.

Table 3-5. Single price algorithm for imbalance settlement

	Positive plant imbalance	**Negative plant imbalance**
Positive zonal imbalance	Plant receives: min (*average downward ASM price*, *DAM price*)	Plant pays: *max* (*average downward ASM price*, *DAM price*)
Negative zonal imbalance	Plant receives: min (*average upward ASM price*, *DAM price*)	Plant pays: *max* (*average upward ASM price*, *DAM price*)

The second change proposed to the Italian electricity market, of importance to this thesis, is in the extension of resources enabled to participate in the ASM. Previously, only dispatchable generation and emergency loads could take part of this market section. After the aggregation projects carried by research institutions and the TSO [26], more categories are now allowed to participate in the ASM and balancing market sections.

A comparison of the resource categories allowed to participate in the MSD section in its current form, and after the reform, is shown in Table 3-6. With the new ruling, non-programmable relevant resources, non-relevant resources, and load would be able to participate. In the last two cases, the participation is conditioned to resources that aggregated by a BSP.

Table 3-6. Resources allowed (A.) and not allowed (N.A.) to participate in the MSD in its current version (C.) and in the reform [25]

<table>
<tr><th colspan="3">Production</th><th>Mixed</th><th>Load</th></tr>
<tr><th colspan="2">Relevant ($\geq \mathbf{10}\boldsymbol{MVA}$)</th><th colspan="2">Non-relevant</th><td rowspan="3">N.A.C. – A.R.</td></tr>
<tr><th>Programmable</th><th>Non-programmable</th><td rowspan="2">N.A.C. – A.R.</td><td rowspan="2">N.A.C. – A.R.</td></tr>
<tr><td>A.C. – A.R</td><td>N.A.C. – A.R.</td></tr>
</table>

The categories for aggregation following the pilot projects carried out by TERNA have also been revisited. From the three initial types of pilot projects (UVAP, that aggregated production and storage units, UVAC, aggregating consumption units and UVAM, aggregating production and consumption units) four categories of units for ASM have been defined:

- UVNA (not-enable units): group of resources not enabled to participate in the ASM;
- UA (single enabled unit): not aggregated but includes single production and consumption resources, represented under single figures of BRP and BSP, and a single dispatching point;

- UVA (virtual enabled units): aggregates both production and consumption units, represented again under single figures of BRP and BSP, but the resources could be located in up to two dispatching points (one for production, and one for consumption);
- UVAM (mixed virtual enabled units): broader category of aggregation, including both production and consumption units, represented by a single BSP but including several BRP, each with their on dispatching point.

A summary of the previous categories and is shown in Figure 3-15. In this Figure, the dotted lines represent the commercial perimeter of aggregation that differs from the perimeter defined for providing each of the ancillary services in the ASM. The aggregation perimeter for ancillary services depends on the type of service; from continental Europe for primary frequency reserve, to the market zones for secondary frequency reserve and to the dispatching node for congestion management.

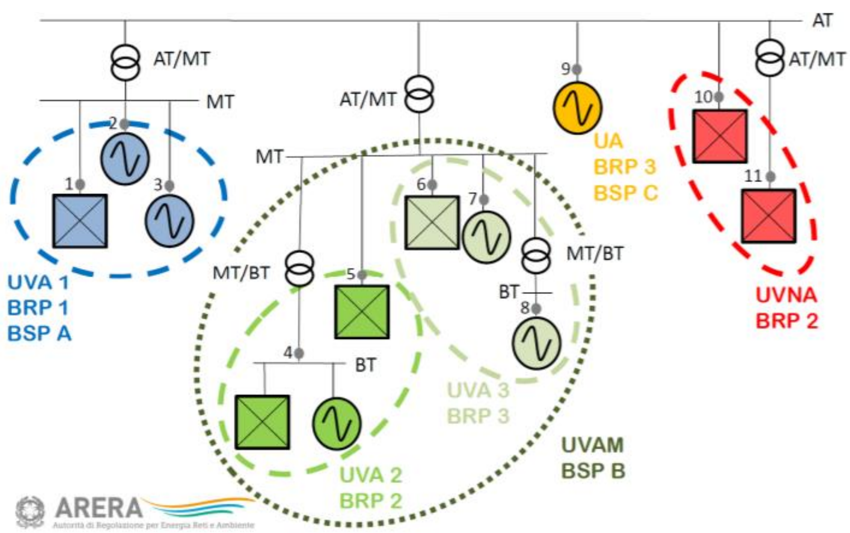

Figure 3-15. Aggregation schemes in the market reform [25]

The final modification of interest corresponds the way in which ancillary services are procured in the ASM. The ASM differs from the previous from the DAM and ID market sections because different products and services are exchanged and procured. As shown in Table 3-7, priority is given for services' remuneration through ASM instead of mandatory requirements.

Table 3-7. Changes in procurement and remuneration of ancillary services [25]

Ancillary Service	**Procurement options and remuneration**	
Frequency containment reserve (primary reserve)	Procurement through descending price auction, remuneration per power available	Mandatory provision by all enabled units, forfeit remuneration
Frequency restoration reserve (secondary reserve)	Procurement through ASM, remuneration per energy	Descending price auctions inside ASM, remuneration per power available
Replacement reserve (tertiary reserve)	Procurement through ASM, remuneration per energy	
Balancing	Procurement through ASM per energy	
Congestion management	Procurement through ASM per energy	
Voltage regulation	Mandatory provision by all enabled units, forfeit remuneration	
Emergency services[8]	Mandatory provision by all enabled units, not remunerated	
Interruptible loads	Procurement through auctions, remuneration per effectively curtailed power for each interruption	

It is worth highlighting that, both in the current and the proposed market reforms, TERNA as the TSO is the single buyer of ancillary services in the market. Moreover, social welfare is maximized through a simplification: TERNA selects bids minimizing the total cost incurred in the process of solving operational and network constraints.

3.6 TSO-DSO coordination in the Clean Energy Package

As a result of more ambitious environmental goals, the development of new communication, supervision and control technologies and infrastructure, and the constantly increasing penetration of distributed energy resources at low voltage levels, the Clean Energy Package envisions a more active role of the DSOs in the planning, deployment, management, and operation of future smart grids.

An integral part to achieve that vision is the possibility of DSOs to participate in the procurement of flexibility services, established in Article 32, numeral 1 on Directive 2019/944 [27]:

> ***Article 32, numeral 1****: Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system. In particular, the regulatory framework shall ensure that distribution system operators are able to procure such services from providers of distributed generation, demand response or energy storage and shall promote the uptake of energy efficiency measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system. Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion."*

[8] Emergency services include black start, tele-tripping and load rejection.

In addition to ability to procure flexibility services found in distribution networks, DSOs shall also coordinate the market interactions with relevant TSOs, as stated in numeral 2 of Article 32, on Directive 2019/944:

> ***Article 32, numeral 2****: "Distribution system operators, subject to approval by the regulatory authority, or the regulatory authority itself, shall, in a transparent and participatory process that includes all relevant system users and transmission system operators, establish the specifications for the flexibility services procured and, where appropriate, standardized market products for such services at least at national level. The specifications shall ensure the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation. Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilization of resources, to ensure the secure and efficient operation of the system and to facilitate market development. Distribution system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs".*

The need of coordination and cooperation between TSOs and DSOs for planning and operation of their networks is reinforced in Article 57 of Regulation 2019 2019/943 [28]:

> ***Article 57, numeral 1:*** *"Distribution system operators and transmission system operators shall cooperate with each other in planning and operating their networks. In particular, distribution system operators and transmission system operators shall exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks."*
>
> ***Article 57, numeral 2:*** *"Distribution system operators and transmission system operators shall cooperate with each other in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system operators and the transmission system operators."*

From the cited Articles, five key points are taken for the procurement of flexibility services from distribution networks:

1. Market schemes are necessary for an efficient, competitive, non-discriminatory and coordinated procurement of flexibility services from distribution networks;
2. Market schemes should be technologically neutral, standardizing products and services but at the same time facilitating the participation of distributed generation, demand response or energy storage and energy efficiency measures;
3. DSOs are the entity mainly responsible of the planning, management, and operation of their networks. In other words, the Clean Energy Package is not advocating for

centralized power systems in which TSOs have complete information and authority on the resources connected to transmission and distribution networks;

4. Nonetheless, the Clean Energy Package still recognizes the importance of an efficiently integrated and coordinated electric system. As a result, distribution networks shall remain integrated into wholesale electrical systems administered by TSO, and do not be planned, developed, and operated independently;
5. Coordination between TSOs and DSOs should comprise the following: I.) establish the specifications for the flexibility services procured and, where appropriate, standardized market products for such services, including the possibility of using them for congestion management II.) ensure the optimal utilization of resources, to ensure the secure and efficient operation of the system and to facilitate market development, III.) exchange all necessary or relevant information for the network operation and deployment, and IV.) allow access to distributed energy resources and the flexibility they provide to transmission and distribution networks.

These general guidelines serve as the basic ground for the development of this thesis and are revisited in following Sections.

4 TSO-DSO coordination

As the context presented in Section 3 shows, can global warming is an urgent problematic that requires shifting the energy sector, and especially the electric systems, from fossil fuels to renewable energies. However, to achieve the Energy Transition successfully and efficiently, the policy and regulatory framework should be adapted accordingly.

For this thesis purposes, the coordinated procurement of flexibility services connected to distribution networks by TSOs and DSOs is the most important regulatory aspect. In this Section, the coordination topic is analyzed from different points of views, maintaining the guidelines provided by the Clean Energy Package and presented in 3.6.

To start, Section 4.1 the attributes of distributed energy resources for providing flexibility services are reviewed. After that, Section 4.2 presents examples found in the literature that have analyzed the coordination problem of TSOs and DSOs, both prior and after the publication of the Clean Energy Package. Finally, Section 4.3 and 4.4 summarized results and current state of European Projects dedicated to study the TSO-DSO coordination topic.

4.1 Distributed Energy Resources and flexibility services

Given the context for the penetration of DER presented in Section 3.2, this Section overviews DER's capabilities to provide flexibility services to distribution networks. These new services added to electrical systems enable the integration of DER in markets designed to procure flexibility services.

In [29] authors describe ancillary services that Distributed Generators are capable of providing to distribution networks. In addition, authors present an early approximation to business models in which DER could participated to allow TSOs and DSOs to make efficient use of the flexibility services they provide. Regarding the first part of the discussion, authors highlight 10 ancillary services that DER can provide, in addition to a classification of services according to the procurement method, as shown in Table 4-1.

Table 4-1. Dispatching Resources from DG and RES. Adapted from [29]

Ancillary Services	Local (L) or Global (G)	Technical requirement (T) or Market Service (M)
Solving congestion during planning phase	L	M
Primary power reserve	G	T
Secondary and tertiary power reserve	G	M
Balancing resources	L	M
Reactive power reserve for voltage regulation	L	M
Active power reserve for voltage regulation	L	M
Demand response and load rejection	L	M
Participation in the recovery of the electricity system	G	T
Availability for use of the intertripping	L	T
Island operation of part of the network	L	T

From theorical to practical demonstrations, the authors [30] present the main results of testing of smart grids solutions in distribution networks in Milan, operated by *A2A Reti Elettriche,* the area's DSO. Although the core of the analysis is dedicated to an automatic procedure for selective fault detection based on logic selectively and fast network configuration, authors also tested two relevant services that enter in the context of flexibility provided by DER: I.) enforcing a centralized voltage regulation by coordination and modulation of DGs reactive power injections, to improve the network's hosting capacity, voltage quality and efficiency, II.) enabling limitation/modulation of active power injections by DG during contingency operation signaled by the DSO, or emergency conditions defined by the TSO, III.) enabling a local dispatch, in order to determine the optimal set points of active and reactive power for generators, according to network conditions and the TSOs requirements, and IV.) making available measurements and forecasts of DG and load every 20 seconds in order to allow the TSO to manage system security, eventually enabling DSOs to implement local dispatch.

In [31] authors propose a bidding scheme for aggregated DER to participate in ancillary services markets. Through the technical representation of different technologies, including Combined Heat and power plants, solar PV, wind, storage systems and demand response, and the standardization of bids, a methodology is proposed to submit bids to an abstract market structure that procures flexibility services. Results show that a proper aggregation method is a key enabler for effectively gathering the flexibility provided by DER. This thesis is revisited in more depth in Section 4.

IRENA presents in [32] a revision of current ancillary services, analyzed through DER capabilities to provide them. First, the vision presented in [29] is supported, as it is clear that DER are not technically limited to provide ancillary services, given the appropriate regulatory incentives. Not only that but, considering new capabilities that DER bring to power systems, it is recommend to policy makers to revisit traditional definitions of ancillary services and defined new ones that contribute to increase the flexibility of existing and future networks. As Figure 4-1 summarizes, flexibility from DER could be procured through two main parts: I.) new ancillary services that take advantage of new technological developments, II.) DER participating in legacy ancillary services, given the appropriate regulatory adjustments.

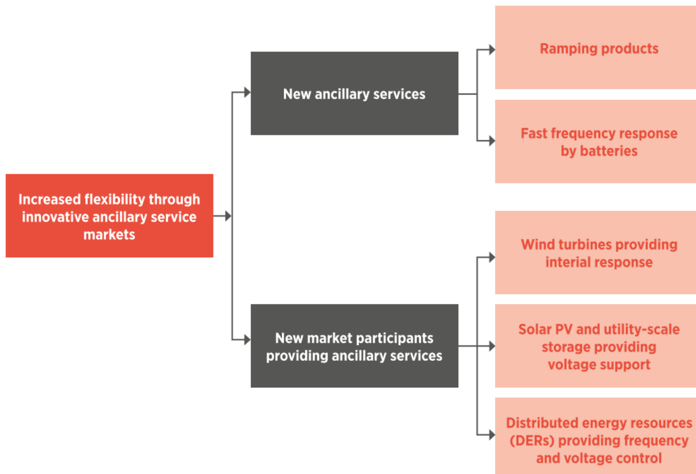

Figure 4-1. Innovation in ancillary services [32]

Recently, UPME, the National Planning entity of Colombia, in Association with Carbon Trust and local and international Universities presented a study to evaluate the deployment of Smart Grids and ambitious GHG emission targets in the country [33]. Colombia serves as an interesting case study for three relevant characteristics of its electric system: I.) Colombian generation mix is dominated by conventional renewables, mainly hydro[9], II.) the penetration of RES and DER is following international trends, with short-term commitments for non-conventional RES in the Energy Mix[10] and increasingly ambitious emission targets[11] and, III.) the delay in the deployment of key Information and Communication Technologies for smart grids, like smart metering and distribution and network automation.

[9] Close to 70% of installed generation capacity is hydroelectricity http://paratec.xm.com.co/paratec/SitePages/generacion.aspx?q=capacidad.
[10] The current government established in its National Development Plan for the period 2018-2022 a goal mandating that retailers must buy between 8 and 10% of their electricity from non-conventional renewable energy resources (solar, wind, biomass, and small-scale hydro).
[11] Colombian government recently updated the country's NDC commitment previously presented to the Paris Accord from 20% GHG emission reductions in 2030, with respect the B.A.U. scenario, to 51% https://www.minambiente.gov.co/index.php/noticias/4877-colombia-reducira-en-un-51-sus-emisiones-de-gases-efecto-invernadero-para-el-ano-2030

The main result of the study is that a decarbonization of the electricity sector in the country between 2030 and 2050 is possible. However, a key factor to efficiently achieve the goal is to procure the flexibility services provided by DER, especially in scenarios in which RES penetration is primarily concentrated in distribution networks. As recommendations for the procurement process, in addition to the deployment of the communication infrastructure required to connect the resources to the market and supervise and control the distribution networks, authors reinforce the need for sufficient regulatory incentives and appropriate market schemes were agents and technologies interact to obtain an efficient outcome.

4.2 TSO-DSO coordination in the literature

Given the expected penetration of DER, and the interest to harness their flexibility from both TSO and DSO, the coordination between these two entities required to achieve an efficient secure planning and operation of transmission and distribution networks has been studied in the literature, even previously to the publication of the first guidelines of the Clean Energy Package. In this Section, a summary of the models for the operative coordination between TSO-DSO in the academic literature is presented. These models are revisited in Section 7, where the mathematical proposal of this thesis' model is described.

In [29], authors proposed three dispatching models, shown see Figure 4-2, to procure the ancillary services presented in Table 4-1 from Distributed Generators. In the first case, **the centralized and extended dispatching model**, the TSO is responsible for procuring global ancillary services from resources connected to distribution networks in a centralized market. On the other hand, the DSO verifies networks constraints of the services procured by the TSO, while also oversees procuring through a fixed tariff local ancillary services like congestion management. In the second case, **the local dispatch by the DSO**, the DSO is now responsible for a local market in charge to procure global ancillary services from DER. Bids from the distribution network are aggregated and passed to TSOs, that then activate bids according to a given criteria. As before, the DSO procures local services through a regulated price. Finally, **in the final cumulative program at the HV/MV interface**, DSOs would be responsible of maintaining a predefined profile in the interface with the transmission network, for which it can use small capacity flexibility resources connected to the distribution networks. TSOs manage the transmission network knowing beforehand the given profile at the HV/MV interface, while having direct access to large DER for global ancillary services.

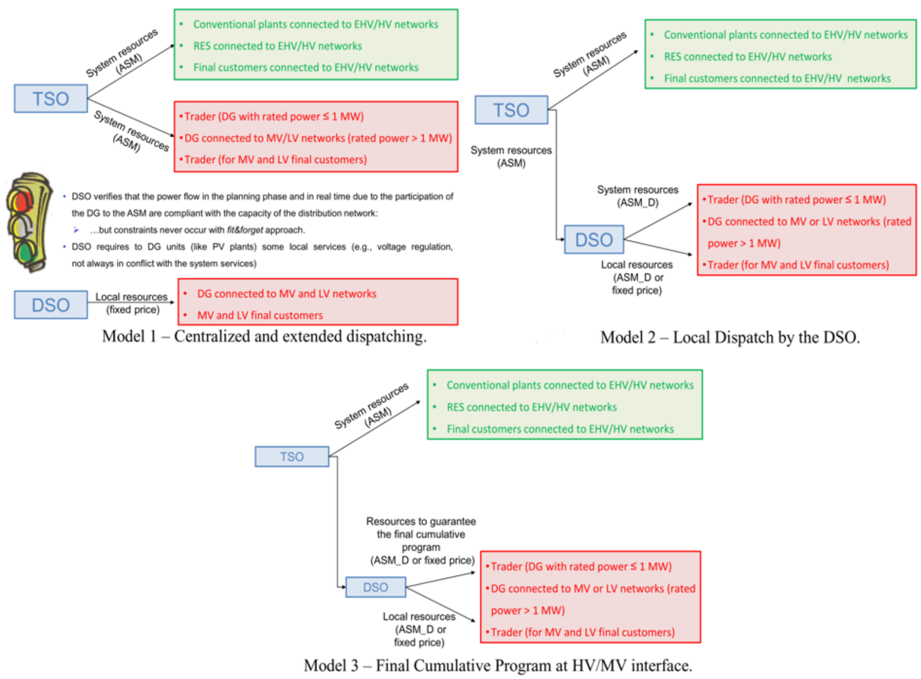

Figure 4-2. Dispatching models for TSO-DSO coordination. Adapted from [29]

These models resemble the ones proposed in the Consultation Document 354/2013/r/eel of the Italian Regulatory authority, and are tested in a real network scenario in [34]. Results show that in any of the proposed models, the high level of DER participation in ancillary services market may be hindered by network constraints at the distribution level, requiring supervision and control technologies to improve network operation by the DSO.

Deepening on coordination models based on a local dispatch of DER by the DSO, authors in [35] present a hierarchical coordination mechanism, illustrated in Figure 4-3. In a similar approach to model 3 of Figure 4-2, DSO shall comply with a given power profile defined by the TSO, which it then uses to solve the dispatching problem at the transmission level. DSOs are responsible for aggregating and later submitting bids to the central Ancillary Services markets, for which the authors proposed a stepwise approximation of the local cost function called Generalized Bid Function (GBF) based on the Bender decomposition of the optimization problem.

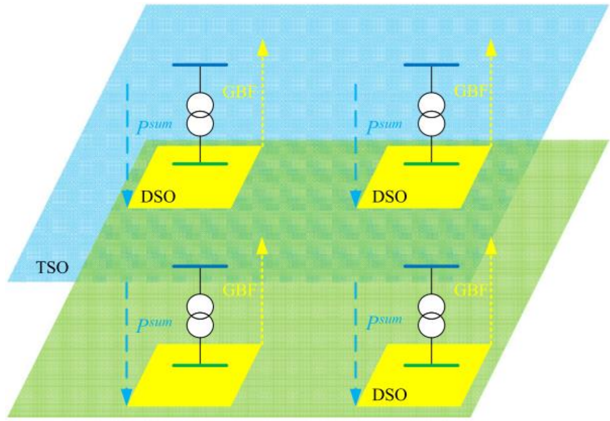

Figure 4-3. Hierarchical coordination mechanism [35]

Authors in [36] analyze the TSO-TSO and TSO-DSO coordination problems starting from defining three system conditions, illustrated for the congestion management case in Figure 4-4. **The green state** is the result of a fit and forget approach for network development or sufficient market signals. In both cases, no corrective dispatch is necessary and network constraints are respected. In the **orange state** not all bids from DER can be accepted simultaneously, due to system constraints, and as a result a corrected dispatch obtained through a flexibility market is necessary. Finally, in the **red state** system constraints were not respected even after adjustment in the flexibility markets, leading to the curtailment of DER with no firm contracts to ensure secure and reliable network operation.

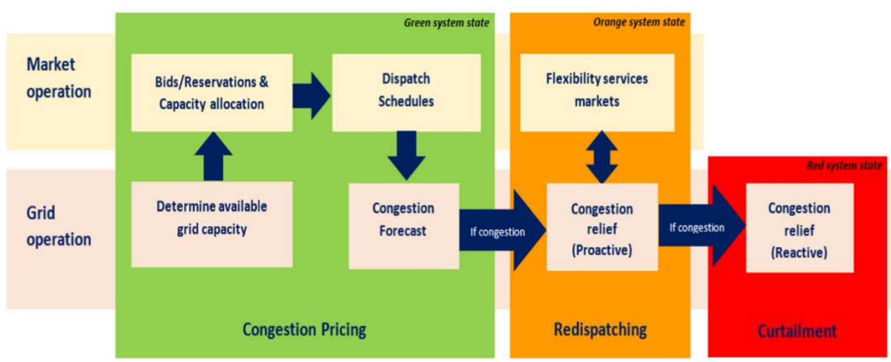

Figure 4-4. Conceptual representation of market and grid operation phases with respect to congestion management [36]

Given the three states, the authors propose TSO-DSO coordination schemes depending explicit or implicit capacity allocation of network interfaces, as shown in Figure 4-5. The schemes are summarized Table 4-2. The main difference from this market architecture to others presented so far is that DER compete for network access in a market session different to the Ancillary or Flexibility markets to gain priority during the dispatching sessions.

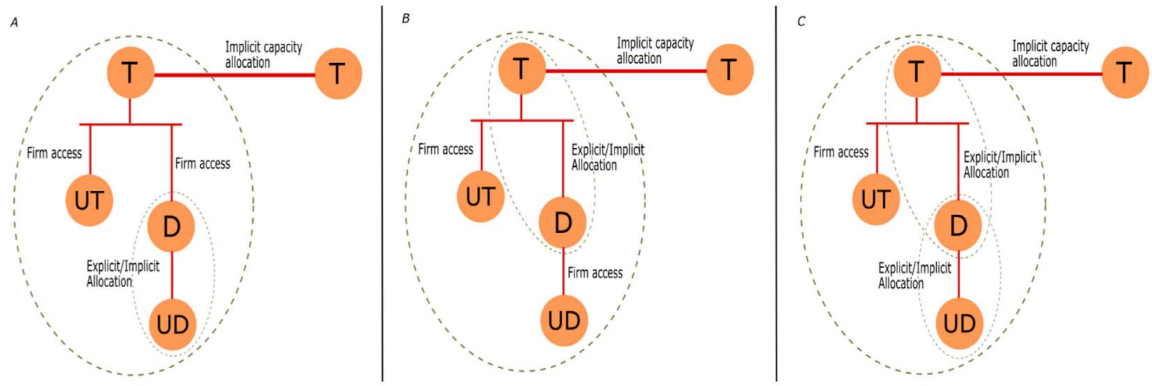

Figure 4-5. Representation of explicit/implicit capacity allocation by the DSO [36] [12]

Table 4-2. TSO-DSO Coordination proposal. Adapted from [36]

Congestion interface / system state	Green	Orange	Red
A (UD-D border congested)	DSO oversees calculating network capacity, according to the constraint interface, and offering it to distribution market participants	• DSO procures flexibility services from DER to solve previously ignored network constraints. • Three options for TSO-DSO coordination: I.) explicit capacity allocation of the D-T interface, II.) jointly procuring flexibility services with implicit allocation of capacity and III.) centralized market in charge of the TSO.	Because only technical measures can be taken to relieve congestion, TSO-DSO cooperation is limited to cases in which there was a previous coordination in place for a given interface in states green and orange, connection to users with firm capacity contracts should be maintained.
B (D-T border congested)	TSO calculates the capacity of the network interface and allocates the capacity between market participants (including aggregators, DER and the DSO)		
C (Both D-T and UD-D borders are congested)	Combination of the previous mechanisms, possibly giving priority to the capacity allocation of the D-T interface		

Authors in [37] extend on model 3 presented in [29] and propose a PQ-charts that should be submitted by DSOs to the respective TSO to accommodate the distribution networks in the central algorithms. These charts, an example shown in Figure 4-6, are calculated using an AC power flow for the distribution network and include both active and reactive power

[12] T: Transmission network, D: Distribution network, UT: User of transmission network, UD: User of distribution network.

characteristics and are calculated to different flexibility conditions assumed for DER. Although they are static in time and do not include prices, TSO could find useful the information, as it provides information that could help to manage voltage problems at the transmission level.

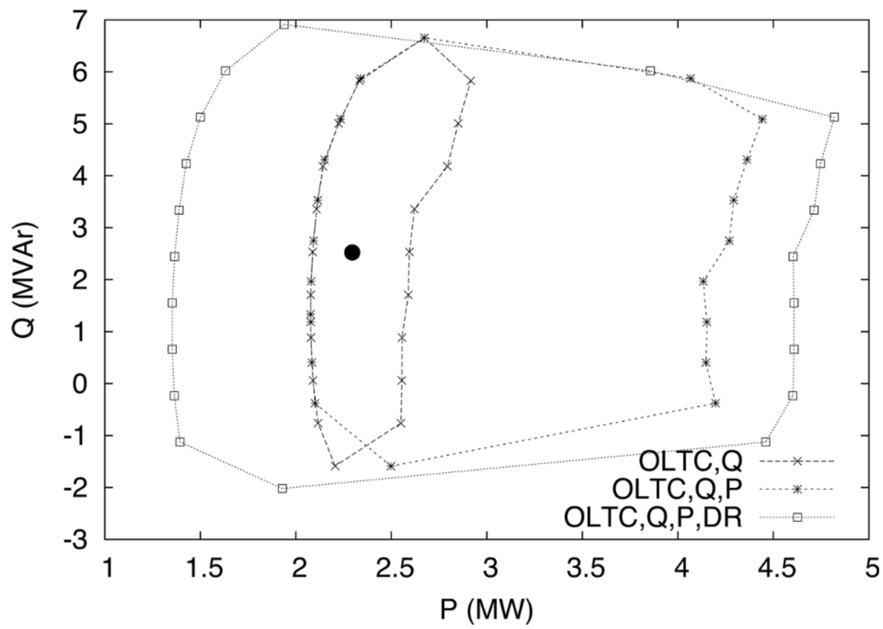

Figure 4-6. PQ charts of distribution network[13] [37]

In [38] the study considers three agents that interact in the coordination schemes: TSOs and DSOs, as presented so far, and retailers, that protect final users from increased prices that might emerge due to peak prices during the settlements. Given these agents, three coordination models are proposed. In the first, sequential procurement**,** TSOs, DSOs, and retailers participate in different markets, with different time frames, to procure flexibility services they need. The second and third markets agents coordinate the timings of the procurements, improving efficiency and increasing liquidity. based on the Shapley value concept, in which a buyer pay-off is its marginal contribution to the total cost of the possible coalitions. In other words, two buyers jointly pay for a service that benefits them both. The second and third schemes are differentiated due to the explicit inclusion of the retailer in the first.

Results show, after simulating during 48 hours in a realistic distribution network, that the most efficient dispatch was obtained using the TSO–DSO coordinated procurement. In addition, the inclusion of the retailers in the joint dispatch does not increase the total welfare, thus

[13]Different cases calculated according to power flow conditions. OLTC, Q refers to flexible reactive power from RES, OLTC, P to flexible active power or curtailment from RES and OLTC, DR to demand response. Load reduction/increase is an option common to all cases.

suggesting that a regulated cooperative dispatch between TSO and DSOs, and a separate competitive market for retailers would result in the most benefits to society.

Finally, in [39] a control methodology based on price signals as a support tool to tradition procurement of flexibility from DER. To start, given a price signals the TSO and DSO, using an artificial neural network and proportional integral controllers, estimate consumer prices responses. User responses are based on a new perspective for ancillary services mechanisms, were no explicit auction takes place but price signal through the generation and submission of time- varying prices that depend on the actual conditions of the grid, each system operators can exploit the flexibility of consumers that are in their territory. TSOs and DSOs have different objectives in their markets, frequency control and voltage management respectively, with power exchanges depending on the network model and the indirect impact on variables of interest. Simulation results show that in the proposed mechanism both TSO and DSO are able to meet their operational constraints simultaneously, in addition to improving the performance of frequency regulation compared to the conventional provision of ancillary services.

4.3 SmartNet project

The SmartNet project (SNP) was a collaborative effort carried out by a consortium of research centers, universities and industrial partners that evaluated and compared different TSO-DSO coordination schemes for acquiring ancillary services from DERs. Due the SNP novelty, scope, importance in the European electric sector and, finally, its relevance for this thesis, it deserves a deeper and broader revision.

Following a comprehensive approach to the subject, the SNP first assessed the role, capabilities and limitations of DER, DSOs and TSOs in the provision and exchange of ancillary services in future distribution networks. As a subsequent step, five coordination schemes for the TSO-DSO coordination for ancillary services provision were proposed. These schemes were evaluated in a simulation platform with three main parts: aggregation, network, and market models, in addition to a cost-benefit tool to compare the schemes' economic performances. In parallel, the SNP implemented three pilot projects to test, among other aspects, DER capabilities and key ICT requirements for the coordination schemes. Finally, policy recommendations dealing with existing technical and regulatory barriers for TSO-DSO coordination in light of the project's results were proposed [40].

4.3.1 *Models for TSO-DSO coordination*

To organize the AS provision, the SNP proposed five basic schemes for TSO-DSO coordination. Each scheme defines a market structure and the roles to be taken by different actors, with special considerations given to those actors in charge of prequalification, activation and settlement of DER [41]. In other words, the coordination models specify the information and economic flows between agents in the AS market sections. Moreover, according to the observability of the network, which is directly connected to the actors and methodologies used to close the AS market, varying levels of network constraints are considered. Figure 4-7 shows the five coordination schemes proposed by the SNP. In addition to the three expected actors, TSO, DSO and DER, the diagram also includes flexible resources in high voltage networks and the aggregator. As explained in previous sections, the aggregator collects, qualifies, and submits bids from DER to the AS market.

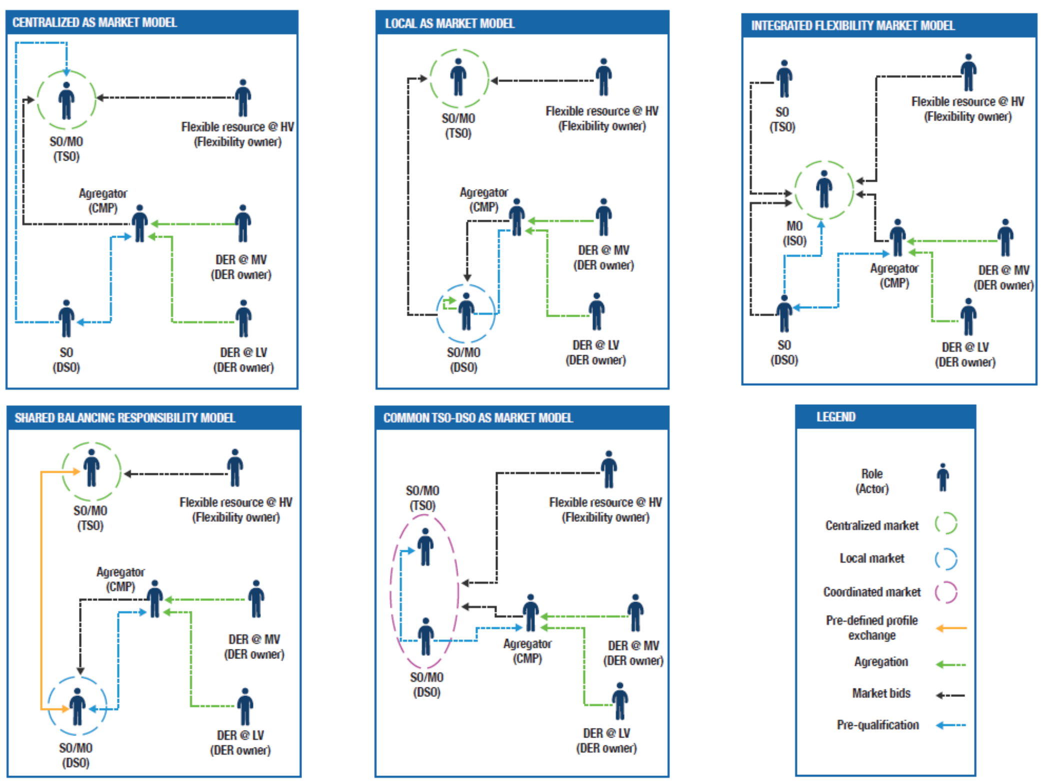

Figure 4-7. TSO-DSO coordination schemes. Adapted from [40]

The first scheme is the **centralized AS market model**. In this case, there is one common market for AS for resources connected to both the transmission and distribution grids. The TSO is responsible for the operation of the AS market, considering network constraints only at the transmission level. Initially, DSO plays no role in the procurement and activation process unless a prequalification bid system is implemented. As a result, DER at medium and low voltage levels, through their aggregators, exchange information directly with the TSO. The main benefit of the first scheme is that it represents no additional costs to the system, as it is a continuation of the *status quo*. However, network constraints at the distribution level could not be respected after the AS market closes, resulting in additional re-dispatching costs.

The second scheme is the **local AS market model**. This scheme revolves around a central unique market at the transmission level, operated by the TSO, and local markets at the distribution level, operated by DSOs. Flexible resources and DER exclusively participate in the central and local markets, respectively. Moreover, both markets consider network constraints at their respective levels. The DSO, after closing its market aggregates and transfers bids to the central market. As a result, the DSO has priority to use DER connected to the distribution grid to solve its own network constraints. On the one hand, the scheme relies on the DSO to operate the distribution grid, enhancing overall grid observability and local constraint management. On the other, the uncertainty in load and generation forecasts could result in excessively conservative margins taken by the DSO for secure grid operation, increasing system costs.

The third scheme is the **shared balancing responsibility model**. As in the previous model, there are two AS markets operated independently by the TSO and DSO. However, in this case the TSO transfers part of the balancing responsibility of the distribution grid to the DSO. The DSO is in charge, using its local AS market, to solve its own network constraints while respecting a pre-defined exchange schedule agreed upon with the TSO. The schedule can be define using historical forecasts for each TSO-DSO interconnection point, or alternatively with congestion constraints for both transmission and distribution grids. Although the scheme ensures that DSO's grid constraints are respected, excessive computational complexity in the market clearing, in addition to uncertainty and transparency concerns related to the activation criteria used by the DSO represent two risks associated to this alternative.

The fourth scheme is the **common TSO-DSO market model**. Resembling the centralized AS market model, the common market approach has a unique market for AS. In this case, both TSO and DSO are responsible for the organization and operation of the market, in which flexible resources connected at any voltage level participate without any type of distinction or discrimination. In contrast to the first scheme, the common model also considers DSO's network constraints in the market's formulation. This approach allows the system to arrive to an AS provision that, at least in theory, maximizes global welfare. Even though from a theoretical standpoint the scheme appears advantageous, the mathematical and computational complexity of such market model could hamper its implementation in real world applications.

The fifth and final scheme is the **integrated flexibility market model**. In this scheme, TSO, DSO, and commercial parties procure flexibility resources in a common market that considers all network constraints. Because perverse incentives could emerge if either the TSO or the DSO acted as market operators, this model requires the figure of an independent market operator. This scheme was not implemented in simulations during the SNP due to regulatory barriers that would make such a coordination scheme unfeasible in Europe.

4.3.2 Simulation platform

Since DERs are typically small plants or loads with a wide variety of technical characteristics, scatter geographically and connected to different voltage levels, the collection and qualification of bids are processes that would benefit from decentralization. The SNP analyzed five aggregation models that, by characterizing and aggregating load groups, can provide ASs [42].

In the models, different aggregation approaches can be adopted depending on the degree of information that is shared between load and aggregators. On the one hand, the physical or bottom-up approach is applied when the aggregator is familiar with the characteristics of each individual load. On the other, the justified approximation or hybrid approach considers virtual devices to represent the aggregated devices. The trace approach sits in between the last two, as it does not use the exact physical representation of the DERs but rather load and cost profiles for each one of them. Table 4-3 presents a summary of the five aggregation models analyzed by the SNP.

Table 4-3. Aggregation models Smart Net Project. Adapted from [42]

Models	Aggregation approach	Type of bid	DER characteristics
Atomic loads	Traces	Non-curtailable UNIT bid[14]	Aggregation of loads with fixed load profiles and can only provide flexibility shifting their starting time or presenting alternative fixed load profiles. Examples include wet appliances and industrial processes
Combined Heat and Power Units	Physical	STEP curtailable Q-bid[15]	Heat production often requires a must-run behavior in the absence of storage. Moreover, estimations are needed to differentiate power and heat productions
Thermostatically Controlled Loads	- Physical - Hybrid	STEP non-curtailable Q-bid[16] or STEP non-curtailable Qt-bid[17]	As the previous category, loads are a combination of must-run facilitates and heat/cooling storage capabilities. Examples include air conditioning systems, heat pumps and water heaters
Electric Energy Storage Units	Physical	STEP curtailable Q-bid or STEP curtailable Qt-bid[18]	Stationary and mobile storage systems including battery storage and pumped hydro facilities belonging to the same geographical area or bidding zone
Curtailable Generation and Curtailable loads	Physical	STEP curtailable Q-bid	Curtailable generation such as wind, photovoltaics, small-scale hydropower and loads that can be curtailed without any rebound effects

The objectives of representing the network in the simulation platform is to assure that technical constraints are not violated when clearing the market while at the same time solving congestion and voltage problems in the grid. Nonetheless, due to the scope of the platform a trade-off between the accuracy in the network representation and its computational complexity inside the optimization problem is needed. Following these guidelines, the SNP opted for using a direct current (DC) model for the transmission network and a second-order cone programming (SCOP) model based on the branch formulation of the DistFlow algorithm [43]. These models are treated in more detailed in Section 6.1

Once the network and the aggregation models have been defined, the market algorithm is proposed [43]. The market receives as an input the bids, in all five different types, from the

[14] Pair of quantity and price not allowing fractional acceptance
[15] Flexibility curve with carrying marginal costs (as multiple pairs of quantity and price) and allowing fractional acceptance
[16] Flexibility curve with carrying marginal costs (as multiple pairs of quantity and price) and not allowing fractional acceptance
[17] series STEP non-curtailable Q-bids for consecutive time steps
[18] Pair of quantity and price not allowing fractional acceptance for consecutive time steps

aggregators and solves an optimization problem that respects the network's constraints. The output of the market corresponds to the activation of DERs. This signal is first sent to the aggregators, which later disaggregate the market result and deliver it to individual DERs. A block diagram summarizing the market model and its connections with the network and aggregation models is shown in Figure 4-8.

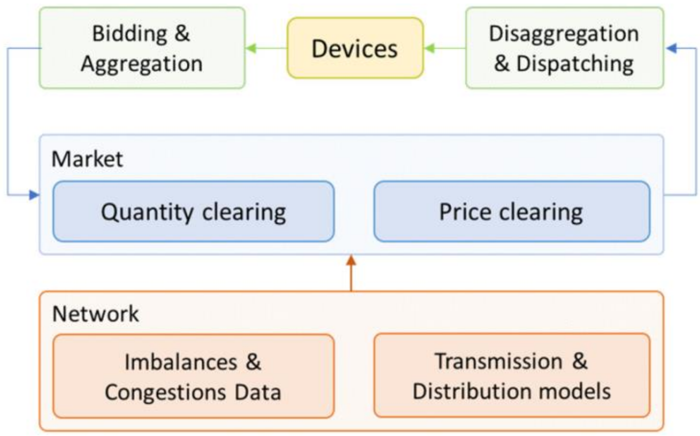

Figure 4-8. Block representation of SNP simulation platform [43]

The objective function of the market model, and the optimization problem itself, are defined according with the coordination schemes and the agents involved in the process. Two types of objective functions are defined in the AS procurement process: I.) minimization of activation costs and II.) maximization of social welfare. In both cases, due to the presence of inter-temporal constraints, it is necessary to consider a time-step objective function because separately solving optimization problems for each time step would result in a solution with worse performance, in terms of activation costs or social welfare, when compared to the case of a single optimization problem that considers a given time horizon.

The SNP evaluated marginal and pay as bid pricing as alternatives for AS in the simulation platform. Marginal pricing was deemed as the most efficient option, and it was adapted to the constraint system using the nodal pricing approach. The nodal prices are obtained from the dual variables of the optimization problem. More specifically, the nodal dual variable associated with the nodal power-balance constraint equals the marginal price at any given node.

Although the previous summary describes theoretically the SNP simulation platform, the detailed information required to include all coordination schemes, DERs and networks amounts to much more than that. First, in [44] the main inputs for the simulation are described as lists of components, plants and agents along with their technical characteristics.

Furthermore, the process of setting-up scenarios and evaluating the results of the simulations is described in [45].

The last block of the SNP simulation platform, not shown in Figure 4-8, is the cost benefit analysis module [46]. The cost benefit analysis module serves to compare the performance of the four coordination schemes evaluated in the SNP. The evaluation was carried out in three national pilot projects: 1.) Italy, which estimated the virtual capacity of the TSO/DSO interface, 2.) Denmark, evaluating AS from indoor swimming pools and 3.) Spain, analyzing AS from radio-base stations. Four cost metrics were used to compare cases: I.) mFFR costs: balancing cost resulting from the market model, II.) aFRR costs: re-balancing the system after resources selected in the market are activated, III.) cost of unwanted measures: emergency actions taken by network operators after unpredicted congestions and IV.) ICT costs: communication and information technologies required to implement the coordination schemes.

4.3.3 Objective function of the market model

The SNP analyzes two main versions of market objective functions applied by the system operator to solve grid problems: minimization of activation costs and maximization of the social welfare [43].

For the minimization of total activation costs, the TSO defines a demand for both downward and upward bids, that could correspond to needs of both congestion and balancing, as shown in Figure 4-9. According to the definition of the authors, where upward bids have a positive quantity an price and the opposite is true for downward bids, the objective function formulation can be unified for both products, being equivalent to a maximization of social welfare.

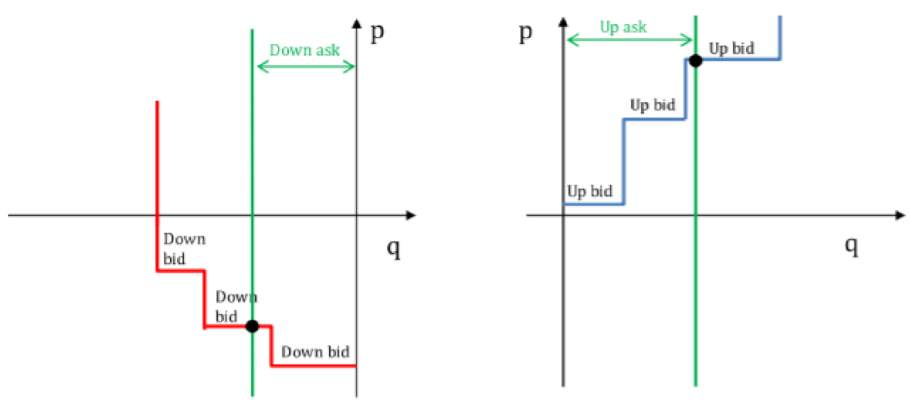

Figure 4-9. Minimization of activation costs in the SNP [43]

For the second case, the direct maximization of the social welfare, to maintain convexity in the objective function, the need for upward and downward bids is represented using *pseudo-bids,* for which the TSO is willing to offer a higher price compared to the bids in the same group, as they are needed to resolve grid problems. It is worth noting that these *pseudo-bids* are not real constraints nor information inside the optimization. After bids are grouped and organized, downward bids are rotated 180° degrees to find the clearing point of the algorithm, which maximizes social welfare as seen in Figure 4-10.

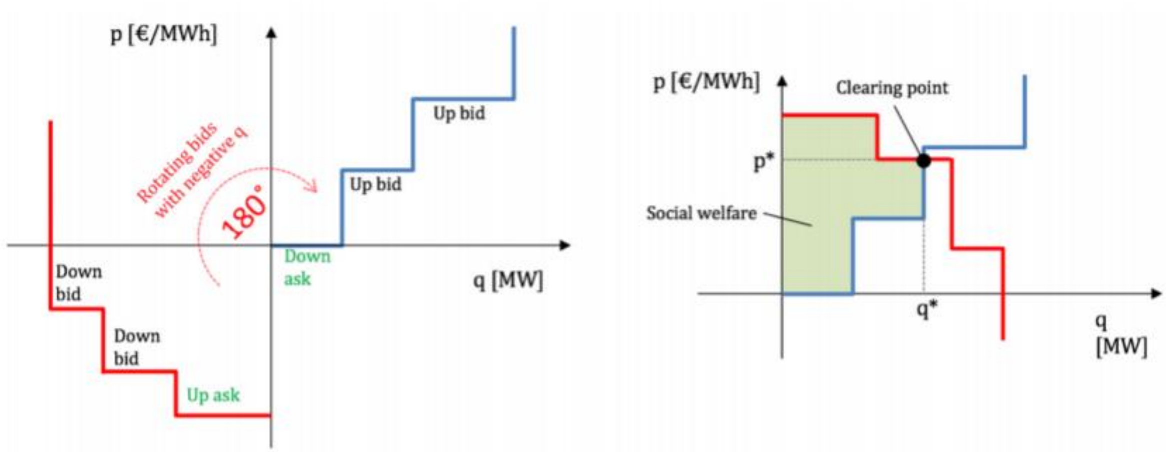

Figure 4-10.Curve-crossing illustration for the maximization of the social welfare [43]

Two important considerations arise when dealing with an objective function that maximizes social welfare. First, the activation algorithms must consider the uncertainty difference between constraints and forecasts close to the gate closure time, and those at the end of the optimization period. For this, the SNP assumes a weight distribution that assigns more importance inside the objective function to periods closer to the gate closure time. Second, the maximization of social welfare algorithm may select bids that are not needed to satisfy network or operational constraints, but nonetheless maximize social welfare. To avoid this problem, the SNP corrects price of bids that might be selected only for maximizing the social welfare.

4.3.4 Results and policy recommendations

The results of the SNP can be divided into two groups: the comparison of coordination schemes carried out along the national pilot projects and the policy recommendations that are derived from the overall project's effort, from both theoretical and practical perspectives.

In the first group, it was demonstrated that the cost of mFRR represent the biggest component in all scenarios, with ICT representing a very small proportion of total costs and unwanted measures being negligible. Furthermore, the effectiveness of the TSO-DSO coordination schemes depends on the level of services requested by the DSO: the centralized model works best when there are few congestions at the distribution level while the common model is the most efficient when congestions are frequent. Finally, as expected, two step optimization models proved less efficient when compared with the common model approach [46].

The most important policy recommendations obtained in the project are presented in [47] and are summarized as follows:

- To implement any of the coordination schemes, significant investments in monitoring and control systems are required, as well as developing expertise on the DSO side;
- Two markets can decrease overall economic efficiency. Thus, if the regulatory framework pushes a two-market solution, the coordination between TSO and DSO is essential to mitigate inefficiencies;
- Markets at the DSO level can suffer from lack of liquidity and low competition levels. Whenever possible, DSOs should merge markets to alleviate the issue;
- The project recommends DSOs to be responsible for local voltage regulation and congestion management of their networks. TSO shall remain responsible of balancing, which should remain being considered a global issue in the electric system;
- New bid types are necessary to ensure level playing field for DERs that wish to participate in the tertiary reserve market.

4.4 Other European projects

At the time this thesis is drafted, other European projects studying the TSO-DSO coordination have finished or are currently under development. The following Sections briefly summarizes their current state, and relevant results, and available literature on the TSO-DSO coordination topic of three projects: EUSysFlex, Inteflex, Coordinet and OSMOSE.

4.4.1 EUSysFlex

EUSysflex is a horizon 2020 project, funded by the European Union, expected to be completed by October 2021, although most of the documents have already been published. The consortium is formed by 34 members from 15 countries across Europe, including TSOs, DSOs, Aggregators, technology providers, Consultants, Research institutes and Universities [48].

The main goal of the project was to identify long-term needs and technical scarcities, in the future European power system that is expected to have at least 50% of electricity coming from renewable sources. Once the first step is completed, the project is working on establish the necessary flexibility solutions to enhance the market and regulatory framework to overcome the challenge, from both a theoretical and practical point of view in the sector. Finally, the project will result in a long-term roadmap for actions across Europe to facilitate the large-scale integration of new technologies and capabilities [48].

With respect to the TSO-DSO coordination problem and the provision of flexibility services from DER, the project is currently completing 4 demonstration projects [48]:

- Italy, provision of flexibility services from resources connected to the MV DSO network. The demonstration site, Emilia Romagna region, is in an area with strong renewable generation penetration, low consumption, and frequent back feeding from MV to HV networks.
- Finland, demonstration of provision of flexibility services from distributed LV or MV assets. Aggregation of distributed assets to the TSO's ancillary services markets and for balancing DSO's needs. In addition, a mechanism for optimizing the reactive power procurement in the DSO market is being developed.
- Portugal, flexibility hub, provision of active and reactive power and dynamic grid models to the system using DSO grid connected resources. The project is located in the north of Portugal, with high levels of wind and solar generation that frequently surpass consumption.
- France, aggregation approaches for the provision of multi-services from a portfolio of distributed resources. Demonstration in EDF Concept Grid facilities, of the provision through a portfolio of wind, PV, and storage of ancillary services.

From a theoretical standpoint, the project presents several proposals to consider in market formulations, bidding processes and aggregation of flexibility services from DER and the coordination between TSOs and DSOs. To start, [15] presents a comprehensive revision of possible increments in ancillary services needs due to renewable energy penetration. The main findings, from a qualitative standpoint, is presented in Table 3-1.

In [16], the project analyzes different products and flexibility services that serve to cope the previously identified needs. Each of the proposed products shown in Table 4-4 has an associated time, depending on the requirement that it is trying to supply.

Table 4-4. Basket generic system services [16]

System service	Aim	Timeframe
Inertial response	Minimize RoCoF	Immediate
Fast response	Slow time to reach nadir/zenith	t<2 secs
Frequency Containment Reserve	Contain the frequency	5 secs < t < 30 secs
Frequency Restoration Reserve	Return frequency to nominal	30 secs < t < 15 min
Replacement Reserve	Replace reserves utilized to provide faster products	15 mins < t < hours
Ramping	Oppose unforeseen sustained divergences, such as unforecasted wind or solar production changes	1 hours < t < 8 hours
Voltage Control Steady-State	Voltage control during normal system operation	Long or short timeframe for activation
Dynamic Reactive power	Voltage control during a system disturbance and mitigation of rotor angle instability	t < 40 milliseconds
Congestion management	Manage congestion that occurs because of a range of situations	Minutes < t < hours

Of special relevance to this thesis is the definition of products for congestion management. The project highlights market-based products (flexibility procurement, dynamic grid tariffs or dynamic connection agreements) and operative and mandatory ones (network reconfiguration, countertrading and redispatching). As final measures, network reinforcements or upgrades can be carried out by the relevant agent [16].

Due to the increasing costs of the last solutions, justifying the search for a most cost-efficient solution, the EUSysFlex is analyzing the possibility of solving network constraints with existing products for frequency control, incorporating, by necessity, locational aspects or in designing Congestion Management products that are bespoke and uniquely different from frequency control products to address different needs for the process of Congestion Management [16]. In addition, authors remark that regarding congestion management products market-based solutions should be preferred in all cases when market power and increase/decrease gaming can be limited sufficiently. Moreover, the solutions must ensure sufficient visibility and predictability for system operators and market. However, if the liquidity is poor and increase/decrease gaming cannot be limited sufficiently, voluntary non-firm connection agreements for loads and mandatory participation with cost-based remuneration for generation can be a potential option [49].

Regarding TSO-DSO coordination schemes, the EUSysFlex project analyzes in depth two alternatives: centralized and decentralized models. The description, advantages and disadvantages of each alternative are summarized in Table 4-5. Authors highlight that both alternatives are technically feasible for all flexibility services, and do not reduce market liquidity by design [49].

Table 4-5. EUSysFLEX TSO-DSO Coordination schemes, Adapted from [49]

TSO-DSO Coordination	Description	Advantages	Disadvantages
Centralized	One optimization for all system operators solve all their scarcities. All necessary information is directed into a single algorithm to consider constraints at all voltage levels and select the most appropriate bids.	Optimal allocation of resources at a system wide level.	Complexity of the algorithm
Decentralized	There is one optimization for each system operator to solve the respective scarcity, requiring a coordination scheme for the different optimization levels. Three coordination options are possible: • Optimization at the distribution level, followed by optimization at the transmission level • Optimization at the distribution level, followed by optimization at transmission level and again at distribution level • Optimization at transmission level, followed by optimization at distribution level	• Lower computational complexity, in addition to higher resilience of the individual algorithm • Easy integration, specially in a top-down coordination approach, for distribution networks that need locational products to solve voltage and congestion problems • Model is more suited for current regulatory framework	• Lower overall efficiency • It requires a coordination scheme between TSOs and DSOs

For any of the schemes, the project introduces the figure of Optimization Operator. It is its responsibility to select bids (clear the market or choose in an order book) considering grid data and switching measures. This new function can be carried out by TSOs, DSOs, a joint venture or third parties, but in any case, both TSOs and DSOs shall provide all grid-related information for the Optimization Operator to take the appropriate decisions [49].

4.4.2 Interflex

The Interflex project is Horizon 2020 initiative that, with the participation of 20 partners (DSOs, energy retailers, service providers, equipment manufactures and research centers) from 6 different European countries, with equal number industry-scale demonstrators, during three years, starting in 2017, investigated interactions between stakeholders and the technical and economic potential of local flexibilities to relieve existing or prevent future grid constraints, actively contributing to the energy transition, fostering both the development of renewable energy sources and the decarbonization of heating and transport sectors [50].

While the EUSysFlex project gives specially to flexibility from DER at the TSO level, the Interflex initiative is mainly interested in DER flexibility to solve constraints in distribution networks. The procurement of flexibility resources is justified from three perspectives: I.) grid operation, solving grid constraints due to network incidents, extreme weather conditions or planned maintenance, II.) grid development, avoiding or postponing grid reinforcement, and III.) balancing, for cases like islanded microgrids when local balancing is DSOs responsibility [50].

Regarding the procurement schemes for flexibility services by the DSO, the project initially analyzed three main proposals for the DER activation [51]. In the first mechanism, DSOs own and directly control assets in this mechanism, resources are activated by the DSO without involving third parties. In the second case, legal or contractual agreements, bilateral contracts are put in place between the DSO and the flexibility provider which defines the conditions of flexibility activation. Finally, in the market response approach, flexibility provider bids are activated in response to a DSO market demand and activates its flexibility according to market rules and results. These schemes are shown in Figure 4-11, with their respective uses to solve system scarcities and constraints. It is worth noting that the first two cases resemble current regulatory states in European countries, while the latter approach is adapted to the developments presented in the Clean Energy Package [52].

	DSOs own flexibilities	Legal or Contractual Agreements	Market response
Grid Operation Constraint due to extreme conditions		●	●
Grid Operation Situation of incident	●		●
Grid Operation Planned maintenance		●	●
Grid Development Flexibility to avoid grid reinforcement	●	●	
System Operation Balancing	●	●	

Figure 4-11. Activation mechanisms for DSO needs in InterFlex [51]

Regarding the TSO-DSO interactions, the Interflex project proposed and tested in the demonstrator projects the business case shown in Figure 4-12. The DSO analyzed the offers from several aggregators and selected the most suited ones. If there was a match between DSO demand and aggregator bids, the DSO sent its activation requests to the aggregators who dispatched them through specific activation channels to their flexibility providers. By doing so, the aggregators provided the expected flexibility service at the minimum cost. The DSO's formulation of flexibility requests, the bidding process as well as the flexibility activation process was channeled through both DSO and aggregator platforms and the corresponding interface. In this coordination scheme, the TSO is presented as an additional buyer that can enhance the development of flexibility offers, whether they are local or not [50].

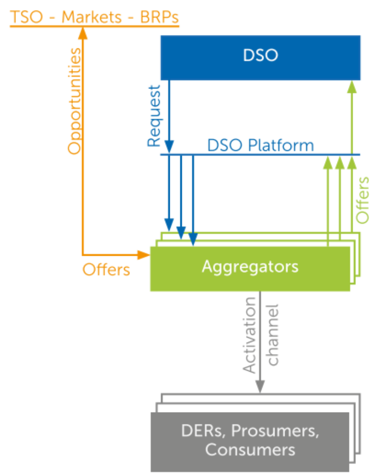

Figure 4-12. Business cases tested in Dutch and French networks [50]

In summary, the project analyzes procurement schemes were the DSO has priority over the flexibility resources connected to distribution network to solve local constraints, more accordingly to the current regulatory and technological framework of European electric systems. However, the interaction with wholesale ancillary services markets and the TSO, two requirements established in the Clean Energy Package, are left for future works.

4.4.3 COORDINET

The Coordinet Project is a research initiative founded by European Horizon 2020 that is currently studying the TSO-DSO coordination problem. It is carried out by 23 partners from Academia, TSOs, DSOs, industry, aggregators, service providers, municipalities and it is expected to be completed by the year 2022 [53]. The project is composed of 8 several parts comprising, among other:

- Literature review of current markets and regulatory framework, already complete and presented in [24].
- Three large-scale demonstration projects in Spain, with ENDESA, Sweden, with VATTENFALL, and Greece, with HEDNO.

- Proposal for a market and platform to coordinate the procurement of energy services, including the lessons learnt from the pilot projects.
- Dissemination and exploitation campaigns.

4.4.4 OSMOSE Project

The OSMOSE project is another European Horizon 2020 initiative currently under development, with the aims to identify and develop the optimal mix of flexibilities for the European power system to enable the Energy Transition [54]. The project started in 2018 and is structured around a four-year plan to delivery its main results. As in previous initiatives, the OSMOSE Project is a collaborative framework with the participation of 33 partners (TSOs, electricity producers, manufactures-integrators, IT companies, research centers and Universities).

The working plan of the project is organized around eight delivery packages, see Figure 4-13, that will conclude in four large-scale demonstrators to explore the technical and economic feasibility of innovative flexibility services and providers, including: I.) grid forming, II.) multi-services by hybrid storage, III.) near real-time cross border exchanges, and IV.) smart zonal energy management system [54].

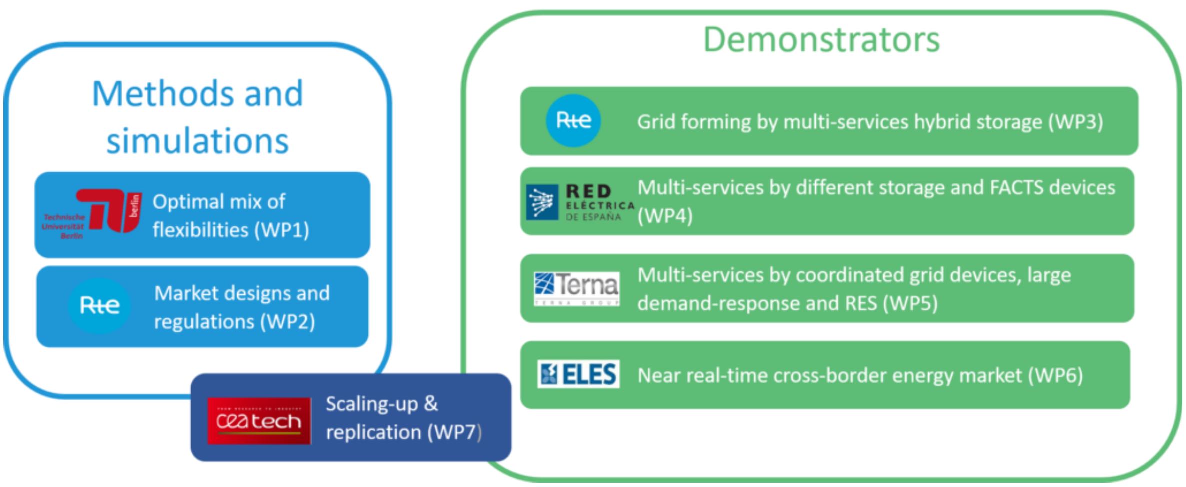

Figure 4-13. Work-plan OSMOSE Project [54]

In the work package referring to *Market designs and Regulations,* the OSMOSE project is analyzing market designs candidates to integrate flexibility in future electricity systems. The four main alternatives discussed and presented in [55] are summarized in the following:

1. **Power exchange with zonal pricing – MD1a**: in this alternative National power markets are coupled via the single day-ahead and intraday market coupling under a zonal pricing scheme, balancing markets with common principles for the procurement, activation and the settlement of balancing services are implemented as stipulated by the Electricity Balancing Guidelines. This market design, based on current regulatory guidelines, would have to emphasize relevant aspects for future energy markets: I.) higher temporal resolutions, II.) flexibility products, III.) shorter activation times of flexibility products, III.) congestion management, IV.) improve coordination on re-dispatching, and V.) integration of energy and reserves;
2. **Power pool with nodal pricing – MD2a:** this design is based on USA market approaches to deal with network congestion, deviating from common practices in the European Union. It entails a day-ahead market with hourly locational marginal prices for the next day and a real-time market in which current prices are calculated at five-minute intervals based on actual grid operating conditions. Locational marginal prices are determined by the so-called Independent System Operator (ISO) within a centralized optimization maximizing welfare subject to constraints. As before, the market design should prioritize: I.) co-optimization of energy and reserves using a real-time approach, II.) new reserve qualities (products and their characteristics), and III.) enhancing forward markets;
3. **Local flexibility markets – MD1b:** this design, an extension of market MD1a, with local flexibility markets at the distribution level. Following the ENERA approach, this variation will introduce order books at a local level with anonymized orders allowing TSOs and DSOs to procure local flexibility for system services like re-dispatching;
4. **LMPs at distribution level – MD2c:** this alternative, based on market design MD2a, authors focus on Local Marginal Pricing at the distribution level, to enhance distributed flexibility valuation;
5. **Transactive energy market – MD1d/ MD2d**: in this market approach, further emphasis is given to Peer-to-Peer (P2P) transactions in the market for balancing and other flexibility services. A balancing market with P2P with the TSO as the "insurer of last resort" allows to ensure sufficient levels of reliability in a price discriminative way.

With the current European market framework and guidelines as a *Status quo*, authors organized the market design candidates depending on the extend and speed of change required to achieve the final system state, as shown in Figure 4-14. Implementing local flexibility markets at the distribution level is seen as a disruptive challenge that would require the re-construction of current market designs. Going further, in terms of allowing P2P transactions for flexibility products and resources is considered and even more demanding change, requiring what authors called *a revolution* in the current regulatory framework.

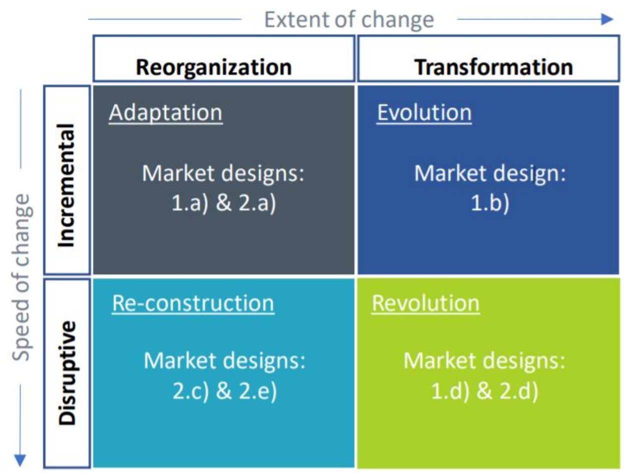

Figure 4-14. Market designs considerations [55]

.

5 Bidding structure and Aggregation

The aggregator is a new entity that has being created in electric systems to simplify, for both market operators and agents, the integration of DER at a large scale. The aggregator operates several DER at the same time, creating a capacity similar to that of a conventional generator, enabling the participation of the aggregated resources in wholesale electricity markets. An aggregator smooths out the integration of DER into the power system, allowing them to deliver ancillary services to the grid operator and thus, increasing the system flexibility [56].

The aggregator accomplishes several functions in the electric systems. First and foremost, the aggregator represents the DER interests in the ASM. In a competitive environment, this means that the aggregator is trying to maximize DER's profits. Second, the aggregator qualifies and submits bid to the ancillary services markets. Bids summited by the aggregator must respect the technical characteristics and respond to the necessities of DER, while at the same time complying with the grid and market requirements. Third, once bids have been accepted or rejected by the market the aggregator needs to disaggregate the bids, sending appropriate control signals to the DERs. These functions, in addition to the financial accountability for DER imbalances, are grouped by the 2019 Clean Energy Package in the figure of Balancing Responsible Parties (BRP).

In the following sections, the bidding function of the aggregator is studied in detailed. The idea of the analysis, that goes along with the ancillary services market design, is to define the bids that will be modeled in the simulation framework develop in this thesis. Moreover, as it is the focus of the project, special attention is given to products and bids related to balancing and congestion management. Other aspects of the aggregation process are out of the scope of the present work.

In this discussion, a clear trade-off emerges. On the one hand, ASM and product standardization should strive towards increasing competition levels and liquidity, in addition to reducing complexity and market fragmentation [57]. For local ASM, with an expected limited number of participants, these aspects play a vital role in the viability of the TSO-DSO coordination. On the other, bids should help aggregators to represent technical characteristics of different DER. The ASM design, and the associated bid categories, should ensure that the outcome is both economically efficient and technically feasible. This dichotomy drives this chapter and the bidding proposal presented in Sections 5.8.

5.1 Bidding in European balancing energy platforms

In their efforts to unify and integrate national electricity markets into cross-European markets, European institutions have developed a series of guidelines and requirements to help in the process. The current regulation REG 2017/2195 establishes a series of guidelines for electricity balancing in a cross-European framework. Among those, Article 25 and 26 deal with standard and specific products for balancing markets[19].

Standard products help to ensure a liquid and competitive market by defining a set of common characteristics across balancing markets. The common characteristics should facilitate the participation of demand response, conventional and non-conventional power plants and storage units [57]. Figure 5-1 and the associated list show the most important characteristics of standard products:

a) Minimum and maximum quantity of single bids expressed in MW (Item 4);
b) Full Activation Time: sum of preparation period (Item 2) and ramping period (Item 3);
c) Full Delivery Period: sum of ramping period, minimum and maximum duration of delivery period (Item 5) and Deactivation period (Item 6);
d) Divisibility: minimum divisible unit of balancing energy expressed in MW;
e) Validity period: date for which offer is valid;
f) Price of bid ($/MWh);
g) Mode of activation: manual or automatic;
h) Minimum duration between end of deactivation period and following activation;

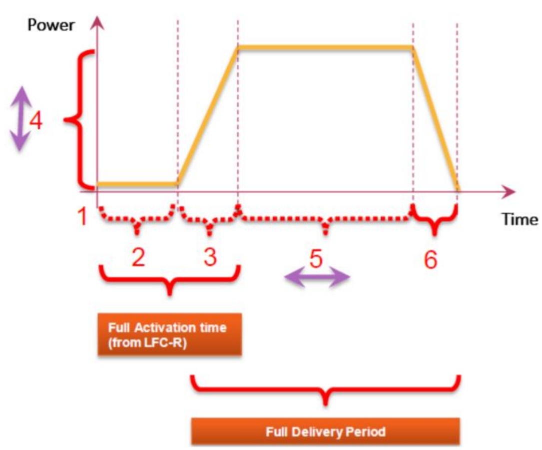

Figure 5-1. Standard products for Balancing energy [58]

[19] For a complete summary of the Electricity Balancing guidelines refer to [84]

Although Standard products shall be the norm of the electricity balancing markets, TSOs can also develop proposals defining specific products. TSOs should justify the necessity of specific products to ensure operational security and system balance, in addition to establish the conditions for specific products not to create inefficiencies and distortions in the balancing markets. Nonetheless, specific products should always be implemented in parallel to standard products. Moreover, whenever possible TSOs should convert specific products into standard products [57].

5.2 The Italian experience with aggregation: UVAM pilot projects and Electricity Dispatching Reform

Responding to the European guidelines and internal efforts to transform the ASM, the Italian regulator (ARERA) develop a series of pilot projects to evaluate the provision of ancillary services from aggregated DER. These projects are a first step towards allowing non-relevant units, with a capacity lower to 10 MW, to participate in the ASM. The pilot projects were divided into three stages: UVAC (virtually aggregated consumption units), UVAP (virtually aggregated production units) and UVAM (virtually aggregated mixed units) [59]. Table 5-1 summarizes the characteristics of the pilot projects.

Table 5-1. Italian aggregation pilot projects [26]

Pilot project	Main characteristics	Ancillary services provided	Bids and payments
UVAC	- Aggregation of consumption units - All DER in the same perimeter of aggregation - Maximum control power of at least 10MW	- Tertiary replacement reserve - Balancing	- Couple of price/quantity for the minimum consumption - Couple of price/quantity for the minimum consumption - Pay as bid
UVAP	- Aggregation of production units - All DER in the same perimeter of aggregation - Regulating power between 1MW and 5MW - Able to implement dispatching order within 15 minutes and maintain it for at least 3 hours	- Tertiary replacement reserve - Balancing - Congestion management	- UVAP sends baseline - Couple price/quantity for selling and buying offers
UVAM	- Aggregation of both production and consumption units - All DER in the same perimeter of aggregation - Minimum regulating power of 1MW - Able to implement dispatching order within 15 minutes and maintain it for at least 2 hours	- Resolution of congestions - Spinning tertiary reserve - Replacement tertiary reserve - Balancing	- Baseline of production/consumption - Uninterruptable loads excluded - Splitting coefficient for each DER

With respect to the bidding process, two elements are worth highlighting. First, pilot projects must report and respect a set of technical constraints. These constraints are shown in Figure 5-2 for the UVAC case, but the same ideas are applicable to the other types of pilot projects. Although they share characteristics with those defined for standard products, as shown in Figure 5-1, the minimum acceptable power of the bid (an indivisible offer) plays an important role for many DER, especially for demand response and consumers.

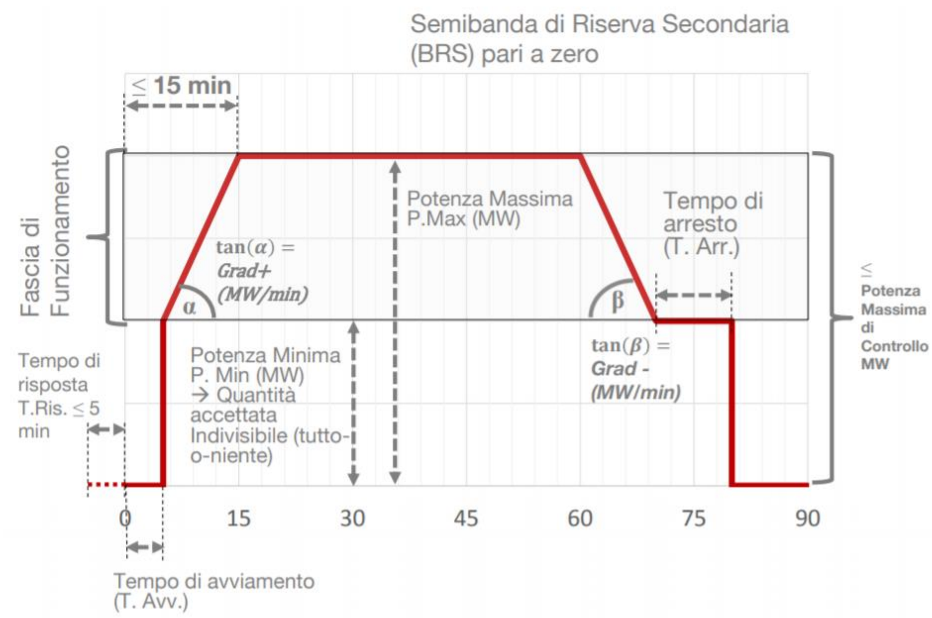

Figure 5-2. Bid characteristic for UVAC projects [60]

In addition to the technical characteristics of the bid, aggregators also submit an energy baseline, as shown in Figure 5-3. The baseline, which can also have negative values, describes the aggregator's behavior for the next 24 hours and is the initial input to the ASM. From the baseline formulation are excluded uninterruptible loads. Starting from the baseline, aggregator imbalances and bids with the characteristics of Figure 5-2 are accepted or rejected.

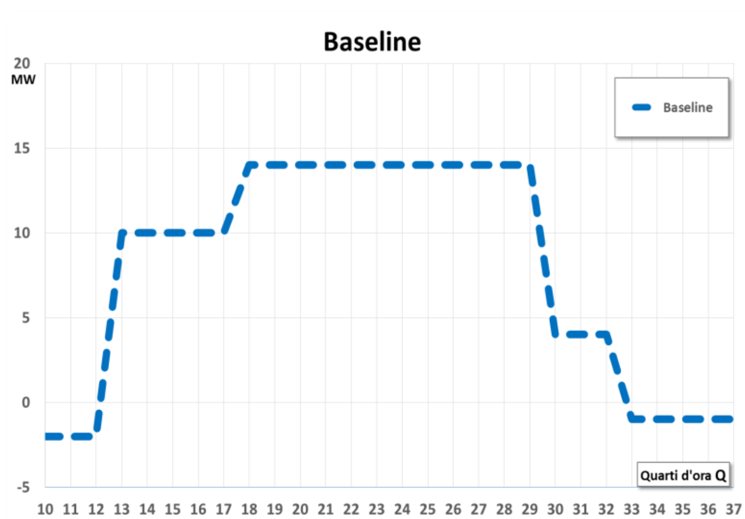

Figure 5-3. Baseline for UVAM projects [26]

Continuing with the market reform, the Italian regulator is currently studying an overall dispatching reform in the consultation document 322/2019/R/eel. After several consultation and deliberation steps, in which the contents of the reform might change, it is expected to be implemented by 2022 [25].

With respect to ASM and aggregation, two important aspects from the reform proposal are worth mentioning. To start, the participation of non-relevant units in the ASM through aggregation is arranged through the categories shown in Table 5-2. The new categories collect lessons learnt from the aggregation pilot projects and generalize participation conditions, in addition to being more in line with the concepts and roles of the BRP and the Balancing Services provider (BSP) enforced by the Clean Energy Package at the European level.

Table 5-2. Aggregation in consultation document 322/2019/R/eel

Aggregation category	Main characteristics	Ancillary services provided
Single Enabled Units	- One production or one consumption unit - 1 BRP, 1 BSP and 1 dispatching point - No perimeter of aggregation; equal to the connection point	- Congestion management - Resolution of congestions - Spinning tertiary reserve - Replacement tertiary reserve - Secondary reserve - Balancing
Virtual Enabled Units	- Any combination of production and consumption units (up to two) - 1 BRP, 1 BSP and 1 or 2 dispatching points - Minimum between market zone and smallest reference perimeter for the ancillary service[20]	
Mixed Virtual Enabled units	- Any combination of production and consumption units - Several BRPs, 1 BSP and several dispatching points - Minimum between market zone and smallest reference perimeter for the ancillary service	

The second aspect, directly linked to the bidding requirements from aggregators, is a revision of the existing ASM. On the one hand, tertiary reserve, balancing, congestion management, voltage regulation and emergency services (black start, tele-tripping and load rejection) are planned to suffer no changes. On the other, the reform proposes that primary and secondary reserves can be procured either through existing conditions or using an auction mechanism.

Summarizing, the participation of DER through aggregators in ASM in Italy is expected to follow the European guidelines for balancing markets, keeping the bids as simple quantity/price pairs with minimum activation levels and their respective prices.

[20] The minimum perimeter for ancillary service provision is dependent on the specific service; for congestion management it is the connection point and for primary frequency regulation it corresponds to continental Europe

5.3 European Union founded projects: SmartNet and INTERRFACE

Among the European Union founded research project dealing with TSO-DSO coordination schemes, the SNP and the INTERRFACE projects have already dealt with the issue of aggregation and bidding.

Section 4.3 briefly discusses the simulation platform of the SNP, including the aggregation and disaggregation blocks. Specifically, Section 4.3.1 presents a summary of the five aggregation models used with respect to the aggregation approach, the type of bids and the load characteristics. In this section, this topic is analyzed in greater detailed.

To define the aggregation models used in the simulation platform, the SNP grouped DER that are expected to penetrate distribution networks into five categories according to their technical characteristics. The categories allowed the common modelling of DER that share attributes and have similar behaviors, but represent different users possibly located at different parts of the network. The fourth column of Table 4-3 presents the load characteristics and main examples of each DER category [42].

Once grouped, the aggregation approach for each DER can be specified. This selection depends on three decision factors: the level of detailed on the model of every individual DER, the information available to the aggregator and the computational complexity of the aggregation approach. Considering this, and the DER categories defined previously, the SNP studied four aggregation approaches applicable to distribution networks [42]:

1. Physical or bottom-up approach: it assumes that the aggregator knows all the parameters of each individual devices as physical entities, accounting for the peculiarities and characteristics of possibly heterogenous technologies;
2. Traces approach: the aggregator in this case no longer knows exact physical DER characteristics, but has access to load profiles and the associated costs;
3. Data-driven approach: instead of trying to model specific devices, the aggregator emulates the behavior of a DER pool. It predicts future behavior based on historical data in a process that can be improved through time and becomes more efficient as agents and the aggregator itself gains more experience in the market;
4. Justified approximation or hybrid approach: the aggregator uses a limited number of real devices to emulate the behavior of a DER pool.

In an ideal scenario, an aggregator with unlimited time and resources should always select the first aggregation approach as it provides the best chances of accurately capturing all technical characteristics of DER and as a result, having the best chances of maximizing their welfare. However, this approach could result burdensome for many real applications due to the extensive modelling and the excessively large number of input parameters required. In many cases any of the simplified approaches would be justifiable.

Linking the DER categories with the aggregation approaches, the SNP defined the types of bids to be submitted to the simulation platform. Nine bid types were proposed, organized according to their curtailability and their relationship with other bids in terms of price/quantities and time. Figure 5-4 shows the standard bids implemented by the SNP in the simulation platform.

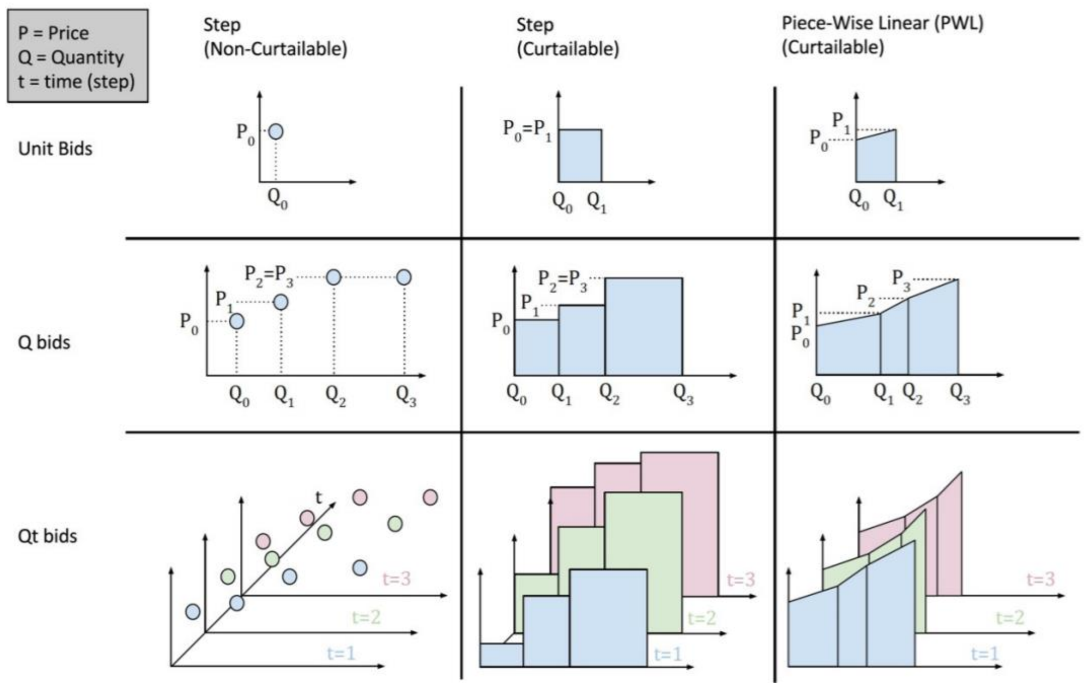

Figure 5-4. Standard bids Smart-Net project [43]

Following the columns of Figure 5-4, bids are presented according to the possibility of curtailment. Some loads, as it is the case with thermal processes for example, cannot operate in conditions different to nominal ones and therefore require non-curtailable bids to participate in ASM. In the case of Piece-Wise linear bids the offer can be curtailed, but the price/quantity relationship is not constant.

With respect to the rows of Figure 5-4, bids are shown according to their linking with other bids both in terms of price/quantity and time. The simplest case in which a single price/quantity pair is considered as a complete bid is introduced in the first row. Q bids and Qt bids extend this concept in the energy and time dimensions, respectively. Q bids represent a series of price/quantity pairs, or profile, for a given energy range while Qt bids are series of Q bids for several time periods.

Standard bids are finally formed by combining the characteristics of rows and columns in Figure 5-4. Step Qt bids for example represent a series of price/energy profiles for successive time periods, in addition to being curtailable. This type of bid is the most implemented in the literature and in the current Italian ASM.

Regarding reactive power management, the SNP initially analyzes four different alternatives, as shown in Figure 5-5. These alternatives are summarized as follows:

1. Fixed power factor: reactive power related to real power by a constant capacity factor. This alternative, although can be easily implemented numerically, may lead to inflexibilities in the model;
2. Triangular limit: reactive power may vary between two given power factors;
3. Rectangular limit: two inequalities define both real and reactive power constraints for a given resource or aggregator;
4. Circular limit: fixed maximum apparent power provided by the resource or the aggregator.

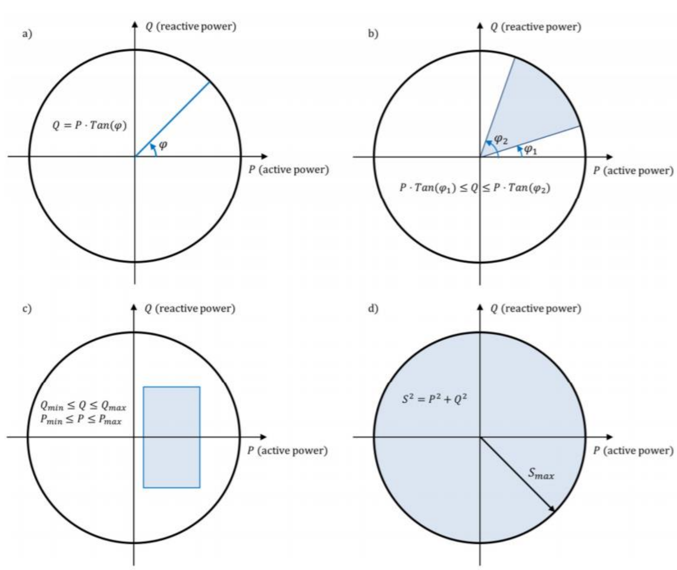

Figure 5-5.Graphical representation of various P-Q limit definition: a) fixed power factor, b) triangular limit, c) rectangular limit and d) circular limit [43]

The INTERRFACE project, as part of their definition and requirements for new market designs deliverables proposed several features for the standard products to be implemented in ASM at both transmission and distribution levels [61]. Among these features, that follow a very similar structure to the guidelines devised by [28] are: I.) curtailability, II.) time granularity of the bids, III.) minimum and maximum bid size, IV.) product availability (enforcing or not a minimum degree of participation from DER in the ASM), V.) modes of activation (manual or automatic), VI.) ramping period and VII.) the remuneration mechanism.

5.4 Bids and market designs in the literature

In the literature, the bidding process for ASM is treated very lightly, or included as part of the market design for ancillary services provision. Nonetheless, this section presents, in an approximated increasing order of complexity, different bid types to be submitted to the ASM.

In the context of market integration of DER, [62] present a local market formulation in which quadratic curves represent the costs associated to DG and demand response customers. Once bids are submitted, the DSO solves the optimization problem that minimizes the total cost of the ancillary service provision while complying with network constraints and DER minimum and maximum real and reactive power limits.

Authors in [63] proposed an ASM design specifically dedicated for voltage control in distribution networks. The study case assumes the availability of reactive resources in the microgrid, and as a result price/quantity pairs for reactive energy are implemented. As a result, the real power output of DER in the network, assumed to be traded in other market sections, is not modified.

In [64] and [65] ramping constraints are included in electricity market formulation. [64] includes market constraints in a market design based on Model Predictive Control approach (MPC) while maintaining simple real energy price/quantity hourly bids. [65] requires the system to procure a minimum level of ramping products in the ASM, in addition to the normal energy requirements for the load and generation balancing.

A market for flexibility products is proposed in [66]. The DSO buys flexibility products from aggregators to ensure distribution network constraints are satisfied. Flexibility bids are first divided into upward and downward reserves, in each one of them can be comprised by up to three price/quantity pairs. Moreover, bids must comply with time (restricted to a specific hour or time interval) and minimum power activation conditions.

So far, the bids submitted to the ASM represent a price/quantity relationship that could respond to several market or DER technical constraints and are normally treated as external inputs to the market. In [31] an approach to optimally obtain these bids from the points of view of the aggregator is developed. The aggregator takes as an input the technical characteristics of several types of DER, their initial offers in a previous market section (intra-day or day-ahead markets) and obtains as an output downward and upward total cost curves, useful to set-up the respective bids. Figure 5-6 shows the structure of the overall structure of the algorithm use to support the bid submission. Among the most important technical and operational limits considered are the step-wise behavior of some resources, specially thermal ones.

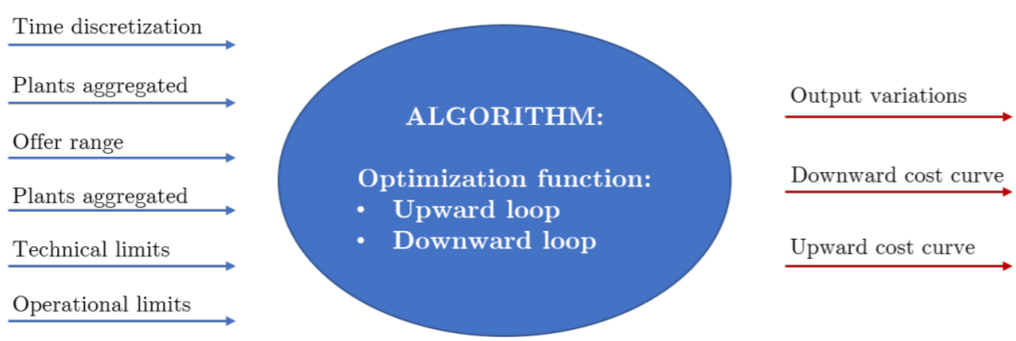

Figure 5-6. Structure of the aggregation model [31]

To create the downward and upward cost curves, the aggregator needs to select and to activate the DER that minimize the total incurred costs over a planning horizon to deliver or absorb a given amount of energy. This process is repeated iteratively, slowly increasing/decreasing the energy set-point required from the aggregator for upward/downward reserves. Although over all time periods the aggregator must respect the technical constraints of the DER pool, the final bids obtained from the aggregation model are simple functions that related total costs and quantities for each time step of the simulation.

The project takes a bottom-up aggregation approach, as presented in the SNP, to model individual DER. Six technologies are included in the model: Combined Heat and Power, storage hydro plants, run-of-river hydro plants, solar PV plants, wind power plants and other storage devices. Whenever possible, the same categories of parameters are used for all DER. This the case for variable and start-up/shut-down costs. Nonetheless, special constraints of some plants, like the thermal behavior of cooling systems and the energy balance equation for storage, are included in the formulation. Finally, the possibility of load shifting is also included, as an additional method to allow demand response to participate in the aggregation.

An example of the results obtained with the simulation platform are shown in Figure 5-7. On the left-side panel, the behavior of each DER to achieve an upward offer of 800 kWh across the simulation horizon is presented. It is worth noting that the resources aggregated start from a given initial profile, and the upward reserve should be achieved as a marginal change from that position. On the right-side panel, an example of the cost curve for upward reserve is shown. The curve is obtained iteratively, reporting the total cost for different upward energy variations, with the figure on the left being just one example. The aggregator in a market environment, and depending on historical values, competition levels and strategic behaviors, would use the total costs curve to submit price bids to the ASM.

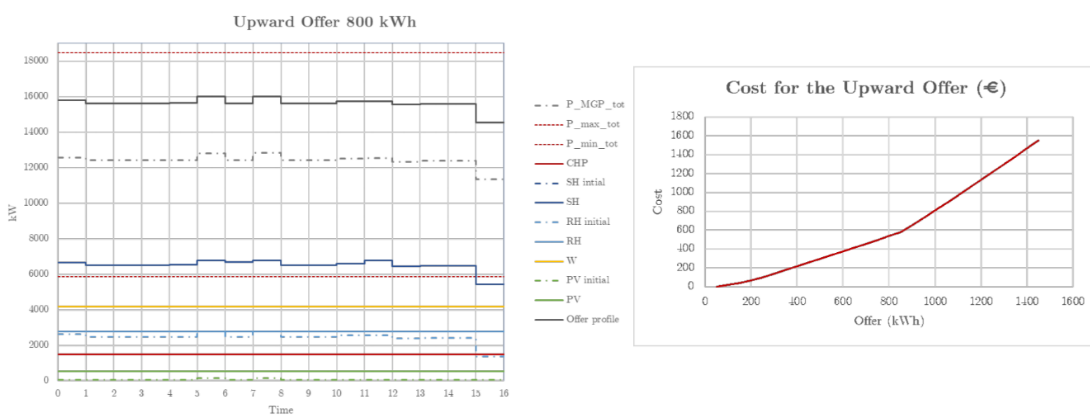

Figure 5-7. Energy variation profile for aggregated DER and upward cost curve. Adapted from [31]

Following a similar idea to the previous work, authors in [67] present an the problem formulation for an optimal bidding strategy for aggregators in the Day-Ahead and ASM. Specifically, the participation to the ASM is carried out through flexibility offers. The maximum flexibility that the aggregator can extract from the DER pool depends on the profile presented to the Day-Ahead market. The aggregator, when solving the stochastic optimization problem, evaluates the forecasted for prices in both markets and decides on which resources will be dedicated to energy or flexibility services. The modelling of DER follows first a physical aggregation approach that includes, in addition to the resources modelled in [31], a more detailed description of thermal processes including reversible heat-pumps, absorption chillers and thermal energy storage. Once DER are represented physically, they are grouped into customer cluster for the final bid submission carried out by the aggregator.

5.5 Load shifting: EV, energy storage and other resources

Two of the most important DER categories that are expected to penetrate distribution networks, mainly Electric Vehicles and Energy Storage Systems, have dynamic characteristics that would be of extreme use to enhance the flexibility of electricity systems. For the discussion of this thesis, primarily concerned with aggregating resources to solve network constraints at the distribution level, the load shifting service that DER with storage capabilities provide is of utmost importance.

Load shifting is defined as the service in which DER modify their initial load patterns, responding to market or operative incentives, to produce a final profile that more appropriately fit the system requirements. While providing this service DER do not alter, in a major way, the total energy they consume, thus only changing the time in which the energy is extracted or injected from or to the network. Although any flexible enough DER can apply load shifting strategies, resources with the ability of storing energy are more suited to the service.

Figure 5-8 shows the operation and result, seen in the initial and final load profiles, of a pumped storage facility operated to provide the load shifting services. In this case, electricity is stored during periods with low prices, later to be sold at higher prices. The storage facility is then responding to market incentives and implicitly reducing the peak consumption of the network. Additionally, on the right-hand side panel a specific characteristic of this energy resource is shown. Due to efficiency loses, the load shifting operation marginally increases the total energy consumed by the plant.

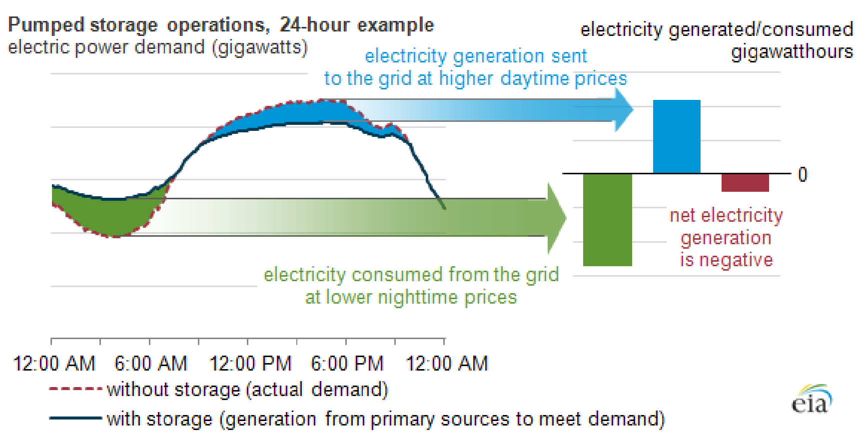

Figure 5-8. Pumped storage capabilities for load shifting, [68]

It is clear from the previous example that properly managed DER with storage capabilities have huge potential for network operation. Electric Vehicles, and their charging stations, are especially relevant for this discussion. To start, the massification of electric mobility alternatives is expected in the short and mid-term. With this, a considerable increment of loads at the distribution level is also foreseen. If this new demand is not properly managed, it could stress existing assets and increase costs incurred by final users.

In the left-hand side panel of Figure 5-9 the situation previously described is shown. In this case, different levels of EV penetration are not properly managed and as a result, the new excess consumption even coincides with the previous peak of the residential load profile. The worst condition for the system materializes, exposing users and distribution system operators to the risk of needing new network investments.

However, as the center and right-hand side panels of Figure 5-9, the EV's load could be distributed along the day, minimizing the impact it has on the distribution network, its operation and planning. These different charging strategies, that should be the rational response of users to market incentives, are key for the efficient integration of DER.

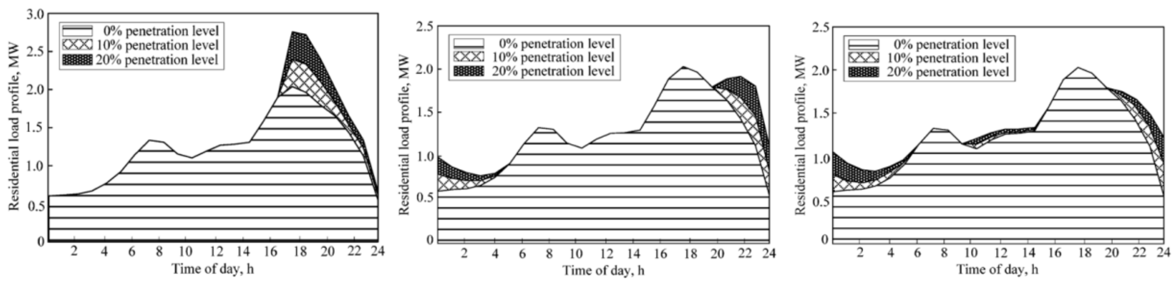

Figure 5-9. Residential load profiles for uncontrolled EV charging on the left, off-peak charging on the center and smart charging on the right. Adapted from [69]

The power shifting services that EV and charging stations provide to distribution systems are part of the broader V2G framework, in which electric vehicles contribute to system flexibility with ancillary services, as explained in Section 5.6.

Although the load shifting service has been emphasized for EV and other storage DER, any flexible load should be able to provide it. In fact, with increasing information availability, demand elasticity is expected to increase. In practical terms, residential loads for example could shift some critical loads (electric ovens, washing machines, driers, and the recharging of electric vehicles) to parts of the day with lower prices, or more stringent network requirements. For industrial loads, the amount of flexibility depends on the characteristics of the industrial process itself, as explained and model in [31]. It is worth noting that for proper modelling of load shifting characteristics requires non-linear constraints in the bid formulation, which would increase the numerical burden of solving the optimization problem and the use of approximated methods.

5.6 DSO's proprietary energy storage systems

Although the modelling approach presented in Section 5.5 is an option to indirectly include ESS, for completeness purposes this Section presents an explicit formulation to represent storage resources operated directly by the DSO, or the market operator, in addition to an approximation to the opportunity costs of such resources. The main difference with respect to what is discussed in the previous Section, in this case the market model has complete knowledge of the ESS's parameters, state and constraints.

As discussed in [70,71], the wide variety of energy storage models available in the literature imply that the appropriate mode should be selected according to the desired application. Figure 5-10 illustrates the tradeoff between the model accuracy on representing the actual physical behavior of the storage unit with the computational complexity of such model, measured in processing time. For power system application, the selection space is generally reduced to two options: the energy Reservoir model or the charge reservoir model with equivalent circuit.

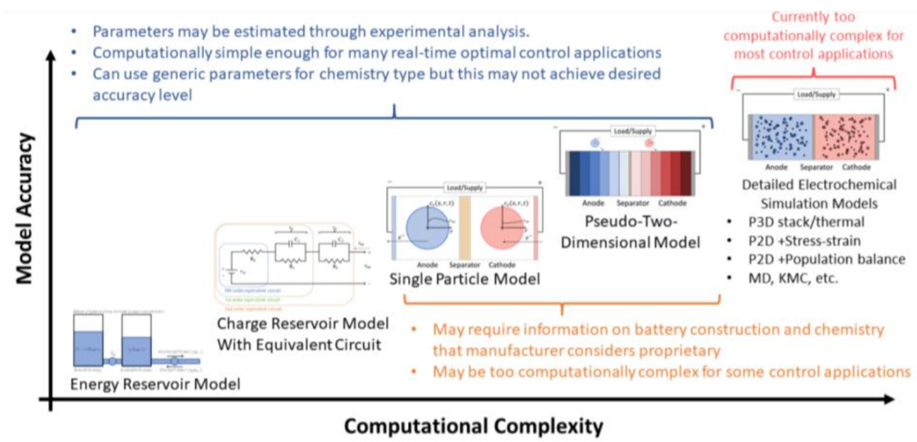

Figure 5-10. Trade-off between model accuracy and complexity in different modelling alternatives [71]

The application studied in this thesis requires a ESS modelling approach that I.) accurately represents its behavior in a time frame range from 15 minutes to one hour, II.) can be easily integrated into a market model and III.) has relatively low computational complexity. These characteristics support the use of an Energy Reservoir model, in which the storage behavior is governed by the maximum energy and power constraints. This model is valid even for frequency related applications, as shown in [70], which required accuracy for shorter time frames.

The Energy Reservoir model is briefly summarized in Equation (5-1), where SoC_t represents the state of charge of an ESS in time t, PC_t and PdC_t the charge and discharge power, η_{PC} and

η_{PdC} the charge and discharge efficiencies and Δt the factor for power to energy conversion ratio. Further details of the Energy Reservoir model are given in following Sections.

$$SoC_t = \frac{\eta_{PC} * PC_t - \eta_{PdC} * PdC_t}{\Delta t} + SoC_{t-1} \tag{5-1}$$

In addition to the state of charge equation, and because the ESS would be directly managed by the market operator, it is important to introduce the opportunity cost associated to the use of the storage resource. A simple approach to define the opportunity cost of a storage system is proposed in [70]. It emerges from the maximum number of cycles that define the life cycle of a BESS, where complete charge/cycle operation between minimum and maximum energy levels define a cycle. Because of this limitation, each cycle can be assigned an opportunity cost. The opportunity cost per cycle depends on market expectations, risk adversity levels and strategies, but it is related to the installation costs of the unit.

5.7 Literature review summary

The concept of aggregation and bidding are key elements in Ancillary Services markets' design and characteristics. Responding to the aggregation requirements and bid's structure agents, aggregators or single DERs, decide how to respond to the markets' design. From the review presented earlier, three main concepts from aggregation and bidding structure are worth highlighting: I.) the real power bidding, II.) time constraints and III.) reactive power representation. Moreover, these concepts can be analyzed through two different domains: the characteristics of the aggregators or the attributes of the individual DERs.

In the literature, in the European Guidelines for balancing markets and in European projects most attention is dedicated to real power representation and bidding. In the end, real power is the product remunerated in Ancillary Services market, and as a result it should be giving priority in the market structure and design. However, from an operative standpoint, reactive power can have an important role for congestion management. Although in distribution networks, with relatively high resistance over reactance relation (R/X), reactive power is less critical compared to transmission systems, it still plays a vital role in an efficient use of existing assets.

According to the expected penetration of DERs in distribution networks, and their wide range of attributes, a long list of time constraints can be included in bids for ancillary services markets. However, there is a trade-off between market simplicity and liquidity with appropriate resource modelling. In this context, due in part to the existence of the figure and the role of the aggregator in accounting for the aggregated DER characteristics, maintaining a simple and liquid market has priority. Bids representing a wide range of resources are simplified, as shown in Figure 5-1 and Figure 5-2. For this thesis, where the center of attention is given to the market model and not the aggregation itself, like it was in [31], an even more simplified approach including only selected characteristics for time constraints can be assumed. In this context, step wise bids could be useful to represent both characteristics of standards bids and some thermal and industrial processes.

The representation and inclusion of reactive power in the models introduced in the literature review for aggregation in Ancillary Services markets is limited. Nonetheless, its importance cannot be undermined; generally, if reactive power resources are available and they can help to manage congestion constraints, they should be given priority. However, standard aggregation of real power presents a simple challenge for reactive power management, as DER normally have individual power factor constraints. An aggregator could have for a given node, for example, a real power output close to zero due to the sum of generators and loads with equivalent values. In this case, the reactive power capabilities of the aggregator would be much greater than could be initially assumed. It is essential then to take a disaggregated approach for reactive power management inside the market model.

Due to the expected penetration of DER with power shifting capabilities (ESS, EV and demand response from both industrial and residential loads), the aggregation and bid modelling of such characteristics is important to obtain relevant results from the market simulations. For that reason, a compromise is needed between mathematical complexity and the resources' representation in the framework of this thesis. Nonetheless, an approach to explicitly include the ESS could be useful for the purposes of this thesis.

Although there exists the possibility of including aggregation of resources connected to different nodes in a network, this aggregation would not be possible if internal congestion constraints the are to be represented in the market model. For that reasons, bids and resources have a uniquely associated node in the network.

5.8 Proposal for aggregation and bid modelling

In this section, following the literature reviews and the chapter summary presented before, the mathematical formulation for the aggregation and bidding process used in this thesis is discussed.

To start, the price and quantity notation of Expressions (5-2) and (5-3) is adopted. In this matter, Aggregator j submits bid i for period t. The sets of aggregators, bids and periods are represented by capital letters J, I and, T. Bids are divided in two groups: upward and downward bids. Assuming the generator notation for the aggregator, upward bids would represent a bid to sell electricity while downward bids represent an offer to buy electricity:

$$P_{j,i,t}^{up-max},\ \pi_{j,i,t}^{up} \tag{5-2}$$

$$P_{j,i,t}^{dw-max},\ \pi_{j,i,t}^{dw} \tag{5-3}$$

Prices $\pi_{j,i,t}^{up}$ and $\pi_{j,i,t}^{dw}$ represent the opportunity cost and the willingness to pay the aggregator assigns to its resource. The exact price definition depends on the market model, its structure, previous market iterations and their relationship with the Ancillary Services markets, and it is explained in greater detail in following sections. Inside the optimization problem, prices and bid quantities parameters are defined as positive quantities, as shown in Expressions (5-4) to (5-7):

$$P_{j,i,t}^{up-max} \geq 0 \tag{5-4}$$

$$P_{j,i,t}^{dw-max} \geq 0 \tag{5-5}$$

$$\pi_{j,i,t}^{up} \geq 0 \tag{5-6}$$

$$\pi_{j,i,t}^{dw} \geq 0 \tag{5-7}$$

The quantity part of the bids, $P_{j,i,t}^{up-max}$ and $P_{j,i,t}^{dw-max}$ are parameters that represent the maximum power associated to each bid. The same number of variables $P_{j,i,t}^{up}$ and $P_{j,i,t}^{dw}$ are defined to characterize the power accepted in the market for each bid. The accepted quantities, from their definition, are also positive and constrained by the following inequalities:

$$P_{j,i,t}^{up-max} \geq P_{j,i,t}^{up} \geq 0 \tag{5-8}$$

$$P_{j,i,t}^{dw-max} \geq P_{j,i,t}^{dw} \geq 0 \tag{5-9}$$

In addition to the previous quantities, for each aggregator the initial power profile of its resources is defined as $PO_{j,t}$. The total power output of aggregators for each period, $P\_Total_{j,t}$, corresponds to Equation (5-10). For the Sensitivity approach of modelling the network, it is useful to define the variable $P_{j,t}$ as shown in Equation in (5-11). $P_{j,t}$ corresponds to the sum of accepted power from an aggregator, and it can be understood as the power difference with the initial profile of the aggregator:

$$P\_Total_{j,t} = \sum_{i=1}^{I}\left(P_{j,i,t}^{up} - P_{j,i,t}^{dw}\right) + PO_{j,t} \tag{5-10}$$

$$P_{j,t} = \sum_{i=1}^{I}\left(P_{j,i,t}^{up} - P_{j,i,t}^{dw}\right) \tag{5-11}$$

Regarding time constraints, the first one included in the bid structure corresponds to ramp constraints of the total power deliver by the aggregator. Ramps are defined as the net change in power production from one period to the next. Two parameters should be defined by the aggregators: $P_{j,t}^{ramp-up}$ and $P_{j,t}^{ramp-dw}$, in $\left[\frac{kW}{h}\right]$ and both positive quantities. These parameters could be simplified to $P_{j}^{ramp-up}$ and $P_{j}^{ramp-dw}$ (upward and downward ramps constant in time) or even $P_{j}^{ramp-up} = P_{j}^{ramp-dw} = P_{j}^{ramp}$ (upward and downward ramps are equal and constant in time), depending on the level of detail adopted by the aggregators. According to the definition, ramp constraints would be given by Expression (5-12), defined for each aggregator and for all periods except the last. In addition, ramp constraints should respond to the time resolution of the market model, explaining the correction parameter Δt included in Expression (5-12). Δt is equal to 1 if an hourly resolution is chosen, and 4 for fifteen minutes one, for example:

$$-\frac{P_{j}^{ramp}}{\Delta t} \leq P\_Total_{j,t+1} - P\_Total_{j,t} \leq \frac{P_{j}^{ramp}}{\Delta t} \qquad \text{for } t = 1, 2, \dots, T-1 \tag{5-12}$$

The second time constraint included in the bid formulation corresponds to power shifting capabilities of an aggregator. For this case, the aggregator submits to the market two parameters in matrix form, $PS_{j,i}^{up}$ and $PS_{j,i}^{dw}$ that indicate which bids are part of a load shifting product being offered by the aggregator. In this case, the corresponding value in the $PS_{j,i}^{up}$ and $PS_{j,i}^{dw}$ matrices would be one, otherwise it would be zero. Even though the load shifting capability of the aggregator should be related to the time horizon analyzed, for simplicity it is assumed that the load shifting would be applied to all periods, without further constraints. With these considerations, the Energy constraint necessary for modelling load shifting in the bids of each aggregator is shown in Equation (5-13):

$$\sum_{t=1}^{T}\sum_{i=1}^{I}\left(PS_{j,i}^{up} * P_{j,i,t}^{up} - PS_{j,i}^{dw} * P_{j,i,t}^{dw}\right) = 0 \tag{5-13}$$

Before, the discussion related to reactive power, it is worth noting that the total reactive power produced from the aggregators, in generator notation, is represented by $Q_{j,t}$. For reactive power management, several alternatives were analyzed and tested during the development of this thesis. Their advantages and disadvantages are discussed in the following.

The first alternative is a couple of inequalities, as shown in Expression (5-14). In this alternative, the aggregator presents two parameters, $Q_{j,t}^{max}$ and $Q_{j,t}^{min}$ that define the allowed band for reactive power. As it can be seen in Figure 5-11, reactive power is independent of the real power produced by the aggregator. Although this behavior is not realistic for DER, an aggregator with enough information and participating in a market with short-enough time horizon could adapt its bids to this limit. This alternative is referred to rectangular limits in the SNP:

$$-Q_{j,t}^{min} \leq Q_{j,t} \leq Q_{j,t}^{max} \qquad (5\text{-}14)$$

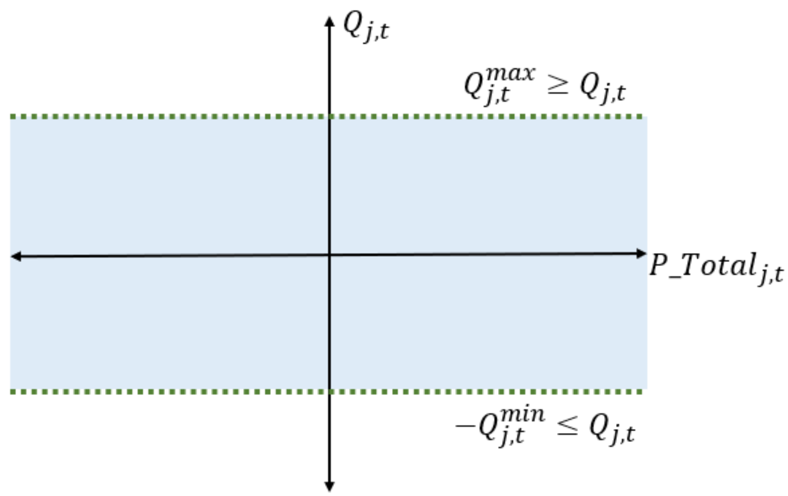

Figure 5-11. Alternative 1 for Reactive power management

The second alternative for reactive power management is shown in Expression (5-15). In this case, the reactive power is related, through the power factor parameter of the aggregator φ_j, to the absolute value of the total power of the aggregator $\text{P\_Total}_{j,t}$. This modelling approach, as shown in Figure 5-12, is closer to the real behavior of a single DER capable of providing both real power injections and extractions to the network. This alternative for reactive power modelling has similarities to the triangular limits in the SNP:

$$-\left|P\_Total_{j,t}\right| * tan\left(acos(\varphi_j)\right) \leq Q_{j,t} \leq \left|P\_Total_{j,t}\right| * tan\left(acos(\varphi_j)\right) \qquad (5\text{-}15)$$

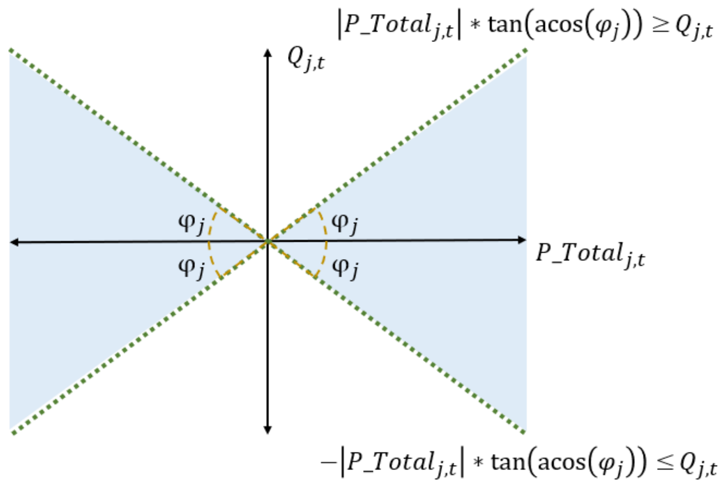

Figure 5-12. Alternative 2 for Reactive power management

Two main disadvantages can be identified for the alternative 2 for reactive power management. The first is that it requires the use of an absolute value function that, due to the conditions shown in Figure 5-12, must be modelled using binary variables. The second and most important disadvantage from this approach is that it limits reactive power capabilities of the aggregator. Assuming an aggregator representing two resources, a generator and a load, could have a real power output close to zero when either the two resources have a real power output equal to zero or when the two resources have a similar power output. In the second case, each of the resources could be providing their reactive power capabilities to the network, but according to Figure 5-12, this characteristic would be limited.

Responding the limitations identified in alternatives 1 and 2, alternative 3 for reactive power management is presented. To start, it is necessary for an aggregator to provide a matrix form parameter, similarly to the matrices identifying upward and downward bids in Equation (5-13), to classify bids coming from load and generation resources, separately. These matrix parameters, $Load_{\mathrm{j,i}}^{\mathrm{up}}$, $Load_{\mathrm{j,i}}^{dw}$, $Gen_{\mathrm{j,i}}^{\mathrm{up}}$ and $Gen_{\mathrm{j,i}}^{dw}$, serve to identify from the total group of bids those corresponding to Load and Generation, indexing those that meet the criteria with a one, otherwise the value in the given position of the matrix would be a zero. In this sense, the total Load $\mathrm{P}_{\mathrm{j,t}}^{\mathrm{Load}}$ and Generation power $\mathrm{P}_{\mathrm{j,t}}^{\mathrm{Gen}}$ is calculated according to Equations (5-16) and (5-17), where $Load_{\mathrm{j},t}^{0}$ and $Gen_{\mathrm{j},t}^{0}$ are parameters representing the initial load and generation profiles of aggregator j in period t. Moreover, in Equations (5-16) matrices and upward and downwards bids are interchanged, to keep the generation notation used in the bids consistent.:

$$P_{j,t}^{Load} = \sum_{i=1}^{I} \left(Load_{j,i}^{up} * P_{j,i,t}^{dw} - Load_{j,i}^{dw} * P_{j,i,t}^{up} + Load_{j,t}^{0} \right) \qquad (5\text{-}16)$$

$$P_{j,t}^{Gen} = \sum_{i=1}^{I} \left(Gen_{j,i}^{up} * P_{j,i,t}^{up} - Gen_{j,i}^{dw} * P_{j,i,t}^{dw} + Gen_{j,t}^{0} \right) \qquad (5\text{-}17)$$

Once the corresponding Load and Generation powers from an aggregator have been disaggregated, reactive power limits for each of the resources are applied, as shown in Expressions (5-18) and (5-19). In the previous expressions there is no need of using integer variables, as both $\mathrm{P_{j,t}^{Load}}$ and $\mathrm{P_{j,t}^{Gen}}$ are positive variables. After that, the reactive power of the aggregator is aggregated for its consideration in the model in Equation (5-20):

$$-P_{j,t}^{Load} * tan\left(acos\left(\varphi_{j}^{Load}\right)\right) \leq Q_{j,t}^{Load} \leq P_{j,t}^{Load} * tan\left(acos\left(\varphi_{j}^{Load}\right)\right) \qquad (5\text{-}18)$$

$$-P_{j,t}^{Gen} * tan\left(acos\left(\varphi_{j}^{Gen}\right)\right) \leq Q_{j,t}^{Gen} \leq P_{j,t}^{Gen} * tan\left(acos\left(\varphi_{j}^{Gen}\right)\right) \qquad (5\text{-}19)$$

$$Q_{j,t} = Q_{j,t}^{Load} + Q_{j,t}^{Gen} \qquad (5\text{-}20)$$

The third alternative is summarized in Figure 5-13. The main advantage of this alternative is that it appropriately describes reactive power capabilities of load and generation resources, while avoiding the use of integer variables as part of the bid formulation. However, this structure of bids limits the ability of the model to include bids from resources with both positive and negative power profiles. Combining both alternatives 2 and 3, such bid modelling would be possible, but it is left as future work and it is not included in this thesis:

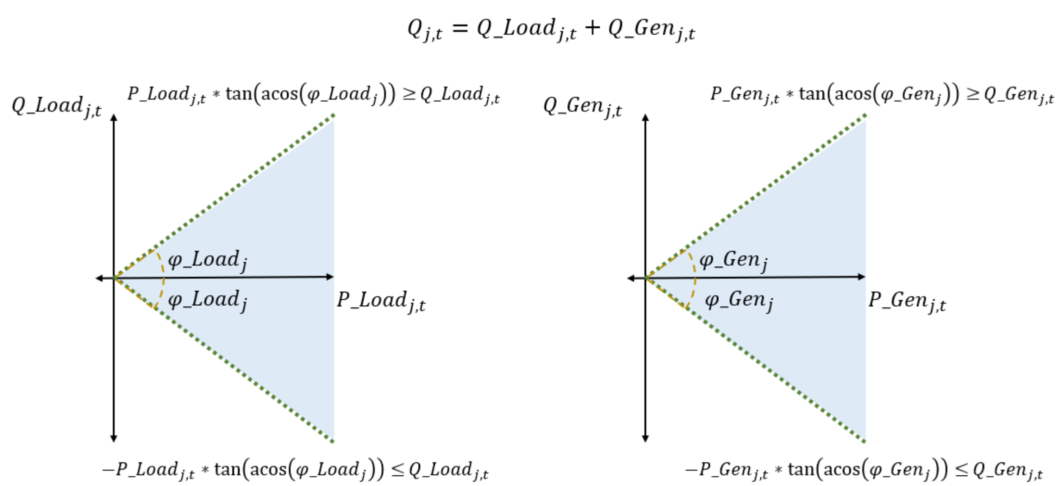

Figure 5-13. Alternative 3 for Reactive power management

A summary of the alternatives, showing their main advantages and disadvantages is shown in Table 5-3. From this analysis, Alternative 3 is selected and used for the rest of testing and results of this thesis. Although Alternative 2 was deeply analyzed and numerically tested, it needs to be completed, with the disaggregation of individual DER, to appropriately represent the reactive power capabilities of the aggregator.

Table 5-3. Summary of reactive power management alternatives

Alternatives	Advantages	Disadvantages
[1]	• Simple modelling that requiring only two inequality constraints per aggregator. • Modelling is completely independent of real power, allowing to include resources with only reactive power capabilities.	• Disconnection between real and reactive power outputs of the aggregator may not be realistic for many DER.
[2]	• Modelling represents the relation between real and reactive power of DER • With the same two inequalities reactive power obtained from a DER with both positive and negative real power outputs can be modelled.	• Alternative requires the use of an absolute power function that cannot be simplified and requires the use of binary variables for its representation. • Aggregation of Reactive power capabilities from both generation and demand DER limits their flexibility.
[3]	• Modelling represents the relation between real and reactive power of DER • Alternative allows reactive power obtained from a DER with both positive and negative real power outputs to be modelled. • Approach includes appropriate reactive power capabilities of both generation and load type resources. • It does not require the use of binary variables or other non-linear function.	• It is necessary to identify bids, effectively disaggregating them, to appropriately represent their reactive power capabilities. • Alternative does not allow individual DER with both positive and negative real power capabilities to be included.

With respect to step bids, a similar notation is adopted. In this case, prices and quantities of upward and downward step bids for each aggregator are represented by the variables shown in (5-20) and (5-21):

$$P_{j,t}^{up-step-max}, \pi_{j,t}^{up-step} \qquad (5\text{-}21)$$

$$P_{j,t}^{dw-step-max}, \pi_{j,t}^{dw-step} \qquad (5\text{-}22)$$

The power selected for each step bid is represented by variables $P_{j,t}^{up-step}$ and $P_{j,t}^{dw-step}$, in addition to being constraint by the set of inequalities (5-23) and (5-24), where $\mathrm{P}_{\mathrm{j,t}}^{\mathrm{up-step-max}}$, $\mathrm{P}_{\mathrm{j,t}}^{\mathrm{up-step-m}in}$, $\mathrm{P}_{\mathrm{j,t}}^{dw\mathrm{-step-max}}$ and $\mathrm{P}_{\mathrm{j,t}}^{dw\mathrm{-step-m}in}$ represent the maximum and minimum quantities that could be accepted from a given bid, and $Y_{j,t}^{up-step}$ and $Y_{j,t}^{dw-step}$ are binary variables that do not allow partial selection of the bids:

$$P_{j,t}^{up-step-min} * Y_{j,t}^{up-step} \leq P_{j,t}^{up-step} \leq P_{j,t}^{up-step-max} * Y_{j,t}^{up-step}, \qquad Y_{j,t}^{up-step} = \{0,1\} \tag{5-23}$$

$$P_{j,t}^{dw-step-min} * Y_{j,t}^{dw-step} \leq P_{j,t}^{dw-step} \leq P_{j,t}^{dw-step-max} * Y_{j,t}^{dw-step}, \qquad Y_{j,t}^{dw-step} = \{0,1\} \tag{5-24}$$

As a result of the previous inequalities, $\mathrm{P}_{\mathrm{j,t}}^{\mathrm{up-step}}$ and $\mathrm{P}_{\mathrm{j,t}}^{dw-\mathrm{step}}$ may vary between their minimum and maximum quantities, if the respective binary variables are activated, or be equal to zero, if they are not. These a very similar behavior to the one shown in Figure 5-2 can be achieved. In addition to the previous constraint, and to avoid any simultaneous activation of upward and downward step bids, expression (5-26) is imposed in upward and downward binary variables:

$$Y_{j,t}^{up-step} + Y_{j,t}^{dw-step} \leq 1 \tag{5-25}$$

Regarding the explicit representation of ESS in the bidding structure, the Energy Reservoir model presented in Section 5.6 is furtherly developed. The set of ESS managed by the market operator is defined by B, containing elements denoted b. In Equations (5-26) and (5-27) the constraints for the state of charge variable $\mathrm{SoC}_{\mathrm{b,t}}$ are defined, where the same notation of Section 5.6 is used and SoC_b^{max} and SoC_b^{min} represent the maximum and minimum state of charge of the storage system:

$$SoC_{b,t} = \frac{\eta_{PC} * PC_{b,t} - \eta_{PdC} * PdC_{b,t}}{\Delta t} + SoC_{b,t-1} \tag{5-26}$$

$$SoC_b^{min} \leq SoC_{b,t} \leq SoC_b^{max} \tag{5-27}$$

The charge and discharge variables $PC_{b,t}$ and $PdC_{b,t}$ are defined positive. Additionally, these power variables are related to both internal characteristics of the cell and the inverter and cannot exceed the parameter P_b^{max}. Furthermore, positive charge and discharge powers cannot be required at the same time for a module, so the two variables are time related. These three technical characteristics are represented in Equations (5-28) - (5-30), where the binary variable $Y_{DoC_{b,t}}$ is in place to avoid simultaneous charge and discharge events. Because minimum charging and discharging power is assumed zero, a condition similar to expression (5-26) is not necessary:

$$PC_{b,t} \geq 0, PdC_{b,t} \geq 0 \tag{5-28}$$

$$PC_{b,t} \leq P_b^{max} * Y_{DoC_{b,t}}, \qquad Y_{DoC_{b,t}} = \{0,1\} \tag{5-29}$$

$$PdC_{b,t} \leq P_b^{max} * \left(1 - Y_{DoC_{b,t}}\right) \tag{5-30}$$

To track the operation of the battery, the number of cycles are defined, using the most simplified for energy models discussed in [70]. The number of cycles $\mathrm{Cycles_b}$ for the ESS is defined according to Equation (5-31):

$$Cycles_b = \frac{\sum_{t=1}^{T}(\eta_{PC} * PC_{b,t} + \eta_{PdC} * PdC_{b,t})}{2 * SoC_b^{max} * \Delta t} \quad (5\text{-}31)$$

Assuming the energy storage is owned by the DSO means, for a flexibility market context and given the discussions presented by the Clean Energy Package, that its use would be limited to solve network constraints. As a result, no profit is assumed and the ESS will not produce a margin from its operation.

A possible approach to include the battery in the model is to include positive charging costs, where energy is paid at a nominal rate, and the discharge costs, that would be used to solve network constraints, have no inherent opportunity cost. Such approach is still a simplification and does not considered: I.) discount rate of the investment, II.) the opportunity cost per cycle, in a framework where the battery cycles can be used for other purposes than solving congestion constraints, III.) additional opportunity costs' assigned by the ESS stakeholder, and IV.) non-linear degradation phenomenon, as discussed in [70].

.

6 Network model for power flow and Optimal power flow problems

6.1 Distribution Network models

This section discusses several power flow algorithms specific for distribution networks. To unify the discussion, the diagram and notation of Figure 6-1 and Table 6-1 are adopted for this section. Shunt parameters, not included in Figure 6-1, are mentioned as necessary when presenting the network modeling approaches. In general, the notation assumes n nodes and m total lines (if the network is radial, $m = n - 1$ holds).

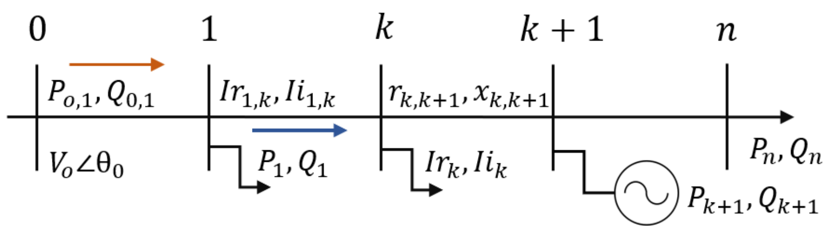

Figure 6-1. Simplified network diagram. Adapted from [72]

Table 6-1. Network notation

Symbol	Meaning	Symbol	Meaning
P_k	Real power withdrawal at node k	$r_{k,j} - G_{k,j}$	Series resistance or conductance of branch between nodes k, j
Q_k	Reactive power withdrawal at node k	$x_{k,j} - B_{k,j}$	Series reactance or susceptance of branch between nodes k, j
S_k	Apparent power withdrawal at node k	$z_{k,j}$	Series impedance of branch between nodes k, j
Ir_k	Real part of current withdrawal at node k	$Ir_{k,j}$	Real part of current flowing through branch between nodes k, j
Ii_k	Imaginary part of current withdrawal at node k	$Ii_{k,j}$	Imaginary part of current flowing through branch between nodes k, j
I_k	Magnitude of current withdrawal at node k	$I_{k,j} = Ib_i$	Magnitude of current flowing through branch between nodes k, j. Also, current magnitude flowing through branch i
V_k	Voltage magnitude at node k	$P_{k,j}$	Real power flowing through branch between nodes k, j
θ_k	Voltage angle at node k	$Q_{k,j}$	Reactive power flowing through branch between nodes k, j

Several aspects are relevant in the discussion of power flow algorithms in the context of this project. First and foremost, It is preferable that the network representation algorithm results in a set of linear constraints, enabling its integration into the linear optimization program that is used to model the TSO-DSO coordination platform in GAMS and the solver CPLEX. Nonetheless, a trade-off between the accuracy of the network's representation and computational complexity is necessary [43]. This is especially relevant as the network model is the base of the optimization platform for TSO-DSO coordination analysis. Still, it is mandatory for the current context to represent key aspects of the distribution network description and steady state behavior like current congestions and over/under-voltage problems. Summarizing, three drivers will guide the discussion and testing presented in this chapter: 1.) the integration of the network into the linear optimization problem, 2.) the accuracy of the network's representation and 3.) its computational complexity.

6.1.1 Branch formulation

The branch formulation is used in radial distribution networks to describe, using a set of recursive equations, the complex power and voltage magnitude at the sending end of a branch with respect to the same quantities at the receiving end.

6.1.1.1 DistFlow

The DistFlow algorithm is a widely known technique to approximate and solve the power flow problem in distribution networks based on the branch formulation [72]. Equations for real, reactive and square voltage in the branches are proposed:

$$P_{k+1,k+2} = P_{k,k+1} + r_{k,k+1}\left(\frac{{P_{k,k+1}}^2 + {Q_{k,k+1}}^2}{{V_k}^2}\right) - P_{k+1} \tag{6-1}$$

$$Q_{k+1,k+2} = Q_{k,k+1} + x_{k,k+1}\left(\frac{{P_{k,k+1}}^2 + {Q_{k,k+1}}^2}{{V_k}^2}\right) - Q_{k+1} \tag{6-2}$$

$${V_{k+1}}^2 = {V_k}^2 - 2\left(r_{k,k+1}P_{k,k+1} + x_{k,k+1}Q_{k,k+1}\right) + \left({r_{k,k+1}}^2 + {x_{k,k+1}}^2\right)\left(\frac{{P_{k,k+1}}^2 + {Q_{k,k+1}}^2}{{V_k}^2}\right) \tag{6-3}$$

Following notation presented in Table 6-1, $P_{k,k+1}$, $Q_{k,k+1}$, $r_{k,k+1}$, and $x_{k,k+1}$ represent real power flow, reactive power flow, resistance and reactance between nodes k and $k+1$, respectively while V_k is the voltage magnitude in node k. Equations (6-1) and (6-2) represent the real and reactive power balance at each node and Equation (6-3) the voltage drop across the distribution lines. The formulation implies that if the power and voltage variables at the beginning of the feeder (slack node conditions $\mathrm{P}_{0,1}$, $Q_{0,1}$ and V_0) are known, all other variables can be obtained [72].

The Smart Net Project (SNP) uses the DistFlow approach to model distribution networks [43]. However, a simplification is needed to arrive from the non-convex formulation to a second-order cone in the optimization problem. Following the network diagram of Figure 6-1, the Equation (6-4) for the power flow in a line can be obtained. The relaxation is achieved by replacing this constraint for Inequality (6-5):

$$I_{k,j}{}^2 = \frac{P_{k,j}{}^2 + Q_{k,j}{}^2}{V_k{}^2} \tag{6-4}$$

$$V_k{}^2 I_{k,j}{}^2 \geq P_{k,j}{}^2 + Q_{k,j}{}^2 \tag{6-5}$$

A simplified Distflow formulation is also presented in [72]. Starting from Equations (6-1)- (6-3), the quadratic terms, that represent losses in the lines, are neglected as they are much smaller than the power flow through the line. Equations (6-6) - (6-8) are the result of such simplifications.

$$P_{k+1,k+2} = P_{k,k+1} - P_{k+1} \tag{6-6}$$

$$Q_{k+1,k+2} = Q_{k,k+1} - Q_{k+1} \tag{6-7}$$

$$V_{k+1}{}^2 = V_k{}^2 - 2\left(r_{k,k+1}P_{k,k+1} + x_{k,k+1}Q_{k,k+1}\right) \tag{6-8}$$

With the new expressions, a general expression can be defined for the power flow through the lines across the radial network:

$$P_{k+1,k+2} = \sum_{i=k+2}^{n} P_i \tag{6-9}$$

$$Q_{k+1,k+2} = \sum_{i=k+2}^{n} Q_i \tag{6-10}$$

Where P_i and Q_i are power extractions from the network in node i. The result from Equations (6-8), (6-9), and (6-10), reflect a very similar result to the simple flow approximation, in which the power flow follows the logic of an ideal hydraulic system. However, Equation (6-8) still represents voltage drops across the network. Moreover, the quadratic term that was neglected is always positive, meaning the voltages calculated with the simplified DistFlow approach are in fact lower than the non-approximated version. This attribute can be valuable when identifying undervoltage problems, common in distribution networks, but problematic when evaluating the effects of DGs. It is worth noting that the previous recursive formulation requires nodes to be numbered and ordered starting from the slack.

With respect to the integration into a linear optimization problem, the branch current as represented in Equations (6-4) or (6-5) poses a problem, as in both cases it would be necessary to use the quadratic form of the power injection variables. Due to this characteristic, the DistFlow formulation, even in its simplified form, cannot be included into a linear programming framework. Instead, a Quadratic Constrained program is required for this network modelling approach.

6.1.1.2 Radial Distribution Load Flow Using Conic Programming

In [73] the complete branch formulation approach is used to solve the power flow problem using conic programming. Equations (6-11) and (6-12) represent the real and reactive power flows across any branch of the circuit. Such flows are constrained by expression (6-13).

$$P_{kj} = G_{kj}V_k^2 - G_{kj}V_kV_j\,cos(\theta_k - \theta_j) + B_{kj}V_kV_j\,cos(\theta_k - \theta_j) \tag{6-11}$$

$$Q_{kj} = B_{kj}V_k^2 - B_{kj}V_kV_j\,cos(\theta_k - \theta_j) - G_{kj}V_kV_j\,sin(\theta_k - \theta_j) \tag{6-12}$$

$$V_k^2V_j^2 = \left((V_kV_j\,cos(\theta_k - \theta_j)\right)^2 + \left((V_kV_j\,sin(\theta_k - \theta_j)\right)^2 \tag{6-13}$$

Where P_{kj} and Q_{kj} follow the same notation as in the previous section, only this time for the branch between nodes k and j. Moreover, G_{kj} and B_{kj} represent the conductance and susceptance of such branch. Furthermore, V_k and θ_k are the voltage magnitude and angle in node k.

As done in [43], constrain (6-13) can be relaxed to allow the use conic programming. With this approximation, and assuming known voltage magnitude in the slack, the resulting optimization problem becomes:

$$max\left((V_kV_j\,cos(\theta_k - \theta_j)\right)^2 \tag{6-14}$$

$$V_k^2V_j^2 \geq \left((V_kV_j\,cos(\theta_k - \theta_j)\right)^2 + \left((V_kV_j\,sin(\theta_k - \theta_j)\right)^2 \text{ for all k,j lines} \tag{6-15}$$

$$\left((V_kV_j\,cos(\theta_k - \theta_j)\right)^2 \geq 0 \text{ for all k,j lines} \tag{6-16}$$

Where Equations (6-11), (6-12) and (6-17) are also constraints in the optimization problem. It is solved by gradually increasing the values of constraint (6-16) until all inequalities (6-15) are active. Once the condition is met, the system converges to the power flow, from where indirect variables can be later obtained. The optimization problem arrives to a solution even in ill-condition systems using commercial solvers [43]. Nonetheless, the proposed approach would require further modifications if a linear programming problem were to be implemented.

6.1.1.3 Novel linearized power flow and linearized OPF models for active distribution networks

Another linearized power flow model based on the branch formulation is presented in [74]. In this case, Equations (6-11) and (6-12) are expressed in terms of resistance and reactance terms, as shown in Equations (6-18) and (6-19):

$$P_{kj} = \frac{r_{kj}V_k^2 - r_{kj}V_kV_j\,cos(\theta_k - \theta_j) + x_{kj}V_kV_j\,sin(\theta_k - \theta_j)}{{r_{k,j}}^2 + {x_{k,j}}^2} \qquad (6\text{-}18)$$

$$Q_{kj} = \frac{x_{kj}V_k^2 - r_{kj}V_kV_j\,sin(\theta_k - \theta_j) - x_{kj}V_kV_j\,cos(\theta_k - \theta_j)}{{r_{k,j}}^2 + {x_{k,j}}^2} \qquad (6\text{-}19)$$

These variables used the same notation as in the previous sections. As a matter of convenience, authors proposed that power injection terms in Equations (6-18) and (6-19) are divided into two parts each, as follows:

$$P_{kj} = P_{kj\_1} + P_{kj\_2} \qquad (6\text{-}20)$$

$$Q_{kj} = Q_{kj\_1} + Q_{kj\_2} \qquad (6\text{-}21)$$

$$P_{kj\_1} = \frac{r_{kj}x_{kj}\left(V_k(V_k - V_j\,cos(\theta_k - \theta_j)\,)\right)}{({r_{k,j}}^2 + {x_{k,j}}^2)x_{kj}} \qquad (6\text{-}22)$$

$$P_{kj\_2} = \frac{x_{kj}V_kV_j\,sin(\theta_k - \theta_j)}{{r_{k,j}}^2 + {x_{k,j}}^2} \qquad (6\text{-}23)$$

$$Q_{kj\_1} = -\frac{x_{kj}V_kV_j\,sin(\theta_k - \theta_j)}{{r_{k,j}}^2 + {x_{k,j}}^2} \qquad (6\text{-}24)$$

$$Q_{kj\_2} = \frac{{x_{kj}}^2\left(V_k(V_k - V_j\,cos(\theta_k - \theta_j)\,)\right)}{({r_{k,j}}^2 + {x_{k,j}}^2)x_{kj}} \qquad (6\text{-}25)$$

To linearize the system, two assumptions are made. First, the trigonometric functions are linearized assuming $\theta_k - \theta_j \approx 0$. Second, voltages in the system are assumed close to their nominal value, or 1 per unit, to simplify the voltages' product. With these assumptions, Equations (6-22) - (6-25) are simplified to Equations (6-26) - (6-29).

$$P_{kj\_1} \approx \frac{H_{kj\_1}(V_k - V_j)}{x_{kj}} \qquad (6\text{-}26)$$

$$P_{kj\_2} \approx \frac{H_{kj\_2}(\theta_k - \theta_j)}{x_{kj}} \tag{6-27}$$

$$Q_{kj\_1} \approx -\frac{H_{kj\_1}(\theta_k - \theta_j)}{x_{kj}} \tag{6-28}$$

$$Q_{kj\_2} \approx \frac{H_{kj\_2}(V_k - V_j)}{x_{kj}} \tag{6-29}$$

Where:

$$H_{kj\_1} = \frac{r_{kj}x_{kj}\left(V_k(V_k - V_j\, cos(\theta_k - \theta_j)\,\right)}{(r_{k,j}{}^2 + x_{k,j}{}^2)x_{kj}} \tag{6-30}$$

$$H_{kj\_2} = \frac{x_{kj}V_kV_j\, sin(\theta_k - \theta_j)}{r_{k,j}{}^2 + x_{k,j}{}^2} \tag{6-31}$$

The simplifications so far allow Authors to obtain a compact form that relates power injections, defined as P_k and Q_k, with voltages and angles, as shown in Equations (6-32) and (6-33):

$$P_k = \sum_{j=1, j\neq k}^{n} \left(\frac{H_{kj\_2}(\theta_k - \theta_j)}{x_{kj}} + \frac{H_{kj\_1}(V_k - V_j)}{x_{kj}}\right) \tag{6-32}$$

$$Q_k = \sum_{j=1, j\neq k}^{n} \left(-\frac{H_{kj\_1}(\theta_k - \theta_j)}{x_{kj}} + \frac{H_{kj\_2}(V_k - V_j)}{x_{kj}}\right) \tag{6-33}$$

Moreover, the previous expressions can be organized in matrix form assuming the voltage and angle at the slack node are known:

$$\binom{\boldsymbol{P}}{\boldsymbol{Q}} - (\boldsymbol{B}_1^c)\boldsymbol{\theta_1} - (\boldsymbol{B}_2^c)\boldsymbol{V_1} = (\boldsymbol{B})\binom{\boldsymbol{\theta}}{\boldsymbol{V}} \tag{6-34}$$

Where matrix **B** is form with the coefficients multiplying angles and voltages in (6-32) - (6-33) and vectors $\mathbf{B}^{c}$ are the first column and row of such matrix. The final expression found is linear, and only depends on the initial slack conditions and the resistance and impedance of the system's lines. To conclude, authors proceed to show that it is possible to include losses and loss factors for distribution systems into the formulation, parameters that can later be used in an optimal power flow application.

6.1.2 Polar power flow formulation

The polar formulation is broadly used for power flow in transmission and distribution networks. Equations (6-35)and (6-36) present the polar formulation. Each node is represented by four electric variables: real power, reactive power, voltage magnitude and voltage phase. According to the information available for each node, three categories are defined: slack (voltage magnitude and phase given), PV node (voltage magnitude and real power given) and PQ node (real and reactive power given). Although known methods to solve the non-linear system can also be applied for distribution networks, like Newton-Raphson or Fast-decouple algorithms, additional considerations and simplifications could apply in the distribution case.

$$P_k = V_k \left(\sum_{j=1}^{n} V_j \left(G_{kj} \, cos(\theta_k - \theta_j) + B_{kj} \, sin(\theta_k - \theta_j) \right) \right) \quad (6\text{-}35)$$

$$Q_k = V_k \left(\sum_{j=1}^{n} V_j \left(G_{kj} \, sin(\theta_k - \theta_j) - B_{kj} \, sin(\theta_k - \theta_j) \right) \right) \quad (6\text{-}36)$$

6.1.2.1 Linear three-phase power flow for unbalanced active distribution networks with PV nodes

Authors in [75] proposed a three-phase power flow for unbalanced active distribution networks. Starting from the previous equations, the same relationships are obtained per phase, as shown in (6-37) and (6-38). Taking the case of real power injections, Equation (6-37) can be divided into terms (6-39) and (6-40) for easier notation:

$$P_k^{\alpha} = V_k^{\alpha} \left(\sum_{j=1}^{n} \sum_{\beta=a,b,c} V_j^{\beta} \left(G_{jk}^{\alpha\beta} \, cos(\theta_k^{\alpha} - \theta_j^{\beta}) + B_{jk}^{\alpha\beta} \, sin(\theta_{kj}^{\alpha} - \theta_{kj}^{\beta}) \right) \right) \quad (6\text{-}37)$$

$$Q_k^{\alpha} = V_k^{\alpha} \left(\sum_{j=1}^{n} \sum_{\beta=a,b,c} V_j^{\beta} \left(G_{jk}^{\alpha\beta} \, sin(\theta_k^{\alpha} - \theta_j^{\beta}) - B_{jk}^{\alpha\beta} \, cos(\theta_{kj}^{\alpha} - \theta_{kj}^{\beta}) \right) \right) \quad (6\text{-}38)$$

$$A = V_k^{\alpha} \left(\sum_{j=1}^{n} \sum_{\beta=a,b,c} V_j^{\beta} \left(G_{jk}^{\alpha\beta} \, cos(\theta_k^{\alpha} - \theta_j^{\beta}) \right) \right) \quad (6\text{-}39)$$

$$B = V_k^{\alpha} \left(\sum_{j=1}^{n} \sum_{\beta=a,b,c} V_j^{\beta} \left(B_{jk}^{\alpha\beta} \, sin(\theta_{kj}^{\alpha} - \theta_{kj}^{\beta}) \right) \right) \quad (6\text{-}40)$$

In these expressions, subscripts α and β represent the three phases (a, b, c) from the system. As a result, $G_{jk}^{\alpha\beta}$ and $B_{jk}^{\alpha\beta}$ represent the cross conductance and susceptance between phases for the branch connecting nodes j and k, while θ_k^{α} is voltage angle of phase α and node k.

Three approximations are proposed to linearize the power flow. First, assuming a small angle difference in the system's branches, the trigonometric functions are simplified as $cos\Big(\theta_k^{\alpha} -$

$\theta_j^{\beta}\big) \approx 1$ and $sin\left(\theta_k^{\alpha} - \theta_j^{\beta}\right) \approx \theta_k^{\alpha} - \theta_j^{\beta}$. Second, the product of two voltages is linearized neglecting second-order terms as $\mathrm{V_k}\big(\mathrm{V_k} - \mathrm{V}_j\big) \approx (\mathrm{V_k} - \mathrm{V}_j)$. Finally, the ZIP load model[21], shown in Equation (6-41) for real power only, is included by neglecting the second order terms of the constant impedance loads, resulting in Equation (6-42):

$$P(V) = (F_Z V^2 + F_I V + F_P)P_0 \tag{6-41}$$

$$P(V) \approx (F_P - F_Z)P_0 + \big((2F_Z + F_I)P_0\big)V \tag{6-42}$$

Where F_Z, F_I and F_P are the impedance, current and power coefficients of the ZIP Model. Applying the previous considerations, Equation (6-39) is approximated to Equation (6-43), shown for phase a:

$$A^a = \frac{3}{2}\sum_{j=1}^{n} V_j^a G_{jk}^{aa} - \frac{1}{2}\sum_{j=1}^{n}\sum_{\beta=a,b,c} V_j^{\beta}\, G_{jk}^{a\beta} + \frac{\sqrt{3}}{2}\sum_{j=1}^{n} G_{jk}^{ab}\left(\theta_k^a - \theta_j^b\right) - \frac{\sqrt{3}}{2}\sum_{j=1}^{n} G_{jk}^{ac}\left(\theta_k^a - \theta_j^c\right) \tag{6-43}$$

The same procedure can be applied to Equation (6-40), leaving the terms related to individual voltages and angles represented for the three-phase system. As a result of the simplifications, a matrix relation between the real and reactive powers and the complex voltage can be found:

$$\begin{bmatrix} P^a \\ P^b \\ P^c \\ Q^a \\ Q^b \\ Q^c \end{bmatrix} = \begin{bmatrix} J_{PV}^{aa} & J_{PV}^{ab} & J_{PV}^{ac} & J_{P\theta}^{aa} & J_{P\theta}^{ab} & J_{P\theta}^{ac} \\ J_{PV}^{ba} & J_{PV}^{bb} & J_{PV}^{bc} & J_{P\theta}^{ba} & J_{P\theta}^{bb} & J_{P\theta}^{bc} \\ J_{PV}^{ca} & J_{PV}^{cb} & J_{PV}^{cc} & J_{P\theta}^{ca} & J_{P\theta}^{cb} & J_{P\theta}^{cc} \\ J_{QV}^{aa} & J_{QV}^{ab} & J_{QV}^{ac} & J_{Q\theta}^{aa} & J_{Q\theta}^{ab} & J_{Q\theta}^{ac} \\ J_{QV}^{ba} & J_{QV}^{bb} & J_{QV}^{bc} & J_{Q\theta}^{ba} & J_{Q\theta}^{bb} & J_{Q\theta}^{bc} \\ J_{QV}^{ca} & J_{QV}^{cb} & J_{QV}^{cc} & J_{Q\theta}^{ca} & J_{Q\theta}^{cb} & J_{Q\theta}^{cc} \end{bmatrix} \begin{bmatrix} V^a \\ V^b \\ V^c \\ \theta^a \\ \theta^b \\ \theta^c \end{bmatrix} \tag{6-44}$$

Where for example $J_{PV}^{aa} = G_{jk}^{aa}$ and $J_{PV}^{ab} = -\frac{1}{2}G_{jk}^{ab} + \frac{\sqrt{3}}{2}B_{jk}^{ab}$.

The relationship shown in Equation (6-44) can be extended to both mesh and radial networks when voltage and angle differences are not too large. The accounting of phase imbalances, common in distribution networks, and the addition of the ZIP load model, included in the formulation when Equation (6-42) replaces the right-hand side of Equation (6-44), are the main advantages of this power flow approach.

6.1.2.2 First order sensitivities

Authors in [76] implement the polar formulation from Equations (6-35)and (6-36) in the context of distribution networks, with especial focus on the optimal power flow problem. The

[21] The ZIP load model can represent loads with constant impedance, constant current and constant power characteristics. Each characteristic has its own correspondent ZIP coefficient.

approach uses first order sensitivities derived from the complete solution of the system to calculate parameters of interest in the optimization problem.

Due to the radial structure of distribution networks, it is possible to assume that small variations in the input parameters of the system would generate a linear change in the output results. The assumption implies that, once the Jacobian and the system's initial operating point are obtained, the output variables of the optimization problem necessary to evaluate the network constraints (voltages and currents) are calculated using linear relations.

For the voltage magnitude, the basic expression following the first order Taylor approximation is presented in Expression (6-45), where $\mathrm{Vo_k}$ is the initial voltage profile calculated using, for example, the non-linear power flow equations and the associated algorithms. Row vectors $\frac{\partial \mathrm{V_k}}{\partial \mathrm{P}}$ and $\frac{\partial \mathrm{V_k}}{\partial Q}$ form the sensitivity matrices $\frac{\partial V}{\partial \mathrm{P}}$ and $\frac{\partial V}{\partial Q}$ of the voltage magnitude with respect to the power injections in the system's nodes.

$$V_k \approx Vo_k + \frac{\partial V_k}{\partial P}\Delta P + \frac{\partial V_k}{\partial Q}\Delta Q \qquad (6\text{-}45)$$

To calculate matrices $\frac{\partial V}{\partial \mathrm{P}}$ and $\frac{\partial V}{\partial Q}$, the first order sensitivity is applied to the power mismatch Equations (6-36) and (6-37). This formulation is usually used when the power flow problem is to be solved with the Newton-Raphson method. In the present case, it is assumed that the power flow has already converged (mismatch vector $\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}$ is approximately zero):

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = -\begin{bmatrix} \frac{\partial P}{\partial V} & \frac{\partial P}{\partial \theta} \\ \frac{\partial Q}{\partial V} & \frac{\partial Q}{\partial \theta} \end{bmatrix} \begin{bmatrix} \Delta V \\ \Delta \theta \end{bmatrix} + \begin{bmatrix} \frac{\partial P}{\partial u} \\ \frac{\partial Q}{\partial u} \end{bmatrix} [\Delta u] \qquad (6\text{-}46)$$

As shown in the previous expression, the mismatch equation can be linearized with respect to an additional variable, u in this case. Solving the system of equation for real and reactive power variations separately assuming a converged power flow, the matrix Equations (6-47) and (6-48) are obtained, where I is an identity matrix with the appropriate dimensions.

$$\begin{bmatrix} \frac{\partial V}{\partial P} \\ \frac{\partial \theta}{\partial P} \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial V} & \frac{\partial P}{\partial \theta} \\ \frac{\partial Q}{\partial V} & \frac{\partial Q}{\partial \theta} \end{bmatrix}^{-1} \begin{bmatrix} I \\ 0 \end{bmatrix} \qquad (6\text{-}47)$$

$$\begin{bmatrix} \frac{\partial V}{\partial Q} \\ \frac{\partial \theta}{\partial Q} \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial V} & \frac{\partial P}{\partial \theta} \\ \frac{\partial Q}{\partial V} & \frac{\partial Q}{\partial \theta} \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ I \end{bmatrix} \qquad (6\text{-}48)$$

On the left-hand side of the previous Equations, the voltage magnitude and angle sensitivities with respect to power injections are found. The voltage magnitude sensitivity is used in Equation (6-45) while the voltage angle sensitivity is used later.

The calculation of the branch current sensitivities with respect to the power injections starts from the relation between the network parameters and the voltage profile. The PI model of the distribution branches is used, as shown in Figure 6-2. In this model, it is possible to find an expression of the complex branch current and the voltage at the sending and receiving end, as shown in Equation (6-49):

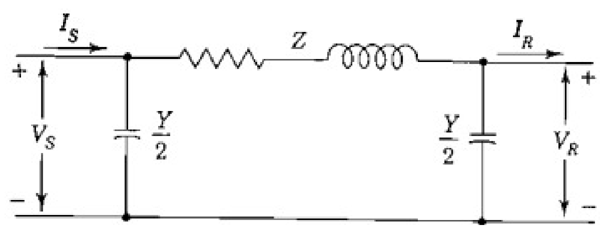

Figure 6-2. PI transmission line model [77]

$$\overline{I_{k,J}} = \bar{Y}\left(1 + \frac{\overline{ZY}}{4}\right)\overline{V_J} + \frac{\frac{\overline{ZY}}{2} + 1}{\bar{Z}}\left(\overline{V_k} - \left(\frac{\overline{ZY}}{2} + 1\right)\overline{V_J}\right) \qquad (6\text{-}49)$$

The previous Equation considers complex voltages at the receiving and sending ends of the branch. To use the previously found magnitude and angle voltage sensitivities, it is necessary to consider first the real and imaginary components of the complex current:

$$\overline{I_{k,J}} = Ir_{k,j} + i * Ii_{k,j} \qquad (6\text{-}50)$$

Once the complex current is divided into its real and imaginary components, the voltage sensitivities are applied to each one of them as shown in Equations (6-51) to (6-56), where the partial derivatives of the current with respect to the voltage angle and magnitude are derived from Equation (6-49):

$$\frac{\partial Ir_{k,j}}{\partial P} = \left(\frac{\partial Ir_{k,j}}{\partial V_k}\frac{\partial V_k}{\partial P} + \frac{\partial Ir_{k,j}}{\partial V_j}\frac{\partial V_j}{\partial P} + \frac{\partial Ir_{k,j}}{\partial \theta_k}\frac{\partial \theta_k}{\partial P} + \frac{\partial Ir_k}{\partial \theta_j}\frac{\partial \theta_j}{\partial P}\right) \qquad (6\text{-}51)$$

$$\frac{\partial Ii_{k,j}}{\partial P} = \left(\frac{\partial Ii_{k,j}}{\partial V_k}\frac{\partial V_k}{\partial P} + \frac{\partial Ii_{k,j}}{\partial V_j}\frac{\partial V_j}{\partial P} + \frac{\partial Ii_{k,j}}{\partial \theta_k}\frac{\partial \theta_k}{\partial P} + \frac{\partial Ii_{k,j}}{\partial \theta_j}\frac{\partial \theta_j}{\partial P}\right) \qquad (6\text{-}52)$$

$$\frac{\partial Ir_{k,j}}{\partial Q} = \left(\frac{\partial Ir_{k,j}}{\partial V_k} \frac{\partial V_k}{\partial Q} + \frac{\partial Ir_{k,j}}{\partial V_j} \frac{\partial V_j}{\partial Q} + \frac{\partial Ir_{k,j}}{\partial \theta_k} \frac{\partial \theta_k}{\partial Q} + \frac{\partial Ir_{k,j}}{\partial \theta_j} \frac{\partial \theta_j}{\partial Q} \right) \tag{6-53}$$

$$\frac{\partial Ii_{k,j}}{\partial Q} = \left(\frac{\partial Ii_{k,j}}{\partial V_k} \frac{\partial V_k}{\partial Q} + \frac{\partial Ii_{k,j}}{\partial V_j} \frac{\partial V_j}{\partial Q} + \frac{\partial Ii_{k,j}}{\partial \theta_k} \frac{\partial \theta_k}{\partial Q} + \frac{\partial Ii_{k,j}}{\partial \theta_j} \frac{\partial \theta_j}{\partial Q} \right) \tag{6-54}$$

Finally, the sensitivities of the current magnitude with respect to the real and imaginary components are integrated into Equations (6-55) and (6-56). With the matrices $\left[\frac{dI}{dP}\right]$ and $\left[\frac{dI}{dQ}\right]$ as the final result of the current sensitivity calculation, Equation (6-57) is the linear relation that could be implemented in the optimization problem.

$$\frac{\partial I_{k,j}}{\partial P} = \frac{\partial I_{k,j}}{\partial Ir_{k,j}} \frac{\partial Ir_{k,j}}{\partial P} + \frac{\partial I_{k,j}}{\partial Ii_{k,j}} \frac{\partial Ii_{k,j}}{\partial P} \tag{6-55}$$

$$\frac{dI_{k,j}}{dQ} = \frac{dI_{k,j}}{dIr_{k,j}} \frac{dIr_{k,j}}{dQ} + \frac{dI_{k,j}}{dIi_{k,j}} \frac{dIi_{k,j}}{dQ} \tag{6-56}$$

$$I_{k,j} \approx Io_{k,j} + \frac{\partial I_{k,j}}{\partial P} \Delta P + \frac{dI_{k,j}}{dQ} \Delta Q \tag{6-57}$$

Equation (6-57) models only current magnitude and as a result, it could be subject to increased error when the current phasor changes direction, for example after a high enough penetration of distributed generation downstream of a given branch.

For the nodal complex power injection sensitivities with respect to power injections in other nodes, the voltage magnitude and angle sensitivities can also be used. Equations (6-58) to (6-61) show these sensitivities, where the partial derivatives $\frac{\partial P_k}{\partial V}$, $\frac{\partial P_k}{\partial \theta}$, $\frac{\partial Q_k}{\partial V}$ and $\frac{\partial Q_k}{\partial \theta}$ are calculated from Equations (6-35) and (6-36):

$$\frac{\partial P_k}{\partial P} = \frac{\partial P_k}{\partial V} \frac{\partial V}{\partial P} + \frac{\partial P_k}{\partial \theta} \frac{\partial \theta}{\partial P} \tag{6-58}$$

$$\frac{\partial P_k}{\partial Q} = \frac{\partial P_k}{\partial V} \frac{\partial V}{\partial Q} + \frac{\partial P_k}{\partial \theta} \frac{\partial \theta}{\partial Q} \tag{6-59}$$

$$\frac{\partial Q_k}{\partial P} = \frac{\partial Q_k}{\partial V} \frac{\partial V}{\partial P} + \frac{\partial Q_k}{\partial \theta} \frac{\partial \theta}{\partial P} \tag{6-60}$$

$$\frac{\partial Q_k}{\partial Q} = \frac{\partial Q_k}{\partial V} \frac{\partial V}{\partial Q} + \frac{\partial Q_k}{\partial \theta} \frac{\partial \theta}{\partial Q} \tag{6-61}$$

As done for the voltage and current relations, the complex nodal power injections can be formulated in the following linear form. These Equations are useful for modelling power exchanges in specific nodes in the network, most importantly the TSO/DSO interface.

$$P_k \approx Po_k + \frac{\partial P_k}{\partial P} \Delta P + \frac{\partial P_k}{\partial Q} \Delta Q \tag{6-62}$$

$$Q_k \approx Qo_k + \frac{\partial Q_k}{\partial P}\Delta P + \frac{\partial Q_k}{\partial Q}\Delta Q \qquad (6\text{-}63)$$

Two disadvantages can be mentioned regarding this approach. First, the algorithm requires the initial conditions of the power flow to obtain the constraints in the new formulation. This solution should be obtained using any of the methods presented in this chapter, or more standardized approaches like Newton-Raphson. Moreover, depending on the amount of constraints to be solved, several adjustments should be made in the network. As the number and relative size of adjustments carried out in the system increases, the more inaccurate becomes the linearization using the Jacobian. In such scenario, it could be necessary to recalculate the initial conditions of the system and the associated Jacobian.

Nonetheless, also two main advantages can be highlighted for the sensitivity approach. First, although it is an approximation, it can be tuned to fit the desired error level, if the system can be linearized near its operation point. Moreover, shunt parameters can be included in the network representation without any special consideration.

6.1.3 Current injection formulation

The general expression that relates current and voltages through the admittance matrix, shown in Equation (6-64), is valid in any electric circuit, transmission and distribution networks being just two special cases. However, in many situations it is preferable to use other approaches because the behavior of loads and generators, both technically and in a market context, is better described under constant power assumptions. Nonetheless, this section presents methods that have as a base the circuit relationship of Equation (6-64).

$$[I] = [Y][V] \qquad (6\text{-}64)$$

6.1.3.1 Linear Three-Phase Load Flow for Power Distribution Systems

Starting from the ZIP load model and a first order Taylor approximation, [78] proposes a linear power flow formulation based on the current injection matrix form. Equation (6-65) and (6-66) show these two initial steps, where the subscript "S" in Equation (6-66) refers to the slack node and S^* is the load's complex power coefficient, with S_{Pk}^*, S_{Ik}^* and S_{Zk}^* being the specific factors of the ZIP load model. It is worth mentioning that the expression (6-65) is equivalent to Equation (6-41), where h is a scaling factor in the ZIP load model.

$$I_S = \frac{S_{Pk}^*}{V_k^*} + hS_{Ik}^* + h^2 S_{Zk}^* V_k \qquad (6\text{-}65)$$

$$\begin{pmatrix} \boldsymbol{I_S} \\ \boldsymbol{I_N} \end{pmatrix} = \begin{pmatrix} \boldsymbol{Y_{SS}} & \boldsymbol{Y_{SN}} \\ \boldsymbol{Y_{NS}} & \boldsymbol{Y_{NN}} \end{pmatrix} \begin{pmatrix} \boldsymbol{V_S} \\ \boldsymbol{V_N} \end{pmatrix} \tag{6-66}$$

Where I_S, and I_N represent the current injections in the slack and the rest of the network, respectively, Y_{SS}, Y_{SN}, Y_{NS} and Y_{NN} the submatrices of the admittance matrix where the subscript S refers to the slack and N to the rest of the network, and V_S and V_N are voltages in the slack and all other nodes.

Applying the first order Taylor approximation to expression (6-65), the linearized Equation (6-67) is obtained.

$$I_S = S_{Pk}^* h(2 - hV_k^*) + hS_{Ik}^* + h^2 S_{Zk}^* V_k \tag{6-67}$$

Starting from the previous expression and Equation (6-66), terms A, B and C, shown in Equations (6-68) - (6-70) can be defined. These terms form the matrix representation of the previous equations.

$$\boldsymbol{A} = \boldsymbol{Y_{NS}} \boldsymbol{V_S} - 2h\boldsymbol{S_{PN}^*} - h\boldsymbol{S_{IN}^*} \tag{6-68}$$

$$\boldsymbol{B} = h^2 diag(\boldsymbol{S_{PN}^*}) \tag{6-69}$$

$$\boldsymbol{C} = \boldsymbol{Y_{NN}} - h^2 diag(\boldsymbol{S_{ZN}^*}) \tag{6-70}$$

Dividing terms in real and imaginary components to obtain a unique real number matrix, Equation (6-71) is derived. The left-hand side of the equation, corresponding initially to current injections, now depends on the slack voltage and the load's ZIP complex power coefficients. On the right-hand side, the matrix is an expression related to the admittance matrix and, again, the load's ZIP complex power coefficients.

$$\begin{pmatrix} -\boldsymbol{A_r} \\ -\boldsymbol{A_i} \end{pmatrix} = \begin{pmatrix} \boldsymbol{B_r} + \boldsymbol{C_r} & \boldsymbol{B_i} - \boldsymbol{C_i} \\ \boldsymbol{B_i} + \boldsymbol{C_i} & -\boldsymbol{B_r} + \boldsymbol{C_r} \end{pmatrix} \begin{pmatrix} \boldsymbol{V_r} \\ \boldsymbol{V_i} \end{pmatrix} \tag{6-71}$$

Current magnitude and power injections can later be obtained using any other approximated method. For simplicity, a sensitivity approach similar to the one developed in [31] is proposed for the current calculation, but this time with current magnitude sensitivities with respect to real and imaginary voltages, as shown in Equation (6-72). A similar approach is proposed for the real and reactive power approximations, as shown in Equations (6-73) and (6-74).

$$I_{k,j} \approx Io_{k,j} + \frac{\partial I_{k,j}}{\partial V_r} \Delta V_r + \frac{\partial I_{k,j}}{\partial V_i} \Delta V_i \tag{6-72}$$

$$P_k \approx Po_k + \frac{\partial P_k}{\partial V_r} \Delta V_r + \frac{\partial P_k}{\partial V_i} \Delta V_i \tag{6-73}$$

$$Q_k \approx Qo_k + \frac{\partial Q_k}{\partial V_r}\Delta V_r + \frac{\partial Q_k}{\partial V_i}\Delta V_i \tag{6-74}$$

6.1.4 Method Comparison

Previous sections have presented different approaches to solve the power flow problem in distribution networks. This section compares such methods with the objective of selecting the appropriate ones for the TSO-DSO simulation platform develop in this thesis. Table 6-2 summarizes the assumptions, advantages, and disadvantages that each method has in the project's context.

Table 6-2. Comparison power flow algorithms for distribution networks

Method	Assumptions	Advantages	Disadvantages
DistFlow [43,72]	- Radial network - Relaxed power equality constraint for convex programming	- Complete representation of the power flow and the voltage	- Strictly limited to radial configurations - Power flow solved using Quadratic constrained programming
Simplified DistFlow [72]	- Radial network - Loss components neglected in branch equations	- Recursive formulas provide direct solutions to the power flow	- Strictly limited to radial configurations - Simplifications may lead to underestimation of over-voltage problems - Power flow solved using Quadratic constrained programming
Branch model using conic programming [73]	- Meshed and radial networks - Relaxed power equality constraint for convex programming	- Formulation not limited to radial networks - Complete representation of the power flow and the voltage	- Power flow solved using conic programming optimization
Linear branch model [74]	- Meshed and radial networks - $\theta_{kj} \approx 0$ - $V_k V_j \approx 1\ p.u.$	- Formulation not limited to radial networks - Matrix expressions provide direct solutions to the power flow - Adaptable losses can be included	- Linearization around small voltage magnitude variations and small voltage angle variations
Linear polar formulation [75]	- Meshed and radial networks - Unbalance grids - $\theta_{kj} \approx 0$ - $V_k(V_k - V_j) \approx (V_k - V_j)$ - Linear ZIP model	- Formulation not limited to radial networks - ZIP load model included - Phase imbalances modelled	- Linearization around small voltage magnitude variations and small voltage angle variations
Optimal power flow for distribution networks [76]	- Meshed and radial networks - Linearization with Jacobian around power flow solution	- Easy integration into power flow formulation - Jacobian constant to calculate sensitivities	- It still requires an algorithm to analyze initial conditions - After several changes, it is necessary to recalculate the linearization (initial setpoints and Jacobian matrix)

Linear ZIP and current injection [78]	- Meshed and radial networks - Linear ZIP model	- Formulation not limited to radial networks - ZIP load model included	- Linearization around small voltage magnitude variations

To help in the selection of the algorithms for the thesis, three main characteristics are analyzed even further: I.) their computational complexity, II.) the accurate description of grids' conditions and III.) the ease with which the model can be integrated to the complete simulation platform.

Starting from the third characteristic, all models allow the representation of bids in forms of power injections/withdrawals, standard procedure for different types of energy markets. Moreover, the last two models implemented a linear ZIP load representation, which can be used to differentiate DER in the simulation platform.

With respect to grid representation, all models relying on approximations to linearize the formulation have shortcomings. However, it goes beyond the scope of this thesis to extensively represent the distribution network. Nonetheless, the voltage behavior across the network and the current through the branches should be represented to respect the main grid's technical limits. The second, fourth and fifth methods could misrepresent voltage problems, and should be use in scenarios where their assumptions are valid. The fifth model differentiates itself from all others by including phase unbalances. This aspect could be of interest to DSOs as phase unbalances are common occurrences in distribution networks, and for DER capable of providing phase-balancing services.

Finally, all methods pay especial attention to reduce the complexity of the non-convex original power flow formulation. Because the network model is the base of the simulation platform proposed in this thesis, the reduction of computational complexity plays an even more important role in this discussion. For their simplicity, the second and last approaches stand-out from the rest in this category. In the case of the simplified DistFlow formulation, the recursive equations can be used directly without using an optimization problem while the Linear ZIP and current injection requires the inverse of the admittance matrix that can be calculated once and store for further use.

As a result of this brief analysis, in the next section three algorithms are to be tested and compared: the DistFlow algorithm, the first order linearization of the power flow formulation as presented in [76] and the current injection model based on the ZIP load linearization shown in [78], and referred in the rest of this document as Garces approach.

6.2 Numerical comparison

To Compare the DistFlow method, the first order Sensitivities approach and the Garces algorithm, two networks are used. The first is a small radial 14 bus network, called TESTOPF, without shunt parameters. The network characteristics are shown in Table 12-1 to Table 12-5. The second is a larger, low loading radial medium voltage network, called RETE81, which main features are presented in Table 12-6, Table 12-7 and Table 12-8. Initial voltages and current profiles for the networks TESTOPF and RETE81 are shown in Figure 6-3 and Figure 6-4. In addition to voltage in per unit and current in amperes, Figure 6-4 represents loading in the branches as a percentage of the branch current over the maximum current capacity of the branch.

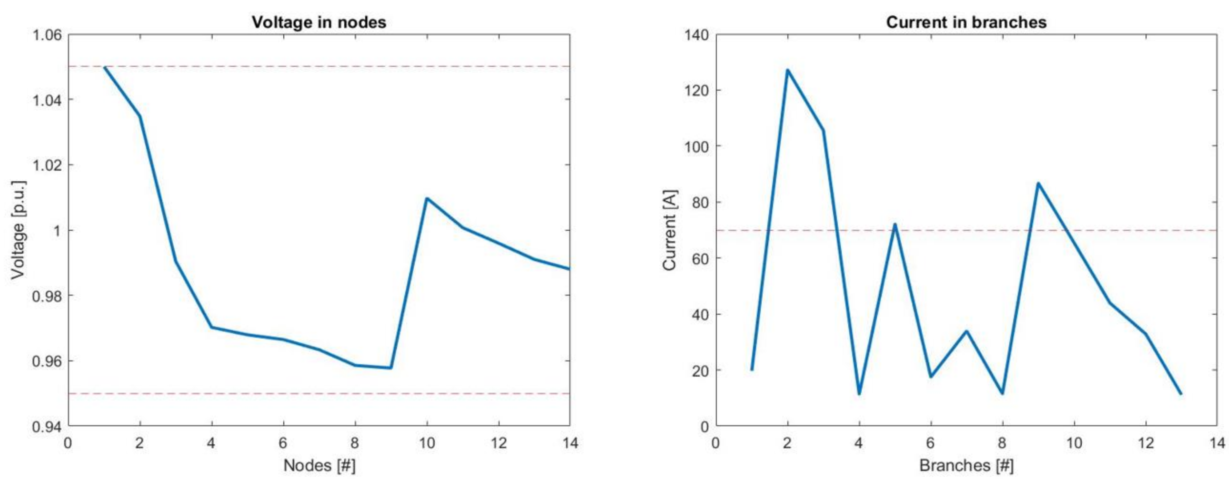

Figure 6-3.Initial voltage and current profile, TESTOPF network

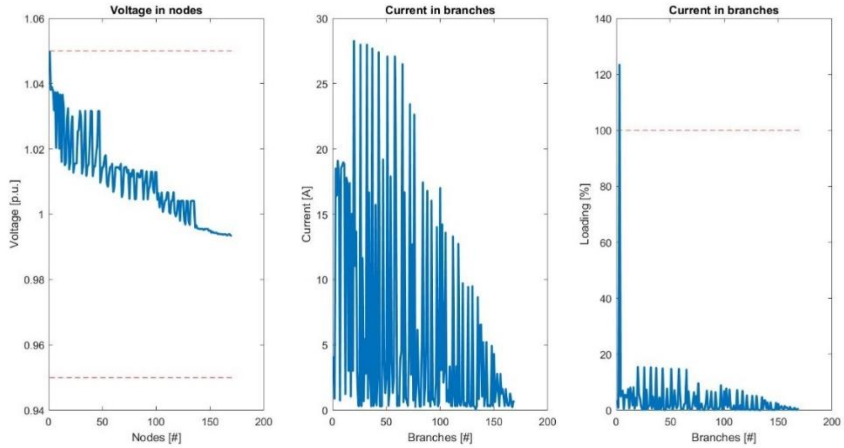

Figure 6-4.Initial voltage and current profile, RETE81 network

To test the algorithms in an environment similar to the Optimal Power Flow implemented later, apart from the initial network condition, real and reactive power variations are included in the generation nodes. These changes emulate the conditions once the network models are included in the Optimization problem framework.

To compare the approximated network models, an *ideal modelling method* is required to make comparisons. A mixed power flow tool based on both the Gauss method, for initial iterations, and the Newton Raphson, for fast convergence after a good enough initial point is found, is used. The toolbox, referred in the following discussion as Gauss Newton Raphson (GNR), is written on MATLAB and was not developed by the author of the Thesis.

Four figures of merit are used to compare network results, all measured with respect to results taken from GNR. The first corresponds to the average and maximum relative error in the voltage magnitude for all nodes, as shown in Equations (6-75) and (6-76).

$$A.R.E.V. = \frac{1}{n}\sum_{i=1}^{n}\frac{|V_i - V_{GNR,i}|}{V_{GNR,i}} \tag{6-75}$$

$$M.R.E.V. = \max_{n}\frac{|V_i - V_{GNR,i}|}{V_{GNR,i}} \tag{6-76}$$

The second and third figure of merit deal with current magnitude in the branches. Just as before, the average and maximum relative error are calculated as shown in Equations (6-77) and (6-78). However, it is important to highlight two aspects of current modelling and how they are treated in an optimal power flow problem. First, unlike voltages, not all branches are relevant. In fact, only those branches with flows close to their nominal capacity are considered in the optimization problem. Moreover, branches with low currents calculated in the GNR module could cause numerical problems in the computation of relative errors. As a result, Equations (6-79) and (6-80) show average error and maximum relative error for relative branches m. r. These are branches with current higher than X% of their nominal capacity, as calculated by the GNR module, and as a result, they are more likely to be taken into consideration in the optimization problem.

$$A.R.E.I. = \frac{1}{m}\sum_{i=1}^{m}\frac{\left|Ib_i - Ib_{GNR,i}\right|}{Ib_{GNR,i}} \tag{6-77}$$

$$M.R.E.I. = \max_{m}\frac{\left|Ib_i - Ib_{GNR,i}\right|}{Ib_{GNR,i}} \tag{6-78}$$

$$A.R.E.I.r. = \frac{1}{m.r.}\sum_{i=1}^{m.r.}\frac{\left|Ib_i - Ib_{GNR,i}\right|}{Ib_{GNR,i}} \tag{6-79}$$

$$M.R.E.I.r = \max_{m.r.}\frac{\left|Ib_i - Ib_{GNR,i}\right|}{Ib_{GNR,i}} \tag{6-80}$$

Similar definitions to the ones presented in Equations (6-79) and (6-80) could be used for Absolute errors where, for example, A. A. E. I. and M. A. E. I. r would represent the average absolute error and the maximum absolute error for relevant lines, respectively.

Finally, the relative errors for both real and reactive power injections in the slack are considered, as shown in Equations (6-81) and (6-82). As it is stated before, the power injections at the slack node are of paramount importance because this node is effectively the interface between the TSO's and DSO's networks.

$$R.E.P. = \frac{|Pslack - Pslack_{GNR}|}{Pslack_{GNR}} \tag{6-81}$$

$$R.E.Q. = \frac{|Qslack - Qslack_{GNR}|}{Qslack_{GNR}} \tag{6-82}$$

As mentioned earlier, to test the algorithms power injection variations are introduced to the network. To evaluate a wide range of power injections and capabilities, four testing scenarios are devised and shown in Table 6-3 for the network TESTOPF. The testing procedure applied is explained in the following steps:

1. Power flow is calculated using the GNR algorithm in its initial state. Interest variables (current, voltages, and power exchange in the slack bus) are calculated;

2. Interest variables (current, voltages, and power exchange in the slack bus) are calculated using the three approximated methods (Sensitivities, DistFlow and Garces). For the linearization approaches, the point of linearization is always the initial testing state;
3. Approximation errors are calculated, having as a base of comparison the results of the GNR algorithm;
4. Power variations are induced in selected nodes (indicated later) and the network state is updated. These power variations are applied to the nodes as real and reactive power injections, depending on the case;
5. Power flow is recalculated using the GNR algorithm, and interest variables are recalculated;
6. Procedures goes back to step 2, with the new an updated system state.

As it can be seen from the power range selected, and the initial loads and generator injections from Table 12-2 and Table 12-3, the changes applied to the network are substantial and thus reproduce extreme conditions for the network algorithms. For this network, the threshold to filter relevant lines is selected as 50%, in accordance to the initial current profile shown in Figure 6-3.

Table 6-3. Testing scenarios – TESTOPF network

Scenario	Nodes changed	Power Range [kW]	Power Factor
1	5	(-1000, 1000)	1
2	14	(-1000, 1000)	0.9
3	[5,7,9,12,14]	(-500,500)	1
4	[5,7,9,12,14]	(-500,500)	0.9

Figure 6-5 to Figure 6-7 show the results for the testing scenario 1 for the first network. Starting from the voltage relative error several trends that are present for all cases can be identified. First, all methods show relative errors below the 3% threshold for the complete range considered in the analysis. However, both the A.R.E.V. and M.R.E.V. are considerably lower for the Sensitivities and Garces approaches. Moreover, only the Sensitivity approach provides zero error when the network remains in its initial condition. Finally, as it is expected from a Linear approximation, the Sensitivity method increases its relative error as the difference between final and initial conditions increases.

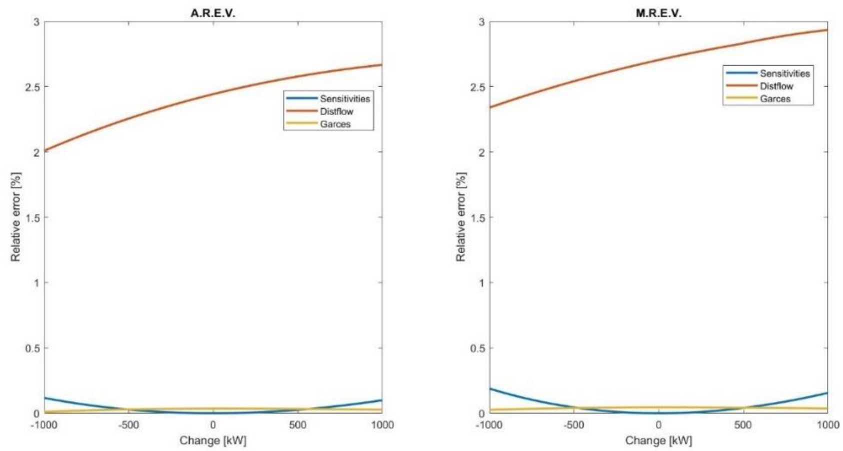

Figure 6-5. Voltage error, scenario 1 – TESTOPF

Regarding the current errors, shown in the four panels of Figure 6-6, some considerations are needed to better understand the results. To start, the step behavior of the A.R.E.I.r and M.R.E.I.r indicators is explained due to the criteria defining relevant branches (50% of loading). Secondly, the peaks found for both the Sensitivity and Garces approaches shown for the A.R.E.I. and M.R.E.I. are caused by branches in which the current direction is changing its directions. The change in current direction occurs when a branch presents relatively low loading, and thus the same behavior is not identified on the panels on the right of Figure 6-6.

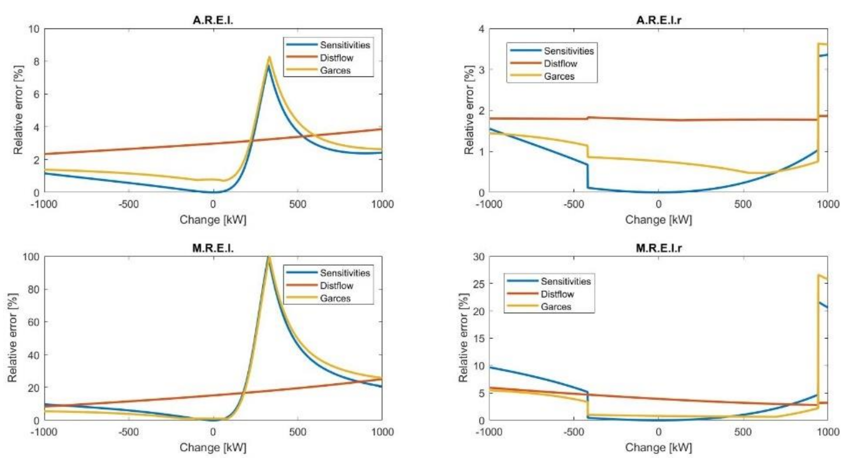

Figure 6-6. Current error, scenario 1 – TESTOPF

With the previous considerations, the main results found in Figure 6-6 are highlighted. In the same way as shown for the voltage results, the relative errors for both the Sensitivities and Garces approaches is close to zero when power injections in node 5 are not changed. Furthermore, when compared using the A.E.R.I.r and M.R.E.I.r indicators all methods result in relative errors close to 2 and 5%, respectively. The figures of merit A.R.E.I. and M.R.E.I. are also comparably low, excluding the aforementioned peak caused by the direction change in the branch's current. Lastly, the DistFlow method presents a more robust behavior for the A.R.E.I. and M.R.E.I. indicators across the testing range.

Relative errors for the power injections in the slack node are shown in Figure 6-7. Generally, all methods describe the power injections with an appropriate relative error, approximately 2% for the DistFlow method and close to the 0.1% level for the Sensitivities and Garces approaches. The behavior for real and reactive power is similar.

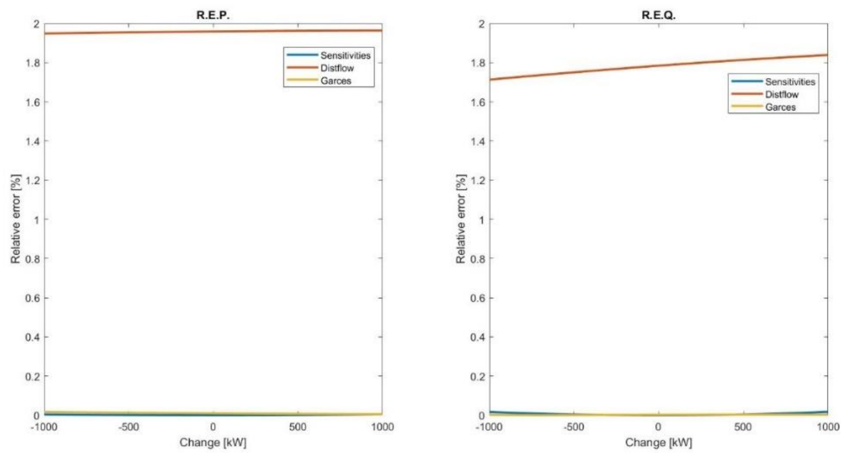

Figure 6-7. Slack error, scenario 1 – TESTOPF

In Figure 6-8 to Figure 6-10 the error results for Case 4 are shown. This is the scenario where more drastic power injections are implemented in the network, and worth considering as a result. Starting from the voltage profile results, Figure 6-8 shows both an average and relative error below 3% and 1% for the DistFlow method and the Sensitivity and Garces approaches, respectively. Compared with the previous testing scenario, voltage errors have increased but not dramatically.

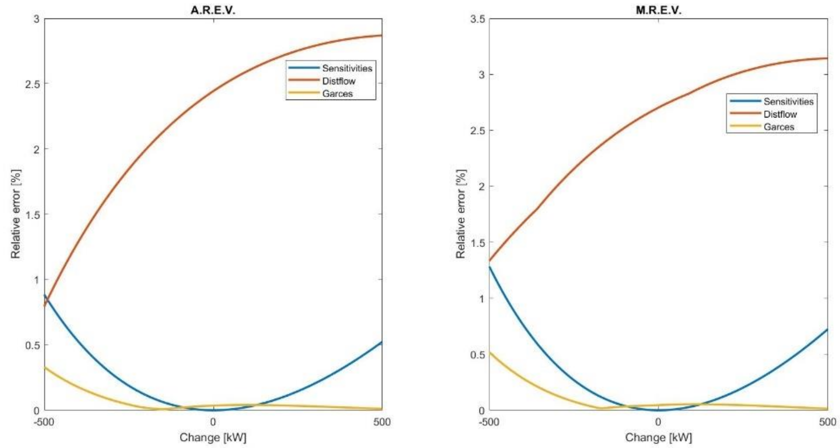

Figure 6-8. Voltage error, scenario 4 – TESTOPF

Figure 6-9 shows current errors for scenario 4. As before, the results displayed on the left-hand side panels of this Figure, in comparison to the average and maximum relative errors for relevant lines on the right-hand side, are explained due to branches with low loading in which the current change direction. Beyond this, the A.R.E.I.r and M.R.E.I.r indicators stay in reasonable ranges for all the testing range. Comparing the performance of the sensitivity approach for these two indicators with respect to the other two methods, it is clear this approximation presents an improved behavior when changes to the network are more limited. In the other two power flow methodologies, current errors stay relatively constant across the testing range.

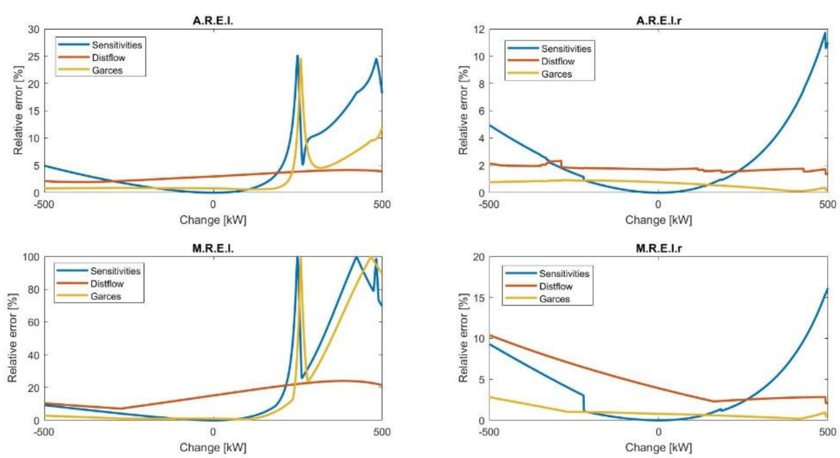

Figure 6-9. Current error, scenario 4 – TESTOPF

Regarding real and reactive power errors, Figure 6-10 shows the R.E.P. and R.E.Q. indicators for testing scenario 4. As in the previous testing scenario, relative errors stay below 2% for the DistFlow approach, while being close to 0.1% for the other two methodologies.

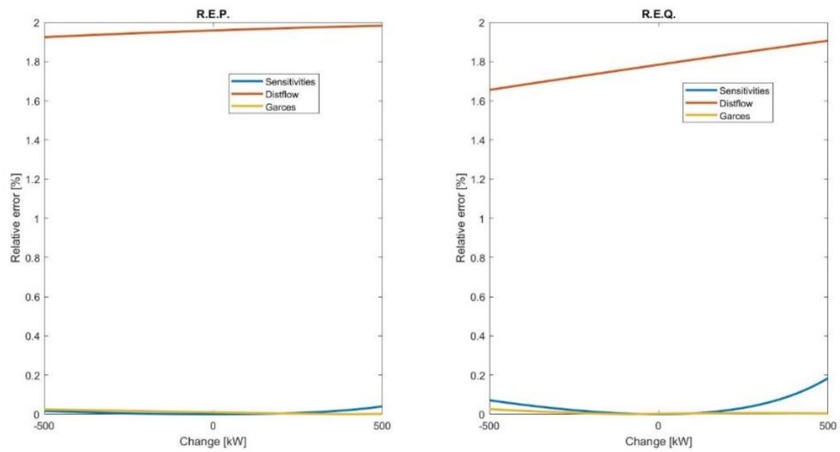

Figure 6-10. Slack error, scenario 4 – TESTOPF

Results for testing scenarios are shown in Figure 12-1 to Figure 12-6. Although they are not discussed here, these scenarios show similar trends to the ones identified in the previous cases.

Similarly to the analysis for the TESTOPF network, Table 6-4 shows four testing scenarios proposed to test the power flow algorithms in the RETE81 network. As before, and in comparison to Table 12-6 and Table 12-8 the power injection variations imposed on the network are substantial. It is worth mentioning that this network is relatively low loaded, and in addition, contains several lines that connect nodes with no load at the end of the respective branches. As a result, two considerations are emphasized before presenting the results:

1. The threshold chosen for relevant lines is only 25% (to avoid that in some cases no relevant lines are selected);
2. For the sake of completeness, all lines are considered when calculating relative errors in branches. However, due to both conditions of the network: i.) relatively low loading, as Figure 6-4 clearly shows and ii.) lines connecting nodes with no actual load, it is possible to find relative errors for individual branches that are several order of magnitudes higher than the normal results, hindering the plots' interpretation;
3. This network is an appropriate testbench to evaluate the behavior of the algorithm in extreme conditions, and thus it is worth considering in the analysis.

Table 6-4. Testing scenarios RETE81 network

Scenario	Nodes changed	Power Range [kW]	Power Factor
[1]	84	(-500, 500)	1
[2]	166	(-500, 500)	0.9
[3]	Buses Table 12-8, except 81 (slack)	(-250,250)	1
[4]	Buses Table 12-8, except 81 (slack)	(-250,250)	0.9

Starting from the voltage A.R.E.V. and M.R.E.V indicators shown for the first testing scenario in Figure 6-11, several comments can be made. As for the smaller network, the Sensitivity approach results in relative errors that increase once power injections variations are induced in the system. In comparison to the previous case, the voltage behavior variations for the other two methodologies are harder to predict, becoming erratic, for different power injections. Finally, average relative errors are bounded by 1% and 2.5% for both A.R.E.V. and M.R.E.V indicators, demonstrating the strength of the algorithms for modelling voltages.

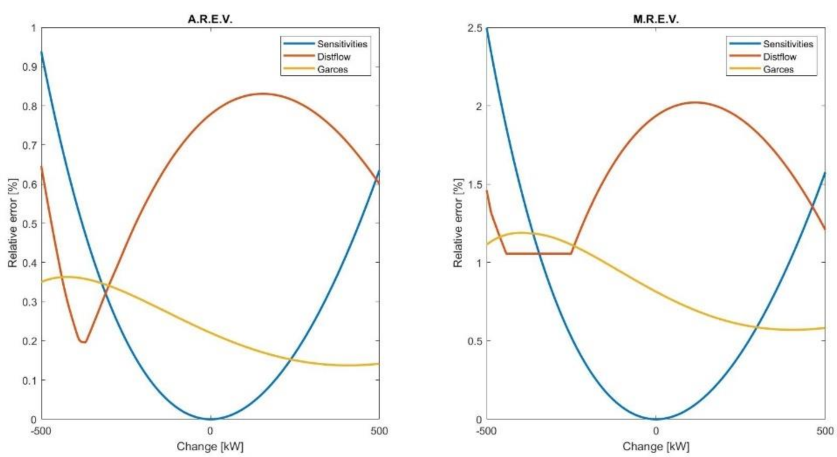

Figure 6-11. Voltage error, scenario 1 – RETE81

Current errors for the first testing scenario are shown in Figure 6-12. From the results, several considerations are worth highlighting:

- Error peaks are found, for different power injections, in both the A.R.E.I.-M.A.R.E.I. and in the A.R.E.I.r - M.A.R.E.I.r. The explanation to such behaviors is again found in the definition of relative error. Large relative errors are caused when the ideal value is low with respect to the absolute error, and such would be the case for a network with low branch loading. However, this situation still occurs even when applying the filtering criteria for relevant lines;

- Nonetheless, in conditions close to no power injection variations, the Sensitivity and the Garces approach show indicators that demonstrate they are appropriately modelling the network;
- As it is clear from the results, the DistFlow performance is considerably worse compared to the other algorithms. In addition to the previous reasons to high relative errors mentioned, the omission of shunt parameters in the DistFlow algorithm is influencing the current profiles obtained.

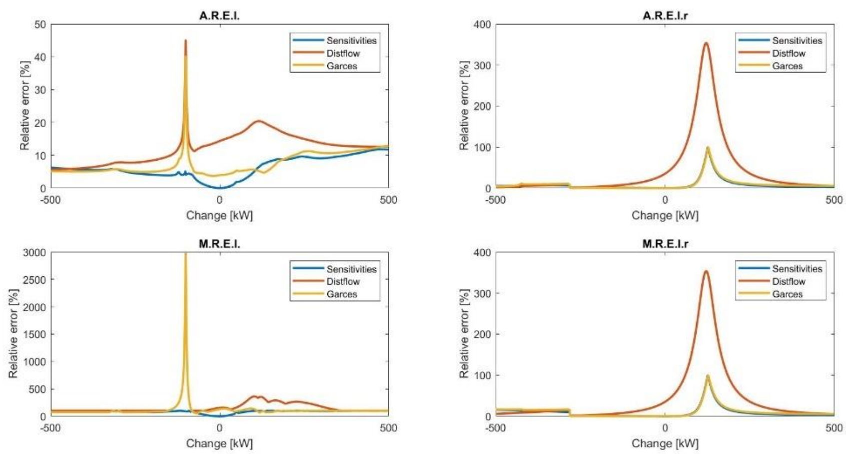

Figure 6-12. Current error, scenario 1 – RETE81

Real and reactive power errors are shown in Figure 6-13. Disregarding the spike shown for the real power error close to 100 kW power injection change, caused by an ideal power injection in the slack, calculated using the GNR tool, close to zero, the power error presents a similar behavior compared to the smaller network; relative errors are bounded by 2.5% for the DistFlow algorithm, while the Sensitivity and Garces approaches stay below 0.5% for the complete testing range.

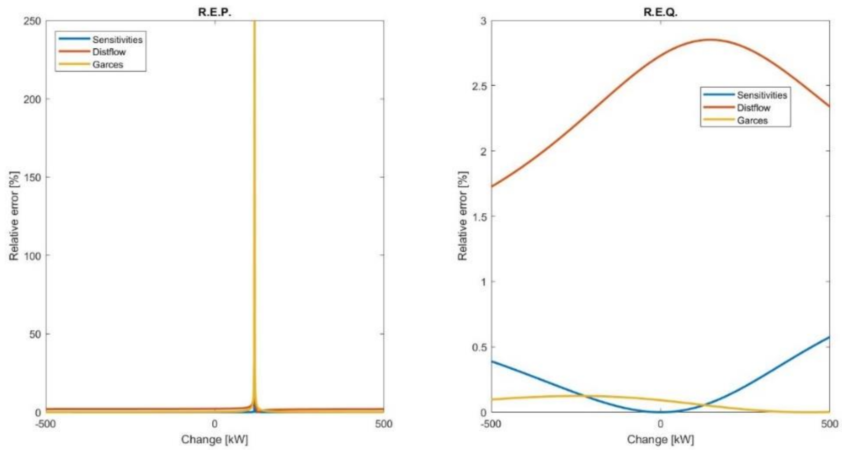

Figure 6-13. Slack error, scenario 1– RETE81

Figure 6-14 presents voltage errors for the testing scenario 4. As for the previous one, average relative errors are bounded by 1% and 2.5% for both A.R.E.V. and M.R.E.V indicators, even when power variations are considerably larger in this case.

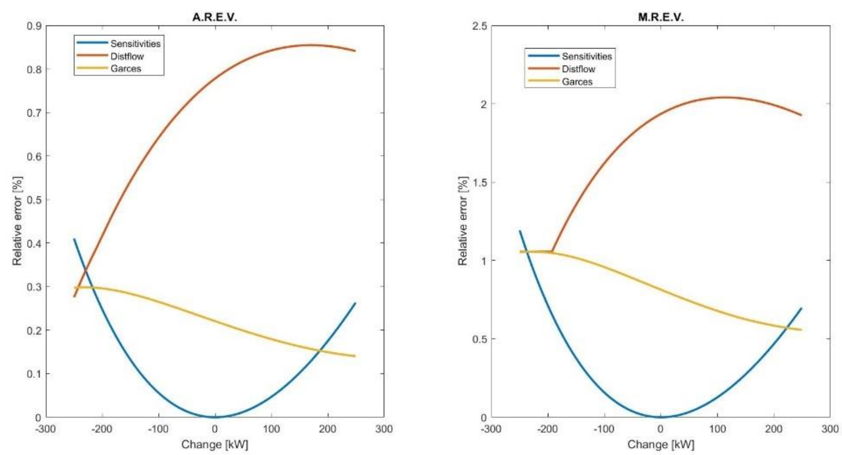

Figure 6-14. Voltage error, scenario 4 – RETE81

Current errors for testing scenario 4 are shown in Figure 6-15. Just as before, relative errors show spikes. However, for this testing scenarios several spikes along the testing range are found, demonstrating inconsistencies in the approximated algorithms applied to networks with the conditions of RETE81. Despite the deficient behavior of the DistFlow algorithm, both the Sensitivity and Garces approach display a proper approximation of the network for low enough power injection variations.

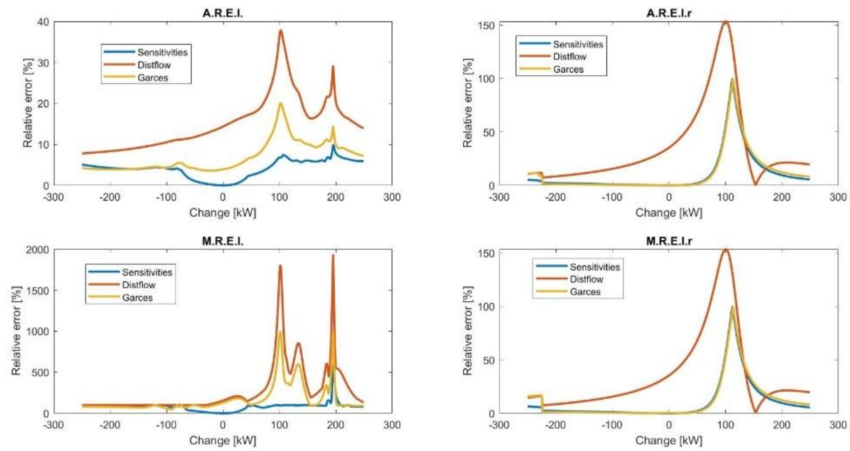

Figure 6-15. Current error, scenario 4 – RETE81

Lastly, Figure 6-16 presents relative errors for both real and reactive power in testing scenario 4. Discounting the points in which the power exchanged by the slack bus approaches zero, and thus the relative error increases dramatically, the relative error for these two variables stays in appropriate values for the complete testing range.

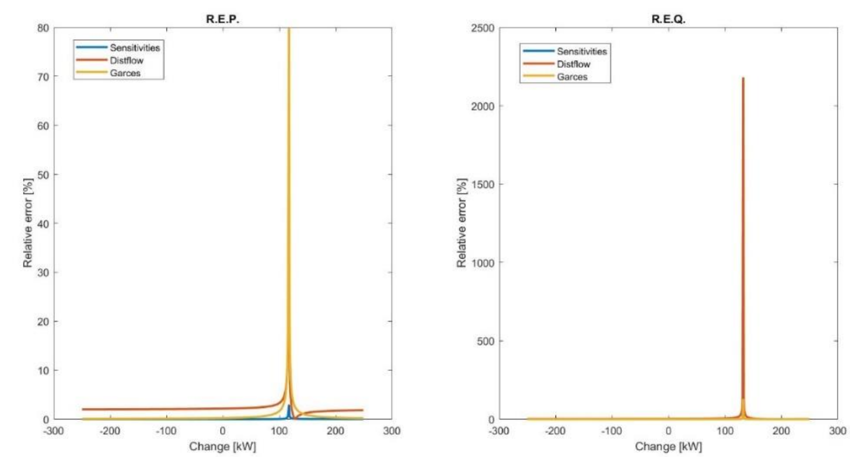

Figure 6-16. Slack error, scenario 4– RETE81

Despite the different conditions identified in which the approximated algorithms showed weaknesses, the testing scenarios are extreme and not realistic for the context of the optimal power flow implemented in the following sections. Moreover, measures are taken in the development of the optimization and market algorithms to avoid situations in which large power injection changes are imposed in the network.

Results for the testing scenarios 2 and 3 for the RETE81 network are shown in Figure 12-7 to Figure 12-12. As mentioned for the network TESTOPF, these plots show similar trends to the ones identified in the previous scenarios and for that results are not commented in this section.

In addition to the previous analyses, Section 12.3 of the Appendix shows a comparison between numerical and analytical sensitivity matrices used for the Sensitivity network modelling approach, for both the TESTOPF and RETE81 networks. The comparison shows that analytical sensitivity matrices represent in most cases the numerical sensitivities with a low relative error.

6.3 Chapter conclusions

The brief theoretical review presented in the previous chapter shows several algorithms have been developed to model medium voltage distribution networks, as needed for TSO-DSO framework developed in the rest of the thesis. In any case, Table 6-2 shows a summary of advantages and disadvantages that lead to the selection of three algorithms to be tested numerically: DistFlow method, the first order sensitivity approach and the ZIP load linearization.

Although numerical testing shows the ZIP load linearization method is comparable to the first order sensitivity approach once power injection variations are implemented, the latter has the advantage that it reproduces the initial voltage and current profile when no variations are induced. Due to this, and because both methods are based on first order sensitivities, of the power injection in the case of [78] and of the network itself in [31], the second method is selected between the two.

With respect to the DistFlow method, its key benefit is that it can be directly included in the optimization problem (not in a linear programming context but using a quadratic constrained formulation instead). In addition, as numerical testing shows for small networks without shunt parameters, the same level of performance can be expected for a wide range of power injection variations. However, errors are always higher than the other approximation approaches, and such errors cannot be improved as they are inherent to the algorithm.

For the Sensitivity algorithm, its core strength is that it perfectly represents the network when no power variations are included. This characteristic, that also ensures avoiding possible divergence and erratic behaviors identified when system changes are sufficiently large, will be used when developing and testing approximated algorithms to solve the optimization problem that is presented in later sections.

For these reasons, the model that is developed to evaluate TSO-DSO coordination for procuring ancillary services is implemented using the first order sensitivity method, as the main approach. Nonetheless, any network algorithm that can be easily integrated into an optimization problem would obtain similar results.

7 Market models for TSO-DSO Coordination

This Section starts with a brief overview of ancillary services market from three points of views: the European guidelines for balancing markets, the Italian market reform and some relevant considerations of the Smart Net Project not discussed before. After partial conclusions are presented, the economic structure and the objective function of the market model is defined. After that, the simplified interaction between the three buildings blocks of the market model is studied from an economic perspective, with the main goal of selecting a set a structure of the market to be implemented later. Finally, the building blocks of the market models are *disaggregated* and formulated in detail for the Sensitivity and the DistFlow network modelling approaches.

7.1 Flexibility Market Structure

Before introducing the TSO-DSO coordination schemes in Section 7.2, it is worth revisiting the three main parts that compose the market structure, in addition to the interactions among them, presented schematically in Figure 7-1.

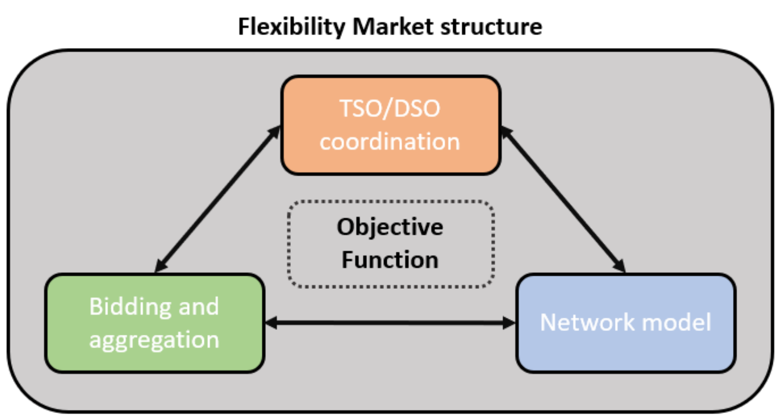

Figure 7-1. Flexibility Market structure

To start, the network model has been developed to represent congestion constraints found in distribution networks, as discussed in Section 5. No explicit representation of transmission networks is included in this thesis, and as a result special attention is given to the TSO-DSO interface (the HV/MV transformer).

Second, a bidding and aggregation proposal is discussed in Section 5 to allow DER to participate in the flexibility market. Due to the limitation of the analysis, and the requirement of meeting network constraints, bids at the distribution level are procured as congestion products.

Because of that, DER and their bids are represented at a nodal level in distribution networks, not allowing geographical aggregation.

Third and most important part of the flexibility market structure is the TSO-DSO coordination scheme, discussed in Section 4. From a regulatory standpoint, the coordination scheme dictates at each level who is responsible for the market operation, in addition to how and with which purpose(s) DER are procured. Moreover, the coordination scheme implicitly how active the DSO, and distribution networks for that matter, are in the flexibility market.

Finally, as shown in the center Figure 7-1, the market structure also includes the decision over how to select the objective function in the flexibility market. Section 4.3.3 briefly discusses important considerations presented in the Smart Net Project where two alternatives, minimization of procurement costs and maximization of social welfare, are analyzed and compared. Following the standard practice in most ancillary services markets, including the Italian market, the flexibility markets and the TSO-DSO coordination schemes are developed considering the the minimization of total activation costs as objective function.

7.2 TSO-DSO Coordination schemes

This Section presents, from a theoretical standpoint, main characteristics of TSO-DSO coordination schemes, inspired by the literature review discussed in Section 4.

7.2.1 Scheme 1: Flexibility market at the transmission level, incomplete information

In the first coordination scheme, shown in Figure 7-2, a Flexibility Market is implemented at the transmission level. In this market, DER submit their bids and the TSO, in return, activates resources according to its objective function. The DSO has no role in the market; it does not provide network information nor participates in the bid's activation.

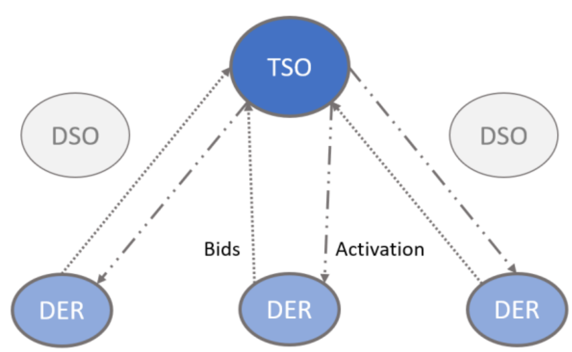

Figure 7-2. Scheme 1: Flexibility market at the transmission level, incomplete information

This scheme very closely resembles the *status quo* of ancillary services markets around the world, where a single entity, commonly the TSO, manages a market at the wholesale level to procure flexibility services required to solve operative and security constraints at the transmission level. The coordination scheme is represented in the Smart Net Project as the centralized ancillary services market [40].

Although the participation of DER is allowed, distribution network constraints are not considered explicitly. As a result, the Flexibility market could result in congestion at low voltage levels, if the *Fit and Forget* approach for designing distribution networks is no longer valid, as it is expected in future power systems. Moreover, the exclusion of the DSO in the scheme, and the lack of TSO-DSO coordination, goes against what is proposed in Clean Energy Package. Moreover, the scheme could be restrained by communication limits, as the bids and activation signals must be regularly exchanged between all DERs and the TSO.

7.2.2 Scheme 2: Flexibility market at the transmission level, complete information

In the Second Scheme, shown in Figure 7-3, a centralized Flexibility market with complete information, managed by the TSO, is proposed. As in the previous case, DER submit bids to the single market, where they are enabled to provide flexibility services after the TSO respond with the appropriate activation signals.

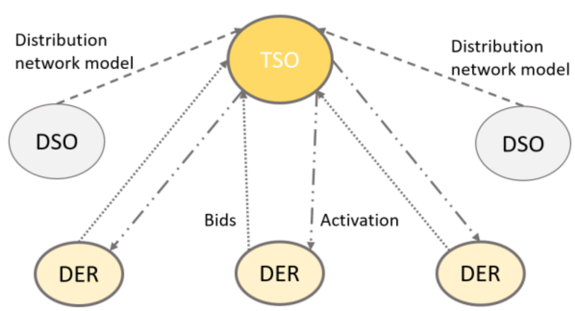

Figure 7-3. Scheme 2: Flexibility market at the transmission level, complete information

In this case, the DSO shares complete network information with the TSO to include in a single optimization problem all existing constraints. The result would be an algorithm with the potential of maximizing the social welfare. However, such coordination scheme faces three main challenges: I.) the computational complexity of such formulation, II.) the coordination problem with DSOs so they can ensure the fidelity and completeness of the information they share with the TSO, and III.) the communication restrictions of exchanging bids and activation signals between DER and the TSO.

The scheme presents an ideal case for flexibility markets, with perfect coordination between all participating entities. However, achieving such implementation seems unfeasible in the near-term, so the coordination strategies that are suggested by the Clean Energy Package should serve as *second best* approaches. In the Smart Net project, this model is referenced as the common TSO-DSO ancillary services market [40].

7.2.3 Scheme 3: Flexibility market at the transmission level, DSO applies acceptance criteria to bids

In the third Scheme, Figure 7-4, the Flexibility market is again implemented at the central level by the TSO. The coordination is achieved in the activation of DER's flexibility services, in which the responsibility is shared between the TSO and DSO.

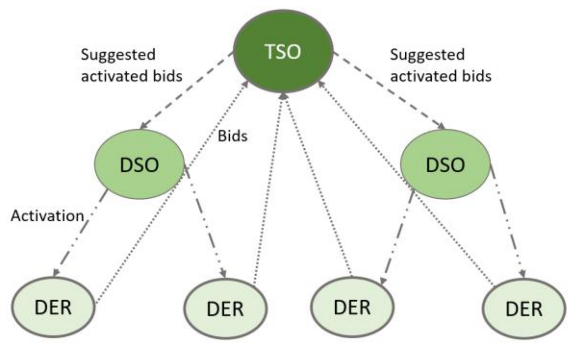

Figure 7-4. Scheme 3: Flexibility market at the transmission level, DSO applies acceptance criteria to bids

In this case, the TSO does not explicitly represent distribution level constraints in the market. Instead, after selecting bids according to the optimization criteria, the TSO sends a list, possibly ordered, suggesting the activation of flexibility services from DER to all DSOs participating in the central market.

After receiving the list of suggested simultaneously active bids, the DSO checks for the compliance of network constraints with its own system's knowledge and information, later returning the analysis to the TSO. Finally, the TSO rebalances the system given the aggregated services provided by DER in every distribution network. Summarizing, the DSO does not implement a local market, but helps the TSO by managing and achieving feasibility conditions in the central one, and similarly to Scheme 1, if the *Fit and Forget* approach to designing distribution network is still valid, the actual role of DSOs would be minimal.

This coordination scheme is inspired by the shared balancing responsibility model in the Smart Net Project [40], and the Centralized and extended dispatching approach from [29].

7.2.4 Scheme 4: Flexibility market at the distribution level

The fourth Scheme, presented in Figure 7-5, is the most basic form of a flexibility market at the distribution level managed by the DSO. The DSO receives flexibility bids from DER connected to their network, and activates them to solve constraints according to the objective function from the local market.

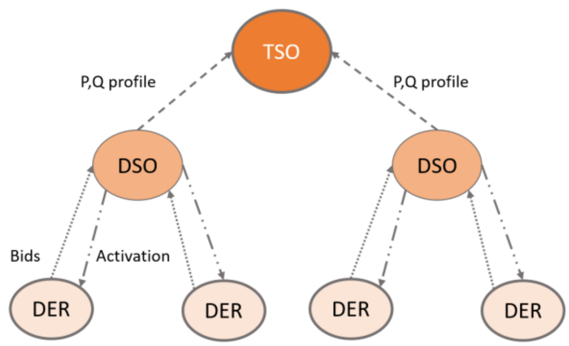

Figure 7-5. Scheme 4: Flexibility market at the distribution level

In this scheme, no explicit coordination between TSOs and DSOs is implemented, as Scheme 1, opposing to what is established in the Clean Energy Package. After solving internal constraints, the DSO communicates the active and reactive power profile at the HV/MV interface. An indirect consequence of such formulation would be that the TSO has no effective access to flexibility services from DER, limiting the possibility of using these resources to manage operative problems at the transmission level.

The local market for flexibility services is a common approach presented in the literature, being analyzed as the Local dispatch by the DSO model in [29], the local ancillary services market in the Smart Net Project [40] and other local markets studied in European research projects presented in Section 4.4.

7.2.5 Scheme 5: Flexibility market at the distribution level, TSO imposes PQ profile at the HV/MV interface

The fifth Scheme, shown in Figure 7-6, is very similar to Scheme 4; the DSO actively manages a local flexibility market, being responsible for receiving bids, solving the optimization problem, and later activating resources connected to their networks. However, in this case, TSO-DSO coordination is achieved by a controlled PQ profile at the HV/MV interface that is decided before hand by the TSO.

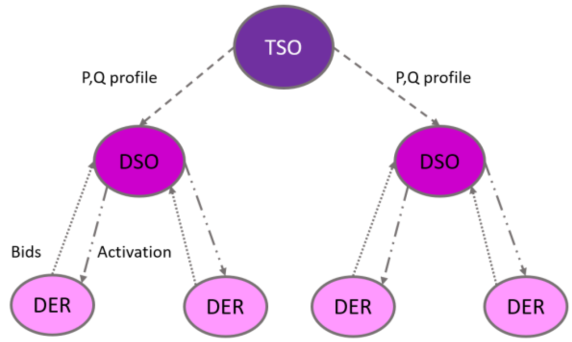

Figure 7-6. Scheme 5: Flexibility market at the distribution level, TSO imposes PQ profile at the HV/MV interface

In this matter, the TSO has indirect access to flexibility services provided by DER. Moreover, the flexibility market at the transmission level is greatly simplified because constraints from distribution networks and bids from DER are not included in this problem. Thus, flexibility services are procured in a decentralized way, assigning an active role to the DSOs, and increasing its responsibilities,

On the other hand, the coordination scheme has some key disadvantages when compared to the benchmark described in Scheme 2. To start, the coordination scheme does not ensure global optimality conditions for the procurement of flexibility services, as the optimization carried out by the TSO in the central market has incomplete information. Moreover, the access to DER is limited by the scheduled PQ profile at the HV/MV interface, meaning some resources could be left unused. Last, the PQ profile requires validation by the DSO, or it could lead to its unfeasibility at the local levels. This step could complicate the coordination strategies, in addition to posing regulatory challenges in dividing responsibilities and managing strategies between TSOs and DSOs.

Coordination scheme 5 is inspired by the final cumulative program at HV/MV interface presented in [29], the distribution networks PQ characteristics discussed in [37], the hierarchical coordination mechanisms from [35] and ideas from the integrated flexibility market and shared balancing responsibility models from the Smart Net Project [40].

7.2.6 Scheme 6: Flexibility market at the distribution level, DSO aggregates and submits bids to TSO

The last coordination scheme proposed, shown in Figure 7-7, is similar in structure to Scheme 5. However, instead of managing and controlling the interaction in the HV/MV interface, the DSO aggregates bids of DER connected to its network. In this aggregation, the DSO is checking the technical feasibility of simultaneously activated bids and ordering them in a supply curve. This supply curve is later submitted to the TSO, where it can be used in the central algorithm designed to procure flexibility services at the transmission level.

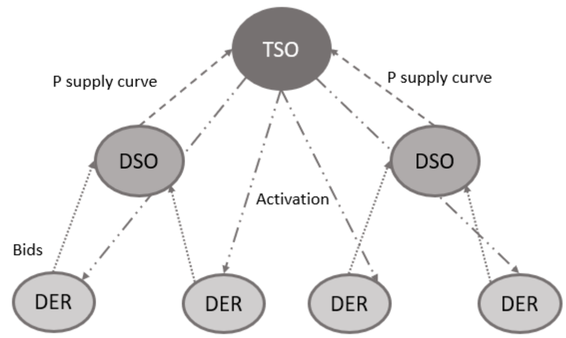

Figure 7-7. Scheme 6: Flexibility market at the distribution level, DSO aggregates and submits bids to TSO

When compared to Scheme 5, this scheme has several advantages: I.) the flexibility services from DER can be fully accessed by the TSO in the central market, without overcoming constraints at the distribution level, II.) the exchange at the TSO-DSO interface is not pre-defined, but instead the result of a market approach to the procurement problem. Among the disadvantages is the increased computational complexity put at the local level, where the market is managed by the DSO. In addition, depending on the overall design and efficiency in the algorithm, the market result could be worse, in terms of global social welfare, when compared to Scheme 2, as the condition of incomplete information is still maintained.

Coordination scheme 6 is a combination of proposals presented in Section 4, including the shared balancing responsibility model from the smart net project [40], and the hierarchical coordination proposal presented in [35]. Moreover, it takes inspiration from the aggregation processes of DER presented in Section 4, as the DSO works towards a supply curve, similar to the results from [31].

7.3 Mathematical and market formulation

Given the coordination Schemes described in the previous Section, their implementation is presented. To start, Table 7-1 summarizes the main characteristics, from a modelling perspective, of each Scheme. The most important information is presented in the last column to the left, where it is indicated if the Scheme can be implemented and simulated with the modelling tools developed in this thesis, which is presented in Sections 0 and 0.

Table 7-1. Summary coordination schemes

Scheme	Coordination procedure	Local Flexibility market	Network Constraint Representation		DER's bids	Implementable
			Transmission	Distribution		
[1]	No	No	Yes	No	Yes	No
[2]	Complete information	No	Yes	Yes	Yes	No
[3]	DSO approves bids' activation	No	Yes	Yes	Yes	Partially
[4]	Known PQ profile at HV/MV interface	Yes	Yes	Yes	Yes	Partially
[5]	Pre-defined PQ profile at HV/MV interface	Yes	Yes	Yes	Yes	Partially
[6]	Aggregated Supply curve from DER	Yes	Yes	Yes	Yes	Partially

To start, it is worth noting that none of the coordination schemes can be fully implemented and tested given the framework developed so far, as it has been built with the main objective of representing constraints and resources at the distribution level. However, Schemes 3 to 6 can be partially implemented, given specially attention to interactions at the distribution level of coordination schemes, markets, bids, and the networks themselves.

Considering the previous assumptions, the mathematical models for the last 4 Schemes are presented and discussed in the following Sections.

7.3.1 Scheme 3

For this scheme, the DSO oversees the verification of the technical feasibility of flexibility bids from DER and their aggregators, previously prioritize by the TSO. In this case, it is assumed that TSO delivers an ordered list to the DSO, so the verification process can be carried out.

The prioritization list could take the form shown in Table 7-2 for each period. In the proposed approach, the TSO assigns to each aggregator that has quantities accepted in the flexibility markets a priority number, the lower the number higher the priority. The DSO then takes the list and modifies the aggregator initial profile in the network to verify technical constraints. This process is repeated, accumulating accepted bids from aggregators with higher priority, for all aggregators with accepted bids, or until network constraints are not satisfied.

Table 7-2. TSO Prioritization list, Coordination Scheme 3

Aggregator	Priority	Accepted quantity in TSO market [kW]
AG_1	3	200
AG_2	1	100
AG_3	N/A	0
AG_4	4	58
AG_5	N/A	0
AG_6	2	300

In the example shown in Table 7-2, the DSO would be responsible for running 4 power flows. The first, accounting only for flexibility selected from aggregator 2 (AG_2). The Second, including accepted quantities from aggregator 2 (AG_2) and 6 (AG_6). The process is repeated until bids from aggregator 4 (AG_4) are integrated in the power flow.

The DSO then would return a similar list to the TSO, with the proposed structure of Table 7-3, with information regarding bids that were activated or not, depending on network constraints. In the example presented in Table 7-3, only bids from aggregator 2 (AG_2) and 6 (AG_6) are completely accepted. Bids from aggregator 1 (AG_1) is only partially accepted, while power from aggregator 4 (AG_4) must be rejected due to network constraints.

Table 7-3. DSO Prioritization list, Coordination Scheme 3

Aggregator	Activation (Yes, No, Partially)	Activated quantity [kW]
AG_1	Partially	100
AG_2	Yes	100
AG_3	N/A	0
AG_4	No	0
AG_5	N/A	0
AG_6	Yes	300

After receiving the activation lists from all relevant DSOs, TSOs would need to rebalance the flexibility market using available resources. Depending on the specific characteristics of the coordination scheme, TSO might require more than one verification process from DSOs, to find a solution to the market as close as possible to the optimal one.

7.3.2 Scheme 4

This Scheme presents local market to procure flexibility services in its most basic form. To start, distribution network constraints are represented in the form of voltage and current operative limits, as shown in Expressions (7-1) and (7-2), where n and m denote nodes and branches from sets N and M, respectively. These constraints are valid for the whole period of analysis.

$$V_n^{min} \leq V_{n,t} \leq V_n^{max} \quad \forall n \in N, \quad \forall t \in T \tag{7-1}$$

$$-I_m^{max} \leq I_{m,t} \leq I_m^{max} \quad \forall m \in M, \quad \forall t \in T \tag{7-2}$$

As was previously mentioned, no explicit TSO-DSO coordination mechanism is implemented in the scheme model. Nonetheless, the TSO knows, before solving the central flexibility market, the active and reactive power profile of the distribution network, represented by $\mathrm{P}_\mathrm{t}^{\mathrm{HV/MV}}$ and $\mathrm{Q}_\mathrm{t}^{\mathrm{HV/MV}}$.

In terms of DER representation and bids, the three groups discussed in Section 5.8 are used: continuous, step bids and ESS owned by DSOs. The notation used to describe them is the same as Section 5.8: in all cases, the sets of aggregators, bids and periods are represented by capital letters J, I and, T, respectively, where individual member of such sets are given by the same lowercase letters. On the other hand, BESS are represented by set B and members b. Moreover, all resources and their bids are directly associated to a node in the distribution networks, characteristic that is discussed in Section 8.

To start with continuous bids, Table 7-4 shows the main variables and parameters used to model continuous bids. Regarding real power, the notation is standard and widely used in the literature. On the other hand, for reactive power management several parameters are used to identify bids according to the resources that is producing them.

Table 7-4. Variables and parameters, Upward and Downward Continuous Bids

Name	Type	Notation	Unit
Prices	Parameter	$\pi_{j,i,t}^{up}, \pi_{j,i,t}^{dw}$	$\left[\frac{\$}{kWh}\right]$
Bid's real power	Variable	$P_{j,i,t}^{up}, P_{j,i,t}^{dw}$	$[kW]$
Total power accepted from aggregator	Variable	$P_{j,t}$	$[kW]$
Bid's maximum real power	Parameter	$P_{j,i,t}^{up-max}, P_{j,i,t}^{dw-max}$	$[kW]$
Aggregator initial total real power profile	Parameter	$Po_{j,t}$	$[kW]$
Aggregator initial total reactive power profile	Parameter	$Qo_{j,t}$	$[kVar]$
Aggregator maximum ramp	Parameter	P_j^{ramp}	$\left[\frac{kW}{h}\right]$
Identifiers for load shifting bids	Parameter	$PS_{j,i}^{up}, PS_{j,i}^{dw}$	N/A
Identifiers for load bids	Parameter	$Load_{j,i}^{up}, Load_{j,i}^{dw}$	N/A
Identifiers for generation bids	Parameter	$Gen_{j,i}^{up}, Gen_{j,i}^{dw}$	N/A
Aggregator initial load and generation profiles	Parameter	$Load_{j,t}^{0}, Gen_{j,t}^{0}$	$[kW]$
Load and generator' power factors	Parameter	$\mathrm{\varphi_j^{Load}}, \mathrm{\varphi_j^{Gen}}$	N/A
Load and generators' reactive power	Variable	$\mathrm{Q_{j,t}^{Load}}, \mathrm{Q_{j,t}^{Gen}}$	$[kVar]$
Aggregators total reactive power	Variable	$\mathrm{Q_{j,t}}$	$[kVar]$
Time interval	Parameter	Δt	$[h]$

In addition to previous variables and parameters, Table 7-5 presents constraints used to model continuous bids. It is worth noting that Alternative 3, where reactive power capabilities from loads and generators are considered independently, is being used, and most of these constraints are in fact implemented to handle reactive power from DER.

Table 7-5. Constraints, Upward and Downward continuous bids[22]

Constraint	Equation	Reference
Power selected	$P_{j,i,t}^{up-max} \geq P_{j,i,t}^{up} \geq 0$ $P_{j,i,t}^{dw-max} \geq P_{j,i,t}^{dw} \geq 0$	(5-8) (5-9)
Total power from aggregator	$P\_Total_{j,t} = \sum_{i=1}^{I} \left(P_{j,i,t}^{up} - P_{j,i,t}^{dw}\right) + PO_{j,t}$	(5-10)
Ramp	$-\frac{P_j^{ramp}}{\Delta t} \leq P\_Total_{j,t+1} - P\_Total_{j,t} \leq \frac{P_j^{ramp}}{\Delta t}$ for $t = 1, 2, \ldots, T-1$	(5-12)
Load shifting	$\sum_{t=1}^{T} \sum_{i=1}^{I} \left(PS_{j,i}^{up} * P_{j,i,t}^{up} - PS_{j,i}^{dw} * P_{j,i,t}^{dw}\right) = 0$	(5-13)
Load power	$P_{j,t}^{Load} = \sum_{i=1}^{I} \left(Load_{j,i}^{up} * P_{j,i,t}^{dw} - Load_{j,i}^{dw} * P_{j,i,t}^{up} + Load_{j,t}^{0}\right)$	(5-16)
Generation power	$P_{j,t}^{Gen} = \sum_{i=1}^{I} \left(Gen_{j,i}^{up} * P_{j,i,t}^{up} - Gen_{j,i}^{dw} * P_{j,i,t}^{dw} + Gen_{j,t}^{0}\right)$	(5-17)
Load reactive power	$-P_{j,t}^{Load} * tan\left(acos\left(\varphi_j^{Load}\right)\right) \leq Q_{j,t}^{Load} \leq P_{j,t}^{Load} * tan\left(acos\left(\varphi_j^{Load}\right)\right)$	(5-18)
Generation reactive power	$-P_{j,t}^{Gen} * tan\left(acos\left(\varphi_j^{Gen}\right)\right) \leq Q_{j,t}^{Gen} \leq P_{j,t}^{Gen} * tan\left(acos\left(\varphi_j^{Gen}\right)\right)$	(5-19)
Aggregator reactive power	$Q_{j,t} = Q_{j,t}^{Load} + Q_{j,t}^{Gen}$	(5-20)

Regarding step bids, Table 7-6 and Table 7-7 present variables, parameters, and constraints This formulation, including binary variables, changes the type of problem that will be analyzed in the market modelling.

Table 7-6. Variables and parameters, Upward and Downward Step Bids

Name	Type	Notation	Unit
Prices	Parameter	$\pi_{j,t}^{up-step}, \pi_{j,t}^{dw-step}$	$\left[\frac{\$}{kWh}\right]$
Bid's real power	Variable	$P_{j,t}^{up-step}, P_{j,t}^{dw-step}$	$[kW]$
Bid's maximum real power	Parameter	$P_{j,t}^{up-step-max}, P_{j,t}^{dw-step-max}$	$[kW]$
Bid's minimum real power	Parameter	$P_{j,t}^{up-step-min}, P_{j,t}^{dw-step-min}$	$[kW]$
Binary activation	Binary Variable	$Y_{j,t}^{up-step}, Y_{j,t}^{dw-step}$	N/A

[22] Column on the left references Equations from Section 5.8, where the bid formulation is discussed.

Table 7-7. Constraints, Upward and Downward step bids

Constraint	Equation	Reference
Maximum power selected	$P_{j,t}^{up-step} \leq P_{j,t}^{up-step-max} * Y_{j,t}^{up-step}$ $P_{j,t}^{dw-step} \leq P_{j,t}^{dw-step-max} * Y_{j,t}^{dw-step}$	(5-23) (5-24)
Minimum power selected	$P_{j,t}^{up-step-min} * Y_{j,t}^{up-step} \leq P_{j,t}^{up-step}$ $P_{j,t}^{dw-step-min} * Y_{j,t}^{dw-step} \leq P_{j,t}^{dw-step}$	(5-23) (5-24)
Simultaneous activation	$Y_{j,t}^{up-step} + Y_{j,t}^{dw-step} \leq 1$	(5-26)

Finally, for ESS owned and operated by the DSO, Table 7-8 and Table 7-9 show used variables, parameters, and constraints. It is worth mentioning that in Section 5.8 a methodology to include BESS is presented, and the model defines a charging price $\pi_{b,t}^{PC}$ that will be later defined in the testing cases. It is also worth noting that the state of charge needs to be represent in an additional period, so the variable $\mathrm{SoC_{b,t}}$ represents the state of charge in period $\mathrm{t}+1$. To keep the notation and the sets consistent in the optimization problem, an additional state of charge equation is included, that represents the initial charge of the ESS, while the final state of charge can be modelled as an equality constraint.

Table 7-8. Variables and parameters, ESS bids

Name	Type	Notation	Unit
State of charge	Variable	$\mathrm{SoC_{b,t}}$	$[kWh]$
Minimum and maximum state of charge	Parameter	$\mathrm{SoC_b^{min}}, \mathrm{SoC_b^{max}}$	$[kWh]$
Initial and final state of charge	Parameter	$\mathrm{SoC_b^{\mathit{ini}}}, \mathrm{SoC_b^{fin}}$	[kWh]
Charge and discharge power	Variable	$PC_{b,t}, PdC_{b,t}$	$[kW]$
Maximum charge and discharge power	Parameter	$\mathrm{P_b^{max}}$	$[kW]$
Charging and discharging efficiency	Parameter	$\eta_{\mathrm{PC}}, \eta_{\mathrm{PdC}}$	[%]
Binary activation for charge and discharge	Binary Variable	$\mathrm{Y_{DoC_{b,t}}}$	N/A
Number of cycles	Variable	$\mathrm{Cycles_b}$	[#]
Charging price	Parameter	$\pi_{b,t}^{PC}$	$\left[\frac{\$}{kWh}\right]$

Table 7-9. Constraints, ESS bids

Constraint	Equation	Reference
State of charge	$\mathrm{SoC_{b,t}} = \dfrac{\eta_{PC} * \mathrm{PC_{b,t}} - \dfrac{\mathrm{PdC_{b,t}}}{\eta_{PdC}}}{\Delta t} + \mathrm{SoC_{b,t-1}}, \quad t = 2, 3, \dots, T$	(5-26)
Initial state of charge	$\mathrm{SoC_{b,1}} = \dfrac{\eta_{PC} * \mathrm{PC_{b,1}} - \dfrac{\mathrm{PdC_{b,1}}}{\eta_{PdC}}}{\Delta t} + \mathrm{SoC}_b^{ini}$	N/A
Final state of charge	$\mathrm{SoC_{b,T}} = \mathrm{SoC_b^{fin}}$	
Minimum and maximum state of charge	$\mathrm{SoC_b^{min}} \leq \mathrm{SoC_{b,t}} \leq \mathrm{SoC_b^{max}}$	(5-27)
Minimum bound charging and discharging power	$\mathrm{PC_{b,t}} \geq 0,\ \mathrm{PdC_{b,t}} \geq 0$	(5-28)
Maximum bound charging and discharging power	$\mathrm{PC_{b,t}} \leq \mathrm{P_b^{max}} * \mathrm{Y_{DoC_{b,t}}}$ $\mathrm{PdC_{b,t}} \leq \mathrm{P_b^{max}} * \left(1 - \mathrm{Y_{DoC_{b,t}}}\right)$	(5-29) (5-30)
Number of cycles	$\mathrm{Cycles_b} = \dfrac{\sum_{t=1}^{T}(\eta_{PC} * \mathrm{PC_{b,t}} + \dfrac{\mathrm{PdC_{b,t}}}{\eta_{PdC}})}{2 * \mathrm{SoC_b^{max}} * \Delta t}$	(5-31)

With the previous network constraints, and bid modelling, the objective function of the problem can be defined. As discussed in Section 4.3.3, for the current framework the minimization of total costs incurred is valid. In addition, in a similar way to proposals for the Italian market reform presented in 3.5, the market modelling does not consider explicitly prices from other market sections. Possible interactions between market sessions, and the strategic behaviors that market players would implement because of regulatory framework, are out of the scope of this thesis.

Considering the previous assumptions, the objective function of the market is divided into three parts, as shown in Expression (7-3) in its schematic form, where **CAC** is the activation cost of continuous bids, **SAC** the activation cost of step bids and **EAC** the activation cost of ESS owned and operated by the DSO. These terms are expanded in Equations (7-4) -(7-6):

$$min\ [CAC + SAC + EAC] \tag{7-3}$$

$$CAC = \left(\sum_{t=1}^{T}\left(\sum_{j=1}^{nAg}\left(\sum_{i=1}^{NbidUp}\frac{\pi_{j,i,t}^{up} * P_{j,i,t}^{up}}{\Delta t} + \sum_{i=1}^{NbidDw}\frac{\pi_{j,i,t}^{dw} P_{j,i,t}^{dw}}{\Delta t}\right)\right)\right) \tag{7-4}$$

$$SAC = \sum_{t=1}^{T}\left(\sum_{j=1}^{nAg}\left(\frac{\pi_{j,t}^{up-step} * P_{j,t}^{up-step}}{\Delta t} + \frac{\pi_{j,t}^{dw-step} * P_{j,t}^{dw-step}}{\Delta t}\right)\right) \tag{7-5}$$

$$EAC = \sum_{t=1}^{T}\left(\sum_{b=1}^{B}\left(\frac{PC_{b,t} * \pi_{b,t}^{PC}}{\Delta t}\right)\right) \tag{7-6}$$

This objective function is proposed in the framework of the minimization of total activation costs in the market. Resources and their bids are activated either to solve internal network constraints, at the distribution level, or to comply with the coordination requirements from the TSO (in other coordination schemes). In the process of activating resources, represented by the three types of bids included in the modelling, the goal should be to minimize the costs incurred by the system, thus the variable is also minimized inside the optimization problem.

Regarding the specific modelling of the coordination Scheme, variables representing the power exchanged at the HV/MV interface, or slack of the distribution network, are calculated: $P_t^{HV/MV}$ $Q_t^{HV/MV}$, both in their load notation. In this case, DSOs oversee only communicating the expected profile to the TSO, where it can be accounted for in a centralized flexibility market.

Summarizing this coordination Scheme, that serves as the basis of the following three, the overall goal is to minimize the activation costs of continuous, step and ESS bids, while respecting basic network constraints, for the complete analysis horizon. It is worth noting that reactive power acts as a free variable in the problem, with no direct opportunity cost attached. The modelling approach selected results in a Mixed Integer Programming formulation.

7.3.3 Scheme 5

Scheme 5 builds over scheme 4 in almost every aspect: network constraints, bid representations and objective function. However, and additional constraints is implemented to represent the TSO-DSO coordination with active and reactive power limits in the HV/MV interface, shown in Expressions (7-7) and (7-8).

$$P_t^{HV/MV-min} \leq P_t^{HV/MV} \leq P_t^{HV/MV-max} \quad \forall t \in T \tag{7-7}$$

$$Q_t^{HV/MV-min} \leq Q_t^{HV/MV} \leq Q_t^{HV/MV-max} \quad \forall t \in T \tag{7-8}$$

$\mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV-max}}$, $\mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV-min}}$, $Q_t^{HV/MV-max}$ and $Q_t^{HV/MV-min}$ are parameters defined by the TSO to control, as needed, the power consumed or injected by a given distribution network, represented by $\mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV}}$ and $\mathrm{Q}_{\mathrm{t}}^{\mathrm{HV/MV}}$ for active and reactive power, respectively.

7.3.4 *Scheme 6*

In Scheme 6, the DSO is responsible for aggregating and sending bids from DER to the TSO. Such interaction could be achieved by a standard supply curve of real power per time step, as shown in Figure 7-8, representing possible and feasible bids at the TSO/DSO interface. Flexibility from DER, as has been presented throughout this thesis, is measured starting from a given *initial profile* and then presented in upward (to sell electricity, from the DSO's perspective) and downward (to buy electricity, from the DSO's perspective) bids.

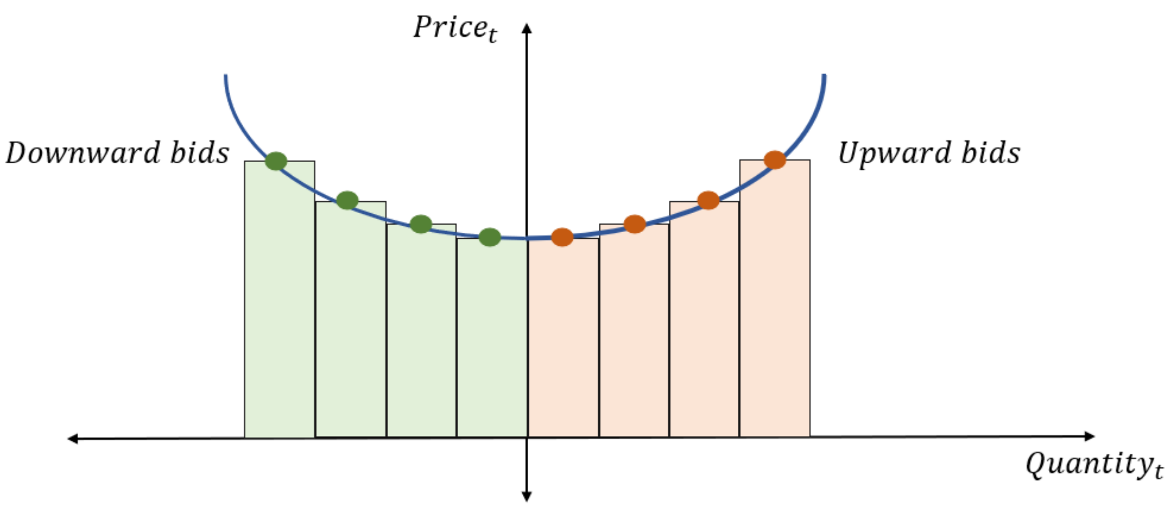

Figure 7-8. Aggregated supply curve for TSO-DSO coordination

It is worth noting that all bids represented in the supply curve must be technically feasible simultaneously, obeying network and DER constraints. As a result, the TSO in other market sections can use these bids, without the risks of needing further re-balancing mechanisms.

In the ideal case, represented by the blue convex line in Figure 7-8, aggregated bids from the distribution network would be continuous in the *Quantity* domain. However, the process to obtain such result could be burdensome and unnecessary, both from economics and computational perspectives. A compromised or middle ground approach would be to obtain step-wise bids using a fixed energy step, similarly to what is presented in [31], shown in the upward (red) and downward (green) bids from Figure 7-8.

In addition to the network constraints, which normally are static through time, the supply curve must also respect DER constraints, that as discussed in Section 5, are time dependent and need to be accounted for. Consequently, individual, and independent calculations could misrepresent the flexibility provided by the distribution network, overestimating it as some constraints might not be included in the procedure.

The proposed methodology presented schematically in Figure 7-9, contains two parts. The first, shown in the left-side panel, is an optimization problem where network and DER constraints remain unaltered, with respect to previous schemes, but the optimization function has been changed to obtain the maximum upward and downward flexibility bids from the distribution network. In the second part, knowing the maximum values, an approximated cost for the intermediate steps is calculated.

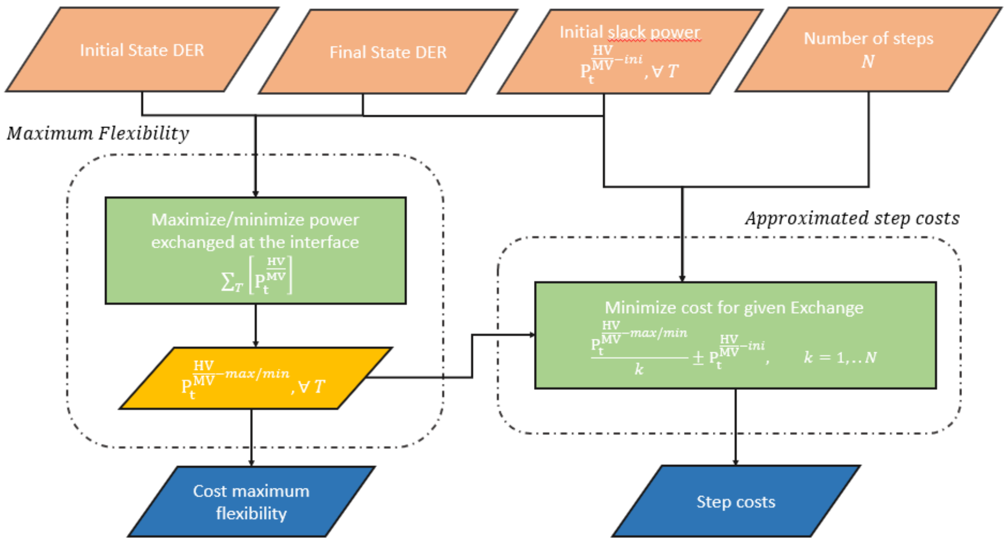

Figure 7-9. Calculation of supply curve for TSO/DSO coordination Scheme 6

Starting from the **Maximum flexibility** side of the algorithm, network and bid constraints remain unaltered, to what has been presented for Scheme 3. However, the objective function shown in (7-3) is no longer minimized, and now serves as a variable in the optimization problem in its time expanded form, as shown in Equations (7-9) - (7-12), where TC_t represents total costs incurred in any given period of the analysis horizon.

$$TC_t = CAC_t + SAC_t + EAC_t \qquad (7\text{-}9)$$

$$CAC_t = \sum_{j=1}^{nAg} \left(\sum_{i=1}^{NbidUp} \frac{\pi_{j,i,t}^{up} * P_{j,i,t}^{up}}{\Delta t} + \sum_{i=1}^{NbidDw} \frac{\pi_{j,i,t}^{dw} * P_{j,i,t}^{dw}}{\Delta t} \right) \qquad (7\text{-}10)$$

$$SAC_t = \sum_{j=1}^{nAg} (\pi_{j,t}^{up-step} * P_{j,t}^{up-step} + \pi_{j,t}^{dw-step} * P_{j,t}^{dw-step}) \qquad (7\text{-}11)$$

$$EAC_t = \sum_{b=1}^{B} \left(\frac{PC_{b,t} * \pi_{b,t}^{PC}}{\Delta t} \right) \qquad (7\text{-}12)$$

Given the goal of finding the maximum/minimum power profile at the HV/MV interface, the objective function presented in Expression (7-13) is proposed. This objective function is used to identify the minimum/maximum power exchanged at the interface between TSO and DSOs networks.

$$min/\,max\left[\sum_{t=1}^{T} P_t^{HV/MV}\right] \tag{7-13}$$

As a result of this formulation, the overall maximum/minimum profile at HV/MV is found, with a cost per period given by TC_t in Equation (7-9). It is worth noting that the activation cost is then simply a resulting variable from the optimization problem and can be calculated later with the system's final state. Thus, after solving the optimization problem the quantity part in the last bid from Figure 7-8 is the value of variable $P_t^{HV/MV*}$, and the price is calculated as the ratio between TC_t^* and $P_t^{HV/MV*}$.

For the **approximated step** part of the algorithm, the same structure as Scheme 5 is used, eliminating constraint (7-8) and turning constraint (7-7) into its equality form, as shown in expression (7-14). For ease of calculation, the objective function to be minimized is taken in its time expanded form, as shown in Equation (7-9).

$$P_t^{HV/MV} = P_t^{HV/MV-temp} \qquad \forall t \in T \tag{7-14}$$

In this case, $P_t^{HV/MV-temp}$ is a parameter used to calculated individual steps for bids, according to the coordination requirements between TSOs and DSOs. Assuming the number of steps required to be $N\_Steps^{TSO/DSO}$, and with equal power assigned to each step, the parameter $P_t^{HV/MV-temp}$ would take values given by the series shown in (7-15), for upward bids and (7-16), for downward bids. In both series, $P0_t^{HV/MV}$ is the initial power profile at the HV/MV interface.

$$P_t^{\frac{HV}{MV}-temp}(s) = \frac{s}{N_{Steps}{}^{\frac{TSO}{DSO}}} * \left(P_t^{\frac{HV}{MV}^*} - P0_t^{\frac{HV}{MV}}\right) + P0_t^{\frac{HV}{MV}} \qquad s = 1, 2, \dots, N\_Steps^{TSO/DSO} \tag{7-15}$$

$$P_t^{\frac{HV}{MV}-temp}(s) = -\frac{s}{N_{Steps}{}^{\frac{TSO}{DSO}}} * \left(-P_t^{\frac{HV}{MV}^*} + P0_t^{\frac{HV}{MV}}\right) + P0_t^{\frac{HV}{MV}} \quad s = 1, 2, \dots, N\_Steps^{TSO/DSO} \tag{7-16}$$

Once an optimal solution is found, the quantity part of the bids is given by the value of $P_t^{\frac{HV}{MV}-temp}$, in the respective iteration, while the price is obtained by the ratio between TC_t^*, the minimized total cost per period, and $P_t^{\frac{HV}{MV}-temp}$. The results of the algorithm would follow the structure shown in Figure 7-10, an example for two steps for upwards and downward aggregated supply curves that the DSO would submit to the TSO.

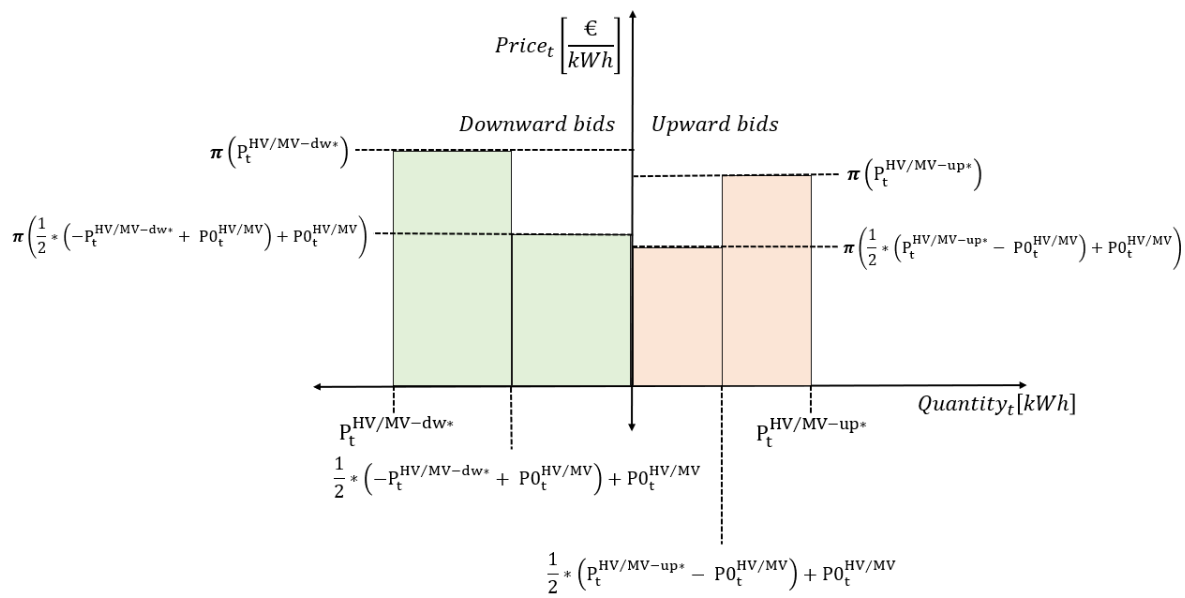

Figure 7-10. Expected results of aggregated supply algorithm[23]

[23] In the Figure, $\pi(Q)$ refers to the Price at quantity Q, calculated by the algorithm using the methodology presented.

8 Iterative optimization algorithm

In the previous Section, the market models for several TSO/DSO coordination Schemes were described using the structure shown in Figure 7-1. The formulation is general and can be used in any framework that allows the electrical representation of distribution networks. The minimal requirements for such model would be to represent: I.) nodal voltages, II.) branch current magnitudes and III.) real and reactive power exchanges at the HV/MV interface.

Section 5 presents a literature revision of several methods to represent distribution networks, with the previous requirements in mind. Due to the possibility of representing all network elements in the power flow and the prospect of reducing approximation error by recalculating the operating point of the system, all while maintaining a linear formulation, the first order linearization method presented in [76] was shown to be the most advantageous for this thesis framework.

To represent the distribution network using the linearization approach inside the optimization problem, Equation (6-45) for voltage magnitude, (6-57) for current magnitudes at branches, and Equations (6-62) and (6-63) for real and reactive power exchanges at the slack buss are slightly modified to accommodate bids selected in the market algorithm. These expressions are summarized in Table 8-1, including now the appropriate subscripts and sets for time, nodes and branches introduced in Section 7.3. Sensitivity matrices are calculated using vectors Po_net_t and Qo_net_t, representing real and reactive power injection profiles for all nodes in period t, and $\mathrm{V}_{\mathrm{slack,t}}$, the known and fixed voltage level at the slack.

Table 8-1. Network equations, linearization approach

Equation	Reference in Section 6	New reference
$\mathrm{V}_{\mathrm{n,t}} \approx \mathrm{Vo}_{\mathrm{n,t}} + \frac{\partial V_{n,t}}{\partial P}\Delta P_t + \frac{\partial V_{n,t}}{\partial Q}\Delta Q_t$	(6-45)	(8-1)
$I_{m,t} \approx Io_{m,\mathrm{t}} + \frac{\partial I_{m,\mathrm{t}}}{\partial P}\Delta P_t + \frac{dI_{m,\mathrm{t}}}{dQ}\Delta Q_t$	(6-57)	(8-2)
$\mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV}} \approx \mathrm{Po}_{\mathrm{t}}^{\mathrm{HV/MV}} + \frac{\partial \mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV}}}{\partial P}\Delta P_t + \frac{\partial \mathrm{P}_{\mathrm{t}}^{\mathrm{HV/MV}}}{\partial Q}\Delta Q_t$	(6-62)	(8-3)
$Q_{\mathrm{t}}^{\mathrm{HV/MV}} \approx Q\mathrm{o}_{\mathrm{t}}^{\mathrm{HV/MV}} + \frac{\partial Q_{\mathrm{t}}^{\mathrm{HV/MV}}}{\partial P}\Delta P_t + \frac{\partial Q_{\mathrm{t}}^{\mathrm{HV/MV}}}{\partial Q}\Delta Q_t$	(6-63)	(8-4)

To start, it is worth noting that the vectors ΔP_t and ΔQ_t, have dimension equal to the number of nodes, N, and represent the power changes in generation notation that occurred in the network, measured from the state in which the linearization was carried out. As a result, it is necessary to relate selected bids from DER in the market algorithm, located in specific nodes throughout the network, to the variation vectors used to approximated voltages, currents, and slack powers.

With this purpose, the indexation matrices Im_Ag and Im_B are created, for bids coming from aggregators and the ESS owned by the DSO, respectively. These matrices, with dimensions $[\mathrm{nA}g, N]$ and $[B, N]$, have rows in which all elements equal to zero, except in columns where the DER is located. Expression (8-5) shows an example of matrix Im_Ag for a system with $N = 4$ and $\mathrm{nA}g = 2$, where aggregators are in busses 2 and 3.

$$Im_{Ag} = \begin{bmatrix} 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \end{bmatrix} \tag{8-5}$$

Given the locational signal, terms ΔP_t and ΔQ_t in Equations (8-1) - (8-4) can be adjusted with power selected in the market algorithm. Considering the notation defined in Section 7.3, and the three types of bids implemented, matrix expressions (8-6) and (8-7) show the complete definition of real and reactive power variations. Power quantities are converted to per units before including them into the linearization Equations using the base parameter.

$$\Delta P_t = \frac{\left[Im_{Ag} * P_{j,t} + Im_{Ag} * \left(P_{j,t}^{up-step} - P_{j,t}^{dw-step}\right) + Im_B * \left(PdC_{b,t} - PC_{b,t}\right)\right]}{base} \tag{8-6}$$

$$\Delta Q_t = \frac{Im_{Ag} * (Q_{j,t} - Qo_{j,t})}{base} \tag{8-7}$$

Considering the coupling between expressions (8-1) - (8-4) , (8-6) and (8-7) any of the coordination schemes can be implemented. However, as it is shown in Section 6, the approximation error in the linearization approach when modelling the distribution network rises as the nominal magnitude of ΔP_t and ΔQ_t increases. For this reason, an iterative methodology is implemented to better approximate the network, thus contribution to finding a solution that is the closest possible to the global optimal point.

It is worth noting that in a solution method that follows the principle of an approximation, more so a first order linearization, the trade-off between the representation error of the distribution network, and the value of the objective function, must be analyzed. Generally, solutions from the optimization should be accepted if and only if the representation of the network is accurate. In other words, an operating condition with low total costs, but high approximation error, should be neglected.

The driving idea behind the iterative method presented in this Section is to approximate the solution as power is being selected from the bids, repeating the linearization process in each iteration. Consequently, the method's goal is to arrive to operating conditions with relatively low approximation error. Once the approximation error in the network is low, the total cost incurred in the coordination scheme is a valid figure of merit.

The proposed algorithm to iteratively solve the optimization problem is shown schematically in Figure 8-1. Starting from **(1),** the initial system state is defined. In practical terms, the system would be defined by the network topology, physical characteristics in electric elements (ampacity and impedance for lines, maximum and minimum node voltages, etc.) and real and reactive power injections at all nodes. In step **(2),** the sensitivity matrix necessary for Equations (8-1) - (8-4) are calculated. As explained in Section 5, these matrices are based on a convergent power flow, calculated using an AC algorithm in MATLAB that employs both Gauss and Newton-Raphson solution methods. In case the power flow diverges, the system cannot be analyzed, and thus the iterative algorithm stops. Following to step **(3),** the optimization problem for the coordination scheme being studied is solved, using the CPLEX solver in GAMS. As before, if the resulting problem is unfeasible, the iterative algorithm stops. In the opposite case, values of selected bids and the objective function are stored. In step **(4)** the convergence condition of the algorithm is evaluated with a stopping criterion based on approximation errors for relevant network variables and the objective function's value. If the algorithm has converged, the final system state is stored, otherwise the process continues. Step **(5)** serves to check if a maximum number of iterations has been reached, and thus the algorithm stops, and the partial solution is stored. If the maximum number of iterations has not been reached, in step **(6)** two procedures are carried out to update the system's conditions for the new iteration. First, bids and the objective problem are adjusted, according to selected values in the previous iteration. Second, the network power profiles are updated, using again the information from bids selected in the optimization problem. The algorithm then returns to the loop in step **(2),** where sensitivity matrices are recalculated using the new information.

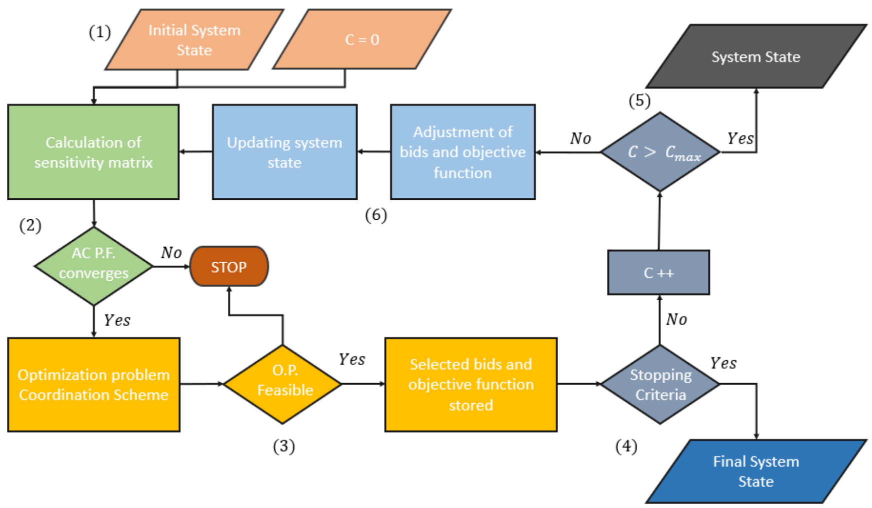

Figure 8-1. Iterative optimization algorithm

In the following subsections, important parts of steps **(3)**, **(4)** and **(6)** are discussed, considering that the other steps have either been presented earlier, or do not require further explanation to the one provided while describing Figure 8-1.

8.1 Step (3): Optimization algorithm and bid selection

Section 7.3 presented the mathematical formulation for four coordination schemes, three of which require the solution of a mixed-integer linear optimization problem (MILP). To address this task, the optimization problem is implemented in GAMS language, and solved using the commercial version of CPLEX.

After solving the optimization problem, the variation power profiles for all periods shown in (8-6) and (8-7) are obtained. As presented, these vector aggregate selected bids from continuous bids, step bids, charge, and discharge powers from ESS. In addition, the value of the objective function is obtained from the respective expression, that depends on the coordination scheme. For later steps, values of these variables are stored with the index c, keeping track of the current iteration: $\Delta P_{t,c}$, $\Delta Q_{t,c}$ and $OF_{t,c}$, where the last generic variable represents the value of the objective function depending on the coordination scheme.

8.2 Step (4): Stopping criterion

Given that the algorithm is based on a network approximation, it would be useful to save computing resources to include a stopping criterion. Moreover, the criterion would also serve to identify, or flag, which results from the algorithm can be trusted, and which cannot be due to numerical issues.

To formulate an appropriate stopping criterion, two approaches are taken. The first, from a network perspective, is based on the analysis presented in Section 6.2 where it was identified that, for the linear sensitivity method for distribution network approximation, current in branches was the least accurate variable of interest. According to this, as a figure of merit to evaluate the performance of the network approximation, the indicator $\mathrm{M.R.E.I.r}$, representing the maximum relative error for relevant lines, shown in Equation (6-80) is selected.

Two parameters are then needed to evaluate the network's figure of merit. First, a threshold to select relevant lines, for which normally 50% of loading is assumed because these are lines that could surpass their maximum level in the optimization problem, thus being critical for the iterative method. This value should be selected to, at least, have a relevant line. The second, a minimum level for accepting the $\mathrm{M.R.E.I.r}$ indicator, referred from now as $\mathrm{M.R.E.I.r}^{MIN}$. For this, a value between 0.5 and 1% would be acceptable, as for a line with 100 A current the maximum allowed error would be around 0.5 and 1 A, sufficiently low. It is worth noting that to check this condition, a power flow computation is necessary for each period, which might slow down the algorithm if it is repeated for every iteration.

From the market side, a measure of how the total cost of the market is changing is needed. In this context, two cases arise. First, if the market cost is zero, and no changes are observed between iterations, as it would occur in a solution where only reactive resources are being used, the only figure of merit would be the network representation discussed before. When the objective function has a value different than zero, a figure of merit due to cost variation can be considered. For this, the relative cost change between iterations is calculated, and then compared with the minimum threshold $\Delta\mathrm{OF}.R.^{MIN}$ according to Expression (8-10). In this case, a value for $\Delta\mathrm{OF}.R.^{MIN}$ lower than 0.05% would be more than sufficient.

$$\left[\frac{\Delta OF_{t,c}}{OF_{t,c}}\right] \leq \Delta OF.R.^{MIN} \tag{8-8}$$

Summarizing the stopping criterion, the algorithm would be stopped, $\mathrm{STOP} = 1$, when the conditions presented in Expression (8-11). Otherwise, it would run until a given number of iterations are reached, as indicated in Step **(5)** from Figure 8-1 . This condition could be verify in more than one consecutive iteration, to ratify convergence conditions.

$$STOP = \begin{cases} OF_{t,c} > 0, & \left\{\dfrac{\Delta OF_{t,c}}{OF_{t,c}} \leq \Delta OF.R.^{MIN}\right\} \wedge \{M.R.E.I.r^{MIN} < M.R.E.I.r\} \\ OF_{t,c} = 0, & M.R.E.I.r^{MIN} < M.R.E.I.r \end{cases} \tag{8-9}$$

8.3 Step (6): Updating system state

Two interchangeable procedures are necessary to update system conditions before a new iteration of the algorithm. The first process consists of updating the power profiles for the recalculation of sensitivity matrices used in Equations (8-1) - (8-4). For this context, the initial power profiles and the objective function value are updated, according to expressions (8-10) - (8-12). After updating the power profile, sensitivity matrices and the initial condition of voltages, currents and power can be recalculated using the new operating condition.

$$Po\_net_{t,c+1} = Po\_net_{t,c} + \Delta P_{t,c} \tag{8-10}$$

$$Qo\_net_{t,c+1} = Qo\_net_{t,c+1} + \Delta Q_{t,c} \tag{8-11}$$

$$OF_{t,c+1} = OF_{t,c} + \Delta OF_{t,c} \tag{8-12}$$

The next step consists in integrating bids selected in the last iteration before solving the new optimization problem and accounting that power changes have been accounted in the sensitivity matrices. In this part, a different but equivalent approach is taken for continuous bids, on the one hand, and step and ESS, on the other.

Starting with **continuous bids**, new auxiliary variables are created to represent bids that have been selected in the previous iteration of the algorithm. Variables and parameters used to define the auxiliary bids are shown in Table 8-2. Power selected from auxiliary bids are constraint by expressions presented in Table 8-3 In both cases, variables are denoted with the index c, corresponding to the respective iteration inside the solution algorithm, with the same indexation given to standard variables. In the first iteration, c = 0, parameters P_aux^{up-max} and P_aux^{dw-max} are equal to zero.

Table 8-2. Variables and Parameters, Auxiliary continuous bids

Name	Type	Notation	Unit
Prices	Parameter	$\pi\_aux_{j,i,t}^{up}$, $\pi\_aux_{j,i,t}^{dw}$	$\left[\frac{\$}{kWh}\right]$
Bid's real power	Variable	$P\_aux_{j,i,t,c}^{up}$, $P\_aux_{j,i,t,c}^{dw}$	$[kW]$
Bid's maximum real power	Parameter	$P\_aux_{j,i,t,c}^{up-max}$, $P\_aux_{j,i,t,c}^{dw-max}$	$[kW]$

Table 8-3. Constraints, Auxiliary continuous bids

Constraint	Equation
Power selected	$P\_aux_{j,i,t,c}^{up-max} \geq P\_aux_{j,i,t,c}^{up} \geq 0$ $P\_aux_{j,i,t,c}^{dw-max} \geq P\_aux_{j,i,t,c}^{dw} \geq 0$

To relate the standard and auxiliary continuous bids between iterations, the following expressions are implemented. To start, in Expression (8-13) the price condition prices from auxiliary bids are defined to be the opposite of their standard counterparts, meaning that their activation would reduce system costs:

$$\pi\_aux_{j,i,t}^{up} = -\pi_{j,i,t}^{up}, \qquad \pi\_aux_{j,i,t}^{dw} = -\pi_{j,i,t}^{dw} \tag{8-13}$$

Second, the maximum power parameter from both standard and auxiliary bids are updated according to Expressions (8-14) and (8-15), for upward bids, and (8-16) and (8-17), for downward bids. The main idea behind these expressions to assign the power that has been selected from a standard bid to the auxiliary variable, so the algorithm can go backwards in terms of power selected after the sensitivity matrices have been recalculated:

$$P_{j,i,t,c+1}^{up-max} = P_{j,i,t,c}^{up-max} - \left(P_{j,i,t,c}^{up} - Paux_{j,i,t,c}^{up}\right) \tag{8-14}$$

$$P\_aux_{j,i,t,c+1}^{up-max} = P_{j,i,t,c}^{up-max} - \left[P_{j,i,t,c}^{up-max} - \left(P_{j,i,t,c}^{up} - Paux_{j,i,t,c}^{up}\right)\right] \tag{8-15}$$

$$P_{j,i,t,c+1}^{dw-max} = P_{j,i,t,c}^{dw-max} - \left(P_{j,i,t,c}^{dw} - Paux_{j,i,t,c}^{dw}\right) \tag{8-16}$$

$$P\_aux_{j,i,t,c+1}^{dw-max} = P_{j,i,t,c}^{dw-max} - \left[P_{j,i,t,c}^{dw-max} - \left(P_{j,i,t,c}^{dw} - Paux_{j,i,t,c}^{dw}\right)\right] \tag{8-17}$$

A numerical example for a single upward bid, denoted as $\mathrm{P_c^{up}}$, is demonstrated in Table 8-4. On the first column, iterations are shown. Prices, in the second column, are constant in all iterations. In the third column, parameters defining maximum power that can be selected for the standard and auxiliary bids are shown. In the last column, values of variables after the supposed solution of the optimization problem are presented. In the first iteration, 6 units of the standard bid are selected, while none from the auxiliary variable, that has not been initialized yet. In the second iteration, maximum power parameters are updated according to expression (8-14) and (8-15). In this new optimization problem, 2 units in the standard bid are selected, and none from the auxiliary bid, even when it was possible to use it to reduce total costs of the optimization problem. For iteration 3, power is only selected from the standard bid, meaning that the optimization problem, and the network linearization, go in the opposite direction to the two previous iterations. In the last iteration, no power is selected from any of the bids. It is worth noting that the optimization will always select either the standard or the auxiliary bids, due to their completely opposite effect in the optimization problem.

Table 8-4. Numerical example, Auxiliary continuous bids

Iteration	Prices	Parameters	Variables (after optimization)
[1]	$\pi^{up} = 100$ $\pi\_aux^{up} = -100$	$P_1^{up-max} = 10, P\_aux_1^{up-max} = 0$	$P_1^{up} = 6, P\_aux_1^{up} = 0$
[2]		$P_2^{up-max} = 4, P_{aux_2}^{up-max} = 6$	$P_2^{up} = 2, P\_aux_2^{up} = 0$
[3]		$P_3^{up-max} = 2, P_{aux_3}^{up-max} = 8$	$P_3^{up} = 0, P\_aux_3^{up} = 1$
[4]		$P_4^{up-max} = 3, P_{aux_4}^{up-max} = 7$	$P_3^{up} = 0, P\_aux_3^{up} = 0$

Finally, the last step is to correct Expressions and constraints from Table 7-5, accounting for the presence of auxiliary variables. In each iteration, the total value selected from a given continuous bid, denoted in Table 7-5 by either $P_{j,i,t}^{up}$ or $P_{j,i,t}^{dw}$, is now the subtraction of the respective standard and auxiliary variables, as shown in (8-18) and (8-19).

$$P_{j,i,t}^{up} = P_{j,i,t,c}^{up} - P\_aux_{j,i,t,c}^{up} \tag{8-18}$$

$$P_{j,i,t}^{dw} = P_{j,i,t,c}^{dw} - P\_aux_{j,i,t,c}^{dw} \tag{8-19}$$

For **step and ESS variables**, it is worth noting that they might respond to stepwise changes between iterations, due to the nature of their modelling. As a result, a different approach for integrating selected bids from these two types is necessary. To start, initial quantities for step bid quantities, and charging and discharging powers of the ESS. These parameters are all equal to zero in the algorithm first iteration. Moreover, variation auxiliary variables are also formulated to model changes in these bids between iteration. Auxiliary variables and parameters are defined according to Table 8-5.

Table 8-5. Auxiliary variables and parameters, steps and ESS bids

Name	Type	Notation
Step Bid's initial power	Parameter	$Po_{j,t}^{up-step}, Po_{j,t}^{dw-step}$
Step Bid's power variation	Variable	$\Delta P_{j,t}^{up-step}, \Delta P_{j,t}^{dw-step}$
Charge and discharge initial power	Parameter	$PCo_{b,t}, PdCo_{b,t}$
Charge and discharge power variation	Variable	$\Delta PC_{b,t}, \Delta PdCo_{b,t}$

Given the previous auxiliary variables and parameters, Equations (8-20) - (8-23) are proposed to account for possible variations that might occurred between iterations. All constraints shown in Table 7-7, for step bids, and Table 7-9, for ESS, still apply to the original variables, shown in the left hand-side of the Equations.

$$P_{j,t}^{up-step} = Po_{j,t}^{up-step} + \Delta P_{j,t}^{up-step} \quad (8\text{-}20)$$

$$P_{j,t}^{dw-step} = Po_{j,t}^{dw-step} + \Delta P_{j,t}^{dw-step} \quad (8\text{-}21)$$

$$PC_{b,t} = PCo_{b,t} + \Delta PCo_{b,t} \quad (8\text{-}22)$$

$$PdC_{b,t} = PdCo_{b,t} + \Delta PdCo_{b,t} \quad (8\text{-}23)$$

The main difference with respect to the approach used to model continuous bids is that in this case, no addition variables with opposite prices are created. As a result, the objective function of the problem must be partially modified. Specifically, terms *SAC* and *EAC* from expression (7-3), as an example for coordination Scheme 3, are modified to replace original variables, with their variation counterparts, as shown in the following.

$$SAC = \sum_{t=1}^{T}\left(\sum_{j=1}^{nAg}\left(\frac{\pi_{j,t}^{up-step} * \Delta P_{j,t}^{up-step}}{\Delta t} + \frac{\pi_{j,t}^{dw-step} * \Delta P_{j,t}^{dw-step}}{\Delta t}\right)\right) \quad (8\text{-}24)$$

$$EAC = \sum_{t=1}^{T}\left(\sum_{b=1}^{B}\left(\frac{\Delta PCo_{b,t} * \pi_{b,t}^{PC}}{\Delta t}\right)\right) \quad (8\text{-}25)$$

In the first iteration of the iterative procedure, when auxiliary initial parameters are equal to zero, the behavior of the optimization problem would be the same as the ones previously presented in 7.3. However, in following iterations, when bids have been selected the algorithm would try to vary the variation variables to minimize total costs, while respecting network constraints. Achieving this goal might require to completely go back on bids previously selected, which is allowed in the proposed formulation.

8.4 Numerical convergence issues

During the development of this thesis, numerical problems were found during testing of the iterative process used to approximate the solutions. As mentioned in previous Sections, the approximation error depends on how close the operation condition is to the final solution of the optimization problem. Variations or oscillations between operating conditions with similar costs, or figures of merit, would not be ideal in other solution approaches. However, in the framework develop in this thesis, they could be especially harmful due to the network model that was selected, and the resulting recalculations and differences that might emerge in sensitivity matrices.

To mitigate numerical problems that might arise, the following Sections present approaches that have been implemented and tested to reduce this problematic. The analysis carried out in this thesis is not complete and is mainly based on the results found during testing. This topic deserves further attention and deeper study in future works. While Sections 8.4.1 and 8.4.2 attempt to mitigate numerical problems directly, considerations presented in Section 8.4.3 address them indirectly, by reducing the size of the optimization problem that needs to be solved.

8.4.1 Reactive power management

The first problem that is found in the iterative process is the management of reactive power. In the context of the market formulation of coordination Schemes presented in Section 7.3 that no price is associated to reactive power from DER, even though it can have a real effect on solving network constraints and reducing total costs incurred. The result is that reactive power could behave as a free variable and change between iterations of the algorithm. This behavior emerged during testing and needed to be addressed.

To manage reactive power, the first modelling approach was to associate to a small cost that would discourage its variations between iterations. However, because reactive power can take both positive and negative power in the formulation, depending on aggregators acting as a capacitive or inductive resource, a simple cost cannot be implemented. Instead, the first step is to bound reactive power variations, shown in Equations (8-7) and (8-11) by a positive variable $\Delta Q_{j,t}^{bound}$, according to Expression (8-26), where $Q_{j,t}$ and $Qo_{j,t}$ are the reactive power from DER in consecutive iterations.

$$-\Delta Q_{j,t}^{bound} \leq \left(Q_{j,t} - Qo_{j,t}\right) \leq \Delta Q_{j,t}^{bound} \qquad (8\text{-}26)$$

Once the bound is imposed to reactive power variations, a cost is associated directly to the limit, as shown in Equation (8-27), to be later included in the objective function. For the formulation to work, the reactive power cost πQC_j should be sufficiently low to not affect the selection of other real power bids, as reactive power flexibility should be prioritized. After each iteration, reactive power cost is removed from the objective function, to avoid double counting between iterations.

$$QC = \sum_{t=1}^{T}\left(\sum_{j=1}^{nAg}\left(\frac{\Delta Q_{j,t}^{bound} * \pi QC_j}{\Delta t}\right)\right) \qquad (8\text{-}27)$$

The result of this formulation is to reduce the incentive that the solver might find to freely move reactive power between iterations.

$$0 \leq \Delta Q_{j,t}^{bound} \leq \Delta Q_{j,t}^{max} \tag{8-28}$$

8.4.2 ESS management

In a similar way to reactive power, charging and discharging variables could behave as free variables in the optimization problem. The additional degrees of freedom might emerge from: I.) the no-cost assumption for the discharging of the battery, II.) similar charging prices between periods, and III.) periods with similar characteristics to charge and discharge.

To mitigate this problematic, bound variables are associated to both charging and discharging power variations, as shown in Expressions (8-29) and (8-30). In the same way as reactive power, a cost is associated to the bounds and the additional term presented in Equation (8-31) is included in the objective function of the problem.

$$-\Delta PCo_{b,t}^{bound} \leq \Delta PCo_{b,t} \leq \Delta PCo_{b,t}^{bound} \tag{8-29}$$

$$-\Delta PdCo_{b,t}^{bound} \leq \Delta PdCo_{b,t} \leq \Delta PdCo_{b,t}^{bound} \tag{8-30}$$

$$CB = \sum_{t=1}^{T} \left(\sum_{b=1}^{B} \left(\frac{\Delta PCo_{b,t}^{bound} * \pi_{b,t}^{PC-bound}}{\Delta t} + \frac{\Delta PdCo_{b,t}^{bound} * \pi_{b,t}^{PdC-bound}}{\Delta t} \right) \right) \tag{8-31}$$

To not affect the selection of DER and their bids, prices for the bounds $\pi_{b,t}^{PC-bound}$ and $\pi_{b,t}^{PdC-bound}$ should be sufficiently low. Moreover, the CB term is removed in each iteration from the final value of the objective function, to avoid double counting between iterations.

8.4.3 Modelling relevant constraints

In addition to the previous filtering of the sensitivities, it is also possible to remove voltage and current constraints from the formulation altogether when their values are not expected to overcome their physical limits. A criterion could be defined by comparing the initial values of the variable of interests to a given threshold, which allows to only include relevant constraints. For example, current constraints are modelled when branches have an initial loading higher than 25-50%. As with the filtering of sensitivity matrices, this verification process should be repeated for each period and iteration.

9 Simulation results

In this Section, simulation results for the algorithms discussed thus far are presented. First, results for a proof-of-concept model are presented, while more realistic cases are shown later. Results are obtained and discussed considering two main aspects: I.) impacts of the coordination schemes, from and electrical and economic standpoint, and II.) the numerical and computational performance of the algorithms.

Regarding the first type of results, it is worth noting that the simulation framework developed, as explained in Section 7, is insufficient to fully understand the behavior of market agents in the different coordination schemes. Thus, bids presented to the market, and the equilibrium results obtained, are merely based on assumptions, and would not represent a complete result from and economic perspective. Annex 12.4 discusses some of the assumptions used to create the testing systems.

Concerning the second type of results, as discussed in Section 8 the simulation framework is based on an approximated network model. Although measures are taken to get a better and better network representation, numerical problems might emerge during testing. When they do appear, they are presented and dully discussed. Nonetheless, as demonstrated in Section 6, the linear approximation being used provides a better network representation compared to other methods, even before the improvement algorithm presented in Section 8 is applied, ensuring the quality of results presented. Moreover, to represent the computational complexity of the problem, the computing time parameter resulting from GAMS, and the total number of iterations for the model, are used[24].

9.1 Proof-of-concept model

The proof-of-concept model is based on the 14-bus network used in Section 6.2 to compare power flow algorithms, with the branch topology and electrical characteristics of shown in Table 12-1, however, load and generation profiles of resources that participate and do not participate in the flexibility market are modified, with respect to load and generation information presented in Table 12-2 and Table 12-3. To test the time-related constraints and functionalities, the model presents a network operating for 12 consecutive periods. Each period is assumed equivalent to 2 operation hours, meaning the parameter Δt introduced in Section

[24] All tests are carried out using GAMS build 38380/38394, the commercial version of the CPLEX solver, MATLAB R2019b, in a personal computer with the following characteristics: processor Intel Core i7-8550U, and 16 GB of RAM.

7.3 is equal to 0.5 to emulate 24-hour operation. In all tested cases, the price set for the reactive power bound, πQC_j, is set to 100 times lower than the minimum price offered by the respective aggregator. Lastly, no filtering of constraints is carried out.

To start, load resources that do not participate in the flexibility market are presented in Table 9-1. Two types of loads are used: type 1, a load that ranges between 25 and 100% of its nominal value, and type 2, a constant load, as shown in Table 9-2. For each node, a given power factor is assumed. As it can be seen, initial load power is evenly distributed across the network. The result of the previous assumptions is the cumulative load profile, in load notation, shown in Figure 9-1. No base generation is assumed in the network.

Table 9-1. Base load, proof-of-concept model

Node	**Load type**	**Nominal power [kW]**	**Power factor**
1	0	0	0
2	1	350	0.95
3	1	350	0
4	2	350	0.95
5	2	350	0
6	1	350	0.95
7	1	350	0
8	2	350	0.95
9	2	350	0
10	1	350	0.95
11	1	350	0
12	2	350	0.95
13	2	350	0
14	1	350	0.95

Table 9-2. Load profiles, proof-of-concept model

Period	Type 1 [%]	Type 2 [%]
1	0.25	1
2	0.5	1
3	0.75	1
4	1	1
5	0.75	1
6	0.25	1
7	0.25	1
8	0.75	1
9	1	1
10	0.75	1
11	0.5	1
12	0.25	1

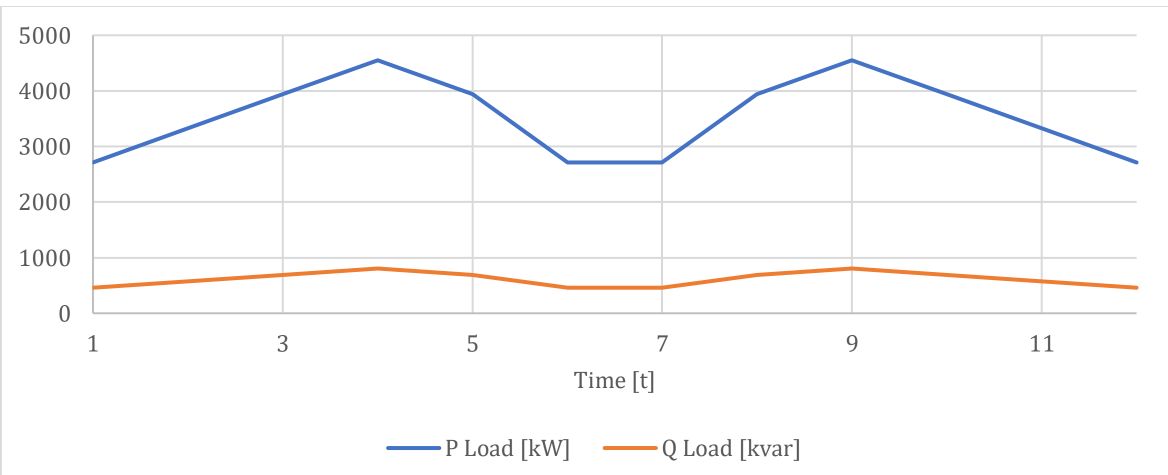

Figure 9-1. Cumulative load profile, proof-of-concept model

For the flexibility markets, seven aggregators, with equivalent resources and behavior, are modelled. Their main characteristics are summarized in Table 9-3. In this case, aggregators have both load and generation assets. For generation resources, a profile that has some resemblance to photovoltaic power output during the days is used, as presented in Table 9-4. Considering the information presented, the cumulative initial profile for all aggregators, in generation notation, is shown in Figure 9-2.

Table 9-3. Aggregator information, proof-of-concept model

Aggregator	Node	Load type	Nominal load power [kW]	Load Power Factor	Nominal PV power [kW]	PV Power Factor
AG (2)	2	2	200	0.9	300	0.9
AG (5)	5	2	200	0.9	300	0.9
AG (7)	7	2	200	0.9	300	0.9
AG (9)	9	2	200	0.9	300	0.9
AG (11)	11	2	200	0.9	300	0.9
AG (12)	12	2	200	0.9	300	0.9
AG (14)	14	2	200	0.9	300	0.9

Table 9-4. Solar profile, proof-of-concept model

Periods	[%]
1	0
2	0.2
3	0.4
4	0.6
5	0.8
6	1
7	1
8	0.8
9	0.6
10	0.4
11	0.2
12	0

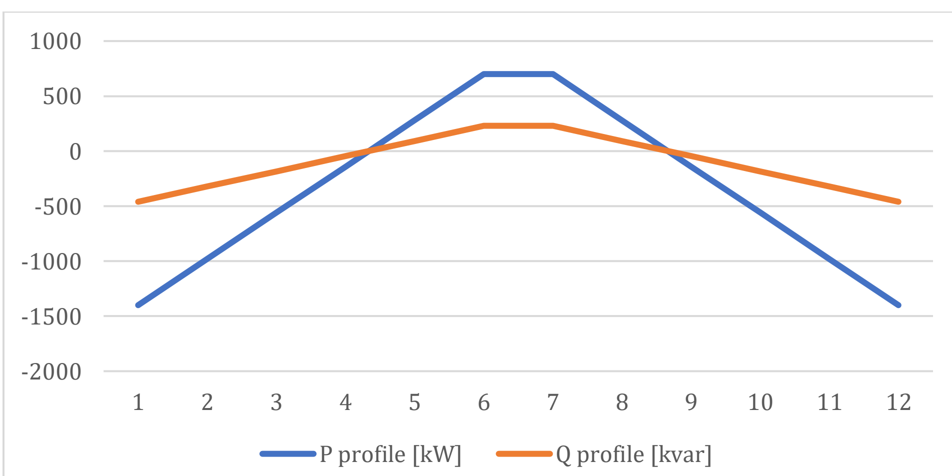

Figure 9-2. Cumulative aggregators profile, proof-of-concept model

The electrical results of including in the network both the initial load profile, and the aggregators profile, is summarized in Figure 9-3, where active network constraints for every testing period are shown. As it can be seen, two current constraints are active for periods 1-5 and 8-12 (no bars are shown for other variables because only current constraints are active).

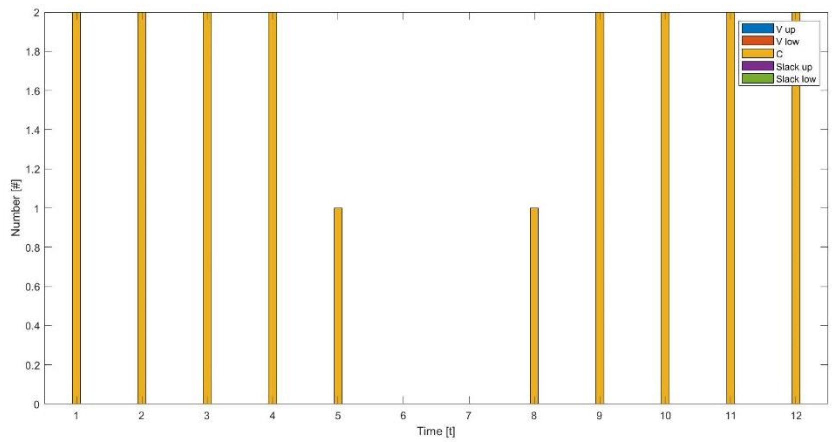

Figure 9-3. Active network constraints, proof-of-concept model

The two active network constraints are highlighted in red circles in the diagram of Figure 9-4. As a result of their location, it would be expected that aggregators not located in feeder one in the diagram would not be activated if the only objective of the coordination scheme is to solve local network constraints.

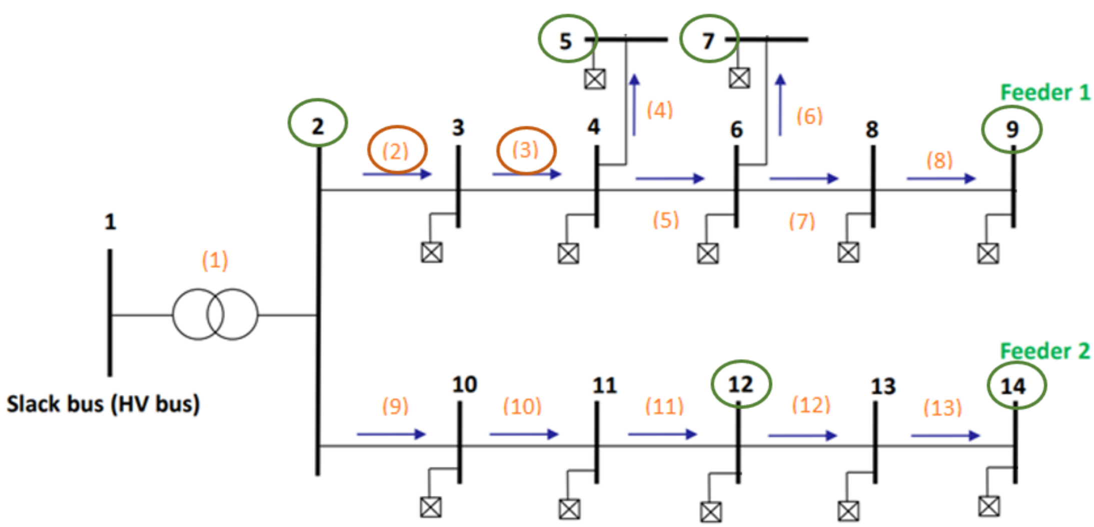

Figure 9-4. Active branches constraints (red) and aggregators' location (green), proof-of-concept model

Once the initial condition of the network is defined, the market information is presented. For the aggregators' continuous bids, the logic presented in Appendix 12.4 is used, summarized as follows:

- Generation/load resources can provide one upward flexibility step, corresponding to an increment in their generation/consumption;
- Generation/load resources can provide two downward flexibility steps. The first, corresponds to a decrement in their generation/consumption. The second, represents their almost complete disconnection from the system;
- The first upward and downward flexibility steps from load resources are subject to load shifting constraints, as described in Table 7-5;
- Bid prices are defined as percentages from the previous market section price, shown in Table 9-5. As it has been explained before, bids represent only the cost of flexibility over the initial power profile, while energy is remunerated at a different price, that could come from a previous market section;

Table 9-5. Previous market section price, proof-of-concept model

Period	Price [$/kWh]
1	0.07
2	0.065
3	0.06
4	0.055
5	0.05
6	0.045
7	0.045
8	0.05
9	0.055
10	0.06
11	0.065
12	0.07

Considering the previous assumptions and information, the continuous bids are defined. Examples of continuous upward and downward bids are presented in Table 9-6 and Table 9-7. The cumulative maximum flexibility of aggregators in the network is shown in Figure 9-5, in generation notation. As it can be seen, the flexibility follows closely initial profile shown in Figure 9-2. It is worth noting that aggregators can also provide their reactive power flexibility to the network, represented in by the maximum power factors for both generators and loads shown in Table 9-3.

Table 9-6. Continuous upward bids for periods 2-3, proof-of-concept model

Aggregator	Time	P1 [kW]	P2 [kW]	P3 [kW]	π1 [$/kWh]	π2 [$/kWh]	π3 [$/kWh]
AG (2)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (5)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (7)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (9)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (11)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (12)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (14)	**2**	20	1.8	140	0.013	0.0195	0.052
AG (2)	**3**	20	3.6	140	0.012	0.018	0.048
AG (5)	**3**	20	3.6	140	0.012	0.018	0.048
AG (7)	**3**	20	3.6	140	0.012	0.018	0.048
AG (9)	**3**	20	3.6	140	0.012	0.018	0.048
AG (11)	**3**	20	3.6	140	0.012	0.018	0.048
AG (12)	**3**	20	3.6	140	0.012	0.018	0.048
AG (14)	**3**	20	3.6	140	0.012	0.018	0.048

Table 9-7. Continuous downward bids for periods 5-6, proof-of-concept model

Aggregator	Time	P1 [kW]	P2 [kW]	P3 [kW]	π1 [$/kWh]	π2 [$/kWh]	π3 [$/kWh]
AG (2)	**5**	50	24	192	0.005	0.015	0.045
AG (5)	**5**	50	24	192	0.005	0.015	0.045
AG (7)	**5**	50	24	192	0.005	0.015	0.045
AG (9)	**5**	50	24	192	0.005	0.015	0.045
AG (11)	**5**	50	24	192	0.005	0.015	0.045
AG (12)	**5**	50	24	192	0.005	0.015	0.045
AG (14)	**5**	50	24	192	0.005	0.015	0.045
AG (2)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (5)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (7)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (9)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (11)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (12)	**6**	50	30	240	0.0045	0.0135	0.0405
AG (14)	**6**	50	30	240	0.0045	0.0135	0.0405

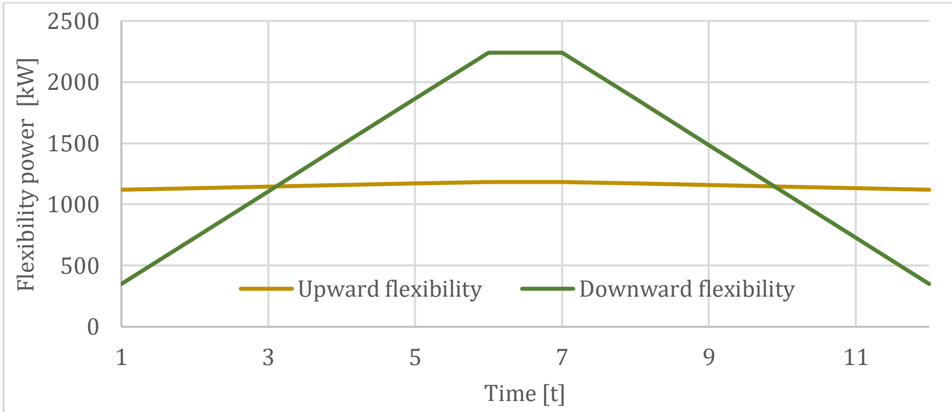

Figure 9-5. Cumulative flexibility from continuous bids, proof-of-concept model

Regarding step bids, Table 9-8 and Table 9-9 present information from step bids. For simplicity, they are model only in two aggregators, AG (5) and AG (11). Moreover, upward, and downward step bids have the same quantity, and could vary between 50 and 100 kW. However, prices between upward and downward bids are different, while they are still a percentage of the previous market section price.

Table 9-8. Upward Step bids, proof-of-concept model

Time	AG (5)			AG (11)		
	Min power [kW]	Max power [kW]	Price [$/kWh]	Min power [kW]	Max power [kW]	Price [$/kWh]
1	50	100	0.0035	50	100	0.0035
2	50	100	0.00325	50	100	0.00325
3	50	100	0.003	50	100	0.003
4	50	100	0.00275	50	100	0.00275
5	50	100	0.0025	50	100	0.0025
6	50	100	0.00225	50	100	0.00225
7	50	100	0.00225	50	100	0.00225
8	50	100	0.0025	50	100	0.0025
9	50	100	0.00275	50	100	0.00275
10	50	100	0.003	50	100	0.003
11	50	100	0.00325	50	100	0.00325
12	50	100	0.0035	50	100	0.0035

Table 9-9. Downward Step bids, proof-of-concept model

Time	AG (5)			AG (11)		
	Min power [kW]	Max power [kW]	Price [$/kWh]	Min power [kW]	Max power [kW]	Price [$/kWh]
1	50	100	0.014	50	100	0.021
2	50	100	0.013	50	100	0.0195
3	50	100	0.012	50	100	0.018
4	50	100	0.011	50	100	0.0165
5	50	100	0.01	50	100	0.015
6	50	100	0.009	50	100	0.0135
7	50	100	0.009	50	100	0.0135
8	50	100	0.01	50	100	0.015
9	50	100	0.011	50	100	0.0165
10	50	100	0.012	50	100	0.018
11	50	100	0.013	50	100	0.0195
12	50	100	0.014	50	100	0.021

Table 9-10 presents parameters to represent two energy storage systems. These systems are operated directly by the DSO and follow the formulation of Section 7.3. The energy/power relation for both BESS is set to one for both systems, taking into account the units are set to be use in an energy service. For simplicity, no charging nor discharging efficiencies are considered, meaning that parameters η_{PC} and η_{PdC} are equal to 1. Moreover, the Initial and Final energy parameters for both storage systems are set equal to half of their maximum energy, meaning that the storage systems have available energy, but it must be restored before the final period.

Table 9-10. BESS, proof of concept model

Node	Max Energy [kWh]	Max Power [kW]	Initial Energy [kWh]	Final Energy [kWh]	Charging Efficiency [%]	Discharging Efficiency [%]
9	500	500	250	250	100	100
14	100	100	50	50	100	100

Using previous assumptions, the following Sections present the results for coordination Schemes 4, 5 and 6.

9.1.1 Scheme 4

In this coordination Scheme, flexibility resources coming from DER are used to solve internal network constraints, while the power exchanged at the HV/MV interface is simply reported to the TSO.

Before analyzing the coordination scheme outcome, the behavior of the algorithm between iterations is presented, when no stopping condition is applied. To start, Figure 9-6 summarizes variables of interest in the iterative process. In the upper panel, the evolution of the objective function is presented. As it can be seen, after few iterations the total cost of solving local network constraints stabilizes around 153.3 $, amount representing only flexibility services and not energy from upwards bid, expected to be paid at a different price.

In the lower panels, the aggregated evolution of the variation variables, which are discussed in Section 8, are presented. In the lower-left and lower-center panels, real and reactive absolute value power variations, for both continuous and step bids coming from all aggregators, are presented. It is expected for a convergent algorithm to reach aggregated variations equal to zero, as no more power changes would be needed to achieve the solution point in the optimization problem. The results from these two panels show, similarly to the cost plot, that an equilibrium is reached after no more than 4 iterations.

However, the result in the lower-right panel, showing the aggregated variation variables for the ESS do not stabilize after the same number of iterations, and oscillates before reaching the final equilibrium at zero. Although the variable changes between iterations, the total cost incurred by the system does not change, meaning that the variations have no apparent effect on the objective function nor on the system constraint.

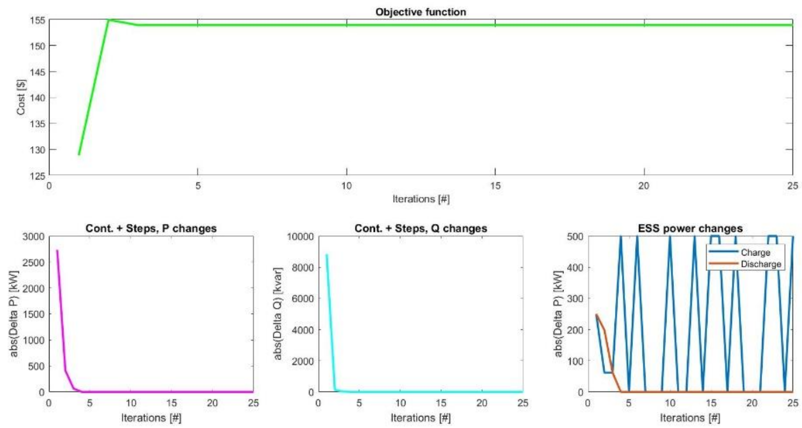

Figure 9-6. Summary, Scheme 4, proof-of-concept model

The previous behavior is detailed in Figure 9-7, where the value of the variable $\Delta PCo_{1,t}$ is presented. In the right panel, it can be seen that the optimization problem is choosing to charge the ESS either in period 6 or 7, rotating between the two options. Because in neither of these periods the system has active constraints, according to the information of Figure 9-3, and the day-ahead price is the same, as presented in Table 9-5, no practical difference between period 6 and 7 exists.

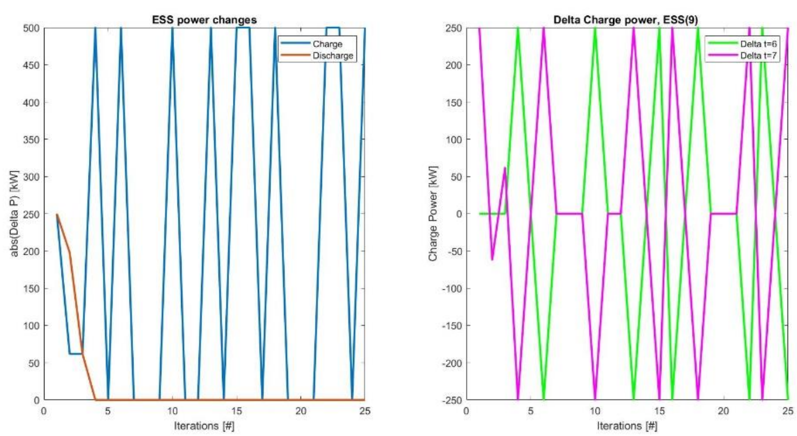

Figure 9-7. ESS power variations, Scheme 4, proof-of-concept model

Although the effect of the previous variations is not apparent on the total cost of the system, they are in terms of the approximation errors achieved. Figure 9-8 shows the evolution of average and maximum absolute errors in the line currents, that as discussed in Section 6.2, are the most representative errors of the first order linear approach. As it can be seen, both average and maximum absolute errors converge to a relatively low value after no more than 10 iterations. Nonetheless, the approximation error in the last iteration, which are presented in detailed in Figure 9-9 for all and relevant lines (those with loading higher than 50%), show that the iterative procedure arrives to a network approximation with low errors, but that can certainly be improved.

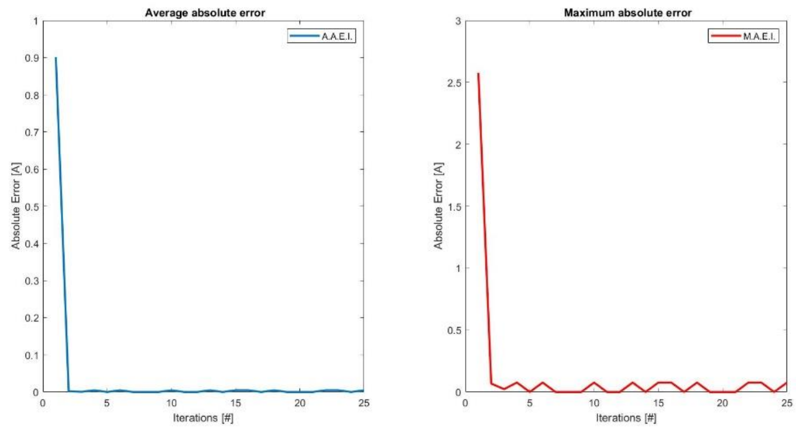

Figure 9-8. Evolution absolute error, Scheme 4, proof-of-concept model

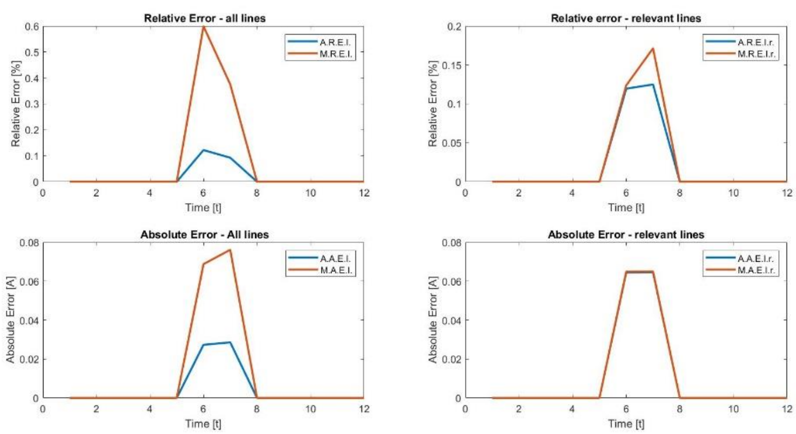

Figure 9-9. Final errors, Scheme 4, proof-of-concept model

The problem with the charging variable, and its oscillations between iterations, could be solved if a low price is applied to a bound defined for variables $\Delta PCo_{b,t}$ and $\Delta PdCo_{b,t}$, as explained in Section 8.4.2. No effects in the overall results of the system would be expected, as the variation occurs in periods with no relevant characteristics for the optimization. Applying the limits shown in Equations (8-29) and (8-30), with $\pi_{b,t}^{\mathrm{PC-bound}}$ and $\pi_{b,t}^{\mathrm{PdC-bound}}$ equal to 0.1% of the charging price of the battery in the respective period, results in Figure 9-10. As expected, the system converges to the same total cost previously obtained, but oscillations in the ESS are eliminated. Errors in the final iteration, presented in Figure 9-11, shows that the system converges to an accurate network approximation.

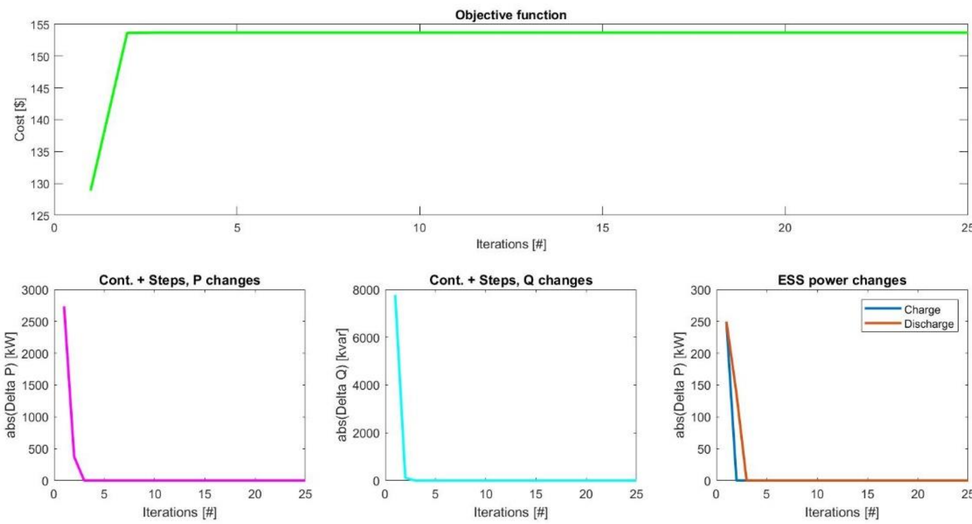

Figure 9-10. Summary, Scheme 4 – limit charging/discharging ESS, proof-of-concept model

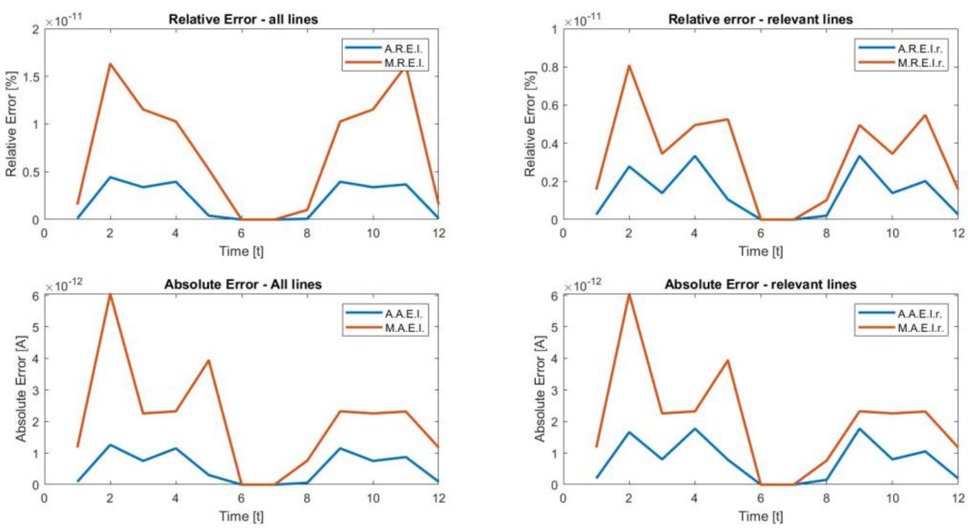

Figure 9-11. Final errors, Scheme 4, proof-of-concept model – limit charging/discharging ESS

Considering the final iteration, Table 9-11 and Table 9-12 present accepted bids of both continuous and step offers to the market. Regarding these results, the following comments can be made:

- Continuous and step bids are only selected if located in the first feeder, as shown in Figure 9-4;

- No downward step bids were selected, as the current constraints would be solved with the activation of only upward bids downstream. Some continuous downward bids were selected, shown as negative values in Table 9-11, to comply with load shifting constraints put in place in the model;
- Even though all aggregators have the same price for their bids, which is a stressed case for the optimization problem, Aggregators located in nodes 7 and 9 are more competitive to Aggregator (5). This result is explained from the sensitivity values, which indicate power from nodes further down the circuit are more effective in changing current of branches 2 and 3.

Table 9-11. Continuous bid selected, Scheme 4, proof-of-concept model

Period (t) – Aggregator	**AG (5) [kW]**	**AG (7) [kW]**	**AG (9) [kW]**
1	20.00	20.00	20.00
2	21.80	21.80	96.26
3	23.60	96.89	163.60
4	33.46	165.40	165.40
5	-50.00	0.00	0.00
6	-50.00	-50.00	-50.00
7	-50.00	-50.00	-50.00
8	0.00	-50.00	0.00
9	33.46	165.40	165.40
10	23.60	96.89	163.60
11	21.80	21.80	96.26
12	20.00	20.00	20.00

Table 9-12. Step bid selected, Scheme 4, proof-of-concept model

Period (t) – Aggregator	AG (5) [kW]	AG (11) [kW]
1	100	100
2	100	100
3	100	100
4	100	100
5	76.12	0
6	0	0
7	0	0
8	78.69	0
9	100	100
10	100	100
11	100	100
12	100	100

For the ESS, only the one located in node 9 in the network is operated, with charging and discharging vectors shown in Table 9-13. The result of the accumulated state of charge is presented in Figure 9-12, with the additional period required to model initial and final values for the ESS, as explained in the problem´s formulation. It is worth noting that the battery completely charges itself in period 7, only possible due to the convention adopted for the proof-of-concept model, where every simulation period represents two operation hours. Moreover, the battery operates exactly one cycle, with active energy constraints for periods 3-7 and 8-11, which means that a larger model would still be used by the optimization problem.

Table 9-13. ESS selected variables, Scheme 4, proof-of-concept model

Period (t) – ESS (9)	Charge [kW]	Discharge [kW]
1	0	62.85
2	0	62.15
3	0	0
4	0	0
5	0	0
6	0	0
7	250	0
8	0	0
9	0	0
10	0	0
11	0	62.15
12	0	62.85

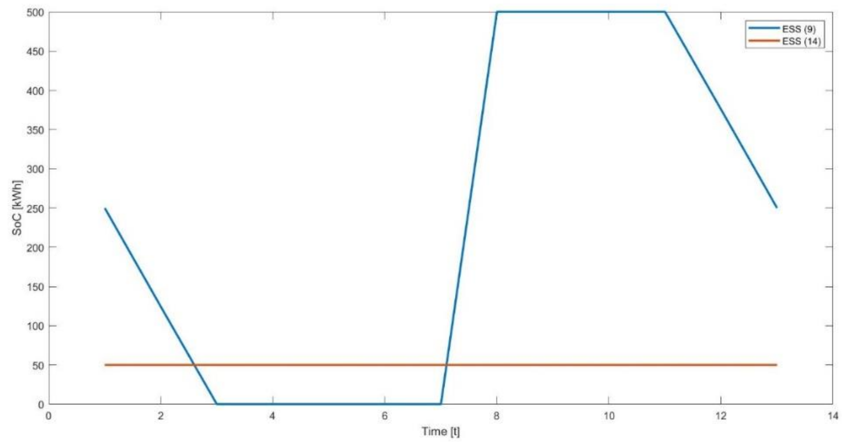

Figure 9-12. State of Charge, Scheme 4, proof-of-concept model

Finally, Figure 9-13 presents the slack real and reactive power before and after applying the coordination scheme. According to the formulation, this information is supplied by the DSO to the TSO, which would oversee incorporating it in its global flexibility and balancing markets. From the right panel the changes induced by the algorithm in the reactive power resources in the network can be seen, which are also being used to solve internal network constraints.

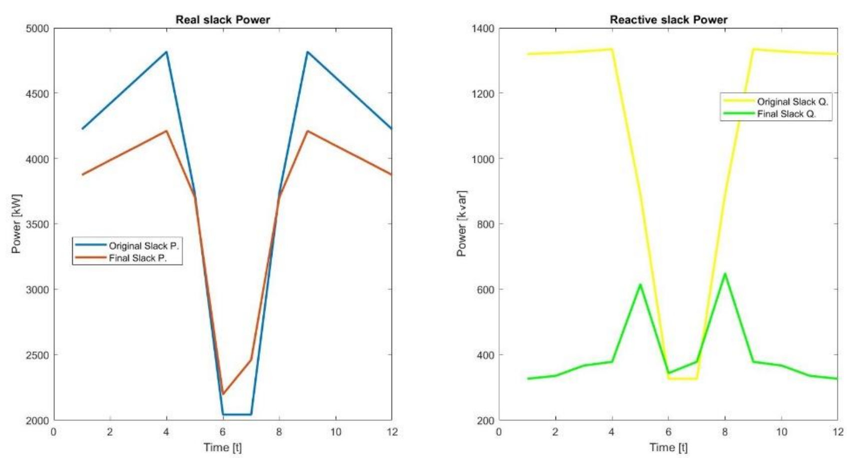

Figure 9-13. Slack power, Scheme 4, proof-of-concept model

Total CPU time, reported by GAMS, is equal to 3.53 seconds, averaging 0.1413 per iteration. The complete algorithm in MATLAB, that includes the time reported by GAMS, is equal to 47.76 seconds, 1.91 per iteration. These results hold approximately constant for the proof-of-concept, and as a result are not reported again.

9.1.2 Scheme 5

To test this Scheme, two profiles for the network's slack are tested. In the first, the TSO establishes upper and lower limits of 3.9 MW and 3.7 MW for all periods, as shown in the dotted lines from the left panel of Figure 9-14. The resulting slack power, compared again with the initial value, is shown in the same Figure, where is clear than local flexibility available is sufficient to comply with the slack constraints. The total cost incurred by the market is approximately 348 $, and no numerical issues for the convergence of the problem are observed, as presented in Figure 9-15.

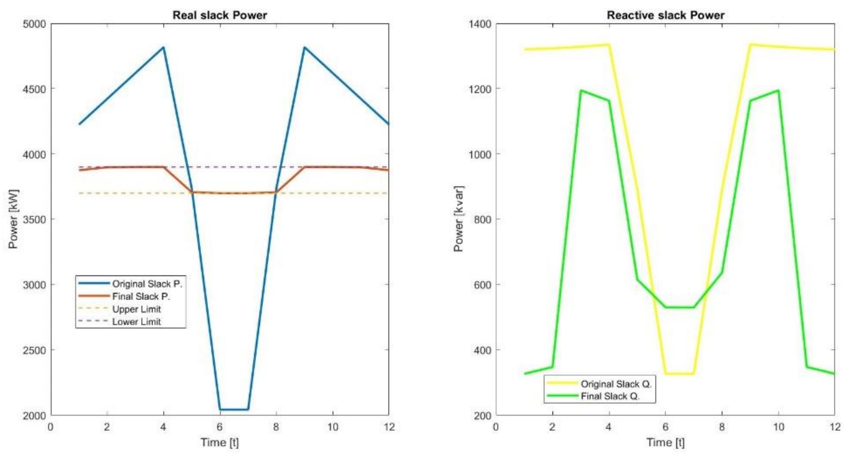

Figure 9-14. Slack power, Scheme 5-1, proof-of-concept model

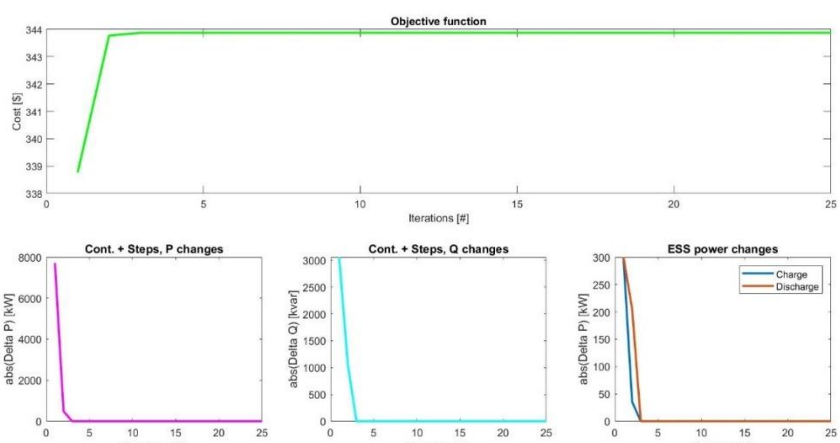

Figure 9-15. Summary, Scheme 5-1, proof-of-concept model

From the results presented, and comparing with the ones for Scheme 4, it is clear that the slack constraints are now the dominant active condition in the system, increasing the use of DER to meet the requirements. Selected resources are shown in Figure 9-16. For the periods 1-4 and

9-12, production from local resources is increased, to reduce the overall loading at the slack. On the other hand, for periods 5-7 total consumption from the network is increased, achieved by either cutting generation resources or increasing load consumption. It is also worth noting that now resources from two branches in the system are being used, as no longer internal constraints are priority. In summary, the load profile at the slack is considerably flatten, which could be of interest to a TSO.

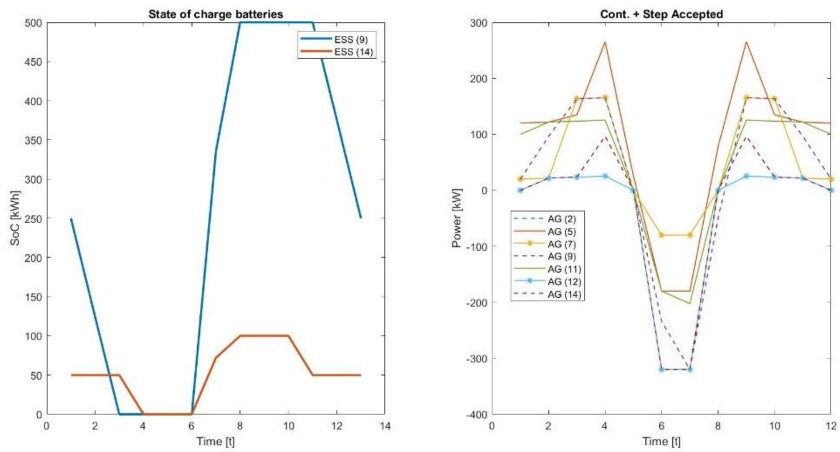

Figure 9-16. Accepted Resources, Scheme 5-1, proof-of-concept model

The second case tested for coordination Scheme 5 requires a more dynamic profile from the network, as shown in the dotted lines of Figure 9-17. In this case, the constraint that would be set by the TSO are active, interchanging between the upper and lower bound of the slack. The system converges with no numerical issues to a total cost of 401.7 $, according to Figure 9-17Figure 9-18, and selected resources shown in Figure 9-19. Moreover, resources from both branches in the circuit are being used when required by the TSO.

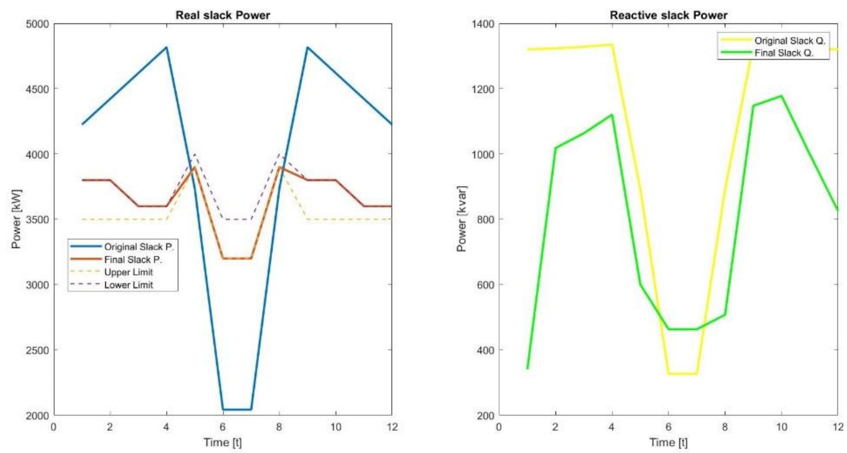

Figure 9-17. Slack power, Scheme 5-2, proof-of-concept model

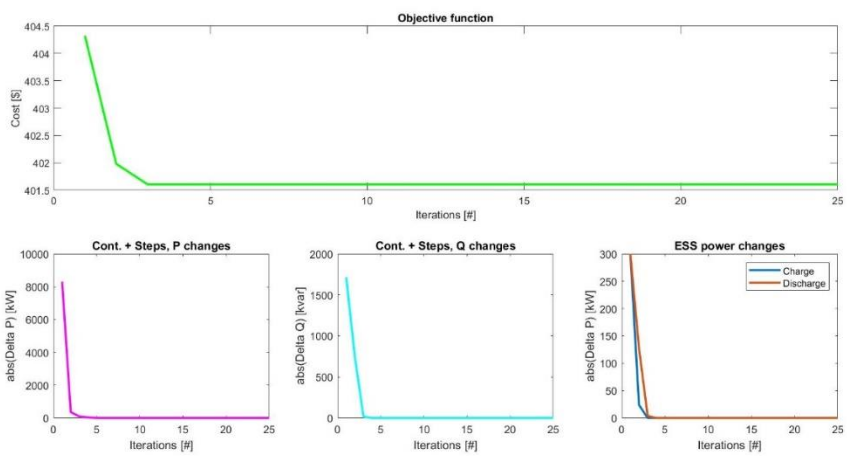

Figure 9-18. Summary, Scheme 5-2, proof-of-concept model

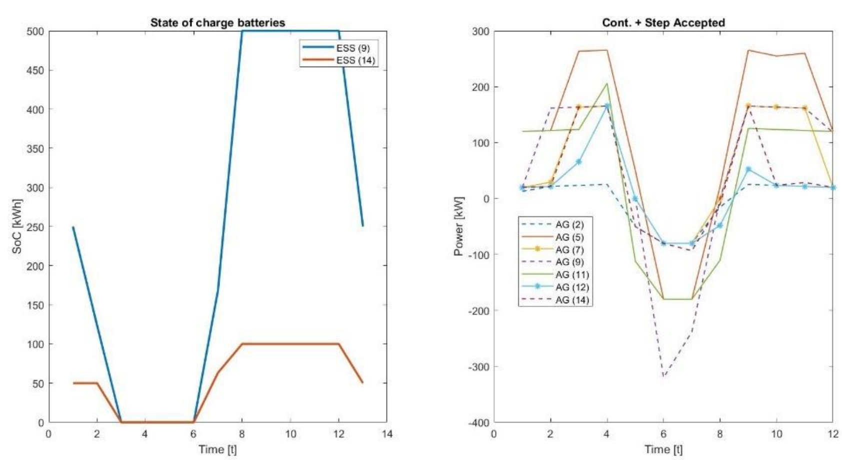

Figure 9-19. Accepted Resources, Scheme 5-2, proof-of-concept model

Summarizing, the coordination scheme results in a network behavior similar to an aggregator, but at a bigger scale that respects both resources and network constraints while submitting a profile to the TSO.

9.1.3 Scheme 6

For this Scheme, approximate profiles that could be offered by the DSO to the TSO are obtained for the complete testing period, following the procedure discussed in Section 7.3.4. According to algorithm, the first step is to define maximum and minimum profiles from the network. Starting with the maximum profile, the results shown in Figure 9-20 and Figure 9-21 are presented. As it can be seen, the maximum profile, from the left panel in Figure 9-20 is obtained in few iterations and now numerical convergence problems, with a total cost of approximately 1420 $.

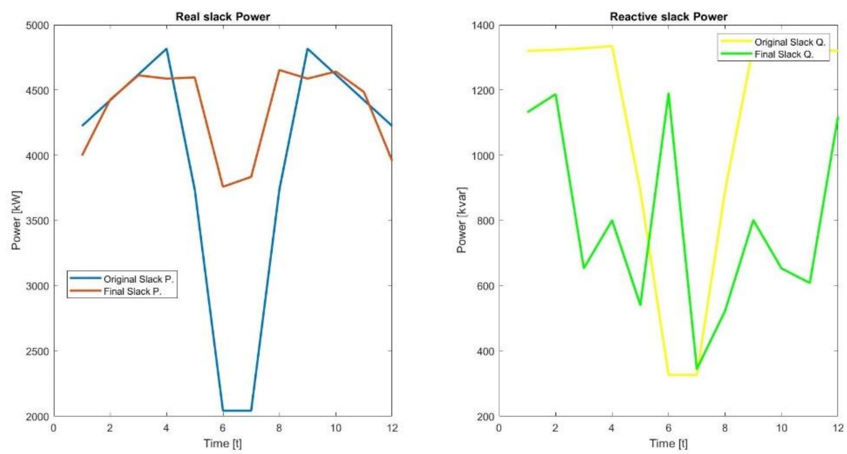

Figure 9-20. Slack power, Maximum profile Scheme 6, proof-of-concept model

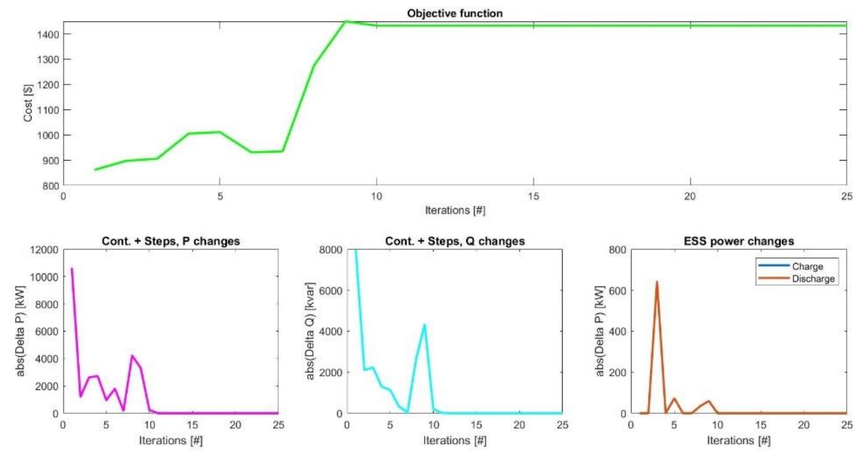

Figure 9-21. Summary, Maximum profile Scheme 6, proof-of-concept model

Once the maximum profile was obtained with the specific optimization problem formulated with that purpose, the optimization problem of Scheme 5, this time with an equality constraint for the slack real power, is applied. As it can be seen from Figure 9-22, the same profile could be achieved with a different power profile, represented by a different cost to the one previously found. In other words, the solution to the maximum power profile was not unique. Moreover, this solution is found after a slow convergence of the algorithm, that results in a total cost equal to 497.44 $. Accepted resources in the two solution points are presented Figure 12-20 and Figure 12-21.

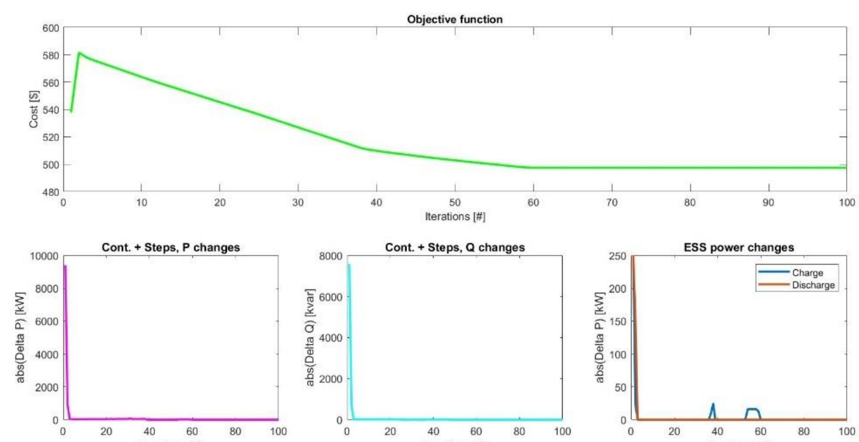

Figure 9-22. Summary, Minimum cost – Maximum profile Scheme 6, proof-of-concept model

The second step in the algorithm is to obtain the minimum power profile at the slack. Once the optimization problem is applied, the results presented in Figure 9-23 and Figure 9-24, and resources accepted in Figure 12-22. Just as in the previous case, the cost obtained could be improved applying the cost-minimization algorithm.

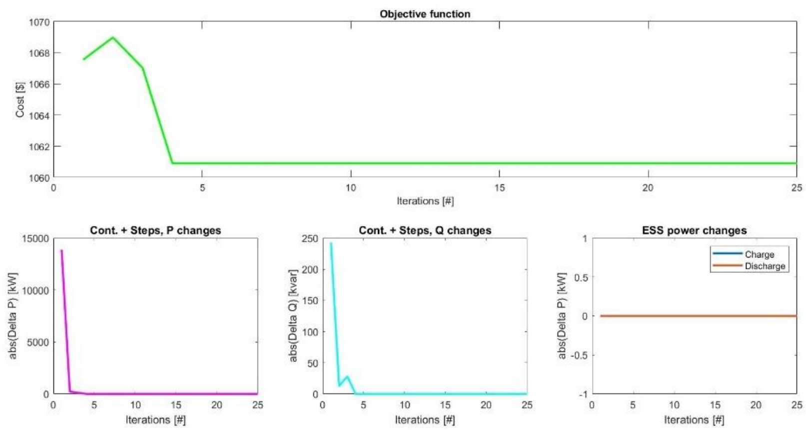

Figure 9-23. Summary, Minimum profile Scheme 6, proof-of-concept model

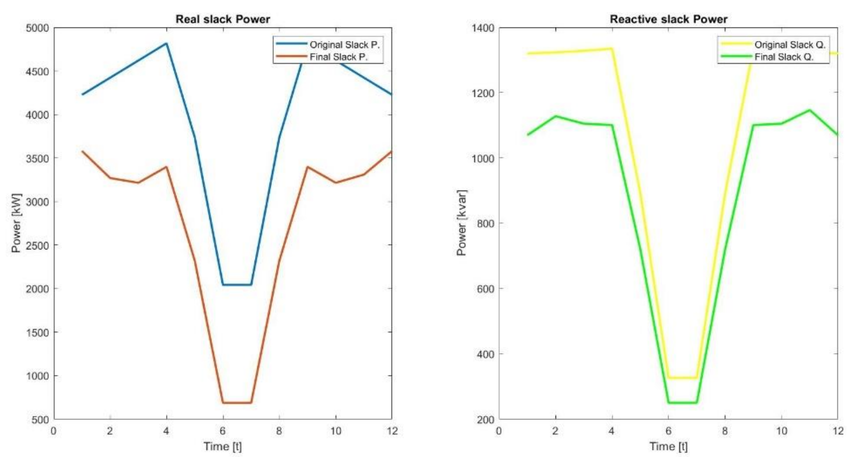

Figure 9-24. Slack power, Maximum profile Scheme 6, proof-of-concept model

Once the minimum and maximum power profiles are given, subsequent intermediate steps between them and the original result from Figure 9-13 are calculated. The results of the complete algorithm are presented in Figure 9-25, where the solid lines represent the original, maximum, and minimum profiles, while the dashed lines are the intermediate steps. Moreover, the color of each individual line represents the total cost incurred by the market to achieve the network outcome. According to the coordination Scheme, this information would then be transmitted from the DSO to the TSO, where it would be used in system-wide flexibility market.

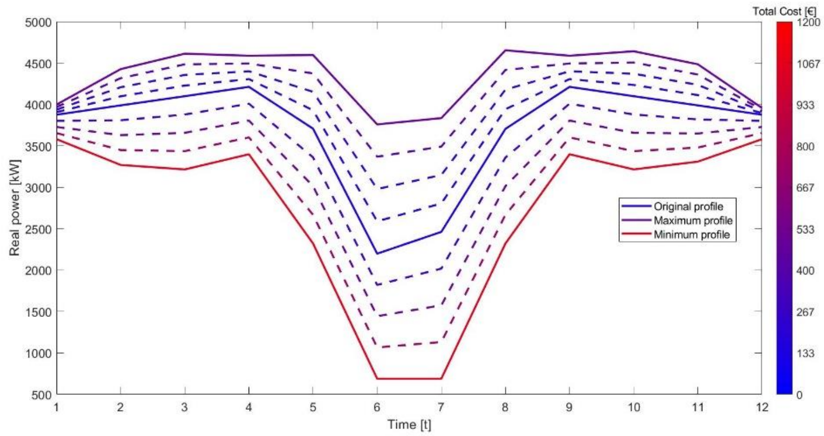

Figure 9-25. Feasible profiles and cost, Scheme 6, proof-of-concept model

9.2 TESTOPF – 96 periods

This testing case is also based in the 14-bus network used in Section 6.2. However, 96 periods are modelled, equivalent to a full operation day, resulting in a Δt parameter equal to 4. Resources present in the network, and their respective profiles, are modelled according to the tool developed for the thesis, described in detail in Appendix 12.4. As in the previous testing case, for all simulations the price set for the reactive power bound, πQC_j, is set to 100 times lower than the minimum price offered by the respective aggregator. No cost for variations in charging and discharging power of ESS are assumed. Finally, no filters are applied to the constraints in the system.

To start, resources that do not participate in the flexibility market, and serve as a base profile for the network, are presented in Table 9-14. Both load and generation resources are included, leading to the aggregated profile, in load notation, shown in Figure 9-26. This profile is constant and cannot be altered by the DSO in any of the coordination schemes.

Table 9-14. Non-flexibility resources, TESTOPF – 96

Node	Load type	Nominal Power load (kW)	PF	PV profile	Month	Nominal power PV (kW)	PF
1	11	0	0	0	0	0	0
2	18	300	0.95	4	3	50	0
3	9	300	0	4	3	50	0
4	18	300	0.95	0	0	0	0
5	9	300	0	4	3	50	0
6	18	300	0.95	4	3	50	0
7	9	300	0	4	3	50	0
8	11	300	0.95	0	0	0	0
9	9	300	0	4	3	50	0
10	11	300	0.95	0	0	0	0
11	9	300	0	4	3	50	0
12	9	300	0.95	4	3	50	0
13	11	300	0	4	3	50	0
14	9	300	0.95	4	3	50	0

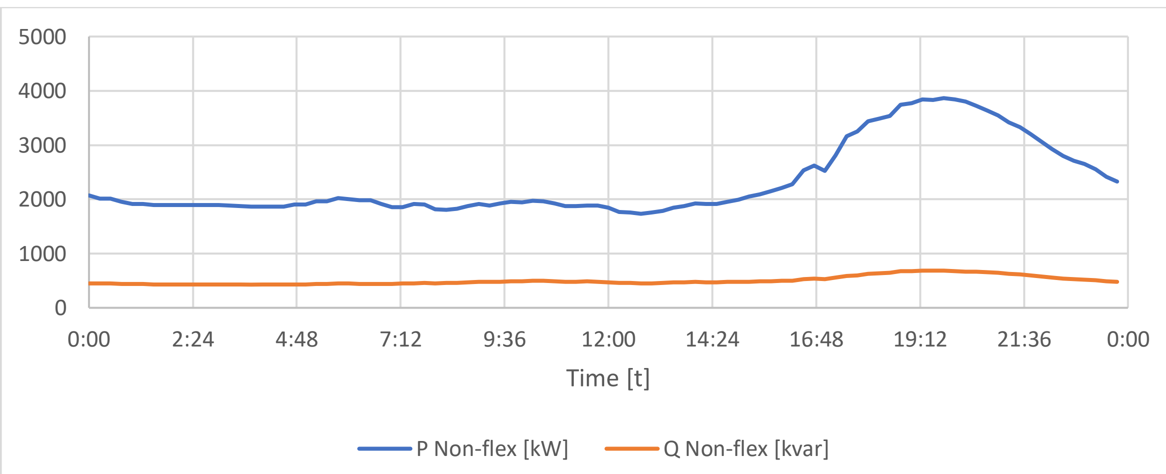

Figure 9-26. Cumulative Non-flexibility resources profile, TESTOPF-96

Regarding resources that do participate in the flexibility market, they are described in Table 9-15. As before, both load and generation resources are modelled in 7 nodes, resulting in the cumulative profile shown in Figure 9-26, in generation notation. As it can be seen, resources participating in the market between hours 00:00 - 06:00 and 17:00 - 23:45 are predominantly load resources, while for the period 06:15 - 16:45 the presence of PV resources is more prevalent.

Table 9-15. Flexibility Resources, TESTOPF-96

Node	Load type	Nominal power load (kW)	PF	PV profile	Month	Nominal power PV (kW)	PF
2	9	500	0.95	4	4	500	0.95
5	10	800	0.95	4	4	500	0.95
7	8	0	0.95	4	4	1000	0.95
9	10	200	0.95	4	4	500	0.95
11	9	500	0.95	4	4	100	0.95
12	8	500	0.95	4	4	200	0.95
14	18	0	0.95	4	4	300	0.95

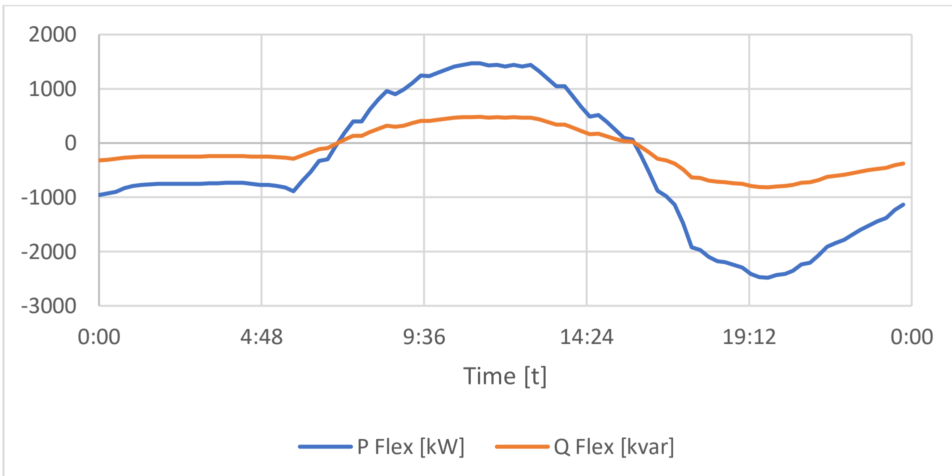

Figure 9-27. Cumulative Flexibility resources profile, TESTOPF-96

Regarding lines' maximum loading, modifications are carried out to differentiate this case from the previous one. In this testing case, maximum current is set for branch 1, and branches from Feeder 1 and 2 is equal to 35, 100 and 90 amperes., respectively. The results of the power flow for this network conditions are shown in Figure 9-28, where between periods 75 to 88[25], 2 or three current constraints are active. Active constraints are highlighted in red in Figure 9-29, in addition to the location of aggregators in green.

[25] Hours and number of periods are used indistinctively in this Section.

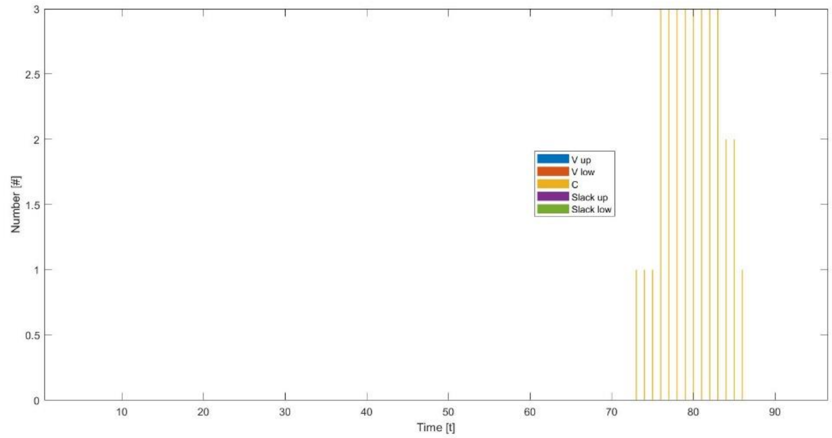

Figure 9-28. Active network constraints, TESTOPF-96

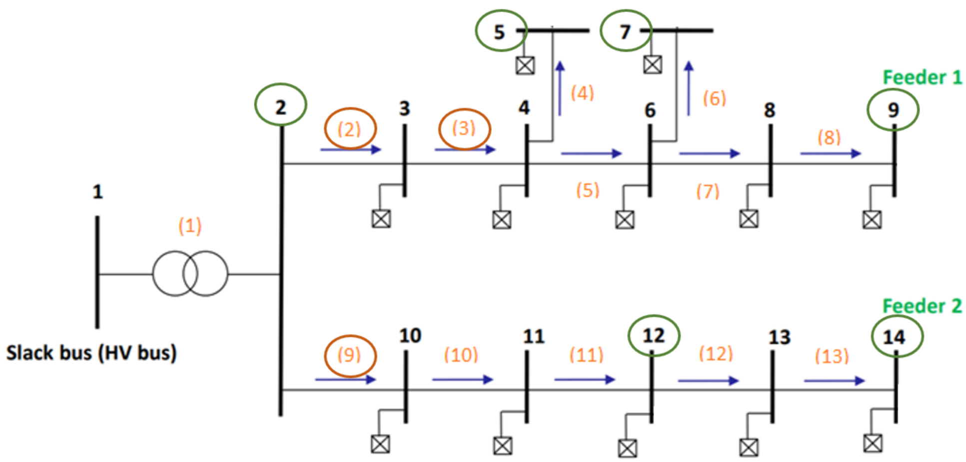

Figure 9-29. Active branches constraints (red) and aggregators' location (green), TESTOPF – 96

For the 7 aggregators modelled, their bids are generated depending on their initial power profile, and the price of the previous market section. For this testing case, prices are taken from the first example shown in Figure 12-19, corresponding to an average price for the Colombian day-ahead market in January 2019. Regarding quantities, maximum aggregated flexibility that can be obtained from continuous bids is presented in Figure 9-30.

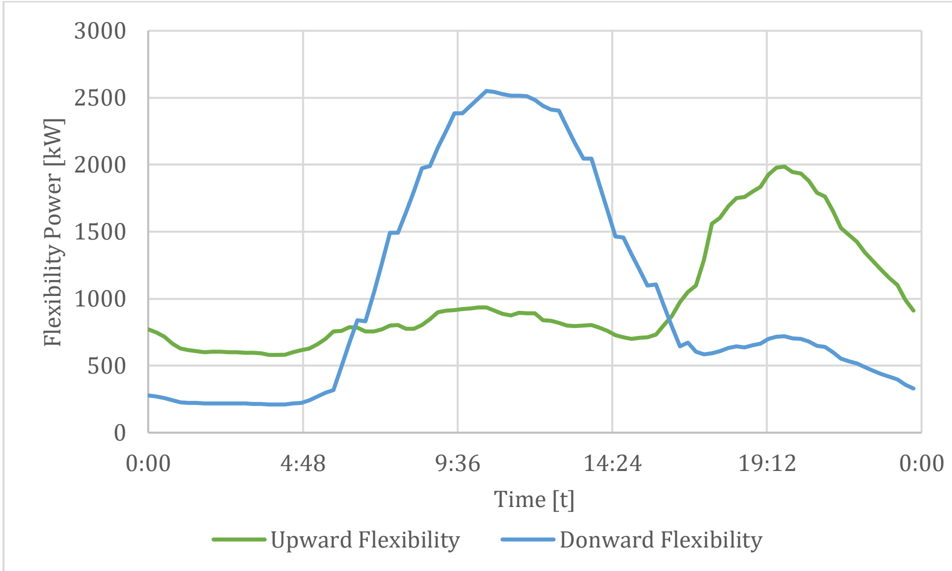

Figure 9-30. Cumulative flexibility from continuous bids, TESTOPF – 96

Step bids are generated using the characteristics shown in Table 9-16. For this testing case, a minimum acceptance rate equal to 80% of the bid power is assumed. The resulting upward and downward flexibility profiles of step bids are presented in Figure 9-31.

Table 9-16. Step bid characteristics, TESTOPF-96

Node	Step bids up type	Step bids up power [kW]	Step bids Down type	Step bids Down Power [kW]
2	2	50	2	100
5	3	75	2	50
9	2	100	5	100
11	3	50	4	50
12	5	100	4	100
14	3	50	1	25

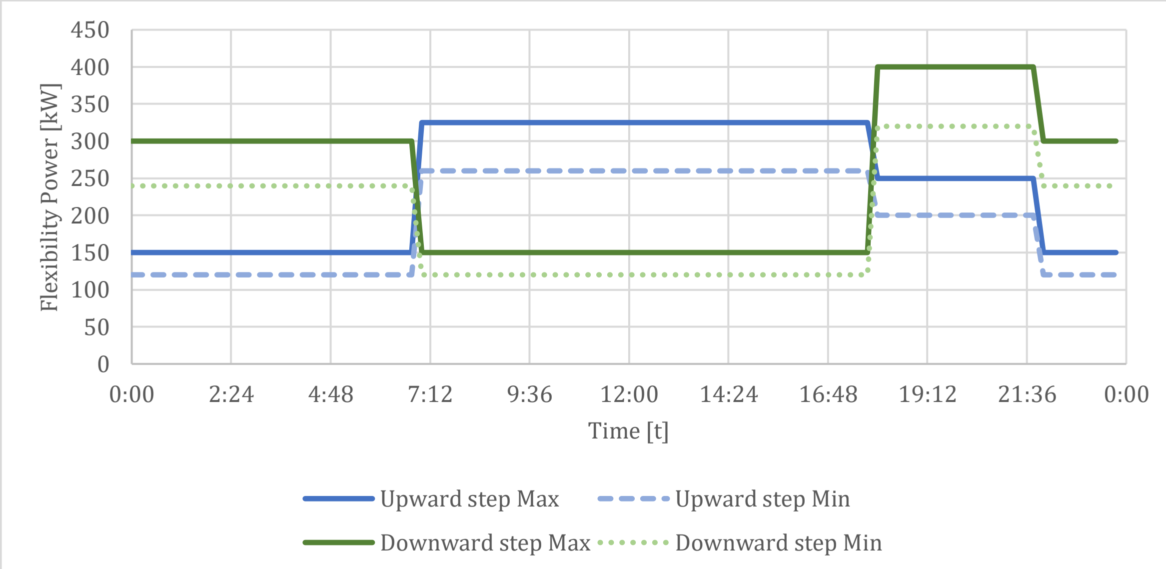

Figure 9-31. Cumulative flexibility from step bids, TESTOPF – 96

Finally, three BESS operated by the DSO are included in the network. Their descriptive information is shown in Table 9-17. Charging and discharging efficiencies are taken from [79], where experimental testing is carried out for Lithium Ion Batteries, and efficiencies are reported according to the discharge/charge current. The values reported in Table 9-17 correspond to efficiencies measured at nominal rates, which is an appropriate assumption for energy models like the one applied in this thesis. Moreover, three different power to energy ratios are assumed for the BESS in the network, ranging from 2 to 0.5.

Table 9-17. BESS, TESTOPF – 96

Node	Max Energy [kWh]	Max Power [kW]	Initial Energy [kWh]	Final Energy [kWh]	Charging Efficiency [%]	Discharging Efficiency [%]
2	500	1000	250	250	97	98
6	1000	200	500	500	97	98
11	200	200	100	100	97	98

Given the previous assumptions, results for the coordination Schemes are presented in the following Sections. For the simulations, the stopping criterion with parameters $\Delta\mathrm{OF.R.}^{\mathrm{MIN}} = 0.025\ \%$ and $\mathrm{M.R.E.I.r}^{MIN} = 0.5\%$ is implemented, checked in every iteration.

9.2.1 *Scheme 4*

In the scheme, only the constraints shown in Figure 9-28 are to be solved. The result of applying the market algorithm is summarized in Figure 9-32, where it is seen that the method converges after 5 iterations to a total cost equal to 14.57 $. Final errors in the simulation are presented in Figure 9-33, being bounded by the stopping criterion described earlier.

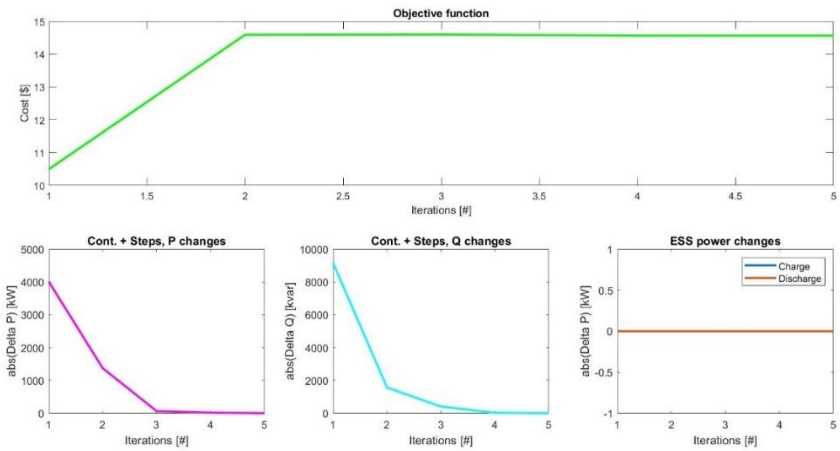

Figure 9-32. Summary, Scheme 4, TESTOPF – 96

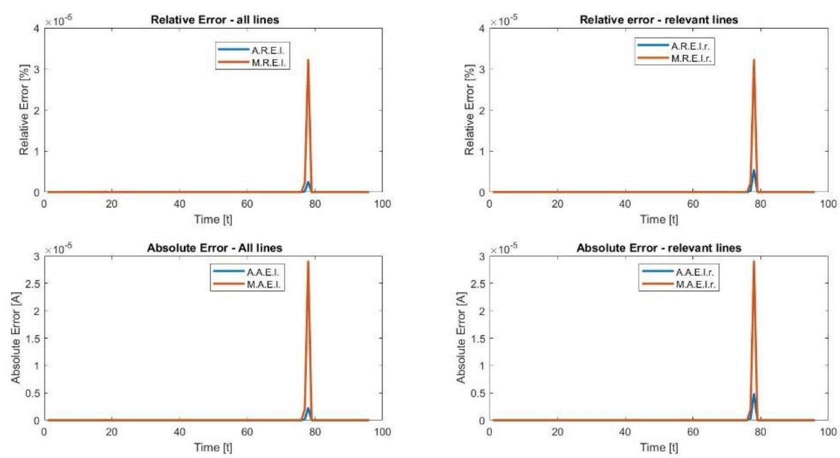

Figure 9-33. Final errors, Scheme 4, TESTOPF – 96

Moreover, the result of the market algorithm are the resources selected, shown in Figure 9-34, and the slack power from Figure 9-35. Not many changes in the initial power profile were needed in the network to solve the constraints, and most of the flexibility was harness from reactive power. None of the ESS were operated, remaining at their initial condition for the complete operation horizon.

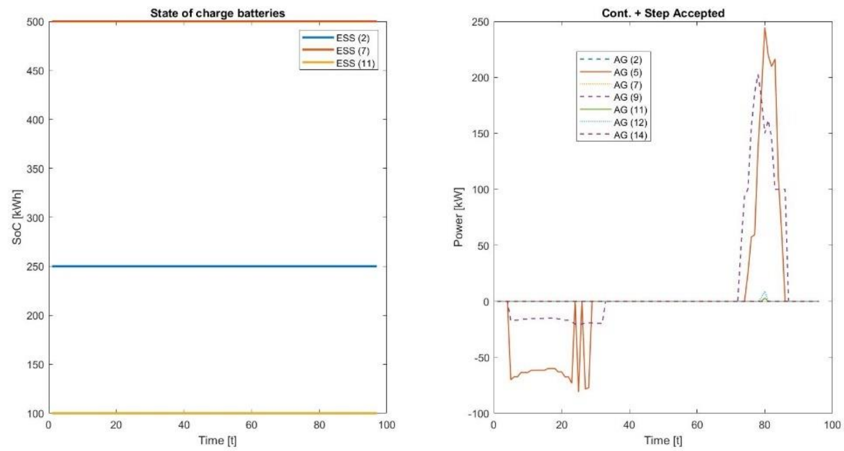

Figure 9-34. Accepted Resources, Scheme 4, TESTOPF – 96

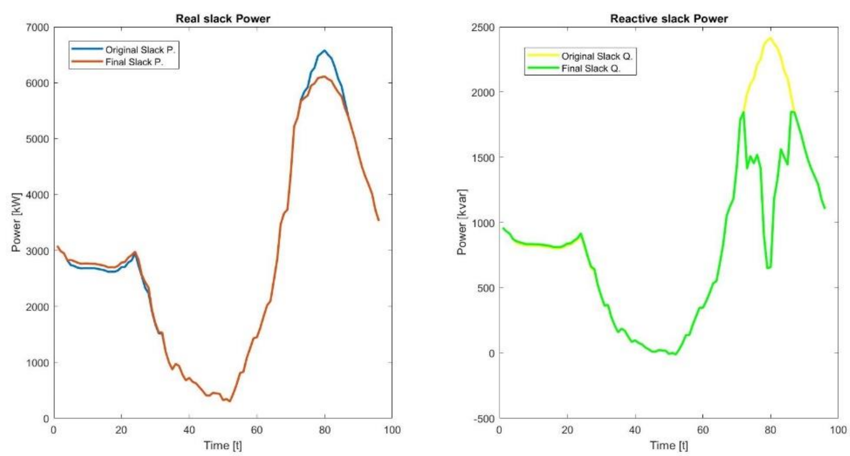

Figure 9-35. Slack powers, Scheme 4, TESTOPF – 96

Finally, the computation time per iteration was equivalent to 0.6156 seconds, as reported by GAMS, while the complete simulation in MATLAB took 40.81 seconds, roughly 8 seconds per iteration. Considering the problem grew at least 8 times in size, with respect to the proof-of-concept model, the scaling in the solver is acceptable. Computation time remains similar in simulations, so it is not reported again.

9.2.2 Scheme 5

For this Scheme, results for two required profiles are tested. The first, shown in the dotted lines in Figure 9-36 corresponds to the case where the TSO sets minimum and maximum power profiles in the slack to both reduce the maximum power drawn during peak hours, and reduce the injection of PV resources during the middle of the day.

The market algorithm converged at 5 iterations to a total cost of 1020.5 $, with the convergence characteristics shown in Figure 12-23. Resources selected for the solution are seen in Figure 9-37, now that includes the operation of ESS to meet the TSO requirements. In addition to the expected behavior, were the two constraints set by the TSO are active, increase consumption is seen during the first part of the day, from resources that must comply with load-shifting requirements.

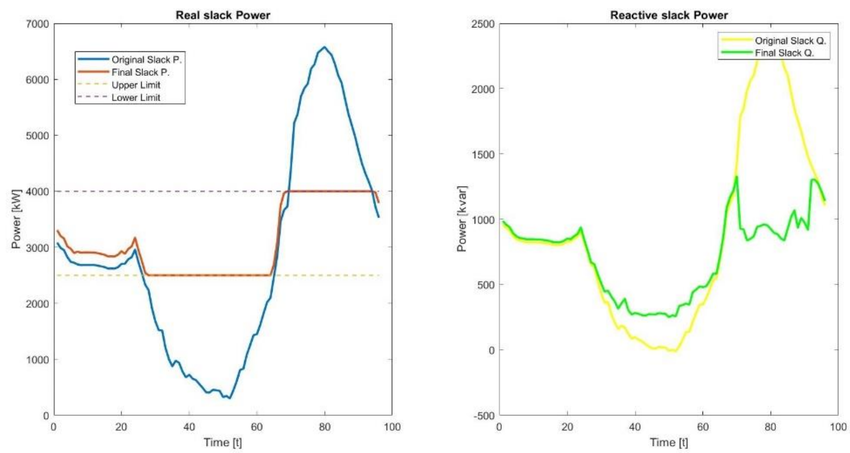

Figure 9-36. Slack power, Scheme 5-1, TESTOPF – 96

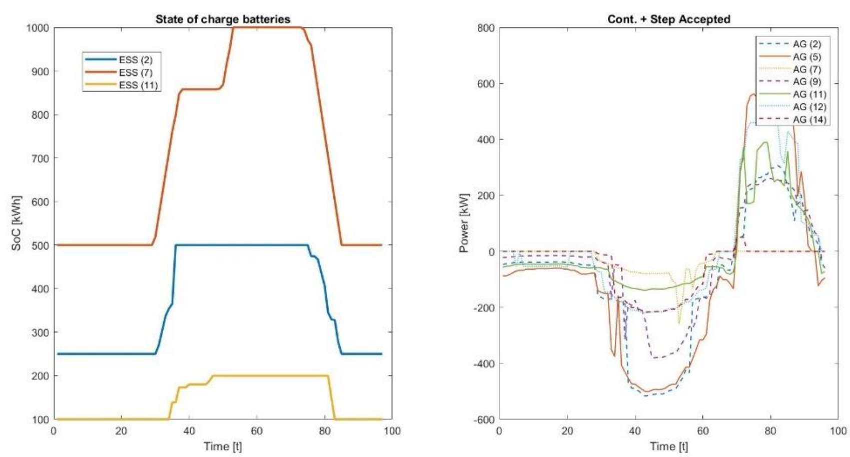

Figure 9-37. Accepted resources, Scheme 5-1, TESTOPF – 96

In the second test, the requirements shown in the dotted lines from Figure 9-38 are imposed to the network. First, a more flexible maximum and minimum bound, in comparison to the ones in Figure 9-36 are established. However, shorter, and more stringent steps are also put in place. The resulting behavior of DER, presented in Figure 9-39, is to operate almost at complete capacity the BESS, and increase/decrease dramatically the output from aggregators in brief period. This behavior could be problematic in the case of ramp constraints, which are not included in this testing case. Nonetheless, the algorithm converges to a cost of 904.4 $, with the evolution described in Figure 12-24.

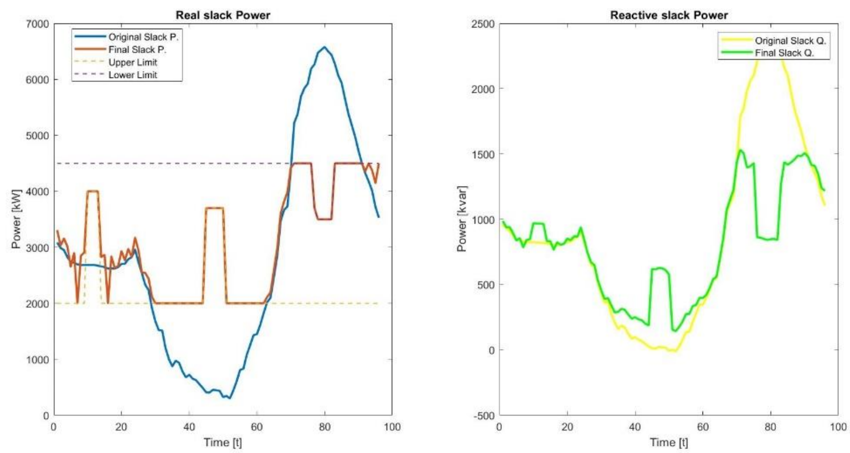

Figure 9-38. Slack power, Scheme 5-2, TESTOPF – 96

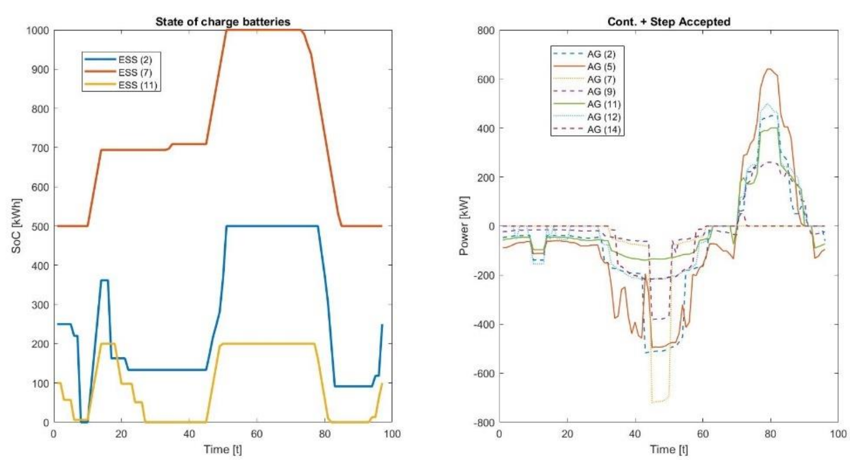

Figure 9-39. Accepted resources, Scheme 5-2, TESTOPF – 96

9.2.3 Scheme 6

For this network, the algorithm described in Section 7.3.4 is not applied to the complete simulation horizon. Instead, a small sample of periods, that could be of interests for the TSO-DSO coordination is selected. This modification is applied assuming the TSO would be more interested in changes of the power consumed/produced by the distribution network for a specific time horizon, peak hours during the night as an example, instead of the complete operation day.

For the given period, power in the slack is maximize/minimize, to later define the intermediate profiles between that condition, and the profile that fulfills internal network constraints shown in Figure 9-35. Moreover, costs presented in the plots come from the complete day of operation, even when the profiles show only the window of interest.

The first sample for which the algorithm is applied has the objective to minimize the power exchanged in the slack during the network's peak, define between periods 69 and 96. This could be useful, for example, when the TSO is observing system-wide ramping constraints that cannot be fulfilled. The results are summarized in Figure 9-40, while detailed information is presented in Figure 12-25. Reaching the maximum flexibility during this period requires a total cost of 510 $, but instantaneous power consumption can be reduced by more than 2 MW. As expected, intermediate steps have lower costs.

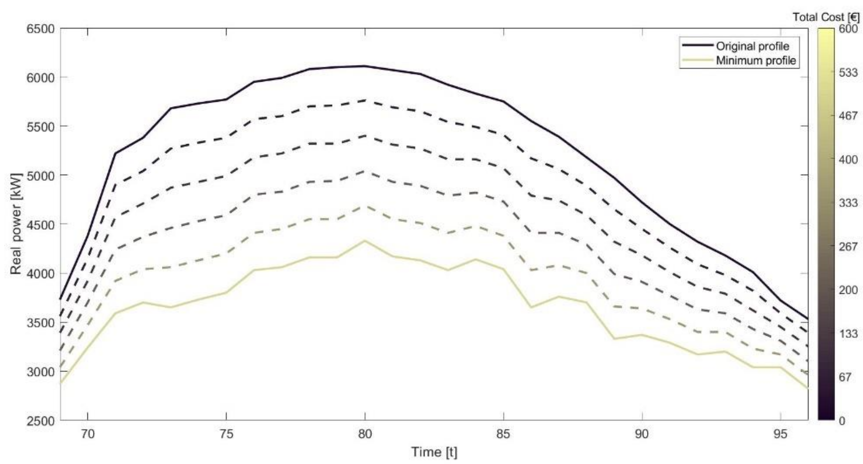

Figure 9-40. Cost and minimum power profile for periods 69-96, Scheme 6, TESTOPF – 96

The second sample has the objective of reducing the so-called duck-curve effect, described in Section 3.2. For this, a period between 27-65 is defined, for which the total power consumption from the network is to be maximized. As the Figure 9-41 shows, the power profile can be almost flattened, with a net change close to 3 MW, but at a total cost of 1243.2 $. Requiring less flexibility reduces costs incurred fast, as no longer is needed to curtail resources, which is assumed to be valued at a higher opportunity cost by DER. Detail information for the calculation of the maximum bound is presented in Figure 12-26.

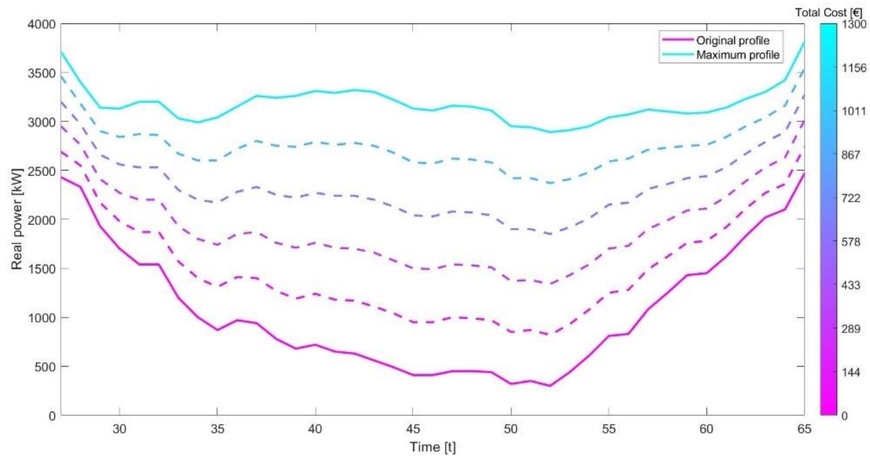

Figure 9-41. Cost and maximum power profile for periods 27-65, Scheme 6, TESTOPF – 96

Lastly, the algorithm is reversed to obtain the minimum power profile possible for periods 27-65, as shown in Figure 9-42, and detailed information in Figure 12-27. In this case, load resources are curtailed in the network, resulting in a distribution network that, in aggregate, could behave like a generator. The maximum power output from the network, approximately 836.6 kW, is achieved for the profile with a total cost equal to 656.57 $. The flexibility described in this case could be useful to a TSO in urgent need of additional generation resources due to, for example, large generators or transmission infrastructure contingencies.

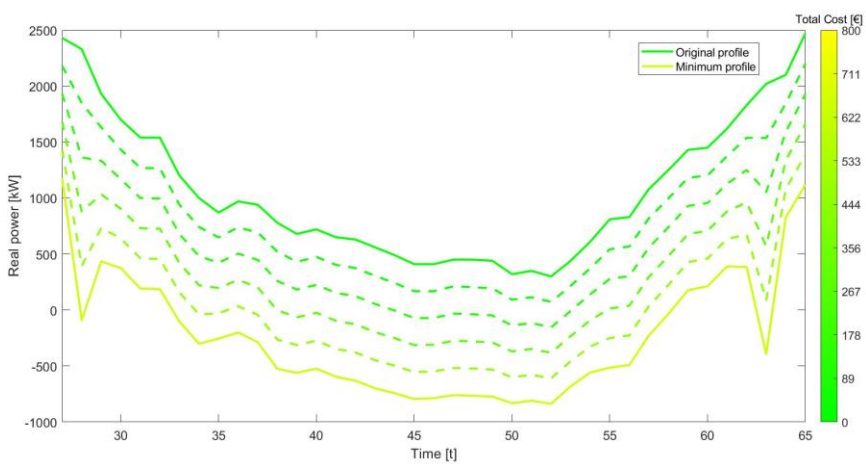

Figure 9-42. Cost and minimum power profile for periods 27-65, Scheme 6, TESTOPF – 96

It is worth noting that the numerical behavior of the algorithm designed to obtain the maximum/minimum power profile is deficient compared to the one used to minimize costs incurred in the market algorithm, due slower convergence to an equilibrium and worse final approximation errors. Moreover, the cost obtained was different to the one reported by the cost-minimization problem, meaning that the slack constraint can be fulfilled with more than one combination of DER profiles.

9.3 Rete81 – 96 periods

For this case, the 170-bus network with the topology described in Table 12-6 and Table 12-7 is used. As in the previous case, 96 periods are considered to represent a complete day of operation, with a 15-minute time resolution. Resources, and their bids, are modelled using the logic described in Appendix 12.4, and the initial price profile #5, corresponding to GME's day ahead market from 04/01/2019.

First, resources that do not participate in the flexibility market, are characterized by the power profile shown in Figure 9-43, in load notation. On the other hand, the initial profile from flexibility resources provided by 14 aggregators is shown in Figure 9-44 in generator notation, while their complete description is presented in Table 12-13. As it can be concluded from the comparison between two plots, most resources included in the network participate in flexibility market and can be used in case of network needs. Moreover, the amount of generation resources modelled results in a network that could inject power to the TSO network during the middle of the day, while the night peak is still supported by the centralized system. This would be the expected behavior in distribution networks with high penetration of solar PV plants with little to no internal storage. Ramp constraints are included for aggregators and are equal to the maximum power change observed in their initial profile for the complete testing horizon.

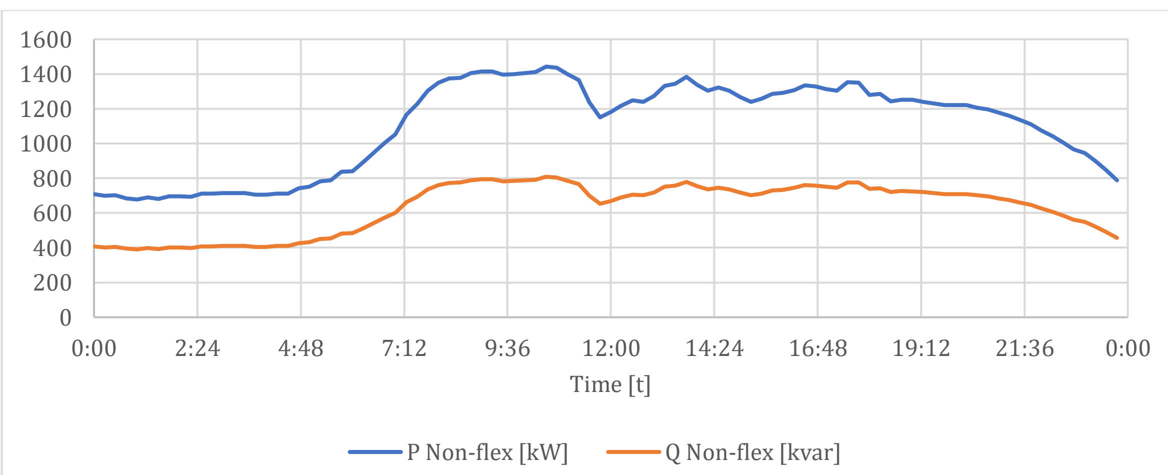

Figure 9-43. Cumulative non-flexibility resources profile, RETE81

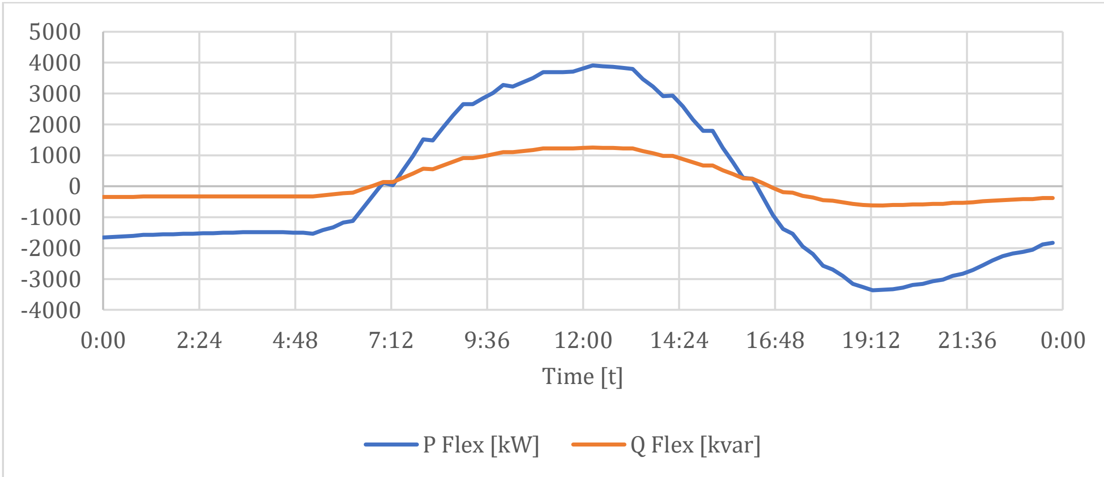

Figure 9-44. Cumulative Flexibility resources profile, RETE81

Two modifications are carried out to the network's technical limits with respect to the ones initially presented in Table 12-6 and Table 12-7: ampacity is reduced to around 30%, and voltage limits are set to 1.07 and 0.925. Both changes are applied to include more constraints in the model, representing what could be a more conservative network operation. The result of these modifications, and the profiles from flexibility and non-flexibility resources in terms of constraints, is summarized in the active network constraints shown in Figure 9-45. As it can be seen, following the initial profiles leads to upper voltage constraints been surpassed during mid-day, due to excessive PV production, while current and lower voltage constraints are not respected during the night's peak.

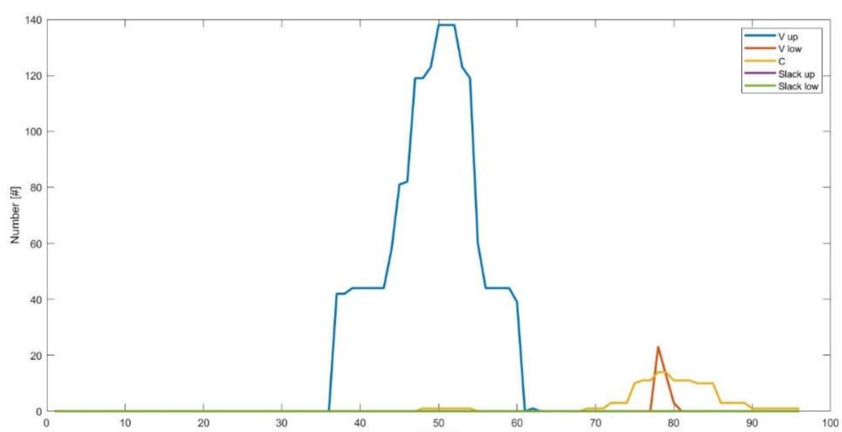

Figure 9-45. Active network constraints, RETE81

Maximum flexibility that can be provided by continuous and step bids are presented in Figure 9-46 Figure 9-47. As in the previous cases, bid prices are modelled as a percentage from the previous market section. Step bids are detailed in Table 12-14. Finally, BESS with the same technical characteristics to the ones shown in Table 9-17 are used, but this time connected to nodes 4, 31 and 88.

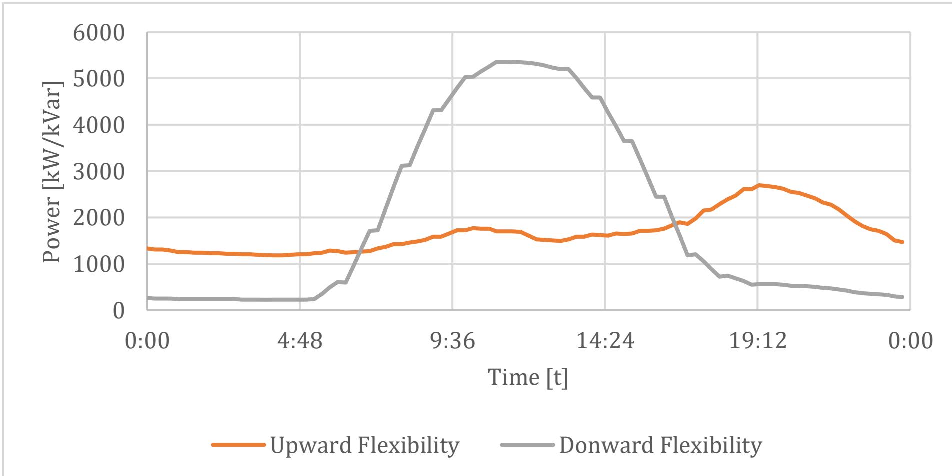

Figure 9-46. Cumulative flexibility from continuous bids, RETE81

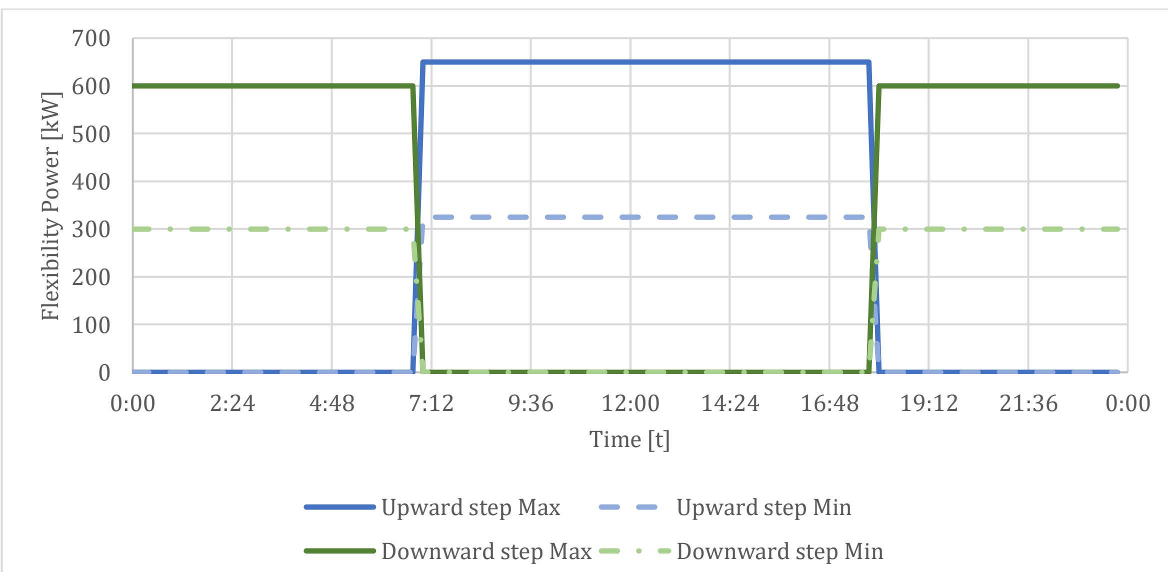

Figure 9-47. Cumulative flexibility from step bids, RETE81

Given the previous assumptions, results for the coordination Schemes are presented in the following Sections. For the simulations, the stopping criterion with parameters $\Delta\mathrm{OF.R}^{\mathrm{MIN}} = 0.025\ \%$ and $\mathrm{M.R.E.I.r}^{MIN} = 0.5\%$ should be complied in two consecutive iterations for the algorithm to stop. Moreover, considering that the testing case is larger than the previous ones, additional measures are taken to reduce simulation time and avoid numerical problems:

- Only relevant voltage and current constraints are modelled, as discussed in Section 8.4.3;
- A penalty is introduced for ESS charging and discharging cycles, as presented in Section 8.4.2, equal to 100 times lower than the respective day-ahead price;
- An initial reactive power penalty equal 100 times lower than the minimum bidding price, gradually increased until convergence is reached. This assumption is discussed in detail in Section 9.3.1;
- In the loop shown in Figure 8-1 power flows and sensitivity matrices are only updated if a change in the network profile for the respective period is obtained in the market solution.

9.3.1 Scheme 4

In addition to the standard results of Scheme 4, this Section also presents numerical problems found in the iterative solution process. After applying the algorithm with a reactive cost, πQC_j, equal to 100 times the minimum bid price the behavior shown in Figure 9-48 is obtained.

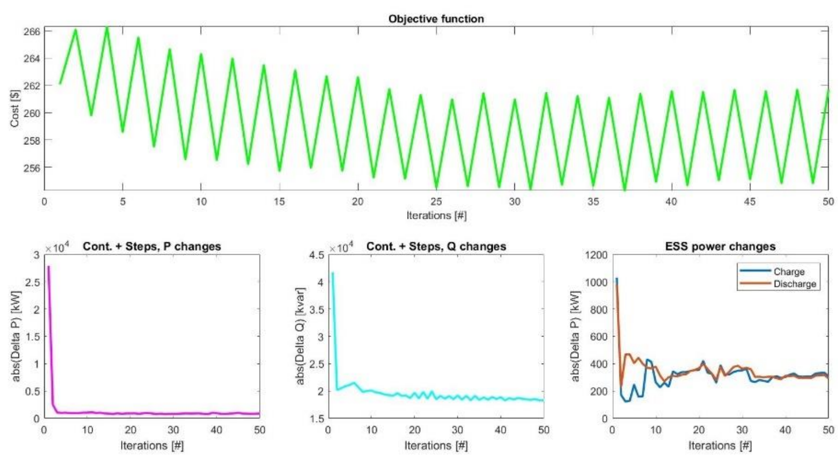

Figure 9-48. Summary, Scheme 4 – Oscillations, RETE81

As it can be seen in the lower panels, bids from DER do not approach zero and instead tend to oscillate around an operation condition. These oscillations are identified both by the variations of the objective function, and the relatively constant real and reactive power changes between iterations. The effect on the solution method is critical, as the network approximation requires low power variation to achieve convergence, and as Figure 9-49 shows, this is not the case.

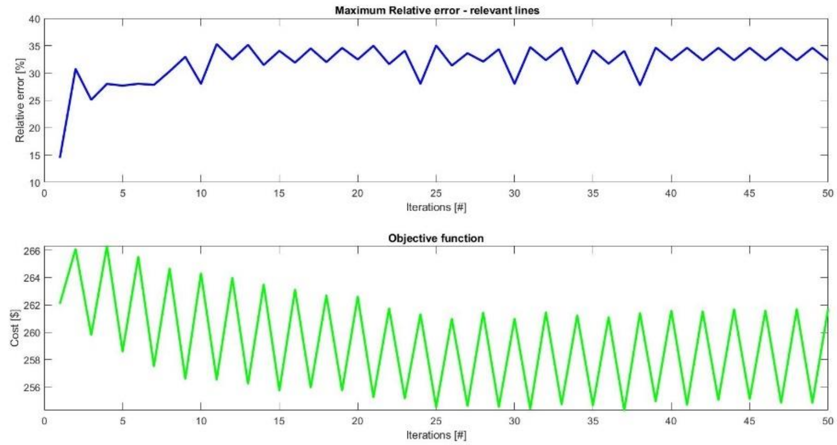

Figure 9-49. Objective function and maximum relative error, Scheme 4 – Oscillations, RETE81

From testing the numerical problems were isolated to reactive power, as the oscillations are still present even when only continuous bids are included. Moreover, issues are not caused by the filtering of relevant constraints, a new feature implemented for this testing case to reduce simulation time.

To mitigate the observed numerical problems, several ideas were tested and implemented. The most effective one was to gradually increase reactive power cost in the algorithm after the oscillations are observed. With the increased cost, reactive power variations are less likely to occur, allowing the sensitivities to properly approximate the solution found by the optimization problem.

Specifically, for this scenario starting in iteration 4 reactive power cost is gradually increased until it reaches 100 times the minimum bid price around iteration 15. The increment is carried out with constant steps between iterations 4 and 15, until it reaches the maximum value specified before. From testing, the require value to eliminate reactive power variations seems lower, but the previous value is selected to assure convergence. Given this new approach for reactive power management, the results shown in Figure 9-50 and Figure 9-51 are obtained. As it can be seen, the solution algorithm reaches a total cost equal to 301 $, with minimal approximation errors in the final iterations.

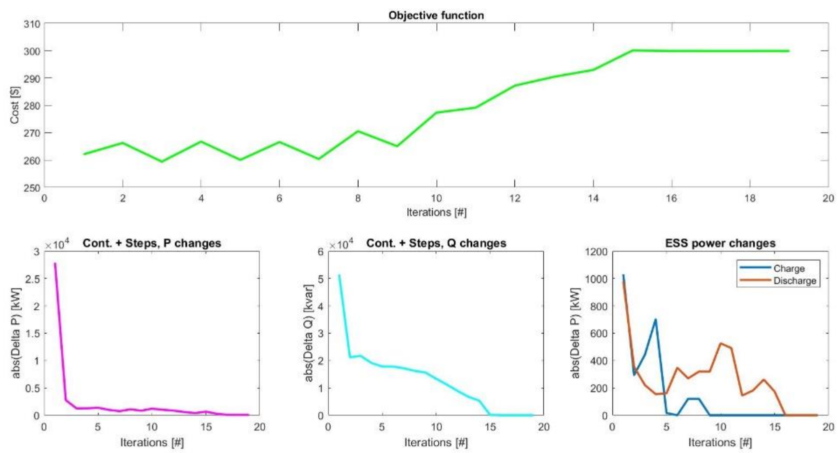

Figure 9-50. Summary, Scheme 4, RETE81

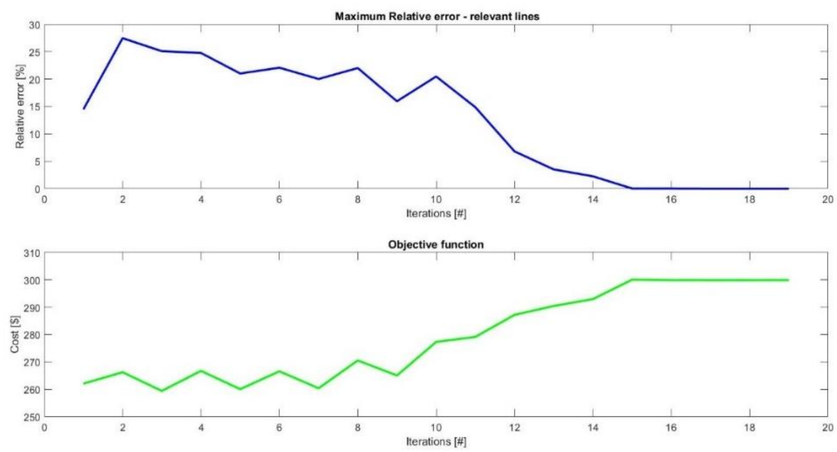

Figure 9-51. Objective function and maximum relative error, Scheme 4 – Oscillations, RETE81

In addition to the total cost obtained, Figure 9-52 and Figure 9-53 present the slack power profile and the accepted bids, respectively. As it can be seen, reactive power is aggressively used to reduce the voltage constraints that were identified in the system. Real power is only used during the night load peak, where current constraints were also present. The use of real power is related to the effect of the load shifting bids, which is seen in the first periods of the simulation. Finally, only one of the ESS system is used to achieve the optimal operation condition.

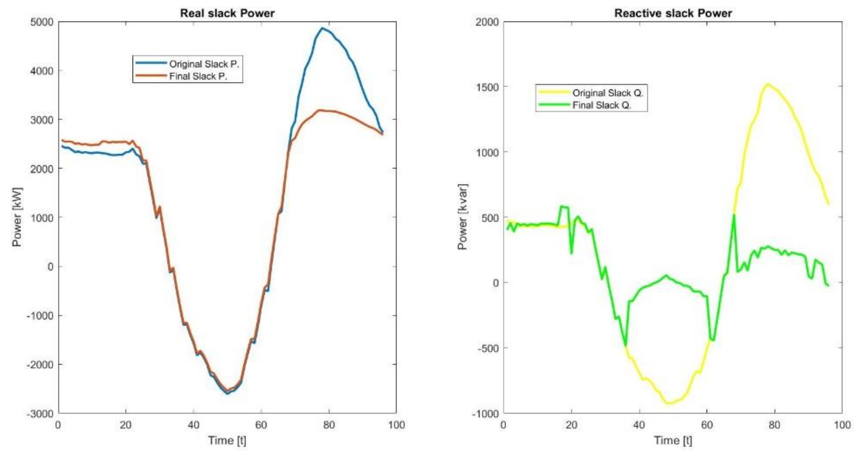

Figure 9-52. Slack powers, Scheme 4, RETE81

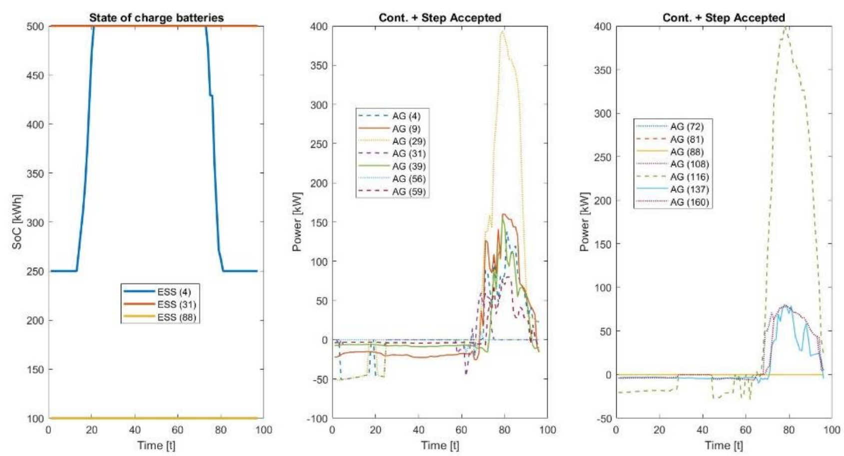

Figure 9-53. Accepted resources, Scheme 4, RETE81

Finally, for the current system the total simulation time in MATLAB is equivalent to 42 seconds per iteration in average, while the computing time in GAMS is equivalent to 3.5 seconds per iteration. As in the previous cases, simulation time remains approximately constant between the simulations and it is not reported again.

9.3.2 Scheme 5

Two examples are shown for this coordination case. In the first, the network is required to not inject power to the transmission system in any point during the complete operation day, which is equivalent to a low bound of real power in the Slack bus equal to zero. In this condition, the system converges to a total cost equal 802.13 $, with the summarized results shown in Figure 9-54 and Figure 9-55.

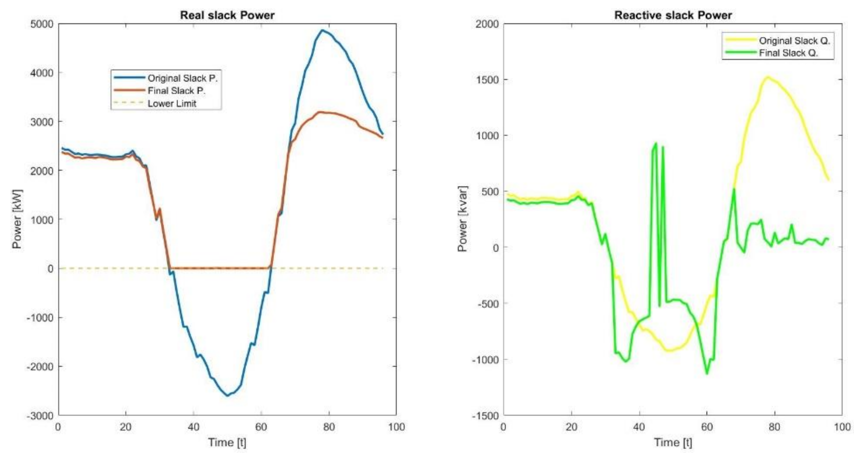

Figure 9-54. Slack powers, Scheme 5 – 1, RETE81

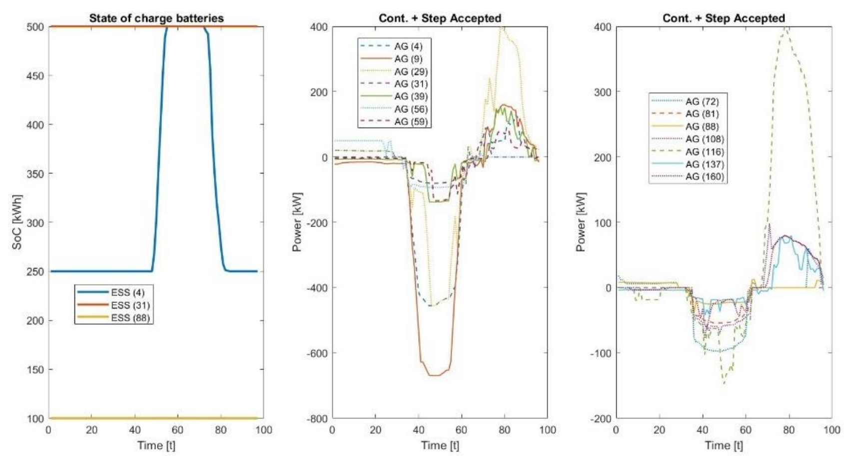

Figure 9-55. Accepted resources, Scheme 5 – 1, RETE81

In the second scenario, real power exchange at the TSO-DSO interface is limited between -1 MW and 2 MW for the complete simulation horizon. In this condition, the system converges to a total cost equal to 814 $, with the results summarized in Figure 9-56 and Figure 9-57. In this case, all ESS systems are being used, while in the previous one only the system connected to node 4 was being activated. Moreover, the aggregated flexibility cost between the two cases is similar, even when the constraints imposed are considerably different.

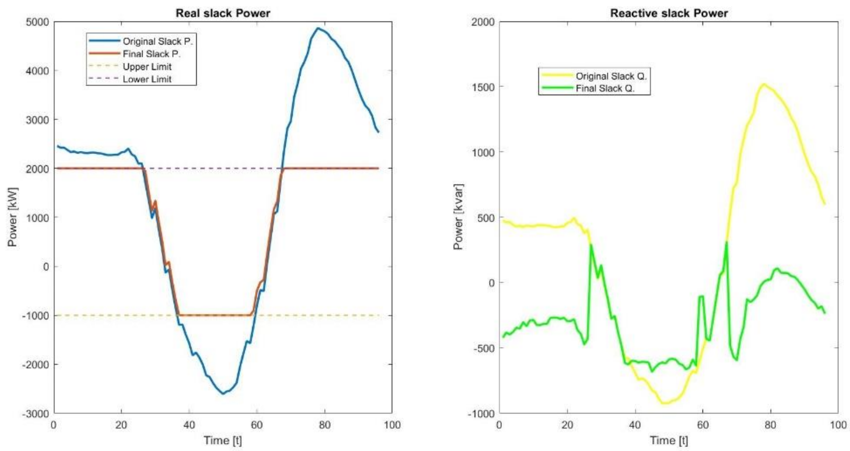

Figure 9-56. Slack powers, Scheme 5 – 2, RETE81

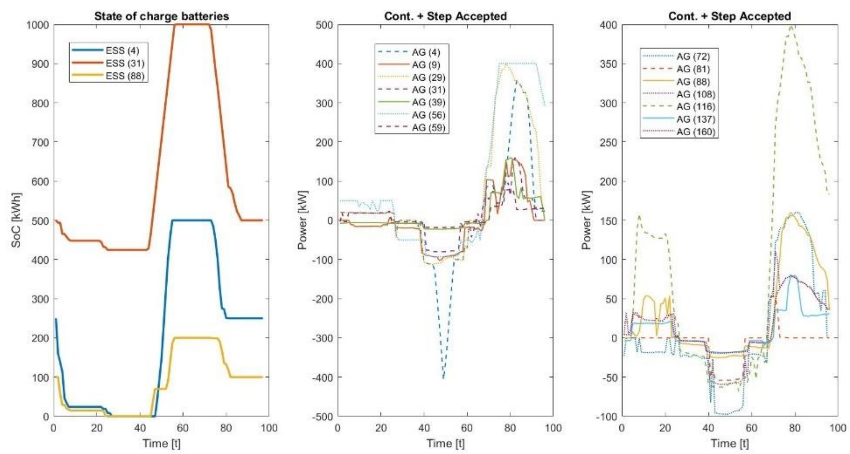

Figure 9-57. Accepted resources, Scheme 5 – 2, RETE81

9.3.3 Scheme 6

For this testing case, the algorithm presented in Section 7.3.4 is slightly modified. Instead of using the first part of the process to obtain the maximum/minimum power exchange between two periods, an approximated maximum/minimum **constant** power profile during two consecutive hours is calculated. In other words, the first part of the algorithm is used to *manually* identify the maximum constant flexibility that can be provided by the network following a stepwise behavior for two hours. The second part of the algorithm, used to minimized activation costs, is used unmodified.

This modified algorithm is implemented to closely represent the aggregation requirements for DER in the Italian regulatory framework, which are briefly discussed in Section 5.2, and serves as an extension or alternative point of view to coordination Scheme 6 while still having the objective of sending an equivalent supply curve to the TSO.

In Figure 9-58, the results for the two-hour step bids between periods 46 and 53 are presented. These plots, in comparison to the ones presented for Scheme 6 so far, show only the difference between the obtained profile and the original one that respects all network constraints, discussed in Scheme 6. As it can be seen, the system can follow 4.5 MW, 3 MW and 1.5 MW steps for the desired range, with the additional flexibility cost indicated by plot's color. Moreover, achieving the stepwise behavior at minimum cost induces an imbalance in the slack power exchanged, shown in the plot's legend, which is caused by the ramp constraints included in the current testing case and energy constraints from DER. The aggregated imbalance is significant and increases as more flexibility is required from the network, and as a result should be taken into consideration when applying an equivalent coordination scheme.

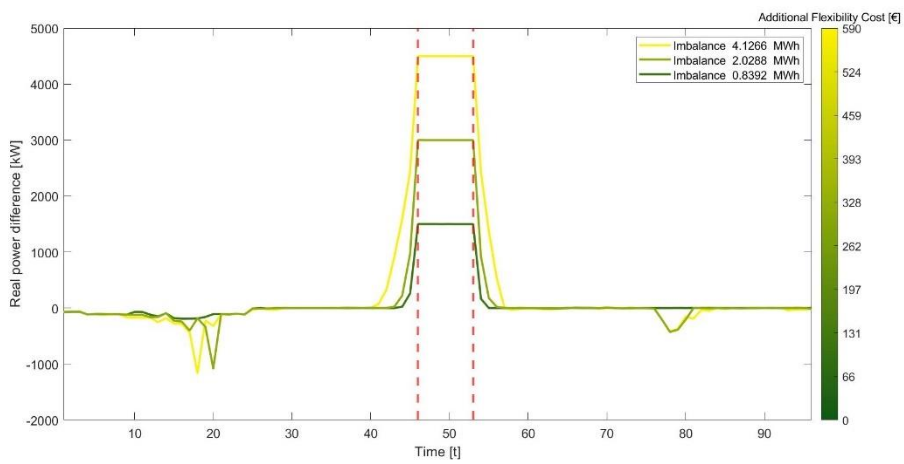

Figure 9-58. Two-hour step bids periods 46-53, Scheme 6, RETE81

For the second case, an upward step is required from the network between periods 6 and 13, as shown in Figure 9-59. The flexibility steps are chosen to be 200 kW, 400 kW and 600 kW, respectively. As before, achieving the flexibility requirement induces an imbalance in the system, although it is much lower than the one observed in Figure 9-58.

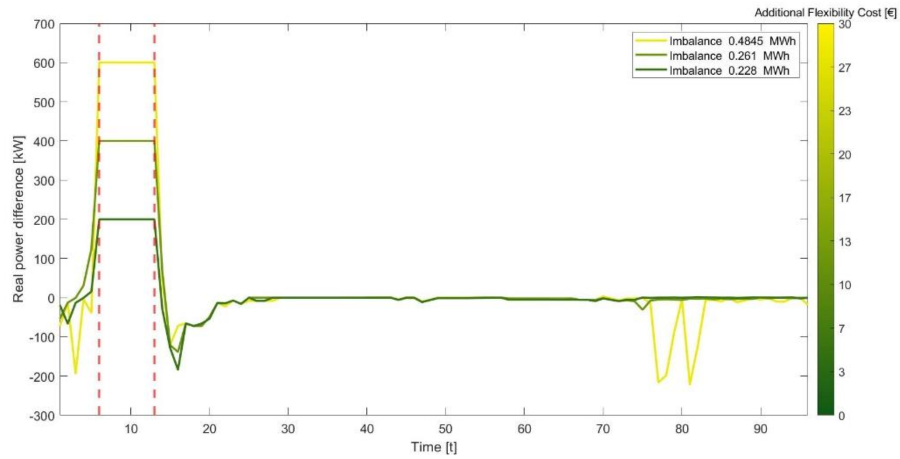

Figure 9-59. Two-hour step bids periods 6-13, Scheme 6, RETE81

For the last case, an aggregated downward flexibility step is demanded from the network between periods 75-82. The steps, shown in Figure 9-60, are equal to 500 kW, 1000 kW and 1500 kW. It is worth noting that the total imbalance induced in the network is close to the relative size of the bids, coherent with the energy constraints that have been introduced in the system, in addition to the active ramping constraints that are observed once more flexibility is required.

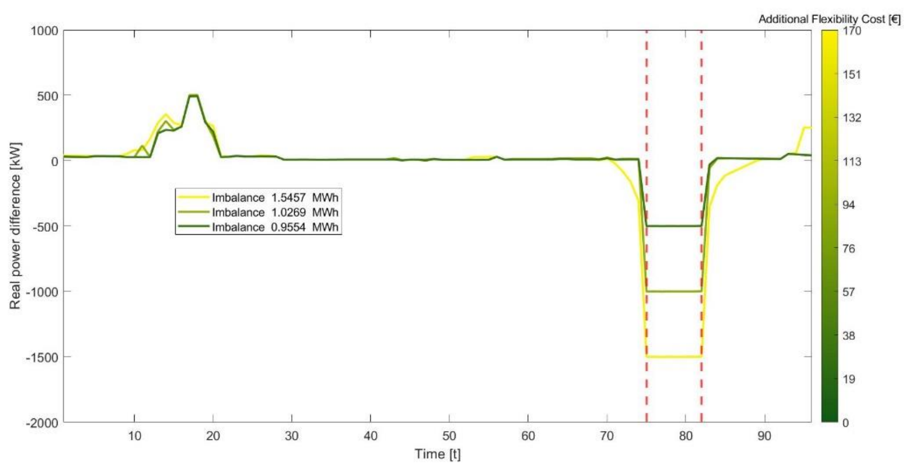

Figure 9-60. Two-hour step bids periods 75-82, Scheme 6, RETE81

It is worth noting that the imbalances shown in the previous cases are measured with respect to the profile presented in Scheme 4, and not with respect to the initial network profile that does not respect network constraints. As a result, the imbalance could be part of the coordination scheme and could not immediately represent additional costs for the DSOs.

9.4 Results Discussion

To start, it is necessary to discuss the numerical behavior of the algorithm in the simulated cases. It was shown, both in the proof-of-concept model and in bigger test scenarios, that variables and equations outside the normal market structure were needed to support the algorithm in its convergence. These additions were needed as the solution process requires smaller and smaller power changes between iterations to approach the optimal system state, with a reasonable approximation error. More work in this regard is required, to improve the methods used to solve numerical concerns in the problem.

On the other hand, simulation time is reasonable regarding the size of the problem and the constraints that have been included. In a more realistic scenario, DSOs or the entity in charge would run the algorithm for a shorter horizon, in which case the solution time would improve even further. Although methods to reduce the size of the problem have been implemented and have proven effective, the platform could be improved by, for example, reducing the number of power flows calculated in iterations by not recalculating it when power changes lower than a sufficiently low threshold are observed.

Regarding the results of the coordination scheme, the framework developed in this thesis is still insufficient to provide a definitive answer in the problem. For that, an economic and agent-based modelling approach, that integrates strategic behavior from aggregators, DSOs and TSOs is needed. Nonetheless, results do show the potential that DSOs possess to act as a second level aggregator for DER connected to distribution networks.

First, it is worth pointing out that if the fit and forget is to be maintained, in which case no possible combination of power injection profiles by DER breaks network constraints, no coordination scheme would be required. In this scenario, communication infrastructure limits aside, the TSO could access all the flexibility resources connected to distribution networks.

However, with the increased penetration of DER, and the efficiency and coordination guidelines provided by the Clean Energy Package, the fit and forget approach is expected to be less and less common for network operation and planning. As a result, effectively using existing network assets becomes a must, translating to the necessity of coordination schemes for using flexibility from distribution networks. These conditions are represented in testing cases in which distribution networks have some active constraints if DER are not managed appropriately.

The Coordination Schemes tested show, to different degrees depending on the specific case, that the role of the DSO would be similar to an aggregator of DER at the network level. The DSO would, by aggregating and presenting flexibility resources that respect distribution network constraints, give access to these resources to the TSO, without directly involving it into distribution network management. As a result, an efficient, effective, and secure operation of increasingly complex electric systems could be achieved.

The selection of the appropriate coordination scheme would depend on economic, operative, and regulatory factors. Among the most important ones are: I.) the degree of responsibility of DSOs in managing local flexibility resources, II.) the possibility of establishing a local flexibility market, like in the schemes numerically tested in this thesis, III.) overall efficiency of the coordination schemes, and IV.) the incentives to exert market power and abuse strategic positions. The last aspect is especially relevant given that DSOs would have the availability to procure and remunerate resources, which entails a level of independency and transparency that might not exist in current regulatory frameworks. In this context, management of ESS owned by DSO should be treated with care, as they would directly compete with other DER. Depending on the incentives from the regulatory framework, DSOs could unfairly prefer their own assets, resulting in an inefficient market result.

In addition to previous aspects, the differentiation between flexibility products, and how that affects the procurement process, should also be considered. During this thesis, it was implicitly assumed that all bids are standard products and are procured indifferently. In a more realistic scenario, flexibility requirements could be grouped in two large groups: frequency and congestion services. The first ones are mainly of interest to the TSO, while the second could be used locally by DSOs, or globally by TSOs. The possible competition that might emerge between the two type of services deserves further attention.

Finally, it is worth point out that the results presented are insufficient to provide answers to the decentralization requirement proposed by the Clean Energy Package, and how it could be helped to temporarily improved global welfare. As highlighted by the literature and the European Research projects, centralized and complete information flexibility markets are, by design, the most efficient and competitive. However, technical constraints are obstacles that electric systems need to overcome to achieve such ideal scenario in the short and mid-term. These challenges are not represented in the proposed simulation framework but should be included for a more complete evaluation of the topic.

10 Conclusions and future work

To address and organize the conclusions from this project presented in this section, they are divided into three parts: I.) simulation platform, II.) regulatory framework and III.) future work.

10.1 Simulation platform

The simulation platform developed in this thesis to analyze the TSO-DSO coordination problem presents some comparative advantages to the ones presented in the literature, and even those develop by European founded projects.

First, the network approximation method used and integrated into the optimization algorithm has the potential to achieve an adequate and sufficiently good representation of physical constraints. Moreover, the potential to improve the solution iteratively as the algorithm progresses is worth further attention, as it could be used to appropriately modelled network cases where other approximated methods failed to do so.

Moreover, the representation of DER and their aggregation improves upon previous works by including a more realistic method on managing their reactive power. This enhancement is especially relevant as network codes start requiring voltage support characteristics to DER to mitigate congestion problems. By including a direct way to prioritize reactive power use in the market schemes to solve internal network constraints, the model developed presents a more realistic approximation to the coordination problem in flexibility markets, in comparison to models where only real power is considered.

Finally, the three coordination schemes numerically tested, in addition to their small modifications or alterations presented during the simulation results, show the capability of the simulation framework to effectively represent coordination schemes. The model's potential could facilitate the comparison and improvement of coordination schemes once DSOs, TSOs, and the regulator are in the process of selecting the appropriate approach.

However, these advantages are only accessible and effective when numerical concerns are solved. Attention has been given during this thesis to solve issues observed in the solution method, but additional work is needed to arrive to an algorithm that ensures the operation condition found resembles, in the best possible way, the optimal solution of the problem. In this process, comparison with other tools, including commercial ones, could prove useful.

10.2 Regulatory framework

It is worth mentioning that the simulation framework developed is insufficient to provide a definitive answer regarding the TSO-DSO coordination problem for flexibility markets. As it is explained in the next Section, the analysis requires a broader perspective, similarly to how it is carried out in other European research projects.

Nonetheless, the models developed, and their numerical results, show insights into what could be an effective and efficient coordination scheme. In general terms, in all coordination schemes in which the DSO is involved, they are taking a similar role to the one aggregators assume when they administer and present bids of their respective DER. However, there is a main key difference between the two: while the traditional aggregator obtains profits from their DER and the market, the DSO should take a neutral position that contributes to maximizing social welfare.

As a result, the regulatory framework for TSO-DSO coordination schemes should provide sufficient incentives for DSO to efficiently aggregate resources connected to their networks, before later presenting them to upper market sections. Minimizing their inherence in the process is a vital condition to achieve an efficient equilibrium that maximizes the flexibility that can be provided by DER at all voltage levels. Among other aspects, regulators should consider I.) the strategic position DSOs have in their incumbent networks, II.) the incentive DSO would naturally possess to reserve the *best* resources for themselves and with them, maximize their revenue by, among other actions, avoid local network investments, and III.) the possibility of DSOs prioritizing their own resources, like directly managed ESS, instead of allowing a fair competition between all DER connected to their networks.

Regarding the decentralization paradigm proposed by the Clean Energy Package for all Europeans, it presents a trade-off between efficiency, on the one hand, and computational and communication infrastructure constraints, on the other. From a pure economic standpoint, the *best* solution is, and always will be, the one that explicitly represents in the same problem all resources, bids, and constraints. Although nowadays this ideal case is far from being a reality, coordination schemes should serve as an intermediate step that actively contributes to harness flexibility wherever is found, while minimizing negative impacts on overall system efficiency and social welfare. Both previous requirements are a must in electricity systems that use more and more renewable energy resources and other low carbon solutions, with the goal of achieving carbon neutrality in mind.

10.3 Future work

Many of the weakness of the simulation framework have already been discussed during this document. Here, the most important paths to improvements are highlighted, which are derived from both the developing and testing process, in addition to a comparison with the literature and other research project.

First, the modelling approach and the simulation platform assumes complete and static information about the distribution network and the DER connected to it. Nowadays, this is not the case because in low voltage network direct measurements are limited, meaning no complete information regarding variables of interest is available. As a result, it is necessary to integrate into the simulation platforms state estimation procedures, which could enable the incorporation of available information to represent network conditions more realistically. Moreover, it is also necessary to integrate Distribution System Management practices that could help to mitigate system constraints before activating and remunerating flexibility resources.

Secondly, it is necessary to complete DER modelling with aggregation rules for participating in flexibility markets. This step is necessary to understand the coupling between aggregators and the way in which DSOs could handle their flexibility at the distribution level. Among the bid constraints not implemented in the simulation framework are minimum on/off time for step bids, and ramp constraints for such bids. In addition to the previous characteristics for standard bids, other specific products could be introduced in the model, according with the needs of DSOs, aggregators and DERs. It is worth noting that the iterative algorithm developed is flexible enough to accommodate such requirements.

Once standard and specific products are appropriately modelled, an additional step in the development process would be to establish different requirements for flexibility products. In the discussion presented, no differentiation is established for flexibility products at the distribution level, and their procurement process. However, such differentiation is more evident at the Transmission level, especially between frequency and congestion mitigation services. As a result, coordination schemes should also integrate and evaluate possible implication of flexibility services divided into categories.

Given these additions to the simulation platform, the coupling with agent-based modelling of market participants would be useful to better understand, from an economic perspective, the implications of the coordination schemes. The approach taken in this thesis to emulate the aggregation procedure of participating agents is limited and serves only to obtain sufficient numerical insights in the coordination process. However, a modelling approach that incorporates the incentives and behavior of each aggregator, which in turn depends on their technologies, their opportunity costs, and the level of competition in the market, is needed to understand dynamics that might emerge in the coordination schemes. In addition, this framework also enables further evaluation of the DSO strategic position in local flexibility markets and the coordination schemes.

Furthermore, it is necessary to understand the interaction in the coordination schemes once different DSOs participate in the flexibility markets. Once TSOs have different options to compare and procure flexibility needs, in addition to resources connected to the transmission level, the effectiveness and efficiency of the coordination schemes can be better understood and evaluated.

Finally, at the European level and more broadly in the discussions of market integration proposed by the Clean Energy Package, it is necessary to also incorporate into the simulation platforms different TSO-TSO coordination schemes, and their implications downstream for DSOs, and DER. In this context, the geographical and physical requirements for different flexibility products should be treated in more detail.

11 Bibliography

[1] PJM, Learning Center PJM, (2020). https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx (accessed September 11, 2020).

[2] UN, UN Population Data Base, (2020). https://www.un.org/en/development/desa/population/ (accessed December 31, 2020).

[3] OMS, Our World In Data Energy, Oxford Martin School. (2020). https://ourworldindata.org/energy (accessed October 20, 2020).

[4] International Protocol on Climate Change, Climate Change 2014 Synthesis Report: Summary Chapter for Policymakers, 2014. https://doi.org/10.1017/CBO9781107415324.

[5] United Nations Environment programme, Emissions Gap Report 2018, Nairobi, 2018. http://wedocs.unep.org/bitstream/handle/20.500.11822/26895/EGR2018_FullReport_EN.pdfissions-gap-report-2018.

[6] World Meteorological Organization, U. Environment, G.C. Project, IPCC, United In Science: High-level synthesis report of latest climate science information convened by the Science Advisory Group of the UN Climate Action Summit 2019, 2019. https://library.wmo.int/doc_num.php?explnum_id=9937.

[7] L. Cozzi, T. Gould, S. Bouckart, D. Crow, T.-Y. Kim, C. McGlade, P. Olejarnik, B. Wanner, D. Wetzel, World Energy Outlook 2020, 2050 (2020) 1–461. https://www.iea.org/reports/world-energy-outlook-2020.

[8] I. Pérez-Arriaga, C. Knittel, A. Bharatkumar, M. Birk, S. Burger, J.P. Chaves, P. Duenas-Martinez, I. Herraro, S. Huntington, J. Jenkins, M. Luke, R. Miller, P. Rodilla, R. Tabors, K. Tapia-Ahumada, C. Vergara, N. Xu, Utility of the Future, 2016. http://energy.mit.edu/research/utility-future-study/.

[9] IRENA, Renewable Power Generation Costs in 2019, 2020. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf.

[10] IRENA, Electricity storage and renewables: Costs and markets to 2030, 2017. http://irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets%0Ahttps://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf.

[11] Green Energy Markets, Projections for distributed energy resources-solar PV and stationary energy battery systems, (2020). https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-

methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en.

[12] M. Hatzopoulou, L. Minet, Clearing the air, Toronto, 2020. https://clearingtheair.ca/.

[13] T. Gersdorf, P. Schaufuss, S. Schenk, P. Hertzke, McKinsey Electric Vehicle Index: Europe cushions a global plunge in EV sales, McKinsey. (2020). https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/mckinsey-electric-vehicle-index-europe-cushions-a-global-plunge-in-ev-sales (accessed January 2, 2021).

[14] J. Hamilton, B. Walton, J. Ringrow, G. Alberts, S. Fullerton-Smit, E. Day, Electric vehicles Trends, setting a course for 2030, 2020. https://www2.deloitte.com/uk/en/insights/focus/future-of-mobility/electric-vehicle-trends-2030.html.

[15] EU-SysFlex, State-of-the-Art Literature Review of System Scarcities at High Levels of Renewable Generation, (2018) 1–114. http://eu-sysflex.com/wp-content/uploads/2018/12/D2.1_State-of-the-Art_Literature_Review_of_System_Scarcities_at_High_Levels_of_Renewable_Generation_V1.pdf.

[16] EU-SysFlex, Product Definition for Innovative System Services, (2019) 96. https://eu-sysflex.com/wp-content/uploads/2019/08/D3.1_Final_Submitted.pdf.

[17] A. Nouicer, L. Meeus, The EU Clean Energy Package, Florence, 2019. https://doi.org/10.2870/33236.

[18] European Comission, Clean energy for all Europeans, 2017. https://doi.org/10.2833/9937.

[19] European Commission, Stepping up Europe's 2030 climate ambition Investing, EXECUTIVE SUMMARY OF THE IMPACT ASSESSMENT REPORT Accompanying, 2020. https://knowledge4policy.ec.europa.eu/publication/communication-com2020562-stepping-europe's-2030-climate-ambition-investing-climate_en.

[20] European Commission, Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people, Journal of Chemical Information and Modeling. 53 (2020) 1689–1699.

[21] The European Commission, Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Official Journal of the European Union. 2017 (2017) 312/6-312/53.

[22] Z. Vujasinović, D. Vlaisavljević, D. Orlić, Final Report : Models of regional cooperation for balancing energy – Exchange of balancing energy (Task 4), 2019. https://www.energy-community.org/dam/jcr:e46d0613-35e0-43d0-9d2a-d98d430e315d/EKC_IMP_task4report_032019.pdf.

[23] ENTSO-E, Electricity Balancing, (2019). https://www.entsoe.eu/network_codes/eb/ (accessed October 25, 2020).

[24] J.P. Chaves Ávila, L. Lind, CoordiNet Deliverable D1.1: Market and regulatory analysis: Analysis of current market and regulatory framework in the involved areas, 2019. https://coordinet-project.eu/publications/deliverables.

[25] ARERA, TESTO INTEGRATO DEL DISPACCIAMENTO ELETTRICO, Documento per la Consultazione 322/2019/R, Milano, 2019. https://www.arera.it/it/docs/19/322-19.htm.

[26] TERNA, Progetto pilota UVAM e altri Progetti pilota ai sensi della delibera 300/2017/R/eel, 2018. https://www.terna.it/it/sistema-elettrico/progetti-pilota-delibera-arera-300-2017-reel/progetto-pilota-uvam.

[27] European Parliament, Directive 2019/944 on Common Rules for the Internal Market for Electricity, Official Journal of the European Union. (2019) 18. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019L0944.

[28] European Parliament and the Council, Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity, Official Journal of the European Union. 2019 (2018) 54–124. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN.

[29] M. Delfanti, A. Galliani, V. Olivieri, The new role of DSOs : ancillary services from RES towards a local dispatch, in: CIRED Workshop, Rome, Italy, 2014: pp. 1–5. http://www.cired.net/publications/workshop2014/papers/CIRED2014WS_0428_final.pdf.

[30] M. Delfanti, E. Fasciolo, V. Olivieri, M. Pozzi, A2A project: A practical implementation of smart grids in the urban area of Milan, Electric Power Systems Research. 120 (2015) 2–19. https://doi.org/10.1016/j.epsr.2014.11.019.

[31] S. Verzeri, C. Bovo, V. Ilea, Ancillary Services and Aggregated Units: Computational Model as Support Tool for the Offer Submission in the New Market Structure, Master Thesis in Energy Engineering, Politecnico di Milano, 2018.

[32] IRENA, Innovative Ancillary Services: innovation Landscape Brief, (2019) 24. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovative_ancillary_services_2019.pdf?la=en&hash=F3D83E86922DEED7AA3DE3091F3E49460C9EC1A0.

[33] UPME, Carbon Trust, Universidad Nacional, Imperial College of London, Despliegue de tecnologías de redes inteligentes en Colombia, Bogotá, 2020. https://www1.upme.gov.co/simco/Cifras-Sectoriales/Paginas/Publicaciones.aspx.

[34] G. Petretto, M. Cantù, G. Gigliucci, F. Pilo, G. Pisano, N. Natale, G.G. Soma, M. Coppo, R. Turri, Representative distribution network models for assessing the role of active distribution systems in bulk ancillary services markets, in: 19th Power Systems Computation Conference, PSCC 2016, Genoa, Italy, 2016. https://doi.org/10.1109/PSCC.2016.7541020.

[35] Z. Yuan, M.R. Hesamzadeh, Hierarchical coordination of TSO-DSO economic dispatch considering large-scale integration of distributed energy resources, Applied Energy. 195 (2017) 600–615. https://doi.org/10.1016/j.apenergy.2017.03.042.

[36] S.Y. Hadush, L. Meeus, DSO-TSO cooperation issues and solutions for distribution grid congestion management, Energy Policy. 120 (2018) 610–621. https://doi.org/10.1016/j.enpol.2018.05.065.

[37] F. Capitanescu, TSO–DSO interaction: Active distribution network power chart for TSO ancillary services provision, Electric Power Systems Research. 163 (2018) 226–230. https://doi.org/10.1016/j.epsr.2018.06.009.

[38] A. Vicente-Pastor, J. Nieto-Martin, D.W. Bunn, A. Laur, Evaluation of flexibility markets for retailer-dso-tso coordination, IEEE Transactions on Power Systems. 34 (2019) 2003–2012. https://doi.org/10.1109/TPWRS.2018.2880123.

[39] G. De Zotti, S.A. Pourmousavi Kani, J.M. Morales, H. Madsen, N.K. Poulsen, A Control-based Method to Meet TSO and DSO Ancillary Services Needs by Flexible End-Users, IEEE Transactions on Power Systems. (2019) 1–1. https://doi.org/10.1109/tpwrs.2019.2951623.

[40] SmartNet Project, TSO-DSO Coordination for Acquiring Ancillary Services from Distribution Grids, 2019. http://smartnet-project.eu/publications.

[41] H. Gerard, E. Rivero, D. Six, Basic schemes for TSO-DSO coordination and ancillary services provision, 2020. http://smartnet-project.eu/publications.

[42] F.S. Vito, G.L. N-side, N.R. Tecnalia, M. Marroquin, C. Andersen, M. Dzamarija, Aggregation models, 2018. http://smartnet-project.eu/publications.

[43] G. Leclercq, M. Pavesi, T. Gueuning, A. Ashouri, P. Sels, F. Geth, R. D'hulst, H. Le Cadre, Network and market models, 2019. http://smartnet-project.eu/publications.

[44] M. Rossi, J. Rodrigues, D.M. Camargo, Y. Vardanyan, R. Ebrahimy, J. Jimeno, N. Ruiz, SmartNet simulation platform, 2019. http://smartnet-project.eu/publications.

[45] H. Svendsen, M. Rossi, G. Viganò, J. Merino, J. Henein, Scenario setup and simulation results Authors :, 2019. http://smartnet-project.eu/publications.

[46] I. Gomez, S. Riaño, C. Madina, M. Rossi, P. Kuusela, P. Koponen, H. Aghaie, G. Migliavacca, E. Rivero,

H. Xu, I. Kockar, Cost-benefit analysis of the selected national cases, 2019. http://smartnet-project.eu/publications.

[47] D. Siface, G. Migliavacca, M. Rossi, M. Andrei, H. Gerard, Y. Vardanyan, P. Koponen, Policy recommendations to implement and / or overcome barriers and enable TSO-ISO integration, 2019. http://smartnet-project.eu/publications.

[48] EU-SysFlex consortium, EU-SysFlex - System operation and flexibility solutions for integrating 50 % renewables by 2030, (2018) 24. https://eu-sysflex.com/wp-content/uploads/2019/10/EUSysFlex-brochure_web.pdf.

[49] EU-SysFlex, Conceptual market organisations for the provision of innovative system services : role models , associated market designs and regulatory frameworks, (2020).

[50] InterFlex, Project Summary - January 2017 December 2019, (2020). https://interflex-h2020.com/.

[51] T. Gross, G. Jarry, A. Larsen, M. Willems, T. Wagner, Market Models for Local Flexibility Procurement : Interflex Experience and Main Challenges, in: 25 Th International Conference on Electricity Distribution, Madrid, Spain, 2019: pp. 3–6. https://www.cired-repository.org/handle/20.500.12455/756?show=full.

[52] C. Dumbs, G. Jarry, D. Laffaille, S. Hes, D. Panic, I. Leisse, J. Bruschi, Flexibility for DSO on a local scale: Business models and associated regulatory questions raised in the Interflex project, CIRED Workshop. (2018) 7–8. https://interflex-h2020.com/wp-content/uploads/2018/04/Flexibility-for-DSO.pdf.

[53] Coordinet, Coordinet Project, (2020). https://coordinet-project.eu/ (accessed January 3, 2021).

[54] OSMOSE, OSMOSE, (2021). https://www.osmose-h2020.eu/ (accessed April 2, 2021).

[55] M. Villavicencio, J.-H. Keppler, P. Geoffron, B. Bocker, M. Bucksteeg, C. Weber, S. Bortolotti, Candidate market mechanisms and regulatory frameworks, 2020. https://www.osmose-h2020.eu/project-overview/#osmose-approach.

[56] IRENA, Innovation Landscape for a Renewable-Powered Future: solutions to integrate variable renewables, 2019. https://www.irena.org/publications/2019/Feb/Innovation-landscape-for-a-renewable-powered-future.

[57] European Commission, Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation, Official Journal of the European Union. L 220 (2017) 1–120.

[58] ENTSO-E, Supporting Document for the Network Code on Electricity Balancing, 2013. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_TO_RECOMMENDATION_032015/140806_NCEB_Supporting_Document.pdf.

[59] L. Marchisio, F. Genoese, F. Raffo, Distributed Resources in the Italian Ancillary Services Market: taking stock after two years, 2019. https://download.terna.it/terna/0000/1224/90.PDF.

[60] TERNA, Progetto pilota su partecipazione della domanda al MSD ai sensi della delibera 300 / 2017 / R / eel, 2017. https://www.terna.it/it/sistema-elettrico/progetti-pilota-delibera-arera-300-2017-reel/progetto-pilota-uvac.

[61] INTERRFACE, ENTSO-E, UPRC, EMP, BME, RTU, TUT, RSE, EUI, D3.2 Definition of new / changing requirements for Market Designs, 2020. http://www.interrface.eu/sites/default/files/publications/INTERRFACE_D3.2_v1.0.pdf.

[62] M. Mashhour, M.A. Golkar, S.M. Moghaddas Tafreshi, Efficient aggregation of distributed generations and interruptible loads: A new tool for market integration of distributed recourses, in: 2010 7th International Conference on the European Energy Market, EEM 2010, IEEE, Madrid, Spain, 2010: pp. 1–6. https://doi.org/10.1109/EEM.2010.5558776.

[63] A.G. Madureira, J.A. Peças Lopes, Ancillary services market framework for voltage control in distribution networks with microgrids, Electric Power Systems Research. 86 (2012) 1–7. https://doi.org/10.1016/j.epsr.2011.12.016.

[64] M. Velasquez, N. Quijano, A. Cadena, Economic Dispatch Problem, IEEE Latin America Transactions. 15 (2017) 656–662.

[65] D. Godoy-González, E. Gil, G. Gutiérrez-Alcaraz, Ramping ancillary service for cost-based electricity markets with high penetration of variable renewable energy, Energy Economics. 85 (2020) 104556. https://doi.org/10.1016/j.eneco.2019.104556.

[66] A. Esmat, J. Usaola, M.Á. Moreno, Distribution-level flexibility market for congestion management, Energies. 11 (2018). https://doi.org/10.3390/en11051056.

[67] M. Di Somma, G. Graditi, P. Siano, Optimal Bidding Strategy for a DER Aggregator in the Day-Ahead Market in the Presence of Demand Flexibility, IEEE Transactions on Industrial Electronics. 66 (2019) 1509–1519. https://doi.org/10.1109/TIE.2018.2829677.

[68] IEA, Today in Energy, (2020). https://www.eia.gov/todayinenergy/detail.php?id=11991 (accessed September 13, 2020).

[69] K. Qian, C. Zhou, M. Allan, Y. Yuan, Modeling of load demand due to EV battery charging in distribution systems, IEEE Transactions on Power Systems. 26 (2011) 802–810.

https://doi.org/10.1109/TPWRS.2010.2057456.

[70] O. Megel, Storage in Power Systems : Frequency Control , Scheduling, Doctoral Thesis, ETH Zurich, 2017. https://www.research-collection.ethz.ch/handle/20.500.11850/171342.

[71] D.M. Rosewater, D.A. Copp, T.A. Nguyen, R.H. Byrne, S. Santoso, Battery Energy Storage Models for Optimal Control, IEEE Access. 7 (2019) 178357–178391. https://doi.org/10.1109/ACCESS.2019.2957698.

[72] M.E. Baran, F.F. Wu, Network reconfiguration in distribution systems for loss reduction and load balancing, IEEE Transactions on Power Delivery. 4 (1989) 1401–1408. https://doi.org/0884-8977/89/0400-1401$01.00.

[73] R.A. Jabr, Radial distribution load flow using conic programming, IEEE Transactions on Power Systems. 21 (2006) 1458–1459. https://doi.org/10.1109/TPWRS.2006.879234.

[74] H. Yuan, F. Li, Y. Wei, J. Zhu, Novel linearized power flow and linearized OPF models for active distribution networks with application in distribution LMP, IEEE Transactions on Smart Grid. 9 (2018) 438–448. https://doi.org/10.1109/TSG.2016.2594814.

[75] Y. Wang, N. Zhang, H. Li, J. Yang, C. Kang, Linear three-phase power flow for unbalanced active distribution networks with PV nodes, CSEE Journal of Power and Energy Systems. 3 (2017) 321–324. https://doi.org/10.17775/cseejpes.2017.00240.

[76] C. Bovo, V. Ilea, Optimal Power Flow in Distribution Networks, Politecnico Di Milano, Fondazione Politecnico, Siemens SpA. (2019) 1–32.

[77] J.J. Grainger, W.D. Stevenson, Power System Analysis, McGraw-Hill, New york, 1994.

[78] A. Garces, A Linear Three-Phase Load Flow for Power Distribution Systems, IEEE Transactions on Power Systems. 31 (2016) 827–828. https://doi.org/10.1109/TPWRS.2015.2394296.

[79] K. Li, K.J. Tseng, Energy efficiency of lithium-ion battery used as energy storage devices in micro-grid, in: IECON 2015 - 41st Annual Conference of the IEEE Industrial Electronics Society, IEEE, Yokohama, Japan, 2015: pp. 5235–5240. https://doi.org/10.1109/IECON.2015.7392923.

[80] J.A. Jardini, C.M.V. Tahan, M.R. Gouvea, S.U. Ahn, F.M. Figueiredo, Daily load profiles for residential, commercial and industrial low voltage consumers, IEEE Transactions on Power Delivery. 15 (2000) 375–380. https://doi.org/10.1109/61.847276.

[81] L. Calearo, A. Thingvad, K. Suzuki, M. Marinelli, Grid Loading Due to EV Charging Profiles Based on Pseudo-Real Driving Pattern and User Behavior, IEEE Transactions on Transportation Electrification. 5 (2019) 683–694. https://doi.org/10.1109/TTE.2019.2921854.

[82] US Department of Energy, Fuel Economy, (2020). https://www.fueleconomy.gov/ (accessed January 3, 2021).

[83] L. Meeus, A. Nouicer, The EU Clean Energy Package, Florence, 2018. https://doi.org/10.2870/013463.

[84] D. Simoncelli, C. Bovo, V. Ilea, European Platforms for the Exchange of Balancing Energy, Master Thesis in Energy Engineering, Politecnico di Milano, 2018.

12 Appendix

12.1 Network characteristics

Table 12-1. Branch TESTOPF (base 100MVA)

Bus From	Bus To	R [p.u.]	X [p.u.]	Imax [A]
1	2	0.1	1.4292	70
2	3	0.75	1.333333	70
3	4	0.45	0.666666	70
4	5	0.46	0.7556	70
4	6	0.09	0.222222	70
6	7	0.37	0.5778	70
6	8	0.548	0.8889	70
8	9	0.16	0.266666	70
2	10	0.6667	1.111111	70
10	11	0.32	0.533333	70
11	12	0.26	0.4	70
12	13	0.33	0.622222	70
13	14	0.61	1.033333	70

Table 12-2. Generation TESTOPF (base 100MVA) – Slack node 1

Bus	PG [kW]	QG [kVar]
1	0	0
5	250	110
7	250	-110
9	250	110
12	250	110
14	250	110

Table 12-3. Bus TESTOPF (base 100MVA)

Bus	PD [kw]	QD [kvar]	Vn [kV]
1	0	0	132
2	0	0	15
3	500	250	15
4	500	250	15
5	500	250	15
6	500	250	15
7	500	250	15
8	500	250	15
9	500	250	15
10	500	250	15
11	500	250	15
12	500	250	15
13	500	250	15
14	500	250	15

Table 12-4. Branch TESTOPF (base 2.5MVA)

Bus From	Bus To	R [p.u.]	X [p.u.]	B [p.u.]	Imax [A]
1	2	0.0100	0.0800	0.0000	20.91
2	3	0.0022	0.0016	0.0006	241

3	4	0.0015	0.0011	0.0004	241
4	5	0.0276	0.0205	0.0077	241
5	6	0.0321	0.0239	0.0090	241
6	7	0.0254	0.0189	0.0071	241
7	18	0.0000	0.0000	0.0000	184
8	9	0.0132	0.0066	0.0024	184
9	10	0.0011	0.0005	0.0002	184
10	11	0.0264	0.0131	0.0047	184
11	20	0.0007	0.0000	0.0001	184
12	21	0.0063	0.0031	0.0011	184
12	23	0.0950	0.2040	0.0000	11.59
13	22	0.0026	0.0013	0.0005	184
13	15	0.0004	0.0002	0.0001	184
14	24	0.0011	0.0006	0.0002	184
14	25	0.0000	0.0002	0.0001	184
15	16	0.0017	0.0009	0.0003	184
16	17	0.0045	0.0023	0.0008	184
17	26	0.0007	0.0003	0.0001	184
18	8	0.0000	0.0002	0.0001	184
19	12	0.0000	0.0000	0.0000	184
20	19	0.0475	0.0237	0.0085	184
21	13	0.0075	0.0037	0.0013	184
22	14	0.0035	0.0017	0.0006	184
23	27	0.3236	0.2407	0.0001	241

Table 12-5. Bus TESTOPF (base 2.5MVA)

Bus	**PD [kW]**	**QD [kvar]**	**Vn [kV]**
1	0	0	69
2	0	0	24.9
3	0	0	24.9
4	55	29	24.9
5	16	8	24.9
6	0	0	24.9
7	0	0	24.9
8	174	89	24.9
9	45	22	24.9
10	4	2	24.9
11	52	23	24.9
12	0	0	24.9
13	32	17	24.9
14	122	63	24.9
15	0	0	24.9
16	414	20	24.9
17	45	23	24.9
18	0	0	24.9
19	0	0	24.9
20	4	2	24.9
21	17	8	24.9
22	206	121	24.9
23	0	0	24.9
24	27	21	4.16
25	28	14	24.9
26	83	-391	24.9
27	450	225	24.9

Table 12-6. Bus TEST81 (base 100MVA)

Bus	**PD [kW]**	**QD [kvar]**	**Vn [kV]**	**Bus**	**PD [kW]**	**QD [kvar]**	**Vn [kV]**
1	0.00	0.00	132	86	8.88	5.07	15
2	0.00	0.00	15	87	4.15	2.71	15
3	0.00	0.00	15	88	123.00	65.61	15
4	0.00	0.00	15	89	0.00	0.00	15
5	0.00	0.00	15	90	15.09	8.77	15
6	0.00	0.00	15	91	6.92	4.09	15
7	0.00	0.00	15	92	0.00	0.00	15
8	17.25	9.85	15	93	0.00	0.00	15
9	0.00	0.00	15	94	18.03	9.74	15
10	0.00	0.00	15	95	0.00	0.00	15
11	0.00	0.00	15	96	9.20	5.23	15
12	0.00	0.00	15	97	46.63	25.30	15
13	28.75	16.25	15	98	0.00	0.00	15
14	0.00	0.00	15	99	6.82	4.04	15
15	61.45	33.57	15	100	14.09	8.27	15
16	0.00	0.00	15	101	36.04	19.43	15
17	7.07	4.16	15	102	0.00	0.00	15
18	24.64	13.22	15	103	0.00	0.00	15
19	44.68	24.32	15	104	0.00	0.00	15
20	0.00	0.00	15	105	0.00	0.00	15
21	0.00	0.00	15	106	0.00	0.00	15
22	0.00	0.00	15	107	14.62	8.53	15
23	221.60	112.48	15	108	0.00	0.00	15
24	0.00	0.00	15	109	13.66	8.05	15
25	7.74	4.50	15	110	0.00	0.00	15
26	7.73	4.49	15	111	7.93	4.59	15
27	0.00	0.00	15	112	0.00	0.00	15
28	6.82	4.04	15	113	0.00	0.00	15
29	0.00	0.00	15	114	0.00	0.00	15
30	16.18	9.31	15	115	6.83	4.04	15
31	0.00	0.00	15	116	0.00	0.00	15
32	0.00	0.00	15	117	6.96	4.11	15
33	6.83	4.04	15	118	59.98	54.40	15
34	0.00	0.00	15	119	12.65	7.55	15
35	27.94	15.84	15	120	0.00	0.00	15
36	0.00	0.00	15	121	0.00	0.00	15
37	6.83	4.04	15	122	0.00	0.00	15
38	0.00	0.00	15	123	6.91	4.72	15
39	7.69	4.47	15	124	0.00	0.00	15
40	0.00	0.00	15	125	0.00	0.00	15
41	0.00	0.00	15	126	0.00	0.00	15
42	8.24	4.74	15	127	0.00	0.00	15
43	0.00	0.00	15	128	0.00	0.00	15
44	0.00	0.00	15	129	0.00	0.00	15
45	7.02	4.14	15	130	6.83	4.04	15
46	6.98	4.12	15	131	0.00	0.00	15
47	7.02	4.14	15	132	6.83	4.04	15
48	0.00	0.00	15	133	6.84	4.05	15
49	0.00	0.00	15	134	0.00	0.00	15
50	0.00	0.00	15	135	7.27	4.26	15
51	0.00	0.00	15	136	50.48	27.30	15
52	0.00	0.00	15	137	19.08	10.76	15
53	7.56	4.41	15	138	0.00	0.00	15
54	30.24	17.00	15	139	0.00	0.00	15

55	0.00	0.00	15	140	0.00	0.00	15
56	0.00	0.00	15	141	0.00	0.00	15
57	0.00	0.00	15	142	0.00	0.00	15
58	0.00	0.00	15	143	0.00	0.00	15
59	0.00	0.00	15	144	0.00	0.00	15
60	0.00	0.00	15	145	6.94	4.10	15
61	7.03	4.14	15	146	9.43	5.34	15
62	0.00	0.00	15	147	6.83	4.04	15
63	7.38	4.32	15	148	7.07	4.16	15
64	83.13	74.98	15	149	0.00	0.00	15
65	0.00	0.00	15	150	6.85	4.05	15
66	40.49	22.18	15	151	0.00	0.00	15
67	13.75	8.10	15	152	13.62	8.03	15
68	97.19	38.59	15	153	0.00	0.00	15
69	21.54	12.65	15	154	0.00	0.00	15
70	17.63	10.04	15	155	0.00	0.00	15
71	7.59	4.42	15	156	6.83	4.04	15
72	0.00	0.00	15	157	0.00	0.00	15
73	22.94	13.34	15	158	26.87	19.17	15
74	0.00	0.00	15	159	0.00	0.00	15
75	113.21	62.40	15	160	0.00	0.00	15
76	0.00	0.00	15	161	6.87	4.06	15
77	0.00	0.00	15	162	0.00	0.00	15
78	4.15	2.71	15	163	0.00	0.00	15
79	0.00	0.00	15	164	7.98	4.62	15
80	24.39	14.07	15	165	7.83	4.54	15
81	47.63	12.80	15	166	0.00	0.00	15
82	5.49	3.38	15	167	15.98	9.21	15
83	5.49	3.38	15	168	0.00	0.00	15
84	123.00	65.61	15	169	15.60	8.61	15
85	0.00	0.00	15	170	13.83	8.14	15

Table 12-7. Branch TEST81 (base 100MVA)

Bus From	**Bus To**	**R [p.u.]**	**X [p.u.]**	**B [p.u.]**	**Imax [A]**	**Bus From**	**Bus To**	**R [p.u.]**	**X [p.u.]**	**B [p.u.]**	**Imax [A]**
1	2	0.020	0.571	-0.002	109	79	86	0.234	0.254	0.000	203
1	3	0.020	0.571	-0.002	109	80	88	0.010	0.051	0.000	429
2	4	0.027	0.036	0.000	15	85	89	0.272	0.848	0.000	247
2	5	0.486	2.563	0.001	338	85	90	0.139	0.206	0.000	137
4	6	0.074	0.048	0.000	332	87	91	0.424	0.460	0.000	203
5	7	0.859	3.459	0.001	247	88	92	0.071	0.250	0.000	247
6	8	0.014	0.001	0.000	182	89	93	0.069	0.216	0.000	247
6	9	0.129	0.066	0.000	332	89	94	0.025	0.002	0.000	182
7	10	0.014	0.063	0.000	364	91	95	0.416	0.939	0.000	182
9	11	0.007	0.033	0.000	429	91	96	0.464	1.048	0.000	182
10	12	0.393	0.856	0.000	247	93	97	0.139	0.206	0.000	137
11	13	0.008	0.013	0.000	211	93	98	0.239	0.402	0.000	156
11	14	0.895	0.123	0.000	219	95	99	0.016	0.036	0.000	182
12	15	0.070	0.304	0.000	338	95	100	0.275	0.621	0.000	182
12	16	0.000	0.001	0.000	182	98	101	0.219	0.683	0.000	247
14	17	0.482	0.769	0.000	211	98	102	0.019	0.043	0.000	182
14	18	0.010	0.025	0.000	198	101	103	0.320	0.723	0.000	182
15	19	0.097	0.426	0.000	338	101	104	0.243	0.033	0.000	219
16	20	0.211	0.411	0.000	182	102	105	0.189	0.426	0.000	182

17	21	0.261	0.590	0.000	182	103	106	0.198	0.448	0.000	182
17	22	0.282	0.575	0.000	182	103	107	0.007	0.011	0.000	137
19	23	0.078	0.339	0.000	338	104	108	0.293	0.040	0.000	219
20	24	0.112	0.253	0.000	182	104	109	0.037	0.004	0.000	182
20	25	0.398	0.587	0.000	137	105	110	0.000	0.001	0.000	182
20	26	0.013	0.019	0.000	137	105	111	0.032	0.072	0.000	182
21	27	0.029	0.065	0.000	182	106	112	0.010	0.022	0.000	182
21	28	0.016	0.036	0.000	182	106	113	0.074	0.166	0.000	182
22	29	0.544	0.118	0.000	156	108	114	0.101	0.014	0.000	219
22	30	0.030	0.033	0.000	203	108	115	0.016	0.002	0.000	182
23	31	0.041	0.184	0.000	338	110	116	0.105	0.063	0.000	182
24	32	0.173	0.390	0.000	182	112	117	0.301	0.679	0.000	182
27	33	0.231	0.522	0.000	182	113	118	0.128	0.289	0.000	182
29	34	0.089	0.008	0.000	156	113	119	0.025	0.037	0.000	137
31	35	0.054	0.245	0.000	338	114	120	0.077	0.174	0.000	182
32	36	0.240	0.542	0.000	182	114	121	0.167	0.023	0.000	219
32	37	0.020	0.029	0.000	137	118	122	0.298	0.672	0.000	182
33	38	0.163	0.368	0.000	182	120	123	0.598	0.665	0.000	182
34	39	0.031	0.003	0.000	182	121	124	0.019	0.043	0.000	182
34	40	0.289	0.028	0.000	182	121	125	0.010	0.022	0.000	182
35	41	0.006	0.025	0.000	338	122	126	0.051	0.116	0.000	182
36	42	0.017	0.026	0.000	137	122	127	0.269	0.503	0.000	182
36	43	0.147	0.332	0.000	182	124	128	0.067	0.150	0.000	182
38	44	0.214	0.484	0.000	182	125	129	0.352	0.795	0.000	182
38	45	0.029	0.066	0.000	182	126	130	0.278	0.629	0.000	182
40	46	0.008	0.001	0.000	182	127	131	0.022	0.051	0.000	182
40	47	0.264	0.025	0.000	182	128	132	0.386	0.872	0.000	182
41	48	0.191	0.596	0.000	247	128	133	0.033	0.075	0.000	182
41	49	0.000	0.002	0.000	364	129	134	0.077	0.180	0.000	182
43	50	0.016	0.036	0.000	182	129	135	0.057	0.121	0.000	182
43	51	0.020	0.029	0.000	137	131	136	0.188	0.452	0.000	182
44	52	0.040	0.090	0.000	182	131	137	0.015	0.001	0.000	182
44	53	0.021	0.047	0.000	182	136	138	0.044	0.126	0.000	182
48	54	0.007	0.010	0.000	137	138	139	0.041	0.093	0.000	182
48	55	0.122	0.381	0.000	247	139	140	0.029	0.065	0.000	182
49	56	0.140	0.013	0.000	156	139	141	0.061	0.137	0.000	182
50	57	0.119	0.016	0.000	219	139	142	0.019	0.043	0.000	182
51	58	0.131	0.072	0.000	137	140	143	0.102	0.231	0.000	182
52	59	0.186	0.419	0.000	182	141	144	0.109	0.246	0.000	182
55	60	0.165	0.513	0.000	247	142	145	0.317	0.715	0.000	182
55	61	0.146	0.325	0.000	137	143	146	0.101	0.229	0.000	182
57	62	0.189	0.426	0.000	182	143	147	0.314	0.708	0.000	182
57	63	0.070	0.103	0.000	137	143	148	0.033	0.074	0.000	182
58	64	0.365	0.035	0.000	182	144	149	0.154	0.347	0.000	182
58	65	0.000	0.000	0.000	182	144	150	0.013	0.019	0.000	137
59	66	0.160	0.361	0.000	182	149	151	0.211	0.477	0.000	182
59	67	0.045	0.103	0.000	182	149	152	0.022	0.033	0.000	137
60	68	0.177	0.555	0.000	247	151	153	0.009	0.020	0.000	182
60	69	0.065	0.006	0.000	156	151	154	0.041	0.093	0.000	182
62	70	0.134	0.310	0.000	182	153	155	0.016	0.036	0.000	182
62	71	0.083	0.188	0.000	182	153	156	0.013	0.029	0.000	182
65	72	0.046	0.004	0.000	156	154	157	0.272	0.614	0.000	182
66	73	0.068	0.279	0.000	364	155	158	0.398	0.900	0.000	182
66	74	0.330	0.359	0.000	203	157	159	0.025	0.037	0.000	137
68	75	0.072	0.264	0.000	247	157	160	0.173	0.188	0.000	203
73	76	0.201	0.019	0.000	182	157	161	0.014	0.021	0.000	137
73	77	0.088	0.270	0.000	234	159	162	0.358	0.529	0.000	137
74	78	0.190	0.207	0.000	203	160	163	0.026	0.058	0.000	182

74	79	0.296	0.322	0.000	203	160	164	0.015	0.022	0.000	137
75	80	0.044	0.149	0.000	247	162	165	0.058	0.132	0.000	182
75	81	0.011	0.045	0.000	364	162	166	0.338	0.499	0.000	137
76	82	0.251	0.024	0.000	182	163	167	0.080	0.181	0.000	182
76	83	0.251	0.024	0.000	182	163	168	0.356	0.833	0.000	182
77	84	0.104	0.010	0.000	182	166	169	0.050	0.073	0.000	137
77	85	0.023	0.072	0.000	247	166	170	0.255	0.575	0.000	182

Table 12-8. Generation TEST81 (base 100MVA) – slack node 81

Bus	PG [kW]	QG [kvar]
1	0	0
4	9.35	19.4
9	8.09	-2.6
29	330.98	12.8
31	172.77	26.65
31	157.3	27.16
56	50.84	-2.86
56	50.08	-3.2
72	120.13	4.89
81	0	0
81	0	0
116	85.23	14.98

12.2 Results from Network testing scenarios

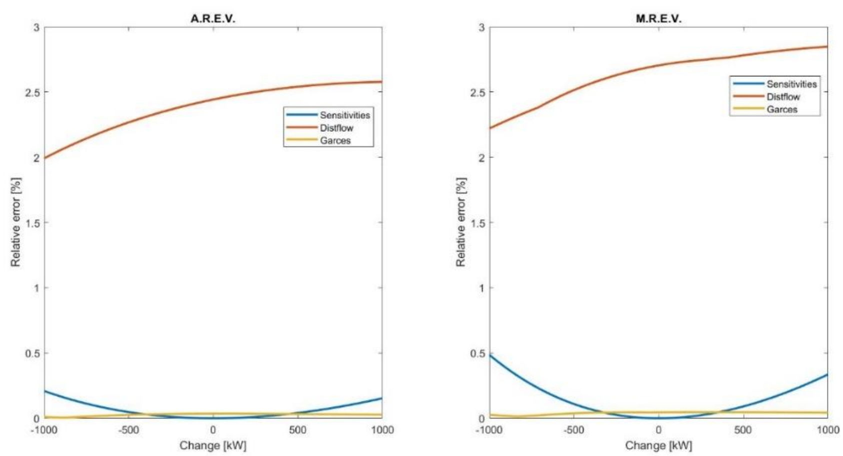

Figure 12-1. Voltage error, scenario 2 – TESTOPF

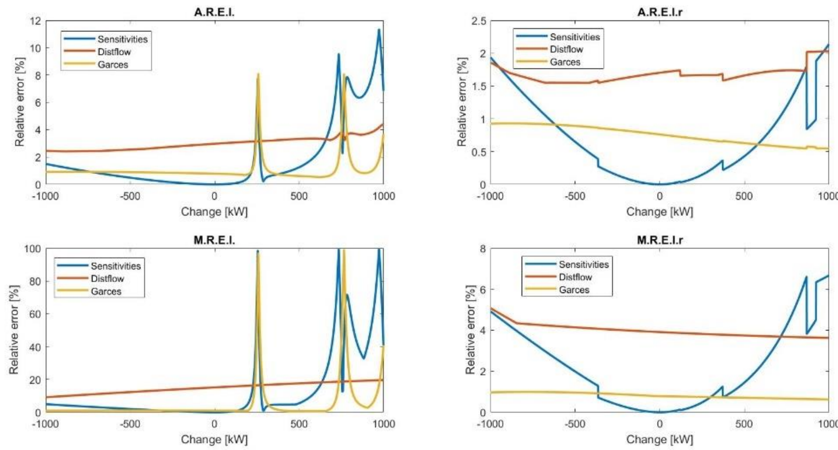

Figure 12-2. Current error, scenario 2 – TESTOPF

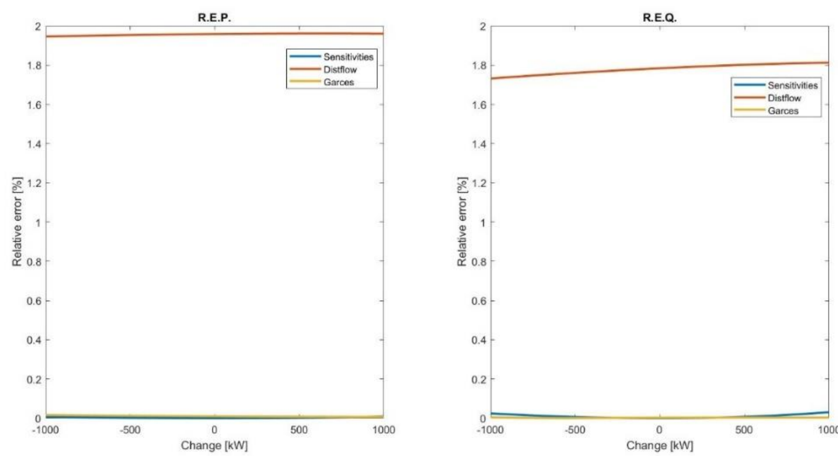

Figure 12-3. Slack error, scenario 2 – TESTOPF

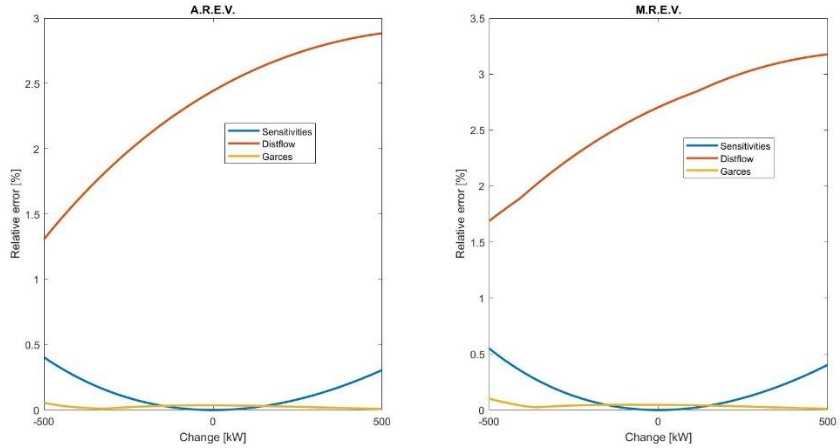

Figure 12-4. Voltage error, scenario 3 – TESTOPF

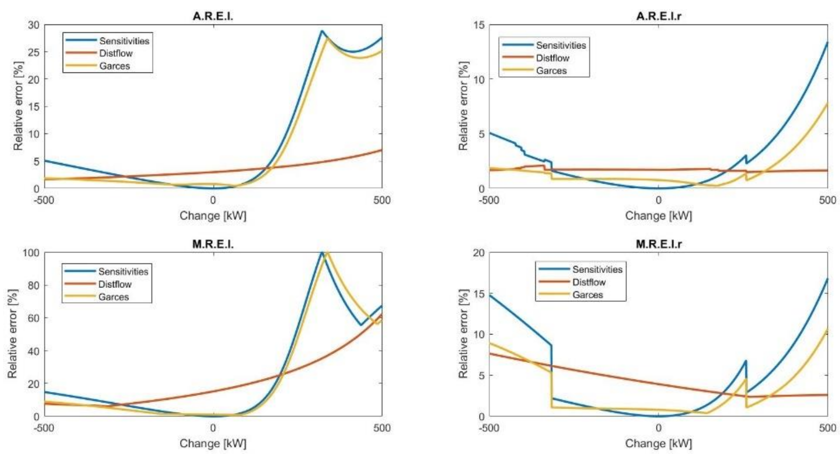

Figure 12-5. Current error, scenario 3 – TESTOPF

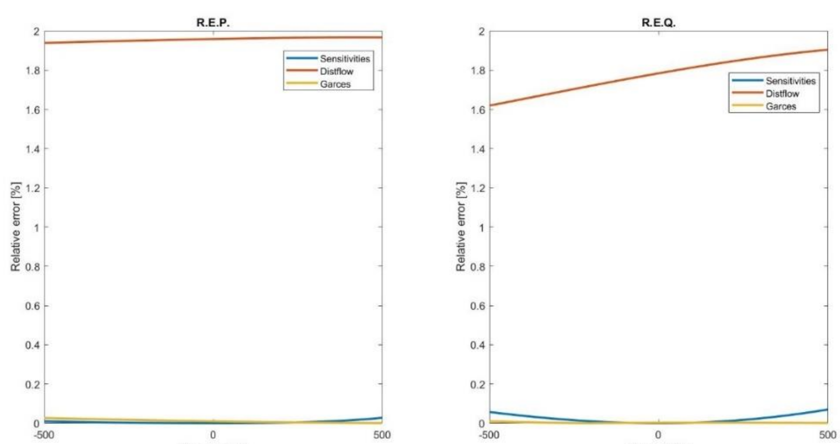

Figure 12-6. Slack error, scenario 3 – TESTOPF

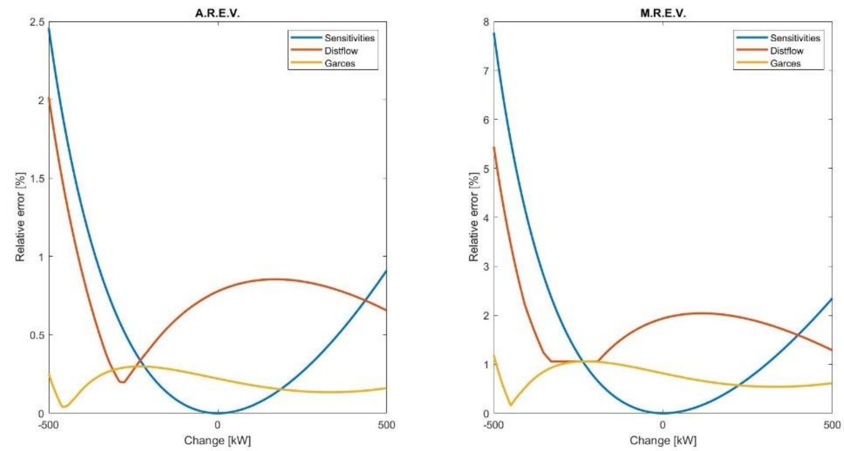

Figure 12-7. Voltage error, scenario 2 – RETE81

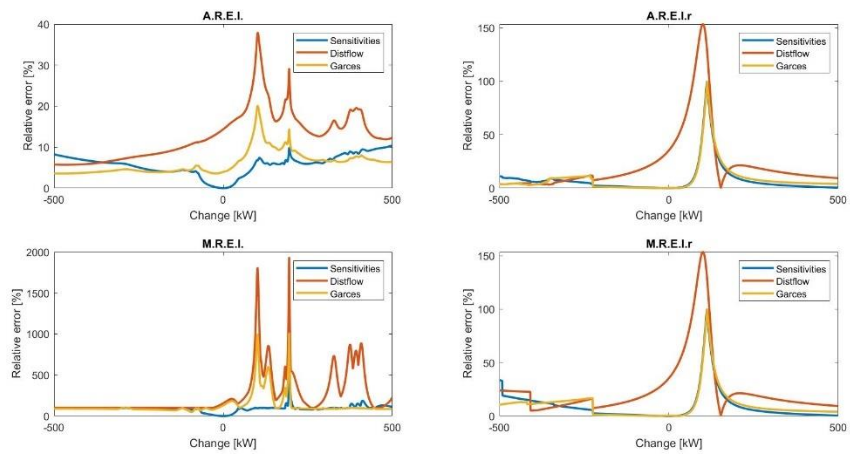

Figure 12-8. Current error, scenario 2 – RETE81

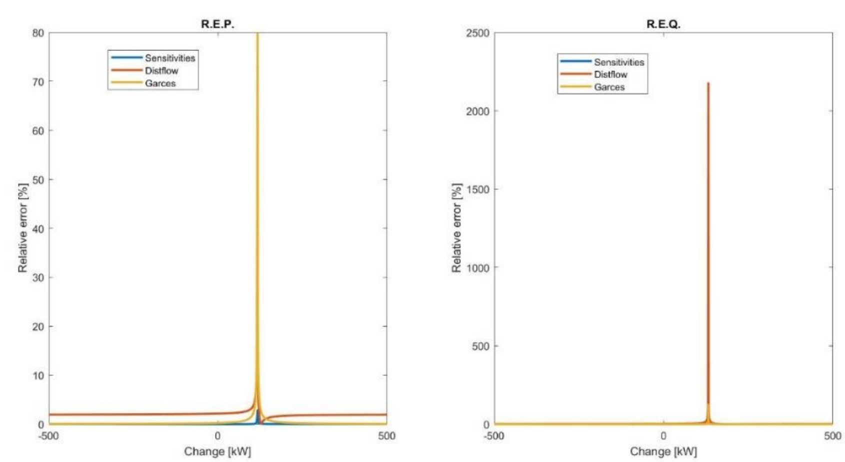

Figure 12-9. Slack error, scenario 2– RETE81

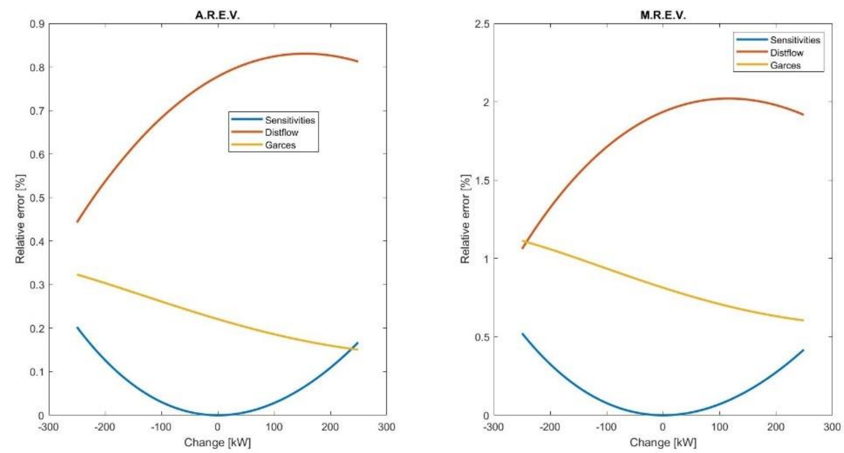

Figure 12-10. Voltage error, scenario 3 – RETE81

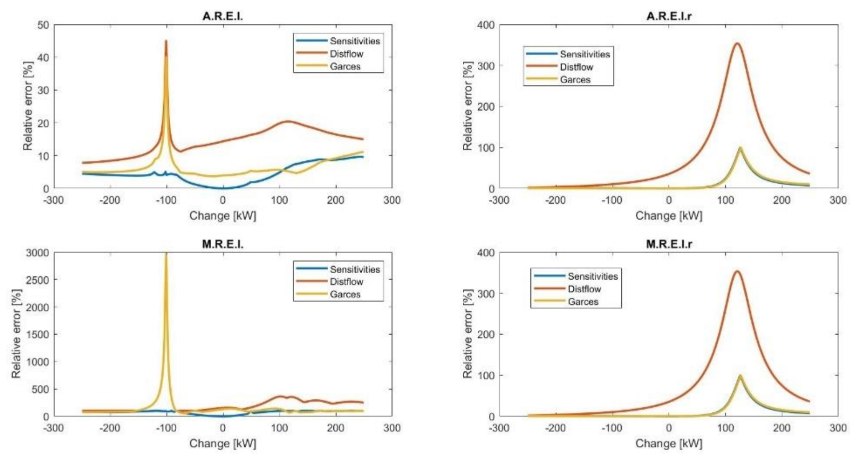

Figure 12-11. Current error, scenario 3 – RETE81

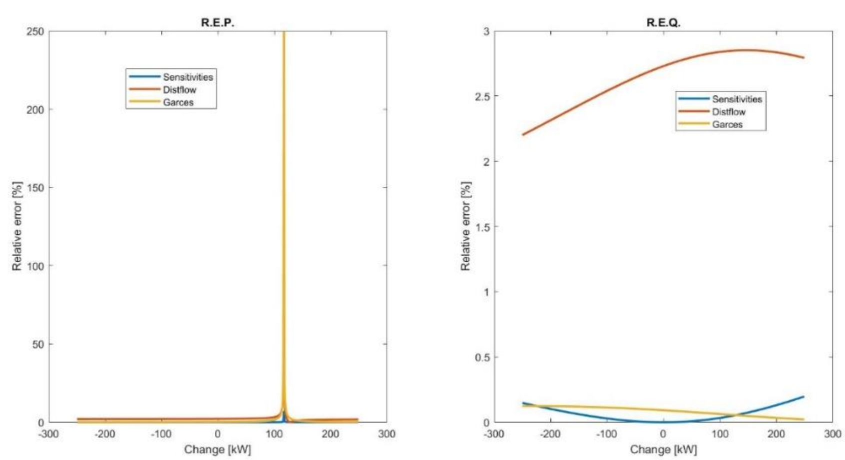

Figure 12-12. Slack error, scenario 3– RETE81

12.3 Numerical versus analytical sensitivity matrices

As an additional verification step for the Sensitivity approach to model the network, this section validates the calculation of analytical sensitivity matrices. To achieve this objective, the following algorithm is followed:

1. For the given operating conditions, the power flow is calculated using the MATLAB Toolbox;
2. Using the results of the power flow, analytical sensitivity matrices are calculated using Equations (6-47) and (6-48)for voltage sensitivity matrices $\frac{\partial V}{\partial \mathrm{P}}$ and $\frac{\partial V}{\partial Q}$,, and Equations (6-55) and (6-56) for current sensitivity matrices $\frac{\partial I}{\partial \mathrm{P}}$ and $\frac{\partial I}{\partial Q}$;
3. Numerical sensitivities are calculated. Starting again from power flow results, one by one a real/reactive power change is induced in each node. After the real/reactive power change is included in the power profile, the power flow is recalculated, and network results (voltages and currents) are stored for calculating the numerical sensitivities. Equation (12-1) shows the calculation of numerical sensitivities for the voltage in node i and real power injections in node j, as an example. In this case, $N\frac{\partial V_i}{\partial P_j}$ is the numerical element in the matrix, ΔP_j is the real power change in node j, V_i is the initial voltage in node i and $V_i^{\Delta P_j}$ is the voltage calculated in the same node after the change in the real power profile:

$$N\frac{\partial V_i}{\partial P_j} = \frac{V_i^{\Delta P_j} - V_i}{\Delta P_j} \qquad (12\text{-}1)$$

4. Finally, the numerical and analytical sensitivities are compared to verify the accuracy of the latter. The selected figure of merit is the relative error, calculated as shown in Equation (12-2). The same considerations to analyze the results that were mentioned earlier in Section 6.2 apply in this case, mainly possible issues with high relative error when the denominator approaches zero:

$$R.E.\frac{\partial V_i}{\partial P_j} = \frac{\left|N\frac{\partial V_i}{\partial P_j} - \frac{\partial V_i}{\partial P_j}\right|}{\left|N\frac{\partial V_i}{\partial P_j}\right|} \qquad (12\text{-}2)$$

Following the previous steps, the accuracy of sensitivity matrices for both network cases is evaluated. Figure 12-13 and Figure 12-14 show the average relative errors for voltage and sensitivity matrices[26] in the TESTOPF network, on the left panel. In addition, the standard deviation and maximum relative errors are also shown in the middle and right panels. Operating conditions, shown as changes from the initial state of the TESTOPF network in the X axis of the previous graph and written in generation notation, are applied to generation nodes indicated in Table 12-2. These results can be summarized as follows:

- Average relative error in voltage sensitivity matrices, except for some conditions when the operating conditions with changes close to -1 MW stay bounded by 0.02%. Maximum relative error is bounded by 0.1%;
- Apart from errors in the operating conditions close to -1 MW, sensitivities with respect to real and reactive power injections present similar behaviors;
- Average relative errors in current sensitivity matrices are bounded by 0.1%, while maximum relative error reaches 1%. These considerations apply for those conditions with no divergences in the calculation of relative error, that as shown by the standard deviation are rare;
- As before, the results of both current sensitivity matrices with respect to real and reactive power injections are similar;
- Divergences in the calculation of relative errors, as seen in both Figure 12-13 and Figure 12-14 do not necessarily mean a high error in nominal terms. Nonetheless, these results demonstrate the need of error correction measures and acceptance criteria for the network modelling approaches once the optimization problem is implemented.

[26] The voltage sensitivity matrices have N by N elements, where N is the number of nodes in the network. The current sensitivity matrices have N by Melements, where M is the number of branches in the network. Average, standard deviation and maximum figures are calculated over the complete range of elements in the matrices.

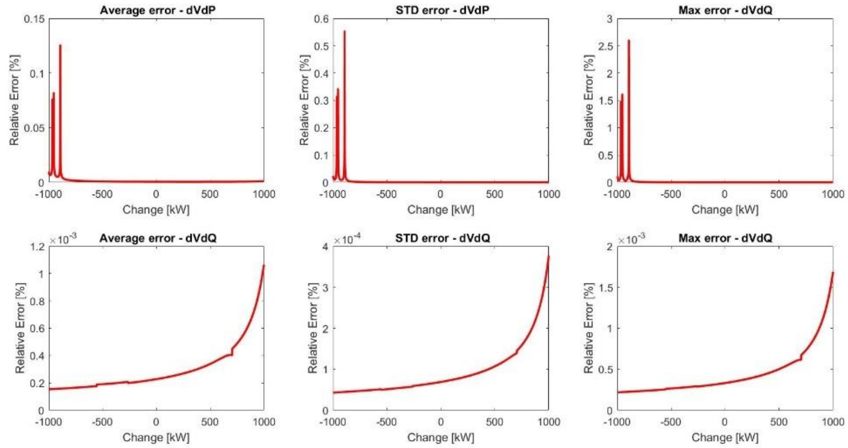

Figure 12-13. Relative error in voltage sensitivities – TESTOPF

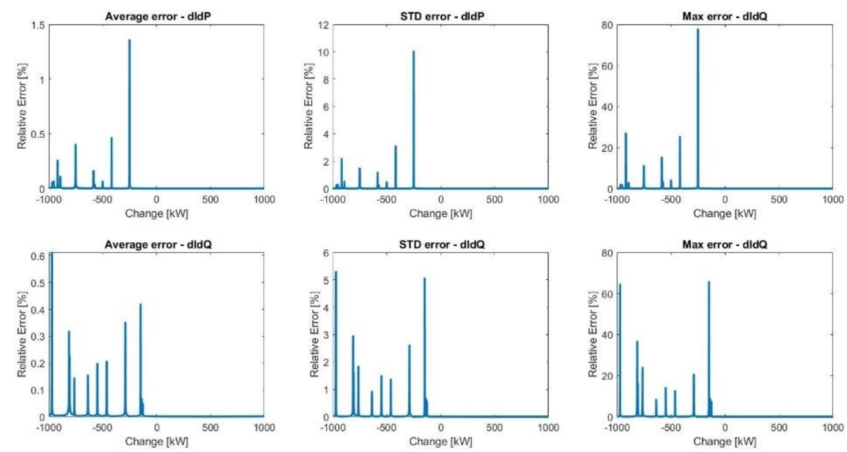

Figure 12-14. Relative error in current sensitivity matrices – TESTOPF

In Figure 12-15 and Figure 12-16 the previous calculations are carried out for the RETE81 network. As before, operating point changes are induced in the generation nodes shown in Table 12-6 and displayed in generation notation. From these results, similar conclusions to the previous network case can be highlighted. However, the relative error divergences are only seen in the current sensitivity matrices.

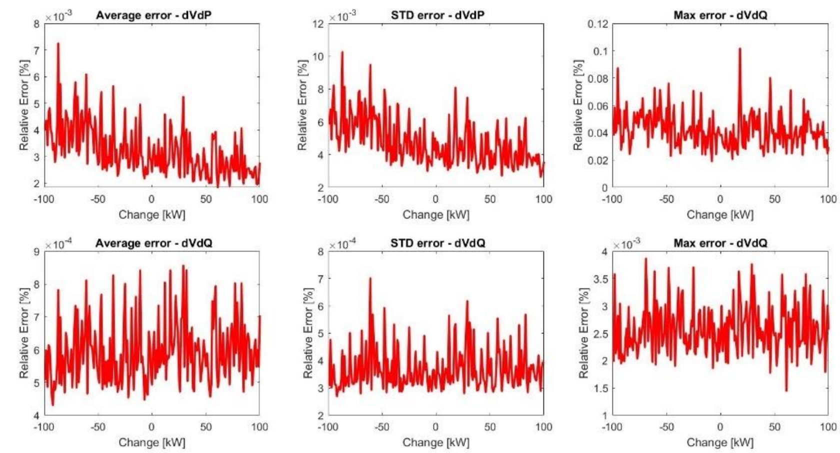

Figure 12-15. Relative error in voltage sensitivity matrices – RETE81

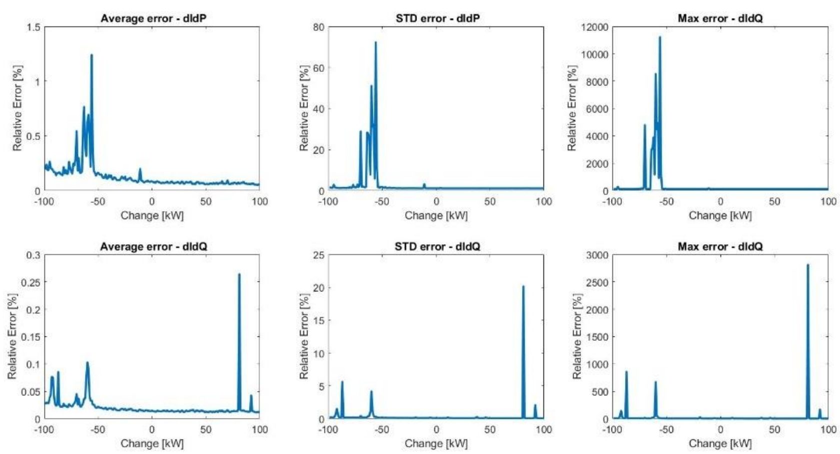

Figure 12-16. Relative error in current sensitivity matrices – RETE81

12.4 Automatic network generation tool

To facilitate testing of the market schemes, a tool in EXCEL and VBA is developed to generate example networks. Given a network topology, load and generation profiles, and aggregators bids, are created with the structure of the optimization problem in mind.

Load profiles are obtained from [80], [69] and [81]. The first reference is selected to represent standard residential, commercial, and industrial loads, while the last two includes examples of expected changes in load profiles after different levels of electric vehicles penetration. Original load profiles are presented in Figure 12-17 and described in Table 12-9[27].

[27] Data is manually obtained from these articles using the online tool https://automeris.io/WebPlotDigitizer/.

Especial attention is later given to the difference after the integration of electric vehicles in the load profile, in profiles penetration_0_EV [3] and penetration_100_EV [3], as the new charge could represent a new source of flexibility to harvest in market models.

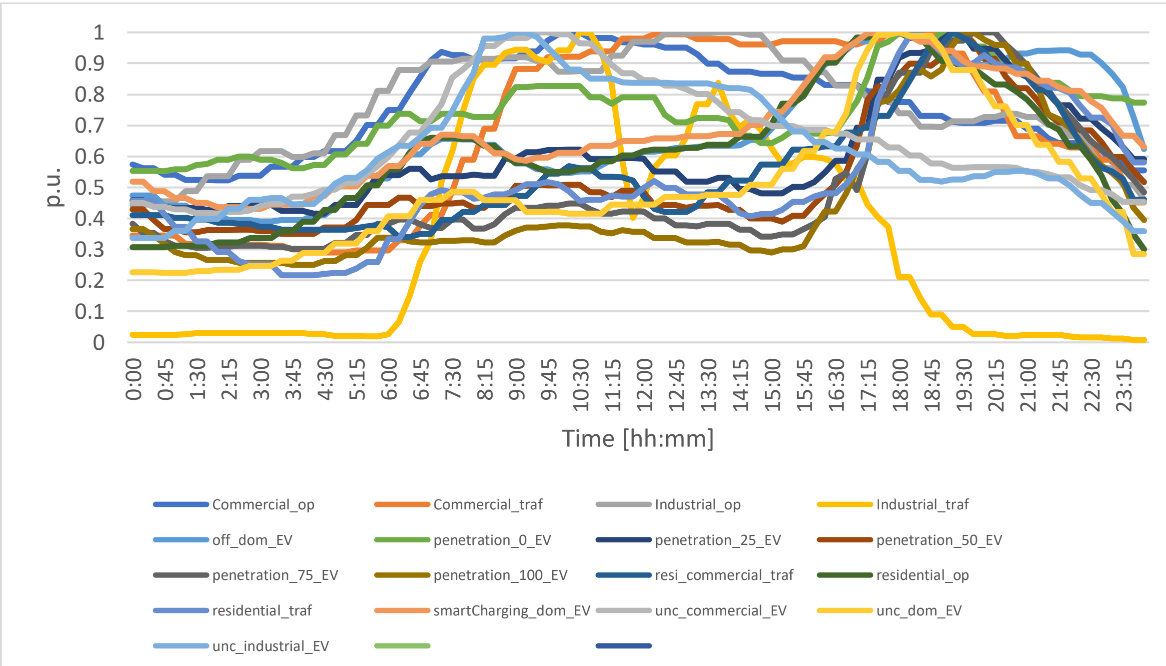

Figure 12-17. Load profiles [80] *– [1],* [69] *– [2] and* [81] *– [3] in per unit*

Table 12-9. Load profile description [80] *– [1],* [69] *– [2] and* [81] *– [3]*

Profile and reference	**Description**
Commercial_op [1]	Commercial load profile measured at the network coupling point
Commercial_traf [1]	Commercial load profile measured at a medium voltage transformer
Industrial_op [1]	Industrial load profile measured at the network coupling point
Industrial_traf [1]	Industrial load profile measured at a medium voltage transformer
resi_commercial_traf [1]	Residential plus commercial load profile measured at a medium voltage transformer
residential_op [1]	Residential load profile measured at the network coupling point
residential_traf [1]	Residential load profile measured at a medium voltage transformer
off_dom_EV [2]	Residential load profile with off-peak EV charging
smartCharging_dom_EV [2]	Residential load profile with EV smart-charging strategy
unc_commercial_EV [2]	Commercial load profile with uncontrolled EV charging
unc_dom_EV [2]	Domestic load profile with uncontrolled EV charging
unc_industrial_EV [2]	Industrial load profile with uncontrolled EV charging
penetration_0_EV [3]	Domestic load profile, with no EV penetration
penetration_25_EV [3]	Domestic load profile, with 25% EV penetration
penetration_50_EV [3]	Domestic load profile, with 50% EV penetration
penetration_75_EV [3]	Domestic load profile, with 75% EV penetration

penetration_100_EV [3]	Domestic load profile, with 100% EV penetration
Zero	Zero load profile
Constant	Constant (1.p.u.) load profile

With respect to PV generation profiles, the NSRDB Solar Radiation Data platform is used[28]. The database provides estimated PV generation profiles for any location on earth. Using the geographical tool, hourly generation data for year 2015, and six locations worldwide are obtained. Detailed information for the location is shown in Table 12-10.

Table 12-10. Geographical information for PV profiles

Location	Latitude [°]	Longitude [°]
Barranquilla (Colombia)	-10.785	-74.976
Modena (Italy)	44.548	-11.104
Sevilla (Spain)	37.206	-5.303
Cairo (Egypt)	30.498	28.330
San Gil (Colombia)	6.561	-73.143
Bogota (Colombia)	4.617	-74.074

After obtaining the hourly information, an average profile is calculated for each month in the year. As a result, each location results in 12 possible generation profiles that can be adjusted to feed network information. Examples of these average profiles for the first three months are shown in Figure 12-18.

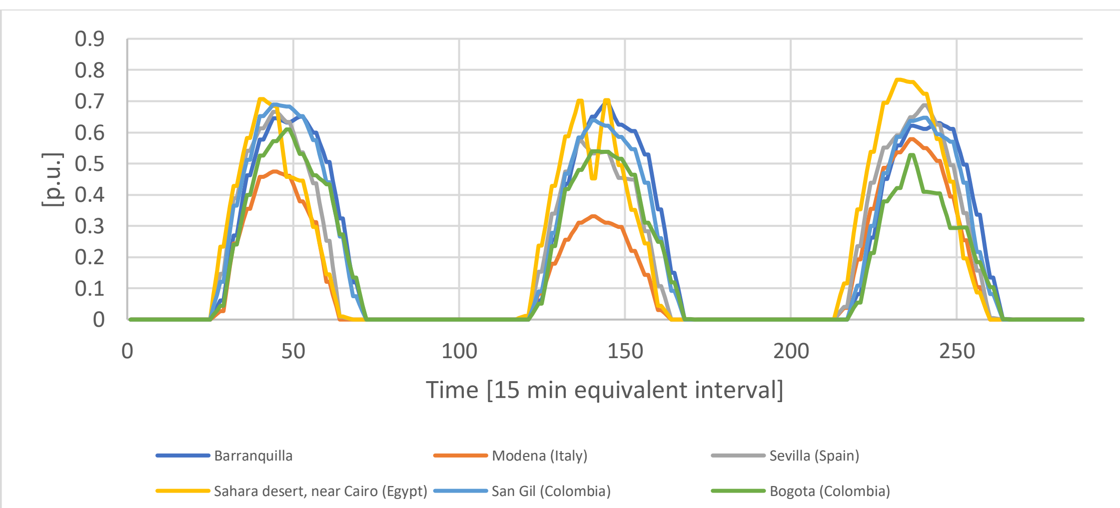

Figure 12-18. Average monthly generation profiles – January to March

[28] Information publicly available at https://ec.europa.eu/jrc/en/PVGIS/downloads/NSRDB, with the photovoltaic geographical information tool available at https://re.jrc.ec.europa.eu/pvg_tools/en/tools.html.

Given the load and generation profiles in per unit, and an initial power factor, initial daily network information can be configured by assigning a given installed capacity to the resource, repeating this procedure for each network node. Resources are further divided into those not participating in the flexibility markets, and those that participate. As a result, in a single node there can be one load and one generation resource that will not participate in the flexibility market, in addition to one load and one generation resource that will participate.

Once the initial behavior of the resources is available, flexibility provided by them is assumed and then aggregated. It is important to highlight that this step would be carried out in a decentralized manner by all agents playing in the market. However, this step is beyond the scope of this thesis and, as a result, assumptions are used to obtained flexibility bids from agents and aggregators.

To start, upward and downward flexibility quantities are assumed for load profiles. An upward quantity bid for a load resource means to increase their consumption, while a decrement is expected for downward bids. Assuming nominal behavior for the load, consumption increments, if possible, would not amount to a great percentage of total consumption. On the other hand, if compensated appropriately, loads could offer their partial or complete disconnection from the network as a flexibility service.

In addition to the previous considerations, additional flexibility is considered for load profiles that have any penetration of electric vehicles, highlighted in the name shown in Table 12-9. This additional flexibility is measured as an approximate between the load profile without EV, and the profile with them. Moreover, charging and discharging of electric vehicles are subject to energy constraints, as discussed in Section 5.8., using the upward and the first downward step. Pondering previous factors, Table 12-11 shows flexibility quantities for all load types, presented in load notation and in percentage of the initial profile.

Table 12-11. Load flexibility quantities

Profile and reference	Upward step [%]	First downward step [%]	Second downward step [%]
Commercial_op [1]	10	10	80
Commercial_traf [1]	10	10	80
Industrial_op [1]	10	10	80
Industrial_traf [1]	10	10	80
resi_commercial_traf [1]	10	10	80
residential_op [1]	10	10	80
residential_traf [1]	10	10	80

off_dom_EV [2]	25	25	80
smartCharging_dom_EV [2]	25	25	80
unc_commercial_EV [2]	25	25	80
unc_dom_EV [2]	25	25	80
unc_industrial_EV [2]	25	25	80
penetration_0_EV [3]	10	10	80
penetration_25_EV [3]	20	$\min[penetration\_25\_EV - penetration\_0\_EV, 10]$	80
penetration_50_EV [3]	25	$\min[penetration\_50\_EV - penetration\_0\_EV, 10]$	80
penetration_75_EV [3]	30	$\min[penetration\_75\_EV - penetration\_0\_EV, 10]$	80
penetration_100_EV [3]	35	$\min[penetration\_100\_EV - penetration\_0\_EV, 10]$	80
Zero	25	25	80
Constant	25	25	80

Flexibility quantities for PV generators is defined in a similar way. Upward bids, in generation notation, should be limited, assuming close to nominal operating condition in the initial profile. However, as loads, generators could offer their disconnection as flexibility services to the market. With these assumptions, flexibility quantities for all solar profiles are shown in Table 12-12.

Table 12-12. PV flexibility quantities

	Upward step [%]	**First downward step [%]**	**Second downward step [%]**
Solar profiles	3	3	30

It is worth nothing that all flexibility values presented in Table 12-11 and Table 12-12 can be altered without any impact on the market model or formulation, and they simply represent assumptions to create the testing cases.

With respect to prices, it is worth revisiting the mathematical formulation of coordination Schemes based on local flexibility markets, as presented in Section 7.3.2. In these cases, two major assumptions are used:

- Aggregators have a pre-defined initial power profile, assumed as an input to the market model. Their profiles emerge from other market sections that out of the scope of this thesis;
- Bid prices represent the opportunity cost of flexibility provided by aggregators, measured from the initial profile mentioned earlier.

From an aggregator simplified standpoint, the initial profile is being paid at a given and known price from other market sections (day-ahead price, in the most simplified case). This is the case even when markets run in parallel, as it occurs in the Italian market reform discussed in Section 3.5. As a result, aggregators should expect for their flexibility, understood as an additional service that requires variations from the initial condition, an opportunity cost that is higher to the one already received.

Given the previous considerations, the opportunity cost discussion should be divided into upwards (to sell electricity) and downward (to buy electricity) bids:

- For **upward** bids, electricity should be sold at a price higher or equal to the one received in previous market sections;
- For **downward** bids, electricity should be bought back from the system at a price higher or equal to the one paid in previous market sections.

In existing ancillary services market, like the one currently in operation in Italy, downward bids are remunerated between a price equal to previous market sections, equivalent of *giving back* the energy at the same price it was originally bought, and zero, meaning that no remuneration is returned while the energy is.

To keep the notation simple, and accordingly with the literature review presented in Section 3, bids represent the additional cost of flexibility **measured over the previous market section price.** Assuming, for example, a day-ahead price of 50 $\left[\frac{\$}{MWh}\right]$, an upward bid with a price of 10 $\left[\frac{\$}{MWh}\right]$ implies that the aggregator is 60 $\left[\frac{\$}{MWh}\right]$ for their offer of selling electricity, from which 10 corresponds to the additional opportunity cost of flexibility. On the other hand, a downward bid with a price of 15 $\left[\frac{\$}{MWh}\right]$ means that the aggregator is willing to give back to the system of 35 $\left[\frac{\$}{MWh}\right]$, of the initial 50 $\left[\frac{\$}{MWh}\right]$ received in the previous market section.

Now that the price-opportunity cost relation has been defined, other assumptions necessary to define bid prices are discussed. To start, it is worth mentioning that both for loads and generators, a single upward bid is defined. On the other hand, for downward bids, to possible steps are modelled: the first representing a small flexibility offer while the second implies an almost complete disconnection from the system. It would be expected that the most extreme step taken by the aggregator would have a price equal or higher than the one asked for the first step.

For the previous market section price, information of XM, the Colombian market operator, and GME, the Italian one, is used. In both cases, prices are taken from the day-ahead market section. The price profiles that are implemented in the automatic network generation tool are shown in Figure 12-19, designated a code from 1 to 8 in the same order as shown in the legend of the plot.

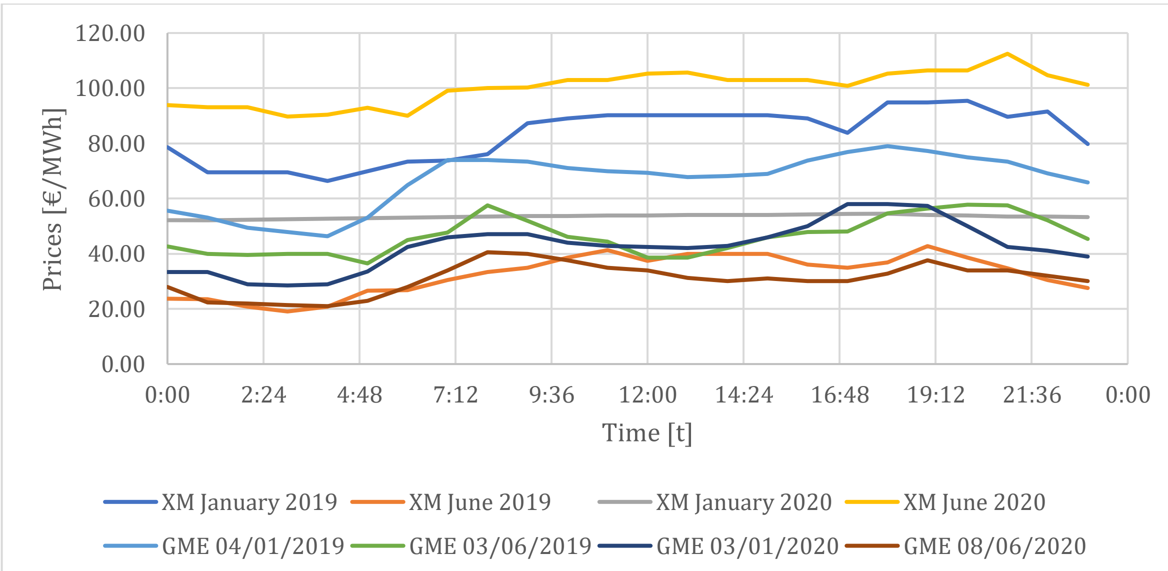

Figure 12-19. Day-ahead prices, XM and GME

12.5 Information and Additional simulation results

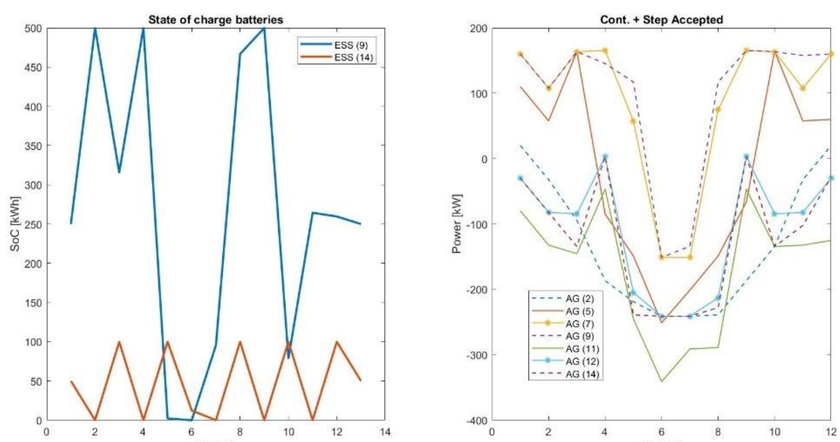

Figure 12-20. Maximum profile, Accepted Resources, Scheme 6, proof-of-concept model

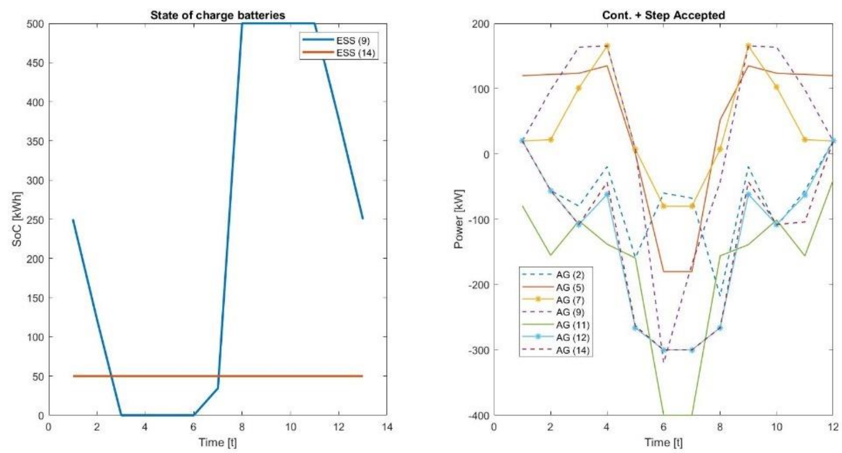

Figure 12-21. Maximum profile – minimum cost, Accepted Resources, Scheme 6, proof-of-concept model

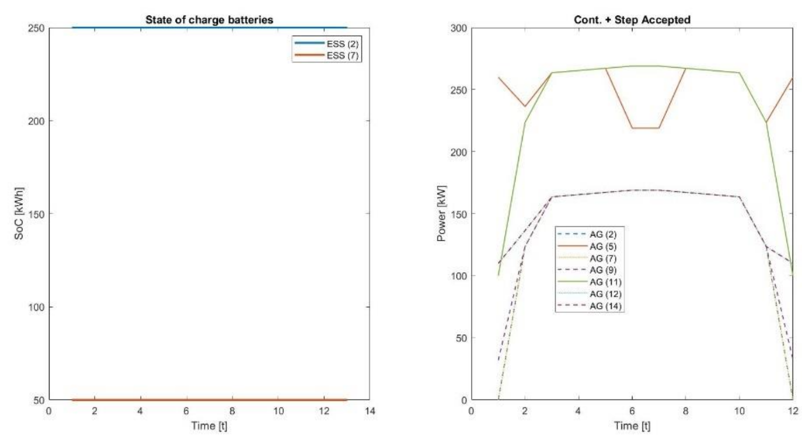

Figure 12-22. Minimum profile, Accepted Resources, Scheme 6, proof-of-concept model

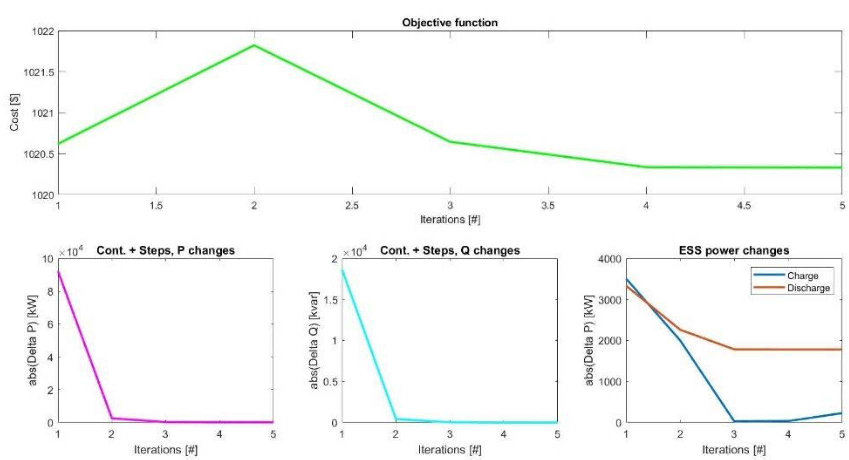

Figure 12-23. Summary, Scheme 5-1, TESTOPF – 96

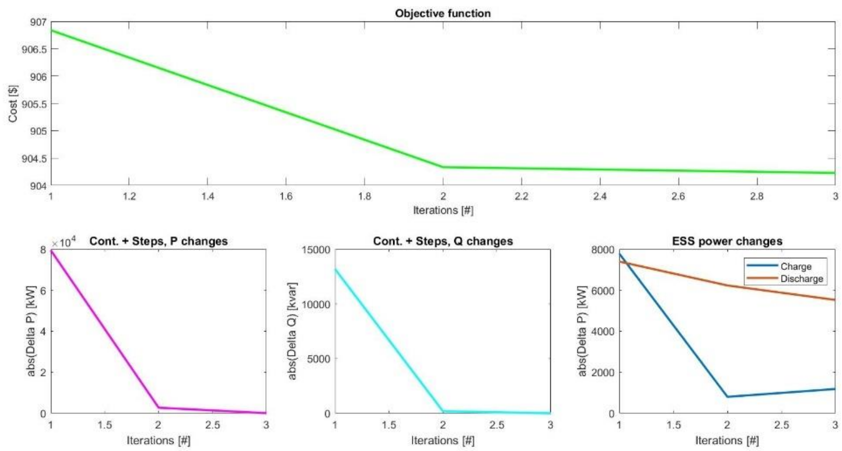

Figure 12-24. Summary, Scheme 5-2, TESTOPF – 96

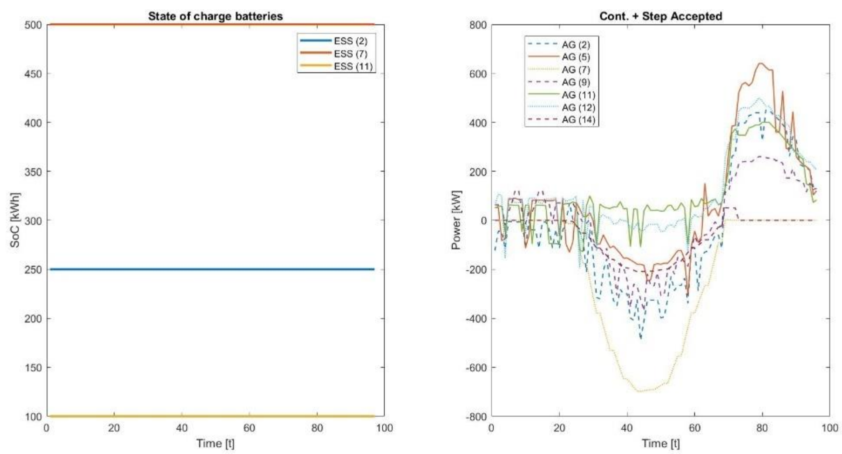

Figure 12-25. Accepted resources, Scheme 6, minimum power between periods 69-96, TESTOPF – 96

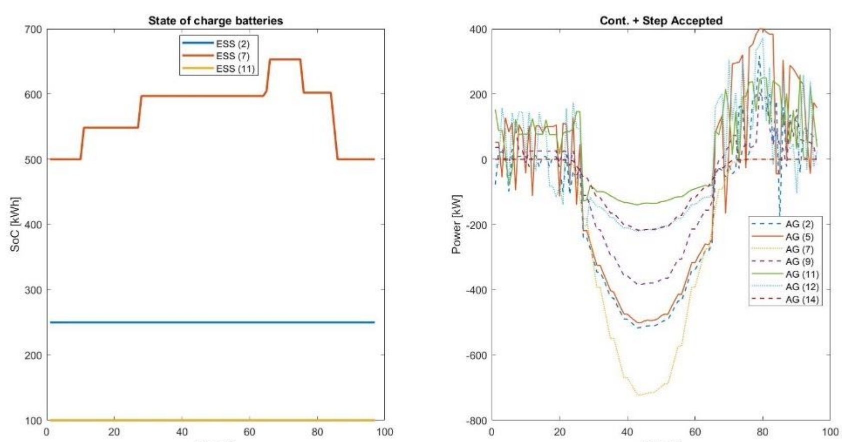

Figure 12-26. Accepted resources, Scheme 6, maximum power between periods 27-65, TESTOPF – 96

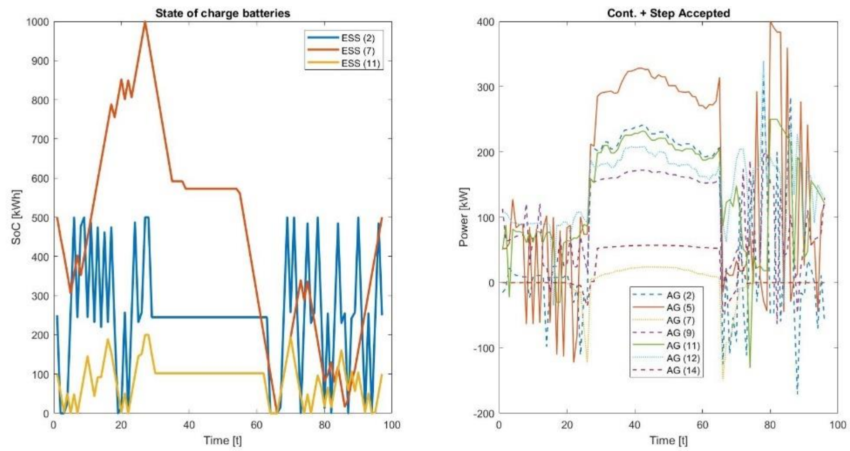

Figure 12-27. Accepted resources, Scheme 6, Minimum power between periods 27-65, TESTOPF – 96

Table 12-13. Flexibility Resources, RETE81

Node	Load type	Nominal Power load (kW)	PF	PV profile	Month	Nominal power PV (kW)	PF
4	11	500	1	4	6	600	0.95
9	10	200	1	4	6	1000	0.95
29	11	500	0.95	4	6	600	0.95
31	9	200	0.95	4	6	1000	0.95
39	9	200	1	4	6	200	1
56	18	500	0.95	4	6	600	0.95
59	9	100	1	4	6	200	1
72	9	200	0.95	4	6	1000	0.95
81	9	0	1	4	6	750	0.95
88	11	200	1	4	6	200	1
108	11	100	1.0	4	6	750	0.95
116	11	500	0.95	4	6	500	0.95
137	9	100	1	4	6	200	1
160	11	100	1	4	6	200	1

Table 12-14. Step bid characteristics, RETE81

Node	Step bids up type	Step bids up power [kW]	Step bids Down type	Step bids Down Power [kW]
4	3	50	4	100
9	3	100	4	50
29	3	100	4	50
31	3	50	4	100
39	3	0	4	0
56	3	100	4	50
59	3	0	4	0
72	3	50	4	100
81	3	50	4	50
88	3	0	4	0
108	3	50	4	50
116	3	100	4	50
137	3	0	4	0
160	3	0	4	0

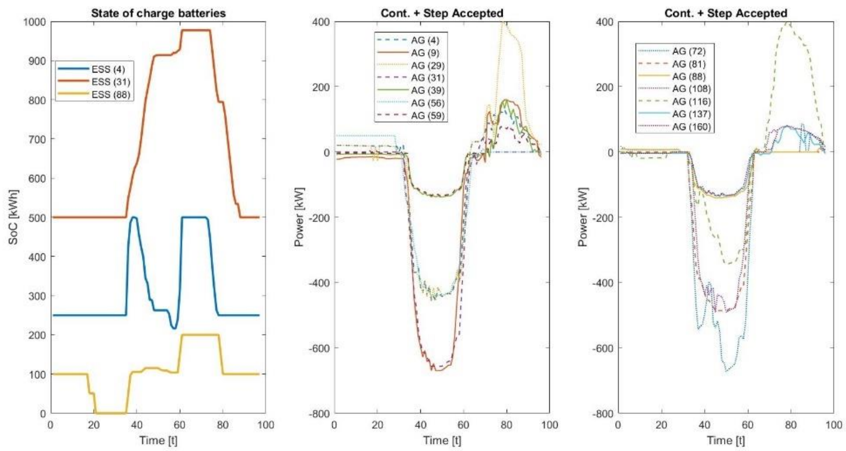

Figure 12-28. Accepted resources, Scheme 6, Minimum power between periods 35-60, RETE81