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Case Studies and Verification

Balancing Power in the European System (BPES)

Report on Work Package 5

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Executive Summary

This report pursues two major goals: first, the methods presented in the report on work package 4 [1] are applied to different case studies to demonstrate their potential and applicability. Second, based on the report on work package 3 [2], the major challenges that fall within the scope of the BPES project are identified. The methods are assigned to the challenges they tackle and their impact as well as the applicability are discussed in terms of necessary changes to the status quo, as well as a possible timeline.

Within the scope of the BPES project five challenges resulting from large scale integration of renwable energy sources have been identified and alleviating methods are proposed.

The improved modeling techniques for scenarios of *spatio-temporal coupling of infeed uncertainties* result in more accurate and more realistic results, e.g. when applied in a stochastic unit commitment. This leads to a reduction of expected system operation costs.

The flexibility from new resources, such as storages, demand side participation or new transmission technologies necessitate *new balancing mechanisms.* In that regard, the project outlines a stochastic predictive approach for the dispatch of regulating power. The variation of different parameters has revealed significant changes on the performance of the balancing operation.

Limited transmission capacity can result in a reduction of operational flexibility, e.g. reserves might not be accessible depending on the location in the grid. This phenomenon of limited transmission capacity, termed *locational flexibility*, is addressed. A method to quantify the operational flexibility at a given location provides insights on infeed disturbances that can be contained by the system. This information can be further used in the procurement process of reserves. The procured reserves are allocated such that the energy can be delivered in every scenario considered.

The operation of power systems with multiple control areas and high shares of renewable energy sources require an increased effort in the *coordination of operational data* between the individual system operators (TSOs). Proposed is a method that allows an efficient coordination of available operational flexibility between TSOs resulting in a more efficient utilization of inter-area interfaces (tie-lines, HVDC) and an overall more flexible operation.

Finally, different methods demonstrate how to *increase the transmission flexibility*. Dynamic line rating, a control-based grid expansion approach, is integrated in current dispatch processes and allows to operate the system more economically with a controllable risk of thermal overloadings. The controllability of HVDC interconnections are used to increase the overall operational flexibility. In that respect, a special focus is on the segmentation of the capacity between reserves and energy markets.

Contents

Chapter 1

Introduction

1.1 Goal of this report

This report pursues two major goals: first, the methods presented in the report on work package 4 [1] are applied to different case studies to demonstrate their potential and applicability. Second, based on the report on work package 3 [2], the major challenges that fall within the scope of the BPES project are identified. The methods are assigned to the challenges they tackle and their impact as well as the applicability are discussed in terms of necessary changes to the status quo, as well as a possible timeline.

For brevity, the methods, as well as the case study setups, are not described in detail. In the corresponding sections, the reader is referred to the report on work package 4 for the detailed method descriptions and to publications with the detailed case study data.

The report is structured as follows: in the introduction chapter, the findings of the scenario report [2] are briefly summarized and the challenges are identified. Subsequently, for every challenge identified, we dedicate a chapter which first sketches the challenge, followed by various case studies for different methods and concluded by a summary of the impacts of the methods on the challenge in question as well as necessary requirements for a successful implementation of the methods.

The last chapter summarizes the conclusions and provides recommendations for future research.

1.2 Summary of Findings of Scenario report

In the *scenario report* on work package 3 [2] we analyzed the possible development of the deployment of renewable energy sources , for the years 2020, 2030 and 2050, based on different publicly available forecast scenarios.

Using publicly available data and in line with the four visions for 2030 from ENTSO-E [3] (*slow progress, money rules, green transition* and *green revolution*), and the scenarios for 2050 from the European Commission Roadmap (2050) [4], we qualify the different visions and different unit types on the needed degree of coordination and the capabilities to provide flexibility to the system. These are distinguished between the following unit types:

- Demand response: all measures resulting in a more controllable demand side.
- Conventional units, such as gas fired power plant (flexible) or coal-fired power plants (less flexible).
- Controllable renewable energy sources, e.g. hydro power plants, concentrated solar power plants with storage capabilities.
- Uncontrollable renewable energy sources, e.g. wind or photovoltaic power plants.
- Load: inflexible part of the demand side.

Fig. 1.1 shows the characterization for 2030 on the left side, and for 2050 on the right side. The detailed arguments and interpretations are found in [2].

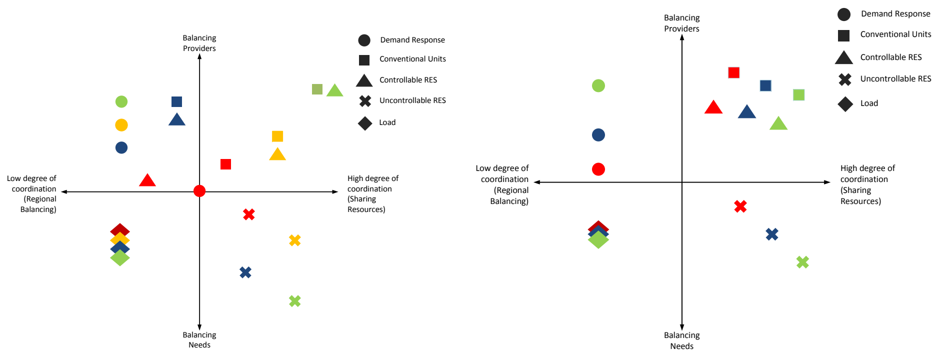

Figure 1.1: LEFT: Red: Vision 1 - Slow progress; Yellow: Vision 2 - Money rules; Blue: Vision 3 - Green transition; Green: Vision 4 - Green revolution. RIGHT: Red: *Scenario RES 40* (ScRES40); Blue: *Scenario RES 60* (ScRES60); Green: *Scenario RES 80* (ScRES80).

An excerpt of the discussion is repeated for completeness [2]:

"(...) If polytopes are drawn that for each vision that envelop the five types, one can make the observation, that the areas are increasing from Visions 1 to 4. Considering Vision 1 the balancing needs are not increasing substantially and thus also the balancing provision is not. For Vision 2 and especially 3, the needs and provision is increasing with the difference, that Vision 2 is more focused on a higher degree of coordination. A higher degree of coordination between the areas implies that sufficient transmission capacity is available and the resources can be shared effectively enabled by a suitable market design and efficient communication between the responsible parties, e.g. the TSOs. The balancing needs have to be covered by the available flexibility. With increasing balancing needs, the operational uncertainty as well as the planning complexity (e.g. due to correlations between uncertainties) increase. The extreme Vision 4 results in high balancing needs but also in increased balancing provision possibilities. For this vision a regional balancing enabling demand response is used as well as high international coordination of resources. (...) For 2050 (...), the polytopes connecting the five types of units define larger areas moving from ScRES40 to ScRES80 scenarios. The increasing penetration of uncontrollable RES reduces the available balancing providers, i.e., conventional units and controllable RES, and increases the balancing needs of the system. This structural reform of the power system has to be compensated by higher degree of coordination and efficient sharing of balancing resources. In line with this, new transmission corridors have to be established in the European system that along with the proper market mechanisms will allow transferring flexibility across different regions."

The need for grid expansion has been noticed and different entities are working on projects to increase the transmission capacity. In Fig. 1.2, the major congestions are illustrated. It can be observed, that for an integrated market as well as for an improved coordination and sharing of resources between the areas, these congestions have to be removed.

1.3 Identified challenges

Fig. 1.3 presents a high-level breakdown of the challenges arising from the large scale integration of renewables. Their inherent characteristics, i.e., distributed and intermittent infeed, will challenge the current operational practices due to potential lack of controllable generation to cope with the partially predictable imbalances as well as the increased network utilization to transfer power over large distances that will lead into more frequent grid congestions. In order to respond effectively in these challenges, system/market operators have to re-design their operational tools and revise their balancing options. In the meantime, network infrastructure must be-

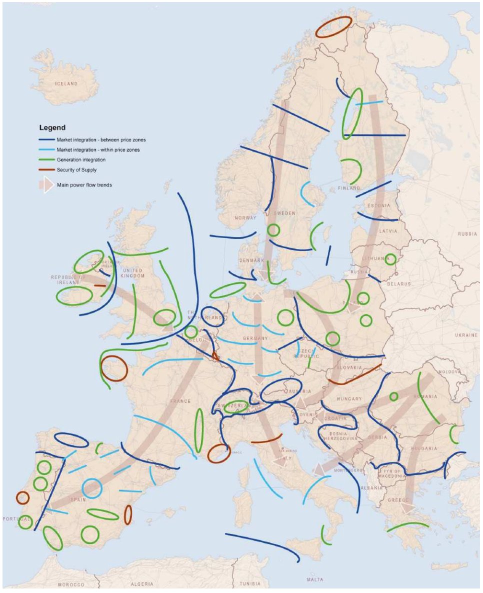

Figure 1.2: Main congestions in Europe as well as major power flow directions.

come more flexible both in terms of technical capabilities as well as regarding the operational schemes to increase coordination among neighbouring power systems and make optimal use of the available assets.

Within the scope of the BPES project, we focus on the development of methods to support decision processes of operators of transmission systems. In a next step, the identified challenges, based on the scenario report [2], that fall within the scope of the project are listed. The list is not exhaustive, i.e. issues, e.g. concerning the distribution and low voltage grid level and their market integration etc., are not considered. We focus on five major challenges which will be described next. In subsequent chapters, every challenge will be described in more detailed and methods tackling the corresponding challenge will be listed and applied in case studies.

Spatio-Temporal Coupling of Uncertainties Increasing shares of intermittent energy sources lead to increasing infeed uncertainties. The uncertainties are coupled spatially as well as temporally. These uncertainties need to be modeled properly and integrated in the operation planning.

New Balancing Mechanisms and new Resources On the one hand, conventional providers of flexibility, i.e. controllable conventional power plants are not profitable anymore and thus mothballed. On the other hand, new resources of flexibility are identified; for example control-

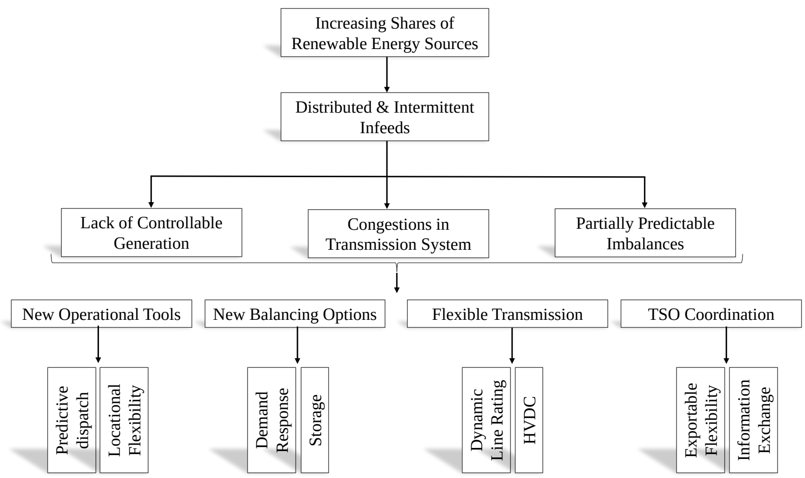

Figure 1.3: Breakdown of Challenges related to the BPES project.

lability of the demand side, intermittent energy sources, storages or techiques allowing a more flexible transmission. While traditionally one of the major challenges in balancing was load following, the forecast uncertainties with partially high ramping rate requirements, are becoming increasingly challenging. New balancing mechanisms should account for different types of uncertainties as well as incorporate new sources of flexibility.

Locational Flexibility While the transmission grid was designed for a production close to the load centers, the renewable (intermittent) energy sources are often placed further away, which leads to power flows over larger distances and with changing power flow patterns. Increasing market activities further aggravates this issue. This has led to a transmission system which is more often congested and cannot be approximated as copperplate anymore when it comes to balancing, i.e. although a reserve might be available, it may not be activated as a congested transmission grid disallows to.

Inter-TSO coordination While the coordination and exchange of operational data was comparably small, with increasing cross-border flows with more frequent changes, the coordination between TSOs becomes more important. For tasks, such as grid expansion and operation involving different TSOs, e.g. HVDC interconnections with large capacities, a coordinated planning increases the efficiency of the system operation.

Increased Transmission Flexibility Needs As has been seen in the introduction, upgrading the existing transmission system by increasing the transmission capacity as well as the controllability of the power flows is a necessity. The transmission grid can be upgraded in many different ways, having different advantages and disadvantages, however, the expansion should happen in a reasonable amount of time, with as little costs as possible and be adequate for the challenges arising.

Chapter 2

Spatio-Temporal coupling of Uncertainties

2.1 Challenge description and overview of the contributing methods

Considering that the existing power systems in Europe are accommodating increasing shares of variable and partly predictable generation, e.g., wind power, system operators have to account for the potential real-time imbalances due to the forecast errors. Instead of relying on single-value forecasts that provide limited information about the plausible realizations of uncertainty, system scheduling methodologies have to consider the complete spatio-temporal structure of uncertainty. The purpose of this chapter is provide methodological approaches that integrate this information on power system operational practice.

The proposed methodology employs the stochastic unit commitment model presented in the report on work package 4 [1] Chapter 2 using as input the a set of spatio-temporal scenarios of wind power produced according to the method outlined in the same chapter.

2.2 System Scheduling based on Stochastic Unit Commitment

The stochastic unit commitment model is applied to a modified IEEE 14-bus system shown in Fig. 2.1, which includes four conventional generators and two wind farms. The technical and the economic data of the system are given in [5]. The wind farms located at nodes 5 and 13 have installed capacity of 50 MW and 25 MW respectively and their power production is modeled using a set of spatio-temporal scenarios from the available dataset

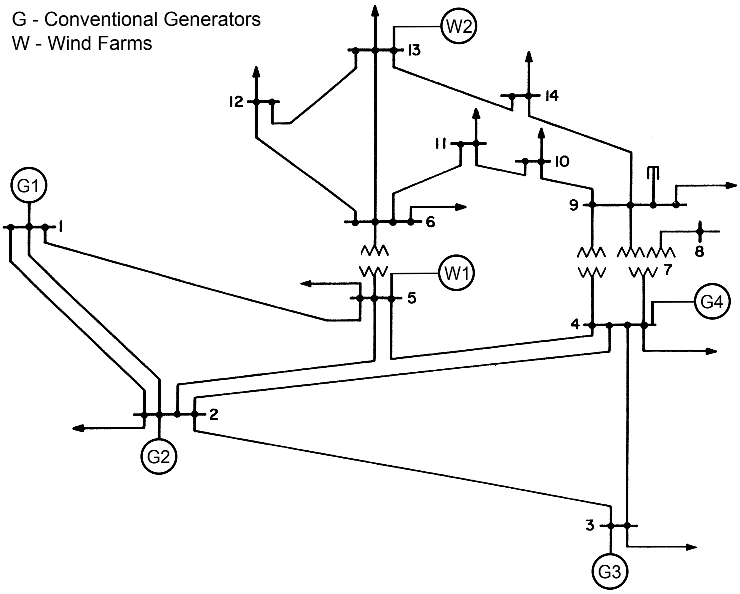

Figure 2.1: Network topology 14-bus power system.

which present minimal correlation in generation and forecast errors. The value of lost load V^{LOL} is set to 200$/MWh while the cost of wind curtailment V^{WSP} is zero.

Figure 2.2 presents the production schedule of the units for the 24 hours of the day. It can be observed that most of the system demand is covered by Units 3 and 4, which have the lowest production costs. Especially, Unit 4 is fully dispatched during the whole day, apart from the first period due to the ramping constraints. Units 2 and 3 serve mainly the intermediate load of the system whereas Unit 1 is dispatched only in periods 17-19 in order to cover the peak demand. In addition, up and down regulation is provided by Units 2 and 3 to cover any real-time imbalances. The amount of dispatched wind power varies during the day according to scenario forecasts, the technical constraints of the system and the network topology. Table 2.1 shows the day-ahead and the expected balancing and total operating costs of the power system. It should be noted that the expected balancing cost is negative because of the down regulation needs arising from the wind uncertainty.

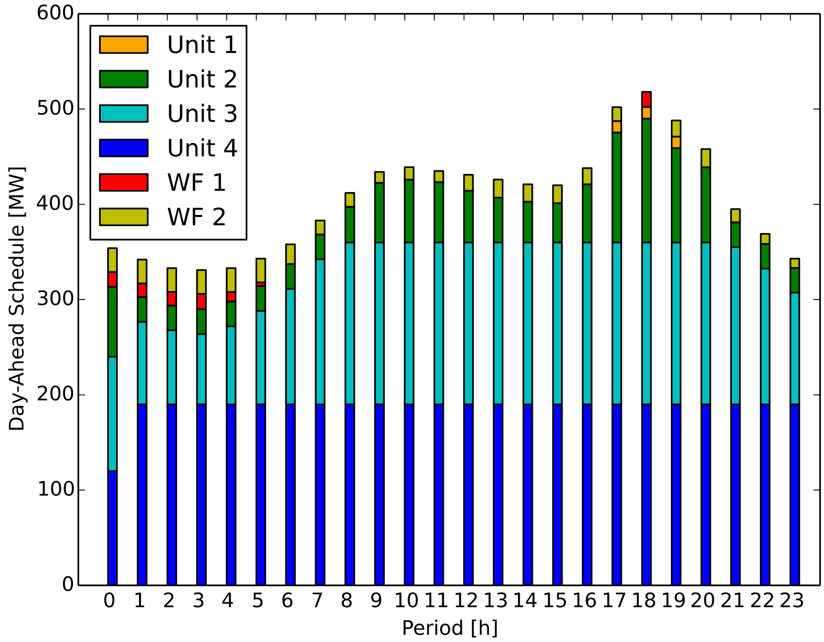

Figure 2.2: Optimal generation schedule.

Table 2.1: System cost

	Expected Total	Expected Balancing	Day-ahead	Start-up	Shut-down
Cost ($)	171092.2	-1930.24	168372.5	4400	250

2.3 Summary of Impacts

This chapter presented the results a stochastic unit commitment model as a method to integrate complete spatio-temporal information of wind power uncertainty in the operational practice of a system/market operator. This two-stage stochastic optimization model is able to pre-position conventional and wind power generators at the day-ahead stage considering the plausible realizations of uncertainty in real-time in order to minimize the total expected system cost. The day-ahead schedule is subject to the specific uncertainty data (scenarios) and the technical properties of the system. However, an important difference of the stochastic approach compared to 'traditional' deterministic models is that the former may not follow exactly the merit order of generator costs during the day-ahead scheduling since they account for the contribution of each unit in the expected system cost, i.e., day-ahead and balancing stages.

Despite the theoretical advantages of the stochastic optimization models, their application in large-scale problems may be limited by the computational burden arising from the high number of scenarios that are necessary in order to capture the true uncertainty distribution. Hence, in real applications one may employ scenario reduction techniques to decrease the cardinality of the scenario set or more advanced decomposition schemes (e.g. Benders decomposition) in order to approximate the iteratively the optimal solution.

Chapter 3

New Balancing Mechanisms

3.1 Challenge description and overview of the contributing methods

The growth of renewable energy sources (RES) in recent years has been important throughout Europe. The power generation from many RES, e.g., wind power, is fluctuating and non-dispatchable which in turn poses new challenges on scheduling and dispatch of the power system and it increases the need for balancing power. According to the conventional operational paradigm, operation schedules need to be coordinated and planned ahead and reserve needs are driven by the outages of generation units or transmission lines. Hence, balancing operation is mainly reactive and restorative, i.e., manual reserves are dispatched upon observed imbalances to restore the availability of automatic reserves.

In view of the predictability and stochasticity of wind power generation, transmission system operators (TSOs) can benefit from predictive dispatch of slow and manual control reserves in order to maintain reactive reserve levels for unpredictable events. While scenario-based approaches for stochastic optimization are well suited for this problem, it appears that TSOs are hesitant in adopting this method into their practice of predictive dispatch. To support adoption, there is a need to study relevant parameters and trade-offs to be considered in introducing such methods to operation practice, enabling also the investigation of alternate reserve product constraints.

The goal of this chapter is to illustrate the formulation of different operational strategies and assess their performance based on relevant criteria following the methodological framework presented in the report on work package 4 [1], Chapter 7. Further details on the complete mathematical formulation of the operational strategies, relevant assumptions as well as on the data used can be found in [6].

3.2 Parameters of Operational Strategies

Different operational strategies are formulated in order to investigate the effect of their components on the performance of the power system. Table 3.1 summarizes the main parameters for the six operational strategies (S1 to S6) considered in this case study. Reducing the minimum up time T^{up}_{min}, from 60 to 30 minutes, allows more frequent re-dispatching of the balancing resources according to the predicted imbalances. In addition, lower lead time, from 30 to 15 minutes, is chosen in order to account for the improved quality the available forecasts of wind production. Objective function J^M_I refers to cost minimization aiming at the economic efficiency of balancing operation. Finally, using objective J^M_{II}, the TSO is able to reduce directly the needs for automatic reserves and increase their availability during a contingency event.

Table 3.1: OPERATIONAL STRATEGIES

	S1	S2	S3	S4	S5	S6
T^{up}_{min} (min)	60	60	60	60	30	30
T^{lt} (min)	15	30	15	30	15	15
Objective	J^M_I	J^M_I	J^M_{II}	J^M_{II}	J^M_I	J^M_{II}

3.3 Simulation Results and Evaluation of Operational Strategies

In order to illustrate the effect of different operational strategies on the the actual dispatch of automatic and manual reserves, a simulation study is performed based actual wind power measurements provided publicly by the Australian Energy Market Operator (AEMO) [7] and synthetic forecast trajectories according to the methodology described in [6].

According to figure 3.1 and one can observe that reserve activation follows a similar pattern in all strategies, which is mainly dictated by the sign and the magnitude of the forecast imbalance. However, the exact amount of each reserve type activated in every period changes depending on the applied operational strategy. Strategies S3, S4 and S6 activate higher amounts of manual reserves in to order to decrease the utilization of automatic reserves. On the contrary, strategies S1, S2 and S5 find the optimal combination of available balancing resources in order to minimize the expected cost of the system. It should be noted, that during certain periods it is possible to have counter-activation of manual and automatic reserves with different sign, i.e., up and down regulation. This can be justified by the fact that the actual imbalance has opposite direction than the one predicted in the scenarios.

Table 3.2 provides the values of some relevant performance metrics for each operating strategy. It can be observed that the total balancing cost reduces significantly using operational strategies that employ objective function J_I^M compared to those that use objective function J_{II}^M. On the contrary, using objective function J_{II}^M, the reduction of automatic reserve utilization E^A, despite their higher activation cost, is not able to compensate the cost increase entailed by the larger volumes of manual reserves utilization E^M. Shorter lead time has a marginal effect on the balancing operation, reducing the needs for manual reserves both in terms of energy and capacity but increasing to a small extent the needs of automatic resources. Finally, the decrease in minimum up time has the most profound positive effect on the balancing operation, regarding both the cost and the reserve needs. This underlines the importance of market rules and indicates that increased flexibility of the resources may bring considerable benefits in the power system.

Table 3.2: PERFORMANCE METRICS

Performance Metric	S1	S2	S3	S4	S5	S6
Total Cost ($\times 10^3$€)	652.83	662.29	907.01	909.51	**602.49**	810.58
Max P_t^{up} (MW)	**46.27**	46.36	48.09	47.97	46.95	53.73
Max P_t^{dn} (MW)	**52.69**	54.29	76.25	79.51	66.39	80
Max $P_t^{a,up}$ (MW)	35.94	37.26	65.20	73.13	**30.30**	39.25
Max $P_t^{a,dn}$ (MW)	104.76	102.37	100.73	**96.69**	105.97	103.93
E^M (GWh)	**2.17**	2.21	2.53	2.56	2.23	2.54
E^A (GWh)	1.25	1.23	1.06	1.05	1.04	**0.86**

3.4 Summary of Impacts

Given the substantial changes of the generation mix across the European power system due to the large shares of stochastic in-feed from renewables, TSOs need to re-design their balancing policies in order to integrate more advanced uncertainty representations and utilize optimally all the available balancing resources. However, this re-design process has to take into account a number of parameters and while assessing their impact on the efficiency of the balancing operation.

Aiming to contribute towards this direction, this work provided a framework for the definition and formulation of operational strategies for reserve activation focusing on the predictive dispatch of regulating power needed to cope with wind uncertainty. The main parameters considered in the current framework are *i.* the minimum up time, *ii.* the lead-time and *iii.* the objective function of the optimization algorithm. The evaluation of each strategy based on various relevant criteria has revealed significant changes on the performance of the balancing operation, indicating that the optimal design of balancing mechanisms is a multi-criteria process where the TSO has to consider plausible trade-offs between the different objectives. However, it should be noted that the most influential parameter, according the case study results, is the definition of the balancing products, in terms of minimum up time, which underlines also the importance of flexibility providers on the efficient operation of the power system.

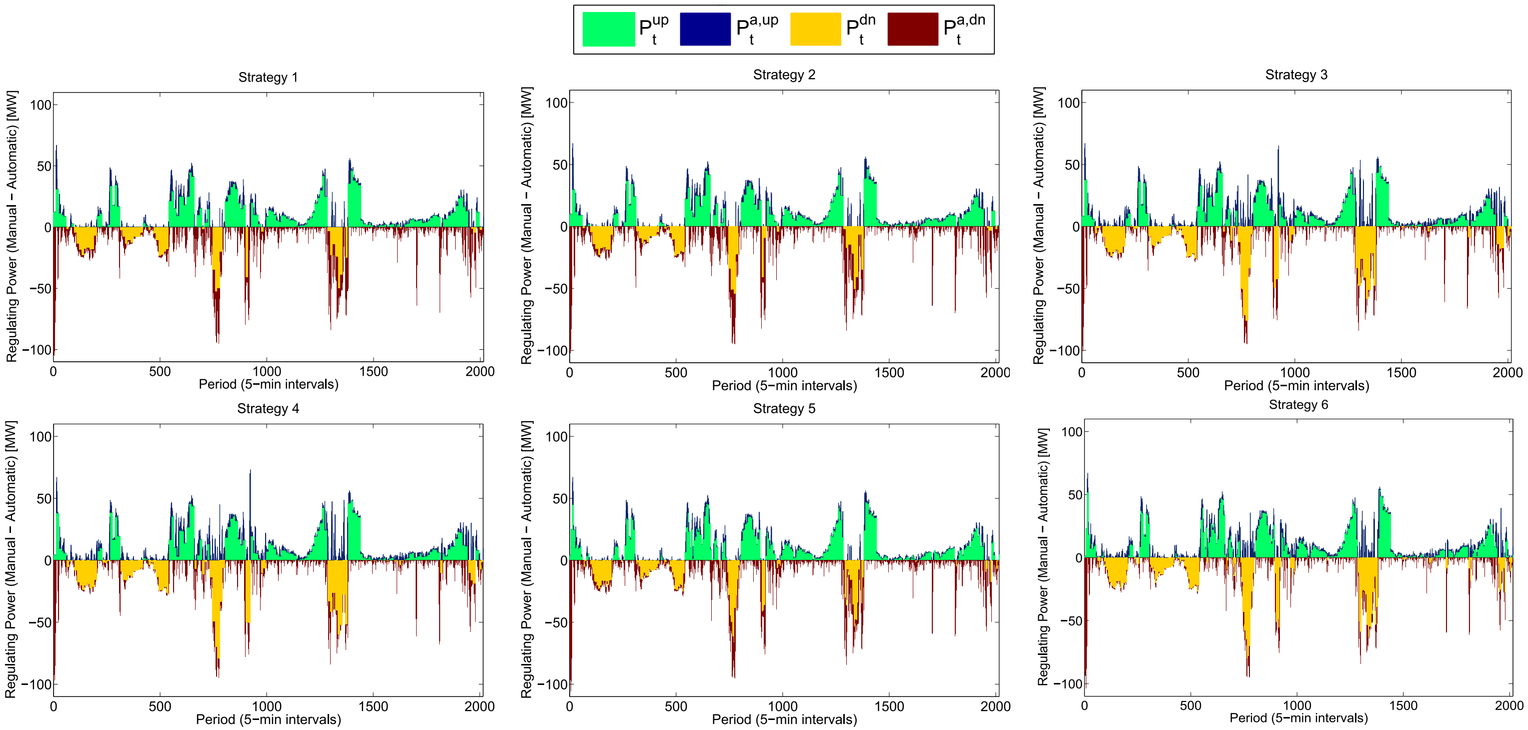

Figure 3.1: Dispatch of manual and automatic reserves for the different operational strategies

Chapter 4

Locational Flexibility

4.1 Challenge description and overview of the contributing methods

Traditionally, the transmission grid was constructed for a centralized production close to the load centers. However, renewable (intermittent) energy sources are constructed in a distributed way where the geographical and meteorological conditions are optimal, often far away from load centers and thus at buses with limited transmission capacities. Due to transmission over longer distances as well as the resulting power flow patterns, that could change rapidly, the transmission system is operated closer to the limits and leads to a generally more congested system. Increasing market activities may aggravate the problem even further. Although that the total amount of reserves capacity might not change significantly due to the increase in forecast uncertainty, the location in the system and their characteristics (e.g. ramping rate, power capacity, etc.) needs to be considered during procurement and operation as the transmission system may not be considered as a 'copperplate' anymore when it comes to balancing. In this chapter, we present a framework to approximately characterize the flexibility a TSO has at his disposal in a certain grid location. The knowledge can be used in different perspectives, e.g. whether the reserve availability is sufficient (during reserve procurement) or how an additional transmission line effects the flexibility available in a certain region (during grid expansion). Especially, it is interesting to study the available flexibility at a certain location with the required flexibility needs. The resulting linear characterizations of the locational flexibility, called the *flexibility set*, and the uncertainty can be efficiently integrated in various processes. We study the integration in a robust procurement process for reserves. The case study uses an illustrative 3-bus system and also demonstrates the application to the IEEE RTS96 2-area system. The details can be found in [1], [8].

4.2 Illustration of Locational Flexibility

4.2.1 Illustrative 3-bus example

The case study is based on a 3-bus system as depicted in Fig. 4.1. Each bus has a predominant unit type: bus 1 has storage capabilities, bus 2 has intermittent energy sources and bus 3 represents a load center combined with conventional, base load, generation units [8].

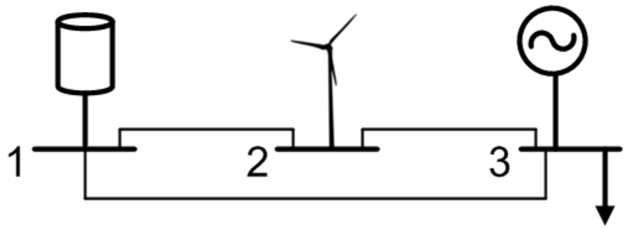

Figure 4.1: 3-bus system with storage, (intermittent) wind farm, conventional generation and an aggregated load.

In a first case study, we determine the locational flexibility at bus 2 and thereby quantify the characteristics of possible deviations of the wind farm from the schedule. This characterization is done in terms of the active power deviations over three consecutive timesteps. Fig. 4.2 shows the feasible regions for three different cases with different transmission capacities available. For comparison, possible realizations of the disturbances are also displayed. In order for the system to remain stable, the polytope of the disturbance has to be contained in the corresponding polytope representing the locational flexibility. It can be seen that the available transmission capacity plays a crucial role. While for medium transmission capacity and for a copperplate assumption the disturbances can be contained, it is not the case for the third case. It can thus be concluded that the incorporation of the network constraints become more important if the transmission system is operated closer to the margin.

4.2.2 Quantification of Flexibility in IEEE RTS96 system

Similar to the previous case study, we now determine the locational flexibility also for the IEEE RTS96 2-zones system shown in Fig. 4.3. We determine the maximal active power deviation over two consecutive timesteps and additionally, for the same two timesteps, the maximal ramping rates are also calculated. Different cases are investigated:

- Location: Bus 217 is in a central location and it is thus expected to exhibit a higher locational flexibility. Bus 207 is a bus in a more remote location.

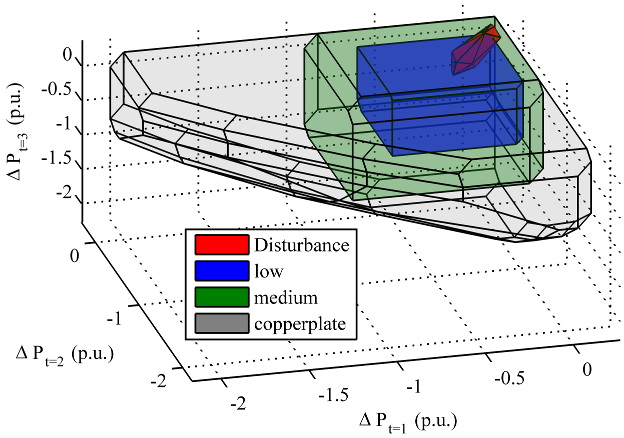

Figure 4.2: Locational flexibility at bus 2 for different transmission capacities compared to the set of possible disturbances.

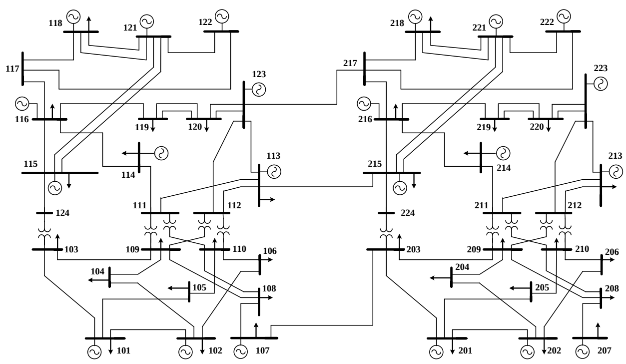

Figure 4.3: IEEE RTS96 system with 2 areas.

- Congestion: The capacity of the three tie-lines connecting the two areas are selected either according to the original values or to have reduced capacity (referred to as the congestion case).
- Ramping: The amount the generation units are able to ramp up or down is selected to be either 100% or 10% of the installed capacity.

In Figs. 4.5 and 4.4 the results are shown. It is observed that the ranges for possible disturbances at the two buses are directly influenced by their location, the available transmission capacity as well as the ramping capabilities of the units. It should be pointed out that the evolution of the disturbance over time plays a crucial role as well. For example considering the case *Bus 217, Ramping 10%, uncongested*, the realization of $\Delta P_{t=1}$ limits the feasible deviations at $t = 2$. For all other cases, the feasible range of power deviation is a rectangle and thus the deviation of $t = 1$ is not influencing the feasibility

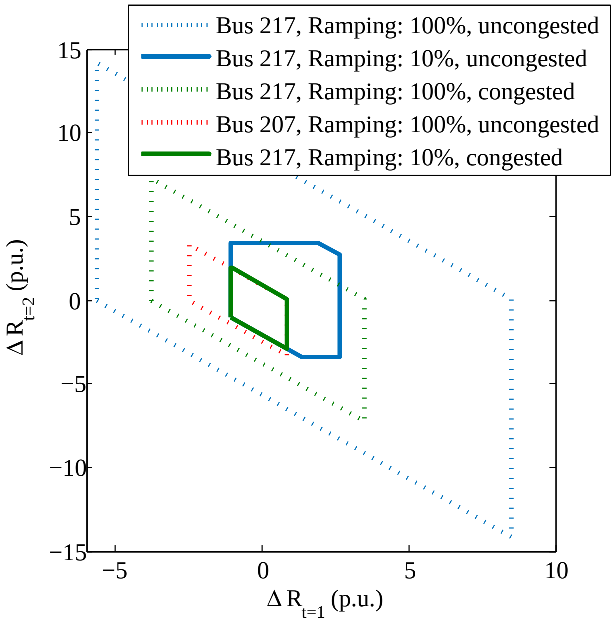

Figure 4.4: Ramping: Locational flexibility at buses 217 and 207 for time steps $t = \{1, 2\}$.

of possible future realization, however, the location, transmission capacity, etc. still is.

4.3 Procurement considering Locational Flexibility Requirements

The last case study focuses on the integration of location-dependent uncertainty in a procurement algorithm for manual reserves, i.e. a procurement considering locational flexibility needs. For easier interpretation, we use the same 3-bus system as above. We apply the algorithm outlined in [8], [1]. We focus on the procurement costs and the magnitude of deviations with respect to two parameters, namely, the possibility of curtailment of production at bus 2 and the storage capacity of the storage (with very fast ramping capabilities) at bus 1. For simplicity, the power rating is fixed to 1 p.u. and the initial state of charge is assumed to be 50%. The curtailment is given as the relative share of the current production that is allowed to be curtailed. The full list of parameters are found in [8].
In Fig. 4.6 the procurement costs are shown. The parameters curtailment and storage size have both a significant influence as it reduces the necessity to procure reserves from conventional generation units. The lowest procurement costs are achieved by a combination of both parameters. It is a

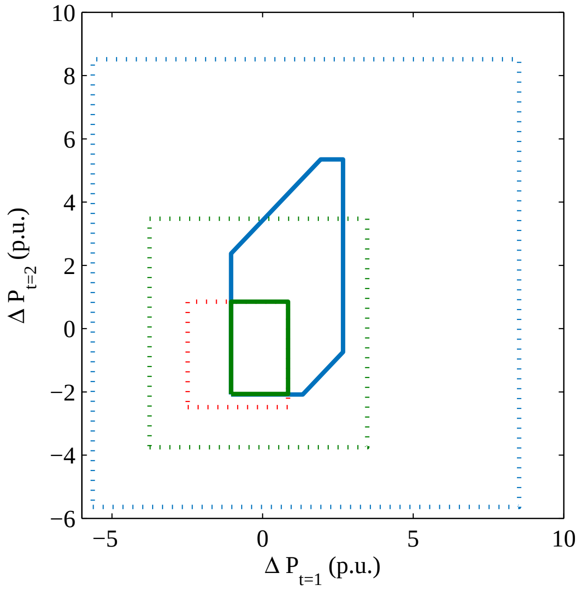

Figure 4.5: Power: Locational flexibility at buses 217 and 207 for time steps $t = \{1, 2\}$.

trade-off between the additional reduction in procurement costs and the additional costs, such as investment costs of the storage, but already rather small curtailment possibilities combined with some storage results in substantially lower costs in the present case study.

An alternative problem is considered in the second part with results displayed in Fig. 4.7. Instead of considering the procurement costs, we focus now on the magnitude of the disturbance. We use an uncertainty set as for example displayed in Fig. 4.2 (in red) and scale it linearly until a system constraint becomes binding. In other words, we investigate how much large a disturbance at bus 2 could become until the limits of system stability are reached. It can be observed, that increasing either the possibility for curtailment or the storage size does not lead to a large increase in the scaling factor. However, using a suitable combination of the two results in a substantial increase in the locational flexibility at bus 2.

4.4 Summary of Impacts

The case studies have shown that three different factors, amongst others, play a crucial role when it comes to the set of feasible deviations from a scheduled system state:

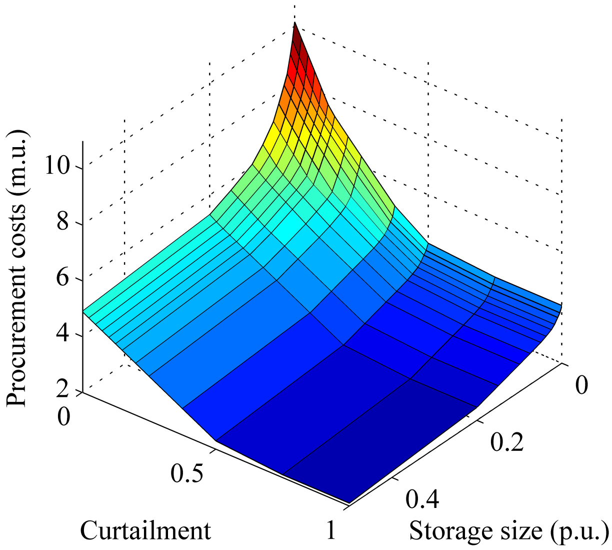

Figure 4.6: Capacity reservation costs as a function of curtailment and storage size.

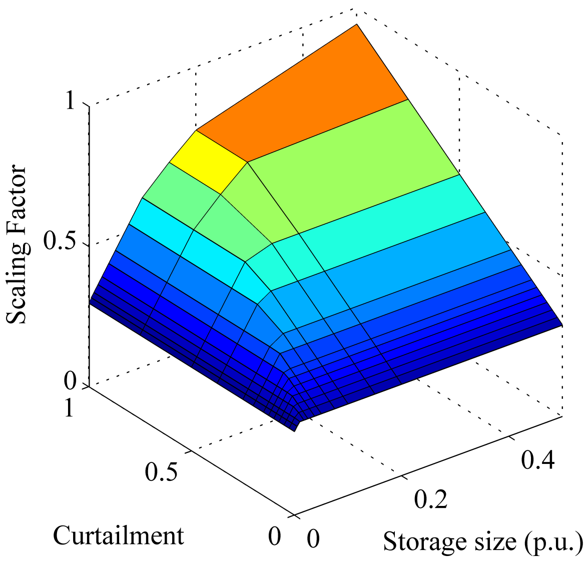

Figure 4.7: Scaling factors of normalized feasible disturbances for different curtailment possibilities and storage sizes. For illustration purposes, the x and y axes are rotated.

- Location: transmission constraints limit the disturbances that can be handled at a certain node in the grid.
- Unit parameters: the operational flexibility a single unit can provide depends on different physical and economical constraints. In this work the parameters ramping, power capacity and storage capacity were used.
- Temporal evolution: the available flexibility at a given timestep depends on the previous realizations of the disturbances.

The location as well as the trajectories of the disturbances were often neglected in previous works. The flexibility set has been integrated in a procurement process for manual reserves and effects of curtailment and the size of energy storage are investigated. It has been shown, that a suitable combination of the two remedies allows to reduce the procurement costs, respectively, to handle higher forecast uncertainties.

The presented framework can readily used by a TSO to analyze available operational flexibility, given that the required operational data is available. For the integration of locational flexibility needs in prevalent procurement procedures, further research is needed, especially in terms of scalability.

Chapter 5

Inter-TSO coordination

5.1 Challenge description and overview of the contributing methods

For historic reasons Europe has many different TSOs. Their respective control areas correspond mainly to countries. The exchange of information and operational data as well as the coordination between the TSOs is rather limited. First initiatives, such as CORESO, are trying to improve the coordination to increase the system security. While traditionally the tie-lines have mainly been used to increase the security of the whole interconnected system, these lines are congested more often as the inter-area power flows increase. Reduced availability of traditional, controllable units to provide control reserves necessitate a suitable sharing of reserves between the control areas to allow for an economical and efficient operation. It is expected that an increased coordination of operational flexibility and the exchange of suitable operational can increase the system's security and improve the use of the (cross-border) transmission infrastructure. In this chapter we focus on the coordination of the involved entities, i.e. the TSOs and we present a tool to efficiently manage, i.e. share, the available operational flexibility between neighboring TSOs taking into consideration the transmission limits. The details of the case studies are found in [9].

5.2 Managing Flexibility in Multi-Area Power Systems

The IEEE RTS96 system (Fig. 4.3) is used for the case study. This test system consists of two areas, that are interconnected with three tie-lines, with a total of 48 buses. The details on the setup are found in [9].

5.2.1 Illustration of Method and Exportable Flexibility

As indicated in [1], the proposed coordination approach uses feasible combinations of flow deviations on tie-lines. The corresponding bounds are constructed respecting inter- and intra-zonal transmission limits and, if available, capacity of different fast-ramping generation units for redispatching actions. This case study compares the flexibility that can be exchanged between different control areas. Figs. 5.1, 5.2 display these bounds for the active approach, i.e. redispatching measures are considered, and the passive approach, i.e. only the remaining transmission capacity is considered. The perspective we take is from the zone with buses 1xx, i.e. these bounds are provided for the TSO controlling buses 2xx. The bounds might look different if we took the perspective of TSO 2xx, as different transmission and generation capacity constraints would become binding. Further, in Fig. 5.2 the N-1 security criterion is considered.
The following observations are made:

- The allowed deviations are in general smaller if the N-1 security criterion is considered as certain transmission capacity has to be withheld. In general parlance, this results in polyhedrons with smaller volumes/areas.
- The magnitude of the largest feasible deviation depends strongly on the combination of lines it is effecting. For example, a deviation effecting only the tie-line 113-215 has to be smaller than a deviation effecting only tie-line 107-203. However, as the line flows adjust automatically according to the voltage angle, respectively the injected power, the location of the deviation within the neighboring area is of importance.
- The passive approach results in a hyperplane, compared to a polyhedron in the active approach, as the passive approach assumes no net energy exchange between the areas.
- Corrective control action and suitable sharing of reserves allows to increase the possible tie-line flow deviations substantially.
- The figures show the available flexibility for a given system state, i.e. a certain demand and generation dispatch. However, these figures might look substantially different for a different system loading. The origin is alway contained by the sets as no deviation has to be feasible.

5.2.2 Range of Shareable Flexibility

In this case study, we try to quantify the flexibility that can be shared between two control areas. We investigate different cases: the amount that can

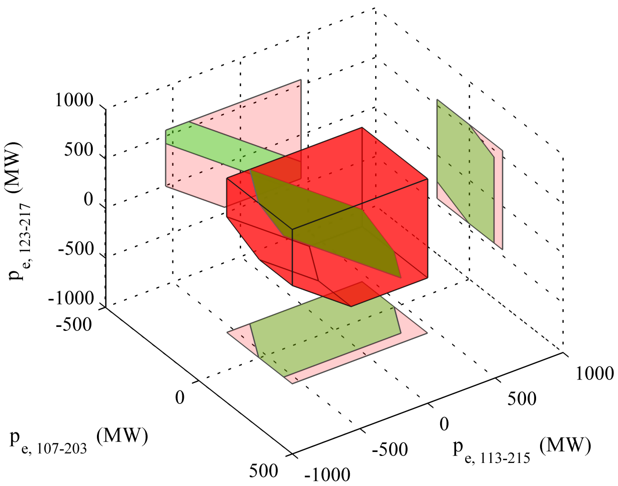

Figure 5.1: Result from the Passive (green) and Active Approach (red) and corresponding projections on planes orthogonal to the axes. The N-1 criterion is *not* considered.

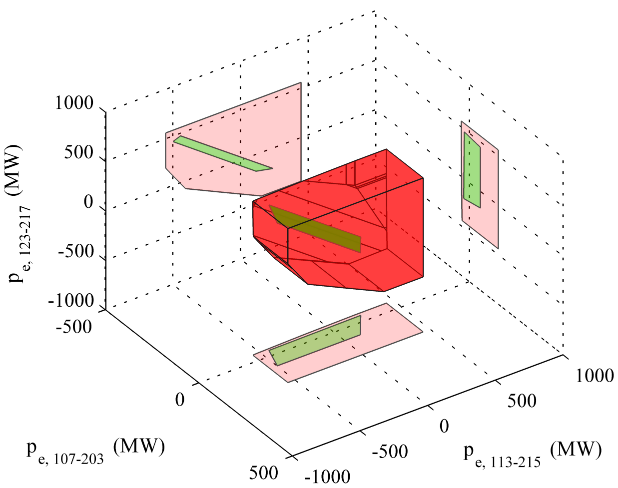

Figure 5.2: Result from the Passive (green) and Active Approach (red) and corresponding projections on planes orthogonal to the axes. The N-1 criterion is considered.

be exported to a neighboring area (negative) or imported from a neighboring area (positive) for the N and N-1 secure case. Two values are determined: the upper bound, which corresponds to a deviation of tie-line power flows such that the import/export is maximized. As most deviations will be different to this maximizing deviation, we determine the lower bound which is the deviation that can be guaranteed for all combinations. Two major observations are made: first, as expected, the range reduces if the N-1 security criterion is imposed. Secondly, the lower bounds, which is a conservative selection, is substantially lower than the upper bounds. Future research topic could address how the flexibility can be traded as a market product or what market schemes enable an efficient but still secure use of the available capacity.

	Lower bound of range (in MW)	Upper bound of range (in MW)
N secure, negative	-175	-564
N-1 secure, negative	-38	-523
N secure, positive	130	1152
N-1 secure, positive	60	1152

5.2.3 Comparison to ATC values

In this case study, we compare the approach to a balancing mechanism that only respects the available transfer capacity (ATC). Figs. 5.3, 5.4 show two comparisons between the feasible flow deviations using the active approach (red wire polyhedron) and possible deviations that are constructed using the ATC. The details are found in [9]. For the active approach two cases are considered with different amounts of control reserves available to be shared with the neighboring control area. In the first case with full redispatching capacities available, the operation using the proposed coordination approach becomes substantially more flexible. The main reason is the consideration of the location of the injection and thus the anticipation of the changes in the power flows. If the available control reserves that are shared with a neighboring TSO are reduced, the allowed tie-line flow deviations reduce. This can be seen in Fig. 5.4. It should be noted, that the ATC only concerns the available transmission capacity, but gives no indication if generation capacity, e.g. for balancing/reserves, is actually available. This is visible in Fig. 5.4: The blue polyhedron exceeds the red one in some locations. As however, the red one takes into account all the available capacity that is allowed to be redispatched, the deviations cannot exceed the red polyhedron in these locations. In other words: sufficient transmission capacity is available, but not enough control reserves.

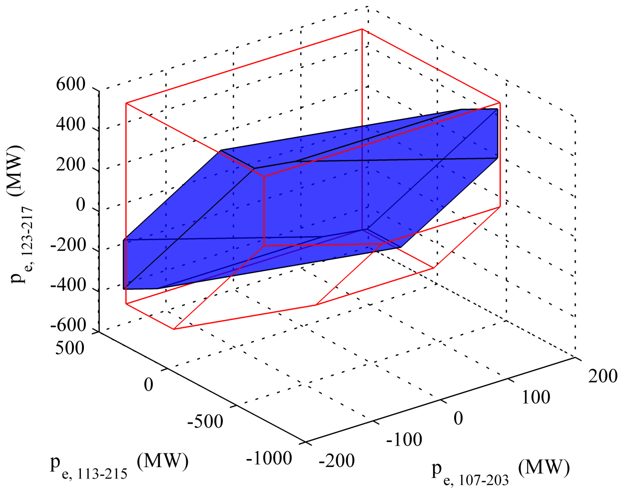

Figure 5.3: Comparison of ATC (blue) and resulting Polytope of the active approach (red) for full redispatching capabilities in region A.

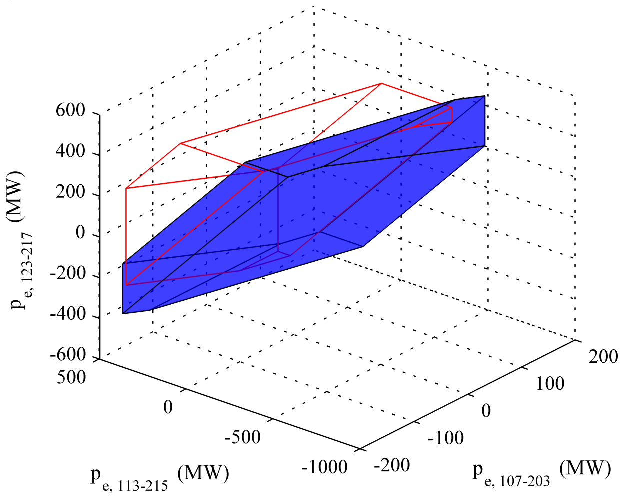

Figure 5.4: Comparison of ATC (blue) and resulting Polytope of the active approach (red) for limited flexibility available in region A. Parts, where ATC polytope is exceeding the area of the active approach corresponds to combinations, where sufficient transfer capacity but insufficient operational flexibility is available in region A.

5.2.4 Potential Nodal Fluctuations

The last case study investigates how the proposed methods effect the largest feasible disturbances, e.g. in terms of forecast errors of intermittent energy sources such as wind farms, at every single bus in the neighboring control area. The disturbances are determined for each bus separately, i.e. the disturbances are not considered to be correlated, by an optimization problem that tries to maximize the disturbance locally. Figs. 5.5, 5.6 show the positive and negative deviations for different buses. The red line corresponds to the passive approach, i.e. no exchange of net energy between the areas but respecting the tie-line flow deviation limitations produced by the passive approach. In orange, the ATC is used under the assumption that sufficient control reserves are always available in the neighboring control area and the corresponding TSO is willing to share them. Shown in blue are feasible nodal fluctuations if the active approach is used. The cases in the two figures differ by the amount of reserves that are available in the local control area. We draw the following conclusion:

- The active approach allows to share more reserves between the areas compared to a balancing mechanism using the ATC. This means, using the proposed method additional intermittent energy sources can be incorporated safely with a reduced need for transmission expansion as the alleviation of larger disturbances is possible. The passive approach gives a lower bound on the deviations as it considers only the transmission limitations but not a net energy exchange.
- If the local control area itself has a high flexibility, i.e. sufficient reserves that can be dispatched from fast-ramping generation units, the relative benefit of the proposed method is lower as many deviations can be dealt with locally.
- If the local area is however not very flexible, the method allow to benefit from flexible resources from the neighboring system.

5.3 Summary of Impacts

The case studies have shown that the limits of the operational flexibility that can be shared between two areas can efficiently be characterized by the feasible tie-line flow deviations away from scheduled cross-border flows. These limits incorporate information on feasible combinations of deviations on different tie-lines without revealing potentially confidential data TSOs are reluctant to share. The framework can be extended to multi-area systems and also incorporate newer transmission technologies, such as HVDC.

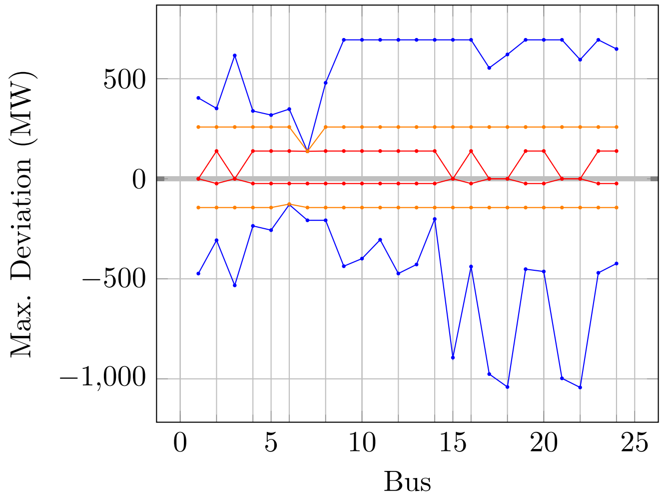

Figure 5.5: Maximal possible deviations at buses in region B for active approach (blue) and passive approach (red) and for comparison the ATC case (orange) for a Region B with low flexibility (5%). Positive values correspond to positive deviations, i.e. additional injections, negative values to negative deviations, i.e. additional consumption or reduced production.

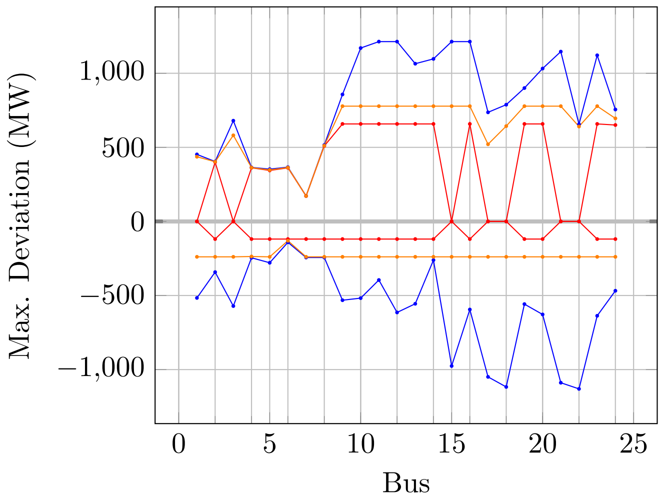

Figure 5.6: Maximal possible deviations at buses in region B for active approach (blue) and passive approach (red) and for comparison the ATC case (orange) for a region B with high flexibility (25%). Positive values correspond to positive deviations, i.e. additional injections, negative values to negative deviations, i.e. additional consumption or reduced production.

The coordination of flexibility between different control areas allows to increase the tie-line utilization compared to a balancing operation using the traditional ATC (available transmission capacity) criterion. This in turn allows to deal with larger infeed uncertainties in the respective areas. The proposed method could readily be applied by TSOs in special situations, e.g. during situations, where the cross-border capacity is available, but limited, and the available reserves in an area are not sufficient in all situations to handle the forecast uncertainty. Future research should focus on how to build a tradeable market product based on flexibility that can be exchanged between areas.

Chapter 6

Increased Transmission Flexibility Needs

6.1 Challenge description and overview of the contributing methods

High fluctuations, increasing market activities as well as injections far away from load centers require an adaptation of the current transmission system. In Fig. 6.1 the expected needed increase in transmission capacity is displayed as well as the main power flow directions. Fig. 6.2 shows different grid expansion projects that are planned and might be implemented in the near future. Especially, HVDC connections are foreseen for transmissions over longer distances and for the inter-connections of different countries.

Grid expansion is usually a tedious process which can be delayed due to public opposition. As investment costs are high, different options and alternatives should be taken into consideration. Aside from building new lines, different options exist to increase the capacity of existing transmission lines. For example using measurement devices in combination with more sophisticated algorithms would allow to increase the efficiency of the transmission system without compromising its security (control-based expansion, such as Dynamic Line Rating). When it comes to balancing of the power in a congested grid, the controllability of the power flows becomes increasingly important. Different technologies are available, e.g. HVDC, that allow to increase the controllability of the power flows while having relative low losses over long distances, or similar, FACTS devices, that also allow to increase the controllability.
In this chapter, we first investigate possible benefits and risks of dynamic line ratings as well as ways to handle the weather forecast uncertainty. In second part, we investigate the performance of the tool for HVDC grid expansion that takes into consideration the increase of operational flexibility in

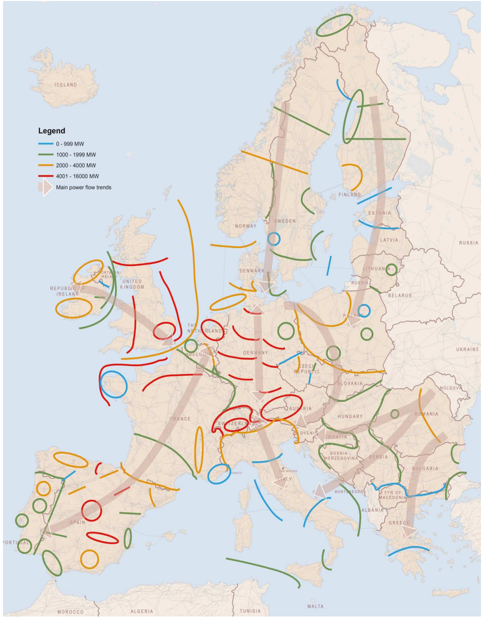

Figure 6.1: Increase in transmission capacity [10].

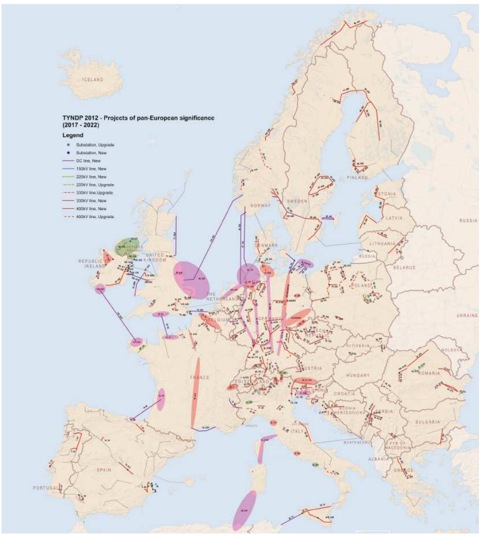

Figure 6.2: Grid expansion projects by 2022 [10].

the grid planning. Finally, we analyse how the cross-border capacity should efficiently allocated between different trading floors, i.e., reserve capacity, day-ahead and real-time markets, under different market clearing setups. Details are found in [1], [11], [12], [13] and [14].

6.2 Dynamic Line Rating

Dynamic line rating (DLR) allows to increase the transmission capacity under some suitable weather conditions as the thermal power limit is traditionally selected under conservative weather assumptions. In this section, we investigate three different aspects: first we analyze the potential of single transmission lines based on weather data, then we investigate the total system cost reduction and the increase of utilization and finally, the focus is on the risk caused by the weather forecast uncertainty. Details are found in [1] and especially in [11] and [12].

6.2.1 Analysis of Potential of DLR and Forecast Uncertainty

For a given conductor temperature limit and different weather conditions, i.e. wind speed and angle, sun irradiation and ambient temperature, the maximum current can be determined. The ampacity directly translates into a power limit. Based on the weather data over the period of one year from 11 different weather stations in Switzerland, the theoretical line ratings are calculated, sorted and normalized to the nominal line rating (NLR: line rating under conservative weather assumptions). The line rating is determined using the cigre model [15]. In Fig. 6.3 the result is shown. One observes that the current selection of line ratings (NLR) are conservatively and thus underestimate physically available transmission capacity in most cases.

When using DLR, the transmission capacity has to be determined based on current weather conditions. As these conditions are not known exactly during an operation planning phase, corresponding forecasts have to be used. These forecasts exhibit some forecast uncertainty which translates into an uncertainty in the actual transmission capacity that is available. The distribution of the forecast error is illustrated next. We use the same weather data as before, but determine the DLR not only based on the actual measurements but also based on the corresponding forecasts, which have a lead time of 24h, 12h and 3h. The forecast errors result in different line ratings. This differences are sorted and normalized to the NLR. The resulting distributions of the DLR forecast error is shown in Fig. 6.4. One can see that substantial forecast errors have to be expected, but the errors reduce in general if the forecast lead times are reduced. Accordingly, the forecast error has to be taken into consideration in a planning phase. On a side note: the meterological conditions might vary along a conductor and thus

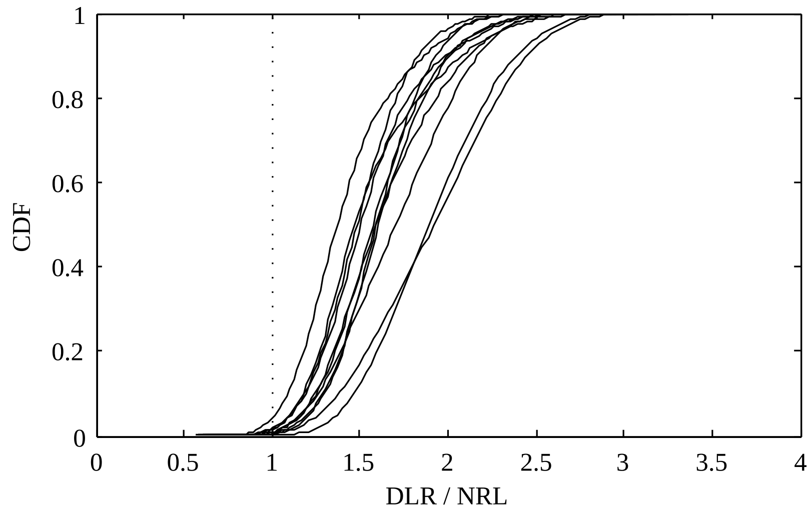

Figure 6.3: Cumulative Distribution Function (CDF) of normalized line ratings based on meteorological data from different stations.

also the ampacities can differ along a conductor. For the rating of the whole conductor, the lowest local rating is pivotal.

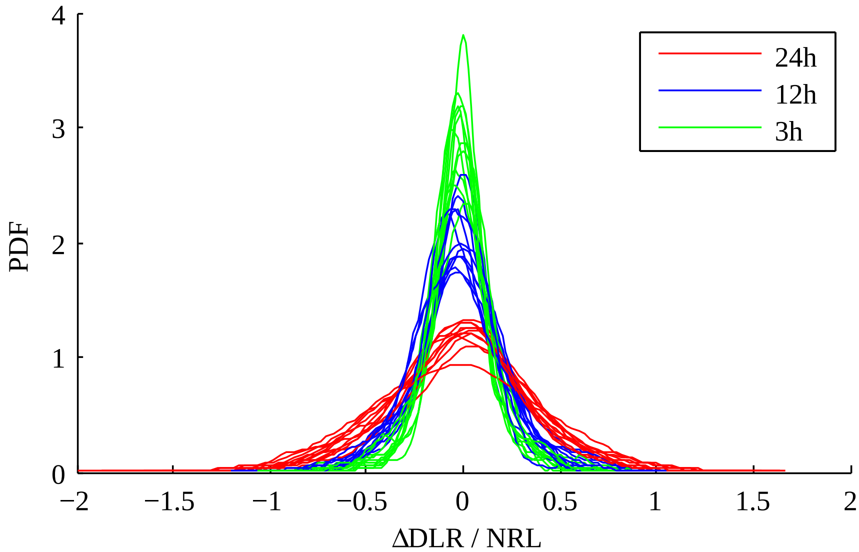

Figure 6.4: Probability Density Function (PDF) of line rating forecast errors for meteorological data from different stations and different forecast lead times normalized to nominal line ratings.

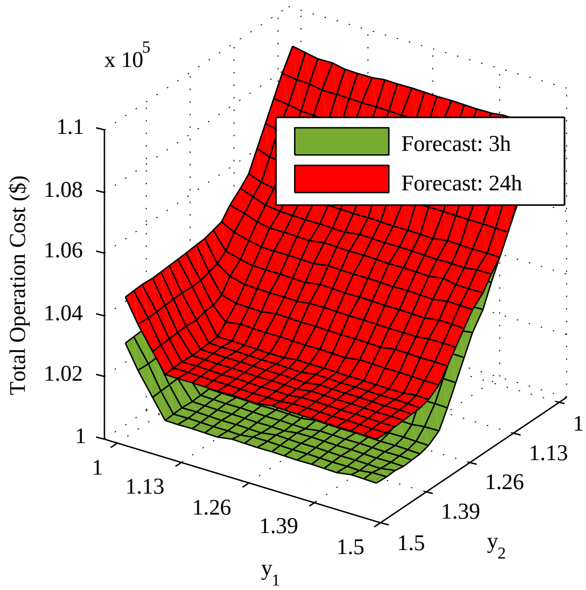

Figure 6.5: Total operational costs for 3h- and 24h-ahead forecast for different levels of guaranteed transmission capacity y measured relative to the nominal transmission capacity (NLR).

6.2.2 Cost reduction and increase of utilization

The methods presented in [12], [11] and summarized in [1] enable the use of the potentially higher transmission capacity, but account for the risk by forecast uncertainties. In this case study we look at two aspects: first, the reduction in the total operation costs and second, the increase in grid utilization enabled by DLR.

In Fig. 6.5 the total operational costs of the system, i.e. the cost of generation to satisfy the demand and potential costs for corrective controls as described in [1], are shown. Two parameters y_1, y_2 are varied, which represent the selected (normalized) line rating for two lines for a given weather forecast, which has a lead time of either 3h or 24h. The following observations are made:

- Using the 3h weather forecast leads to lower costs as less forecast uncertainty needs to be considered.
- In general, the operation costs are sensitive w.r.t. to an increase of the line rating of line 2, but not w.r.t line 1.
- For values of $y_2 \geq 1.4 and y_1 \geq 1.15$, the cost reduces no further as further capacity is needed on the two lines for the least cost dispatch.

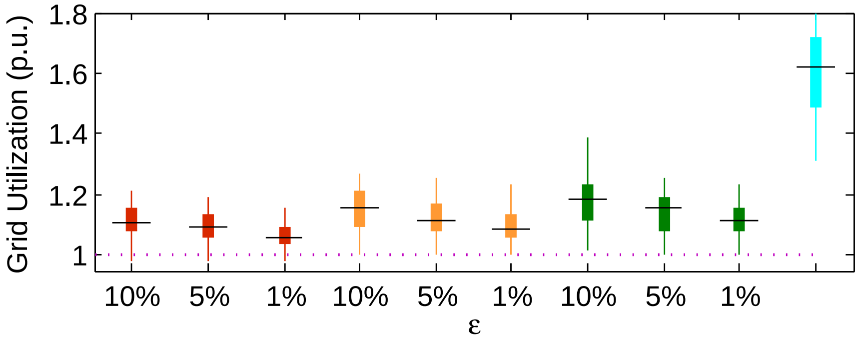

Figure 6.6: Grid utilization for different security levels compared to a perfect forecast (turquoise). Forecasts: red = 24h, yellow = 12h, green = 3h.

- For the case study considered, the cost savings are around 6%. But in general, the savings depend, among many other factors, on the selected lines equipped with DLR, the weather forecast and the corresponding uncertainties.

Instead of quantifying the reduction of the costs, we now reverse the problem and determine how much the utilization of the grid could be increased. We therefore apply the probabilistic approach as in [1]. We determine the grid utilization by maximizing a scalar factor that scales up the load at every bus uniformly. This scaling factor depends on the current weather forecast and on the selected security level ϵ. Details can be found in [12]. In Fig. 6.6 a box-plot for these factors is shown for different security levels ϵ (a lower value indicates a higher risk aversion). For comparison the scaling factors for perfect weather forecasts are shown. The factors are normalized to the scaling factor for the nominal line rating. The color indicate different forecast lead periods. The box plot indicates the 25%, average, 75% quantiles, as well as the extreme values. The following points are observed:

- In general, the factors are above 1, indicating that more transmission capacity could be used.
- A reduction in the forecast lead time increases the possible utilization; an increase in the risk aversion decreases it, but increases system security.
- For the perfect forecast, the average increase in grid utilization is about 50%, neglecting possible bottlenecks such as transformer limits etc.

6.2.3 Risk assessment and Operational Costs

In the last case study, we focus on the risk and costs associated to the operation of DLR. The costs manifest in different ways in the two methods: For the method using corrective control actions in [1], a higher forecast uncertainty coupled with a high scheduled power flows leads to higher costs for corrective control measures, i.e. reservation of capacity and redispatch of generation units. For the probabilistic method in [1], the dispatch is done such that the transmission constraints are not violated with a certain (high) probability. Therefore, the problem becomes a trade-off between a reduction of the dispatch cost versus the number of insecure instances, which can be controlled by the selection of the risk level ϵ.

Fig. 6.7 displays the costs associated with corrective control actions for different forecasts of the line rating μ and different forecast uncertainties σ for the method using corrective control actions. σ and μ are given in p.u. where 1 p.u. corresponds to the nominal line rating (in MW) [11]. We observe, that an increase in the forecast uncertainty translates directly in (monotonically) increasing operational costs. For higher forecasts, the operational costs are reducing as higher DLR can be used without a need for corrective control actions. In the case $M - I, \mu = 1.25 p.u.$ the lowest costs are achieved if the line is used as much as possible which results in relatively high cost expectations for redispatching actions.

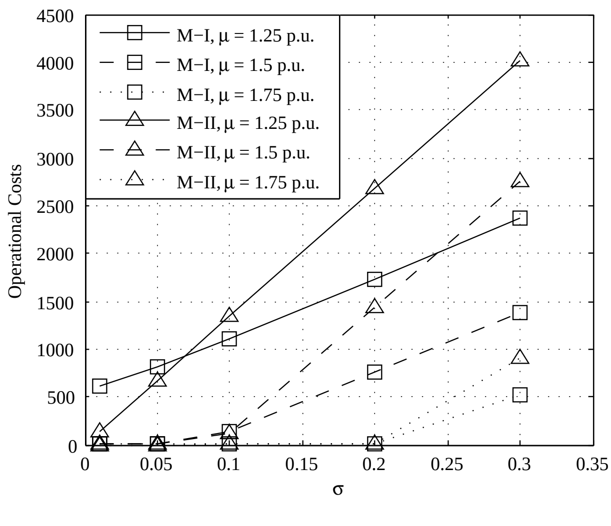

Figure 6.7: Operational costs for point forecasts μ and forecast uncertainty σ.

For the probabilistic method [12], we determine the total dispatch costs for different risk levels ϵ and compare it to the number of insecure instances in a Monte Carlo simulation. The deterministic cases are using the forecasted weather only but don't consider the forecast errors in contrast to the probabilistic cases. For comparison, also the results using the NLR are given. The following points are noted:

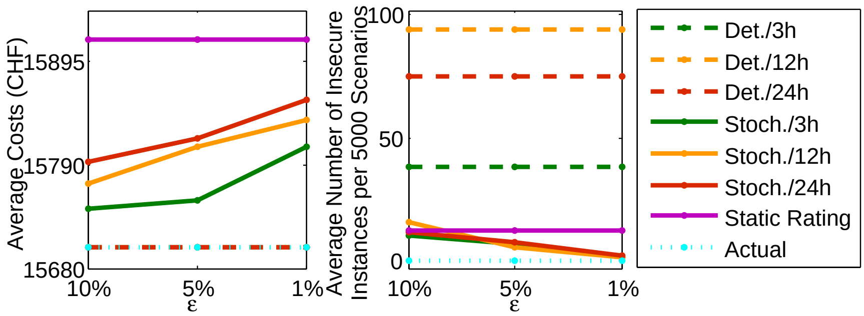

Figure 6.8: Behavior of operational costs and insecure instances for different security levels.

- Increasing the risk aversion results in increasing dispatch costs as more scenarios have to be considered. Using only the forecasted values results in the lowest costs. Using the conservative static line rating (NLR) results in the highest costs as the least transmission capacity is available.
- Based on a Monte Carlo simulation with 5000 scenarios, the deterministic methods result in more congestions and are thus not suitable. The number of insecure instances from the probabilistic method can be influenced by the selection of ϵ. The number of insecure instances reduces even to values lower as in the case with a static rating.
- As in previous case studies, the forecast period plays a crucial role, i.e. the reduction of the forecast lead time from 24h to 3h results lower operational costs and less congestions, especially for the deterministic methods.

6.3 HVDC Grid Expansion considering Flexibility

ï■¿In this section, we investigate the placement of HVDC terminals w.r.t. not only the economical costs but also considering a possible increase in operational flexibility. The placement allows to account for locational flexibility needs and can thus increase the system reliability. We apply the expansion planning method as formulated in [1]. Details on the setup of the case study can be found in [13].

6.3.1 Comparison of Operational costs

In the first part of the case study we compare the operational costs, i.e. the cost to satisfy all the demand, for different numbers of HVDC lines that are (optimally) integrated in the system. Further, the costs are given for different values of the parameter ρ, which is the trade-off factor between flexibility and operational costs. A $\rho = 1$ puts a higher weight on the fulfillment of flexibility criteria, while $\rho = 0$ puts a higher weight on achieving the lowest operational costs. Fig. 6.9 displays the results.

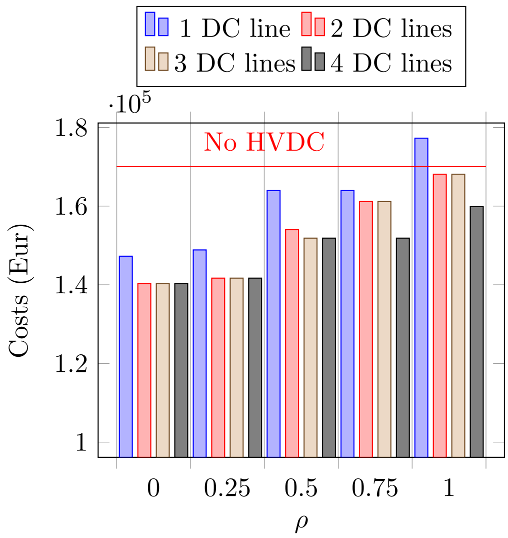

Figure 6.9: Operational costs for different values of ρ and different numbers of HVDC lines.

Two tendencies are observed: on the one hand, increasing the number of HVDC lines generally decreases the operational costs (neglecting the investment costs). On the other hand, focusing more on the increase in operational flexibility, the costs increase and thus leaves the system operator with a trade-off between the cost reduction and the increased system flexibility. In all, except one, cases the costs are reduced compared to the operation without HVDC connections. The exception is a result of a strong focus on the increase of flexibility.

6.3.2 Investigation of Flexibility Increase

The second part of the case study quantifies the gains in operational flexibility for the different, optimally placed, HVDC connections. The flexibility is determined as follows: for every bus, the maximal additional injection or extraction of active power within given time frames is determined. Every bus is considered separately. The system flexibility is considered to be the sum of all the individual flexibilities. Figs. 6.10, 6.11 show the corresponding results.

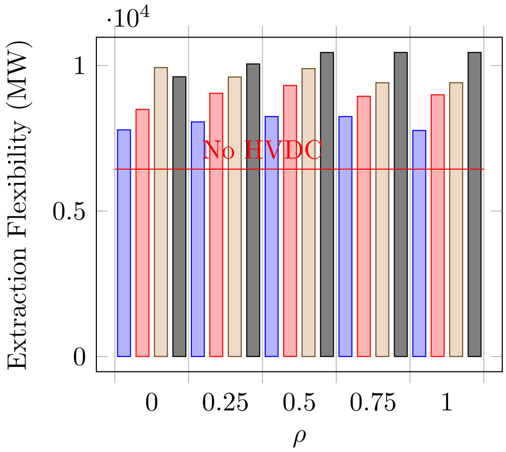

Figure 6.10: Extraction Flexibility for different values of ρ and different numbers of HVDC lines.

The observations are:

- In general, the flexibility is increased by adding HVDC connections and adding more lines leads to a more flexible system.
- Increasing ρ lead to more flexibility in general. It should be noted, that a higher sum of injection/extraction flexibility does not necessarily imply that this flexibility is also available where it is needed (see chapter 4). However, increasing ρ increases the weight on the fulfillment of locational flexibility needs.

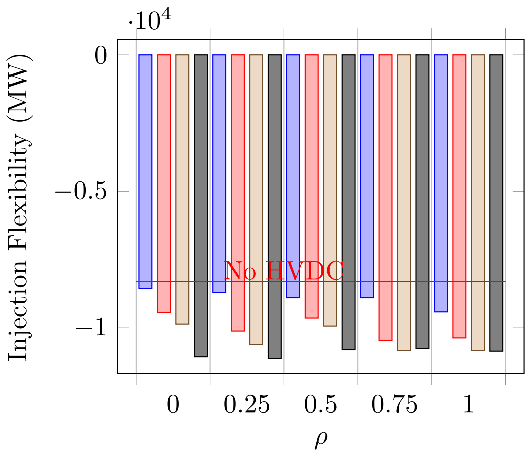

Figure 6.11: Injection Flexibility for different values of ρ and different numbers of HVDC lines.

6.4 HVDC Capacity Allocation for Reserve Exchange

The operational flexibility of the power system depends both on the technical parameters of its components, i.e., generators and transmission infrastructure, as well as on the operational practices that make optimal use of the available assets. This work focuses on alternative market designs that enable sharing of cross-border balancing resources between adjacent power systems through High Voltage Direct Current (HVDC) interconnections which provide increased controllability.

In this context, we formulate a stochastic market-clearing algorithm that attains full spatio-temporal integration of reserve capacity, day-ahead and balancing markets. Against this benchmark we compare two deterministic market designs with varying degrees of coordination between the reserve capacity and energy services, both followed by a real-time mechanism. Our study reveals the inefficiency of deterministic approaches as the shares of wind power increase. Nevertheless, enforcing a tighter coordination between the reserves and energy trading floors may improve considerably the expected system cost compared to a sequential market design. Aiming to provide some insights for improvement of the sequential market-clearing, we analyse the effect of explicit transmission allocation between energy and reserves for different HVDC capacities and identify the market dynamics that dictate the optimal ratio.

An outline of the market clearing algorithms employed in the current study is provided in the report on work package 4 [1], Chapter 6, while the detailed model formulation is presented in [14] along with the relevant case study data based on the IEEE RTS-96 system described in [16] (the two-area version is shown in Fig. 4.3).

6.4.1 Effect of Market Clearing Algorithm on Expected Cost

Figure 6.12 shows the evolution of the expected power system operation cost as wind penetration increases, for the three considered market setups and an HVDC tie-line capacity of 200 MW. The ratio of the installed wind power capacity between areas 1 and 2 is fixed to 2:1 and wind power penetration is defined as a percentage of total system load. It can be observed that stochastic market-clearing outperforms both deterministic approaches in the whole range of wind penetration levels, exploiting the advanced information on the spatial characteristics of wind forecast uncertainty and managing to fully capture the benefits of cost-free wind power. The performance of the two deterministic market setups is similar up to a penetration level of 45%, while beyond this wind power share the deterministic energy and reserve

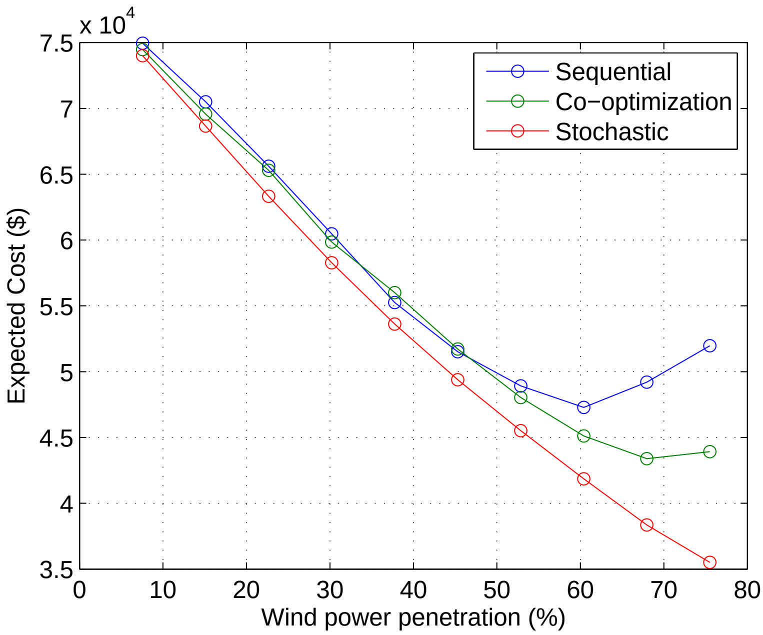

Figure 6.12: Expected cost as a function of wind power penetration for different market-clearing models ($X = 15\%$).

co-optimization model achieves significantly lower expected costs. However, the inefficiency of both deterministic models becomes apparent for large penetration levels, where increasing installed wind power capacity leads to higher expected cost. It should be noted that the curves in figure 6.12 are calculated using in-sample analysis, i.e., the same scenario set Ω describing wind uncertainty in the day-ahead stage is also used to calculate the expected balancing cost of each market design.

6.4.2 Effect of Transmission Allocation Expected Cost

In order to study the effect of the explicit transmission allocation X on the expected system cost, we consider a more penalizing reserve market where OCGT, IGCC and CCGT units provide 50%, 40% and 40% of their capacity for reserve provision at a price equal to 15%, 30% and 30% of their day-ahead offer, respectively. For a constant wind penetration level of 24%, we perform a 'grid-search' on the HVDC tie-line capacity and the parameter X, to obtain the corresponding expected system cost displayed in figure 6.13. The shape of this surface allows to identify three main directions aiming to analyse the effect of these parameters on the overall market efficiency. Note that the dotted line $\mathcal{L}$ represents the locus of the least-cost points for different HVDC capacities. Moving along direction A on the left-hand side of $\mathcal{L}$, the expected cost reduces as the tie-line capacity increases since a larger pool of

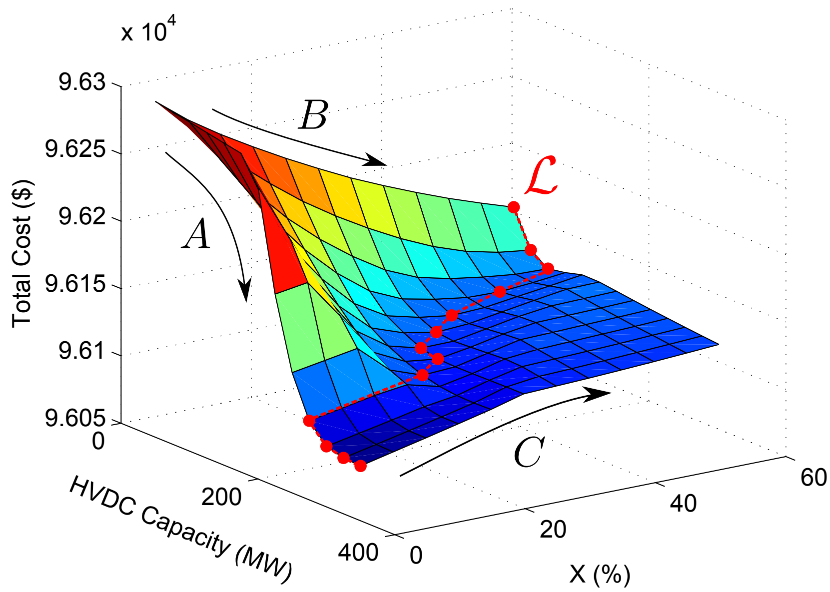

Figure 6.13: Impact of HVDC capacity and transmission allocation X on the expected cost of sequential market-clearing.

common resources is accessible from both areas. A similar trend applies for larger values of X (direction B), where the reserve capacity market does not alter significantly the optimal day-ahead settlement by imposing additional constraints. For example, in a segmented market of reserve resources (low X), expensive units may be assigned to provide downward reserve, enforcing a corresponding lower bound on the energy dispatch, out of the merit order. Large values of X on high HVDC capacity (direction C), allow the reserve market to pick more economical resources based solely on their capacity payment. However, this translates into increased expected balancing cost if mainly excess production situations occur during actual operation, i.e., generators with low marginal (and reserve capacity) cost are willing to buy back their production in lower price.

6.5 Summary of Impacts

The analysis of the available transmission capacity as a function of prevalent meteorological conditions has revealed that a dynamic update of the line rating could lead to a substantial increase in transmission capacity. However, the uncertainty in the weather forecasts are also substantial, especially if the forecast lead times are large, e.g. 24h or more. The methods demonstrated, that the grid utilization as well as the total operational costs can be reduced by using dynamic line ratings. The risk of overloading due to forecast uncertainty is appropriately handled by probabilistic guarantees or corrective control measures that have been procured using robust optimization techniques. Further case studies showed, that it is crucial to increase the forecast accuracy. This accuracy is increased mainly by reducing the forecast lead time, e.g. by running the proposed algorithms close to real-time operation. This would necessitate for the current market schemes to increase the focus on intra-day trading. Future research is needed to investigate different aspects mentioned in [1], however, first conservative implementations could be run readily, given the necessary measurement devices are installed.

The application of the HVDC grid expansion method has shown that there exists a trade-off between a placement for least cost operation and an increase in operational flexibility resulting from the controllability of the power flows on the HVDC lines. In almost all cases of additional HVDC lines installed, the operational costs could be reduced in the study compared to the status quo. The operational flexibility increased in all cases, also the cases where only least-cost operation was the objective. The presented method currently neglects the investment costs as well as limits on the buses that could actually be connected. However, the idea could generally be incorporated in standard expansion planning tools right away or could be used to estimate the flexibility that would be available for different expansion options.

Considering that the operational flexibility of the power system is related both with the technically available flexibility, i.e., the technical limitations of installed generation and transmission assets, but also with the specific decision-making approaches it becomes increasingly important to study their implications on the optimal utilization of the flexible equipment and especially on HVDC interconnections. Our study reveals the improved performance of stochastic market clearing approach, in terms of expected operational cost, for high shares of wind power. Considering different deterministic market designs, we have shown the benefits of co-optimizing reserve capacity and day-markets which also underlines the importance of tighter coordination between different trading floors.

However, if the European market design remains unchanged, i.e., sequential clearing of reserve capacity, day-ahead and balancing markets, system/market operators have to consider the dynamic (explicit) allocation of cross-border transmission capacity between neighbouring systems for the exchange of balancing services in order to improve overall market efficiency by enabling access to larger pool of balancing resources. The optimal allocation to be made is directly related with the specific system properties and further research has to focus on explicit rules that provide the optimal transmission capacity to be released in each market stage.

Chapter 7

Conclusion

This report has focused on the presentation of the applicability of methods developed within the scope of the BPES project aiming to address five main challenges identified based on description of plausible scenarios for the potential future evolutions of the European power systems as outlined in a previous report [2]. The proposed methods aim to contribute towards the following directions, which are considered as important to guarantee the technical and economic efficiency of the European power system in upcoming years:

1. *Spatio-Temporal Coupling of Uncertainties*
2. *New Balancing Mechanisms and New Resources*
3. *Locational Flexibility*
4. *Inter-TSO Coordination*
5. *Increased Transmission Flexibility Needs*

Within the scope of the BPES project and following the above challenges, a number of case studies were carried out in order to assess the impact and the efficiency of the proposed methods and their main findings are summarized here. These case studies are based either on small scale illustrative examples, trying to provide some insights about the main properties of each method, or on larger scale setups in order to appraise the performance of these methods as operational tools to support system/market operator decision-making. The main theoretical properties and the mathematical formulation of the proposed methods are presented in [1].

Regarding the challenge of *Spatio-Temporal Coupling of Uncertainties* arising from the high shares of intermittent energy sources, a stochastic unit commitment method was proposed as an efficient way to integrate complete spatio-temporal information of wind power uncertainty (in form of scenarios) in the decision-making of the system operator. In addition, this methodological approach is able to account for the most important technical constraints, i.e., generation capacity and ramping limits as well as transmission network capacities. Future research in this area may focus on improving the computation time for large scale applications through scenario reduction techniques of decomposition schemes.

Considering the need to revise the existing balancing mechanisms, Chapter 3 presented the application of a methodological framework for the definition and evaluation of new operational strategies for the activation of control reserves. The results of the case study have underlined that the design of future balancing mechanisms should consider the trade-off between various objectives, e.g., operational cost and reserve availability. In addition, the proper definition of the balancing products, e.g., minimum up time of the regulating bids, is a highly important parameter that should be taken into account. Future work on this topic may consider additional technical constraints, i.e., ramping and energy limits and network constraints, as well as the variation of further operational parameters.

The aspect of *Locational Flexibility* is gaining increasing attention as the European power system has to cope with the larger shares of variable renewables. Despite that technical flexibility may be available in the system, in terms of technical capabilities, the proposed method takes a step further in order to quantify the disturbances that the system can contain in every grid location. This information is then integrated in the decision-making of the TSO using a robust optimization approach. The case study presented in this report based on an illustrative small scale system, shows that increased storage capacity and allowed curtailment of renewables are efficient means to reduce the flexibility procurement costs and/or increase the flexibility capabilities of the power system. The method for the illustration of locational flexibility is also applied on larger scale power system, providing an indication for the applicability of this method in an operational framework. The properties of the flexibility procurement methodology can be studied further in order to assess its performance in real-size problems and encounter for potential improvements to reduce its computational burden.

Taking into account the clear trend of European electricity markets to move towards more integrated schemes, the corresponding national/regional TSOs need to develop appropriate coordination schemes in to order to handle effectively the increased cross-border power flows and variable generation patterns of renewables. The case study presented in the first part of Chapter 5 compares the flexibility that can be exchanged between different control areas, characterized by the feasible tie-line flow, and defines the flexibility bounds for two operational approaches (active and passive approach). It is shown that these limits can communicate effectively the necessary information for TSO coordination without revealing potentially confidential data. Future research may focus to multi-area systems and more advanced transmission technologies, such as HVDC, as well as the integration of flexibility in the electricity markets framework by defining appropriate products.

The last part of the report focuses on the challenge regarding the *Increased Transmission Flexibility Needs* of the future European power as identified in scenario report [2]. The first part of this chapter provides the results of a case study on the dynamic line rating (DLR) as a mean to increase transmission capacity under certain ambient conditions. We first analysed the DLR potential in respect to forecast uncertainty deriving the corresponding probability distributions. Having this information as input we examined two specific aspects, i.e., the reduction of total operating cost and the increase in grid utilization. The results of the case study indicate that lower lead-time forecasts and appropriate selection of line ratings may reduce significantly the operational costs. Aiming to assess the risk associated with DLR operation according to a probabilistic method we found that increased risk aversion leads into higher costs.

The second part of Chapter 6, focuses on the grid expansion considering operational flexibility. The expansion planning case study showed that an increased number of HVDC lines decreases operational costs. On the other hand, aiming to increase operational flexibility translates into high costs. This indicates a necessary compromise to be made by the system operator. The last part of this chapter, considers the optimal allocation of HVDC transmission capacity between the different trading floors, i.e., reserve procurement, day-ahead and balancing markets, under three different market setups. Our case study reveals the higher efficiency arising from the tighter temporal coordination of the different market stages, while the stochastic market clearing model attains the highest efficiency. In addition, we show that in case of completely sequential market clearing there is an optimal allocation of the transmission capacity to be made which depends on the specific characteristics of the power system. Future work on this topic will determine explicit rules for the definition of this optimal capacity allocation.

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