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Preprint

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Suggested Citation: Hobbie, Hannes et al. (2021) : Impact of model parametrization and formulation on the explorative power of electricity network congestion management models, ZBW - Leibniz Information Centre for Economics, Kiel, Hamburg

This Version is available at:

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Impact of model parametrization and formulation on the explorative power of electricity network congestion management models

Insights from a grid model comparison experiment

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August 31, 2021

Abstract

Integrating increasing shares of weather-dependent renewable energies into energy systems while maintaining high levels of security of supply constitutes a challenge for network utilities. Obtaining the goal of large shares of renewable-based generation sources on electricity supply requires an effective operation of electricity grids and efficient coordination among grid operators. Therefore, detailed modelling of grid operation has increasingly become important in recent years.

Methods for modelling the operation of (extra) high-voltage grids are undergoing persistent enhancements in academia and energy industries. Existing approaches vary in data granularity and computational methods. Moreover, assumptions on technical details in grid models vary. Differences in input data and modelling methods likely have an impact on simulation results.

This paper aims to identify the most relevant differences present in grid simulation models and methods for studying congestion management in a European context. Differences are studied based on a comparison of grid simulation models from eight German energy modelling institutions. The effects of model parameterization and formulation on congestion management results are further investigated with three different case studies focusing on outage simulation, line-constraint relaxation and the modelling of cross-border measures applying selected grid simulation models.

Results indicate that data parametrization can have large impacts on model results about congestion management volumes and geographic distribution of necessary measures. Model key parameters must be calibrated thoroughly. The findings of this research will assist future

grid modelers and power system planners in efficiently simulating congestion management and increases the validity and explorative power of grid simulation models.

Highlights:

- Various differences in model formulations for grid operation exist in academia
- Soft-constraints are widely used to detect data inconsistencies and infeasibilities
- Simplified outage simulations particularly impact congestion results in meshed grids
- Parametrization of cross-border measures largely affects congestion volumes

Keywords:

Transmission grid; Renewable energies; Sustainable development; Model comparison; Congestion management; Optimal power flow

Word count:

	#words	%
1	702	9
2	1,006	13
3	1,522	20
4	3,701	49
5	651	9
Total	7,582	100

Abbreviations:

AC, alternating current; DC, direct current; DLR, dynamic line rating; FACTS, flexible AC transmission systems; PST, phase-shifting transformers; SCOPF, security-constrained optimal power flow

1 Introduction

Power system models such as market simulations and grid simulations have become standard tools for decision support in energy industries and academia over the past years. Market models are typically used to investigate techno-economic aspects of energy systems to further the understanding of the interactions between innovative technologies and (adaptive) markets. Electricity grid models cover various aspects of the transportation of electricity and are applied to increase the knowledge on the interrelationships between market outcomes and resulting physical electricity transportation requirements.

Latest developments toward a decarbonized electricity supply in the European markets impose structural changes to the operation and management of electricity grids. Traditionally energy flows were directed downstream from centralized conventional large-scale generation stations to end-user applications and congestion management measures were activated by transmission system operators at a large scale. The conversion of the electricity system toward a more distributed structure in conjunction with increasing electrification of decentralized sector-coupling technologies changes traditional practices. New solutions for power supply are not only associated with technical aspects of electricity grids but must also facilitate competitively organized markets to serve grid operators with sufficient means for the management of grid congestions. These developments have also influenced model-based representations of electricity systems. As a result, the topic of modeling and simulating electricity grids has increasingly attracted energy scholars among the different disciplines in recent years to support regulators and policymakers in the design of strategies and development of solutions for an efficient management of future electricity transport.

The structure of electricity grid models differs strongly between modeling institutions depending on the specific institution's background and field of model application. Differences in grid models, for example, comprise the utilized programming language, optimization technique, level of detail of represented power system infrastructure (i.e. voltage levels and grid topology) as well as the applied method for required input data parametrizations. Typically, grid models that are employed at technical institutions feature a greater detail of grid representation (e.g. AC vs. DC approximation) than those used at rather economically aligned departments with a stronger focus on the modeling of market interactions (e.g. perfect competition vs. strategic behavior).

The variety of different grid models existing in academia and industry prompts the question of how model-related simplifications and assumptions on key parameters made impact model results. Model experiments are a valuable method to compare power system models of different kinds to provide insights on the interactions between varying model configurations and model results. While several model experiments with a focus on power market models have been conducted in the past [1], energy science still lacks structured comparisons of grid simulation tools.

Findings in this paper result from the Modex-Net project in which grid simulation models of eight German energy modeling institutions from *TU Dresden (ELMOD)*, *RWTH Aachen University (MarS / ZKNOT)*, *Öko-Institut e.V. (PowerFlex-Grid EU)*, *TU Dortmund University (MILES)*, *Jülich Research Center (Europower)*, *DLR Institute of Networked Energy Systems (eTraGo)*, *Karlsruhe Institute of Technology (PERSEUS)*, and *FfE (ISAaR)* are systematically harmonized and compared based on structured benchmark runs among each other [2, 3]. First insights of the project deal with differences in the modelling of congestion management for European power grids at the different institutions and are focus of this work. Moreover, effects of selected model key parameters and simplifications made in terms of model-based representations of congestion management measures on model results are investigated in

this paper with three different modelling case studies and discussed along learnings from the experiment group.

The remainder of the paper is organized as follows: Chapter 2 highlights existing market-clearing practices in European electricity markets focusing on congestion management and derives implications for the model-based representation of congestion management. Identified differences between the grid simulation models used at the participating institutions in the experiment are discussed at a descriptive level in chapter 3. Impacts of different key parameters and system configurations are explored based on the knowledge derived and insights gained by the different participating modelers and quantified by three selected case studies in chapter 4. Finally, chapter 5 concludes to provide future grid modelers in efficiently simulating electricity grids with increased validity of simulation results and assisting energy policymakers and regulators in the organization and design of future congestion management frameworks.

2 Simulation of grid operation

Legal background, market-clearing practices, and modeling implications

Electricity grid operators are usually tasked to efficiently manage grid infrastructure reinforcements and reliably operate electricity grids. The management and operation of electricity grids is strongly influenced by the existing regulatory framework and present electricity pricing mechanism in the specific market impacting the structure and formulation of congestion management models. Market coordination between electricity suppliers and demanders based on nodal pricing, as practiced for example in Pennsylvania, New Jersey, and Maryland (PJM), considers all transmission limitations already during the settlement of market-clearing prices at the corresponding electricity grid nodes resulting in an integrated market model formulation considering limitations on power line flows.

In Europe, only cross-zonal interconnector capacities are considered during market clearing and resulting market prices account for the entire market zone (typically a country). Electricity grids within a market zone are assumed to have unlimited capacity.¹ Transmission system operators resolve then grid congestions that would arise during the realization of the market result in a second step with the means provided by the regulatory framework. This typically yields in a two-stage formulation of congestion management in which first the market is optimized, followed by an optimizing grid simulation with adjustments of the market clearing dispatch of power plants.

Figure 1 exemplarily illustrates the sequence and interplay of (wholesale) electricity markets and the management of grid congestions in European power markets.²

¹ Latest adjustments in market organisation in Europe comprise the introduction of flow based market coupling in which most critical network lines are considered during market clearing.

² In Germany, the so-called Energiewirtschaftsgesetz [§13 EnWG] constitutes the underlying legal basis for all congestion management measures that grid operators can utilize.

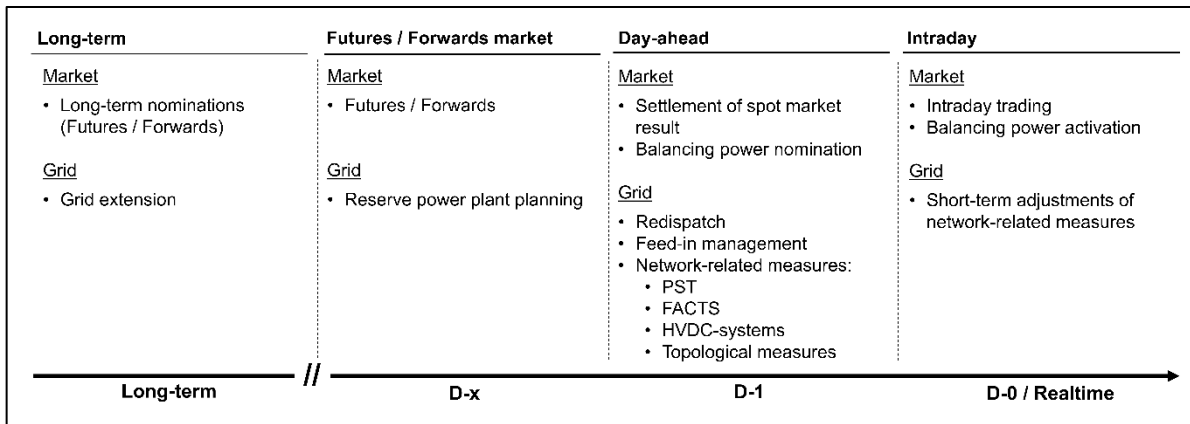


Figure 1: Grid management and market clearing processes

Wholesale electricity markets are typically divided into futures and spot markets according to the lead-time until delivery of contracted power products. Similarly, different congestion management measures are available to transmission system operators depending on the time of market intervention. Long-term measures comprise grid extension planning and reserve power plant nominations, short-term measures relate to all interventions after clearing wholesale markets. These are redispatch of (conventional) generation plants, feed-in management (of renewables) and network-related measures. This paper centers on grid simulation models that resolve grid bottlenecks after clearing wholesale markets.

Congestion management procedure and classification of relevant post-market measures

Modeling congestion management can be done in vastly different ways and involves several steps. According to existing practices in European markets a wholesale market clearing must be simulated based on a zonal market configuration with relaxed intra-zonal grid constraints at first. Typically, power market models do not distinguish between futures and spot markets. All wholesale markets are cleared at once assuming arbitrage-free markets.

The modeled market equilibrium is then fixed and the grid model run initiated with the market equilibrium utilized as a starting solution for the grid simulation. The grid simulation includes in addition to all power balances and generation constraints that are part of the market optimization intra-zonal grid constraints, imposing limitations on the resulting power flows. The simulation of the transmission grid model resolves (all) congestions by interventions into the market clearing result ensuring that electricity demands are satisfied at all corresponding electricity grid nodes considering transmission constraints.

European transmission system operators are provided with several different options to resolve grid bottlenecks according to the specific national electricity transmission regulation. Outweighing economic and environmental aspects of energy supply, regulatory frameworks typically prioritize network-related congestion management measures over cost-intensive market-related measures. Figure 2 summarizes different congestion management measures and their compulsory merit-order that are commonly included in grid simulation tools.

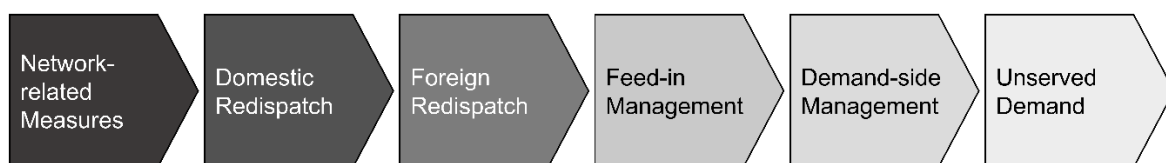


Figure 2: Merit order of congestion management measures

Network-related measures include all assets owned by the TSO that can be used to minimize congestions through redistribution of power flows. Domestic redispatch refers to the simultaneous increase and decrease of conventional power generation at two different locations to resolve grid congestions. Transmission system operators are considered regulated entities. The regulatory framework obliges them to pursue redispatch in a cost-minimizing manner based on the specific plant's marginal cost subjecting grid operators to (competitive) market conditions. Foreign redispatch includes power generation units in neighboring market zones as redispatch options based on international agreements. Feed-in management involves the curtailment of generation from renewable-based generation units. And demand-side management summarizes all measures relating to the increase, decrease, and intertemporal shift of flexible demands. If all those measures are insufficient to resolve a grid congestion conventional electricity generation in conjunction with inflexible demands can be shortened as a last (no-regret) option. The order of mentioned congestion management measures is typically specified in the market regulatory framework. Modelers are challenged to ensure that grid simulations reflect this order to be able to capture the interactions that exist in real-world congestion management tasks.

Optimization problem of congestion management

Market dynamics that determine equilibria and outcomes for resulting electricity transmission requirements are complex and lend themselves to analysis through the deployment of optimization models. The simulation of congestion management typically yields in an optimization problem in the form of the so-called security-constrained optimal power flow (SCOPF). Modelers use SCOPFs to simulate congestion management either for operational planning tasks or investigating future market projections during long-term planning studies assuming a steady state. For operational planning, the steady-state refers to a day-ahead forecast or a selected scenario for long-term projections. [4–7]

The general mathematical form of the SCOPF is then written as: [4–7]

$$\begin{aligned}
 & \text{Min } f(x_0) \\
 & \text{s. t. } g(x_0) = 0 \\
 & \quad h_0(x_0) \leq 0 \\
 & \quad h_k(x_0) \leq 0
 \end{aligned}$$

The vector x_0 describes the fault-free system state including all adjustable remedial actions. The minimizing target function $f(x_0)$ includes all costs related to the utilization of remedial actions that can feature linear, quadratic, or nonlinear components depending on the granularity of model details. Quadratic equations for example account for the representation of losses from physical power flows. The target function is constrained with power flow equations g in every optimized system state x_0 and constraints $h_0(x_0)$ describing the fault-free system state. To prevent congestions in every faulty system state x_k relevant for (n-1)-security, safety margins are included in the constraints $h_k(x_0)$ and guaranteed by adjusting the fault-free system state x_0 accordingly. [4–7]

3 Model-based representations of congestion management

The model comparison experiment revealed multiple differences in the model-based representation of congestion management measures and model formulations. The following summarizes differences present in the models of the participating institutions and highlights advantages and disadvantages in their context of application (cf. Chapter 4).

Power flow calculation

Power flow calculations evaluate system states before, during, and after optimizing the SCOPF for a given set of operational points. Formulating power flow equations typically involve the modelling of nonlinear equation systems. The Newton-Raphson method is a very common approach for solving such systems. [8]

Faster but less accurate solving of active power flow equations can be achieved through the utilization of linearized representations of existing nonlinearities in power flow equations. So-called DC power flow equations neglect reactive power flows, use small-angle approximations and assume constant voltage magnitudes. [8]

Half of the institutions participating in the Modex-Net project uses a DC power flow calculation and the other half an AC power flow calculation, as shown in Figure 3. One reason for this may be the technical or economic orientation of the institution. The slightly higher share of institutions using an AC load flow calculation compared to institutions using a SCOPF based on an AC formulation results from the fact that some institutions additionally perform an AC load flow calculation after solving a SCOPF with DC formulation based on the obtained operating point, for example, to be able to determine power flow losses.

Congestions on cross-border lines

Congestions on cross-border lines can have a significant impact on national congestion volumes reproduced by grid simulation models, if not addressed correctly. In reality, TSOs carry out national congestion management without considering congestions on cross-border lines. After all national congestions are resolved, congestions on cross-border lines are treated through bilateral agreements between the TSOs at both side of the interconnector. Modelling cross-border measures can be done in several ways.

A simple but yet useful approach is to neglect restrictions for maximal allowed power flows on cross border lines. Other methods comprise reducing the number of power plants in neighboring market zones that can contribute to cross-border redispatch and additionally assuming high prices for their use. Both ways can have undesired impacts on model results, e.g. total redispatch volumes. [10]

As Figure 3 depicts, the majority of institutions (88 %) explicitly consider cross-border redispatch. This type of modeling is also in line with latest efforts of European regulators to enable increased coordination for cross border measures. [10]

Time-coupling

Modelling energy storages and operational restrictions of large scale power stations (e.g. minimum runtimes, standstill times and power gradients) comprise the utilization of time-coupling constraints. Many grid simulations avoid the modelling of time-coupling constraints for reasons of improved solve time. [9]

Figure 3 indicates that a majority (88 %) of the institutions participating in the Modex-Net project are able to include time-coupling constraints into the grid simulation, but their use depends strongly on the application case and research framework. Market projections characterized with low penetration levels of electrical storages and larger amounts of flexible generation units may allow to neglect time-coupling constraints.

Dynamic line rating

Line loading margins increase during times of cooling weather conditions. Since current limits reported in line characteristics sheets are calculated assuming worst-case weather scenarios, actual line capacities are larger during most days of the year than those reported. [10, 11]

This additional current carrying capability of overhead lines is exploited increasingly in the operation of transmission grids. So-called dynamic line rating monitors weather conditions along critical lines in the transmission grid and adjusts limits in real-time. [10, 11]

Dynamic line rating can only be modeled by 25 % of the participating institutions Figure 3 summarizes. Discussions among the experiment participants showed that dynamic line rating experiences increasing importance in grid simulation models.

Feasibility feature

Optimizing network simulations are complex programs in terms of model size (number of equations and variables) and structure of optimization problem (linking variables and equations). Even when being formulated as a linear program modelers face challenges regarding problem solving. Moreover, assumptions on input data for future system projections (generation and grid infrastructure) are subject to uncertainty and automated data parametrizations can yield in inconsistencies resulting in model infeasibilities. [12]

Ways for handling model infeasibilities are incremental adjustments of input data or introducing so-called soft constraints. Soft-constraints impute slack variables to (critical) constraints ensuring solvability. Unrealistically intensive uses of slack variables can be controlled by high penalty costs associated with them. [13]

As Figure 3 illustrates, the majority of institutions (75 %) uses soft constraints in their network models. It should be noted that soft constraints mainly serve to simplify tasks related to model parameterizations since such tasks demand great efforts by researchers, in particular for the parametrization of long-term projections. Solutions of models with soft-constraints do not necessarily equal model solutions achieved without such constraints. Moreover, the parametrization of soft-constraints itself can have large impacts on results, as chapter 4 showcases.

Remedial actions

Congestion management measures such as redispatch and changes in operating points of high voltage direct current converters can be approximated with power injections in grid simulation models. The operation of phase-shifting transformers (PST) or flexible AC transmission systems (FACTS) in real-world systems influence power flows and, however, cannot be represented through power injections. Modeling such congestion management measures increases thus the complexity of network simulations.

As Figure 3 shows, only a few participating institutions (25 %) include these devices in their grid modelling. Similar to dynamic line rating, modelling PSTs and FACTS faces a growing interest among power system modelers though a limited penetration of those technologies in the European transmission grid system can be currently recognized.

Merit order of technologies

European transmission system operators have various measures at their disposal to prevent overloads in the transmission grid (see Figure 2). Regulatory-related prioritization of congestion management measures can be represented by sequential solving of separate optimization problems or prioritizing individual measures through penalty costs resulting in a merit-order of congestion management measures. [14]

As Figure 3 depicts, 75 % of the institutions prefer a merit-order based approach utilizing penalty costs. This may be due to additional computational efforts involved with sequential solving of optimization problems for different measures.

Optimization method

Power flow equations typically feature quadratic and trigonometric components resulting in nonlinear optimization problems with a nonconvex solution space. A variety of different approaches exist to solve such problems. These methods can be divided into analytical and heuristic approaches. [15–17]

Heuristic algorithms search the solution space repetitively to find a solution of the SCOPF. Most heuristics learn from feedbacks of last feasible solutions found during prior iteration steps. Usually, these heuristics include a component of randomness mimicking genetics (evolutionary algorithms), intelligent behaviors of animals (swarm optimization), or physical phenomena (optimization based on physics). Their performance highly depends on the non-trivial parametrization. [15–17]

Analytical approaches exploit the mathematical structure of the equation system. Since the SCOPF is nonlinear and nonconvex, they typically relax some of the constraints of the original problem. Most common relaxations make use of linearization techniques in which reactive power is neglected (DC power flow equations), all power flow equations are linearized, or AC power flow equations are quadratically approximated. The linearization of power flow equations depends on the operation point in contrast to DC power flow equations. Linearization errors can be reduced through iterative procedures, in which the optimization of the relaxed linearized problem with updates of the linearization in the prior optimized new operation point are repeatedly performed. [15–17]

The participating institutions in the MODEX-Net project clearly prefer optimization-based methods over heuristics as Figure 3 shows. Among optimization-based methods, DC formulations of the SCOPF with 63 % are more common than AC formulations (37 %). Again this might be due to the institutional backgrounds.

Outage representation

The constraints of the SCOPF need to be secured during fault-free and every relevant outage situation. Therefore, analytical optimization methods use safety margins on line constraints to prevent constraint violation in all relevant outage situations. Dimensioning such safety margins involves the estimation of impacts of each outage on the system state. [18]

The most detailed way for simulating outages is the calculation of power flow equations for every relevant outage situation. This approach reproduces system states and safety margins exactly. On the contrary, it involves high calculation efforts since power flow equations must be solved for every relevant outage situation. [8]

Linearized predictions constitute a faster way for outage simulation through approximation. Also outage approximations consider line-specific impacts of individual outages for dimensioning safety margins.

Flat-rate safety margins, in contrast, consider constant averages for the impact of all relevant outage situations simplifying line-specific impacts. This is less exact compared to the above methods, but has generally positive effects on model solve time.

As Figure 3 illustrates the majority (75 %) of institutions participating in the Modex-Net project uses flat-rate safety margins. A quarter can additionally depict outages based on approximations. The participants do not use detailed outage simulations as this has large computational requirements. Effects of outage modelling on grid simulation results are quantified during the case study in chapter 4.

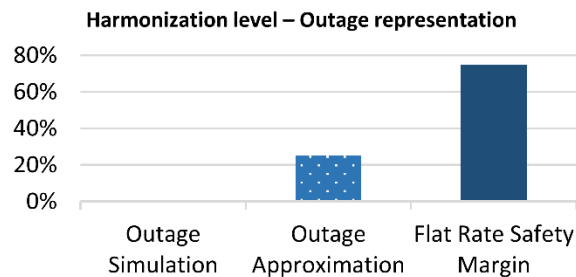
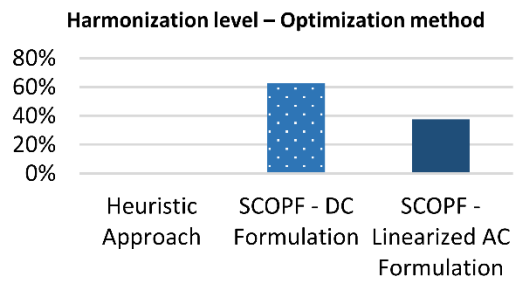
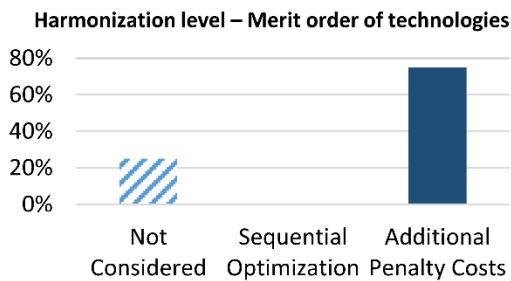
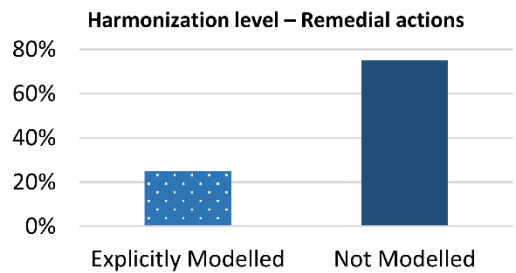
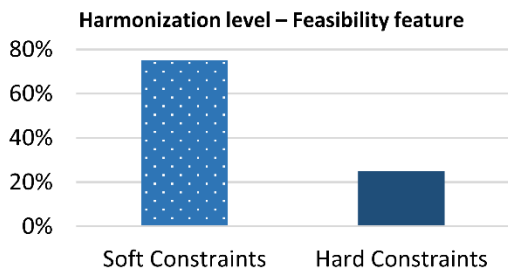
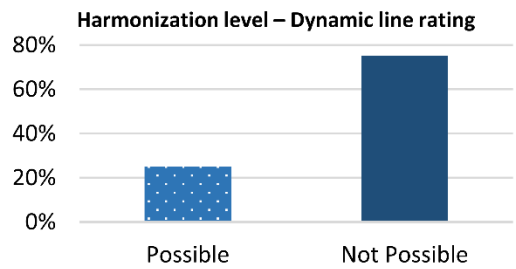
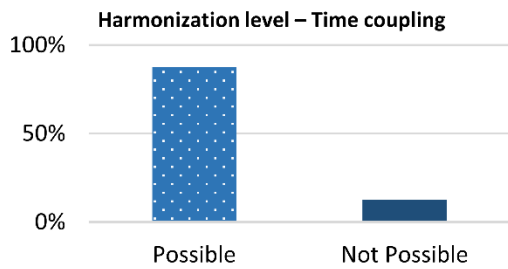
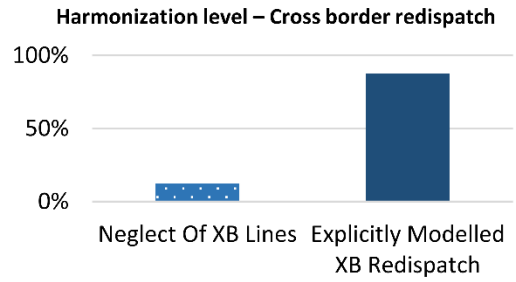
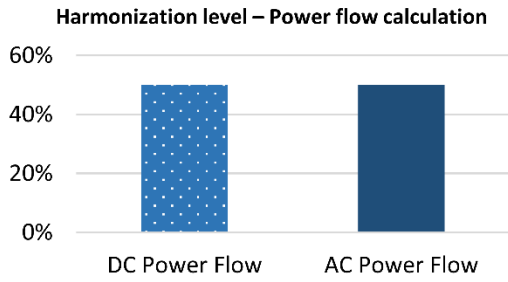


Figure 3: Harmonization level of congestion management's modeling aspects

4 Comparison of model results

4.1 Model extensions and improvements

The following chapter summarizes experiences and learnings gained during the development of grid simulation models by the participants of the model comparison. They were discussed by the participants, and during the runtime of the project, some modelers could also improve their results due to the recommendations and experience shared by the others. Experiences and findings can provide valuable impulses for model improvements to other modelers.

Grid topology

The grid topology between the models used was different in this model experiment. Some models included about 600 high voltage power lines while others optimize the power flow at about 20,000 high voltage power lines (including 110 kV).

Errors in grid topology can occur by connecting the wrong power lines, missing connections, or the presence of stub lines, but also by using the wrong parametrization of power lines. They might be identified when checking the first congestion management results: If there are power lines with recurring extraordinary congestions that cannot be reduced with the given options of remedial actions, their technical parametrization may be adjusted.

Unexpected high rates of remaining overloads can also occur in models which do not take into consideration connections to the neighboring countries. Likewise, interconnections should be added. In border regions and metropolitan areas, 110 kV power lines contribute to the transmission task of the power grid. If they are neglected in the model, unexpectedly higher amounts of redispatch volumes can occur. It might be helpful to add them to the grid topology.

Model formulation: soft / hard constraints

As described above, there are two methods to determine requirements for remedial actions on power lines: Either line congestions are allowed but penalized with high costs, or it is prohibited by capping the line occupancy variable. In the latter case, the resulting power plant dispatch must be compared to that without binding grid restrictions.

There are advantages and disadvantages to both approaches. The approach with soft restrictions has the advantage that two-stage calculations can be performed, which reduces complexity. In the first step, the market result is calculated, which is then used in the second step for the network simulation and the grid optimization. The quantification of the penalty term for line congestion, on the other hand, influences the results and is not free of arbitrariness.

The hard constraints approach ensures optimal deployment of the redispatch power plants, does not need to set a penalty term, and takes into account all the technical constraints of the market model. However, it does not allow to overlook insignificant remaining line congestions. As a result, it has the effect of overestimating the identified need for remedial actions. If problems occur in the network topology as described above, the optimization problem becomes unsolvable.

As a learning, the use of soft constraints at first may provide a valuable method to identify non-resolvable grid congestions indicating errors in line parametrizations or in the network topology. Most of the modelers decided to use soft constraints to determine the need for remedial actions.

Interrelationships between costs of line overloads and parametrization of remedial actions

The change in the amount of remedial actions is not linearly related to that of a line congestion: if a power plant reduces its feed-in, this can reduce congestion on several successive lines. The avoided costs of line congestion add up. On the other hand, if almost all congestions have already been resolved, there may be a case where the reduction in feed-in only causes a marginal reduction in line congestion on one line that is proportionally affected by the feed-in. This illustrates the challenge in "correctly" parameterizing the costs when using soft constraints. One approach to addressing the problem is to vary the penalty costs of line congestion: the optimal value for the penalty costs can be determined at the point where the lines with occurring overloads remain constant and cannot be dissolved.

Redispatch costs for individual power plants should be thoroughly calculated considering the interactions that exist between national and cross-border congestion management. In some models, a large proportion of the redispatch volume occurring was at nodes with individual large power plants. By increasing their redispatch costs gradually an increase in redispatch volumes at other nodes was expected. Nevertheless, especially in border regions, the price increase may exceed a critical value that leads to a ramp-up of foreign power plants. Therefore, the interaction of grid constraints and power plant prices should be considered in model adjustments of this kind.

Congestions on cross-border lines

If the solution space of the optimization of the power flow is reduced to a single-country optimization forcing that each country itself ensures a net balancing, the identified domestic redispatch volumes rise notably if congestions on cross-border lines are cured using only nationally available remedial actions. When the cross-border lines were not blacklisted or cured through simplified available cross-border redispatch options, some project partners found congestions that could not be addressed by domestic redispatch - or where redispatch volumes (and costs) increased disproportionately compared to congestion impacts. One project partner for instance identified a quadruplication of the overall redispatch volume. To clean the model results from this error, the neighboring countries should be included at least as a single node in the observation horizon of the model, or the cross-border lines mostly affected by congestions should be blacklisted.

Most of the modeling partners provide a penalty margin for the use of cross-border redispatch so that this option is placed at the end of the merit order. One partner conducted a sensitivity analysis on the base value of redispatch costs to identify its impact on the modeling results. The results of the analysis which are treated in section 4.2 show a strong influence on the results.

In this context, it is worth mentioning that it makes a difference whether the neighboring countries are modeled as one node with one aggregated power plant at the highest cost or whether the chosen resolution is less aggregated. In some models compared in this project, each country provides power plants of different technologies to participate in redispatch. This higher resolution results in an increase in cross-border redispatch quantities.

In addition to the cost of cross-border redispatch power plants, interconnector capacity plays a significant role in determining the extent of cross-border redispatch. To determine the impact on the results, the dimensioning of the NTCs can be varied.

(n-1)-criterion / safety margin

To make the results comparable, the modeling partners agreed to use a harmonized modeling of outage situations by using the model of a flat rate safety margin approach to

prevent constraint violations in relevant outage situations: the line capacities of each power line are reduced by a constant percentage. Some project partners varied the safety margin to observe its effect on the results. Obviously, the need for redispatch decreases with the assumed safety margin. By lowering the safety margin from 0.3 to 0.25, a decrease in the redispatch volume of 13 % could be observed. In chapter 4, the effects of different representations of outages on the results of grid simulations which are examined by one modeling partner are described.

Dynamic line rating (DLR) and phase-shifting transformers (PST)

Typical grid-related measures reducing congestions are dynamic line rating (DLR) (see chapter 3) and the utilization of phase-shifting transformers (PST). DLR responds to outside temperatures to adjust a line capacity in real-time and PSTs relieve a congestion on a single line by inducing a corresponding load on adjacent power lines (vice versa). Both measures seem to have extremely positive effects on required redispatch amounts. Since most models cannot explicitly model DLR or PST, the model experiment group agreed to exclude DLR or PSTs in the harmonized model versions. One partner reported a strong influence of these technologies on congestion management results that he experienced during the investigation of a future grid projection. These calculations were carried out beyond the harmonized scenarios.

In his calculations, PSTs were added to the network topology according to the confirmed network development plan in Germany. Projections on renewable energies based on the historic distribution of the generation fleet. Under these assumptions, redispatch quantities could be strongly reduced.

Implementing DLR may have an even stronger decreasing effect on congestion management volumes. Contrary to PSTs, DLR affects not only specific points in the power grid, but can be exploited more widely in the grid. Depending on the deployment rate, reductions of remedial actions may exceed those achieved with PSTs. Another partner reported that he allowed in his model DLR extensively for a future grid projection in a test-run. His model results showed huge reductions in congestion management volumes, though the assumed deployment rate was rather high.

4.2 Discussion of selected ‘Case Studies’

The following illustrates how model key parameters and different ways of outage simulation impact congestion management results. In total, three different case studies are performed with a focus on outage simulation, line-constraint relaxation and the modelling of cross-border congestion management.

Impact of formulation of outage simulation

Motivation

Actual network operation is subject to specific security requirements. A common rule applied to ensure a reliable electricity supply is the so-called n-1 criterion. The power grid must always be able to cope with a failure of one relevant line element or another grid component at any time without causing widespread supply outages. All remaining lines must not be overloaded during such an event. Grid simulation models must reflect this requirement though different modeling approaches for outage simulation exist.

Case study description

This case study comprises four simulations with different flat-rate line constraints to investigate the model behavior in outage situations with different parameter variations. Flat-rate margins are applied and line capacities incrementally varied between 65 % and 80 % of the maximum line currents in 5 % steps. Results are then compared against a model run with detailed n-1 outage approximation and a line capacity of 100 %.

Selected case study results

Figure 4 shows the annually cumulated congestion work per line before congestion management for all congested lines. The congestion work describes all work above the line limits. Results indicate that the distribution of congested lines throughout the year differs between the cases of flat-rate line constraints and detailed outage approximation. Whereas main congestions in the center and northwest of Germany occur during both modelling approaches, slight differences in terms of congestion work can be seen in the north, east and west of Germany. In particular, regions allocated in the west of Germany experience grid congestions during the runs with flat-rate margins that are not reproduced by the run with detailed outage approximation.

Comparing the four sensitivities with flat-rate line constraints among themselves, results show that with a decreasing assumed maximum line capacity congestion work increases. The regional distribution, however, remains nearly unchanged. Moreover, single lines with low congestion work do not show any remaining congestion work with a less tight flat-rate line constraints. At the same time, lines with a high levels of congestion work, particularly in the northwest and center of Germany, maintain high congestion works. It can be assumed that those lines strongly influence the magnitude of volumes for remedial actions and geographic distribution to resolve grid bottlenecks.

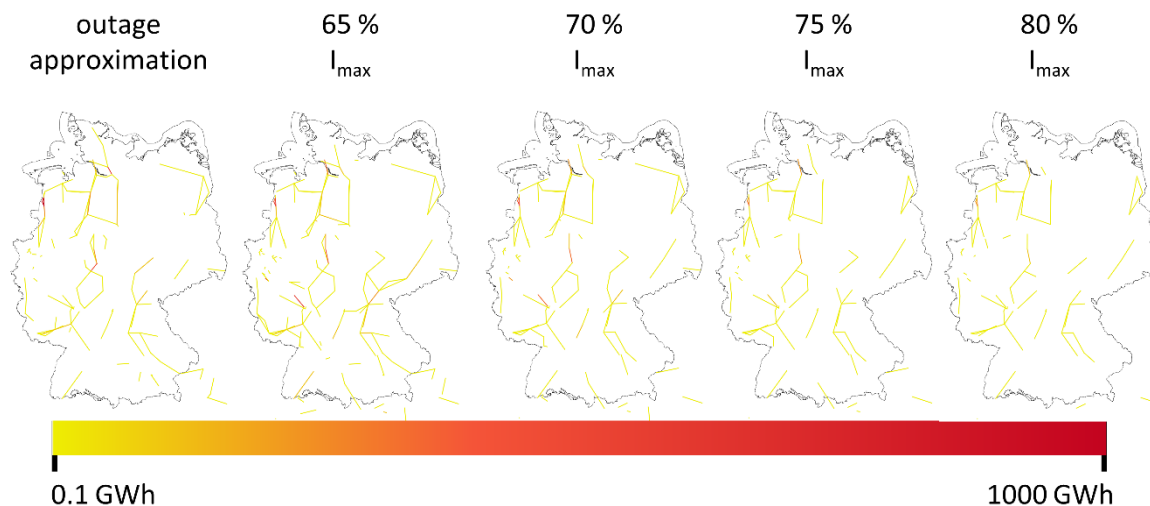


Figure 4: Outage sensitivity - Annually cumulated congestion work per line before congestion management

Figure 5 depicts the annual cumulated volumes of remedial actions per model run. The regional distribution of grid congestions differs between the simulations with a detailed outage approximation and the simulations with flat-rate line constraints, which also affects the regional distribution of remedial actions. The outage approximation yields high levels of negative redispatch in the north of Germany. In contrast, the simulation runs with flat-rate margins result in higher volumes of negative redispatch in the west. Differences in local congestions between both approaches translate into a geographic shift of remedial actions. However, large amounts of grid congestions in the center and northwest of Germany in all model runs require a north-to-south shift of generation from conventional power stations still.

Comparing the four flat-rate line simulations, results show that though the total volumes of remedial actions decrease with a reduction of the security margin in the line constraints, the regional distribution remains unchanged.

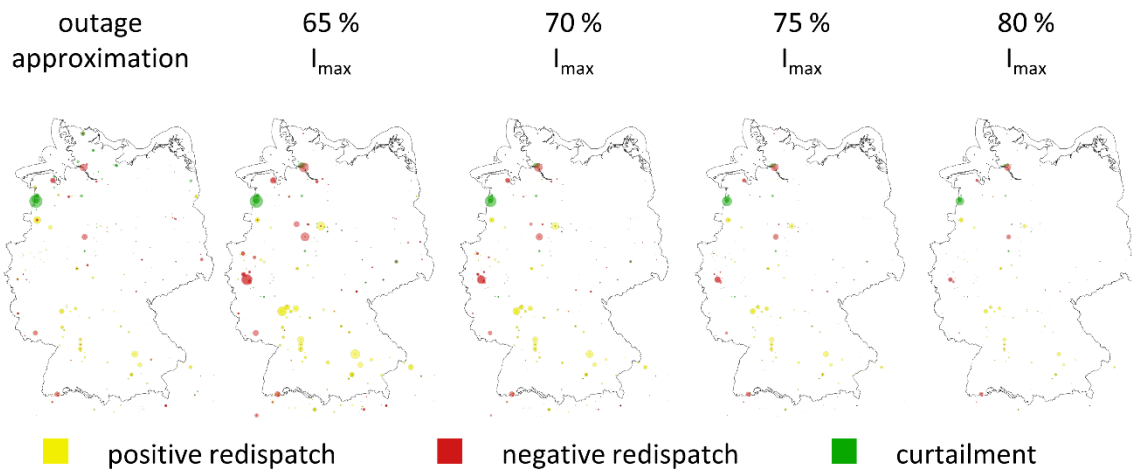


Figure 5: Outage sensitivity - Annually cumulated remedial actions per node

The impact of the geographic distribution of grid congestions on the distribution of remedial actions is also expressed in the annual sum of remedial actions, as Figure 6 depicts. Similar to the results depicted in Figure 5, the overall annual volume of remedial actions decreases with a reduction of the margin in the flat-rate line constraints. Only the run that features a flat-rate line constraint with 70 % capacity of the maximum line currents results in similar amounts compared to the simulation results with outage approximation.

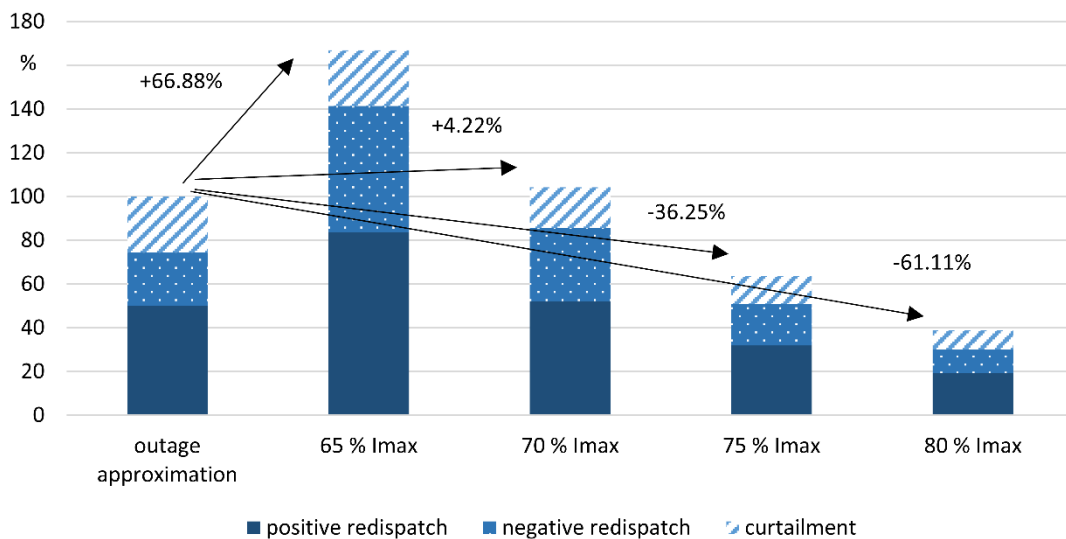


Figure 6: Outage sensitivity - Annual sum of remedial actions

As Figure 7 indicates, despite the close values of total annual volumes for remedial actions, the distribution of redispatch and feed-in management differs. Detailed modelling of outages based on outage approximation leads to a higher percentages of required curtailment quantities compared to the runs with flat-rate line constraints with high security margins (65 %, 70%). Decreasing this security leads to lower congestion management volumes. Nonetheless, all model runs with flat-rate line constraints exhibit a certain value of required

curtailment amounts. Though the relative share of curtailment on the total volume of remedial actions increases in each run.

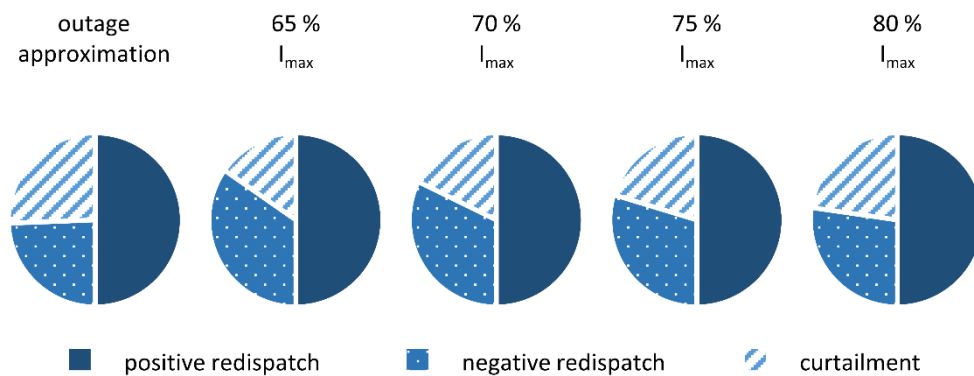


Figure 7: Outage sensitivity – Distribution of annual sum of remedial actions

Summarizing, this case study shows that flat-rate margins can be calibrated to similar total volumes of remedial actions compared to a formulation with a detailed outage approximation. Simplifications involved with flat-rate margins, however, affect the geographic distribution of remedial actions. In particular, regions with highly meshed electricity grids (see West-Germany in Figure 5) experience much lower levels of congestion management amounts required to resolve grid bottlenecks due to better compensating capabilities of meshed grids. Flat-rate line constraints only partly reproduce this stress leveraging effect and yield higher congestion amounts.

Relaxation of line constraints

Motivation

The modelling of grid operation involves several different steps relating to programming but also data compiling. Depending on the specific quality of data sources, several assumptions must be made. Moreover, high amounts of input data sometimes require automated data processing procedures. In consequence, model parametrizations potentially feature data inconsistencies resulting in infeasible power flow equations. A common approach to handle such infeasibilities are so-called soft-constraints on line flow equations. Soft-constraints introduce slack-variables on line limits, that are penalized with high cost parameters ensuring feasible line-flows in every situation. Moreover soft-constraints can be used to identify model inconsistencies.

Case study description

This case study comprises four sensitivity runs on penalty cost variations to investigate benefits and drawbacks of soft line constraints. A benchmark scenario is created in which a congested coupling line between the two stations “Grafenrheinfeld” and “Berggrheinfeld” cannot be resolved in a model formulation based on hard constraints. Such model flaws can easily be a result of slightly over-dimensioned generation capacities from automated capacity regionalization procedures at the end of a stub line. Without using soft constraints the grid simulation model solution might not converge to optimal values or solve only with infeasibilities. In this case study outage simulation is based on flat-rate margins with reduced line capacities (70 % of the maximum line currents). The parametrization of penalty cost for slack variables distinguishes values of 6, 60, 600, and 6,000 times the cost of one equivalent unit of feed-in change of conventional power plants between the different calculated model runs. Since slack-costs apply every time to resolve a limitation on one single line and

remedial actions may affect multiple lines, slack-costs and costs for remedial actions cannot directly be compared.

Selected case study results

Figure 8 summarizes the node-specific annual cumulated volumes of remedial actions. The geographical distribution of remedial actions remains almost unchanged throughout all simulation runs since observed congestions are not affected by the parametrization of slack variables. But, the variation of slack costs impacts model results on congestion management volumes in the different regions (e.g. North-Rhine Westphalia).

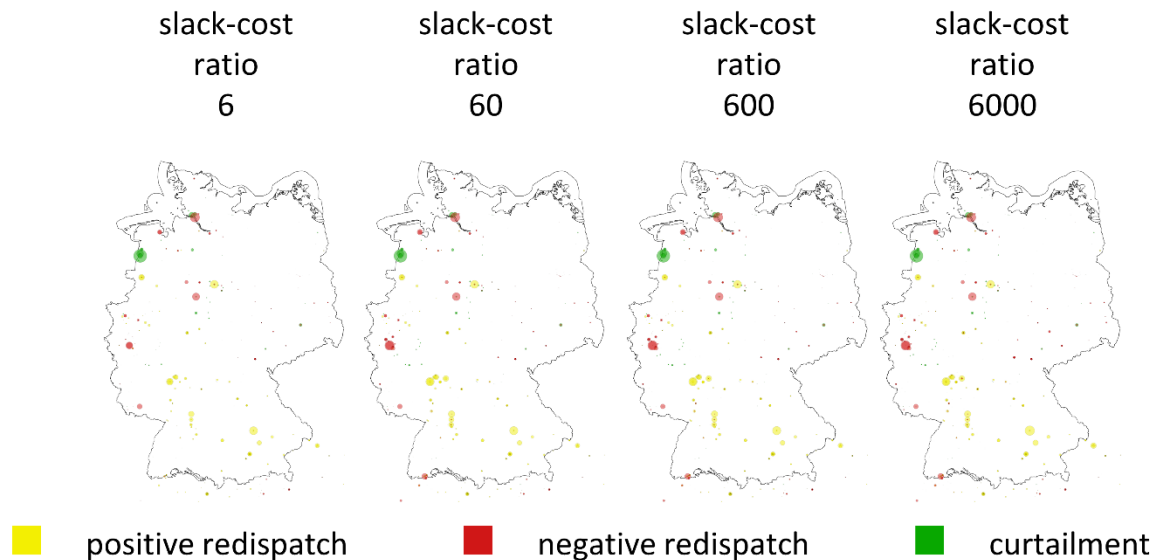


Figure 8: Slack cost sensitivity - Annual cumulated remedial actions per node

The annual cumulated remaining congestion work per line after congestion management is plotted in Figure 9. The model run with an assumed ratio for slack-costs with a level of 6 cannot resolve all grid congestions. Single lines throughout Germany remain congested even though, in theory, these congestions could be resolved as simulations with higher slack-costs indicate. The total remaining congestion work accumulates over all lines to 298.45 GWh.

All congestions can be cleared during the simulations with ratios of slack-costs of 60 and above except the created congestion for demonstration purposes (red circle). Increased slack-cost ratios lower the congestion work on this demonstrating congested line only slightly.

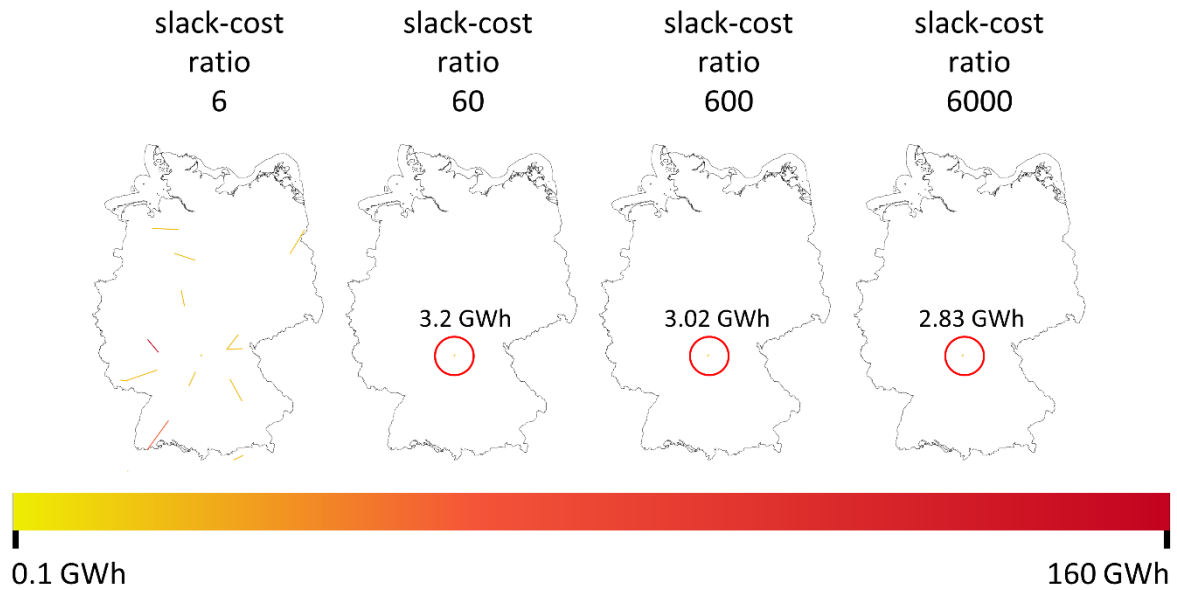


Figure 9: Slack cost sensitivity - Annually cumulated congestion work per line after congestion management

Changes in congestion work of all remaining congested lines in the different simulations with slack-cost ratios of 60 and higher are only low. Changes in annual volumes of remedial actions are significantly higher as Figure 10 shows. The simulation run with a slack-cost ratio of 6,000 results in significant increases of congestion works. The model largely utilizes remedial actions to resolve the bottleneck, but individual actions have only a little effect translating in very high system costs. In this example, the solution of an equivalent model with hard constraints would converge to a similar solution as long it finds a feasible solution.

Figure 10 also highlights undesired effects of too low parametrization values. In the run with very low slack-costs congestions largely remain, yielding in total annual volumes of remedial actions that are significantly lower than actual necessary volumes. Differences in the results of the model runs with ratios between 60 to 600 are rather low. This emphasizes the fact that a wide range of slack-cost parametrization values are acceptable.

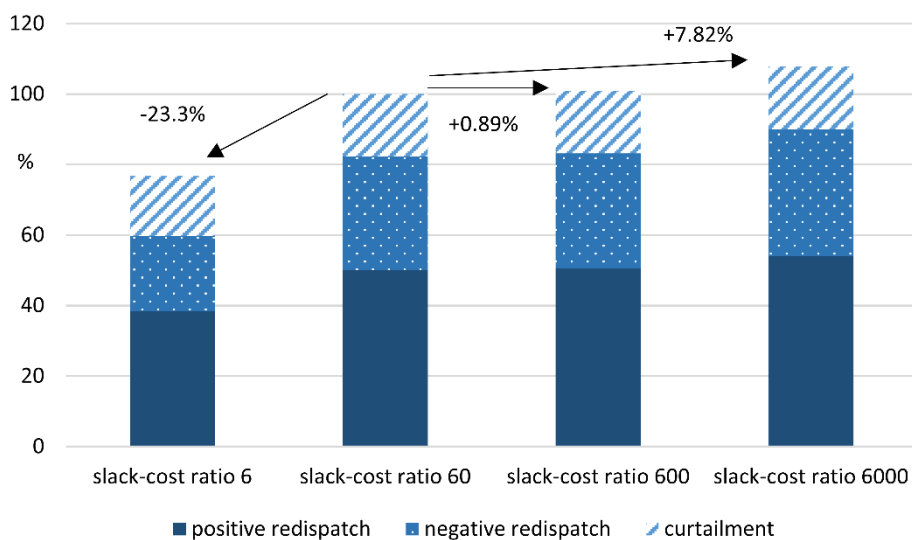


Figure 10: Slack cost sensitivity - Annual sum of remedial actions

Results of this case study highlight that benefits of soft constraints highly depend on the parametrization of the slack-costs. Whereas too low values lead to too low total annual volumes of remedial actions, too high parametrizations overestimate congestion management volumes due to the large utilization of inefficient remedial actions. In addition, very high slack-costs may have undesired effects in terms of solver performance associated with scaling properties of the model. A too low parametrization of slack-costs, however, can reproduce a significantly congested system state even after the optimization. Summarizing, soft-constraints provide a valuable means to detect model inconsistencies, but must be calibrated thoroughly.

Foreign country base value sensitization

Motivation

In practice, the management of grid congestions is carried out in various ways involving multiple different actors and energy stakeholders. Grid operators typically utilize not only measures provided by national power plant operators or flexibility sources from domestic demand-side applications. Also, power utilities in the neighboring countries may be called to contribute to resolving national grid congestions and congestions on interconnecting power lines. The model-based representation of this so-called cross-border congestion management, and in particular cross-border redispatch, may have an impact on model results.

The modeling of cross-border redispatch differs among the grid simulation models participating in this model experiment. The regulatory framework in Germany stipulates a specific order of the existing measures with which grid operators resolve congestions due to interfering energy system development targets. The following illustrates grid simulation results from a selected model which uses a methodology that builds upon penalty costs to create a merit order of different national and foreign country congestion management options. Modeling of congestion management purely based on the marginal cost of a particular measure would deviate from this order.

Case study description

Four different model runs are performed in total with varying structures of penalty costs for congestion management. We call the penalty cost-terms base values since the model adds them to the marginal cost of a particular congestion management measure. The base case assumes penalty costs of 5,000 EUR/MWh that are added to the redispatch cost based on fuel and all other variable cost expenses. The model penalizes redispatch from national generation units with 100 EUR/MWh in addition to the marginal generation cost. All other congestion management measures, i.e. feed-in management, demand-side management, and demand cut-off, are penalized with higher penalty costs of increasing magnitude compared to cross-border redispatch, resulting in the merit order illustrated in Figure 2 since the grid simulation model applies a (total) cost-minimizing target function. The comparison runs assume a base value for cross-border redispatch in the range between 150 – 110 EUR/MWh. All other base values are held constant. The electricity grid in Germany is modeled in great detail. Neighboring market zones are modeled as aggregated nodes. Interconnector lines are represented, however, in a detailed fashion with their existing physical characteristics, to maintain restrictions in the electricity transmission at the border area.

Selected case study results

Model results show that the assumed base values for cross-border redispatch impact both national congestion management amounts and the geographic distribution of utilized

measures. Figure 11 displays selected results of the four model runs on the magnitude and geographic distribution of congestion management measures among the German grid nodes included in the model. The circle charts are scaled based on the base case run making the sensitizations comparable.

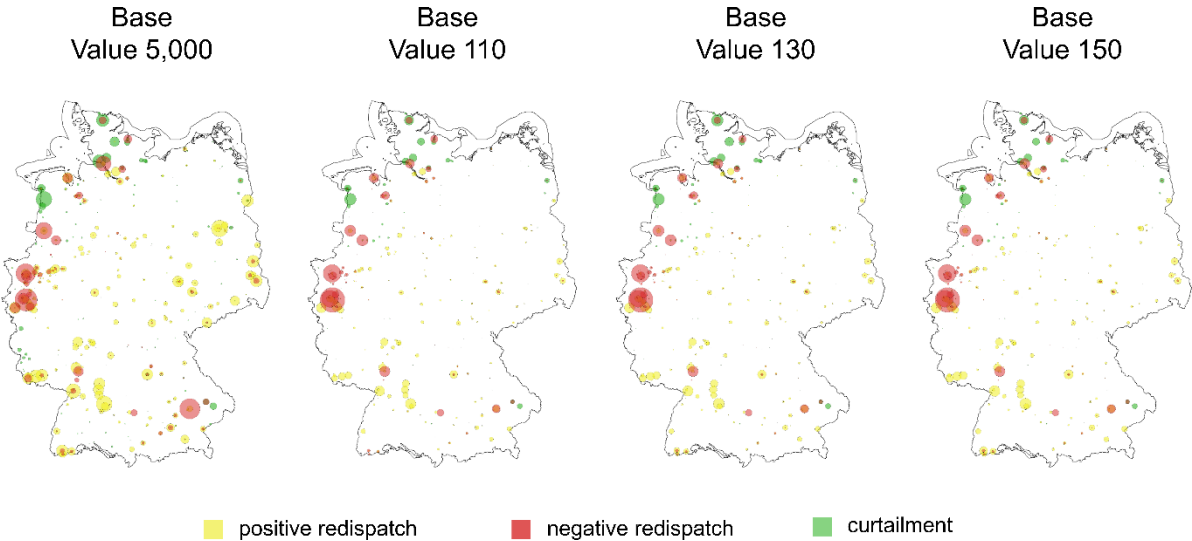


Figure 11: Base value sensitivity - Annual cumulated congestion management per node

The base case run yields in significant amounts of negative redispatch in the north of Germany, around the west of Germany, and in the Munich area. All corresponding grid nodes are in great proximity to interconnecting lines with the neighboring electricity markets. Comparing the base case run with all three other runs, the base case results clearly show larger negative redispatch amounts around Munich, larger curtailment rates in the northwest of Germany, and a more positive redispatch throughout the whole area of Germany. Differences between the comparison runs are not visible at this point. Figure 12 summarizes the total redispatch and curtailment amounts as relative differences compared to the base case run.

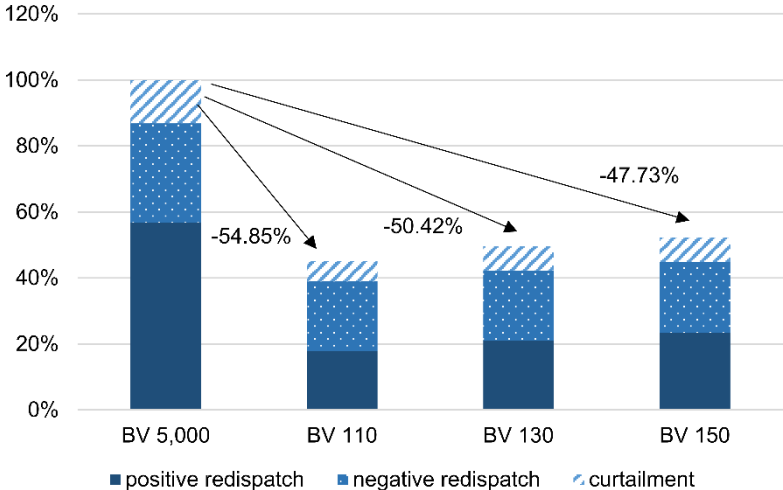


Figure 12: Base value sensitivity - Annual cumulated congestion management per node

Decreasing the base value for cross-border redispatch has an enormous impact on the resulting total congestion management amounts reproduced by the model. The total reduction amounts almost constantly to about 50 % in all comparison runs. It becomes clear that with higher penalty costs for cross-border redispatch, the grid simulation model prefers

more strongly national measures affecting the results a lot. This mechanism is also visible when comparing the sensitization runs among themselves. Moreover, the assumption on the magnitude of the neighboring countries' base value has a much stronger influence on resolving grid congestions at the border area compared to national bottlenecks. Since changes in the dispatch from power stations installed farther into the inland of Germany are impacting interconnector lines only less.

5 Discussion and Summary

Energy academia and industries utilize multiple different simulation tools for the model-based investigation of power transportation systems. Each certainly has its justification in the specific field of application, though their deployment sometimes leads to deviating model results. This paper aims at identifying common differences that exist in selected grid simulation tools from academia and analyzing how assumptions on key parameters and variations in selected modeling approach impact model-endogenous congestion management results.

Power flow equation systems take on a non-linear fashion by nature. Grid modeling, however, involves the deployment of optimizing network models. The complexity associated with non-linear programming problems often yields simplified power flow representations based on linearization methodologies, such as DC approximation, present in half of the investigated models. Other varying model features dealing with the modeling of power flows and generation dispatch are dynamic line rating, the utilization of soft or hard constraints, and the treatment of time-coupling equations. Time-coupling equations and soft constraints are the preferred option for congestion management modeling by most modelers participating in this experiment. Only a few institutions include dynamic line rating methods. Moreover, flat rate margins on power lines are used in favor of a detailed outage approximation due to increasing solving complexity by most grid optimization tools. The models distinguish further in the type, number, and dispatch order of represented congestion management measures. Most include detailed modeling of cross-border congestion management. Grid-related measures, in particular FACTS and PSTs, are only rarely included as an option to resolve grid bottlenecks in the different models. The majority of institutions utilize penalty costs to create a merit-order of individual congestion management measures that resemble real world practices.

A typical modeling task requires thorough consideration and selection of individual model features relevant to the specific needs of conducted research. Modelers must outweigh themselves which of the above-discussed modeling approaches are useful for answering the research questions under investigation. The parametrization of individual model features, however, can be a challenging task. Findings from this research indicate that model key parameters must be calibrated thoroughly since inaccuracies in model calibrations may have undesired effects.

Flat rate margins on power lines can be calibrated to similar congestion management amounts compared to the modeling of detailed outage approximations. Differences in model results between the different approaches become clearer in highly meshed regions. Modelers may evaluate the meshing of grid topology before choosing either way for the modeling of grid outages. Soft constraints on power lines need a careful calibration. Too high slack costs may overly drive congestion management volumes since a too strong penalization leverages the desired compensating effect necessary for incorrectly parameterized power lines. Too low slack-costs, on the other hand, may yield in a too high

capacity of the grid to deal with network congestions resulting in implausibly low total congestion management volumes. Moreover, parametrizing cross-border congestion management can have enormous impacts on total congestion management volumes reproduced by grid simulation models. Too large deviations between the base values for redispatch in the market zone under consideration and the neighboring markets lead to only minor contributions of generation stacks installed in the neighboring markets for cross-border redispatch. If grid congestions frequently occur on interconnecting power lines, this effect largely impacts total congestion management volumes. Special emphasis must be given to the power grid stress at the border region when choosing the appropriate type and scope of modeling cross-border congestion management in the specific field of model application.

In summary, modeling congestion management has proved to be a practical means for supporting system operators and energy policymakers in the design of electricity systems. Features of grid simulation models differ in type and granularity and must be adjusted to the relevant question under investigation. Parametrization of model features, however, can have large impacts on model results and must be done carefully. Future research may comprise a detailed comparison of grid simulation results of all participating institutions.

Authors Contributions

Hannes Hobbie: Conceptualization, Methodology, Software, Validation, Investigation, Data curation, Writing - original draft preparation; **Jonas Mehlem:** Conceptualization, Methodology, Software, Validation, Investigation, Data curation, Writing - original draft preparation; **Christina Wolff:** Conceptualization, Methodology, Validation, Investigation, Data curation, Writing - original draft preparation, Visualization; **Lukas Weber:** Methodology, Software, Validation, Investigation, Data curation, Writing - original draft preparation, Visualization; **Franziska Flachsbarth:** Writing - original draft preparation; **Dominik Möst:** Supervision; **Albert Moser:** Supervision. All authors have read and agreed to the published version of the manuscript.

Funding

This research was funded as part of the MODEX-Net project by the Federal Ministry for Economic Affairs and Energy in the 6. energy research funding program. Grant number: 03ET4074.

Acknowledgements

We would like to thank all partners and project members for their contributions regarding model descriptions and input data harmonization as well as dispatch and redispatch modeling results, especially from Jülich Research Center, Institute of Technoeconomic Systems Analysis: Jochen Linßen and Chloi Syranidou, from DLR Institute of Networked Energy Systems: Oriol Raventós, Chinonso Unaichi, Julian Bartels, Jan Buschmann and Wided Medjroubi, from Forschungsstelle für Energiewirtschaft (FfE): Andreas Bruckmeier, Timo Kern, Felix Böing, Tobias Schmid and Christoph Pellingner, from Karlsruhe Institute of Technology (KIT), Institute for Industrial Production (IIP): Thomas Dengiz, Rafael Finck, Armin Ardone, Katrin Seddig and Manuel Ruppert, from Öko-Institut e.V., Energy & Climate

Division: Matthias Koch, Sebastian Palacios, Christian Winger and Susanne Krieger, from RWTH Aachen, Institute of High Voltage Equipment and Grids, Digitalization and Energy Economics (IAEW): Annika Klette, Levin Skiba and Alexander Fehler, from TU Dortmund University - Institute of Energy Systems, Energy Efficiency and Energy Economics (ie3): Björn Matthes and Jan Peper and from TU Dresden, Chair of Energy Economics: Constantin Dierstein, Martin Lieberwirth and David Schönheit.

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