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MODEX-Net: Model comparison of power grid models in the European context

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Final report

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Authors :

Chloi Syranidou	c.syranidou@fz-juelich.de
Jochen Linssen	j.linssen@fz-juelich.de
Björn Matthes	Bjoern.matthes@tu-dortmund.de
Oriol Raventós	oriol.raventosmorera@dlr.de
Wided Medjroubi	Wided.medjroubi@dlr.de
Thomas Dengiz	thomas.dengiz@kit.edu
Dr. Matthias Koch	m.koch@oeko.de
Andreas Bruckmeier	abruckmeier@ffe.de
Jonas Mehlem	j.mehlem@iaew.rwth-aachen.de
Christina Wolff	christina.wolff@tu-dresden.de
Hannes Hobbie	hannes.hobbie@tu-dresden.de

The responsibility for the report contents lies with the authors.

Contents

Abbreviations

AC	Alternating Current
BMBF	Bundesministerium für Bildung und Forschung
BMWi	Bundesministerium für Wirtschaft
BNetzA	Bundesnetzagentur
BU	Bottom Up
CCGT	Close Cycle Gas Turbine
CHP	Combined Heat & Power
DC	Direct Current
DLR	Dynamic Line Rating
DRL-VE	Deutsches Zentrum für Luft- und Raumfahrt – Institut für Vernetzte Energiesysteme
DTW	Dynamic Time Wrapping
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
FZJ	Forschungszentrum Jülich
GDP	Gross Domestic Product
HVDC	High Voltage Direct Current
IAEW RWTH	Elektrische Anlagen und Netze, Digitalisierung und Energiewirtschaft – RWTH Aachen
KIT IIP	Karlsruhe Institut of Technology – Institut für Industriebetriebslehre und Industrielle Produktion
LAU	Local Administrative Unit
MILP	Mixed Integer Linear Programming
MODEX	MODel Experiments
NEP	Netzentwicklungsplan
NTC	Net Transfer Capacity
NUTS	Nomenclature of Territorial Units for Statistics
OEP	Open Energy Platform
PDF	Probability Density Function
PST	Phase Shifting Transformer
PTDF	Power Transmission Distribution Factors
PV	Photovoltaics
RES	Renewable Energy Sources
RMSE	Root Mean Square Error
SCOPF	Security Constrained Optimal Power Flow
TD	Top Down
TSO	Transmission System Operator
TU	Technische Universität
TYNDP	Ten Year Network Development Plan
UNFCCC	United Nations Framework Convention on Climate Change
VRES	Variable Renewable Energy Sources
WP	Working Package

1. Scope of the project

A variety of different developments have resulted in a significant increase to the interest in modeling the European power system in the recent years. The most important of such developments include the commitment of the European Union to decarbonize its economy, the increasing availability of data related to the European power system as well as the gradual transformation of the European power market. Decarbonizing the economy may add substantial changes to the power sector, since consumption is expected to rise and its behavior will be altered due to new technologies. Moreover, the generation mix is expected to change to environmentally sustainable solutions. The new technological landscape may alter and pose substantial challenges to the traditional way of power system operation, control, and security. Solutions regarding cost-efficient and socially acceptable transition pathways may also become difficult to answer. Another significant development consists of the economic transformation of the European power market, where the goal is to accelerate the integration of a single market, to bring market operation closer to the physical constraints of power delivery due to the transmission grid and facilitate a variety of system flexibilities within a liberalized environment.

Because of the increasing variety of involved technologies, available data and research questions, a corresponding variety of divergent modeling approaches have been developed and applied for the same system, hence giving rise to the desire to map these approaches as well as measure and understand their impact. Nevertheless, due to the considerable diversity in the research focus of the various models, this project is limited in investigating models that examine the integration of variable renewable energy sources (VRES) in the mid- and long-term scale. This implies realistic descriptions of the European power system and typically a temporal span of at least one year.

Such models are of particular interest since the implications they examine concern decision makers of public policies as well as individuals regarding both short- and long-term decisions. Since the methodological approaches to transmission grid modeling expand and diversify over time, for example, regarding the type and level of detail of load flow modeling, the derivation of distributed loads and generation, and the grid data used, this may lead to diverging or even contradictory model results. Therefore, it becomes essential to provide adequate information to model developers and users in research, politics and industry about these differences and to enable an open exchange about the differences of the approaches and the reasons for the deviating results. This project is not about evaluating the model approaches against each other, but about enabling model developers and users to classify different modelling approaches and to identify possible development potentials. This helps to improve the transparency of system models and thus to increase the acceptance and usefulness of the results of system-analytical considerations.

1.1 Description of the task

The overall objective of the MODEX-NET research project is to compare existing transmission system models that represent the European transmission system. In the context of this project, this task can be viewed as part of the overall energy system modeling, hence sharing similar issues with regard to complexity and use of data, where the significant variety in the selected approaches may result in contrasting results when attempting to represent the same system. Therefore, the goal of the project is

to compare different models in order to explore their inner workings and provide a deeper understanding of the represented system itself. In this way, all researchers, either participating in the project or not, can benefit from the produced knowledge by gaining more insights about modeling power systems as well as by identifying research gaps and the most critical parts of modeling. Moreover, it may provide additional perspective into the output of such models and hence, improve the understanding of both their significance and possible limitations as well as the conclusions that can be drawn correspondingly. Since a verifiable model behavior is unattainable, it should be noted that the goal of the project is not to rank different models based on their validity but rather to obtain a deeper understanding of their functionality and build a basis when comparing their results.

Besides comparing transmission grid models, one of the main goals of the project is to provide a systematic framework for comparison of power system models. As shown in section 1.4, such an attempt is rarely found in the literature, therefore a corresponding approach is deemed necessary. One of the most important consequences of developing such a framework consists in applying it to other power system models, which have not participated in the project. In this way, the value of the project can keep increasing even after its termination. The developed framework can use the information from the comparison of the participating models in order to better match the challenges of power system modeling, nevertheless it also has to be agnostic enough, since the specifics of each model cannot be known a priori.

One further goal of MODEX-NET is to provide the produced knowledge to the public. The results obtained by the model comparison should become publicly available, such that model transparency and understanding can be improved. Such results include the conclusions derived by the model comparison, the developed framework for model comparison as well as the primary quantitative results. In this way, the produced information is accessible and modelers outside the project can apply the framework and compare their output to the project modelling output. Using this information, they may then identify modelling and results differences, get a better understanding of their specific modeling methods and potentially lead to improvements. Overall, the goal is to improve the transparency and understanding of power system modeling for developers, users, decision makers and the general public.

1.2 Conditions under which the project was carried out

The project was carried out as a collaborative project. The Research Center Jülich (FZJ) was responsible for coordinating the joint project. The project was divided into three work packages. Each work package was coordinated and led by two to three project partners:

- WP 1: Definition of a scenario framework for the model experiments and a framework for the systematic comparison of the models involved. Lead: FZJ, TU Dortmund, Öko-Institut
- WP 2: Spatial and temporal disaggregation of electricity demand and generation, taking flexibilities into account. Lead: KIT IIP, DLR
- WP 3: Grid mapping and simulation. Lead: IAEW RWTH Aachen, TU Dresden

In addition, there was also the role of the data officer, who ensures a link for the topics of “data harmonization” and “data exchange” with the other projects from the MODEX thematic network (Öko-Institut).

Special circumstances were also caused by the Corona pandemic. In the second and third year of the project, therefore, only virtual project meetings and workshops could take place.

1.3 Planning and procedure

The project had a duration of three years and covered various aspects of modeling, hence both time planning and work distribution to separate packages followed the basic principles of power system modeling. Moreover, both of these aspects were adjusted to the constraints posed by the involved models, for instance the majority of models cannot perform grid expansion calculations inherently, hence this aspect affected the corresponding planning and workload. Although the project was organized in working packages with separate coordination, all partners participated in all packages due to the need for detailed information exchange, consensus in decision making, execution, and coordination of the model experiments.

Based on the set targets, available resources and the aspects of power system modeling, the overall work was split into three work packages (WP). The overall coordination was performed by Research Center Jülich, which may also be considered as an overarching working package, since all three of them needed to be connected.

WP 0: Coordination

Coordination: Research Center Jülich

Cooperation partners: all partners

The aim of this work package was to ensure the continuous information flow among all partners and packages, such that the project remains on schedule, and everyone remains updated. Aspects such as data confidentiality, agreement on assumptions needed to be coordinated and communicated properly. Therefore, frequent internal meetings and workshops were necessary to ensure the smooth flow of the project and the adaptation to unexpected challenges. Moreover, communication to scientists and stakeholders besides the project partners was also necessary, which was accomplished by additional workshops and publications.

WP 1: Definition of a scenario framework for the model experiments and a framework for the systematic comparison of the participating models

Coordination: Research Center Jülich

Cooperation partners: all partners

This WP consisted of the:

- qualitative comparison of the involved models
- the scenario framework definition
- the harmonization of models
- the design of a framework for quantitative comparison on the electricity market level.

These aspects were all linked to each other and required the participation of all partners. The qualitative comparison was required in order to identify the major features of each model and guide the design of the scenario framework definition. On the other hand, the scenario definition, model harmonization and quantitative market level comparison were performed sequentially including a feedback loop structure, since additional harmonization requirements could only be identified after the execution of the models. The results of WP1 significantly affected the work of WP3. The scenario data and assumptions as well as the results of the market model experiments along with the developed comparison framework were made publicly available by the end of the project.

Milestones:

- Model factsheets
- Identification of harmonization potential
- Definition of scenario frameworks
- Harmonization of input data
- Design of quantitative indicators and visualizations for the comparison of market output
- Market simulations

WP 2: Spatial and temporal disaggregation of electricity demand and generation

Coordination: (a) KIT-IIP, (b) DLR-VE

Cooperation partners: all partners

In this working package the spatial and temporal distribution aspects of the generation and demand used by the models were compared. Since the project focuses on the whole workflow of modeling the European power system, these aspects may constitute significant aspects where many models deviate and can be a source of significant divergence in their final results. Therefore, a detailed comparison was deemed necessary, both in qualitative and quantitative ways. For the qualitative path, the descriptions of the various workflows to assign VRES generation and load patterns to each grid node were assessed and compared. For the quantitative path, the depiction of the data from all models was harmonized since all models use different grid topologies. Moreover, respective visualizations were produced as well as invariants for each quantity, such that both a comprehensive and detailed comparison could be achieved. WP2 and WP1 collaborated on the qualitative comparison of the models. The results of WP2 can also be combined with the results of WP3 in order to extract deeper understanding and knowledge of the involved

models. Nevertheless, it was observed that this task would need further work that exceeds the limitations of this project and could offer opportunities for further research.

Milestones:

- Collection and comparison of disaggregation workflows
- Design of a comparison framework including quantitative indicators and visualizations for the spatiotemporal distribution of demand and VRES generation
- Comparison and analysis of the obtained results

AP 3: Grid modeling

Coordination: (a) TU Dresden, (b) IAEW

Cooperation partners: all involved partners

WP3 focused on the methods and results of redispatch modeling and congestion management. It constitutes the final part of the modeling chain; hence the comparison of models was the most challenging one since the initial conditions have already been heavily affected by the differences in disaggregation methods and market simulations. Moreover, significant work was required from the modelers in order to align their workflows with the requirements of this project in terms of redispatch modeling. Due to the high complexity and the differences in geographical coverage by the various models, the comparison focused only on Germany, since it constitutes the primary focus for the majority of the models, and it already has the highest number of electrical neighboring countries in Europe. The final results were compared for all models, nevertheless conclusions regarding their difference in modeling congestion management alone could not be drawn safely, since the input data for the modeling part were not harmonized but rather followed from previous parts of the modeling chain. However, during the comparison process, various experiments were conducted by individual models, thus leading to useful insights regarding grid modeling. Such experiments included the investigation of the impact of security and outage constraints, the use of modern grid technologies such phase shifting transformers and dynamic line rating, the use of soft constraints for line overloading as well as the modeling of neighboring countries. Since the majority of the models cannot perform grid expansion calculations intrinsically, this aspect was modeled by designing separate experiments for the cases of on time and delayed deployment of the HVDC north-south corridors within the German transmission grid. Collaboration with WP2 consisted of interpreting the impact of the different regionalization methods to the redispatch results. Similarly, the collaboration with WP1 was to understand the impact of the different market results to the grid results. Due to the high complexity and limited resources of the project, such answers could not be provided within adequate scientific certainty and further research is recommended. Finally, WP3 and WP1 worked together on the qualitative and quantitative comparison of the different methods of modeling the European grid topology as well as its harmonization.

Milestones:

- Comparison of the input grid data and modeling methods

- Harmonization of grid modeling aspects and for both the market and grid simulations
- Design of experiments for the comparison of congestion management methods
- Design visualization methods and quantitative indicators for the comparison of results from the grid simulations

Collection and analysis of the experiments conducted by all models and extraction of conclusions and knowledge

1.4 Scientific and technical state of the art

Model comparisons aim to compare existing approaches in terms of methodology, model structures and data. The aim is to gain a better understanding of the respective approaches and to identify possibilities for further development. In addition, a model comparison offers an ideal platform for in-depth discussion for model developers. Model comparisons have been an effective means of achieving these goals for many years. At the international level, the Energy Modeling Forum (EMF) should be mentioned here, which was introduced in the 1970s and has been continued ever since.

At the EU level, the Energy Modelling Platform for Europe (EMP-E), the project ACROPOLIS (Assessing Climate Response Options: POLIcy Simulations - Insights from using national and international models) and CASCADE-MINTS (CAse Study Comparisons And Development of Energy Models for Integrated Technology Systems) are examples of model comparisons. Between 1997 and 2007, a total of 5 model experiments were conducted by the BMBF and BMWi within the framework of the FORUM for Models. Within the framework of these experiments, model comparisons were carried out on the example of selected problems, which included models of different categories as well as the coupling of models. In current research projects such as RegMex (FKZ 0325874), 4NEMO (FKZ 0324008), BEAM-ME (FKZ 03ET4023), model comparisons are also carried out on a smaller scale (e.g. RegMex: electricity generation models, 4NEMO: electricity market models, among others). A comparison of transmission grid models has not yet been carried out.

Transmission grid models are often used to analyze the effects of integrating high shares of renewable energies into the energy system[1]. In this case, the analysis is usually coupled with the use of power plants[2]. Depending on the focus set, the underlying models can differ, among other things, in the type of load flow modelling and control, the level of detail of the grid mapping, the geographical scope and the consideration of grid expansion and congestion management.

With regard to the load flow calculation in transmission grid models, a distinction can be made between DC, PTDF and AC approaches as well as NTC approaches[3]. Depending on the choice of method, the

[1] H. Posser, und A. Bala: „Praxishandbuch Netzplanung und Netzausbau : die Infrastrukturplanung der Energiewende in Recht und Praxis“, Berlin, de Gruyter, 2013

[2] H. Natemeyer: „Modellierung der Betriebsführung elektrischer Übertragungsnetze für Netzplanungsprozesse“, Dissertation, RWTH Aachen University, Aachener Beiträge zur Hochspannungstechnik, Band 50, Verlagshaus Mainz GmbH, 2017

[3] S. Birbalta: „Application of a network reduction approach on an energy system model and the impact of different node aggregations on the curtailment of renewable energy generation“, Bachelorarbeit, Karlsruhe Institute of Technology, 2015 [Online: http://elib.dlr.de/97336/]

required computational effort allows for different degrees of detail in the system mapping[4] [5]. This is one of the reasons why there are fewer AC approaches, which are used in particular for detailed technical analyses. For similar reasons, network reduction methods are becoming increasingly important[6]. In contrast to AC approaches, the other approaches have a much lower computational effort and thus allow the consideration of more extensive systems at the expense of a lower accuracy of the results[7]. In this respect, the range of existing approaches for modelling transmission networks is justified and these approaches can complement each other[8]. The same applies to the various methodological approaches for the use of load-flow controlling equipment such as cross-regulators or high-voltage DC connections, which, according to the grid development plans[9], will be increasingly integrated into the three-phase grid in the future[10].

Accordingly, the concept of accuracy or the level of modelling detail must be understood and taken into account on several levels in the context of the modelling of electrical transmission grids. The first level is the width of the modelling in the sense of the geographical observation area of the real network topology and in particular the modelling of the edge area. The second level is formed by the different voltage levels of the energy supply system. This horizontal dimension of the grid infrastructure must be represented in the transmission grid model by an appropriate modelling depth with suitable grid equivalents. The last level represents the system-specific abstraction level. Taking into account the diversity and heterogeneity of the grid resources in substations and switchgear, an exact resource-specific modelling of the continental European transmission grid is highly complex. Therefore, within the scope of the modelling, individual electrical systems and resources are summarized and aggregated in a simplified manner[11] in order to be able to subsequently transfer them into a so-called node-edge model[12]. For this purpose, a large number of simplifying assumptions must be made, which have a significant influence on the results

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[4] H. Kile, K. Uhlen, L. Warland und G. Kjølle: „A comparison of AC and DC power flow models for contingency and reliability analysis“, 2014 Power Systems Computation Conference, Wroclaw, 2014, pp. 1-7

[5] B. Stott, J. Jardim and O. Alsac: „DC Power Flow Revisited“ in IEEE Transactions on Power Systems, vol. 24, no. 3, pp. 1290-1300, 2009

[6] S. Birbalta: „Application of a network reduction approach on an energy system model and the impact of different node aggregations on the curtailment of renewable energy generation“, Bachelorarbeit, Karlsruhe Institute of Technology, 2015 [Online: http://elib.dlr.de/97336/]

[7] Jizhong Zhu: „Optimization of Power System Operation“, 2nd Edition, Feb 2015, Wiley-IEEE Press

[8] H. Kile, K. Uhlen, L. Warland und G. Kjølle: „A comparison of AC and DC power flow models for contingency and reliability analysis“, 2014 Power Systems Computation Conference, Wroclaw, 2014, pp. 1-7 and B. Stott, J. Jardim and O. Alsac: „DC Power Flow Revisited“ in IEEE Transactions on Power Systems, vol. 24, no. 3, pp. 1290-1300, 2009

[9] 50Hertz Transmission GmbH, Amprion GmbH, TenneT TSO GmbH, TransnetBW GmbH: „Netzentwicklungsplan Strom“, [Online: https://www.netzentwicklungsplan.de/de]

[10] S. Rüberg: „Strategische Netzausbauplanung in vermaschten Drehstromnetzen unter besonderer Berücksichtigung der Hochspannungsgleichstromübertragung“, Dissertation Technische Universität Dortmund, Dortmunder Beiträge zu Energiesystemen, Energieeffizienz und Energiewirtschaft, Band 1, Shaker Verlag GmbH, 2017

[11] D. Klein, C. Spieker, S. Rüberg, V. Liebenau und C. Rehtanz: *„Aggregation of large-scale electrical energy transmission networks*“, 2016 IEEE International Energy Conference (ENERGYCON), Leuven, 2016, pp. 1-6

[12] North American Electric Reliability Corporation (NERC): „*Node-Breaker Modeling Representation*“, [Online: https://www.nerc.com/comm/PC/NERCModelingNotifications/Node%20Breaker%20Model%20Representation%20Webinar%20Presentations%20-%20December%202016.pdf], 2016

and their informative value. In particular, the way in which switchgear, breakers and individual busbars are mapped in the network model has an influence on the number of nodes and edges[13]. At this point, the situation is aggravated by the fact that the data is only publicly accessible to a limited extent, which makes validation virtually impossible, even though there are increasingly publicly accessible but unconfirmed data sources[14] (e.g. SciGrid[15,16]). The same applies to the edges of the network model, i.e., for the modelling of overhead lines and cables; for example, in the application of overhead line monitoring (OLM), it makes a difference whether the exact courses of a route were taken into account or whether these were only modelled as point-to-point connections with equivalent electrical parameters[17]. Models of the electrical transmission network form the basis for the simulation of diverse network operating condition with partly very different techno-economic questions[18]. The determination of the resource utilization for different grid utilization cases in uninterrupted and interrupted operation represents the basis for further investigations. Both AC- and DC-based methods for calculating the power flow use a grid model as the input data[19]. Subsequently, the determination of optimal operating points of load flow controlling equipment, such as phase-shifting transformers (PST) and HVDC connections, is possible using a grid model as well as the results and parameters of a load flow calculation[20]. The results of load flow calculations are used in combination with a grid model within the framework of comprehensive congestion management simulations in order to resolve any grid bottlenecks as far as possible through redispatch measures[21]. If it is not possible to resolve all identified grid bottlenecks by means of conventional redispatch measures or feed-in management of renewable energy sources, suitable candidates for grid reinforcement and expansion measures can be determined with the help of the grid model parameters[22]. Another field of application for transmission grid models is the determination of cross-border trading capacities in the form of so-called NTC values[23]. These define the maximum

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[13] North American Electric Reliability Corporation (NERC): „*Node-Breaker Modeling Representation*“, [Online: https://www.nerc.com/comm/PC/NERCModelingNotifications/Node%20Breaker%20Model%20Representation%20Webinar%20Presentations%20-%20December%202016.pdf], 2016

[14] W. Medjroubi et al.: „*Open Data in Power Grid Modelling: New Approaches Towards Transparent Grid Models*“, in Energy Reports, Volume 3, 2017,pp. 14-21

[15] W. Medjroubi, C. Matke: „*SciGRID - Open Source Transmission Network Model – USER GUIDE V 0.2*“ [Online: https://www.scigrid.de/releases_archive/SciGRID_Userguide_V0.2.pdf]

[16] SciGRID datasets for the European power and gas grid networks (www.scigrid.de)

[17] T. Ringelband: „*Unsicherheit witterungsabhängiger Übertragungskapazitäten bei der Netzbetriebsplanung*“, Dissertation, RWTH Aachen University, Aachener Beiträge zur Hochspannungstechnik; Band 137, Klinkenberg, 2011

[18] Jizhong Zhu: „Optimization of Power System Operation“, 2nd Edition, Feb 2015, Wiley-IEEE Press

[19] H. Kile, K. Uhlen, L. Warland und G. Kjølle: „A comparison of AC and DC power flow models for contingency and reliability analysis“, 2014 Power Systems Computation Conference, Wroclaw, 2014, pp. 1-7 and B. Stott, J. Jardim and O. Alsac: „DC Power Flow Revisited“ in IEEE Transactions on Power Systems, vol. 24, no. 3, pp. 1290-1300, 2009

[20] Jizhong Zhu: „Optimization of Power System Operation“, 2nd Edition, Feb 2015, Wiley-IEEE Press

[21] J. Eickmann: „*Simulation der Engpassbehebung im deutschen Übertragungsnetzbetrieb*“, Dissertation, RWTH Aachen University, Aachener Beiträge zur Energieversorgung; Band 164, Print Production M. Wolff, 2015

[22] M. Scheufen: „*Mehrstufige Strukturoptimierung für Höchstspannungsnetze*“, Dissertation, RWTH Aachen University, Aachener Beiträge zur Hochspannungstechnik; Band 44, Print Production M. Wolff, 2016

[23] M. Bucksteeg, K. Trepper und C. Weber: „*Impacts of renewables generation and demand patterns on net transfer capacity: implications for effectiveness of market splitting in Germany*“ in *IET Generation, Transmission & Distribution*, vol. 9, no. 12, pp. 1510-1518, 2015

permissible bilateral commercial exchange of power between two neighboring market areas, taking into account the technical limits of the system including the (n-1) criterion.

1.5 Cooperation with other parties

Within the MODEX thematic network, there was a continuous exchange with the other MODEX projects on the topics of data exchange and data harmonization. For all MODEX projects, the following harmonized data sets were made available for use through this exchange:

- Fuel type specific CO_2-emission factors based on the UNFCCC reporting guidelines on greenhouse gas emission inventories [t CO_2/MWh fuel]
- Fuel type specific fuel costs [€/MWh fuel]
- Costs of CO_2-certificates [€/t CO_2]
- Country-specific generation profiles for wind offshore, wind onshore, PV and run-of-river (normalized and in hourly resolution) for the weather year 2016
- Country-specific load profiles (normalized and in hourly resolution) for the year 2016

An important reference point for data management was the open energy platform[24]. For the project's internal data management, a clone of the OEP was first installed on a virtual cloud computer. In this context, an exchange took place with the software developers of the OEP (University of Magdeburg and Reiner Lemoine Institute). At the end of the project, the final market results of the model experiment for the year 2016 have been uploaded to the open energy platform[25].

In addition, the topics of data transparency and data documentation were also discussed in the MODEX thematic network. For this purpose, a specific metadata set was developed and applied for documenting the input data used in the model experiments[26]. Moreover, model factsheets for the individual models were also uploaded to the open energy platform[27].

The project consortium was also actively involved in the program design for the two meetings of the Systems Analysis Research Network and participated as well as conducted several workshops.

[24] https://openenergy-platform.org/
[25] https://openenergy-platform.org/dataedit/view/model_draft
[26] https://openenergy-platform.org/dataedit/view/reference
[27] https://openenergy-platform.org/factsheets/models/

2. Detailed description

In this section, the main findings of the project are described in detail. The achieved results are discussed in terms of scientific and societal significance as well as in comparison to the set objectives. The majority of the discussion can also be found in the corresponding publications in the MODEX special issue of Renewable & Sustainable Energy Reviews, as listed in section 2.6.

2.1 Achieved results, use of the grant and comparison to set objectives

2.1.1 Harmonization and scenario framework

For the structured comparison of transmission grid models, a **framework** was developed and applied in this project. Harmonized input data in the form of scenarios was developed as a basis for the model comparison. Based on the harmonized input data of the scenarios as well as a harmonized parameterization of the transmission grid models, different **model experiments** were performed. For a transparent, structured comparison of the results of the different models, electricity market- and electricity grid-related key figures were developed. The developed framework for the comparison of transmission grid models includes predefined methods and **evaluation routines** for the visualization of the key figures. The framework was programmed in Python and provides an interface to the Open Energy Platform (OEP). The following Figure 1 shows a schematic of the framework for model comparison.

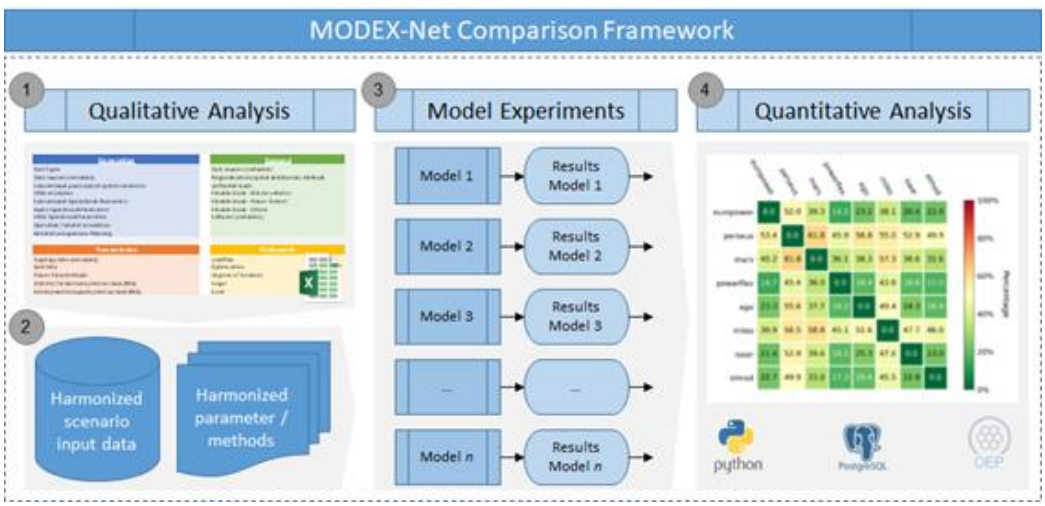


Figure 1. ***Developed framework to compare transmission grid models.***

In order to create the harmonized input data sets and the coordinated model parameterization, the developed comparison framework was utilized to analyze the transmission system models of the participating partners in a **qualitative** manner based on **model factsheets**.

As a starting point, the required input parameters of the models as well as the corresponding data sources were recorded in a tabular structure (Excel). In addition to the input data, the methods used for further data preparation and data intersection were also documented (e.g., regionalization of loads and distributed generation). Furthermore, some model properties as well as the methods used to simulate transmission systems (e.g., solver, grid model, AC/DC load flow formulation, dispatch modeling, redispatch calculation) were also compared. The geographic system boundaries and boundary conditions

(e.g., regional scope and resolution, temporal horizon and resolution) of the models were also analyzed and documented in the factsheets in the form of additional categories. The main categories and their respective features are depicted in Figure 2.

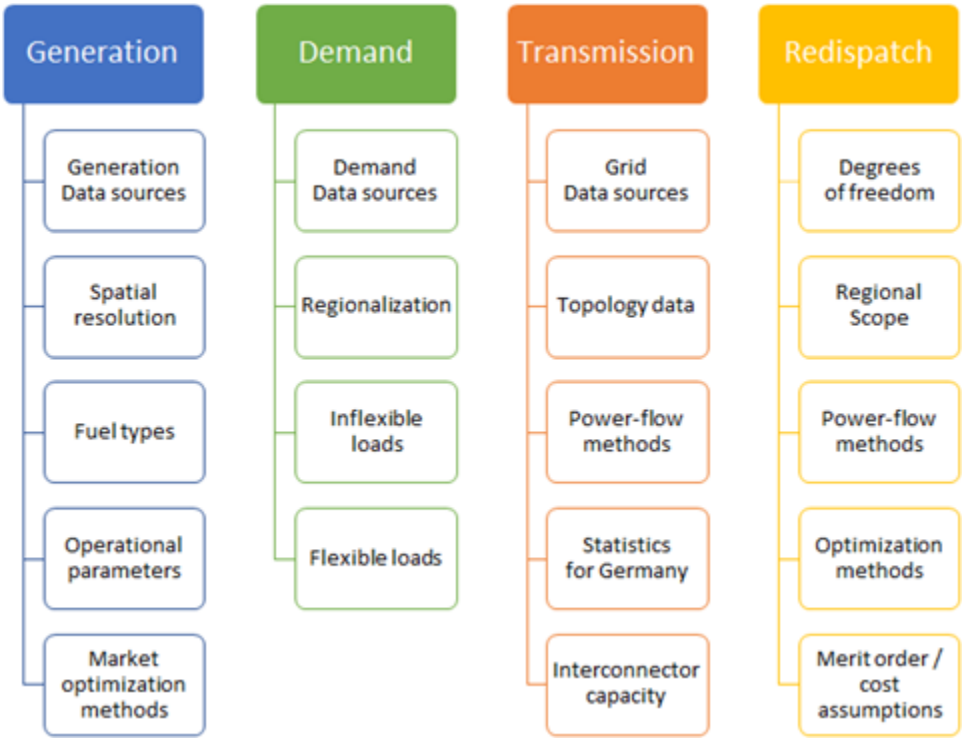


Figure 2. ***Main categories and features of the qualitative model comparison by factsheets.***

The goal of the qualitative analyses by using model factsheets was to identify an intersection of parameters and methods as large as possible in order to subsequently harmonize them. The grid topology and individual line parameters were intentionally <u>not</u> harmonized since a systematic comparison of different transmission grid models has been a central part of the MODEX-Net project. The most important achievements of the **qualitative analysis** based on the model factsheets in each category are listed in the following.

Generation: All models use optimization methods (e.g., LP, MILP, etc.) to calculate unit commit and economic dispatch. None of the models considers stochastic inputs. Thus, all models work with deterministic input data considering only one realization of demand and variable renewable energy sources (RES) time series per optimization. Furthermore, all models assume perfect foresight over the optimization horizon, yet some models make use of rolling horizon approaches. Most models consider bidding zones instead of nodal pricing in market simulation as well as feed-in priority of RES.

Demand: All participating models make use of hourly demand profiles. Some models consider individual load profiles for each sector, e.g., households, commerce, trade and services, industry, whereas other models use one aggregated load profile for the sum of all sectors. Different top-down (TD) and/or bottom-

up (BU) approaches are used to calculate regionalized sectoral demand profiles, e.g., per NUTS region or per transmission grid node, across the different models. Most models assign the regionalized demand data to the nearest substation, yet some models use Voronoi partitions or partly a combination of both approaches.

Transmission: All participating models have a georeferenced grid topology at least for Germany. Most models include grid components and their electrical parameters for voltages above 220 kV in Germany based on TSO static grid models. However, only 4 out of 8 models consider transformers and their electrical parameters explicitly. Most models assign offshore wind parks directly to their respective onshore connection points and do not model the connection systems explicitly.

Redispatch: All considered models make use of optimization approaches to identify remedial actions in terms of conventional redispatch and feed-in management of RES. Most models do not consider the (n-1)-criterion explicitly and reduce line capacities by a simplified flat rate value instead. Most models optimize congestion management measures for each time step separately and do not consider time coupling. Most models consider flexibility of high voltage direct current (HVDC) lines to relieve overloaded AC lines. However, only 2 out of 8 models consider phase shifting transformers (PST). Furthermore, only 3 out of 8 models consider Dynamic Line Rating (DLR).

In conclusion, the qualitative analysis based on model factsheets revealed the main similarities and differences between models and submodules. Based on the completed model factsheets, it was possible to identify the input parameters that could be harmonized for all participating models. Furthermore, those methodological aspects could be identified, which are covered by all participating models and thus could be harmonized as well. Similarly, the smallest common geographical area was identified, which should be the focus of the model experiments. Hence, the qualitative model comparison delivered a starting point for the **harmonization of model inputs and methods**.

The historical weather year installed generation capacities per technology type and country, commodity prices and NTC values were considered as important parameters that should be **harmonized** in the model experiments. To ensure as much consistency as possible across all different MODEX research projects, some basic input parameters from the MODEX model experiment cluster were used for harmonization in this project as well. The fuel type specific emission factors and fuel costs as well as CO2 prices used in this project were aligned with the MODEX model experiment cluster. Furthermore, normalized country-specific load and renewable energy profiles for the year 2016 of the MODEX model experiment cluster were treated as common data in MODEX-Net. However, those partners making use of bottom-up methods to simulate generation and demand time series based on weather data applied their models to generate these time series on their own considering the respective historical data for the year 2016. For the sake of consistency, the simulated time series were scaled to meet the harmonized annual demand and generation.

A **literature survey** was carried out to complete the set of harmonized model input parameters. Publicly available data sources with regard to installed generation capacities per type and country in the relevant scenario years have been identified and analyzed. As there is no consistent data source containing all

relevant data and various source have different values for the same data point, it was decided to reduce the total number of data sources that were considered in the harmonization process to ensure maximum consistency. A special topic in the harmonization process was the consideration of hydro power plants in the different models and the input data necessary to model hydropower generation. The category hydro power was split in subcategories, namely run-of-river, reservoir and pumped hydro plants to have a better starting point for the harmonization of inputs and modelling methods in each subcategory. The installed capacities for each subcategory were mainly aligned with the JRC hydro power data base v05. As a simplification, the storage capacity of pumped hydro plants was approximated to be about eight times the installed generation capacity. Natural inflows were not harmonized, as the methods to calculate them differed across the models quite significantly. Furthermore, the annual demand and annual RES type specific generation per country were harmonized as well as availability factors for conventional power plants. As Germany was identified as the geographic area that is covered by all transmission grid models, the individual power plants including their locations were harmonized in detail with data from BNetzA[28] and NEP[29]. With regard to the transmission grid infrastructure only the topology was harmonized, but not the individual parameters of lines or transformers. However, the NTC values for each scenario year were harmonized. Concerning the modeling methods, it was decided that the (n-1)-criterion will be approximated by a flat rate security margin and not explicitly, as most of the models are only able to do it this way.

Based on the harmonized scenario data and aligned modelling methods, **model experiments** were designed to generate model results that can be used to compare different transmission grid models in a meaningful way. Hence, in the first experiment the transmission grid models were used to simulate the historic year 2016. This back-testing / back-casting model experiment was carried out at first to understand and analyze the models' inner workings with respect to a given set of inputs and known outputs from the real world. Based on the results and learnings from this back-casting experiment a future scenario for the year 2030 was setup to compare the models' capabilities to calculate possible realizations of the future. Additionally, two different grid scenarios have been defined for the year 2030. The base grid scenario includes all confirmed internal HVDC lines in Germany, whereas the second grid scenario considers a significant delay in the grid expansion process. Therefore, only three out of seven HVDC lines were considered to be in operation in the second grid scenario for 2030. Thus, the complete harmonization process has been carried out twice, as the conducted model experiments included **one historic and one future scenario**. The model experiments include model runs with harmonized input data and methods delivering a regionalization (section 2.1.2) of demand and RES as well as hourly load and RES time series data. Based on the regionalization and time series data the models calculate the hourly dispatch of thermal power plants and storages as well as cross-border electricity exchanges (section 2.1.3). Using the hourly load and generation pattern power-flow studies were carried out to calculate the line loadings before remedial actions. Subsequently, overloads and congestions were identified based on

[28] Bundesnetzagentur, list of power plants
https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/SecurityOfSupply/GeneratingCapacity/PowerPlantList/start.html
[29] Netzentwicklungsplan Strom 2030 (2019)
https://www.netzentwicklungsplan.de/de/netzentwicklungsplaene/netzentwicklungsplan-2030-2019

the power-flow simulation's results. Finally, redispatch simulations (section 2.1.4) were carried out to calculate remedial actions that were needed to relief the overloaded lines.

The model runs carried out in the two model experiments delivered the numerical inputs for the **quantitative analysis** based on key indicators using the open framework that has been developed in this project. The methods and key performance indicators as well as the standardized figures used to compare the transmission grid model are described in section 2.1.5.

2.1.2 Regionalization

The process of assigning information to a grid node is called *regionalization* or *disaggregation*, see Figure 3. A regionalization can be a fairly complicated processes involving many inputs and modifications, which are very specific to each model and not always fully documented. That is why the comparison of models is usually done either using their input or their output. Even more, comparison of models usually accounts only for the scope and the spatial resolution. As part of the WP 2**: Spatial and temporal disaggregation of electricity demand and generation**, we collected the regionalization workflows of all models in the project and developed a new method to compare their regionalization workflows. The method and the regionalization comparison for the status quo scenario were published in the MODEX-Net Special Issue[30].

We focused on the regionalization of PV, wind onshore, wind offshore and load, starting from the input data to the transmission grid node allocation. A more detailed comparison was carried out for the status quo scenario, as it allowed for a more accurate comparison of the regionalization outcome, but we also compared a future scenario for 2030.

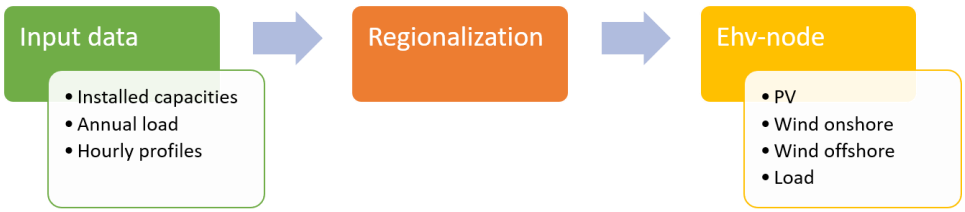


Figure 3. ***Scheme of a regionalization workflow from input data to transmission grid node.***

The first step towards developing a regionalization comparison method was to obtain the modelling diagram of the regionalization workflow for RES and load for each model. The direct comparison of these diagrams proved impossible, since the diagrams were not made following any standard footprint. For this reason, we further developed a list of concrete features of regionalization that could be displayed in a

[30] O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

table. By inspecting those tables, we developed a method for the comparison of the regionalization processes. The regionalization comparison method[31] is sketched briefly in chapter 2.2.1.

After analyzing the data provided for all models, we derived a series of conclusions that were used as building blocks for our comparison method. The first conclusion was that, usually, the installed capacities and the annual demand follow a different regionalization than the profiles. Hence, our method compares both processes separately. The second conclusion was that, the regions used in the regionalization need to be clearly defined beyond the spatial resolution. Those regions could be clustered in two groups: The *node regions*, which surround a node, and the *data region*, which might not have yet any input from the grid. The third conclusion was that, there are mainly three types of regionalization processes for transmission grid networks (although in practice they can always be combined):

1. Allocate data inside a node region directly to the node,
2. Distribute data regions values to its different nodes, and
3. Overlap data and node regions.

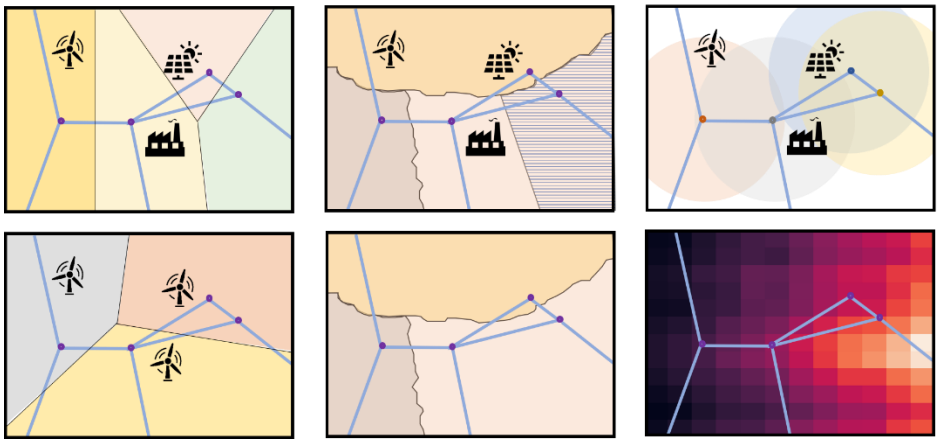


Figure 4. ***Regionalization examples. From top left to bottom right: Data allocated into Voronoi cells; Data allocated into administrative cells' subdivisions; Data allocated into regular node regions; Data distributed inside Voronoi data cells; Data distributed inside administrative data cells; Lattice of data distributed into the nodes.***

A regionalization of type 1 is based on the fact that each node has a unique surrounding region. For instance, one could use the Voronoi cell subdivision of the territory as node regions and the gird nodes as centroids. Geolocated generators are then assigned to the node of the Voronoi cell that they belong to, see Figure 4 (top left). Node regions can also be defined starting from some administrative subdivision of the territory (such as federal states or municipalities) and subdivide or aggregate those regions such that each region has just one node, see Figure 4 (top middle). An alternative is to define regular abstract regions surrounding the nodes, like circles of a fixed radius, and then allocate each generator based on the circle it belongs to (and provide a decision method in case that a generator is in two circles), see Figure

[31] O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

4 (top right). Notice that, type 1 methods are especially used when the available data is geolocated (or georeferenced).

A regionalization of type 2 is based on data regions. Those could be Voronoi cells centered around some type of generators (e.g., wind parks). The generator is then distributed to the nodes in the generator region (this is useful if the connection point of the generator is not clear), see Figure 4 (bottom left). Alternatively, the data regions could be administrative regions, e.g. the population of a certain region used in the regionalization of the annual load gets distributed to the nodes in the regions, see Figure 4 (bottom middle). The data region could also be defined by a lattice of data, e.g., weather data for the computation of the availability profiles, and each node gets the data of the closest lattice vertex, see Figure 4 (bottom right). Notice that, when there is more than one node in one data region, a criterion must be defined for the distribution of generation or load, like Voronoi subdivision or distribution by weighting.

An example of regionalization of type 3 is the use of Voronoi cells for nodes and a weather data lattice, where all the vertices of the lattice belonging to a Voronoi cell are used for the computation of the output data, e.g., solar energy availability profile.

We collected detailed information about how each model constructed the node regions and the results are as follows[32]:

- ELMOD: For RES, node regions defined by Voronoi cells of the EHV-nodes are used, but the load is distributed evenly to the EHV-nodes inside each NUTS 3 region.
- eTraGo: Node regions starting from a LAU region (municipality level) are assigned to the 110 kV node. If two nodes are in one region; the region is subdivided using Voronoi cells around the nodes belonging to it. If a LAU region has no nodes, values get assigned to the closest node. Finally, each 110 kV node region is assigned to an EHV-node region using the shortest grid-path (routing).
- Europower: Node regions are defined by Voronoi cells around the EHV-nodes.
- ISAaR: Data regions are created by assigning data in NUTS 3 areas to the grid node contained in them. If there is no node in a NUTS 3 region, it is assigned to the next-neighbor grid node. If there are more grid nodes within one NUTS 3 area, the assignment is conducted proportionally by area.
- MarS/ZKNOT: Use node regions starting from a LAU region, then assigning to 110 kV nodes using weighting distance and then to an EHV-node region using the shortest grid-path.
- MILES: Data regions are defined by first assigning load and RES data to the centroid of a LAU region and are then distributed to the EHV-nodes within a threshold radius proportionally based on their distance to the centroid.
- PERSEUS: Data regions are assigned to 110 kV nodes by area weights from the interception of the data region (NUTS 3 for demand) and Voronoi cells around the 110 kV nodes. The 110 kV nodes are assigned to an EHV-node using the shortest grid-path (routing).
- Powerflex: Node regions are defined by Voronoi cells around the EHV-nodes.

[32] Page 5 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

Next, the outcome of the analysis of the described regionalization methods for all models in MODEX-NET is presented. The input resolution and source together with a simple bottom-up/top-down description is highlighted. The main aspects of the PV installed capacity regionalization are summarized in Table 1. Notice that, the models use predominantly a bottom-up approach allocating the generators to the node region. The regionalization of wind onshore and wind offshore was essentially done in the same way in most of the models. Except for the fact that wind offshore parks are usually allocated following the cable that connects them to the shore.

Table 1. ***Regionalization workflow characteristics of PV installed capacity for each model.***

Model	BU/ TD	Input resolution & source	Node allocation
ELMOD	BU	LAU Register (EEG)	Generator belonging to a node region
eTraGo	BU	LAU Register (OPSD)	Generator belonging to a node region
Europower	TD	NUTS 2 Register (ENTSO-E) & NUTS 3 distribution	Overlap of generation regions and node regions
ISAaR	BU	LAU Register (MaStR)	Generator belonging to a node region
MarS/ZKNOT	BU	LAU Register (EEG)	Generator belonging to a node region
MILES	BU (& TD)	LAU Register (EEG) (& distributed to nodes in the allocation region)	Generator belonging to a LAU region
PERSEUS	BU	LAU Register (EEG)	Generator belonging to a node region
PowerFlex	TD	LAU Register (EEG) & NUTS 1 statistical data	Overlap of LAU generation region and node regions

The regionalization methods of PV availability profiles are listed in Table 2. Most of the models use high-resolution weather data, overlapping the lattice of weather data with Voronoi cells of generators or nodes. The same technique is also for wind by most of the models.

Table 2. ***Regionalization workflow of profile for PV for each model[33].***

Models	BU/ TD	Input source	Allocation resolution
ELMOD	TD	NUTS 0 profiles (TSOs)	Distribute into the nodes contained into the profile region
eTraGo	BU	Weather data (ERA5 28 × 28 km2)	Closest weather data location
Europower	TD (from BU)	NUTS 2 profiles (EMHIRES using CM SAF SARAH weather data, 5.55×5.55 km2)	Overlap of generation regions and node regions

[33] Table 4.2 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

ISAaR	BU	Weather data (DWD & ECMWF-CAMS, 13 × 13 km2, ICON-EU)	Overlap of weather grid and node regions
MarS/ZKNOT	BU	Weather data (MERRA-2, 50 × 50 km2)	Overlap of weather grid and node regions
MILES	BU	Weather data (COSMO-REA6, 6 × 6 km2)	Overlap of weather grid and node regions
PERSEUS	BU	Weather data (ANEMOS, 20 × 20 km2)	Overlap of weather grid and node regions
PowerFlex	TD	NUTS 0 profiles (TSOs)	Distribute into the nodes contained into the profile region

The regionalization processes for the load are summarized in Table 3. Here most of the models use national profiles of the different sectors, like residential, commerce, industry, or agricultural.

Table 3. ***Regionalization workflow for the demand profiles for each model[34].***

Models	BU/TD	Resolution	Sectors
ELMOD	TD	NUTS 0	Total demand
eTraGo	TD	NUTS 0	Agriculture, residential, commerce and industry
Europower	TD	NUTS 0	Base load
ISAaR	TD	NUTS 0	Residential, commerce and industry
MarS/ZKNOT	TD	NUTS 0	Residential, commerce, agricultural and industry
MILES	TD	NUTS 0	Residential and industry
PERSEUS	BU	LAU	Residential, industry, commercial, trade and services
PowerFlex	TD	NUTS 0	Total demand, but independent energy intensive industry uniform profile

The different regionalizations of annual load are described in Table 4. Almost all the models use parameters with a high spatial resolution (mostly LAU regions). All models use population and most of the models use also gross domestic product (GDP). Just some of the models use other parameters like temperature, employment, or heat demand.

[34] Table 4.4 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

Table 4. *Regionalization workflow for the demand factor for each model*[35].

Models	BU/ TD	Input resolution	Source
ELMOD	TD	NUTS 3	Population, GDP
eTraGo	BU	LAU	Population, GDP, land use
Europower	BU	LAU	Population, temperature
ISAaR	BU	LAU	Population, employment
MarS/ZKNOT	BU	LAU	Population, GDP, temperature
MILES	BU	LAU	Population, GDP, heat demand, conventional vehicles
PERSEUS	TD	NUTS 3	Population, GDP, land use and temperature
PowerFlex	BU & TD	LAU (& NUTS 1)	Population and energy intensive industry (and NUTS 1 statistical data)

Another aspect to take into account when comparing regionalization processes is whether a post-processing correction was applied. For instance, after the regionalization of all PV installed capacities, a global factor could be used to match the national PV installed capacity to a certain reference. This information was compiled in Table 5. Notice that, a post-correction is only necessary in the case of the models using a bottom-up approach.

Table 5. *Post-processing correction workflows for PV*[36].

Models	**Corrections after node assignment**
ELMOD	None
eTraGo	NUTS 0 annual full load hours (ENTSO-E)
Europower	None
ISAaR	NUTS 0 monthly full load hours (ENTSO-E)
MarS/ZKNOT	NUTS 0 annual full load hours (ENTSO-E)
MILES	NUTS 0 monthly full load hours (EEX)
PERSEUS	NUTS 0 annual full load hours (ENTSO-E) (optional)
PowerFlex	None

We noticed that, even if MODEX-Net focus is on the German transmission grid, sometimes the distribution grid is used in the regionalization process. For instance, a generator could be allocated to the closest 110 kV node (equivalently, using Voronoi cells of 110 kV nodes) and then follows the shortest grid path to an EHV-node.

[35] Table 4.5 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

[36] Table 4.3 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

The regionalization of future scenarios has some differences with respect to the status quo scenario. Most of the models use the same regionalized profiles but adapt the installed capacity and the annual demand. The changes in the installed capacities regionalization are summarized in Table 6. Two methods are essentially used. One is to scale the installed capacity without changing the allocation according to some future scenario at national scale. The other method is to construct a potential installed capacity atlas, hence allowing to install generators in new places and potentially changing the current distribution of PV and wind. For the total potential of each generation area the actual installed capacity is decided according to some available global scenarios.

Table 6. *Increase of installed capacities of RES for future scenarios.*

Models	**Scale according to scenario / Potential atlas**	**Resolution (source)**
ELMOD	Scale	NUTS 0
eTraGo	Scale	NUTS 0 (NEP 2015)
Europower	Scale	NUTS 0 (TYNDP)
ISAaR	Potential atlas	
MarS/ZKNOT	Scale	NUTS 0 (NEP 2019)
MILES	Potential atlas	LAU (land cover, land usage, weather)
PERSEUS	Potential atlas	LAU (weather, suitability areas)
PowerFlex	Potential atlas	NUTS 1 (register, population)

Regarding demand, not all models scale the annual demand. Since the predictions of annual demand change considerably from different sources, some models just use the same demand as for the status quo scenario. Oder models scale the demand, mainly according to the NEP scenario[37]. Most models, though, add to the conventional demand e-mobility and power-to-heat demand, see Table 7.

Table 7. *Change in annual demand regionalization for future scenarios.*

Models	Scaling conventional up, resolution (source)	E-Mobility	Power to heat
ELMOD	No	Yes	Yes
eTraGo	No	No	No
Europower	No	Yes (CP)	Yes
ISAaR	Yes, NUTS 0 (NEP...)	Yes (CP, VR) NUTS 3	Yes, NUTS 3
MarS/ZKNOT	Yes, NUTS 0 (NEP...)	Yes	Yes
MILES	Yes, NUTS 0 (TYNDP, NEP...)	Yes (CP, VR, LAU)	Yes (BT, SLP gas) LAU
PERSEUS	Yes, NUTS 0 (TYNDP, NEP...)	Yes (CP, VR)	Yes

[37] https://www.netzentwicklungsplan.de/

PowerFlex	Yes, NUTS 1 (NEP...)	Yes (annual demand)	Yes (annual demand)

2.1.3 Market simulations

Market simulations were organized and performed within WP1 and are closely related to the scenario definition and harmonization of the models. The primary results consist of:

- improved harmonization among the models
- the design and execution of the two main scenarios for all models
- the development of a systematic, quantitative framework for the comparison of market results
- publishing the comparison framework along with the corresponding data
- comparison of the scenario results

The achieved results align with the goals set in section 1.3 for WP1.

Comparing market results

Comparing methodologies and input data provides significant understanding of similarities and differences among models, nevertheless, the comparison of their outputs can provide additional useful insight to their inner workings. Using both sources of information can provide a better understanding of the differences between models. The development of a systematic approach for comparing market and grid results constitutes one of the core results of this project. Since this comparison is one of the first attempts of this kind, significant focus was put on designing the comparison indicators and metrics, since their application to real models have not been tested extensively. Moreover, the usefulness of such a framework extends beyond this present project and can be used and extended by other modelers and researchers as well.

Although combining the comparison of input and output can be useful, a separate comparison of the output is necessary. Since different models may generate a variety of different types of output data, a process similar to the input data harmonization can be applied, where all models should be able to provide the selected output in a comparable format. Moreover, this selection should incorporate sufficient complexity for analyzing the models, while also be simple enough, such that the data are intuitive to interpret as well as easier to be linked to the differences in inputs and methods. To that end, appropriate visualization methods should be designed as well as key performance indicators be derived. It is important to notice that the use of the proposed indicator depends on the comparison context and the goal of the researchers, as well as the involved models. Therefore, the conclusions of the comparisons from this project can be used as guidelines and lessons learned but should not be seen as restrictive to further use or extension of the framework. Nevertheless, one of the most important results of the project constitute the knowledge gained by defining and applying indicators as well as comparing a variety of different models.

The context of power system modeling for the present project is necessarily narrowed as explained in section 1. Power systems can be modeled in a variety of ways, hence the output selected for model comparison should be generic enough to be obtained by all models regardless of their inner structure.

Therefore, the existing paradigm of operating the European power system was followed in a relatively coarse manner and data was provided for two levels: the results of a day ahead market level and of a grid level where the whole transmission grid is taken into account for redispatch calculations. For each of these two levels a collection of minimal output can be selected as shown in Table 8.

Table 8. ***Minimal model results for comparison framework at market level and grid level. Results marked in red are not shared, instead secondary results are used.***

Market level	Grid level
Time series	Time series
• Generation per unit/timestep [MW] • Electricity price per zone/timestep [€/MWh] • Cross-border power flow per interconnection/timestep [MW] • VRES curtailments per zone/timestep [MW] • CO_2 emissions per country/timestep [Gtons] • Charging/discharging per zone/timestep [MW] • State of charge per zone/timestep [GWh] • Load curtailments per zone/timestep [MW]	• Upwards redispatch per node/timestep [MW] • Downwards redispatch per node/timestep [MW] • VRES curtailments per node/timestep [MW] • Congestion work per line/timestep [MW] • Amount of congestion per line/timestep [h] • Overload per line/timestep [%]
Secondary results	Secondary results
• Energy mix per zone [TWh] • Net balances per zone [TWh] • Price convergence per region [%] • Price convergence per interconnection [€/MWh]	• Upwards redispatch per node [TWh] • Downwards redispatch per node [TWh] • VRES curtailments per node [TWh] • Congestion work per line [TWh] • Amount of congestion per line [h] • Maximum overload per line [%]

This section focuses primarily on the discussion of the market level, while the comparison of grid model formulations and corresponding conclusions are discussed in the following section. For the market model comparison, the results of the corresponding list in Table 8 were used. Besides the options in the *secondary results* list, all other results are time series data, thus resulting in comparing two-dimensional data for each model, e.g., a temporal and a spatial dimension for electricity prices. Therefore, the main goal of the comparison of models' output consisted of deriving meaningful values for the differences of these data.

For the purposes of this project, the indicators that were selected followed the principle of reducing the dimensionality of the time series data. This approach can provide more meaningful visualizations as well as help extracting the most important information with respect to model behavior and comparison. Several methods were proposed and tested with the existing models and can be classified in the following general categories based on the reduction principle:

- Reduction of each time series independently by deriving additional results
- Reduction of each time series independently based on an operator
- Reduction of pairs of time series based on a distance metric
- Elimination of the spatial dimension by focusing on a single region of interest

The application of each method and its interpretation depends on the original result including its properties and its significance analyzing the model's behavior. Similarly, the selection of the specific operators and distance metrics depends on each case. Figure 5 summarizes the reduction methods of the time series results suggested by the existing framework. The depicted operators and metrics merely constitute a, far from exhaustive, collection of the most popular alternatives that are typically found in the literature and their application within a power system modeling context was investigated. The recommendations derived from this project stem primarily from the applicability of the metrics and their usefulness in interpreting model behavior. For instance, in many cases comparing the full time series is not necessarily more useful than comparing the respective averages or the corresponding probability density functions. In addition, some of the results are more important for model comparison than others that may be more parameter-sensitive or too complicated to interpret.

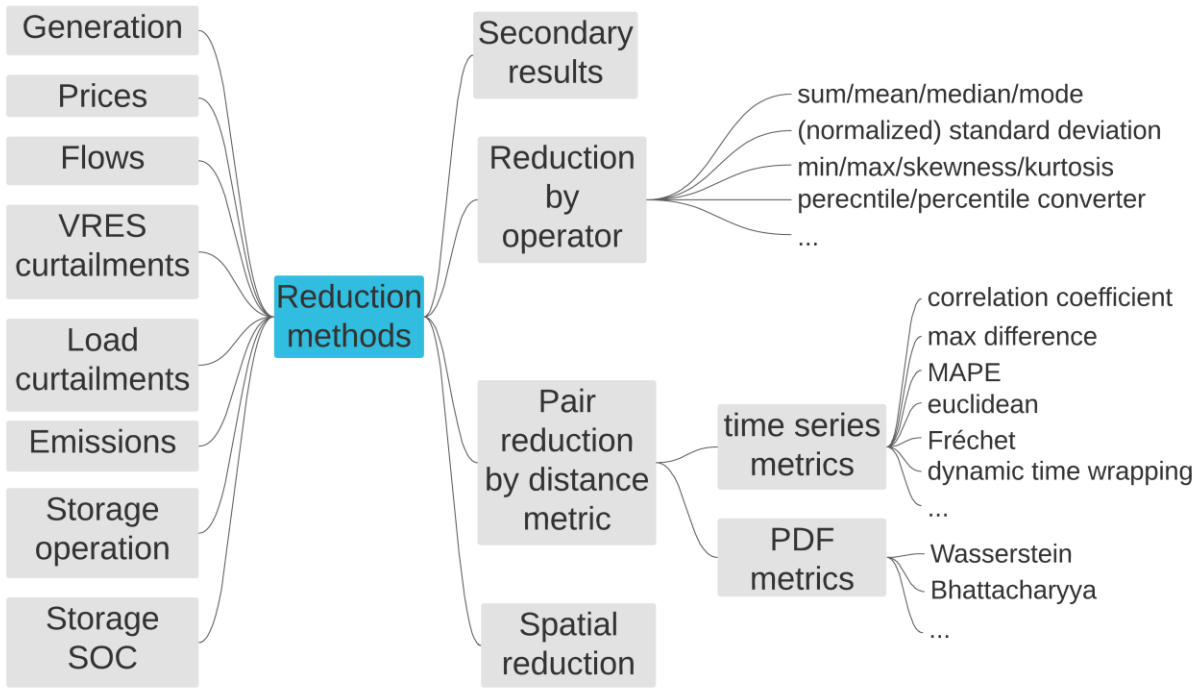


Figure 5. ***Sketch for possible reduction methods of primary market results in order to derive suitable comparison indicators.***

The *percentile converter* operator can be understood as an alternative to the kurtosis of the respective probability density function (PDF) that can provide a value with more direct interpretation for energy systems. It can be essentially viewed as a metric of the curvature of the corresponding duration curve and measures the area for a given percentile as shown in Figure 6. For the case of VRES curtailments this would indicate whether the corresponding energy is concentrated over a few incidents with high volume or are more uniformly distributed over time.

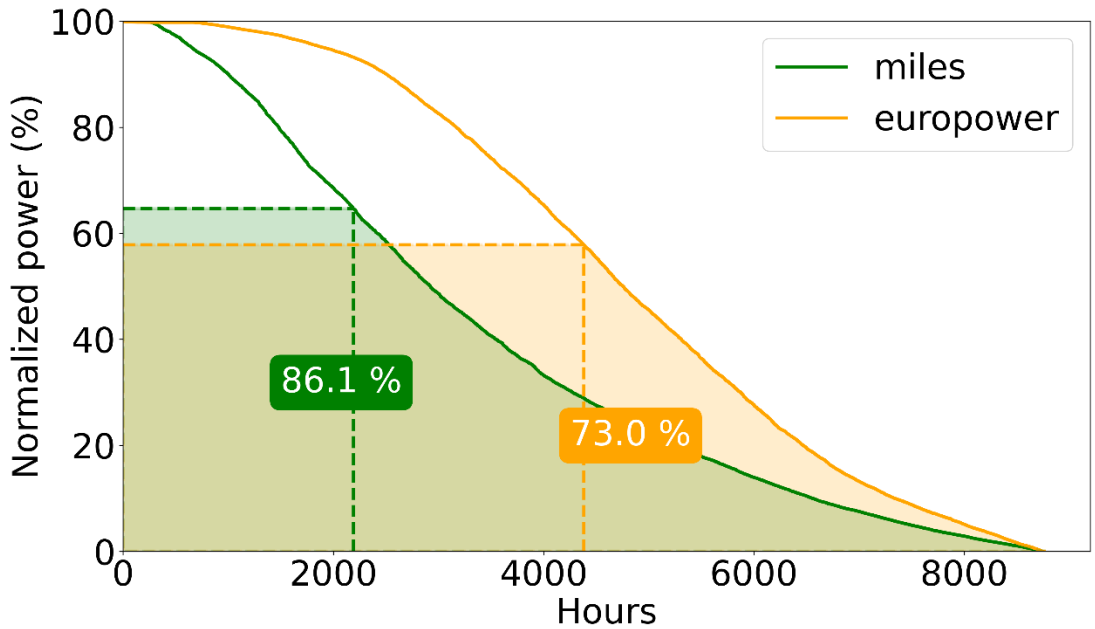


Figure 6. ***Exemplary illustration of different percentile converter indicators for different duration curves and percentiles. The data corresponds to the wind offshore profiles of Germany for miles and europower models.***

Regarding the indicators that measure the distance of time series, two different categories can be distinguished: distance metrics applied on the original time series data (time series metrics) and metrics applied on the derived probability density function (PDF metrics). Both categories can provide different information that may be useful depending on the measured result. For instance, the correlation coefficient may show how similarly two time series fluctuate over time, while measuring the similarity of the shapes of the corresponding PDF can show whether the two data sets exhibit similar distributions in a more averaged manner. A better understanding is given in Table 10, where the various indicators are also applied to exemplary results.

Understanding the behavior of the indicators depends on the original data, therefore the corresponding investigation was performed within this context. Moreover, the analysis was selected to focus on the generation output and electricity prices results, since, compared to the other results, these are observed to be the most relevant for model comparison and can also sufficiently illustrate the relevance for most of the afore-mentioned operators and metrics. This is not entirely unexpected, since the information of how much energy each unit will produce and which price it will receive constitutes the primary result of

every dispatch model. Moreover, the model behavior can be more easily tracked via generation and electricity prices, while patterns in how similarly models behave become also easier to identify.

Reduction method 1: secondary results

Generation output constitutes an extensive set of data that is both very difficult and not useful to compare in its primary form. Since models do not use the same input data or methods for generation units, it becomes more advantageous to aggregate this data in both time and space. The most popular and useful way to accomplish this consists of the initial energy mix, where power units are grouped based on their fuel or technology type, e.g., onshore wind or natural gas CCGT. The corresponding classification depends on the context of the desired information and one obvious selection can be the classification of the harmonization process, nevertheless, the number of generation types can be further reduced for a better visualization.

Error! Reference source not found. shows the annual energy mix for all investigated models for the c orresponding countries including the respective data from ENTSO-E[38] for the year 2016 in both absolute and relative values. It is considered the most important indicator regarding a model's performance with respect to the market behavior since it is comprehensive enough to use for interpretation and comparison. For instance, it can become relatively easy to observe whether models may collectively exhibit similar behaviors such as high nuclear production in France that may be due to overestimation of the available capacity during the harmonization or if there are outliers because of specific modeling aspects.

[38] ENTSO-E, „Statistics and Data," 04 05 2017. [Online]. Available: https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Statistics/Factsheet/entsoe_sfs_2016_web.pdf.

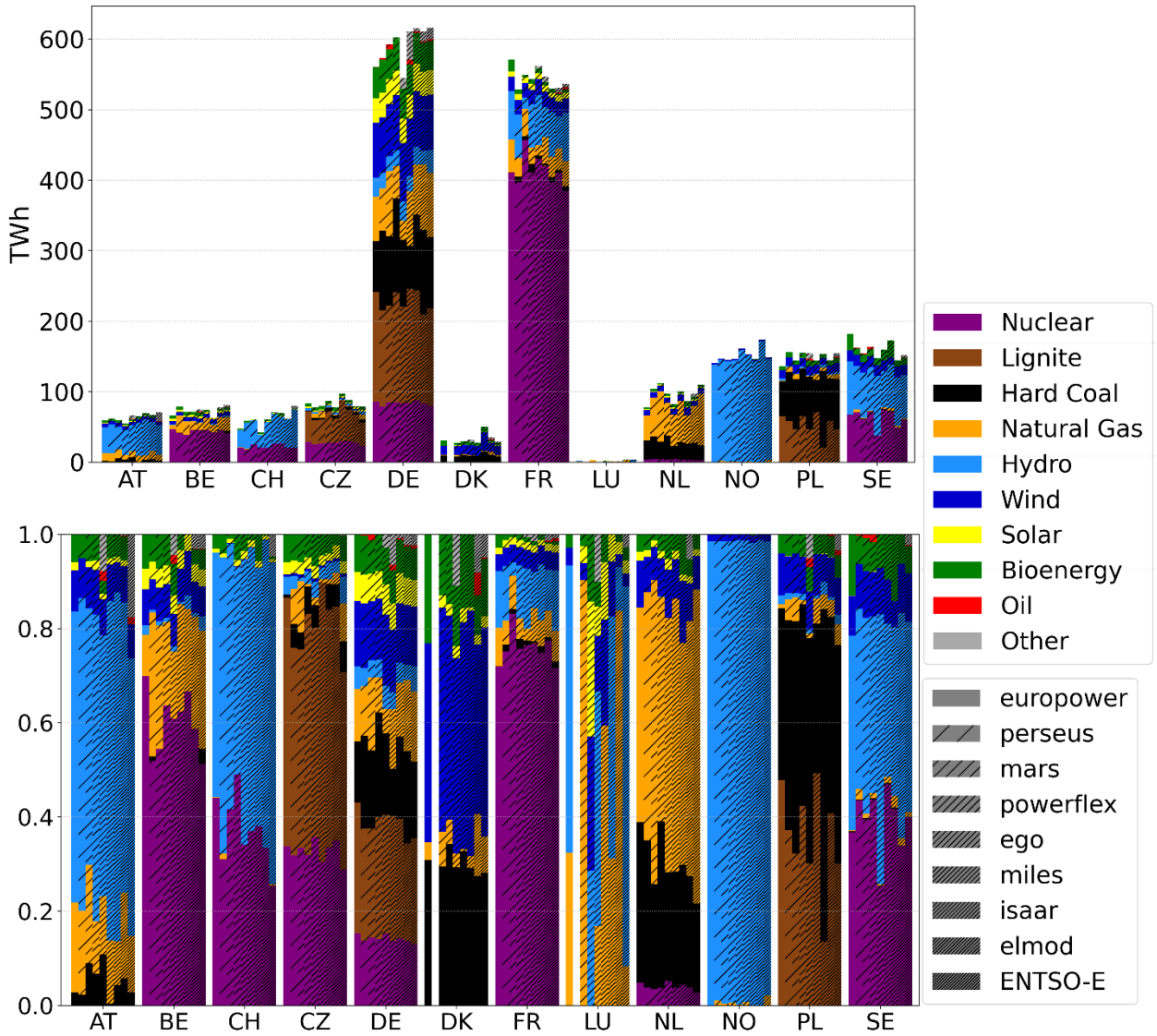


Figure 7. ***Annual energy mix for all investigated models and their common countries including the respective data from ENTSO-E for the year 2016 in both absolute and relative values.***

The annual energy mix was used to identify behaviors in both individual models as well as provide feedback about the harmonization assumptions. The comparison with other models proved to be particularly useful to question whether a specific outcome might be modeled differently or if it could be improved. For instance, a lower gas production for one model may be related to the modeling of CHP units and could be improved accordingly. Therefore, publishing the results as well as the comparison methodologies can help modelers outside the project in identify areas for improvement. The comparison within this project had the significant benefit of frequent exchanges in information and knowledge among experts, which also proved to be particularly beneficial. The various issues that emerged out of this process were collected in an issue list and were resolved in order to achieve a higher convergence among the models thus increasing harmonization and comparability without losing individual modeling differences. The issue list is presented below, where the most important aspects are highlighted in green:

Table 9. *Issue list regarding modeling aspects that may need further harmonization after obtaining the first market results.*

Topic	Issue
Biomass Fuel Costs	Not all models can use/harmonize costs
Dispatch of conventional	Not per se an issue but an observation: More lignite and gas production and less hard coal production for 2016
Initial state of charge	Strong influence on the results. It should be harmonized.
Marginal prices of other Renewables, other conventional and waste	Harmonization of marginal prices of other Renewables, other conventional and waste?
Emissions resolution	Is time series per country necessary?
VRES curtailment	Distinguish curtailment per technology?
German VRES time series harmonization	If we harmonize the time series of VRES, then we cannot compare the effects of regionalization after optimization (when we consider the whole grid optimization)
Keeping import-export in both directions	Store flows in both directions?
NTC Denmark-Sweden	Denmark West-Sweden ~715 MW is missing
Line utilization evaluation	Compare line utilization statistics?
8784 annual hours vs 8760 annual hours	Some models run with 8760 h for 2016 and some with 8784 h
Reservoir capacity	Harmonize storage capacity of reservoir? How?
Reservoir and run-of-rivers overproduction	Without an availability profile (or factor) there is overproduction. ENTSO-E data can lead to inconsistencies
Model Italy and Great Britain	This probably affects market simulations, especially for France.
Technical availability for conventional power plants	It significantly affects the dispatch of power plants and the whole energy mix
Harmonize weather year for hydro	Harmonize the inflow profiles/volume for hydro power plants

Issues related to modeling hydropower and choosing the weather year also appeared in the market results and not only in the harmonization of input. Several solutions were suggested and tested during the project until solutions were unanimously agreed upon.

Reduction method 2: reduction by operator

Electricity prices constitute the second most important indicator since it also includes comprehensive information about a model's behavior, while it is relatively easy to compare since each biding zone only has one time series. Electricity prices were also used as the main dataset to investigate time series comparison in power system modeling. The remaining results of Table 8 do not provide a similarly

comprehensive understanding of the indicators' functionality, since they are not expected to converge as much or because their convergence can have less direct implications on the similarity of the models. Nevertheless, some indicators can provide valuable insights when applied to such results as well, while also depending on the research focus of the comparison. The primary aspects of time series comparison for this project can be best illustrated via electricity prices, where the main conclusions can be then extended to the other types of results as well.

The most direct approach to comparing time series consists of the independent reduction into a single value via descriptive statistics or derivation of secondary results. Besides the 'sum' or the 'percentile converter' operators that do not generate any useful value, all other operators can provide values that can be used for comparing electricity prices. Some of the most directly comprehensible operators for electricity prices consist of the first two moments that can measure the average behavior and spread over the mean value. An additional advantage of this type of time series reduction consists of the ability to use hierarchical clustering in order to identify clusters of models with respect to that operator and measure a respective distance between the clusters. After reduction, a single vector with the various countries as coordinates corresponds to each model. These data can then be clustered using hierarchical clustering for a given distance metric, such as Euclidean, and a linkage criterion, such as minimization of the cluster variance. Figure 8 shows the dendrogram produced for the 'mean' operator applied on electricity prices, where it can be seen which models are closer to each other over all countries.

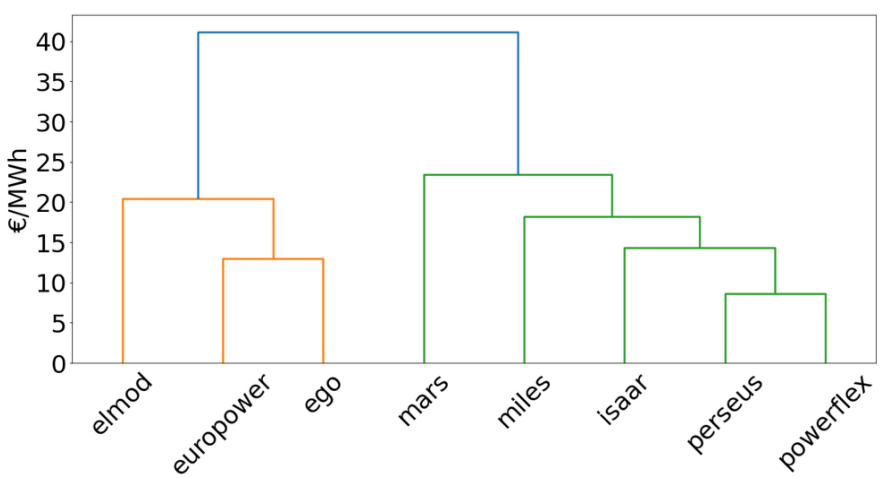


Figure 8. ***Hierarchical clustering dendrogram for the electricity prices reduced by the mean operator for all eight models for the year 2016.***

Reduction method 3: Reduction by distance metric

The third way of comparing model results consists of the comparison of pairs of time series. As shown in Figure 5, there are two main categories for computing distance or similarity indicators, one applied directly on the original time series and the second applied on the respective PDF. Several approaches were tested during the project in order to understand the nuances behind each approach as well as the

respective metrics. In this way, the goal of the project to provide recommendations for appropriate model comparison tools could be achieved.

For a better illustration of the work that was conducted in this direction we consider the electricity price results for Germany using the **PowerFlex** model as reference and compare it to the corresponding results of the **ISAaR** and **Europower** models. The reason for this selection is illustrated in Table 10, where it can be seen that different indicators can show different, even opposite, results with respect to the distance (smaller marked with green) to the two models.

There exist a variety of metrics to measure the similarity of time series and they have been used in a variety of contexts. Such metrics for instance may focus on measuring the correlation, error or apply geometric or more complex approaches. Table 10 includes a non-exhaustive selection of such metrics for both time series and their PDF. Except for the Wasserstein metric that appears to show insignificant differences and hence is not deemed useful for model comparison in this context, the remaining metrics show a similar behavior. That behavior consists of the expected dependency on the difference between the mean values. Figure 9 shows all three timeseries for the month of September. **Europower** correlates to **PowerFlex** better than **ISAaR**, nevertheless with a clear positive offset, while **ISAaR** remains in the similar range but with significantly less correlation.

It follows that, two main indicators can be extracted that are mostly useful for model comparison. The first indicator consists of the difference of the mean values of the two timeseries and the second indicator consists of one or more metrics that measure the distance of the normalized time series (i.e., centered around their mean values). The first indicator measures the average distance and can be connected to the input data such as the bidding prices of generators. The second indicators can also be related to the input data, e.g., the distribution of bids, however, it also reveals additional information about the behavior of the model, assuming a harmonized residual load. For instance, high correlation and high shape similarity of the time series and the corresponding PDF may indicate a higher similarity of the model methodologies. Apart from error scores which are not particularly useful, since a close match is not expected, all other metrics exhibit the same trend, i.e., exhibit shorter distances for more similar shapes. However, it is not straightforward to compare the results of different metrics since they can be interpreted differently and have different "units". For that reason, it is recommended to use the most intuitive ones for the specific context. For instance, the "max difference" metric is easier to interpret, whereas Frechet and DTW distances are less intuitive for power system modeling and more difficult to compute.

Table 10. ***Exemplary distance metrics and their values when comparing isaar and europower to powerflex for the electricity prices in Germany. The green color indicates the lowest distance and the red color indicates that the numbers may be misleading.***

	Metric	Original		Normalized		Comments
		ISAaR	Europower	ISAaR	Europower	
	Mean difference	-0.36	-4.63	0	0	Distance between the mean values

Time series	Correlation coefficient	0.16	0.83	0.16	0.83	Highest score shows the highest correlation
	Max difference	35.6	17.2	35.2	12.6	Maximum difference at any timestep
	MAPE	0.17	0.17	6.1	1.1	Linear error, small values can disproportionately skew the result
	Euclidean	610.3	482.3	609.3	212.2	
	Fréchet	35.4	15.9	35	12.6	Similarity accounting for location and ordering of points[39]
	Dynamic Time Wrapping (DTW)	42,360	42,076	42,108	12,386	A technique to find an optimal alignment between two given sequences[40]
Probability density function	Wasserstein	0.01	0.01	0.01	0.01	Measures the minimal effort required to reconfigure the probability mass of one distribution in order to recover the other distribution[41]
	Bhattacharyya	0.08	0.58	0.08	0.09	Based on the Bhattacharyya coefficient that

[39] B. Aronov, S. Har-Peled, C. Knauer, Y. Wang und C. Wenk, „Fréchet Distance for Curves, Revisited," in *Algorithms - ESA 2006*, Berlin, Heidelberg, Springer, 2006, pp. 52-63.
[40] M. Müller, „Dynamic Time Warping," in *Information Retrieval for Music and Motion*, Berlin, Heidelberg, Springer Berlin Heidelberg, 2007, pp. 69-84.
[41] Panaretos, V. M. und Y. Zemel, „Statistical Aspects of Wasserstein Distances," *Annual Review of Statistics and Its Application,* pp. 405-431, 2019.

						measures the overlap of two samples[42]

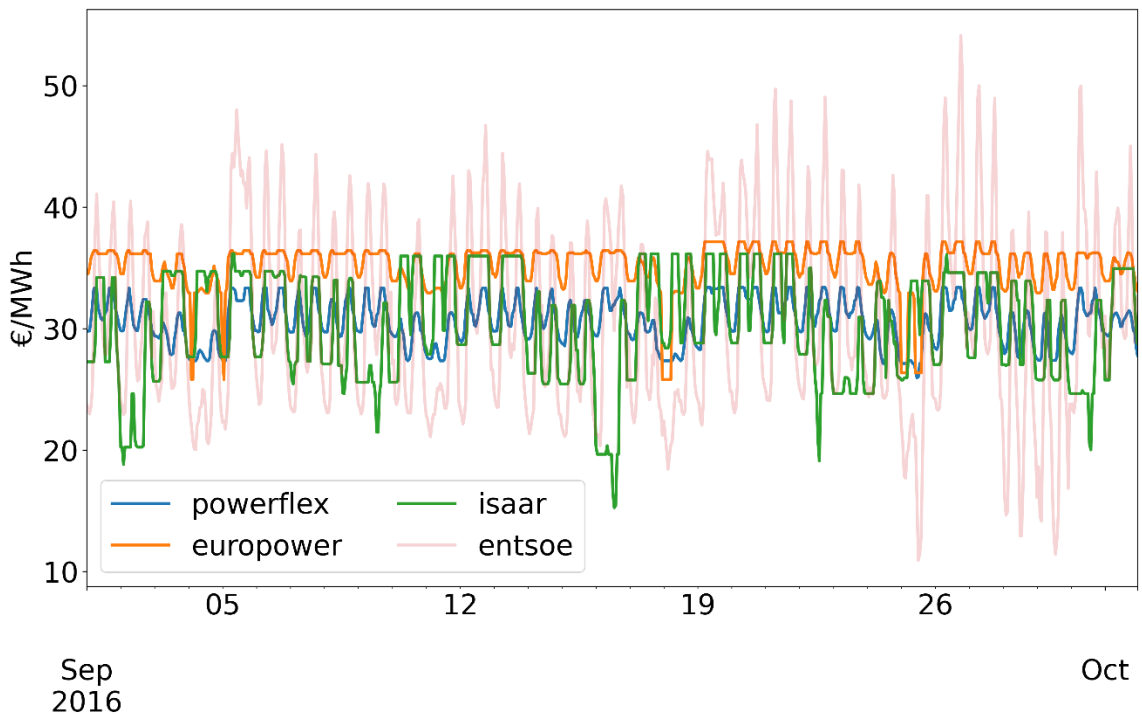


Figure 9. *Electricity prices for Germany in September for the models PowerFlex, ISAaR and Europower as well as ENTSO-E.*

Comparing PDFs instead of the time series directly, additionally holds the advantage of capturing a more average behavior that can be more robust to rare but high differences in the time series or to the modeling of VRES production. As it was shown earlier using reduction operators, even average results can differ substantially and may pose difficulties in comparing models. Hence, analyzing in higher detail is unlikely to provide more useful information for the models. Comparing PDFs constitutes a recommended compromise between analyzing time series in detail and their usefulness for understanding.

Figure 10 shows the PDFs of the three selected time series as well as ENTSO-E. **PowerFlex** and **ISAaR** are closer on average, however **PowerFlex** and **Europower** have a more similar PDF shape. One of the most intuitive methods to quantify that consists of the Bhattacharyya distance applied on the normalized curves, a metric which is based on measuring the curves overlap.

[42] F. J. Aherne, N. A. Thacker und P. I. Rockett, „The Bhattacharyya metric as an absolute similarity measure for frequency coded data," *Kybernetika,* pp. 363-368, 1998.

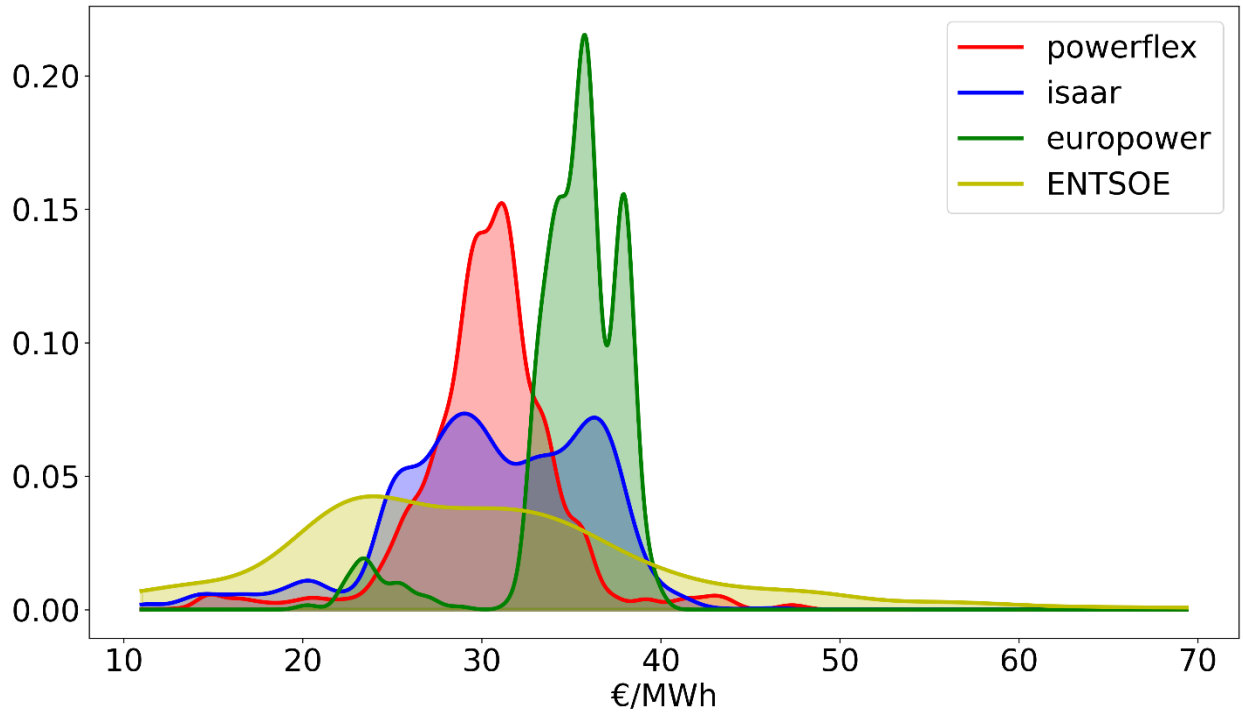


Figure 10. Probability density function for the electricity prices of Germany for the models PowerFlex, ISAaR and Europower as well ENTSO-E.

Reduction method 4: Spatial reduction

Finally, one of the most intuitive methods to reduce data consists of spatial reduction, i.e., focusing on a single region to compare a selected market result. Although seemingly simplistic, it can provide significant insight to the behavior of models, especially when the number of regions is low or when there are critical regions whose behavior can reveal important information about the models overall. Moreover, the reduced data set can be more easily visualized and analyzed in detail. For instance, in the context of the European electricity market, where each region corresponds to a market zone, focusing on a country with an energy mix dominated by only few technologies can reveal information about the modeling of the corresponding technologies. Investigating Germany may also constitute an interesting region, since its high consumption and diversity in production technologies can provide useful insight in how models work. In addition, it is the region with the highest number of neighbors, hence an indicator for comparing the modeling of power exchanges as well. Figure 11 shows the 7-day average of CO_2 emissions in Germany for 2016. There are noticeable differences in average behavior, however most of them show a drop during summer months.

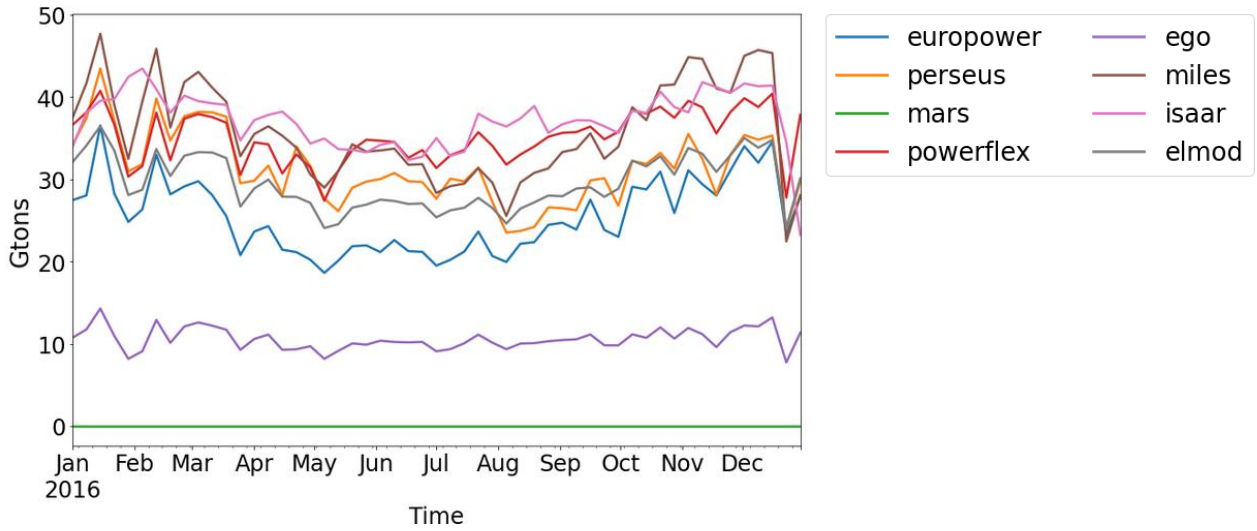


Figure 11. ***Seven-day average of CO_2 emissions of the German power sector for the year 2016.***

2.1.4 Grid simulations

During the MODEX-NET project, the model formulations of grid simulations used by every partner were compared. The model aspects include power flow calculation, treatment of congestions on cross-border lines, time-coupling, dynamic line-rating, feasibility features, remedial actions, merit-order of technologies, optimization methods, and outage representation. The following summarizes the distribution of the used model formulations.

Power flow calculation

Power flow calculations determine the system state based on the given power feed-in and load situation. As Figure 12 shows, one half of the participating models use a DC power flow calculation while the other half uses an AC power flow calculation. While an AC power flow calculation leads to the exact system state, DC power flow calculations are often used as a fast approximation, when the focus lies on active power flow. Since some institutes perform an AC load flow after optimization with a Security Constrained Optimal Power Flow (or SCOPF) with DC formulation, e.g., to be able to determine power flow losses, the share of AC load flow calculation is slightly higher.

Congestions on cross-border lines

The treatment of congestions on cross-border lines lies equally in the responsibility of the affected TSO. Often, only the specific processes of a few TSOs are modeled and arrangements between TSOs are not considered during the handling of congestions on cross-border lines. Therefore, either cross-border redispatch is modeled with high penalty costs or cross-border lines are neglected completely to ensure that unintentional retroactive impacts on national redispatch is prevented. A wide majority of institutes (88%) uses a model formulation with cross-border redispatch as Figure 12 illustrates.

Time-coupling

Operational restrictions of power plants and the limited capacity of energy storages leads to a time-dependent behavior of their utilization during grid simulation. Since these restrictions greatly affect simulation times, they are often neglected. As Figure 12 depicts, a majority (88%) of the institutes are able to model the restrictions. However, their use depends on the additional simulation time requirements of the different models.

Dynamic line-rating

Dynamic line-rating uses cooling weather conditions to enhance line-loading capabilities of overhead lines during grid operation. Unused capabilities can be exploited since data sheets of overhead lines use worst-case assumptions for weather conditions. While, as Figure 12 shows, 25% of the participating institutes are able to model dynamic line-rating, the discussions during the project showed that dynamic line-rating would become an increasingly important feature for power grid models.

Feasibility feature

Especially for problems of grid planning, simulated scenarios are often not congestion-free after optimization. Nevertheless, in order to guarantee the solvability of the optimization problem at any time, soft constraints are usually introduced. As Figure 12 depicts, the majority of participating institutes (75%) uses soft constraints in their grid simulations. Furthermore, many partners introduced soft constraints as an improvement of their grid simulation during the MODEX-NET project.

Remedial actions

Network and market related remedial actions are used during grid simulations to overcome congestions. Especially network-related remedial actions such as phase-shifting transformers of flexible AC transmission systems require additional modelling. Currently, a quarter of the participating institutes includes these assets in their grid simulations, as seen in Figure 12.

Merit-order of technologies

Remedial actions used to relieve congestions underlie regulatory restrictions that specify a prioritized deployment of certain measure over others. These prioritizations do not necessarily align with the costs of the remedial actions. As seen in Figure 12, 75% of the partners use penalty costs to address regulatory restrictions while the rest uses a sequential optimization algorithm with separate optimization steps.

Optimization method

The optimization problem of grid simulations that relieve grid congestions is based on the nonlinear power flow equations. Multiple optimization algorithms have been applied to the problem ranging from linearized and square approximated formulations to heuristic approaches. Since analytical formulations, especially linearized formulations are fast to solve and most often sufficiently accurate all partners use linearized analytical formulations. As Figure 12 illustrates, 37% use an AC formulation and 63% a faster, but less accurate DC formulation.

Outage representation

To ensure grid safety in the fault-free system state as well as in every relevant outage situation, the grid simulation needs to identify the impact of all relevant outage situations on the operational limits. This can be done by iterative power flow calculations, approximations (e.g., linearized) of the system state in the outage situation or by using flat-rate safety margins. Especially the flat-rate safety margins can reduce the simulation time significantly however at the cost of detailed knowledge about every single outage situation. Therefore, the majority (75%) of the participating institutes use flat-rate safety margins as shown in Figure 12. The rest of the models make use of the more detailed approach based on linearized approximations.

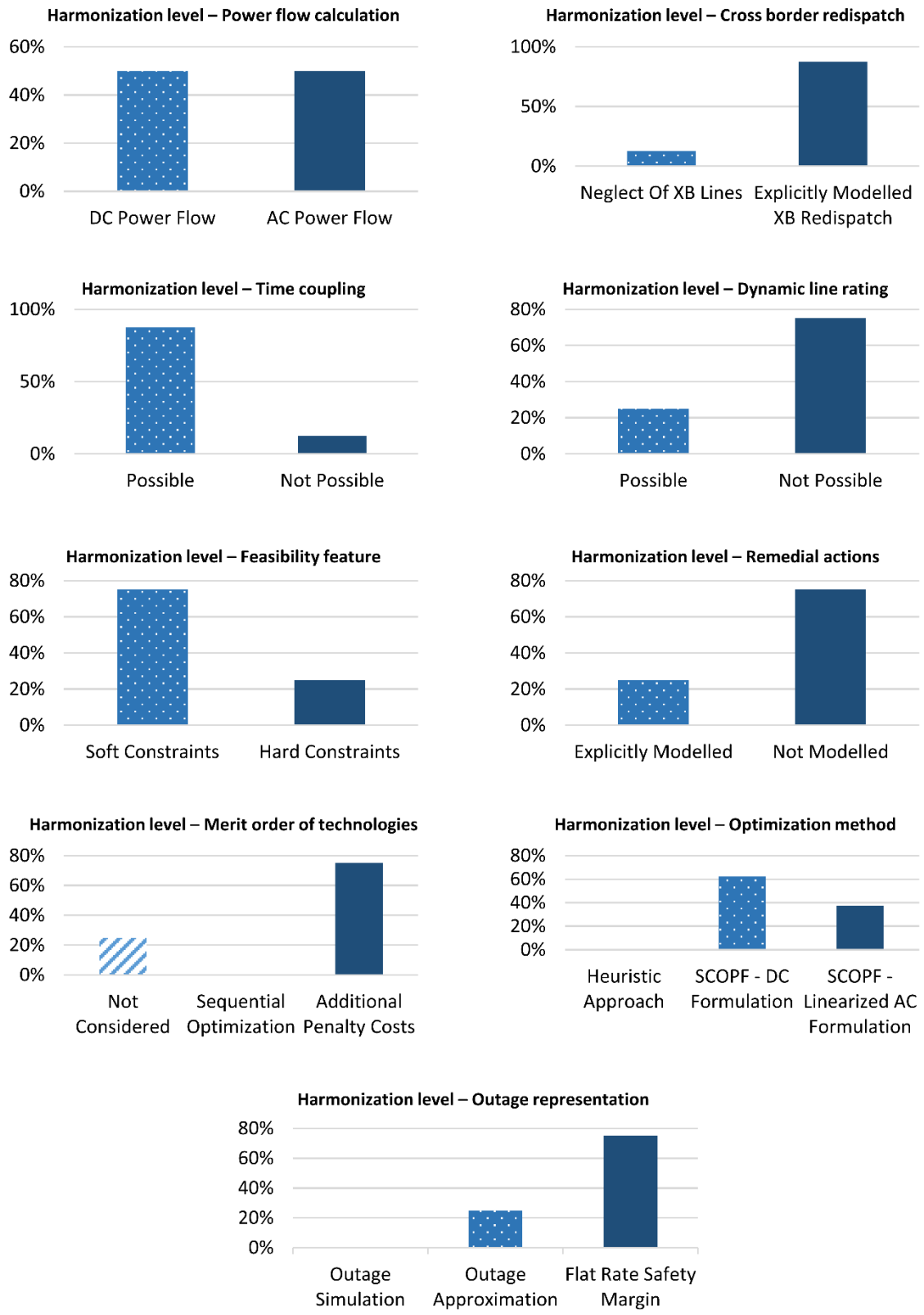


Figure 12. *Overview of the harmonization level of different model formulations*

Presentation of partner specific results for scenario 2016

In the following, the results of the project partners grid simulations are shown and discussed based on the scenario for 2016. For the evaluation, a harmonized visualization of key parameters of the model results for the year 2016 is used. The harmonized visualization includes the distributed amount of positive and negative redispatch as well as curtailment, the annually cumulated number of days overloads occur per line, the annually summed congestion work[43] per line and the annually maximum overload per line. Figure 13 shows an example of the used visualization of those key parameters on a map of Germany.

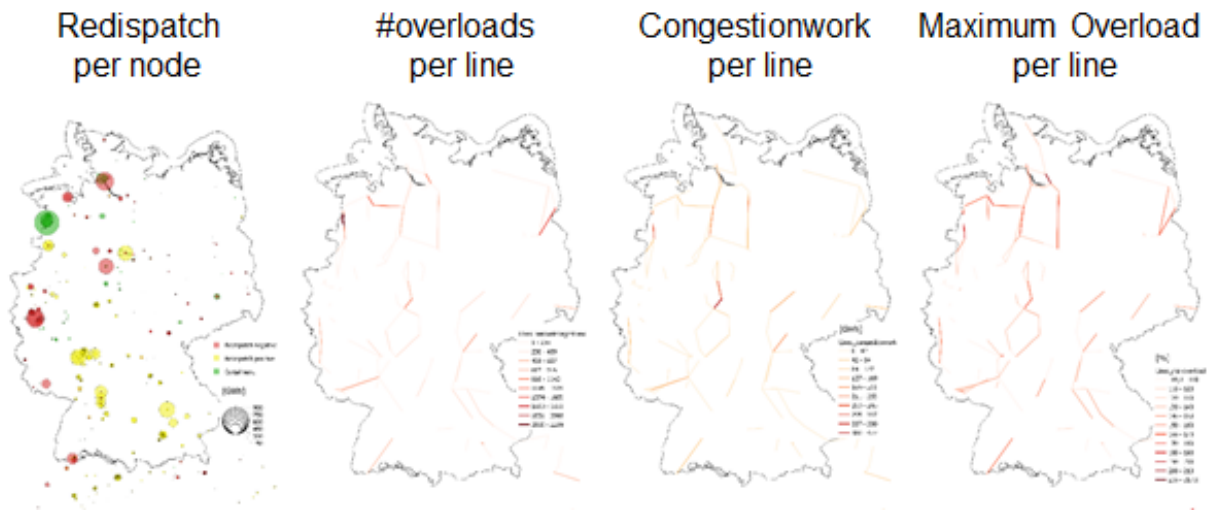


Figure 13. ***Example of the harmonized visualization of the key parameters***

The visualization of the line key-parameters provides an indication about where and with which intensity congestions occur during the year. Based on these graphs, the visualization of the remedial actions allows for drawing conclusions about the geographical distribution of congestions in combination with the subsequent remedial actions.

Additionally, Figure 14 shows an example of the visualization of the fractions of positive redispatch[44], negative redispatch, and curtailment as a result of the total amount of remedial actions.

[43] (loading above line limits in MW – line limits in MW) 1h

[44] Redispatch describes curing congestion on a transmission line by reducing the generation of a power plant in front of the congested line (negative redispatch) and increasing the generation of a power plant behind the congested line (positive redispatch). Chychykina, I., Klabunde, C., & Wolter, M. (2017). *Comparison of different redispatch optimization strategies* (pp. 1-6). IEEE.

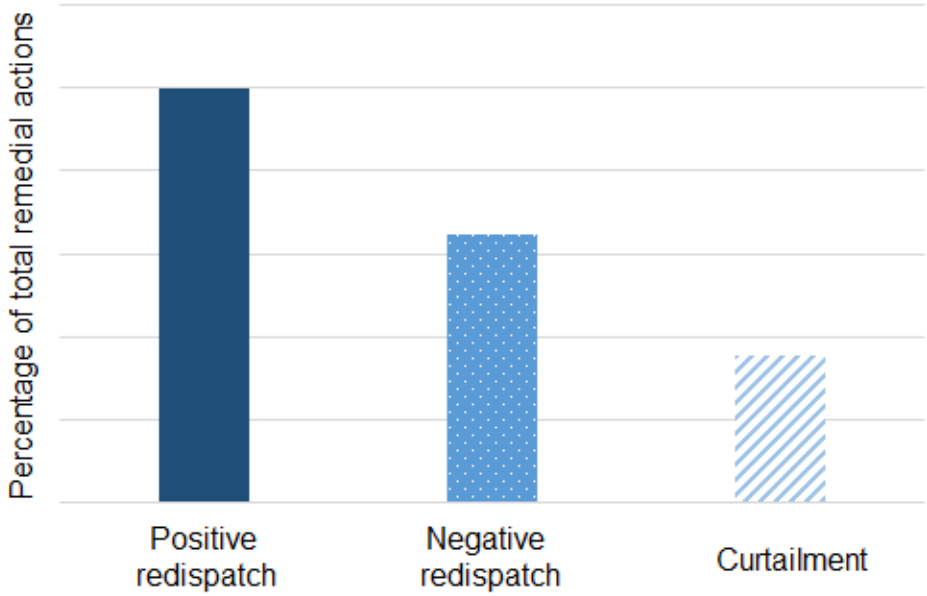


Figure 14. *Example of the harmonized visualization of the amount of remedial actions*

ZKNOT:

The harmonized results for the **ZKNOT** model are shown in Figure 15. The results show that most of the dominating congestions occur in the middle of Germany starting from the northwest towards the southeast. The congestions in the middle and north of Germany show high congestion work in combination with a high number of hours where overloads occur. In single hours these congestions also show high line utilizations. Congestions also occur in the south and east but show little congestion work compared to the congestions in the north and middle. Therefore, these congestions most possibly occur with a high overload in single hours or with little overload in multiple hours.

Especially the congestions in the northwest of Germany lead to significant amounts of necessary curtailment since little potential for negative redispatch is available in this area. The available potential for negative redispatch available in the north of Germany is used to cure congestions in the immediate north. Positive redispatch is used in the south of Germany, but also in the middle and west of Germany where negative redispatch potential or curtailment potential is available as immediate counter- measures.

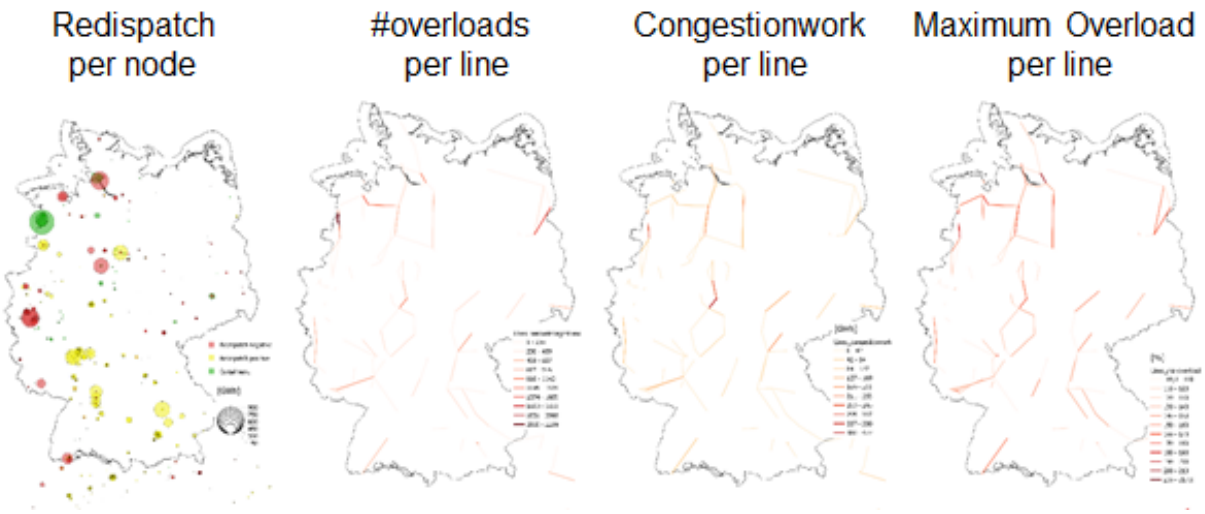


Figure 15. *ZKNOT – harmonized visualization of key parameters*

The fractions of positive redispatch, negative redispatch and curtailment in relation to the total amount of remedial actions is displayed in Figure 16. Since the positive redispatch needs negative redispatch or curtailment as counter measures, it sums up to 50% of the total amount of remedial actions. The relatively high amount of curtailment of 17.755% occurs due to the lack of positive redispatch potential in the northwest of Germany where remedial actions are necessary.

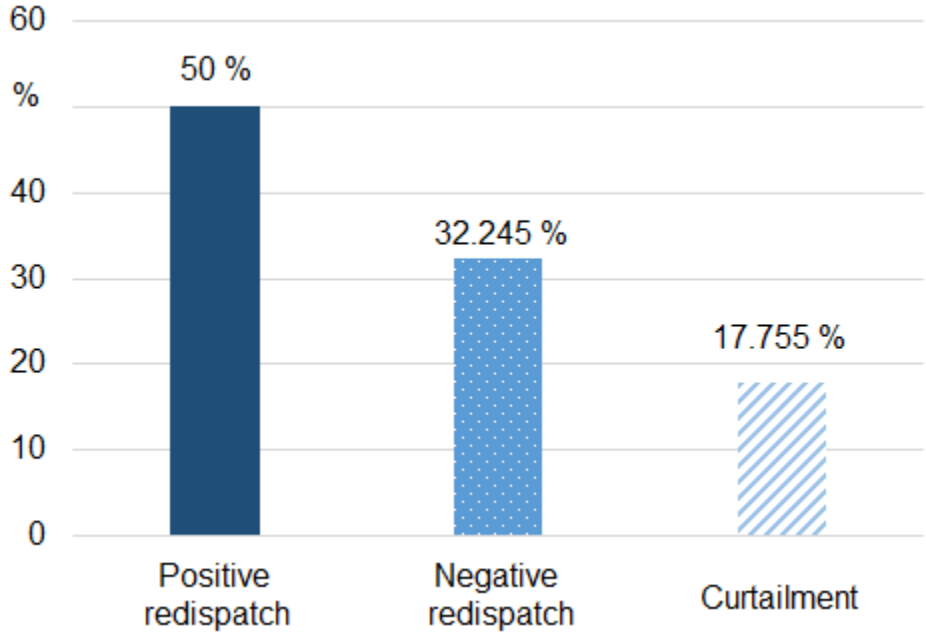


Figure 16. *ZKNOT – harmonized visualization of the amount of remedial actions*

ELMOD:

Figure 17 depicts the harmonized grid results for **ELMOD**. The visual results show that the majority of remedial actions occur in border regions. In the north and west of Germany, curtailment and negative redispatch are predominant. Positive redispatch occurs to a large extent on Germany's eastern border with Poland and in the south. Overloads are mostly occurring in northern regions. Where high feed-in of wind energy is observed at certain times, individual lines are overloaded for most of the year. A closer look at the overloads also shows that lines transporting electricity from the north and west to the south are frequently affected by these congestions. This is resulting in higher negative redispatch and curtailment whereas power plants in the south participate in positive redispatch.

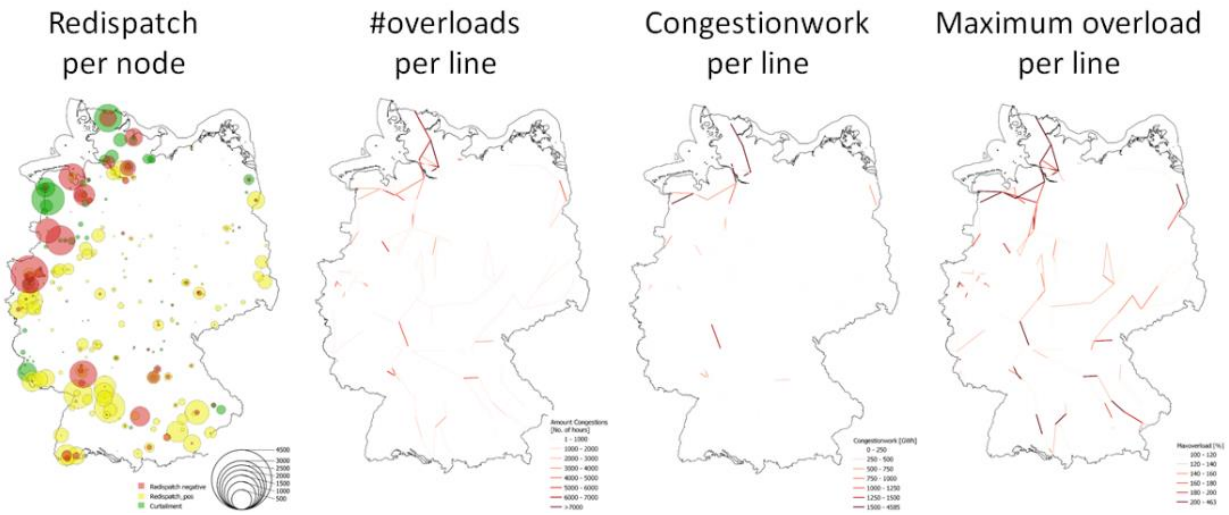


Figure 17. ***ELMOD – harmonized visualization of key parameters***

The distribution of the amounts of different remedial actions are shown in Figure 18. Since the positive redispatch always needs a counterpart of power plants that are shut down in other regions, negative redispatch and curtailment adds up to nearly 50%. However, since **ELMOD** also includes foreign power plants to eliminate domestic bottlenecks, the figures for only German nodes do not add up exactly.

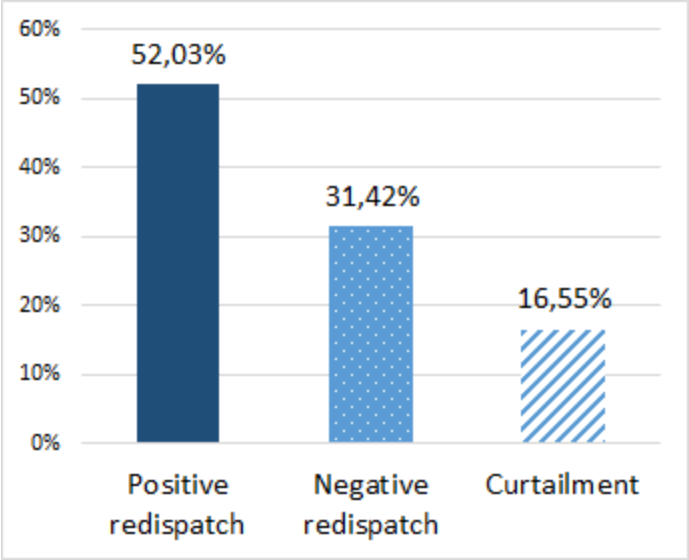


Figure 18. *ELMOD – harmonized visualization of the amount of remedial actions*

MILES:

The harmonized results for the model **MILES** are shown in Figure 19. The results show that most of the dominating congestions occur along wide-ranging transmission corridors. On the one hand, a corridor from the area near Hamburg to the middle of Germany is facing large amounts of congestion work. On the other hand, several areas near cross-border lines as well as areas near offshore connection points are facing overloads as well. For example, the interconnectors between Germany and Denmark, Germany and Poland as well as the lines between Germany and Austria show high congestion work. The congestions near the German borders show high congestion work in contrast to internal lines. This situation defines the overall congestion pattern resulting in large amounts of curtailment in the north of Germany especially near the coast. To compensate these large amounts of curtailment positive redispatch takes place in the south of Germany, as energy cannot be transported due to wide ranging congestions in the middle of Germany.

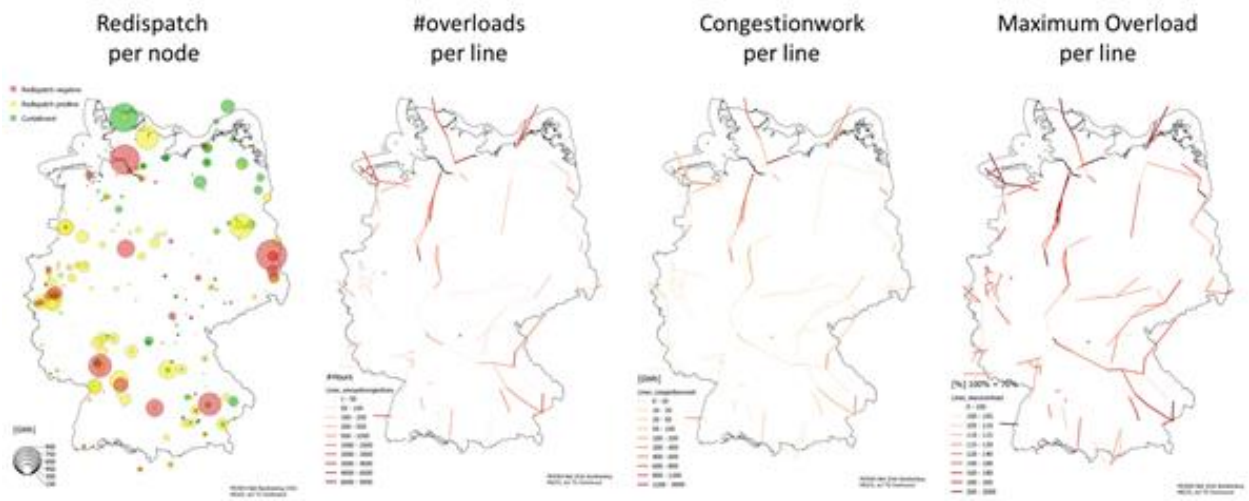


Figure 19. *MILES – harmonized visualization of key parameters*

The fractions of positive redispatch, negative redispatch and curtailment in relation to the total amount of remedial actions is displayed in Figure 20. Since the positive redispatch needs negative redispatch or curtailment as counter measures, it nearly sums up to 50% of the total amount of remedial actions. However, roughly one percent of the remedial actions is covered by dummy generation and load, as the available redispatch potentials are not sufficient in a very few hours of the year. The relatively high amount of curtailment (19%) occurs due to challenges with the integration of large amounts of wind energy in the north of Germany as well as overloaded transmission corridors ranging from the middle of Germany to the German Austrian border.

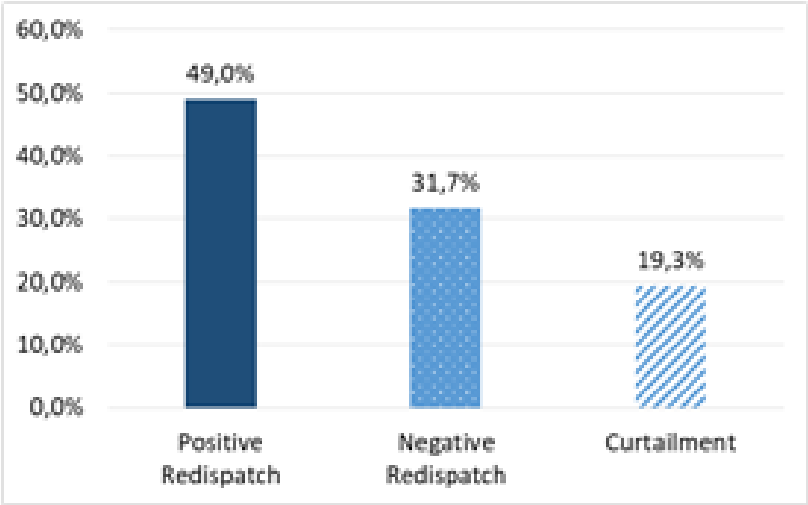


Figure 20. *MILES – harmonized visualization of the amount of remedial actions*

Europower:

The indicators for the **Europower** model for 2016 are shown in Figure 21 and Figure 22. Regarding congestion, the grid is not heavily congested besides specific regions, which are primarily located in the

north and south. For instance, high frequency of overloads and congestion work can be observed from the north to the middle of Germany, as well as congestion in the state of Bayern, towards the border with Austria. Moreover, a number of very short lines can be highly congested. This can be interpreted as a reflection of modeling inaccuracies in developing the grid topology, which may deviate from reality.

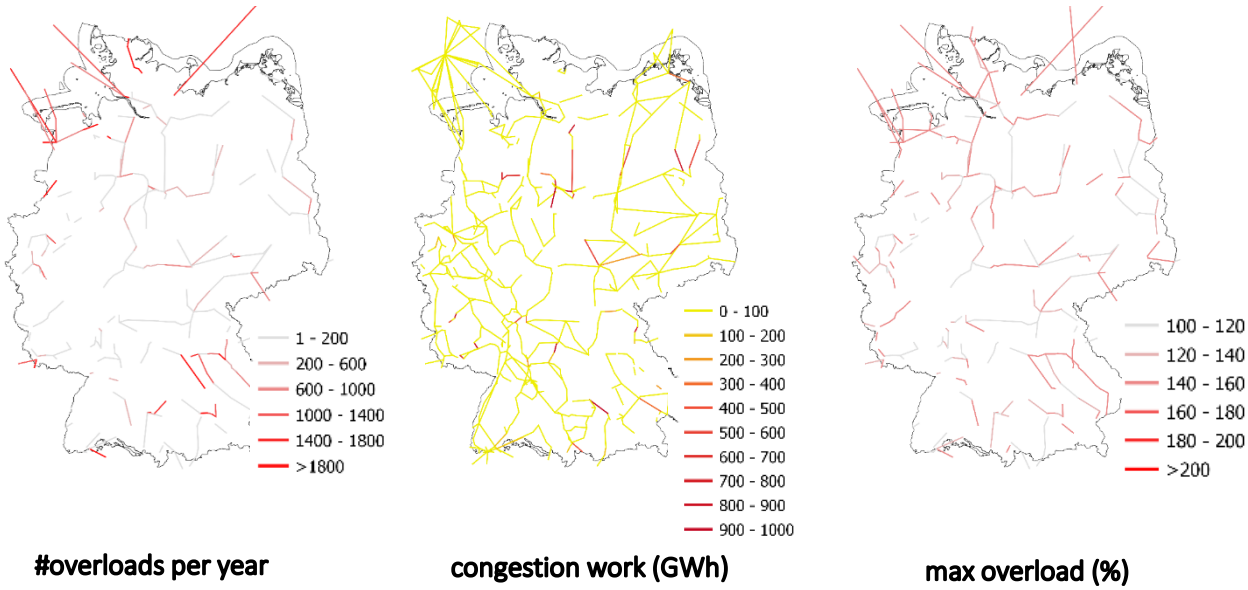
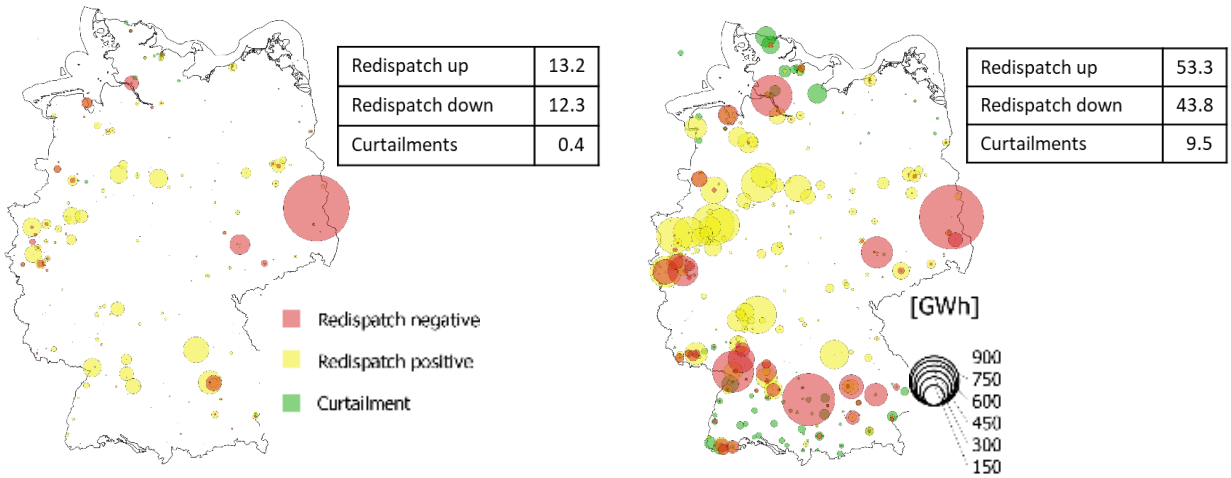


Figure 21. *Europower - Congestion indicators for the europower model for 2016.*

The remarks about grid congestion can also be seen in Figure 22, depicting redispatch indicators. On the left picture redispatch is performed simultaneously to the whole European grid, allowing free cross-border exchanges with the same redispatch costs. It can be observed that negative redispatch is primarily located in the north and central East parts, with a specific lignite plant experiencing high downscaling. Curtailments are barely present due to the high flexibility assumed for all power plants and the prioritization of all other sources before reducing renewable production. Positive redispatch is mostly observed in the central West and south parts of the country, which can resolve the congestion shown inFigure 21. It can also be seen that in many cases positive and negative redispatch values are concentrated in high proximity to each other, which can be explained by the deviations in the topology modeling and the assignment of power plants to the grid nodes. This may also partly explain the relatively high amounts of total redispatch values shown in the table. The right picture in Figure 22 shows the results for the pan-European redispatch case, where additional constraints can be introduced such that enforce net balance of redispatch within each country. This method was developed for the purposes of this project; however, its development was halted due to the significant distortion of the redispatch distribution, especially near borders, and the high total redispatch values.



(a) Pan-European (b) Pan-European redispatch with country constraints

Figure 22. ***Europower - Redispatch indicators for the europower model for 2016. The left picture corresponds to the simultaneous redispatch across Europe including cross border exchanges, whereas the right picture corresponds to the same settings with additional constraints requiring net balance for each country. The total numbers are in TWh.***

eTraGo:

The redispatch and line loading plots for the harmonized 2016 scenario for the **eTraGo** model are shown in Figure 23. One observes an almost neglectable congestion work through the whole grid. The highly congested lines concentrate near industrial areas or big cities in the west. The small length of the congested lines, in comparison with the other models, is explained by the fact that the **eTraGo** is a model with a high resolution extra high voltage grid, with almost no modelling simplification. For instance, the **eTraGo** model has almost 5000 lines, while most of the other models are far under 1000. These few congested lines seem to be highly congested, but just those on the Rhine-Ruhr area have a high number of overloaded hours. Apart from that, there is also some congestion in the north, mainly related to regions with high wind onshore and wind offshore capacity. This causes some curtailment as a remedial action.

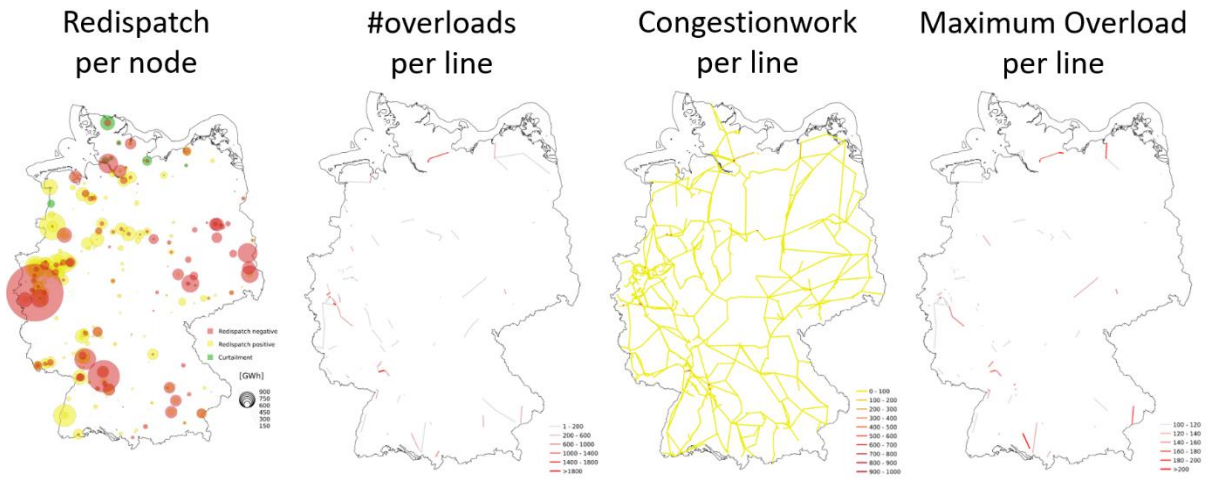


Figure 23. ***eTraGo – harmonized visualization of redispatch and line loading key parameters for the 2016 scenario***

Looking at the relative amount of the remedial actions in Figure 24, one observes that almost not curtailment is used. This is explained, on the one hand, by the fact that the harmonized values for the availability of the renewable energy sources were considered after curtailment and, on the other hand, that the overloading is small, hence it can be resolved by the current grid. If the overloading was bigger and had to be resolved locally, then the curtailment would increase, because there are fewer alternatives for negative redispatch in the northern regions, where there is a big wind installed capacity. In Figure 23, it can be seen that most positive redispatch is happening in the west, close to the border. This could be a consequence of limited border capacities harmonized for these computations, that limit the energy export, specially from France. Negative redispatch on the other hand is more widely distributed, with a big concentration in the Rhine-Ruhr area near the city of Cologne, but also in the region of Stuttgart in the south, Cottbus in the east, and Hamburg in the north.

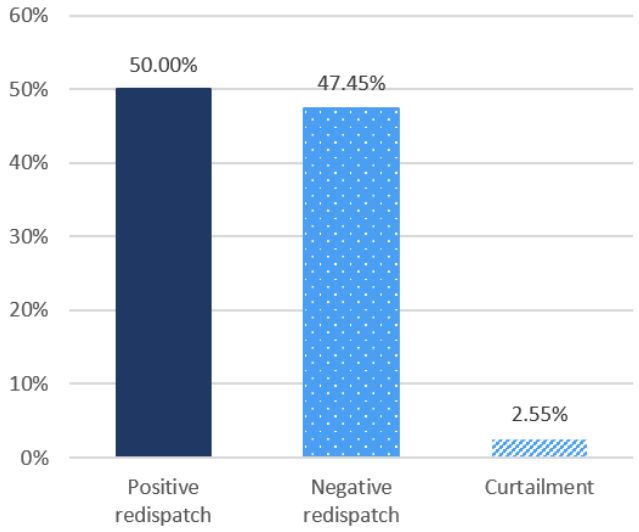


Figure 24. *eTraGo – harmonized visualization of the amount of remedial actions for the 2016 scenario*

PERSEUS:

The results from the grid simulation with harmonized input data for the year 2016 from the **PERSEUS** model are shown in Figure 25. Overloads and congestion work are mainly occurring on a transmission corridor from the Danish border southwards and on lines from the northwestern part of lower Saxony towards the south, where large amounts of electricity from onshore wind and offshore grid connections have to be transported as well as on the circuit Redwitz-Rempendorf in the south-east. This is visible on lines where the redispatch and curtailment measures are applied. Curtailment and negative redispatch occur for the most part northwards of these bottlenecks, i.e., close to the northern sea to relieve the congested lines in the north-western part of Germany and north of Rempendorf within some proximity to the congested circuit. The other congestions are distributed across the middle of Germany and in two corridors towards the southern neighbors. For positive redispatch, mainly plants in southern Germany and even in Switzerland and Austria are used, with another cluster in western Germany in closer proximity to the congested lines in the north-west. A congestion south from Pasewalk is used by curtailment due to a limited thermal capacity in the north (east).

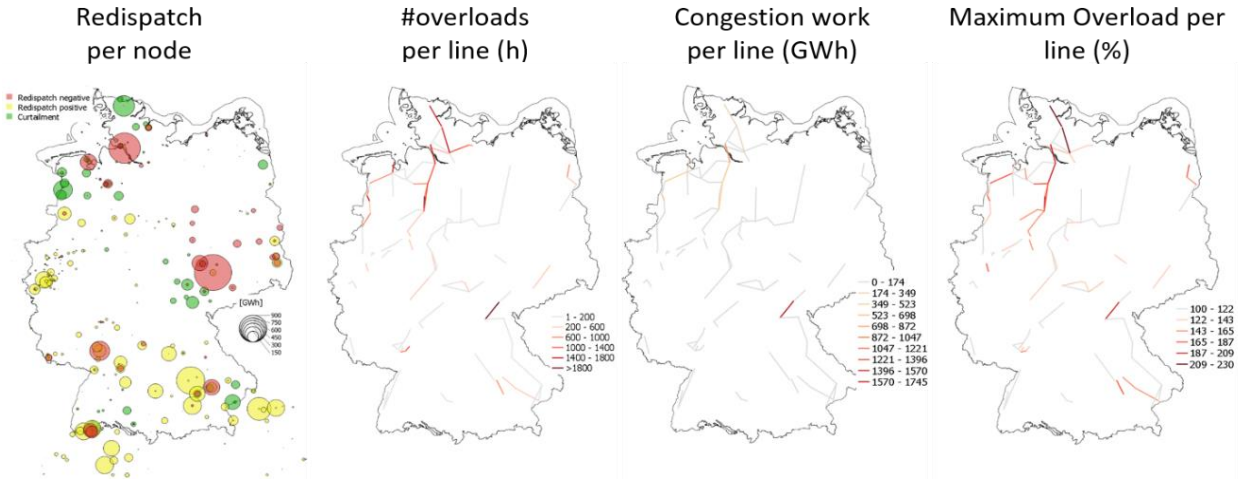


Figure 25. *PERSEUS - Congestion indicators for the harmonized grid simulation 2016 for the PERSEUS model.*

The shares across positive redispatch including grid reserve, negative redispatch and curtailment of renewable energies for the harmonized model run are shown in Figure 26. Losses are neglected in this simulation, so the electricity demand remains unchanged even in the different operational situations and hence the positive redispatch amounts to the sum of curtailment and negative redispatch. Different penalty costs are used for curtailment of renewable energies and negative redispatch, to represent the regulatory requirement, that renewable infeed must be prioritized resulting in a curtailment share of roughly 40% of reduced dispatch or roughly 20% of total remedial actions. In total redispatch (positive and negative) and curtailment of 19,06 TWh are used by the **PERSEUS** model for congestion management in the harmonized model run.

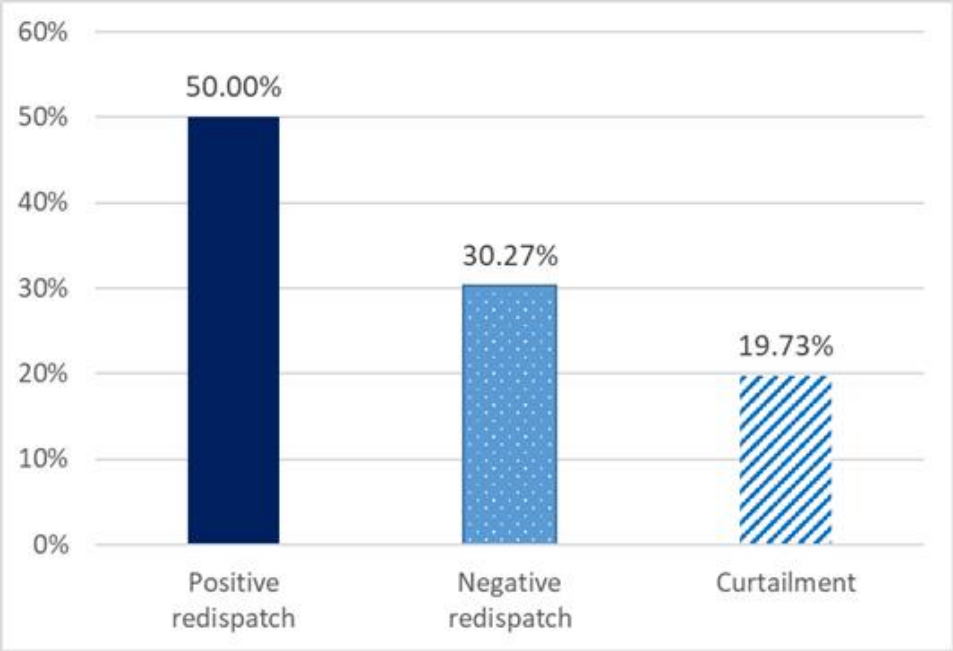


Figure 26. ***PERSEUS – harmonized visualization of the amount of remedial actions for the 2016 scenario.***

PowerFlex:

The results from the grid simulation with harmonized input data for the year 2016 from the **PowerFlex** model are shown in Figure 27. Overloads and congestion work are mainly occuring on transmission corridors from north to south, like for example from Lower Saxony to North Rhine-Westphalia as well as from Lower Saxony to Hesse and Baden-Wuerttemberg. Furthermore, transmission corridors from east to south, like for example from Saxony and Saxony-Anhalt to Baden-Wuerttemberg and Bavaria. This also includes the circuit Röhrsdorf-Remptendorf-Weida in the south-east.

Negative redispatch occur for the most part northwards of these bottlenecks, like for example concerning electricity import from Denmark or coal fired power plants in Hamburg or Rostock. Curtailment of wind energy mainly occurs in the area of Brunsbüttel. For positive redispatch, mainly power plants in western and southern Germany are used. Pump storage powerplants are used for positive as well as negative redispatch, for example in the southern part of the black forest or in the thuringian forest.

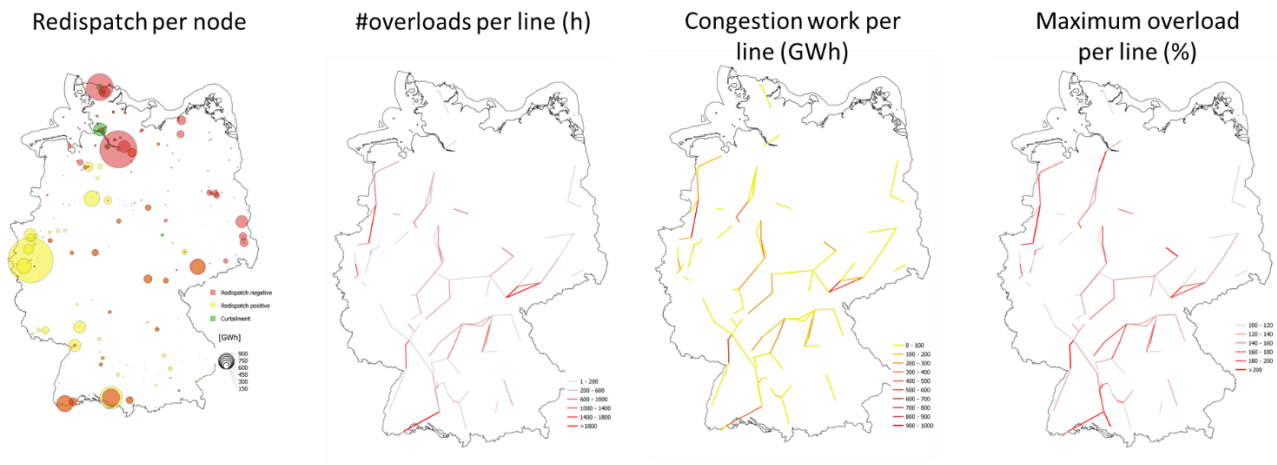


Figure 27. ***PowerFlex - Congestion indicators for the harmonized grid simulation 2016 for the PowerFlex model.***

The shares across positive redispatch including grid reserve, negative redispatch and curtailment of renewable energies for the harmonized model run are shown in Figure 28Figure 28. Losses are neglected in this simulation, so the electricity demand remains unchanged even in the different operational situations and hence the positive redispatch amounts to the sum of curtailment and negative redispatch. Different penalty costs are used for curtailment of renewable energies and negative redispatch, to represent the regulatory requirement, that renewable infeed must be prioritized resulting in a curtailment share of roughly 20% of reduced dispatch or roughly 10% of total remedial actions. In total redispatch (positive and negative) and curtailment of 35 TWh are used by the **PowerFlex** model for congestion management in the harmonized model run.

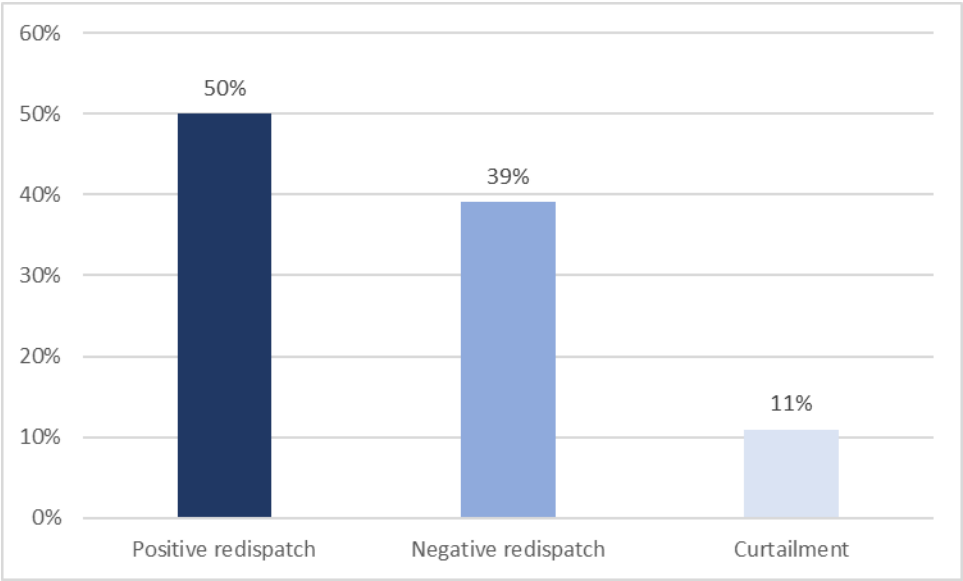


Figure 28. ***PowerFlex – harmonized visualization of the amount of remedial actions for the 2016 scenario.***

ISAaR:

The harmonized results for the model **ISAaR** are shown in Figure 29. Note that these results differ from other results, as the weather year is 2012 with more occurrence of wind. The results show most of the curtailment and negative redispatch occurs in the Northwest of Germany and in the Lausitz region, whereas positive redispatch is required in the Middle west and South. Regarding the congested lines, one can note overloadings in the Northwest and on the way southwards. Furthermore, there occur congestions in the Ruhr area, the Lausitz area, and in the Southeast near the border to Austria.

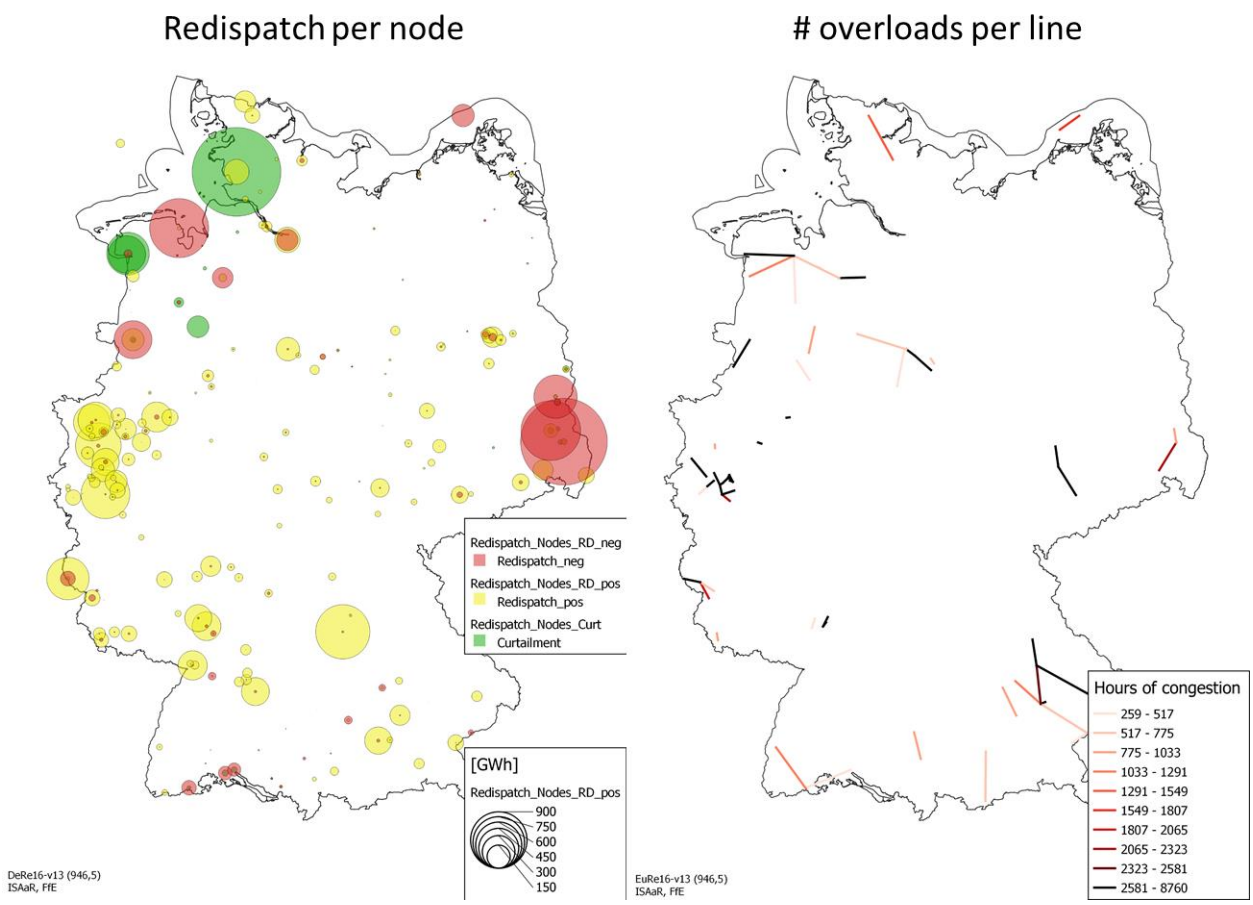


Figure 29. ***ISAaR – harmonized visualization of key parameters***

The fractions of positive redispatch, negative redispatch and curtailment in relation to the total amount of remedial actions is displayed in Figure 30. Where possible, power plant power is reduced (negative redispatch), but for 12% of remedial actions, curtailment of renewables is required to relieve the transmission grid.

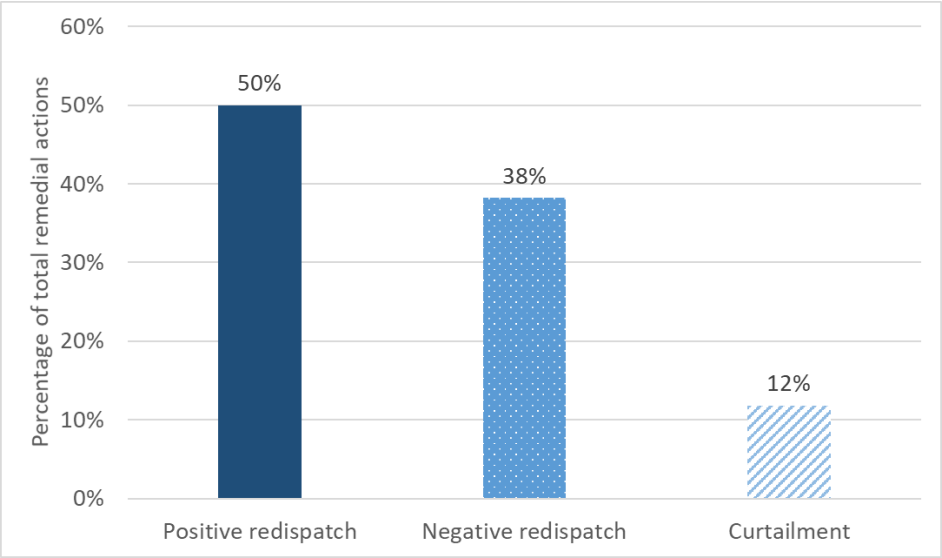


Figure 30. ***ISAaR – harmonized visualization of the amount of remedial actions***

As described above the grid simulations were conducted in WP3. The main objectives of this WP were to harmonize grid modeling aspects for both, the market and the grid simulations to design experiments for the comparison of congestion management methods. In a first step, the grid simulations were conducted for the years 2016 and 2030 by each partner individually. Therefore, each partner used the harmonization for market simulation and regionalization to compute the input data for their grid simulation. Additionally, the grid models were harmonized as much as possible. For all harmonized models the model with the most degree of freedom that all partners have implemented was used. For example, all partners used flat-rate line constraints to model outage situations. However, especially optimization algorithms and load flow calculations were deeply connected with each partner's grid simulation and not harmonizable. For the simulations of 2030 two different scenarios, a progressing HVDC expansion and a delayed HVDC expansion, were created in accordance with all partners and investigated. For the simulation of the progressive expansion of HVDC lines, the assumption was made, that all the HVDC lines were completed on time and put into operation as planned in the TYNDP. In the second scenario for 2030 the simulations were run under the assumption that 5 HVDC lines cannot be put into operation on time.

As described above, the regionalization as well as the harmonization of the grid models turned out to be very challenging. Since the grid simulations showed inherent differences in the way of certain models, we focused on simulation results on model variations. By systematizing model results through the use of standardized benchmark indicators and graphic illustrations on redispatch volumes (positive and negative redispatch and curtailment) as well as maximal line overloadings, number of congestions and the total sum of congestionwork, the models could be tested for conclusive functionality efficiently. Nevertheless, comparing these indicators without taking into account partner specific model characteristics and regionalization methods can lead to wrong interpretations and simply made it impossible to meaningfully compare the numbers of the model results with each other. Therefore, we decided not to compare single values but instead comparing the impact of model parametrization and formulation on the explorative power of electricity network congestion management models. Each partner conducted different

calculations, for example by using soft or hard constraints or by using different ways of how to model cross-border congestions. We then used these learnings to formulate general take aways on the impact of model parametrization and formulation, that support the grid modelling community in academia and industry in efficiently simulating congestion management.

Case Study I – flat-rate line constraints

Congestions are defined as violations of the (n-1)-security criterion. To determine the safety margin needed to ensure grid security in every (n-1)-situation models with differing degrees of detail are used throughout grid simulations. The most accurate, but also most time demanding model usable is the calculation of load flows for every separate outage situation to determine the exact impact of each outage situation on the line loadings. These results are then used to calculate a safety margin for the (n-0)-situation so that no overloading will occur during any outage situation. A less time demanding, but less accurate is the model of outage approximation, where the impact of outage situations is predicted through, in most of the cases, linear approximations. An even less time demanding model is the use of flat-rate line constraints. This model does not calculate the impact of each outage situation but uses the same flat-rate line constraint as safety margin for each line.

In this project a case study is executed, comparing one scenario with a detailed (n-1) outage approximation and four scenarios with different parametrizations of the safety margin of flat-rate line constraints. The flat-rate margins are incrementally varied between 65% and 80% of the maximum line loadings in 5% steps.

The cumulated congestion work per line before congestion management for all scenarios is shown in Figure 31. The results show that the main congestions occur in all scenarios in the northwest and center of Germany. However, differences can be seen in the west, east and north of Germany. Especially the heavily mashed western region shows congestions in the scenarios with flat-rate line constraints, but not in the scenario with the detailed outage approximation.

The comparison of the four scenarios with flat-rate line constraints shows that the regional distribution of congestions does not change with different parametrizations of the safety margin. However, an increase in safety margin leads to an increase in congestion work since lower line loadings are treated as congestions. For the same reason single lines to not show congestions anymore when the safety margin is decreased. The congestions remaining with a low safety margin are the dominating congestions that will also mainly influence the necessary volumes of remedial actions and their geographic distribution.

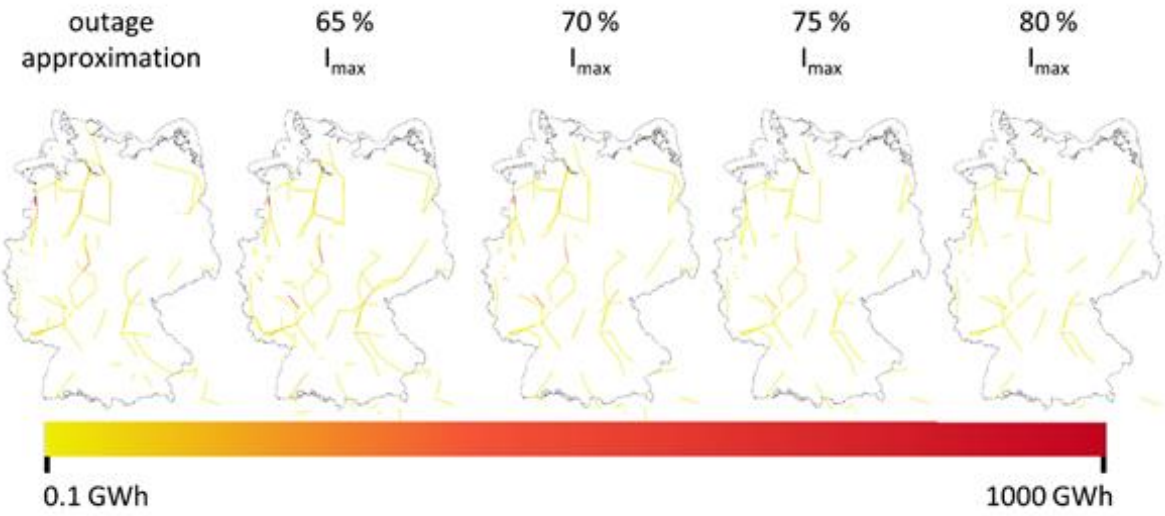


Figure 31. ***Outage sensitivity - Cumulative annual congestion columes per line before congestion management***

The geographical distribution of remedial actions per scenario are shown in Figure 32. Since the scenario with outage approximation shows a different geographical distribution of congestions, the geographical distribution of remedial actions also differs from the other scenarios. The scenarios with flat-rate line constraints show the same geographical distribution of remedial actions. However, with an increase in safety margin the volume of remedial actions increases as well. Because the main congestions in the northwest and center of Germany are represented in all scenarios, a north-south coordination of remedial actions is necessary in all scenarios.

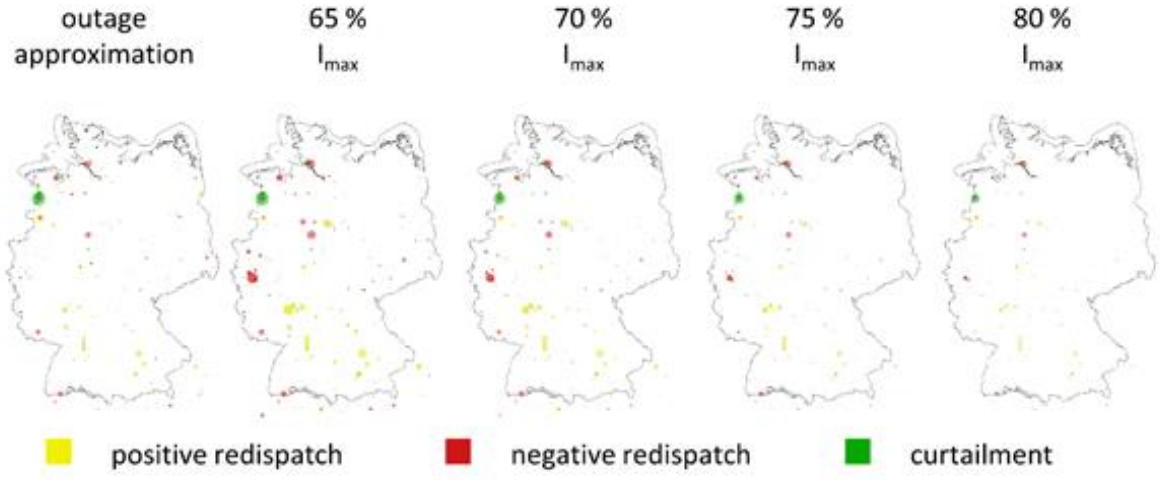


Figure 32. ***Outage sensitivity - Cumulative annual remedial actions per node***

The impact of the difference in geographical location and height of congestions on the distribution of remedial actions is shown in Figure 33. The results show the decrease in total volume of remedial actions with the decrease of the safety margin. While the scenario with the 70% flat-rate line constraint shows a

similar total volume of remedial actions, the distribution of negative adjustments of power feed-in between negative redispatch and curtailment differs due to the different geographical distribution of congestions.

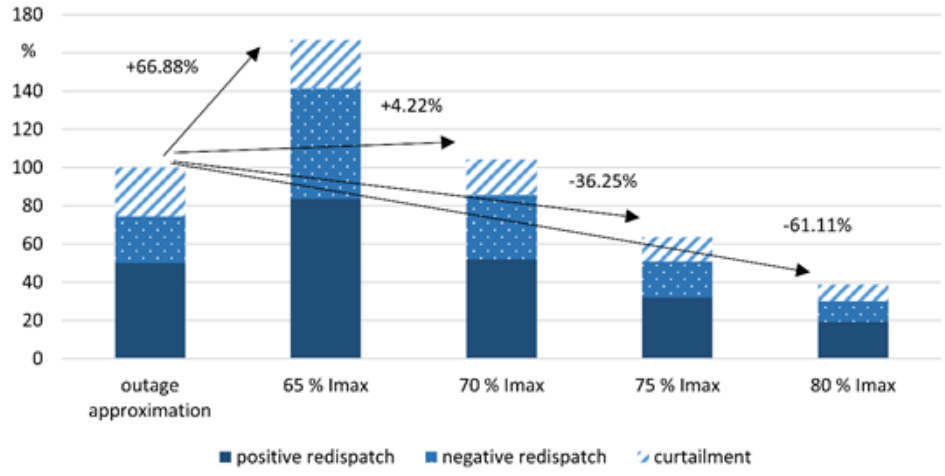


Figure 33. ***Outage sensitivity - Annual sum of remedial actions***

This effect can also be seen in Figure 34. In the scenario with the detailed outage approximation the percentage of curtailment in relation to negative redisptach is high compared to the scenarios with flat-rate line constraints. The percentage of curtailment in relation the negative redispatch also decreases with a decrease in the safety margin.

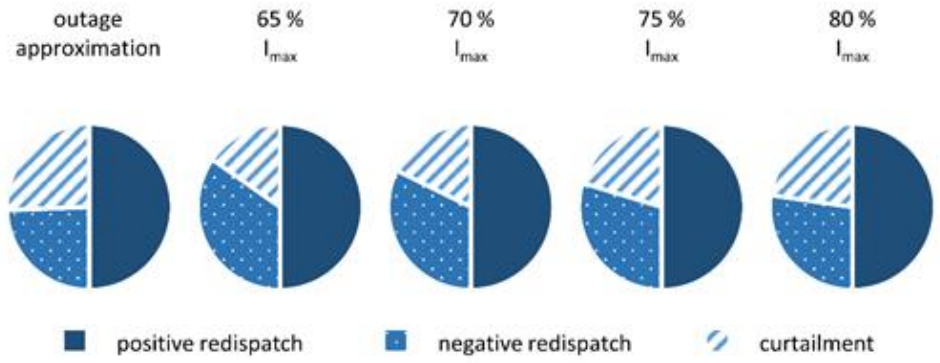


Figure 34. ***Outage sensitivity - Distribution of annual sum of remedial actions***

In summary the flat-rate line constraints can be parametrized in such way, that a rough estimation of the total volumes of remedial actions predicted with the detailed outage approximation model can be met. However, the geographical distribution of congestions and the share of curtailment and negative redispatch differs, even if the total volumes of remedial actions are close. Since differences especially occur in heavily meshed areas, a difference in detail is expected proportionally to the degree of meshed structures present.

Case Study II – Sensitivation of foreign base value

In case of an expected network congestion, the responsible TSO can make use of different measures to prevent the occurrence of this congestion. The order in which the TSO can apply these measures is specified by the regulator and results in the merit order. This order of congestion management measures is shown in Figure 35. As shown, domestic redispatch takes place before foreign redispatch.

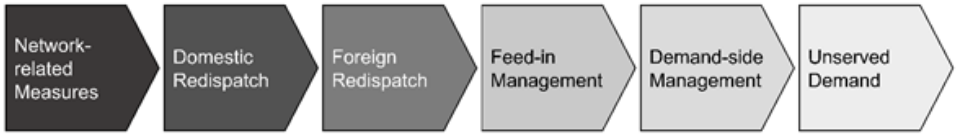


Figure 35. *Merit order of congestion management measures*

In the project, we found that especially in border regions, the use of foreign redispatch can be a useful measure to address congestions. In these cases, it can happen, that the impact of foreign plants on a congestion near the border can be higher than that of domestic power plants. Therefore, power utilities in neighboring countries may be asked to contribute to relieving congestion on the national grid and interconnectors. To show the impact that this so-called cross-border congestion management, and in particular cross-border redispatch, can have on model results, some exemplary results of the **ELMOD** model are presented below. **ELMOD** uses a methodology based on penalty costs to reflect the merit order of the different national and foreign congestion management options.

In this case study, four different model runs were performed with different congestion management penalty cost structures. The so-called base value adds up to the marginal cost of a given congestion management measure. For the base case, a penalty cost of 5,000 EUR/MWh was assumed, which is added to the redispatch cost while all other variable costs are kept equal. The model penalizes redispatch from national generating units at 100 EUR/MWh in addition to the marginal cost of generation. All other congestion management measures are penalized with higher penalty costs compared to cross-border redispatch, the size of which increases. This leads to the merit order shown in Figure 35, as **ELMOD** applies a (total) cost minimizing objective function. To show the impact of sensitization, a base value for cross-border redispatch in the range of 150 - 110 EUR/MWh is assumed in the comparison runs, while all other base values are kept constant.

The model results show that the assumed base values for cross-border redispatch affect both the national congestion management amounts and the geographical distribution of the measures used. Figure 36 shows the regional distribution of congestion management measures required.

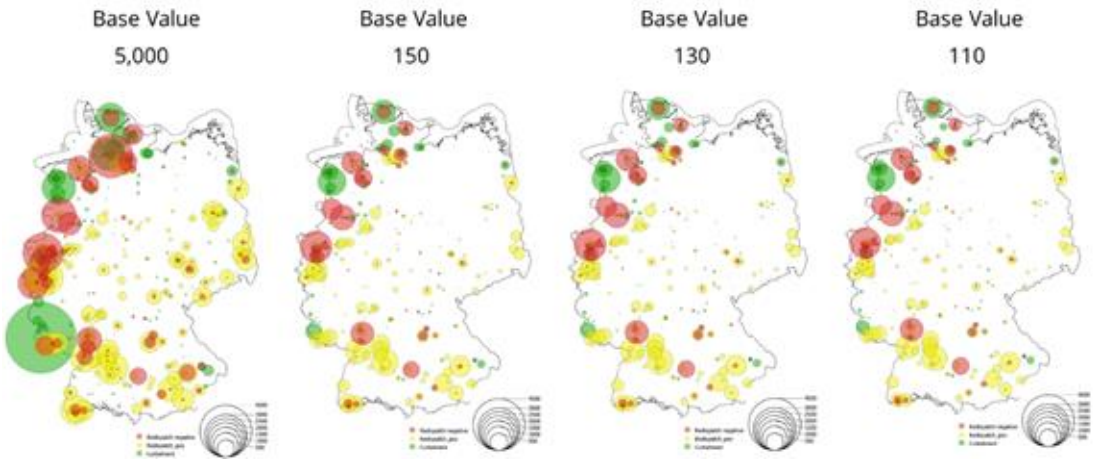


Figure 36. *Base value sensitivity – Cumulative annual congestion management per node*

For the base case run with penalty costs of 5,000 EUR/MWh one important finding was, that nearly no cross-border redispatch is taking place. The costs for the sensitivity analysis were chosen in a way, that ensures on the one hand that foreign cross-border redispatch becomes an economical option to solve bottlenecks but on the other hand that domestic plants are still preferred. The base case run results in significant amounts of negative redispatch in northern Germany, western Germany, and the Munich area. All corresponding grid nodes are located in close proximity to interconnectors with neighboring electricity markets. Comparing the base case run to the other three runs, the base case results show significantly larger amounts of negative redispatch around Munich, larger curtailment rates in northwest Germany, and more positive redispatch throughout Germany. Differences between the comparison runs are not apparent at this point. Figure 37 summarizes the total redispatch and curtailment amounts as relative differences compared to the base case run.

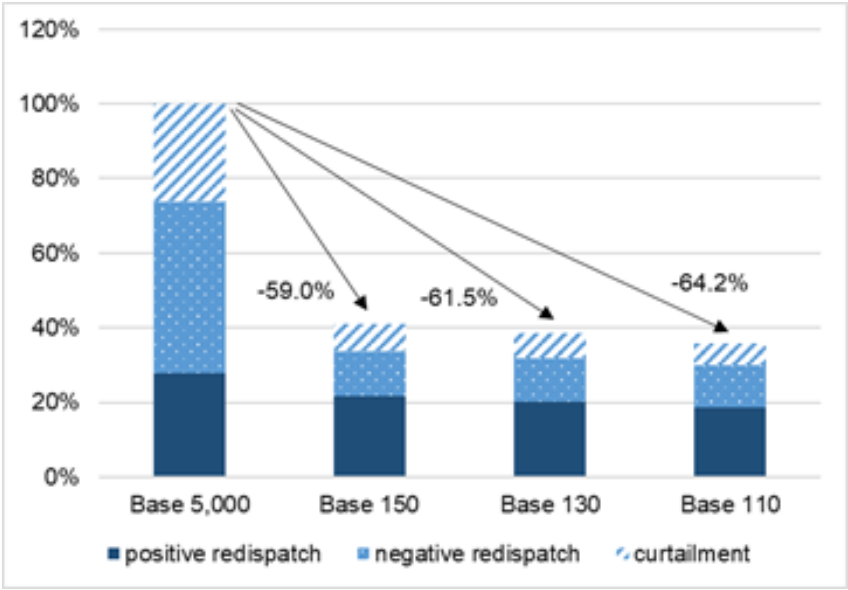


Figure 37. *Base value sensitivity – Relative changes of annual congestion management in Germany*

In summary, the reduction in the cross-border redispatch base value has a huge impact on the total congestion management quantities reproduced by the model. The overall reduction is almost constant at about 50% in all comparison runs. There is a clear indication that an increase in the penalty cost for cross-border redispatch provides an incentive for the network simulation model to make greater use of national measures, which has a strong influence on the results. This mechanism is also evident when comparing the respective sensitivities with each other. In addition, the assumption about the level of the neighboring countries' base value has a much stronger impact on solving grid congestion along the border than on national congestion, since changes in the deployment of power plants installed further inland in Germany have less impact on the interconnectors.

Case Study III – Impact of parametrization of soft constraint on line boundaries

In the grid simulation of congestion management multiple reasons can lead to a non-congestion free system state after optimization. While e.g., in grid planning often grid topologies are examined that still need further grid expansion to be able to become congestions free, inconsistencies in input data can also lead to such system states after optimization. If congestions cannot be fully cured and strictly binding constraints are used, the optimization problem may become infeasible. To always ensure feasibility during optimization often soft constraints are introduced. Soft constraints relax constraints, e.g., line constraints and use costly slack-variables to minimize the violation of line constraints while keeping the optimization problem solvable.

In this project a case study was conducted that compares different parametrizations of penalty cost of the slack-variables. To show the effect of soft constraints on faulty parametrized grids, a benchmark scenario is defined in which a line between the two substations “Grafenrheinfeld” and “Bergrheinfeld” is congested and cannot be relief through remedial actions. In this case the optimization problem would be infeasible without the use of slack-variables. The scenarios are deducted with a flat-rate line constraint (see case study I) of 70% of the maximum line currents. The penalty cost for slack variables is parametrized as 6, 60, 600 and 6000 times the penalty cost of one MW of adjustment in conventional remedial actions.

Figure 38 shows the geographical distribution of the annual cumulated volumes of remedial actions. With an increase in the penalty cost the volumes of remedial actions increases in different regions (e.g., North-Rhine Westphalia). At the same time, the penalty cost parametrization shows only a minor impact on the geographical distribution of remedial actions.

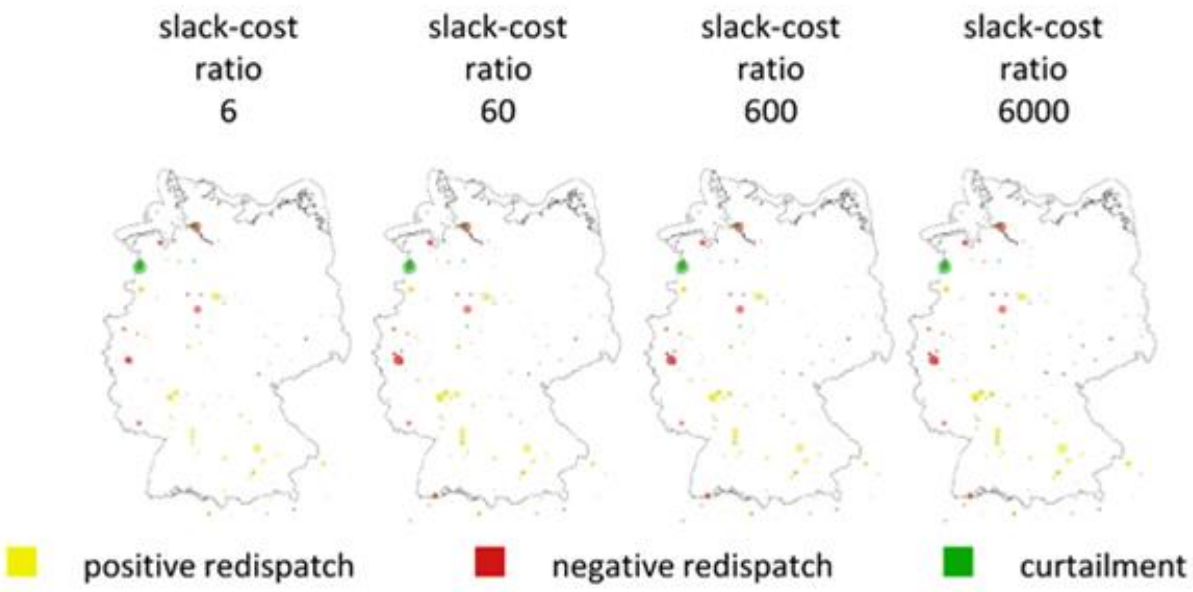


Figure 38. *Slack cost sensitivity - Cumulative annual remedial actions per node*

A visualization of the annual cumulated remaining congestion work on each line after congestion management is shown in Figure 39. In the model runs with a slack-cost ratio of 60 and higher all congestions expect the one on the faulty parametrized line can be relieved. The increase in slack-cost ratio leads to a decrease in the remaining congestion work on this line.

With a slack-cost ratio of 6 multiple congestions throughout Germany remain after congestion management. The cumulated congestion work over all lines adds up to 298.45 GWh.

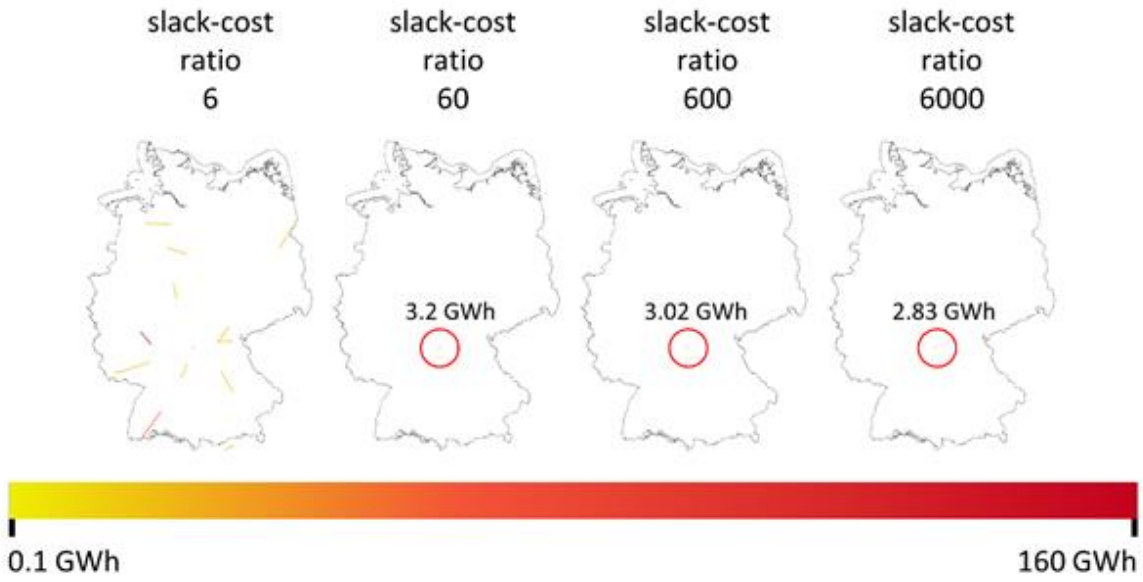


Figure 39. *Slack cost sensitivity - Cumulative annual congestion volumes per line after congestion management*

The changes in remedial actions vary from scenario to scenario as Figure 40 shows. While the difference in volumes of remedial actions between a slack-cost ratio of 60 and 600 is low, significant changes occur in the scenarios with a slack-cost ratio of 6 and 6000. Even though the congestion work on the faulty parametrized line remains similar in the scenarios with slack-cost ratios of 60, 600 and 6000, the high slack-cost ratio of 6000 leads to highly inefficient remedial actions. These remedial actions only have little impact on the faulty parametrized line. An equivalent model that uses hard constraints instead of soft constraints would show similar volumes of remedial actions, if a feasible solution is found.

The small differences in volumes of remedial actions between a slack-cost ratio of 60 and 600 shows that a certain margin for the parametrization of slack-cost ratios is acceptable. Rather than one perfect parametrization, a range of equivalently acceptable parametrizations exists.

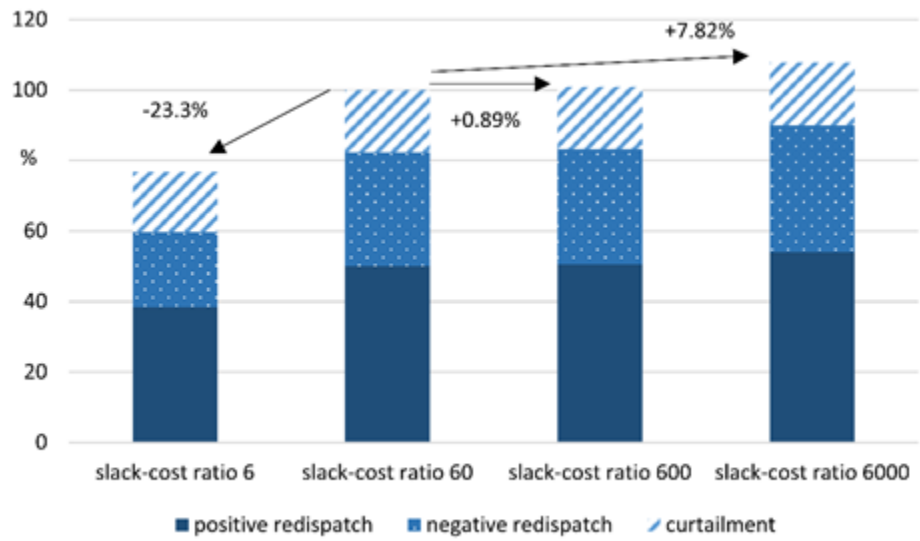


Figure 40. *Slack cost sensitivity – Annual sum of remedial actions*

In conclusion, the results of the case study show that the parametrization of slack-costs of soft constraints has a significant impact on the performance of the grid simulation. Too low slack-cost ratios can lead to unrelieved congestions, while too high slack-cost ratios may produce high annual volumes of remedial actions. The case study highlights the benefit of soft constraints on the convergence of grid simulations on big grids with possibly faulty parametrizations.

2.1.5 Overall comparison

In this project we have described the various challenges and aspects of model comparisons for power systems as well as provided a framework on how to approach such a task. We developed approaches for comparing input data related to generation and demand as well as the grid infrastructure, various methodologies and assumptions regarding the spatial distribution of generation and demand

(regionalization), the operation of conventional power plants (market simulation), the operational concept of power flow controlling devices (grid simulation) as well as the sequence of costly and non-costly remedial actions (congestion management simulation) have been compared, since these are expected to play a vital role in the overall behavior of each model. The developed framework includes comparison methods and tools for all aspects of power system modeling within the specific context such as formulating the system conditions, congestion management methods or market output. Moreover, we applied the framework to all involved models and extracted useful conclusions and recommendations. This comparison was also vital for designing and refining the framework, since it can now better reflect the challenges that accompany power system modeling. Despite the conclusions from each modeling aspect separately, it was agreed that an overall comparison of the models combining all this information cannot be achieved in the context of this project. The involved models differ substantially in almost all modeling aspect, which results in high differences in the respective output for all conducted experiments, including the historical scenario of 2016. Despite the harmonization process, further approaches should be applied in order to obtain results that can be linked to the modeling differences in a scientifically more robust way. Nevertheless, the developed framework and lessons learned constitute a valuable contribution to the research community, decision makers, funding agencies and the public to an area that has not been much explored. Therefore, it can be concluded that the primary targets of this project were achieved and can be useful for the relevant stakeholders.

2.2 The most important elements of quantitative evidence

2.2.1 Regionalization

As part of the regionalization analysis, we also compare the output of the regionalization and try to explain the differences of these outputs in terms of the regionalization workflows from section 2.1.2. The comparison was made by using the installed capacity, availability profiles, annual demand and yearly load from the fixed weather and load year 2016. Since each model uses a different topology for the grid and not all partners were able to make the data public at node level, we collected the data aggregated at NUTS 3 level. Thus, this might produce some bias in the comparison since some models can model the same EHV-node into a slightly different location in different NUTS 3 regions. Nevertheless, since the grid topology of each model is different, there does not exist a totally unbiased method to compare the results and NUTS 3 is an appropriate spatial resolution for the transmission grid. For instance, by counting the number of NUTS 3 regions where each pair of models intersect, we see that they largely agree, Figure 41. Evidently, the models with higher number of NUTS 3 regions with EHV-nodes have more intersections, but when we divide the number of intersecting regions by the total number of regions with data, we see that it is always between 76% and 96%.

	PERSEUS	ISAaR	ELMOD	eTraGo	MarS	MILES	Europower	PowerFlex
PERSEUS	230.0	223.0	214.0	217.0	202.0	219.0	210.0	183.0
ISAaR	223.0	239.0	213.0	221.0	205.0	226.0	210.0	184.0
ELMOD	214.0	213.0	219.0	212.0	191.0	210.0	197.0	171.0
eTraGo	217.0	221.0	212.0	228.0	199.0	215.0	204.0	180.0
MarS	202.0	205.0	191.0	199.0	213.0	201.0	188.0	168.0
MILES	219.0	226.0	210.0	215.0	201.0	239.0	209.0	182.0
Europower	210.0	210.0	197.0	204.0	188.0	209.0	243.0	177.0
PowerFlex	183.0	184.0	171.0	180.0	168.0	182.0	177.0	199.0

Figure 41. ***Number of intersections between models[45].***

In order to compare the installed capacities of solar, wind onshore, and wind offshore and the annual load at NUTS 3 level we used the RMSE across all NUTS 3 regions (using 0 if there was no installed capacity). In order to compare the availability profiles and the load profiles we used the mean value of the Pearson correlation of the profiles across all NUTS 3 regions with installed capacity. Notice that we compare the NUTS 3 regions one by one, without taking into account the location of the regions. This could be remedied using a spatial filter[46] which would diminish the errors produced by modelling EHV-nodes into different, but neighboring regions.

Before showing the results of the regionalized data comparison, we should report that fully harmonized input data was not possible. First of all, **PowerFlex** and **Europower** do not use installed capacities in their models. We assumed the availability profiles by means of full load hours for 2016: 875 h for PV, 1465 h for wind onshore and 2927 h for wind offshore. Regarding the weather year, **Europower** and **ISAaR** used the years 2015 and 2012 respectively. However, their full load hours were adapted to those of 2016. For load profiles, **MILES** and **eTraGo** use the years 2017 and 2011. In this case the profiles were shifted so that the weeks correspond to those of 2016. Even with these adjustments, those models were considered outliers in the comparison.

The comparison of the regionalization outcome was also done for NUTS 2, NUTS 1, and NUTS 0 and we noticed that the NUTS 3 resolution was necessary to see some of the differences between

[45] Figure 5.1 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

[46] C. M. St. Martin, J. K. Lundquist, and M. A. Handschy, *Variability of interconnected wind plants: correlation length and its dependence on variability time scale*, Environmental Research Letters 10.4 (2015): 044004.

regionalizations. At national level, all the models have similar installed capacities and annual loads, see Table 11. Apart from the outliers, the main thing to notice is that there are two groups of models regarding annual load: A group of an annual load close to 500 TWh and another close to 550 TWh. This discrepancy, however, is also found in some of the sources[47].

Table 11. ***Installed capacities and annual demand for Germany in 2016[48].***

Models	PV (GW)	Wind onshore (GW)	Wind offshore (GW)	Annual load (TWh)
Europower	44.12	57.67	3.90	500.06
PERSEUS	40.72	45.45	4.13	511.24
MarS/ZKNOT	39.79	45.00	4.12	556.10
PowerFlex	39.89	45.12	4.13	557.17
eTraGo	38.51	41.29	3.36	501.29
MILES	39.79	45.00	4.15	554.66
ISAaR	39.11	35.00	2.48	554.71
ELMOD	39.79	45.00	4.12	511.53
ENTSOE Factsheets	39.79	45.00	4.12	548.40
ENTSOE transparency	38.69	41.17	3.28	481.09

It is also worth noticing that apart from the outliers, the national availability capacities are also very close between all models, whether or not they use weather data or not, see Table 12.

Table 12. ***Availability factors for Germany in 2016[49].***

Models	PV	Wind onshore	Wind offshore
Europower	0.100	0.167	0.334
PERSEUS	0.100	0.179	0.305
MarS/ZKNOT	0.100	0.157	0.334
PowerFlex	0.100	0.167	0.334
eTraGo	0.102	0.179	0.322
MILES	0.100	0.176	0.370
ISAaR	0.114	0.163	0.570
ELMOD	0.101	0.169	0.332
ENTSOE Factsheets	0.100	0.167	0.334
ENTSOE (OPSD)	0.100	0.184	0.328

[47] ENTSO-E aisbl . Entso-e statistical factsheet 2016. https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Statistics/Factsheet/entsoe_sfs_2016_web.pdf; 2017; and ENTSO-E aisbl . Entso-e transparency platform. https://transparency.entsoe.eu; 2016.

[48] Table 4.6 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

[49] Table 4.7 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

As expected, the outcome of the regionalization of PV has more installed capacity in the south of Germany, but by looking at the plot of the installed capacities, Figure 42, one can see local differences and similarities. However, in order to find out the differences and the clusters of models with a similar regionalization, the invariants described above give a more systematic and concise method.

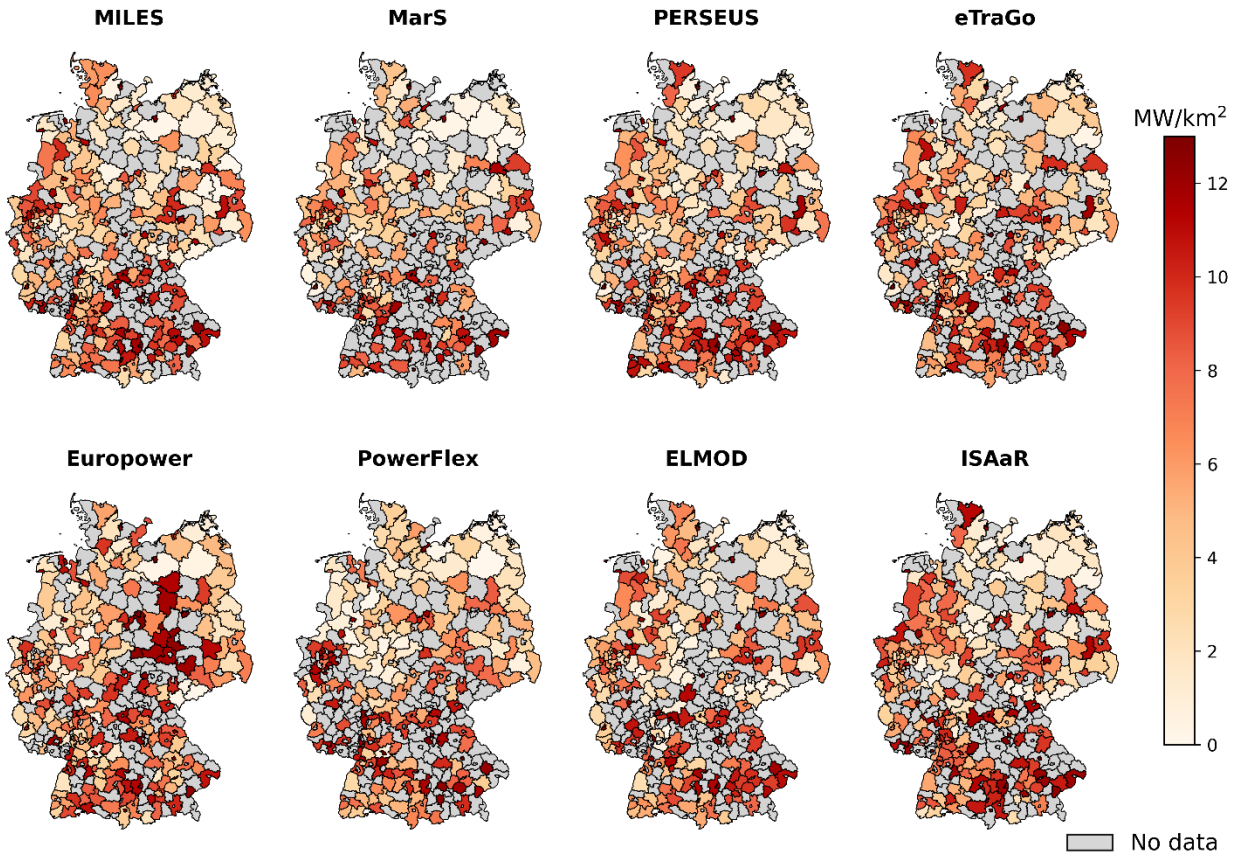


Figure 42. ***PV installed capacity at EHV-nodes aggregated per NUTS 3 region; density plot in MW/km² [50].***

The invariants described above to compare regionalization outputs will be visualized as heat symmetric matrices. In the case of PV, Figure 43 shows the comparison of PV installed capacities regionalization on the left and the comparison of the PV availability profiles on the right. The first thing to observe is that models using a top-down approach have a more different regionalization from the rest. Also, the outliers using a different weather year are clearly identifiable in the profile comparison. Overall, it is important to stress that the outcome of PV regionalization is quite similar despite the regionalization workflow (even with different weather year). This is because of the daily and seasonal pattern of the earth-sun motion.

[50] Figure A.1 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

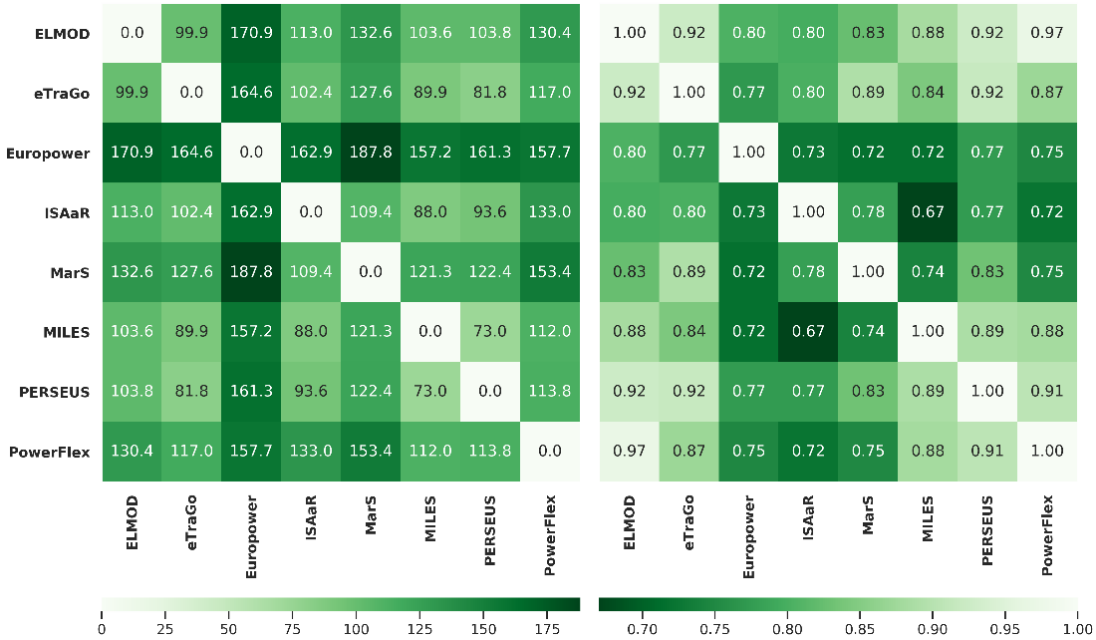


Figure 43. ***RMSE of PV installed capacities differences (MW) across all NUTS 3 regions (left) and mean Pearson correlation of PV profiles across intersecting NUTS 3 regions (right)[51].***

Regarding wind regionalization outcome, we observe in the map of installed capacities, Figure 44, that there is more installed capacity in the north in all the models (as expected), but there are some regional differences, specially, in the federal states of Brandenburg, Mecklenburg-Vorpommern, Niedersachsen, and Schleswig-Holstein.

[51] Figure 4.4 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

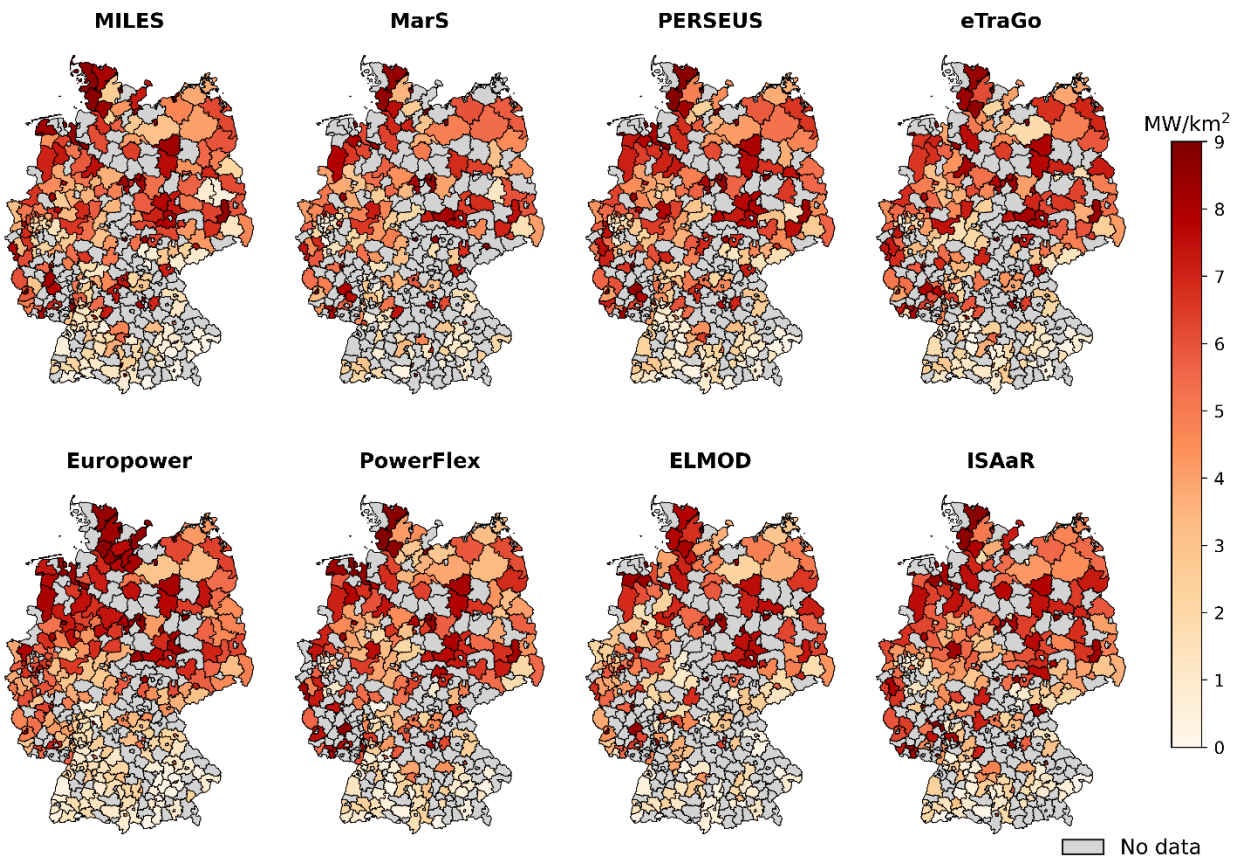


Figure 44. ***Wind onshore installed capacity at EHV-nodes aggregated per NUTS 3 region; density plot in MW/km² [52].***

The invariants comparing the reginoalization of wind onshore, Figure 45, distinguish the models using a top-down approach from the rest. The availability profiles also identify the outliers and cluster the outcome in two groups: **PowerFlex** and **ELMOD** on one side (which both use top-down approach from NUTS 0 data) and **eTraGo**, **MarS/ZKNOT**, **MILES** and **PERSEUS** on the other.

[52] Figure A.2 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

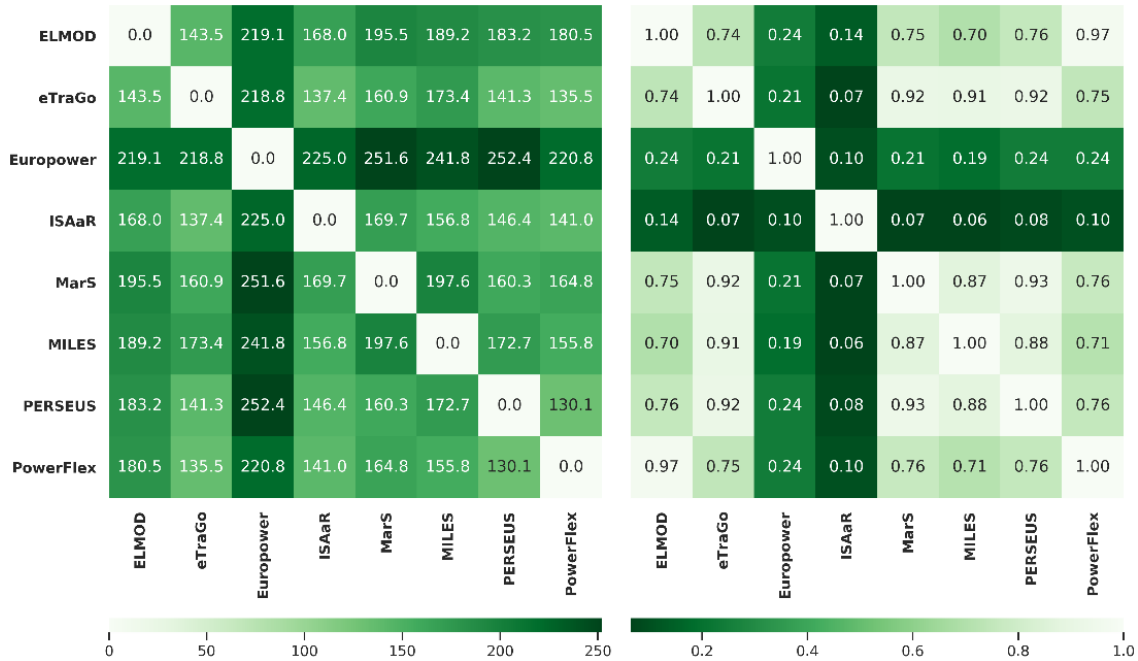


Figure 45. ***RMSE of wind onshore installed capacities differences (MW) across all NUTS 3 regions (left) and mean Pearson correlation of wind onshore profiles across intersecting NUTS 3 regions (right)[53].***

The regionalization of wind offshore is strongly influenced by the allocation into onshore nodes distribution. Hence, the distribution between the Baltic Sea and the North Sea already provides a distinction of the models and the proposed invariants are excessive. The share of wind offshore installed capacity in the Baltic Sea is shown in Table 13. One can see that **eTraGo** and **PowerFlex** have more installed capacity on the Baltic Sea than the rest. This difference is only explained because of the input data considered and not of the regionalization process, since it is very similar in all cases. As in the case of wind onshore, the Pearson correlation of the profiles also detect the outliers, and groups the models in two groups (the ones using the top-down approach and the others).

Table 13. ***Share of wind offshore installed capacities in the Baltic Sea[54].***

ELMOD	eTraGo	Europower	ISAaR	MarS/ZKNOT	MILES	PERSEUS	PowerFlex
0.10	0.20	0.13	0.08	0.09	0.13	0.10	0.17

Regarding the load regionalization, Figure 46 shows that all models have more load concentrated in highly populated and highly industrial areas. This is not surprising, as most of the models use population and

[53] Figure 4.5 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

[54] Table 4.8 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

GDP as the main input. Hence, the regionalization of the annual load is very close despite of the regionalization process.

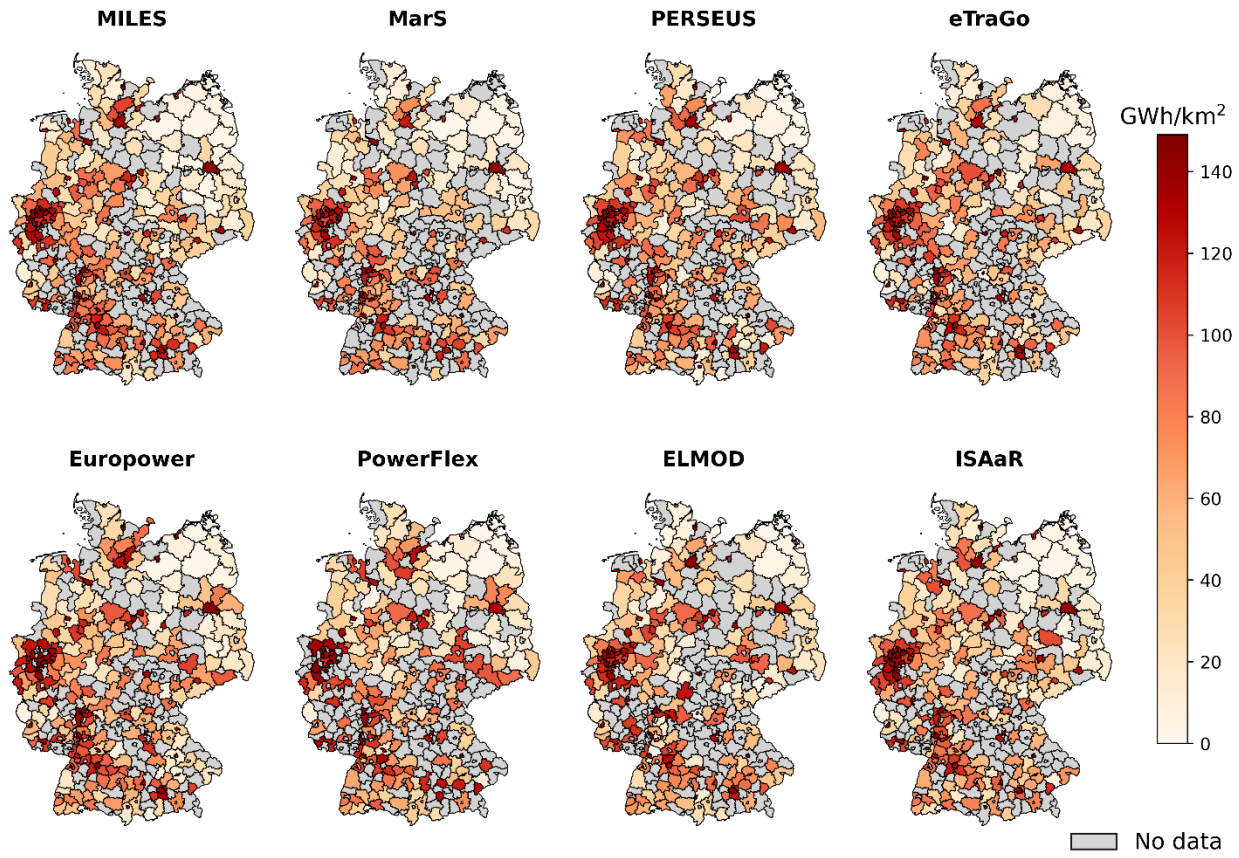


Figure 46. ***Annual demand installed capacity at EHV-nodes aggregated per NUTS 3 region; density plot in GWh/km² [55].***

In Figure 47 the invariants for the regionalization of demand are shown. First of all, we notice again, that the invariants detect the outliers in both annual load and load profiles. Apart from that, all models have a very close regionalization since the regionalization and the input data are very similar. Only **PowerFlex** has a different annual load different regionalization, which is explained by the different regionalization of load factors.

[55] Figure A.4 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

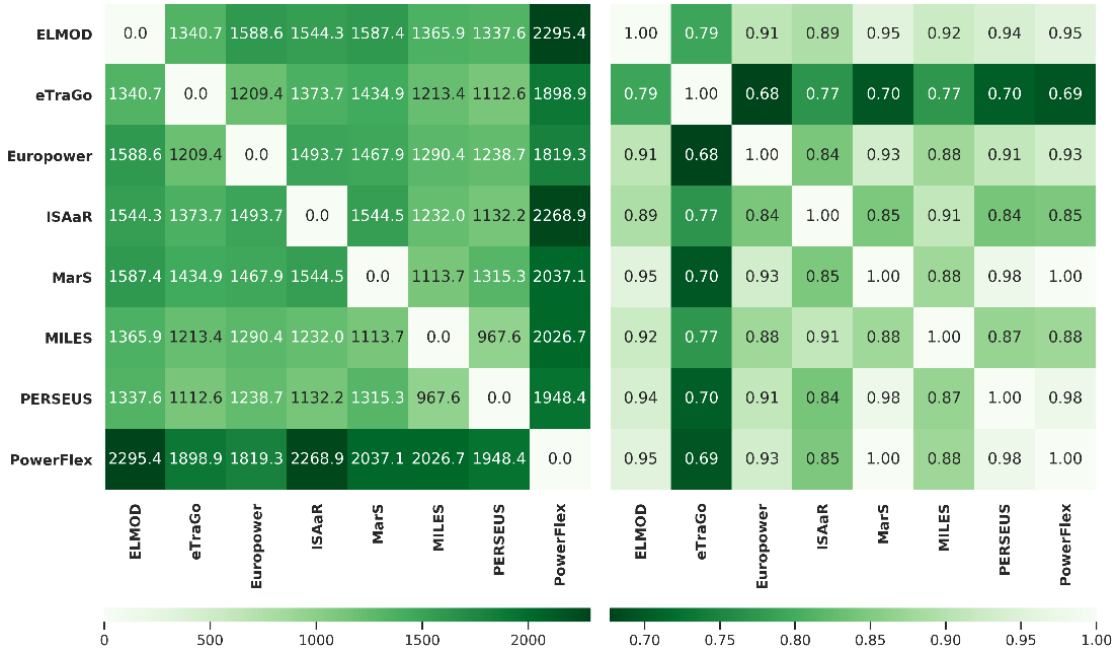


Figure 47. ***RMSE of annual load differences (GWh) across all NUTS 3 regions (left) and mean Pearson correlation of load profiles across intersecting NUTS 3 regions (right)[56].***

Finally, we can conclude from the regionalization study carried out in MODEX-Net that a high spatial resolution is necessary to compare the regionalization workflow output and that NUTS 3 is adequate for transmission grid models. We observed that the input data source and the use of top-down or bottom-up methods are the two main influence factors in the regionalization process. We also noticed that PV and load have a closer regionalization output regardless of the process.

The results in this article could be extended by a study of the impact of different regionalizations onto the optimization of the grid power flow. This is challenging since those regionalization outputs would have to be use in a single optimization model in order to make the results comparable. Probably, a new clustered model would have to be established for this purpose. It would be also interesting to repeat the analysis for future scenarios. As for the invariants used, it would be interesting to see the effect of applying spatial filters to overcome the fact that the models use different grid topologies. Ideally, one would like to study systematically all the different regionalization processes described in section 2.1.2 applied to the same grid. Another challenging problem is to develop a method to compare availability profiles coming from different weather years beyond comparing just the full load hours.

2.2.2 Market simulations

Regarding market simulations, the primary quantitative evidence follows the discussion from section 2.1.3, where it was stated that the primary indicators and market results constitute the generation and electricity prices. Hence, this section is focusing on these quantities since they were proven to be the

[56] Figure 4.8 in O. Raventós, T. Dengiz, W. Medjroubi, C. Unaichi, A. Bruckmeier, and R. Finck, *Comparison of different methods of spatial disaggregation of electricity generation and consumption time series*, to appear in RSER.

most useful for market comparison. The goal of the comparison is to quantify the differences in market results, which better reflect the corresponding modeling approaches as well as identifying groups of models with similar results. In this way, models with the most similar behaviors in terms of market modeling can be identified.

Generation

As discussed in 2.1.3, generation output constitutes a result that is difficult and impractical to analyze in its primary form. This can effectively become prohibitive when comparing models with different sets of generators, therefore the more appropriate method of comparing the energy mix was selected. Figure 7 shows the annual energy mix for all investigated models and their common countries including the respective data from ENTSO-E for the year 2016 in both absolute and relative values. The respective visualization can already provide an important overview of the behavior of the various models for different countries and can be used to identify groups of models with similar outputs as well as potentially distinguished behavior for a specific model and country, which could point out to a specific modeling issue of that model.

Nevertheless, a more quantitative indicator regarding the energy mix was also derived in order to better distinguish the differences between the models and identify and quantify similarities. This was achieved by an error-like indicator which measures the average difference of the energy mix, weighted over all countries and generation types such that differences in small categories, e.g., oil in Denmark, do not skew the results. Figure 48 shows a heatmap of this indicator, where it can become more apparent which models behave more similar than others. For instance, it can be seen that **Europower**, **PowerFlex**, **eTraGo**, **ISAar** and **ELMOD** can form a cluster with similar results. This evidence is not sufficient for concluding a quantifiable similarity of the models themselves, since generation data including the temporal and spatial dimensions can differ substantially, while also generation consists only one of a variety of measurable output. It is also shown that even after a level of harmonization for a historical case and measuring only an average behavior, significant differences can be observed. Therefore, a comparison with more fine data would not serve achieving the goal of this project. On the contrary, this indicator can constitute one of the most important results with respect to comparing market models in the context of this project.

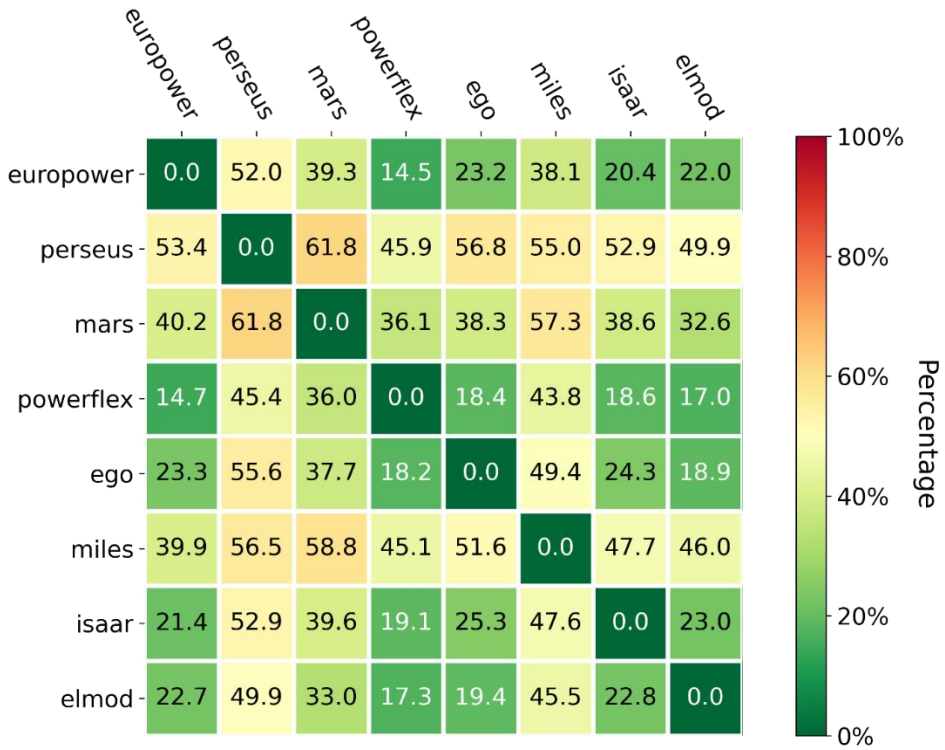


Figure 48. ***Heat map of the average difference of the energy mix, weighted over all countries and generation types.***

Electricity prices

Besides generation results, electricity prices constitute one of the most important market results and relevant for model comparison. This is because a lot of information is encapsulated in these regarding a model's behavior and can also be interpreted in a straightforward manner. Unlike generation data, there is only one time series per region generated by each model. Therefore, it becomes more practical and intuitive to also use this information for comparison. For this reason, electricity prices were analyzed in both of the reduction methods 2 and 3, i.e., reduction by operator and reduction by distance metric.

Regarding the reduction by operator, Figure 49 shows the mean and standard deviation of electricity prices for all models and the harmonized countries, including data from ENTSO-E. Since models tend to behave similarly, it becomes easier to extract conclusion from these visualizations. For instance, it can be observed that, for the mean value, most models have small variations among the countries and similar to each other as well as ENTSO-E. However, for the standard deviation value, it can be seen that models tend to have significantly less spread in comparison to the ENTSO-E values[57], which may be an indicator that models do not sufficiently capture all the temporal dynamics involved as well as strategic behavior. Nevertheless, it can be concluded that most models behave similarly in terms of average values.

[57] ENTSO-E, „ENTSO-E Transparency Platform," 30 06 2019. [Online]. Available: https://transparency.entsoe.eu/.

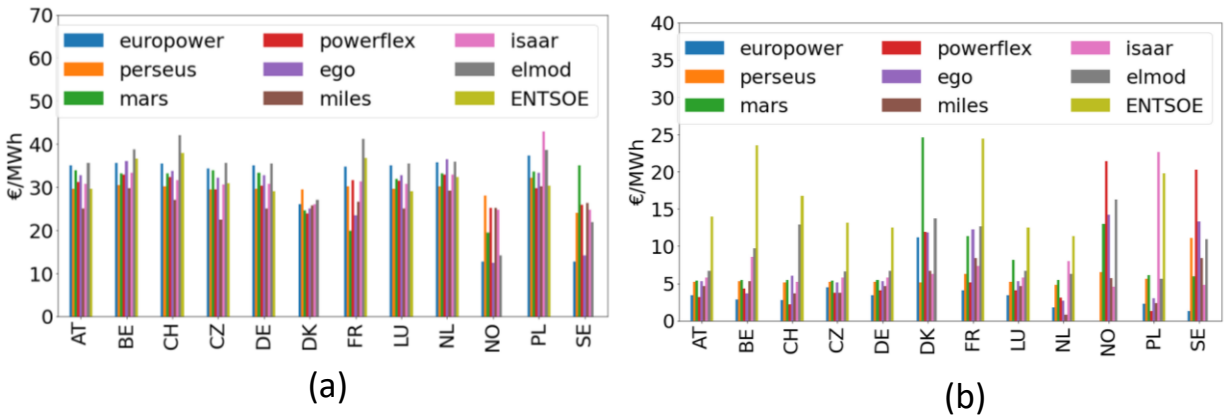


Figure 49. ***Mean (a) and standard deviation (b) of electricity prices for all models and the harmonized countries for the year 2016.***

When time series data is also considered, the picture can change and further estimation about the similarities among models can be identified. Figure 50 shows the Taylor diagram for Germany, where three different metrics are combined to plot the closeness to the reference model, in this case **PowerFlex**. It can be observed that the europower model is the most similar in terms of the time series behavior for Germany. It can also be noticed that in general the other models cannot be considered to be close to **PowerFlex** but this is not particular for this model only. As seen in Figure 51Figure 51, distances between models grow when other countries besides Germany are included.

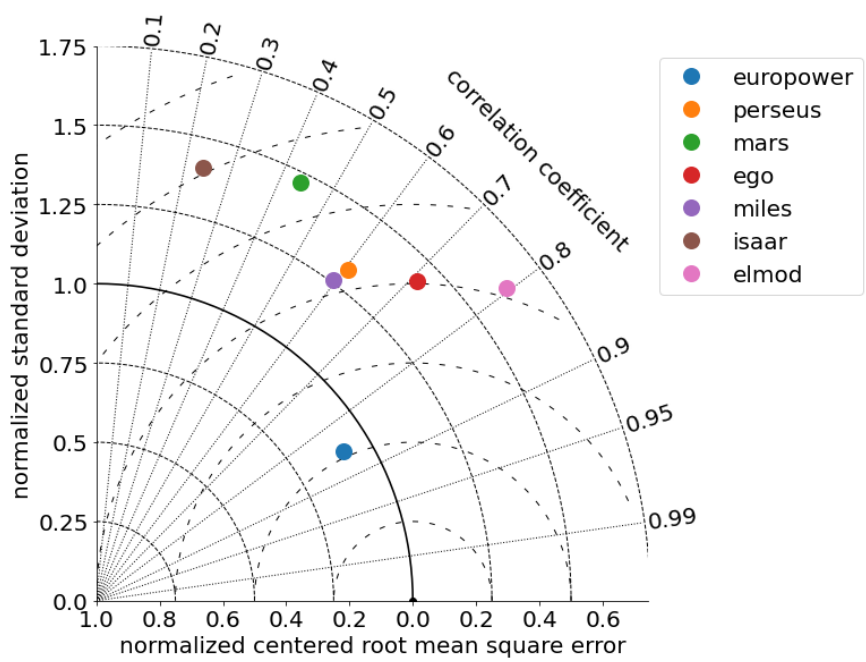


Figure 50. ***Taylor diagram for the electricity prices of Germany for 2016 for the model powerflex as reference.***

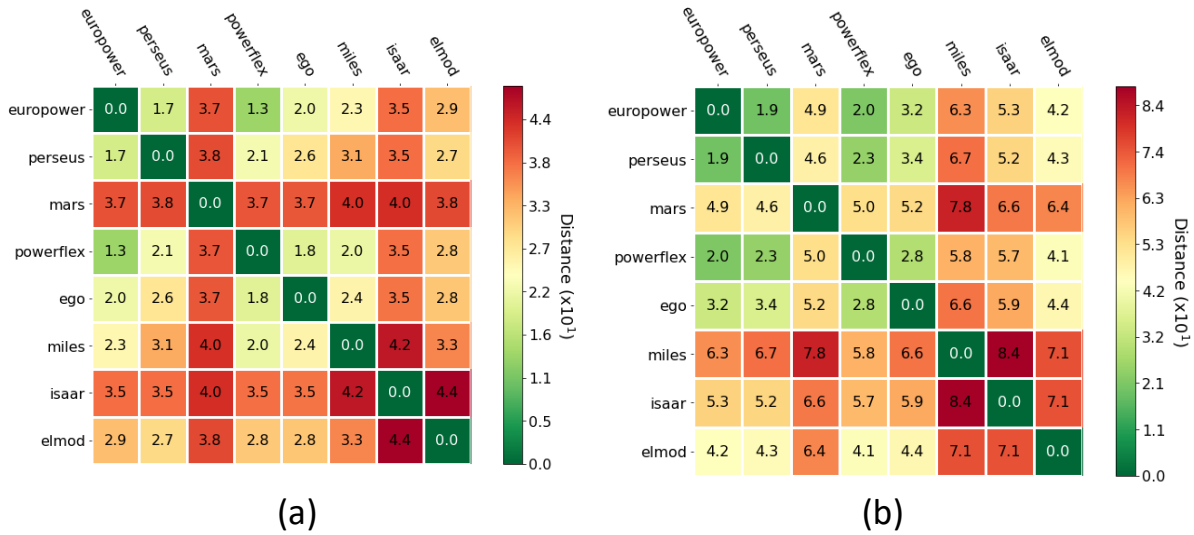


Figure 51. ***Electricity prices heatmap using the max difference metric for (a) Germany and (b) average over all countries.***

Identifying similarity groups

One particular challenge with comparing market output with quantified indicators consists of the combination of the corresponding outcome of those indicators applied to different results. Therefore, even ignoring regionalization and grid simulations, the comparison of the market results alone can pose challenges in drawing conclusions about the similarity of the corresponding models. In order to be able to combine all the output of all indicators, both their relative significance as well as the relative significance of the various results need to be defined. For instance, whether the energy mix is more important than prices for the comparison, a corresponding weight should be applied when combining such indicator results. A similar approach would also be necessary for the different indicators since it is not necessarily clear why one indicator might be more important than another or if they effectively contain the same information but are considered twice. However, even in that case, it would not be straightforward to combine all these values, since they may have different units, which may also not be possible to normalize. For this reason, a rigorous approach to identify groups of similar output was not developed in this project. Instead, a more qualitative approach was selected, where two models may be considered similar based on the maximum difference among all models for the corresponding indicator. A threshold of approximately 1/3 of the maximum difference was selected.

Table 14 summarizes such groupings for different indicators for 2016 and 2030. All models below this threshold are considered to belong to the similarity group for that particular indicator, for instance **Europower**, **PowerFlex**, **eTraGo**, **ISAaR** and **ELMOD** are considered to be similar for the energy mix indicator for 2016 and 2030. However, **eTraGo** for 2030 might cross that threshold when compared to one of the afore-mentioned models in that group. It can be observed that different indicators can form different groups, even when the same market result is considered. Nevertheless, there seems to be a tendency for the Bhattacharyya metric to show different behavior than the others. Moreover, it can be

observed that these groups tend to be the same when all countries are considered instead of just Germany as well as between 2016 and 2030, although this conclusion is less supported by the table.

Table 14. ***Similarity groups for all models based on different indicators. For each column, the green color indicates that the respective model belongs to the similarity group for that indicator, where light denotes a looser participation in that group.***

	models	Generation	Electricity prices					
		Energy mix	Correlation norm mean	Correlation norm DE	Max-diff norm mean	Max-diff norm DE	Bhattacharyya norm mean	Bhattacharyya norm DE
2016	Europower							
	PERSEUS							
	MARS							
	PowerFlex							
	eTraGo							
	miles							
	ISAaR							
	ELMOD							
2030	Europower							
	PERSEUS							
	MARS							
	PowerFlex							
	eTraGo							
	MILES							
	ISAaR							

Although similar group may be identified for both 2016 and 2030 for a specific indicator, the overall distances between the models are significantly higher. Figure 52 shows the average correlation indicator of electricity prices over all countries for 2016 and 2030. It can be observed that all distances are significantly higher, i.e., the model results match less in 2030 than for 2016. Although this can be considered an expected result, it can also signify the high differences that these models can produce for future scenarios, for which case they are typically intended to be used for. Therefore, researchers and any interested parties should remain aware of this behavior.

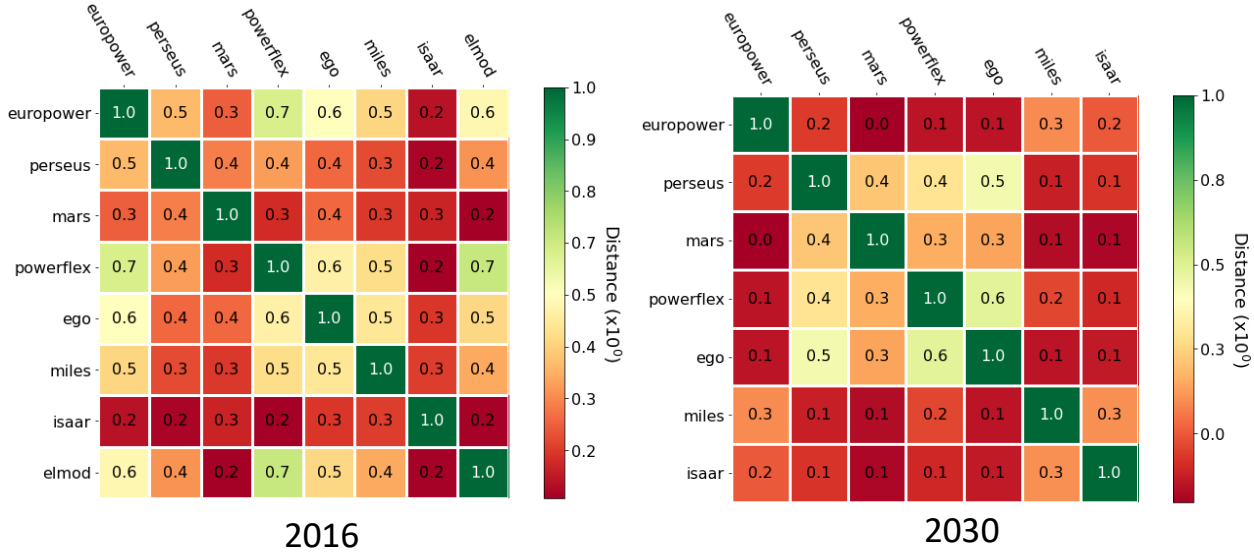


Figure 52. ***Average correlation indicator of the electricity prices for all countries for 2016 and 2030.***

2.2.3 Grid simulations

The key learnings we were able to take away from the grid simulations focus on model formulations and interpretations as well as model comparisons. As described in section 2.1.4 the models used have inevitable model differences that need to be taken into account when analyzing grid results. For example, different load flow characteristics are used (AC / DC), optimization methods differ as well as the way of how neighboring countries are considered in the grid simulation (considered physical and aggregated or not considered). Multiple key features of methods could not be harmonized as this would intervene in the formulation characteristic of the models analyzed. Because of these model differences a grid model comparison should not be reduced to single key values. This would harbor the risk of drawing incorrect conclusions from the results found. While discussing the results, we were able to identify key features for future grid simulations.

The complexity associated with non-linear programming problems used in energy system modeling often necessitates simplification (e.g., simplifying power flow representations based on linearization techniques such as a DC approximation). This results in the need to weigh up the level of detail in the results and the computation times required. During the project we therefore pointed out simplifications that can be made in the grid models and their associated drawbacks.

Another very important key learning is the importance of the use of a meaningful modeling approach for a specific objective. Energy researchers utilize a multitude of simulation tools for the model-based analysis of power transmission systems and the individual approaches used are tailored to their specific field of application. This is the reason why the respective model representations strongly impact the results obtained.

An overarching learning was the use of automated georeferenced visualizations. In a first step it helped to check plausibility of each model and in a second step it helped to visualize differences in regionalization and its impact on results interpretations.

2.3 Necessity and appropriateness of the work performed

By 2045, the federal government aims to be greenhouse gas neutral. High significance is given to a forced utilization of renewable energies and improvement of efficiencies. The increasing integration of renewable energies within the German and European energy systems becomes a major challenge for a reliable energy supply as of today. An essential prerequisite is a powerful European electricity grid.

In the context of the aim to move towards distributed sources of renewable energies, a meaningful grid modelling with European context becomes more relevant. In addition to the question, when load and production are equal, answered by market modelling, grid modelling extends the problem by a locational dimension. This is an essential question in the context of targeting the energy transition with delays in grid extension measures.

In recent years, a wide range of methods of load flow calculations has been utilized, different models to provide regionalized load and generation have been developed, and various input data has been utilized for that. This variety of modelling opportunities can lead to different and converse results.

Within this project, we sensitized energy system modelers and users in science, politics, and economy for differences in grid modelling and the reasons for that. We conducted a public exchange of different approaches in grid modelling and regionalization methods, and we enabled ourselves to reassess the own approaches and discover development potential. Our publicly available work is a contribution to more transparent energy system models. Acceptance and usefulness of generated results is enhanced by that.

2.4 Benefits and future usability of project outcomes

With our work conducted within the project, we generated valuable outcomes which can be grouped into four categories.

- We have condensed our project results into three publications. We conducted a final project workshop to transfer our project findings to other modelers and interested audience. With that, gained knowledge has been distributed to the scientific community.
- With our project work, we have contributed to a further foundation of electricity grid models and regionalization methods. This is a participation towards a more reliable basis for a future electricity supply design.
- As this project was a collaborative work among various partners, we strengthened the cooperation between institutes in the same field of research. We gained mutual insights into the models, which may be a great benefit for potential upcoming collaborations.
- We published model factsheets, harmonized scenarios for model comparisons, methodologies, code, and templates for comparing results, and we provided comparison results on the OEP and on our project web page. Third party institutes are enabled to conduct benchmarks of their own models and compare their results against outcomes of the project members.

2.5 Progress in the field of the project by other parties

To our knowledge, there exist recently finalised research projects RegMex (FKZ 0325874), 4NEMO (FKZ 0324008), and BEAM-ME (FKZ 03ET4023) which conducted model comparisons on a small scale. But we are not aware of a comparison of transmission grid models.

2.6 Existing and planned publications according to No. 11.NKBF98

Paper contributions to the Special Issue on MODEX model experiments of the journal Renewable and Sustainable Energy Reviews:

- Development of an open framework for a qualitative and quantitative comparison of power system and electricity grid models for Europe[58]
- Comparison of different methods of spatial disaggregation of electricity generation and consumption time series[59]
- Impact of model parametrization and formulation on the explorative power of electricity network congestion management models - Insights from a grid model comparison experiment[60]
- Data Harmonisation for Energy System Analysis – Example of Multi-Model Experiments[61]

Participation in conferences and workshops:

- Annual meetings of the MODEX thematic network on 12.11.2019, 09.12.2020 and 01.12.2021
- 3th Annual Meeting of the Research Network Energy System Analysis from 23.-24.05.2019 in Aachen
- 5th Annual Meeting of the Research Network Energy System Analysis from 18-20.05.2021: Workshop 3h “Transmission Grid Models”
- Final MODEX NET Workshop on 25.11.2021
- Planned in 2022, September; International Conference on Operations Research - OR 2022
- Planned in 2022, September; International Conference on Operations Research - OR 2022
- Planned results and lessons learned workshop “Forschungsnetzwerk Energiesystemanalyse”

[58] https://www.sciencedirect.com/science/article/pii/S1364032121013174
[59] https://www.sciencedirect.com/science/article/pii/S1364032122001101
[60] https://www.sciencedirect.com/science/article/pii/S1364032122000910
[61] https://www.sciencedirect.com/science/article/pii/S136403212200377X

List of tables

List of figures