Essays on the Economics of Congestion Management

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Theory and Model-based Analysis for Central Western Europe

Inauguraldissertation
zur
Erlangung des Doktorgrades
der
Wirtschafts- und Sozialwissenschaftlichen Fakultät
der
Universität zu Köln

2012

vorgelegt
von

Diplom-Volkswirtin Barbara Burstedde

aus

Köln

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Tag der Promotion:	10. Januar 2013

To my family.

Acknowledgements

During the preparation of this thesis I have received support in many ways. Although the following list is by no means complete, I would like to express my gratitude to some people and institutions in particular.

- I thank Marco Nicolosi, Christina Elberg, Sebastian Kranz, Joachim Bertsch and Caroline Dieckhöner for their helpful comments on my research and for many fruitful discussions. I also would like to thank Johanna Fimpel and my colleagues from the Institute of Energy Economics (EWI) at the University of Cologne for their day-to-day support.
- A special thank you goes to Martin Lienert and Ariette Nüßler, who introduced some of the methodology applied in my thesis at the Institute of Energy Economics and who have accompanied me a long way.
- Furthermore, I am very grateful for the trust and support by my parents Mia and Heinz-Herbert Burstedde, as well as for the all-time encouragement by Carsten, Sebastian, Kirsten and Mina Burstedde.
- Special thanks goes to the Institute for Energy Systems, Energy Efficiency and Energy Management (ie^3) at TU Dortmund University for providing their network model for my research. In particular, I would like to thank Johannes Schwippe and Marc Osthues for their scientific advice.
- I would also like to thank the Foundation for Research on Market Design and Energy Trading (FORMAET) for the PhD-sponsorship of my thesis. Especially, I would like to thank Thomas Niedrig for his commitment to my research.
- Finally, I would like to thank my supervisor Prof. Dr. Felix Höffler, especially with regard to the helpful discussions towards the end of my thesis. Furthermore, my thanks go to Prof. Dr. Marc Oliver Bettzüge for co-refereeing my thesis.

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Nomenclature

General Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BNetzA	Bundesnetzagentur (German regulator)
CACM	Framework Guidelines on Capacity Allocation and Congestion Management for Electricity
CAES	Compressed air energy storage
CWE	Central Western Europe
DSM	Demand side management
EnLAG	Energieleitungsausbaugesetz (German Energy Transmission Line Extension Law)
ENTSO-E	European Network of Transmission System Operators for Electricity
EWI	Institute of Energy Economics at the University of Cologne
GW	Giga watt
GWh	Giga watt hour
HVDC	High voltage direct current line
Hyd-PS	Pumped hydro storage vintage class
Hyd-S	Hydro storage vintage class
ie^3	Institute for Energy Systems, Energy Efficiency and Energy Management at TU Dortmund University
IEM	Internal electricity market
ISO	Independent System Operator
LMP	Locational marginal pricing
MW	Mega watt
MWh	Mega watt hour
NABeG	Netzausbaubeschleunigungsgesetz (German Network Extension Enforcement Law)
NREAP	National Renewable Energy Action Plan

NTC	Net transfer capacity
OCGT	Open cycle gas turbine
PTDF	Power transfer distribution factor
RES	Renewable energy sources
RES-E	Electricity produced by renewable energy sources
TSO	Transmission system operator
TWh	Tera watt hour
VOLL	Value of lost load

Chapter 2

Indices

c	Country
h	Hour
n, m	Model regions or nodes
st	Storage technology
t	Technology
y	Year

Parameters

av_ntc	Available percentage of NTC
av_sec	Securely available percentage of transmission capacity
av_SR_spin	Tech. ability to provide spinning secondary reserve
av_SR_stand	Tech. ability to provide standing secondary reserve
av_tech	Available percentage of installed generation capacities
av_TR_spin	Tech. ability to provide spinning tertiary reserve
av_TR_stand	Tech. ability to provide standing tertiary reserve
b	Network susceptance matrix
cap_comp_unused	Compressor capacities not used in the dispatch
cap_unused	Capacities not used in the dispatch
cap^{PL}	Optimal level of capacity in part load operation from dispatch
$comp$	Optimal compressor dispatch
$curtail$	Optimal RES-E curtailment from dispatch
eff	Efficiency of generation
eff_comp	Efficiency of compression
ex_inflow	Natural inflow to hydro storage basins
exc	Optimal NTC-based exchange from dispatch
fom_c	Fixed operation and maintanance costs per MW
$fuel\_c$	Variable fuel and CO_2 costs

$fuel\_c^{PL}$	Variable fuel and CO_2 costs in partload operation
gen	Optimal generator dispatch
$initial\_level$	Initial storage level
$inst\_cap$	Installed capacity
$instcap$	Installed generation capacity
k	Network transfer matrix
l	Transmission line
$line\_cap$	Thermal line capacity
$load$	Hourly demand for electricity
min_comp	Minimum load levels of compressors from dispatch
min_gen	Minimum load levels from dispatch
min_load	Minimal load level
ntc_cap	Net transfer capacity
$other\_vc$	Other variable costs of production
$renewables$	Energy produced by renewable energy sources
res_load	Hourly residual demand
$slack$	Slack node parameter
SR_neg	Demand for negative secondary reserve
SR_pos	Demand for positive secondary reserve
$start\_attr$	Attrition costs induced by ramping
$start\_time$	Time required for starting-up plants
$storage$	Optimal storage levels from dispatch
vc	Variable production costs of re-dispatch
vc_rto	Variable generator ramping costs of re-dispatch
vc_rto^{COMP}	Variable compressor ramping costs of re-dispatch
vc^{COMP}	Variable compressor costs of re-dispatch
vc^{PL}	Variable part load production costs of re-dispatch
vol_factor	Ratio of storage volume and generation capacity
Variables	
CAP_DOWN	Generation capacity ramped down
CAP_DOWN_COMP	Compressor capacity ramped down
CAP_RTO	Generation capacity ready to operate
CAP_RTO_COMP	Compressor capacity ready to operate
CAP_UP	Generation capacity ramped up
CAP_UP_COMP	Compressor capacity ramped up
$COMP$	Electricity consumption by compressors
$COMP\_REDIS\_down$	Negative re-dispatch of compressors
$COMP\_REDIS\_up$	Positive re-dispatch of compressors
$CURTAIL$	Curtailment of RES-E

$DELTA$	Phase-angle
$DELTA\_DIS$	Re-calculated DC phase angle from dispatch
EXC	Power export based on NTC
FC^{OM}	Total fixed operation and maintanance costs
GEN	Electricity production
GEN_REDIS_down	Negative re-dispatch of generators
GEN_REDIS_up	Positive re-dispatch of generators
$GEN\_REDIS\_up^{PL}$	Positive re-dispatch of generators in part load operation
$GEN\_REDIS\_up^{STAND}$	Positive re-dispatch of standing generators
NEG_SR	Negative secondary reserve
$NEG\_SR\_SPIN\_COMP$	Spinning negative secondary reserve from compressors
$NEG\_SR\_STAND\_COMP$	Standing negative secondary reserve from compressors
$NEG\_TR\_SPIN\_COMP$	Spinning negative tertiary reserve from compressors
$NEG\_TR\_STAND\_COMP$	Standing negative tertiary reserve from compressors
$NETINPUT$	Net import based on DC load flow
$NETINPUT\_DIS$	Re-calculated DC-based net exchange from dispatch
$NETINPUT\_REDIS$	Variation of DC-based net exchange in re-dispatch
POS_SR_COMP	Positive secondary reserve from compressors
POS_SR_SPIN	Spinning positive secondary reserve
POS_SR_STAND	Standing positive secondary reserve
POS_TR_SPIN	Spinning positive tertiary reserve
POS_TR_STAND	Standing positive tertiary reserve
RC	Total re-dispatch costs
RES_down	RES-E curtailment in re-dispatch
VC_REDIS	Total variable costs of re-dispatch
SR	Secondary balancing reserve
$STORAGE\_LEVEL$	Hourly storage level
TC	Total costs of electricity production
TR	Tertiary balancing reserve
VC^{PROD}	Total variable costs of production
VC^{RTO}	Total variable ramping costs

Chapter 3

Indices

k	Clustering step $k \in \{1, \dots, N-1\}$
n	Node $n \in \{1, \dots, n, m, \dots, N\}$

Parameters

$b_{n,m}$	Binary parameter indicating neighboring nodes n, m

$\bar{d}$	Mean of d_k
d_k	Critical distance at clustering step k
$\bar{p}_{i,k}$	Mean vector of prices in cluster i at stage k
p_n	Price vector of node n
s_d	Standard deviation of d_k
Variables	
$C_{i,k}$	Cluster i at step k
$E_{i,k}$	Sum of squared Euclidean distances of cluster i at step k
I_k	Feasible clusters at step k

Chapter 4

Indices	
g	Generator
n, m	Node $n, m \in \{1, \ldots, N\}$
Parameters	
δ	Fixed factor in spot price-based re-dispatch
ϵ	Individual marginal cost estimator in spot price-based re-dispatch
d_n	Demand at node n
$\bar{l}_{n,m}$	Transmission capacity limit of line l between nodes n, m
p^N, p^Z	Hourly nodal and zonal electricity market prices
$\bar{q}_n$	Production capacity limit at node n
Variables	
C_n	Production costs at node n
ΔPS	Difference in zonal and nodal producer surplus
$F_{n,m}$	Electricity flow between nodes n, m
$FR_{n,m}$	Electricity flow between nodes n, m induced by re-dispatch
$I_{n,g}$	Payments for redispatch at node n to generator g
PS	Producer surplus
Q_n	Production at node n
R_n	Redispatch at node n
RC	Total re-dispatch costs
TC	Total costs of electricity supply

Chapter 1

Introduction

This thesis begins with an outline of the motivation underlying the presented research. Furthermore, the methodological foundation of the thesis is briefly introduced. Thereby, a critical acclaim of its limitations as well as of essential assumptions is given. The introduction closes with an overview of the presented work.

1.1 Motivation

The implementation of the Internal Energy Market (IEM) is a declared goal of the European Commission which is currently enforced by the third legislative package for electricity and gas markets.[1] Thereby, the IEM is no political end in itself but directly supports the target of economic, secure and sustainable energy supply in Europe. Since the coalescence of the national markets evolves both on an institutional level as well as in physical terms, synergies can be achieved with respect to all aspects of the energy policy triangle. Whereas the institutional market integration especially allows for a better coordination of trade and of regulation, the physical coupling by the means of transmission network extensions largely determines the magnitude of the attainable benefits.

With regard to electricity markets, the international transmission network contributes to system security by balancing regional deficits and surpluses of supply. Furthermore, structural differences in the local costs of electricity production can be exploited to achieve the least-cost supply mix within the interconnected system. This also refers to renewable energy sources (RES), whose levelized energy costs are influenced by the local yield of the primary energy source. In this context, the transmission network also performs the task of balancing temporal supply fluctuations.

[1] Directive 2009/72/EC, 13 July 2009.

Under consideration of these factors of influence, the availability of cross-border transmission capacities finally determines the ratio of national electricity market prices. Provided that thermal line capacities do not impose a binding restriction on international trade, the national marginal costs of supply converge such that all markets reveal the same price for electricity. However, if the optimal level of electricity exchange is prevented by limited network capacities, the national prices will diverge. In this case, the markets reveal the opportunity costs of congestion and regional scarcities. Ultimately, these transparent signals set incentives for market participants to adapt their decisions to the structural conditions. Furthermore, the economic benefit of network extensions is revealed to transmission system operators (TSOs) and regulators.

The tasks of the national transmission network coincide with those of the cross-border interconnectors, although security of supply and arbitrage opportunities are now primarily defined on a local level. However, the visibility of the opportunity costs of internal congestion is limited. Since most of the European markets rely on uniform pricing systems which constitute one bidding zone per country, national bottlenecks will not be reflected by regional prices.[2] Instead, trade within the national markets neglects the existence of physical transmission constraints. Since the regional TSO has the legal obligation to ensure system security, she counteracts the resulting overload of the network by operative adjustments of dispatch schedules (so-called re-dispatch) or by strategic transmission investments. However, recent experience e. g. from Germany reveals that the geographical development of supply and demand and hence the required transmission volumes evolve faster than the network extensions. In the meantime, the need for short-term congestion management increases considerably.

Since the main reasons for the delay of national transmission extensions is mainly caused by a time-consuming process of approving as well as by the opposition of the local population, one strategy is to simplify the bureaucratic process and to enforce the investments legally. This path has for example been adopted in Germany by the enactment of the Energy Transmission Extension Law (German: Energieleitungsausbaugesetz, EnLAG) and the Law on the Acceleration of Network Extensions (German: Netzausbaubeschleunigungsprozess, NABEG). This strategy aims at the retention of the single German price zone and accepts the necessity to apply re-dispatch in times of congestion.

An internationalized approach has been suggested by the European Agency for the Cooperation of Energy Regulators (ACER) in their 2011 Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (CACM). ACER promotes the implementation of regional bidding zones which reflect the fundamental market and

[2] Norway and Sweden as well as Italy have established several bidding zones per country, which allow for a market splitting in times of congestion. However, all nodes within each zone are still priced uniformly.

network structure in Europe and which are thus decoupled from national borders. In consequence, congestion management between zones is implicitly integrated into wholesale market trade, such that the need for re-dispatch is ideally reduced. This zonal pricing strategy aims at a European view on congestion and at the intensification of regional price signals in comparison to the status quo. Again, market participants are intended to react to regional incentives and to reduce the stress of the network until necessary extensions have been made. However, zonal pricing comes with several challenges. Since the definition of zones shall not only be based on the fundamental market structure but also on criteria of welfare, liquidity, competition and re-dispatch costs, it is by no means trivial.[3] The smaller the zones, the more important local liquidity and market concentration become for the efficiency of the markets.

In the end, the weighting of uniform pricing on the one hand and zonal or even nodal pricing on the other hand largely depends on the trade-off between price signals, static and dynamic incentives, liquidity, competition and distribution effects.[4] With the exception of the last point, the combination of the said aspects determines the overall efficiency of a market design and its congestion management. However, the magnitude of distribution effects is not to be neglected since it influences the political feasibility of a given design.[5]

The thesis at hand addresses itself to various aspects of the described trade-off. The aim of the presented research is to indicate the potential benefits of improving congestion management and to identify some of the associated obstacles. Due to the complexity of the issues at hand, the understanding of the interdependencies between fundamental factors and design choices is of special importance for the development of national and European electricity market policies. With regard to the European context, this thesis presents a methodology to identify suitable bidding zones under consideration of the fundamental market structure. The application of the approach reveals both local heterogeneity as well as cross-border similarities within Central Western Europe, which may jointly shape an alternative definition of regional markets. The presented research indicates that an international solution to congestion management may combine favorable aspects of nodal and uniform pricing into a beneficial zonal design.

A further contribution of the thesis is an in-depth evaluation of the regional impact of congestion management using the example of Germany. Thereby, the influence of nodal

[3] Cf. ACER (2011).

[4] Nodal pricing is an extreme form of market splitting, in which each node of the network constitutes one bidding zone.

[5] Furthermore, the pricing systems may require different institutional approaches, which reflect the complexity of the market clearing process. Nodal pricing systems are usually implemented in combination with a central Independent System Operator (ISO), whereas zonal and uniform pricing systems allow for a more decentralized approach. The discussion of the institutional setup is however outside the scope of this thesis.

and uniform pricing schemes on the local allocation of generation and producer surplus is analyzed. The presented results thus demonstrate the effect of regional transmission bottlenecks on a market's allocative efficiency and furthermore indicate the relevance of local incentives as drivers for dynamic efficiency. The findings also suggest that the magnitude of the distribution effects resulting from an introduction of local bidding zones may be greater than the corresponding gain in market efficiency. Given the findings with regard to the impact of congestion management on the national wholesale market, the importance of a well-designed re-dispatch mechanism is highlighted. Based on a theoretical analysis of incentives for the TSO and re-dispatched generators induced by different re-dispatch remuneration schemes, the thesis also provides a quantitative indication of the importance of design choices on the relative efficiency of internal congestion management.

On the basis of the findings of the presented thesis, further research on the impact of liquidity and market power on the eligibility of congestion management schemes may be conducted. Also the relevance of institutional changes required by a potential restructuring of the European markets and their congestion management needs to be evaluated further. This includes both the initial costs of a regime switch as well as the day-to-day transaction costs of market operation. Furthermore, continuing analyses of strategic interactions between market participants and TSOs and their impact on investment decisions may be considered. Finally, these considerations may impact the regulation of the transmission network. Overall, the complexity of the thematic constellation indicates that policy definition should be supported by a high variety of research. Besides economic aspects, the importance of electrotechnical developments and advancements in information technology needs to be highlighted at this point.

1.2 Methodology

In this thesis, three distinct methodologies are used to evaluate congestion management mechanisms and their economic impact on the electricity market. The central part of the quantitative analyses is conducted by the means of a fundamental electricity market model, which optimizes the European power plant dispatch as well as the corresponding re-dispatch in high temporal resolution. Thereby, a normative cost-minimization approach is applied, which reflects the perspective of the social planner. The analysis of the dispatch results is partly supported by a cluster analysis based on Ward's minimum variance criterion, which identifies structural similarities in the optimal marginal costs of production. The third methodological building block is constituted by a theoretical analysis of different re-dispatch remuneration schemes and their impact on the surplus of re-dispatched generators. In the following, the advantages and caveats of the methods are summarized.

1.2.1 The Fundamental Electricity Market Model ***NEULING***

In the course of the presented research, the fundamental electricity market model *NEULING* has been developed.[6] The purpose of the model is to analyze the cost-minimal allocation of generation in the European electricity market under consideration of the power flows on the intermeshed high-voltage transmission network. On this basis, the costs of electricity production as well as the costs of congestion can be determined. The latter are either derived from dispatch calculations or are specified in the course of the re-dispatch optimization. The dispatch model is applied in various scenarios which represent diverse wholesale market designs and consider different resolutions with regard to the transmission network. The re-dispatch scenarios are distinguished with regard to the associated remuneration schemes. Thereby, the remuneration schemes are represented by exogenous cost parameters, which are derived according to individual criteria.

The model follows a normative approach which is characterized by the pre-defined objective of cost-minimization. The optimization is therefore conducted from the point of view of a social planner. The problem is specified subject to economic and technical constraints, as well as subject to a central balance equation which ensures that the exogenously given demand is served at each location and at every point of time. The assumption of inflexible demand constitutes the equality of the cost-minimization problem to a welfare maximization approach. According to the first welfare theorem, a competitive market may reproduce the welfare-maximizing allocation. The results of the model-based analysis may thus be interpreted as the market outcome under perfect competition. Accordingly, market power cannot be replicated by the model. Although market power is an important issue in the analysis of congestion management mechanisms, the application of the model is driven by the motivation to determine the impact of fundamental factors such as the location of generation, demand and network capacities on the market. Nonetheless, the model reveals regional scarcities which may ultimately give rise to market power.

The assumption on inelastic demand simplifies the specification of the model and its solution, since it enables a linear problem formulation. Incorporating demand elasticity would require the definition of a corresponding assumption as well as a non-linear model setup. The latter would complicate the solution of the already highly complex model.[7]

[6] A detailed model description as well as a discussion of the relevant literature is given in chapter 2.

[7] In the highest spatial resolution and under consideration of 8760 consecutive hours, the dispatch model takes approximately six days to solve.

For the given dispatch model, the real-time elasticity of electricity demand is of relevance, since it allows for the adaptation of consumption to hourly price signals. The empirical literature on the real-time elasticity however indicates that the corresponding values are very small.[8] Although the incorporation of demand elasticity into the model would reduce the overall costs of electricity supply, the absolute magnitude of the deviations are assumed to be small.

Another central assumption of the model is perfect foresight. In consequence, the impact of uncertainty and risk preferences on the market is neglected. With regard to the model results, this property will lead to an underestimation of the true dispatch and re-dispatch costs. However, with respect to the purpose of the presented analyses, this simplification facilitates the interpretation of the results considerably.

This is especially true with respect to the marginal costs of supply, which are of special importance for the identification of opportunity costs of congestion as well as for the derivation of local producer surplus. However, the explanatory value of the marginal costs with respect to market prices is limited. The dispatch model provides short-run marginal costs of supply through the value of the shadow price of the balance equation in the optimum. These marginals can be interpreted as market prices under certain assumptions, such as perfect competition and overcapacities. In reality however, the assumption on overcapacities can only be fulfilled temporarily. Therefore, the short-run marginal costs cannot be interpreted as long-run equilibrium prices of an energy-only market. Equilibrium prices would include scarcity pricing according to the peak-load pricing model which guarantees the recovery of fixed costs in the long-run.[9] In consequence, the marginal costs only indicate a lower bound of the market prices.

Furthermore, some rather technical details of the model formulation limit the degree to which the model approximates reality. These include the lack of unit commitment and physical ramping constraints, which increases the flexibility of the model and thus lowers the total costs and the volatility of the marginal costs. With regard to the re-dispatch model, the neglect of inter-temporal constraints needs to be emphasized. Although this implies an overestimation of ramping costs, it also increases the flexibility of the model artificially.

An important feature of *NEULING* is its DC load flow model, which provides a linear approximation of the physical power flows induced by local consumption and production. Especially with regard to the focus of the model applications in the context of congestion management, this is an indispensable quality. Although the relative performance of the DC load flow in comparison to alternative power flow models still needs to be tested

[8] Cf. Lijesen (2007) for estimates for the Dutch market and an overview of previous studies.
[9] For an introduction, see Stoft (2002).

for the specific framework, the literature suggests a high adequacy of the method for the evaluation of congestion management schemes.[10] Nonetheless, the linear DC load flow can neither replicate transmission losses nor reactive power flows, such that the explanatory value of the results is reduced. Especially due to the neglect of reacitve power flows congestion may be underestimated, especially in hours with relatively high reactive power flows in comparison to active flows (cf. Green (2007)). Furthermore, the sensitivity of the results to the choice of the so-called slack bus needs to be tested in greater detail.[11]

The underlying network model as well as the technical parameters have been provided by the Institute for Energy Systems, Energy Efficiency and Energy Management (ie^3) at TU Dortmund University and have been applied repeatedly.[12] However, the model only represents an aggregated network which is reduced significantly in comparison to the true European high-voltage network. Additional aggregations carried out for the sake of some market design scenarios further impair the degree to which the model represents real-world power flows.

Since *NEULING* does not include investment decisions in its present setup, the model requires the specification of assumptions on generation capacities. The assumptions are based on the power plant data base of the Institute of Energy Economics at the University of Cologne which provides geo-coded data as well as information on projected capacity commissioning and decommissioning. This enables the definition of plausible scenarios, but does not provide an accurate forecast. With respect to assumptions on local demand and RES capacities, extensive research has been conducted for the purpose of this thesis. The data has been collected from public sources and has been treated with due diligence. This process facilitates a bottom-up assignment of present-day RES capacities to the model regions, whereas forecasted extensions are allocated on the basis of additional criteria such as local potentials. With regard to local demand, the projected development of the regional population is used as an indicator. Finally, the choice of the cost parameters is decisive. The assumptions on fuel and CO_2 costs are based on public sources whereas the values of other parameters are based on own assumptions which reflect the author's experience.

Finally, the universal validity of the model results is limited by a general caveat of mathematical programs with discrete cost functions. Due to the technology-specific definition of variable costs which is for the most part independent from the hourly level of generation, the supply function is not strictly monotone. In consequence, the solution

[10] A literature review is provided in chapter 2.

[11] Although Schweppe et al. (1988) states that the definition of the slack bus is not overly critical, other sources such as Waniek (2010) suggest the selection of a node with high input.

[12] Cf. Waniek (2010).

of the overall least-cost dispatch is not necessarily unique in the sense that the optimal level of total costs can be achieved by only one combination of variable values and shadow prices. Although the application of the DC load flow reduces the chance that the dispatch of capacities of the same technology at different nodes has an identical impact on the total system costs, this does not necessarily eliminate the underlying problem of non-unique solutions. Although the repeated computation of one scenario with the same algorithm will generate identical solutions, a change of the algorithm may yield a different outcome. The assessment of the associated effect in the given context is a subject of further research.

1.2.2 Cluster Analysis

One aim of the thesis at hand is to identify structural differences between nodal price regions as well as to evaluate the loss of information produced by merging nodes into bidding zones. According to the underlying intuition, the welfare loss induced by the definition of bidding zones is the smaller, the greater the fundamental similarity between the nodes is. The criterion for similarity is given by the hourly marginal cost curves of the nodes as calculated by *NEULING*, which contain all relevant information on the local structure of supply and demand as well as on the opportunity costs of congestion induced at the node. The comparison of the marginal cost curves is accomplished by applying a hierarchical cluster analysis on the basis of Ward's minimum variance criterion (cf. Ward (1963)). This general approach has e. g. been suggested in Bjørndal and Jørnsten (2001).

Cluster analysis is a tool from multivariate statistics which is used to group variables with multiple observations according to the variables' similarity. Thereby, the available approaches differ in their basic definition of similarity.[13] Connectivity models as the one applied in this thesis rely on metrics which measure e. g. the Euclidean distances between the variables' observations. The clusters are then identified in a hierarchical process. Thus, the variables are grouped in the order of increasing distances (so-called agglomerative clustering) or split in the order of decreasing distances (divisive clustering). As a result, the number and composition of clusters are given subject to critical distance levels. In the presented analysis, a hierarchical approach is chosen.

Hierarchical models are complemented by various algorithms which allow for different linkage criteria. For example, the single-linkage approach defines the smallest distance between the individual elements of two classes as decision criterion and compares the respective values of all available combinations of classes. Alternatively, the average-linkage

[13] Refer to Handl (2010) for an introduction.

approach uses the average of the distances between the individual elements of two classes as a measure for similarity. Although both approaches are common, they are assumed not to capture the full information contained in the marginal cost curves. Since an aggregation of nodes is supposed to yield homogeneous zones in terms of absolute height of as well as in terms of variation in marginal costs, Ward's minimum variance criterion is implemented instead. The underlying algorithm finally minimizes the variance of the hourly prices within clusters and thus maximizes the variance between clusters.

Furthermore, the hierarchical model has two major advantages with respect to the analysis at hand. First, the continuous computation of optimal clusters for each possible level of aggregation provides the complete range of combinations from which to choose in only one model run. Since the desired number of price zones can hardly be specified beforehand, this property simplifies the analysis considerably. Second, the hierarchical model provides the leaps in critical distance levels between clustering steps. The evolution of the distances in the course of the clustering process reveals the rise in in-cluster heterogeneity induced by each additional aggregation. On this basis, a heuristic developed by Mojena (1977) and Milligan and Cooper (1985) can be applied to identify the critical clustering step at which the heterogeneity increases exponentially. This point can be used as an indicator for the optimal number of clusters. However, the underlying criterion has been developed in a general context which may not be perfectly suited for the analysis at hand.

However, sensitivity analyses should be conducted with regard to alternative clustering approaches. Especially centroid-based clustering may provide a powerful tool due to its efficient algorithms. Instead of explicitly evaluating distances between variables, centroid-based clustering defines cluster centers and measures the distance of the data points to the centers. Each variable is then grouped to the nearest center, which is not necessarily an element of the original data set. However, most of the associated heuristic k-means algorithms require an ex-ante specification of the number of cluster centers k, whose location is then optimized. Furthermore, the results are sensitive to the given starting points of the centers' locations.

In the end, the method is a substitute for an integrated optimization of the size and location of bidding zones. Theoretically, each constellation would need to be tested with regard to the associated loss in efficiency as indicated by the increase in total system costs induced by internal re-dispatch. Then, the loss would have to be weighted against a quantitative measure of the aggregation's benefit, for example with respect to transaction costs, liquidity and market power. The derivation of such a measure however requires additional research. Furthermore, the computational effort associated with this approach appears not to be manageable at the moment.

1.2.3 Theoretical Evaluation of Re-dispatch Remuneration Schemes

The last methodological building block of the presented thesis is provided by a theoretical model of producer surplus under nodal and zonal pricing, as e. g. applied in Ding and Fuller (2005) and Hermans et al. (2011), which is extended to incorporate the impact of re-dispatch remuneration schemes. In the zonal setup, the producer surplus thus originates from wholesale market trade as well as from re-dispatch. The aim of the model is to provide deeper insights into the incentives and the dynamic efficiency induced by re-dispatch.

The applied benchmark for the efficient allocation of generation and producer surplus is provided by nodal pricing. In the analytical part of the analysis, it is assumed that re-dispatch may implement the first-best allocation of generation, irrespective of the remuneration scheme. Furthermore, the designs are assumed not to influence the zonal spot market. The differences in the re-dispatch designs finally show in their ability to replicate the nodal producer surplus by payments to or charges from the re-dispatched generators. The model thus demonstrates whether and under which theoretical conditions the designs achieve the efficient outcome.

The analytical model relies on several very strict assumptions. First, the generators are modeled as price-taking market participants. In consequence, any considerations on the influence of market power or on strategic behavior in general are restricted to the qualitative discussion. Second, the model provides a static snapshot of producer surplus at times of re-dispatch. Accordingly, the hourly producer surplus is assumed to be the only relevant indicator of dynamic efficiency. However, this assumption can only be fulfilled in an ideal world with perfect foresight and without economies of scale in generation, as well as under the condition that the electricity network is planned efficiently by a central institution.

The definition of nodal pricing as a benchmark for dynamic efficiency is thus the most critical property of the model. According to Brunekreeft et al. (2005), the lumpiness of transmission investments may lead to large deviations between present nodal prices and their long-run equilibrium. The uncertainty of network extensions may therefore complicate the price forecast on which a power plant investment decision is based. Furthermore, Inderst and Wambach (2007) state that due to the long planning horizons for generation and network capacity investments, the alternating expectations on investments are likely to effect capacity developments. This is confirmed by Rious et al. (2011), who show that the costs of anticipating power plant investments may determine the degree to which the TSO takes new generation into account when planning the network.

Nonetheless, the literature on dynamically efficient pricing schemes suggests that nodal pricing is still the first-best instrument to induce an optimal use of the transmission network. Therefore, it is usually one component of the said pricing models. With regard to the presented analysis, the model can thus be interpreted as a framework which imposes minimum requirements on the re-dispatch designs. Any demonstrated deviations from the efficiency benchmark thus indicate even greater challenges in a more realistic setting.

1.3 Thesis Outline

As a preparation for the following sections, chapter 2 gives a detailed representation of the fundamental electricity market model *NEULING*, which has been developed for the purpose of the presented research. In addition to the model equations, references to the relevant literature on electricity market models and power flow models are provided.

In chapter 3, the implications of establishing zonal pricing in Europe are analyzed with regard to potential zonal delimitations and associated effects on total system costs. Thereby, a nodal model sets the benchmark for efficiency and provides high-resolution input data for a cluster analysis based on Ward's minimum variance method. The proposed zonal configurations are tested for sensitivity to the number of zones and structural changes in the electricity market. Furthermore, dispatch and re-dispatch costs are computed to assess the costs of electricity generation and transmission. The results highlight that suitable bidding zones are not bound to national borders and that losses in static efficiency resulting from the aggregation of nodes into zones are relatively small.

The fourth chapter is dedicated to the analysis of re-dispatch, which is still a widespread congestion management mechanism in Europe. Its popularity mainly stems from the possibility to adhere to uniform pricing on the national spot markets. Nonetheless, given the substantial delay in network expansions and increasing internal congestion, this approach has its limitations. The necessity to coordinate generation and transmission investments suggests an integration of local price signals into congestion management. With the help of theoretical models, the presented approach analyzes the short- and long-term efficiency of different re-dispatch designs and thus evaluates their ability to set regional incentives. The results show that although a well-designed re-dispatch is able to implement the optimal allocation of production, the mechanism does not induce dynamically efficient incentives for generators. Moreover, some designs may introduce additional distortions.

In chapter 5, the impact of congestion management on the efficiency of electricity markets and its influence on the allocation of costs and surpluses is quantified. Using the example of Germany, the impact of congestion management on the wholesale market is demonstrated by a comparison of the current uniform pricing system to nodal pricing as a benchmark for short-term efficiency. Both approaches deviate in their ability to internalize the opportunity costs of congestion and thus in the allocation of generation. In consequence, the presented analysis reveals significant distribution effects within Germany as well as differences in the overall wholesale market costs. The analysis of the uniform pricing system is complemented by the evaluation of three re-dispatch designs, which resolve internal congestion after the clearing of the spot market. Since even a well-designed re-dispatch mechanism will most likely miss the efficient allocation of generation in practice, the analysis indicates the magnitude of the associated bias. The results show that the details of the re-dispatch design largely determine the degree to which additional distortions are introduced.

Chapter 2

The *NEULING* Model

This chapter introduces the fundamental electricity market model NEULING, which has been developed for the purpose of this thesis. The underlying methodology is discussed in the context of the existing literature. Hereby, a special focus is on the classification of the applied DC load flow approach. Furthermore, the equations of the dispatch and re-dispatch models are presented in detail.

2.1 Some Conceptual Foundations

Electricity market models are a well established tool to analyze the fundamental principles governing the operation and the development of power markets. According to Ventosa et al. (2005), three modeling streams can be distinguished. First, simulation models aim at the reproduction of observed market conditions and results, for example to identify strategic behavior on the part of market participants. An example for this approach can be found in von Hirschhausen et al. (2007). Second, optimization models compute the market outcome with respect to a specified normative goal, for example profit maximization or welfare maximization. Profit-maximizing models usually reflect the perspective of a single price-taking market participant, as in Gatzen (2008). In contrast, welfare maximization reflects the perspective of a social planner or, according to the first welfare theorem, the result of a perfectly competitive market. A welfare maximizing approach is e. g. implemented in Leuthold et al. (2012). The third category according to Ventosa et al. (2005) comprises equilibrium models, which explicitly consider the strategic behavior of individual market players. Thereby, the models may consider one- or multi-stage settings (for an application, see Shanbhag et al. (2011)).

The electricity market model *NEULING* presented in this chapter has been developed for the purpose of an in-depth analysis of the European electricity market. The focus of the model applications is on the identification of fundamental drivers of the market outcome such as the local generation and transmission network capacities. Furthermore, the impact of market design choices and congestion management shall be analyzed under consideration of physical power flows. In this context and under consideration of the large scale of the problem at hand, the method of choice is a normative social planner approach. The following discussion thus focuses on fundamental optimization models as well as on approaches to power flow modeling.

2.1.1 Fundamental Electricity Market Models

Fundamental electricity market models optimize the satisfaction of demand by a set of power plants from the point of view of a social planner. The supply side may be defined by the available technologies (e.g. renewable, conventional and storage plants), their capacities and specific costs, as well as by technical constraints which restrict the plants' operation. Demand is either modeled as invariant and exogenously given, or as cost sensitive and flexible.[14] Both approaches reflect different assumptions regarding the price elasticity of electricity demand. Furthermore, demand my be differentiated according to products such as electricity and balancing reserves. The complexity of the optimization problem is finally driven by the structure and number of the technical or economic constraints, by intertemporality and the number of variables, which among others depends on the spatial and temporal resolution as well as on the modeling of electricity transmission (see section 2.1.2). The central results of the optimization comprise information on the spatial and temporal allocation of demand and supply, on regional power exchange, the costs and benefits of electricity supply as well as on the marginal values of production and transmission.

Fundamental electricity market models may be distinguished in cost minimization and welfare maximization approaches. The concepts usually imply different assumptions on demand elasticity. Generally, cost minimizing models make use of fixed (i. e. completely inelastic) demand values and therefore only optimize supply. In contrast, welfare maximizing models usually compute the optimal difference between the utility and the cost functions. Therefore, the objective function implicitly comprises information on the slope of the inverted demand function, and thus on elasticity. Independent of these classical model setups, both mathematical problem formulations can theoretically be adapted to inelastic and elastic demand functions. The combination of welfare maximization and inelastic demand however requires a specification of the value of lost load

[14] Since (marginal cost-based) prices are an ex-post interpretation of the market clearing constraint's dual variable, demand cannot be represented by a direct function of the market price. Instead, the value of consumption is calculated as the space below the inverted demand function in dependency of the supplied quantity.

(VOLL), in order to provide the solvers with a bounded solution space. Irrespective of the assumed demand elasticity, both setups are connected via the duality of the welfare maximization problem and the expenditure minimization problem of the social planner. The concept of duality implies that the objective function of one problem forms a constraint of the other and vice versa. Furthermore, it ensures that the optimal solutions of the primal variables are identical in both problems and that the models' dual variables take the reciprocal values of each other.[15] Concerning the social planner approach in general, the first welfare theorem implies that the socially optimal outcome can be implemented in a perfectly competitive market. In the context of the electricity market, this is illustrated in Schweppe et al. (1988).

Both cost minimization and welfare maximization approaches have been widely applied. For the case of welfare maximization, examples can be found in Weigt (2006) and Green (2007), whereas cost minimization models are applied in Bartels (2009) and Nicolosi (2012). With regard to the model specification and parameterization, welfare maximizing models require a non-linear problem formulation and the definition of assumptions on demand elasticity. Since the real-time elasticity of electricity demand is assumed to be small, the simplification applied in cost-minimizing models is often accepted in exchange for less computational effort.[16]

Non-linear elements may also be introduced into fundamental electricity market models by considerations of unit commitment, as in Leuthold et al. (2012). With the help of mixed-integer problem formulations, technical ramping constraints an minimum load conditions may be considered in greater detail. Again, this increases the computational complexity of the models. However, the alternative of applying linearized operational constraints as e. g. discussed in Kuntz and Müsgens (2007) has been shown not to impair the quality of the results significantly (see Abrell et al. (2008)).

Further issues influencing the complexity of the model are the considered time horizon as well as the applied temporal resolution. The time horizon is especially relevant for investment models which consider the economic impact of additional capacities over their respective lifetime.[17] With regard to dispatch models or dispatch components of investment models, the temporal resolution influences the representativeness of the results. Instead of computing the operation of power plants over an entire year, the definition of type-days allows for a reduction of the computational effort. Type-days are usually chosen to reflect typical combinations of load and feed-in from renewable energy sources (RES) and thus often neglect extreme events. This approach is applied both in dispatch as well as in combined dispatch and investment models, such as in Nüßler

[15] A general comment on duality can e. g. be found in Chiang and Wainwright (2005).
[16] On the real-time elasticity of electricity demand, see Lijesen (2007).
[17] Cf. EWI (2011).

(2012) and EWI (2011). In contrast, Gatzen (2008) chooses a model specification with reflects 8760 consecutive hours of a given year for the purpose of the assessment of the profitability of pumped-storage plants. As demonstrated in Nicolosi (2012), the temporal resolution may influence the results of investment models considerably, especially in systems with a high share of RES.

Time is also an important factor in stochastic electricity market models, which allow for the representation of a gradual disclosure of market-relevant information. In contrast to models which are based on the assumption of perfect foresight, unit commitment or investment decisions may be made without full knowledge about future developments. This may e. g. concern the production of RES or the evolution of demand. Corresponding examples may be found in Meibom et al. (2006) and Abrell and Kunz (2012).

Furthermore, fundamental electricity market models can be differentiated according to the representation of the transmission network. An overview of common approaches is given in the following.

2.1.2 The Power Flow Model

The consideration of electricity exchange is an important property of fundamental electricity market models which aim at a realistic representation of an interconnected electricity system. A simple approach to the analysis of power exchange is the definition of one-node regions and the use of variables which define bi-directional flows between the regions. In this setup, the limits of power exchange are commonly defined by so-called net transfer capacities (NTC). Since the physical flows in the real world are governed by Kirchhoff's and Ohm's laws, the NTC-approach is a substantial simplification. Given that the constellation of local consumption and production influences the power flows on the entire network, the results of NTC-based models will be sub-optimal or even infeasible in reality.

The available alternatives are alternating current approaches (AC), direct-current approaches (DC) and the use of power transfer distribution matrices (PTDF). The properties of the models are discussed in detail in Schweppe et al. (1988) and Stigler and Todem (2005) (both AC and DC), as well as in Waniek (2010) (PTDF) and Nüßler (2012) (all approaches). The AC approach constitutes the most detailed representation of power flows, since it considers both active and reactive power as well as transmission losses. Thus, the flows on highly complex networks can be reproduced. However, solving the AC models requires an iterative process which may not converge at all times.[18] Furthermore, the integration of an AC approach into large-scale electricity market models is challenging. Thus, applications as in Barth (2007) are rare.

The DC approach provides a linear approximation of power flows and can thus be directly incorporated into electricity market models. The linearization is achieved by a neglect of reactive power flows, by the assumption of small phase angles and by a normalization of the voltage magnitudes to one. According to Schweppe et al. (1988), all of the assumptions become more inaccurate for lower voltage and distribution lines, as well as in times of high line loading. Furthermore, assuming a constant rather than a time-variant resistance-reactance ratio will lead to approximation errors. As stated in Schweppe et al. (1988), the last assumption may however facilitate the interpretation of a market model's results. Purchala et al. (2005) test the validity of the DC assumptions and conclude that the overall performance of the approximation is good, although errors on individual lines may occasionally be significant.

Power transfer distribution factors also allow for a linear representation of power flows. Just as the DC approach, PTDF matrices can neither reflect reactive power flows nor losses. The underlying factors may either be derived from AC or from DC models and reflect the load flows in a specific consumption and production constellation. Thus, the matrices vary with the use of the network. However, the matrices are usually defined on the basis of a representative constellation rather than for each each of them. Baldick (2002) and Lui and Gross (2002) demonstrate theoretically and empirically that this approximation is usually justifiable. However, Duthaler et al. (2008) highlight that the approximation error becomes substantial if the calculations are based on a zonal model. This is especially the case, if the zones are not defined in accordance with the fundamental market structure. In general, a new calculation of PTDF matrices is inevitable in the case of a change in the network topology.

Both DC and PTDF approaches have been applied in various settings. The DC approach is often applied in the context of nodal pricing models. For example, Overbye et al. (2004) demonstrate that the DC-based power flow calculation in locational marginal pricing models is fairly close to the AC solution using the case of the Midwest U.S. transmission system. Further applications in nodal pricing scenarios are among others presented in Weigt (2006), Green (2007) and Kunz (2009). In contrast, the PTDF approach is often used in the analysis of international power flows. Waniek (2010) demonstrates that the application of PTDF matrices is preferred to NTC-based specifications of international transmission capacities with respect to welfare.

[18] Cf. Groschke et al. (2009).

Both approaches are also common in the fundamental analysis of re-dispatch. Re-dispatch is a congestion management approach applied within bidding zones that resolves internal congestion by the means of adjusting power plant generation schedules. Just as in the case of dispatch models, the re-dispatch optimization problem can be specified by a social planner approach. Thereby, the accurate representation of power flows is of special importance. Nüßler (2012) uses a PTDF approach to calculate re-dispatch in the German market. Also Linnemann et al. (2011) use a PTDF approach and furthermore demonstrate a method to integrate (n-1)-security constraints into a re-dispatch model by the means of an iterative process. DC approaches are applied in Kunz (2011) and Görner et al. (2008), who also emphasize the possibility of network topology optimization as a congestion management option.

2.1.3 Classification of the *NEULING* Model

The New European Linear Investment and Grid Model *NEULING* as applied in the thesis at hand calculates the cost-minimal generation dispatch and re-dispatch of a given power plant portfolio for 8760 hours of a year. The high temporal resolution allows for the consideration of general structural patterns such as seasonal variations in load as well as of extreme events.

The spot market dispatch of conventional power plants is determined such that the residual demand (exogenous system demand including network losses less electricity produced by renewable energy sources and less must-run generation from combined heat and power plants) is met in each hour. Furthermore, the demand for positive and negative balancing reserve needs to be covered. The conventional power plant fleet including hydro storage (Hyd-S), pumped storage (Hyd-PS) and compressed air energy storage (CAES) plants is grouped into 25 so-called vintage classes according to primary fuel, age and technological characteristics such as efficiency. Each vintage class is then dispatched under consideration of variable and ramping costs, as well as linearized minimum- and part-load restrictions.

The cost-minimal nodal dispatch is subject to network restrictions implemented by a DC power flow model. The DC power flow gives an approximation of the physical flows over the high-voltage alternating current transmission network in the so-called core model regions. Thereby, both losses as well as reactive power are neglected in order to keep the problem linear. The lines' physical capacities are standardized and multiplied with a factor of 0.8 in order to account for a security margin. Furthermore, interconnectors to and in between so-called satellite regions are implemented by the use of net transfer capacities (NTC).

The basic spatial resolution of *NEULING* gives a nodal representation of the core model regions. Depending on the object of investigation, the nodes can be aggregated into zones. Although the zonal dispatch assumes internal copperplates, the information on the nodal net injections is preserved. Thus, the usage of the internal grid can be determined ex-post and the necessary re-dispatch in case of violations of network constraints can be calculated based on the plants' operating status and their utilization.

The optimal flow-based re-dispatch is represented by the least-cost combination of upward and downward ramping, which at the same time relieves the overloaded line and keeps the balance between demand and supply at each node. The marginal costs of a plant's upward re-dispatch are given by its variable fuel and ramping costs, while the marginal savings of its downward re-dispatch equal the avoided costs of generation. This basic setup corresponds to a cost-based mechanism in which the generators are either compensated or charged as to render them indifferent with regard to being re-dispatched.

2.2 Technical Model Description: Dispatch

In the following, the dispatch problem as solved by *NEULING* is introduced in detail. Its core is defined by cost equations as well as by market clearing and load flow constraints. Further equations restrict the dispatch solution by imposing technical limits on power plant operation. Additionally, the provision of positive and negative reserve may set upper or lower bounds to spot market production.

2.2.1 Total Costs of Electricity Production

NEULING minimizes total costs of electricity production TC over all model regions n for a given year y. Thereby, TC comprises variable costs of production VC^{PROD}, variable ramping costs VC^{RTO} and fixed operation and maintenance costs FC^{OM}:

$$\min_{y}! TC_y = VC_y^{PROD} + VC_y^{RTO} + FC_y^{OM}. \tag{2.1}$$

The variable costs of production equal the sum of fuel and CO_2 costs $fuel\_c$ as well as miscellaneous variable costs $other\_vc$ multiplied by electricity production GEN over regions n and all generation technologies t. The set of technologies includes both conventional (nuclear and thermal) as well as storage technologies such as pumped hydro storage, hydro reservoirs and compressed air energy storage (CAES). The latter subset may be addressed separately by the use of the index st. Compared to producing units, relatively higher costs apply to the portion of capacities which are kept ready to operate without actively contributing to the hourly demand-supply-balance in order to avoid start-ups or to provide positive balancing reserve: These capacities ($CAP\_RTO - GEN$) are priced with part load fuel costs $fuel\_c^{PL}$ and $other\_vc$. Furthermore, compressors of pumped storage or CAES plants operating ($COMP$) and those only ready to operate (CAP_RTO_COMP) also induce $other\_vc$. The associated consumption of energy is priced implicitly with the marginal cost of electricity supply since it raises the demand for electricity.

$$\begin{aligned} VC_y^{PROD} = &\sum_{h,n,t} GEN_{y,h,n,t} * (fuel\_c_{y,h,n,t} + other\_vc_{n,t}) \\ &+ \sum_{h,n,t} (CAP\_RTO_{y,h,n,t} - GEN_{y,h,n,t}) \\ &\quad * (fuel\_c^{PL}_{y,h,n,t} + other\_vc_{n,t}) \\ &+ \sum_{h,n,st} COMP_{y,h,n,st} * other\_vc_{n,st} \\ &+ \sum_{h,n,st} (CAP\_RTO\_COMP_{y,h,n,st} - COMP_{y,h,n,st}) * other\_vc_{n,st} \end{aligned} \tag{2.2}$$

Variable costs of ramping procedures are approximated by the part of capacity ramped-up in a given hour CAP_UP and CAP_UP_COMP, multiplied by fuel and attrition costs ($start\_attr$) incurred during the required start-up time $start\_time$. Whereas ramping up is thus associated with costs, ramping down is assumed to be free. However, reducing generation comes at the price of opportunity costs of ramping up again at a later point in time. Ramping costs are relevant for generation units of conventional technologies as well as for turbines and compressors of storage plants.

$$\begin{aligned} VC_y^{RTO} = &\sum_{h,n,t} CAP\_UP_{y,h,n,t} \\ &\quad * (fuel\_c_{y,h,n,t} + start\_attr_t) * start\_time_{y,h,n,t} \\ &+ \sum_{h,n,st} CAP\_UP\_COMP * start\_attr_t * start\_time_{y,h,n,t} \end{aligned} \tag{2.3}$$

Additionally to the variable costs of electricity supply, fixed operation and maintenance costs fom_c per installed MW of capacity $instcap$ enter the calculation of the total annual costs.

$$FC^{OM} = \sum_{n,t} instcap_{y,n,t} * fom\_c_t \tag{2.4}$$

2.2.2 Market Clearing and Network Capacity Constraints

The central constraint in the optimization is the balance equation which ensures that demand is met at all times. The hourly demand values of *load* include both final consumption and network losses, but not the consumption of storage plants which is modeled endogenously. Energy produced by renewable energy sources *renewables* is provided exogenously to the model and reduces total demand to residual demand *res_load*:

$$res\_load_{y,h,n} = load_{y,h,n} - renewables_{y,h,n} \tag{2.5}$$

The residual load is then provided for by domestic generation and power exchange between model regions. Exchange between so-called core regions ($NETINPUT$) is represented by a DC load flow, whereas trade with and between so-called satellite regions EXC is based on net transfer capacities (NTC). Consumption of storage plants increases the required production, while curtailment of electricity produced by renewable energy sources (RES-E) decreases total supply. Curtailment comes at costs of zero and is thus applied when there is excess supply, either due to renewable infeed or ramping constraints and balancing market obligations of conventional capacities. It is restricted by the hourly infeed from renewables, such that $CURTAIL_{y,h,n} \leq renewables_{y,h,n}$. The balance equation is now given by:

$$\begin{aligned} &\sum_t GEN_{y,h,n,t} - \sum_{st} COMP_{y,h,n,t} - NETINPUT_{y,h,n} + \sum_m EXC_{y,h,m,n} \\ &= res\_load_{y,h,n} + \sum_m EXC_{y,h,n,m} + CURTAIL_{y,h,n} \end{aligned} \tag{2.6}$$

Thereby, $NETINPUT$ is specified as follows, where $DELTA$ is a free variable representing the phase-angle at a given node and b is the network susceptance matrix which represents the susceptances of all lines connecting nodes n and m:[19]

$$NETINPUT_{y,h,n} = \sum_m b_{y,n,m} * DELTA_{y,h,m} \tag{2.7}$$

The DC load flow is restricted by the available line capacities:

$$-av\_sec * cap\_line_{y,l} \leq \sum_n k_{y,n,l} * DELTA_{y,h,n} \leq av\_sec * line\_cap_{y,l} \tag{2.8}$$

where *av_sec* times *line_cap* equals the thermal capacity of line l reduced by a security margin which is a linear substitute for a (n-1)-security criterion. k represents the network transfer matrix which relates the susceptance of a line to its start- and end-nodes. In

[19] In a DC load flow, the susceptance of a line defines the degree to which power fed in at a connected node flows through the given line. It is determined by the reactance and resistance of the line.

order to guarantee the solvability of the DC load flow problem, $DELTA$ is set to zero at the so-called slack node via a non-zero parameter *slack*. If all bus injections were specified, the energy balance constraint would almost certainely not be satisfied due to an overspecification of the model (cf. Schweppe et al. (1988)). Thus, the following equation is specified:

$$slack_n * DELTA_{y,h,n} = 0 \tag{2.9}$$

The positive variable EXC is restricted via the following constraint to the available net transfer capacity *ntc_cap*, which typically varies per season:

$$EXC_{y,h,n,m} \leq av\_ntc_h * ntc\_cap_{y,n,m} \tag{2.10}$$

2.2.3 Balancing Reserve Market Constraints

NEULING only considers the capacity provision of balancing reserve markets, not the call. Thus, the model calculates the least-cost alternatives for positive and negative reserve which implies a reduction of available capacities for spot market production and an increase of must-run generation respectively. The central balancing market constraints balance national supply and demand for each reserve product (here: secondary reserve SR and tertiary reserve TR) under consideration of prequalification constraints. Thereby, demand is specified per country c.

The example for positive secondary reserve *SR_pos* shows that standing and spinning reserves (POS_SR_STAND and POS_SR_SPIN) are differentiated. Standing reserves may be provided by (extramarginal) generating units not operating at the spot market, which start up quickly enough as to ensure timely production. Less flexible technologies may only serve as spinning reserve, i.e. when they are already generating and guarantee sufficiently quick increases in production levels. Accordingly, technology specific binary prequalification parameters (av_SR_stand and av_SR_SPIN) are assigned under consideration of the plants' flexibility and the lead times for the given reserve product. Furthermore, a separate variable for compressors of storage plants participating in the balancing market, POS_SR_COMP, is introduced. Compressors may only provide positive reserve by ramping-down (spinning) units, thus reducing consumption.

$$
\begin{aligned}
SR\_pos_c = &\sum_{n \in c,t} av\_SR\_stand_t * POS\_SR\_STAND_{y,h,n,t} \\
&+ \sum_{n \in c,t} av\_SR\_spin_t * POS\_SR\_SPIN_{y,h,n,t} \\
&+ \sum_{n \in c,st} av\_SR\_spin_{st} * POS\_SR\_COMP_{y,h,n,st}
\end{aligned}
\tag{2.11}
$$

The case of negative secondary reserve SR_neg is different to the extent that it can either be provided by spinning generation capacities ramping down or by both standing and (not yet fully used) spinning compressor capacities increasing their consumption.

$$
\begin{aligned}
SR\_neg_c = &\sum_{n \in c,t} av\_SR\_spin_t * NEG\_SR_{y,h,n,t} \\
&+ \sum_{n \in c,t} av\_SR\_spin_{st} * NEG\_SR\_SPIN\_COMP_{y,h,n,st} \\
&+ \sum_{n \in c,st} av\_SR\_stand_{st} * NEG\_SR\_STAND\_COMP_{y,h,n,st}
\end{aligned}
\tag{2.12}
$$

Both equations 2.11 and 2.12 can be reproduced for the case of tertiary reserve.

2.2.4 Storage Constraints

Storage plants require separate equations accounting for the intertemporal constraints on storage levels. The storage volume is implicitly given by the installed capacity $inst\_cap$ of the generating units multiplied by a volume factor vol_factor, which gives the average regional ratio of capacity and storage. The storage level ($STORAGE\_LEVEL$) at the beginning of the modelled time period is determined by an additional factor, $initial\_level$:

$$
\begin{aligned}
&STORAGE\_LEVEL_{y,h=1,n,st} \\
&= initial\_level_{n,st} * vol\_factor_{n,st} * inst\_cap_{y,n,st}
\end{aligned}
\tag{2.13}
$$

The upper and lower bounds of the storage level are given by the size of the storage and buffers for additional charging and discharging due to calls of secondary or tertiary balancing reserve (SR, TR).

$$\begin{aligned}
&STORAGE_LEVEL_{y,h,n,st} \\
&\leq vol_factor_{n,st} * inst_cap_{y,n,st} \\
&- av_SR_spin_{st} * NEG_SR_SPIN_COMP_{y,h,n,st} \\
&- av_SR_stand_{st} * NEG_SR_STAND_COMP_{y,h,n,st} \\
&- av_TR_spin_{st} * NEG_TR_SPIN_COMP_{y,h,n,st} \\
&- av_TR_stand_{st} * NEG_TR_STAND_COMP_{y,h,n,st}
\end{aligned} \tag{2.14}$$

$$\begin{aligned}
&STORAGE_LEVEL_{y,h,n,st} \\
&\geq av_SR_spin_{st} * POS_SR_SPIN_{y,h,n,st} \\
&+ av_SR_stand_{st} * POS_SR_STAND_{y,h,n,st} \\
&+ av_TR_spin_{st} * POS_TR_SPIN_{y,h,n,st} \\
&+ av_TR_stand_{st} * POS_TR_STAND_{y,h,n,st}
\end{aligned} \tag{2.15}$$

The intertemporality of storage plant dispatch is embodied by the following dynamic equation relating the hourly change of the storage level to the preceding compressor and generator operation. Thereby, the efficiencies (eff, eff_comp) of both components are accounted for, as well as natural inflow ex_inflow in the case of hydro storage.

$$\begin{aligned}
&STORAGE_LEVEL_{y,h,n,st} \\
&= STORAGE_LEVEL_{y,h-1,n,st} \\
&+ eff_comp_{st} * COMP_{y,h-1,n,st} - \frac{1}{eff_comp_{st}} * GEN_{y,h-1,n,st} \\
&+ ex_inflow_{h-1,n,st} * vol_factor_{n,st} * inst_cap_{y,n,st}
\end{aligned} \tag{2.16}$$

Furthermore, a yearly cycle may be defined for pumped storage and CAES plants by the use of the following equation:

$$\begin{aligned}
&STORAGE_LEVEL_{y,h=1,n,st} \\
&= STORAGE_LEVEL_{y,h=8760,n,st} \\
&+ eff_comp_{st} * COMP_{y,h=8760,n,st} - \frac{1}{eff_comp_{st}} * GEN_{y,h=8760,n,st}
\end{aligned} \tag{2.17}$$

2.2.5 Operational Constraints

The operation of power plants at the spot market is physically limited by their technical availability av_tech (typically varying per season) and potential balancing market obligations. This is reflected via the capacity ready to operate CAP_RTO. Its lower bound is given by the level of spot market production and the contracted positive reserve provided by spinning units. The latter ensures that the corresponding capacities are ready to operate in the (hypothetical) case of a call.

$$\begin{aligned} CAP\_RTO_{y,h,n,t} \geq\ & GEN_{y,h,n,t} \\ & + av\_SR\_spin_t * POS\_SR\_SPIN_{y,h,n,t} \\ & + av\_TR\_spin_t * POS\_TR\_SPIN_{y,h,n,t} \end{aligned} \tag{2.18}$$

The upper bound of CAP_RTO is defined by the plants availability and the provision of positive standing reserves. The latter ensures that production may be increased in case of a call, but does not require the capacity to be ramped-up already.

$$\begin{aligned} CAP\_RTO_{y,h,n,t} \leq\ & av\_tech_{h,n,t} * inst\_cap_{y,n,t} \\ & - av\_SR\_stand_t * POS\_SR\_STAND_{y,h,n,t} \\ & - av\_TR\_stand_t * POS\_TR\_STAND_{y,h,n,t} \end{aligned} \tag{2.19}$$

The level of capacity ready to operated can be influenced on an hourly basis by upward and downward ramping, CAP_UP and CAP_DOWN. Thus, the following dynamic constraint holds:

$$\begin{aligned} CAP\_RTO_{y,h,n,t} =\ & CAP\_RTO_{y,h-1,n,t} \\ & + CAP\_UP_{y,h-1,n,t} - CAP\_DOWN_{y,h-1,n,t} \end{aligned} \tag{2.20}$$

The variable CAP_RTO eventually restricts the level of spot market production. While the upper level of production is implicitly stated by 2.18, its lower bound is set by an approximation of minimal load levels ($min\_load * CAP\_RTO$) plus obligations on negative reserve markets. The additive connection ensures that a call of negative reserve does not lead to the plant being switched off completely. Furthermore, the connection between CAP_RTO and generation indirectly ensures that spinning reserves are only provided by producing units.

$$\begin{aligned} GEN_{y,h,n,t} \geq\ & min\_load_t * CAP\_RTO_{y,h,n,t} \\ & + av\_SR\_spin_t * NEG\_SR_{y,h,n,t} \\ & + av\_TR\_spin_t * NEG\_TR_{y,h,n,t} \end{aligned} \tag{2.21}$$

The restrictions on and imposed by capacity ready to operate also apply to compressor units. Thereby, the specific definitions of reserves provided by compressors have to be accounted for.

$$\begin{aligned} CAP\_RTO\_COMP_{y,h,n,st} \geq\ & COMP_{y,h,n,st} \\ & + av\_SR\_spin_{st} * NEG\_SR\_SPIN\_COMP_{y,h,n,st} \\ & + av\_TR\_spin_{st} * NEG\_TR\_SPIN\_COMP_{y,h,n,st} \end{aligned} \tag{2.22}$$

$$\begin{aligned} CAP\_RTO\_COMP_{y,h,n,st} \leq\ & av\_tech_{h,n,st} * inst\_cap_{y,n,st} \\ & - av\_SR\_stand_{st} * NEG\_SR\_STAND\_COMP_{y,h,n,st} \\ & - av\_SR\_stand_{st} * NEG\_TR\_STAND\_COMP_{y,h,n,st} \end{aligned} \tag{2.23}$$

$$\begin{aligned} CAP\_RTO\_COMP_{y,h,n,st} =\ & CAP\_RTO\_COMP_{y,h-1,n,st} \\ & + CAP\_UP\_COMP_{y,h-1,n,st} \\ & - CAP\_DOWN\_COMP_{y,h-1,n,st} \end{aligned} \tag{2.24}$$

$$\begin{aligned} COMP_{y,h,n,st} \geq\ & min\_load_{st} * CAP\_RTO\_COMP_{y,h,n,st} \\ & + av\_SR\_spin_{st} * POS\_SR_{y,h,n,st} \\ & + av\_SR\_spin_{st} * POS\_TR_{y,h,n,st} \end{aligned} \tag{2.25}$$

2.3 Technical Model Description: Re-dispatch

The concept of re-dispatch may be categorized as curative congestion management. Curative instruments address congestion after the closure of the dispatch markets and the announcement of the resulting generation schedules.[20] Consequently, they imply the invisibility of network constraints within the bidding zone and the potential infeasibility of power flows resulting from trade.

In accordance with common practice, the re-dispatch module of *NEULING* is therefore decoupled from the dispatch problem. The connection between both parts is established by transferring the dispatch results to the re-dispatch model: (Dispatch-) Optimal generation levels, balancing market obligations and the NTC-based exchange between core and satellite regions eventually enter the re-dispatch calculation as exogenous input parameters. The re-dispatch module also requires information on further parameters

[20] In contrast, preventive congestion management mechanisms aim at influencing the dispatch before market closure as to reduce the risk of overloading network elements.

such as demand, RES-E and variable costs, which remain unchanged with respect to the dispatch. Concerning the modules' inputs, the crucial difference lies in the network parameters. As a basis for re-dispatch, all flows over the entire network have to be calculated, whereas the dispatch only considers transmission between bidding zones. Therefore, the set of transmission lines is more comprehensive in the second model step. Furthermore, the lines' start and end nodes have to be redefined.

In the following, the implementation of re-dispatch in *NEULING* is discussed equation by equation.

2.3.1 Re-dispatch Costs

The objective function of the re-dispatch module is defined by the sum of the hourly variable costs of re-dispatch, which is minimized in the course of the solution process.

$$\text{min! } RC_y = \sum_{h,n} VC\_REDIS_{y,h,n} \tag{2.26}$$

The variable costs equal the sum of additional fuel and CO_2 costs, other variable costs of production and ramping costs incurred by increasing generation at one point (GEN_REDIS_up) and the corresponding savings realized by decreasing generation at another point (GEN_REDIS_down).[21] In the case of upward re-dispatch, separate variables are introduced for standing and part load generators: Positive re-dispatch of standing generators ($GEN\_REDIS\_up^{STAND}$) is restricted to quick-starting technologies, while re-dispatch from part load operation ($GEN\_REDIS\_up^{PL}$) is priced with part load variable costs (vc^{PL}). Furthermore, the consumption of compressors may be decreased as an option of positive re-dispatch ($COMP\_REDIS\_up$) or increased as a negative re-dispatch option ($COMP\_REDIS\_down$). Since compressors are quick starting units and do not incur significant losses from part load operation, the variables are not distinguished any further. The underlying cost parameters equal those of the dispatch model and are summarized by the production costs vc or vc^{COMP}, and ramping

[21] The model does not explicitly consider any remuneration schemes which compensate re-dispatched generators. This is consistent with the chosen social planner approach. Nonetheless, the variable costs of re-dispatch as calculated by *NEULING* may be thought of as the outcome of perfect cost-based re-dispatch. For a detailed discussion of re-dispatch remuneration schemes refer to chapter 4.3.

costs vc_rto or vc_rto^{COMP}.

$$\begin{aligned} VC\_REDIS_{y,h,n} = & \sum_t GEN\_REDIS\_up_{y,h,n,t} * (vc_{y,h,n,t} + vc\_rto_{y,h,n,t}) \\ & + \sum_t GEN\_REDIS\_up^{STAND}_{y,h,n,t} * (vc_{y,h,n,t} + vc\_rto_{y,h,n,t}) \\ & + \sum_t GEN\_REDIS\_up^{PL}_{y,h,n,t} * \left(vc^{PL}_{y,h,n,t} + vc\_rto_{y,h,n,t}\right) \\ & - \sum_t GEN\_REDIS\_down_{y,h,n,t} * vc_{y,h,n,t} \\ & + \sum_{st} COMP\_REDIS\_down_{y,h,n,st} * \left(vc^{COMP}_{y,h,n,st} + vc\_rto^{COMP}_{y,h,n,st}\right) \\ & - \sum_{st} COMP\_REDIS\_up_{y,h,n,st} * vc^{COMP}_{y,h,n,t} \end{aligned} \tag{2.27}$$

2.3.2 Balance and Network Capacity Constraints

In order to quantify the need for re-dispatch, the power flows resulting from the dispatch have to be calculated once more. Since in a zonal setup the dispatch model only considers a limited set of network constraints, the true flows are obscured. Therefore, the re-dispatch model uses the nodal results for generator and compressor operation (*gen*, *comp*), NTC-based trade (*exc*), the curtailment of RES-E (*curtail*), as well as the nodal residual demand parameters as inputs for the calculation of the associated load flow-based nodal net exchange $NETINPUT\_DIS$. The net exchange is defined analogously to chapter 2.2.2.

$$\begin{aligned} & \sum_t gen_{y,h,n,t} - \sum_{st} comp_{y,h,n,st} - NETINPUT\_DIS_{y,h,n} + \sum_m exc_{y,h,m,n} \\ & = res\_load_{y,h,n} + \sum_m exc_{y,h,n,m} - curtail_{y,h,n} \end{aligned} \tag{2.28}$$

Again, the load flow calculation requires the fixation of the dispatch-related phase angle ($DELTA\_DIS$) at the slack node.

$$slack_n * DELTA\_DIS_{y,h,n} = 0 \tag{2.29}$$

After these preparatory load flow calculations, the re-dispatch balance equation can be defined. It implicitly requires the modifications of the DC power flows not to impair the local balance of supply and residual demand. Thus, all re-dispatch related changes in the nodal balance need to net out exactly. Changes may be induced by ramping domestic generators and compressors up or down, by additional RES-E curtailment (RES_down)

and/or by modifying the load flow-based net exchange $NETINPUT\_REDIS$.

$$\begin{aligned}
&\sum_t \left(GEN_REDIS_up_{y,h,n,t} + GEN_REDIS_up^{STAND}_{y,h,n,t}\right) \\
&+\sum_t \left(GEN_REDIS_up^{PL}_{y,h,n,t} - GEN_REDIS_down_{y,h,n,t}\right) \\
&-\sum_{st} (COMP_REDIS_down_{y,h,n,st} - COMP_REDIS_up_{y,h,n,st}) \\
&-RES_down_{y,h,n} - NETINPUT_REDIS_{y,h,n} \\
&=0
\end{aligned} \tag{2.30}$$

For the calculation of the re-dispatch induced power flows, a separate slack condition has to be defined.

$$slack_n * DELTA\_REDIS_{y,h,n} = 0 \tag{2.31}$$

The final goal of the re-dispatch is to relieve overloaded transmission lines. Thus, the sum of dispatch and re-dispatch related load flows needs to respect the individual line capacities.

$$\begin{aligned}
-av_sec * cap_line_{y,l} \leq &\sum_n k_{y,n,l} * DELTA_DIS_{y,h,n} \\
&+\sum_n k_{y,n,l} * DELTA_REDIS_{y,h,n} \leq av_sec * line_cap_{y,l}
\end{aligned} \tag{2.32}$$

2.3.3 Operational Constraints

The last part of the re-dispatch model consists of the capacity constraints which limit the ramping of generators and compressors. First the upward re-dispatch out of part load generation is restricted to the capacity currently in part load operation (cap^{PL}), which is an output of the dispatch.

$$GEN\_REDIS\_up^{PL}_{y,h,n,t} \leq cap^{PL}_{y,h,n,t} \tag{2.33}$$

Furthermore, the positive re-dispatch of capacities standing or in full load operation is limited to the unused capacity *cap_unused*. Again, *cap_unused* is an output from the dispatch model and equals the part of capacity neither used for generation nor reserved for balancing services. As stated above, capacities standing as a result of the dispatch may only start up if the technology is flexible enough.

$$GEN\_REDIS\_up^{STAND}_{y,h,n,t} + GEN\_REDIS\_up_{y,h,n,t} \leq cap\_unused_{y,h,n,t} \tag{2.34}$$

In the case of downward re-dispatch, GEN_REDIS_down is limited by the dispatch level of generation as well as by technological or reserve-related minimum load levels (min_gen).

$$GEN\_REDIS\_down_{y,h,n,t} \leq gen_{y,h,n,t} - min\_gen_{y,h,n,t} \tag{2.35}$$

Analogously, the re-dispatch from compressors is limited.

$$COMP\_REDIS\_up_{y,h,n,st} \leq comp_{y,h,n,st} - min\_comp_{y,h,n,st} \tag{2.36}$$

$$COMP\_REDIS\_down_{y,h,n,st} \leq cap\_comp\_unused_{y,h,n,st} \tag{2.37}$$

Concerning the use of storage technologies, positive re-dispatch of the generators requires sufficiently high storage levels. The hourly storage level values ($storage$) are given by the dispatch.

$$storage_{y,h,n,st} - \frac{1}{eff_{st}} \left(GEN\_REDIS\_up^{STAND}_{y,h,n,t} + GEN\_REDIS\_up_{y,h,n,t} \right) \geq 0 \tag{2.38}$$

Finally, RES-E curtailment in the course of congestion management is restricted to the remaining in-feed after dispatch.

$$RES\_down_{y,h,n} \leq renewables_{y,h,n} - curtail_{y,h,n} \tag{2.39}$$

Chapter 3

From Nodal to Zonal Pricing - A Bottom-Up Approach to the Second-Best*

Congestion management schemes have taken a prominent place in current electricity market design discussions. In this paper, the implications of establishing zonal pricing in Europe are analyzed with regard to potential zonal delimitations and associated effects on total system costs. Thereby, a nodal model sets the benchmark for efficiency and provides high-resolution input data for a cluster analysis based on Ward's minimum variance method. The proposed zonal configurations are tested for sensitivity to the number of zones and structural changes in the electricity market. Furthermore, dispatch and re-dispatch costs are computed to assess the costs of electricity generation and transmission. The results highlight that suitable bidding zones are not bound to national borders and that losses in static efficiency resulting from the aggregation of nodes into zones are relatively small.

3.1 Introduction

On the way to the internal energy market (IEM) special attention is paid to possible advancements in congestion management schemes. Important improvements have already been made by the successive introduction of implicit auctions of transmission capacities, e.g. in the case of the Central Western European (CWE) market coupling

*Paper submitted to Energy Economics. A previous version of this paper was presented in May 2012 at the 9^{th} International Conference on the European Energy Market, held in Florence, Italy.

between France, the BeNeLux states and Germany. Following this process, the scope of the discussion has broadened to include national transmission networks as well.

In the recently published Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (CACM, ACER (2011)) the Agency for the Cooperation of Energy Regulators (ACER) explicitly recommends the definition of bidding areas or zones whose implementation is meant to support adequate congestion management and to contribute towards local price signals. Thereby, the zonal delimitations shall be proposed by the transmission system operators (TSOs) and may span one or more control areas in case no significant congestion occurs within or between areas.

However, the CACM guidelines do not clarify at which degree of congestion a bottleneck qualifies as significant. Instead, ACER defines "overall market efficiency" as the main principle in the definition of zones, including aspects of "socio economic welfare, liquidity, competition, network structure and topology, planned network reinforcement and re-dispatching costs" (cf. ACER (2011), p. 7). Especially, the TSOs' analysis of zonal delimitations shall be based on detailed data on re-dispatching costs and structural congestion.

Relevant criteria for the evaluation of zonal market configurations are also discussed in Frontier Economics and Consentec (2011) and Supponen (2011). In Frontier Economics and Consentec (2011), the consequences of a potential division of the German-Austrian bidding zone are analyzed with regard to technical and economic implications. The mainly qualitative evaluation covers changes in market concentration, liquidity and transactions costs as well as in static and dynamic market efficiency and is based on a hypothetical division of today's market zone into two separate areas along the most critical bottleneck observed in the year 2009. On the said line, congestion arises at 10% of the hours of the year. Supponen (2011) introduces further criteria for the choice of bidding zones such as the direction of the wind power flow and a coincidence of zonal boundaries with physical congestion points. Finally, a zonal configuration is proposed which divides the European market into 45 zones. Thereby, Germany, the BeNeLux countries, France, Austria and Switzerland are assigned to 11 zones.

A stronger focus on quantitative measures is put in Stoft (1997), Walton and Tabors (1996) and Bjørndal and Jørnsten (2001). Stoft (1997) states that the definition of zones should be based on nodal price differences which comprise all relevant information on network related costs. This is underlined by the findings in Stoft (1996) which show that the loss in welfare by creating uniformly priced zones despite internal congestion is proportional to the squared error in the uniform prices. In Green (2007), the decrease in welfare induced by implementing a single price zone instead of nodal pricing is quantified for the English and Welsh system as 1.3% of the generators' revenues. Walton and Tabors

(1996) therefore combine statistical tests for price uniformity with information from practical experience to identify zones, but do not formalize a method to test the results' adequacy. In Bjørndal and Jørnsten (2001), the authors show that absolute differences in nodal prices do not yet provide an adequate basis for the definition of zones since similar price differences may lead to variations in the optimal zonal configurations in different scenarios. Thus, cluster analysis is suggested as one possible methodological refinement.

Cluster analysis is i. a. used in Olmos and Pérez-Arriaga (2008) and Yang et al. (2006). Authors in Olmos and Pérez-Arriaga (2008) apply two clustering methods, Autoregressive Kohonen Maps and the k-means algorithm, to a set of power transfer distribution factors (PTDF) due to a lack of information needed for nodal price computations. PTDFs give the relative impact of a marginal change in the net input of a node on any given line in the system and therefore do not reflect all relevant information on the structure of the electricity system. In Yang et al. (2006), a set of potentially congested lines is identified by the means of probability analysis. Then, sensitivities of nodal power injections to the flows over the congested lines are computed and used as a substitute for nodal prices in a fuzzy c-means cluster analysis.

The research presented in this paper develops a set of market zones for the CWE region, Switzerland and Austria (CWE+) for both 2015 and 2020 on the basis of hourly nodal prices and a hierarchical cluster analysis. Knowing that zonal pricing is in general the second-best solution to enhancing efficiency (see e.g. Hogan (1998)), the error made in aggregating nodes into zones is reduced by including as much information on the (spatial) market structure as possible. The underlying methodology is introduced in section 3.2 while section 3.3 describes the data basis and relevant assumptions. In section 3.4 the results of the nodal model and the zonal aggregation are discussed. In order to challenge the newly defined market zones, their dispatch and re-dispatch is calculated. Thus, the change in total system costs by switching from the first-best nodal solution to a zonal system is quantified. Some implications of the gained insights are given in section 3.5.

3.2 Methodology

The derivation of market zones and the subsequent evaluation of total system costs are based on two methodological building blocks. The *NEULING* model optimizes the European (re-)dispatch for given nodal and zonal configurations, while the latter result from cluster analysis subject to a minimum variance criterion.

3.2.1 The *NEULING* Model

The New European Linear Investment and Grid Model (*NEULING*, cf. chapter 2) is used to calculate the cost-minimal generation dispatch and re-dispatch of a given power plant portfolio for 8760 hours of a year. The high temporal resolution allows for the consideration of general structural patterns such as seasonal variations in load as well as of extreme events. Thus, an adequate data base for the later cluster analysis is generated.

3.2.1.1 Dispatch and DC-Load-Flow

The spot market dispatch of conventional power plants is determined such that the residual demand (exogenous system demand including network losses less electricity produced by renewable energy sources (RES-E) and less must-run generation from combined heat and power plants) is met in each hour. Furthermore, the demand for positive and negative balancing reserve needs to be covered. The conventional power plant fleet including hydro storage (Hyd-S), pumped storage (Hyd-PS) and compressed air energy storage (CAES) plants is grouped into 25 so-called vintage classes according to primary fuel, age and technological characteristics such as efficiency. Each vintage class is then dispatched under consideration of variable and ramping costs, as well as minimum- and part-load restrictions.

The cost-minimal nodal dispatch is subject to network restrictions implemented by a DC power flow model as introduced in Schweppe et al. (1988) and applied e.g. in Leuthold et al. (2008). The DC power flow gives an approximation of the physical flows over the high-voltage alternating current transmission network in the so-called core model regions (cf. Schweppe et al. (1988) for the derivation of the DC model and Groschke et al. (2009) for a discussion on optimal power flow models). Thereby, both losses as well as reactive power are neglected in order to keep the problem linear. The lines' physical capacities are standardized and multiplied with a factor of 0.8 in order to account for a security margin. Furthermore, interconnectors to and in between so-called satellite regions are implemented by the use of net transfer capacities (NTC).

3.2.1.2 Re-dispatch

The basic spatial resolution of *NEULING* gives a nodal representation of the core model regions. Depending on the object of investigation, the nodes can be aggregated into zones. Although the zonal dispatch assumes internal copperplates, the information on the nodal net injections is preserved. Thus, the usage of the internal grid can be determined ex-post and the necessary re-dispatch in case of violations of network constraints can be calculated based on the plants' operating status and their utilization.

The optimal flow-based re-dispatch is represented by the least-cost combination of upward and downward ramping, which at the same time relieves the overloaded line and keeps the balance between demand and supply at each node. The marginal costs of a plant's upward re-dispatch are given by its variable fuel and ramping costs, while the marginal savings of its downward re-dispatch equal the avoided costs of generation. This setup corresponds to a cost-based mechanism in which the generators are either compensated or charged as to render them indifferent with regard to being re-dispatched.

In theory, the nodal injections after cost-based re-dispatch correspond to those of the optimal nodal dispatch if no additional restrictions on technical flexibility apply and the plants' cost functions are identical in dispatch and re-dispatch (cf. Hermans et al. (2011)). In this case, the total costs of both designs are equal. However, this assumption is not trivial. Due to the time lag between day-ahead dispatch and re-dispatch the technical restrictions on the latter are tighter, thus increasing the variable costs of generation. Furthermore, intraday trade requires costly adjustments of the re-dispatch schedule on short notice.

In the presented approach, re-dispatch is priced with the hourly variable costs of the dispatch. Furthermore, the same technical flexibility as in the dispatch is assumed, with the exception of limiting quick starts of non-spinning units to open cycle gas turbines (OCGT) and hydro power. Both assumptions underestimate the true costs of re-dispatch by trend. However, re-dispatch is modeled by the hour such that ramping costs are overestimated in comparison to an intertemporal optimization. This is especially true if structural congestion requires continuous re-dispatch.

3.2.2 Cluster Analysis

In multivariate statistics, cluster analysis is used to group variables with multiple observations according to the variables' similarity. Two prominent model-classes are connectivity-based and centroid-based clustering, which differ in their basic definition of similarity (refer to Handl (2010) for an introduction). Connectivity models rely on metrics such as Euclidean distances between the variables' observations to identify clusters in a hierarchical process. Thus, clusters are merged in the order of increasing distances (agglomerative clustering) or split in the order of decreasing distances (divisive). As a result, the number and composition of clusters are given subject to critical distance levels. Hierarchical models are complemented by various algorithms which allow for different linkage criteria. The best choice of an algorithm finally depends on the structure of the given data set. Instead of explicitly evaluating distances between variables, centroid-based clustering defines cluster centers and measures the distance of the data points to the centers. Each variable is then grouped to the nearest center, which is not necessarily an element of the original data set. Most of the associated heuristic k-means algorithms require an ex-ante specification of the number of cluster centers k, whose location is then optimized. Furthermore, the results are sensitive to the given starting points of the centers' locations.

Since the goal of the presented research is to identify structural differences between price regions as well as the loss of information produced by merging nodes into zones, the leaps in critical distance levels between clustering steps contain valuable information which is easily provided by agglomerative hierarchical methods. Furthermore, the desired number of price zones cannot be specified beforehand. Thus, the continuous computation of optimal clusters for each possible level of aggregation provides the complete range from which to choose in only one model run. In consequence, a hierarchical model is applied.

The input data for the cluster analysis is provided by *NEULING* and consists of 8760 observations of marginal costs of generation for each node. Since an aggregation of nodes is supposed to yield homogeneous zones in terms of absolute height of and variation in marginal costs, Ward's minimum variance criterion (cf. Ward (1963)) is implemented. At each clustering step $k \in \{1, \ldots, N-1\}$ where N equals the number of nodes, the algorithm merges two classes such that the resulting increase in in-cluster variance is minimal. The i^{th} cluster at stage k is represented by $C_{i,k}$. At the beginning of each clustering step, the sum $E_{i,k}$ of the squared Euclidean distances between the price vectors p_n at node $n \in \{1, \ldots, N\}$ and the cluster $C_{i,k}$'s mean vector $\bar{p}_{i,k}$ is calculated, if n is an element of the set $C_{i,k}$:

$$E_{i,k} = \sum_{n \in C_{i,k}} (p_n - \bar{p}_{i,k})'(p_n - \bar{p}_{i,k}). \tag{3.1}$$

$E_{i,k}$ is thus a measure for the homogeneity of a cluster and is equal to zero at the starting point where every node forms a separate cluster. The measure for the quality of the complete cluster set is given by the sum of $E_{i,k}$ over all clusters $C_{i,k}$. In consequence, the optimal configuration of clusters is chosen as the combination that yields the minimal decrease in quality:

$$\arg\min_{I_k} \Delta := \sum_{i \in I_k} E_{i,k} - \sum_{j \in I_{k-1}} E_{j,k-1}. \tag{3.2}$$

Here, I_k represents a feasible cluster set at the kth stage of the algorithm. Thereby, only combinations of neighboring nodes give valid clusters. This restriction is implemented in an additional constraint that includes a binary parameter $b_{n,m}$ which is equal to 1 if the nodes n and m are adjacent, and zero otherwise.

The result of the hierarchical clustering can be further evaluated by analyzing the critical distances at which two clusters are merged, which equal the sum of all optimal $E^*_{i,k}$ over i at step k. These distances are denoted by d_k and increase with the number of clustering steps. In order to identify the ideal level of aggregation, Mojena (1977) proposes a benchmark based on the normalized measure

$$\hat{d}_k = \frac{d_k - \bar{d}}{s_d} \tag{3.3}$$

which increases monotonically over k and where $\bar{d}$ is the mean over all d_k and s_d is the standard deviation of d_k. Based on simulations, Milligan and Cooper (1985) recommend to choose the previously optimized cluster set containing $N + 1 - k^*$ clusters, where k^* is determined by the index of the first cluster step at which $\hat{d}_k > 1.25$ holds.

3.3 Data and Parametrization

The regional coverage used in the model runs is given in figure 3.1. The core regions Austria, Switzerland, Germany and Luxembourg, the Netherlands, Belgium and France are divided into 72 basic regions, which each represent one node of the DC network.[22] The shape of the regions is chosen to best reflect the grid structure, but also considers the boundaries of national administrative areas.[23] Directly adjacent countries as well as Great Britain and the Scandinavian countries are modeled as national, one-node regions.

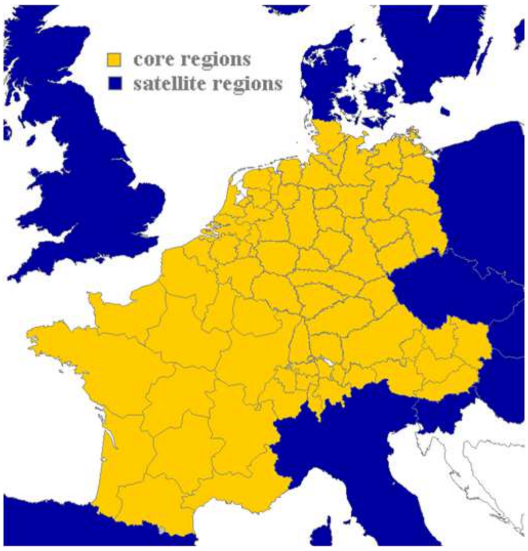
The network structure as well as relevant technical parameters such as line resistance, reactance and capacity are kindly provided by the Institute for Energy Systems, Energy Efficiency and Energy Management (ie^3) at TU Dortmund University. Planned grid extensions are considered on the basis of the Ten-Year Network Development Plan provided by the European Network of Transmission System Operators for Electricity (ENTSO-E (2010)). Besides the core regions, also the neighboring countries connected to the core regions via the AC network are considered as one node each in the DC load flow. In total, *NEULING*'s DC load-flow simulates the optimal power flow between 79

[22] The node representing Luxembourg is merged with the adjacent German node. In the following, the corresponding data is subsumed under the label "DE".

[23] The German model regions were first defined in Nüßler (2012). All other core regions have been developed in the course of the work presented in this paper.

nodes via 434 lines (2015) and 446 lines (2020) respectively. Additionally, the NTC values of interconnectors to and between satellite regions are implemented according to ENTSO-E.

FIGURE 3.1: Regional coverage of *NEULING*



Source: Own illustration.

The power plant database of the Institute of Energy Economics at the University of Cologne (EWI) provides geo-coded data of the existing and planned European conventional generation capacities, including expected decommissioning dates. The installed capacities per main technology are given on a national level in table 3.1. Fuel and CO_2 price assumptions are based on EWI (2011) and given in table 3.2.

TABLE 3.1: Installed generation capacities in 2015 and 2020 per main technology

[MW]		Nuclear	Lignite	Hard Coal	Gas	Oil	Hyd-S	Hyd-PS	CAES
AT	**2015**	0	300	470	5,020	450	3,490	4,140	0
	2020	0	300	470	5,960	370	3,490	4,500	0
CH	**2015**	3,220	0	0	900	10	7,050	3,380	0
	2020	2,860	0	0	1,270	0	7,050	4,980	0
DE	**2015**	12,050	18,950	27,080	20,770	0	230	7,630	320
	2020	8,100	17,490	29,070	18,450	0	230	9,630	320
NL	**2015**	450	0	9,560	20,910	160	0	0	0
	2020	450	0	9,560	19,650	160	0	0	0
BE	**2015**	5,560	0	1,940	5,910	50	0	1,180	0
	2020	3,840	0	1,670	5,440	50	0	1,180	0
FR	**2015**	63,130	0	7,060	8,800	6,340	10,390	5,510	0
	2020	59,550	0	5,340	8,720	1,570	10,390	5,510	0

Source: Own calculation based on EWI power plant database.

Data of the regional installed capacities of combined heat and power plants (CHP) is also available in EWI's database. In combination with hourly heat demand curves, the

TABLE 3.2: Fuel and CO_2 price assumptions

[EUR/MWh$_{th}$]	Uranium	Lignite	Hard Coal	Nat. Gas	Oil
2015	3.60	1.40	13.20	25.70	47.20
2020	3.60	1.40	13.40	28.10	50.25
CO_2 2015: 22.00 EUR/tCO_2, **2020:** 35.00 EUR/tCO_2					

Source: EWI (2011).

local feed-in of electricity from CHP is calculated. The assumptions on total electricity production are based on EURELECTRIC (2011). The data on fossil-fuel plants is supplemented by location-specific capacities of renewable energy sources for all core regions which have been researched for the purpose of this study.[24] The location of today's capacities, regional potentials and historic regional developments are used to allocate the forecasted installations given in the EU-wide National Renewable Energy Action Plans (NREAP, cf. EC (2010)). The feed-in structure of wind and solar power is derived from locational hourly data on wind speeds and solar radiation provided for the year 2008 (cf. EuroWind (2011) and figure 3.2). Thus, the concurrence of power generation between regions and between RES-technologies is consistent. From the given data, total electricity production from RES is calculated as to match the values given in the NREAP.

Regional load data is derived from information on regional electricity demand or population and its future development.[25] Total demand includes network losses and is assumed according to EURELECTRIC (2011). Aggregated data on RES and demand is given in table 3.3.

TABLE 3.3: Total consumption and electricity production from RES per technology in 2015 and 2020

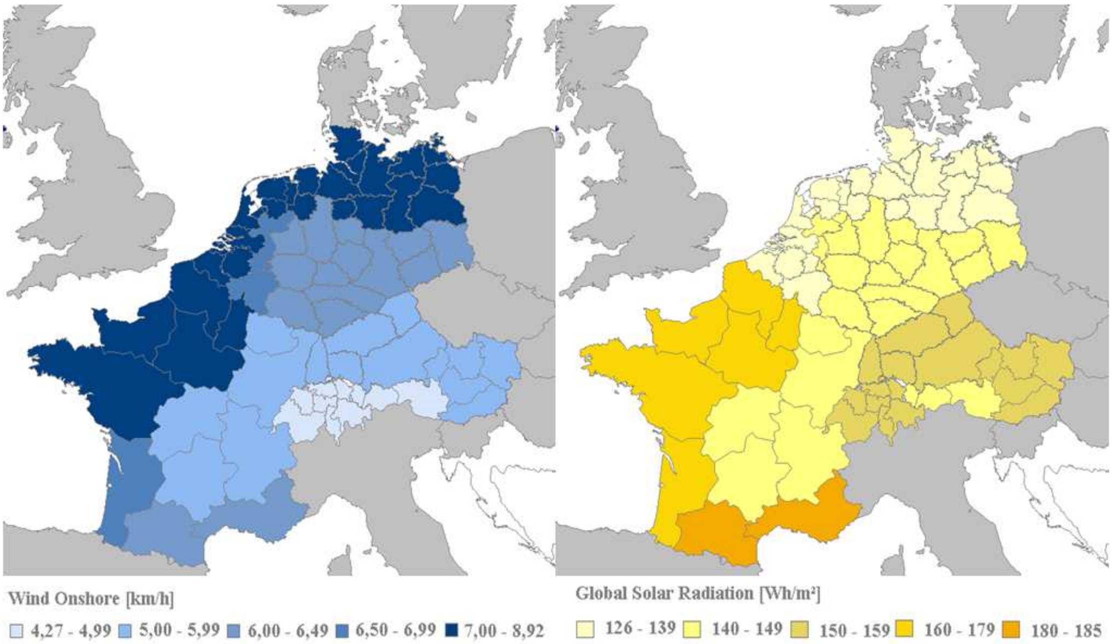
[TWh]		Consumption	RES-E (Total)	*Hydro*	*Biomass*	*Solar*	*Wind Onshore*	*Wind Offshore*	*Other*
AT	**2015**	70.8	28.5	*19.7*	*4.8*	*0.2*	*3.8*	*0.0*	*0.0*
	2020	77.0	29.0	*19.8*	*5.2*	*0.3*	*3.8*	*0.0*	*0.0*
CH	**2015**	64.3	18.1	*17.6*	*0.0*	*0.4*	*0.2*	*0.0*	*0.0*
	2020	65.1	18.5	*17.6*	*0.0*	*0.6*	*0.3*	*0.0*	*0.0*
DE	**2015**	546.7	158.6	*19.4*	*42.3*	*26.2*	*62.2*	*8.0*	*0.4*
	2020	524.4	217.7	*20.1*	*49.8*	*41.5*	*72.9*	*31.8*	*1.7*
NL	**2015**	126.7	27.5	*0.2*	*13.4*	*0.3*	*9.5*	*4.2*	*0.0*
	2020	139.2	50.3	*0.7*	*16.6*	*0.6*	*13.4*	*19.0*	*0.0*
BE	**2015**	100.2	13.1	*0.4*	*6.0*	*0.6*	*2.1*	*4.0*	*0.0*
	2020	113.9	23.1	*0.4*	*11.0*	*1.1*	*4.3*	*6.2*	*0.0*
FR	**2015**	513.9	67.6	*23.5*	*10.5*	*2.6*	*22.7*	*8.0*	*0.3*
	2020	533.4	104.7	*23.2*	*17.2*	*5.9*	*39.9*	*18.0*	*0.5*

Source: Own calculation based on EURELECTRIC (2011), EC (2010).

[24]For the case of Germany, the data base of the currently installed capacities was established by Nüßler (2012).

[25]For Germany, the regional demand structure has been provided by Nüßler (2012).

FIGURE 3.2: Regional wind speeds onshore and global solar irradiation in the core regions



Source: Own illustration based on EuroWind (2011).

3.4 Results and Discussion

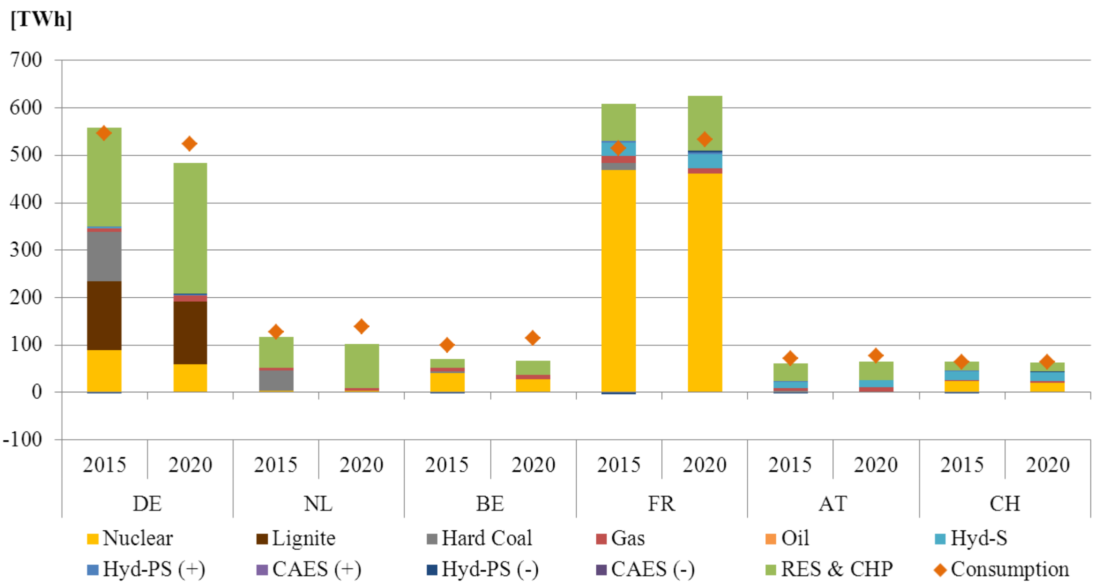
In the following section, the results of *NEULING* and of the cluster analysis are presented. The first scenario year discussed in detail is 2015. The stability of the results is then controlled for by a comparison with calculations for the year 2020. This relates to the CACM guidelines, which propose a regular assessment of zonal delimitations every two years. Regarding the effort of market participants to prepare for changes in zonal definitions, Frontier Economics and Consentec (2011) suggest a time frame of five years between those modifications. Furthermore, an auxiliary scenario in which a flow-based market coupling of national copperplates is implemented provides a further benchmark.

3.4.1 Nodal Dispatch

As a first result of the nodal dispatch calculations, the generation mix for the years 2015 and 2020 is given in figure 3.3, both for core and satellite model regions. The characteristics of the respective national power plant fleets translate in deviations in the use of primary fuels.

Table 3.4 gives an overview of the demand-weighted average marginal-cost-based prices (AMC) in 2015, both for the nodal model and a flow-based coupling of the national

FIGURE 3.3: Annual electricity generation in the nodal model in the years 2015 and 2020 per country and technology



Source: Own calculation.

copperplates (CU). In each case, the marginal prices comprise generation- and network-based costs. The only difference between the calculations consists in the assumptions concerning the transmission capacities between the core regions. In the nodal model, the full network as described in section 3.3 is implemented. In contrast, the underlying assumption in the national model is that network capacities within countries are abundant.

TABLE 3.4: Average marginal costs (AMC) of electricity supply in 2015

[EUR/MWh]	AT	CH	DE	NL	BE	FR
Nodal Pricing						
AMC	53.65	53.52	51.74	53.27	53.54	51.54
Min. AMC at Node	45.24 Tauern	52.83 Chamoson	50.05 Roehrsdorf	49.95 Eemshaven	53.19 Avelgem	50.80 Bordeaux
Max. AMC at Node	55.51 Wien	54.93 Sils	52.88 Eichstetten	58.01 Vierverlaten	54.18 Gramme	52.92 Sierentz
National Market Coupling (Copperplate)						
AMC	51.72	52.98	52.04	52.58	53.30	50.72

Source: Own calculation.

On a national level, both the demand-weighted average nodal costs as well as the average marginal costs of the copperplates are rather homogeneous such that the maximum difference between countries amounts to no more than 2.11 EUR/MWh and 2.58 EUR/MWh respectively. Furthermore, the comparison shows that national marginal costs of supply are by trend lower in the CU than in the nodal model. In the given set-up, this result is straight forward: Since the CU computation is less restrictive, it allows for the realization of greater efficiency gains from international trade. Thereby, the observed homogeneity of the copperplates' marginal costs implies a high degree of interconnection between the national markets.[26] At the same time, the deviations between the nodal and the CU set-ups already hint the relevance of costs of congestion in evaluations of total costs of electricity supply, at least as long as national copperplates are fiction rather than fact.

The true impact of regional constraints is revealed by the differences in the nodal distribution of marginal costs as shown in table 3.4. While on a national level the average marginal costs of electricity supply are mostly lower in the CU calculation, average marginal prices at some locations in the nodal case clearly undercut the former. On the one hand, this is due to the fact that locational marginal prices reflect the flow-based effect of a change in the nodal net input on congested lines. In case the effect is relieving, the node's marginal network costs are negative and reduce the overall price. Analogously, a congestion aggravating effect is associated with positive costs. Both kinds of externalities are ignored in the CU case. On the other hand, differences in marginal prices reflect variations in the generation mix at each node including the contribution of RES, as well as locational demand. As a result of both effects, the difference between the overall maximum AMC (Vierverlaten, NL) and their minimum (Tauern, AT) amounts to 12.77 EUR/MWh on average. While the generation in Tauern is exclusively hydro-based, the only power plants available at Vierverlaten are gas-fired. Additionally, Vierverlaten is a net-importing node with a disadvantageous position in the network. But even the deviations in marginal cost-based prices of nodes within one country can be substantial. Due to the steep increase in the national merit order between the dominating hydro and gas-fired technologies, the highest in-country difference is observable in Austria (10.27 EUR/MWh). These observations do not only highlight the regional heterogeneity of the power market but also the implications of locational marginal pricing for the spatial distribution of rents.

The analysis of the DC power flows and the utilization of the transmission network resulting from the nodal model shows that 68 out of 390 lines in or between core regions are subject to congestion in the course of the year 2015.[27] Those lines' average utilization amounts to 44%, whereas congestion of at least one of these lines occurs in 7,284 (83%) hours of the year. The most critical line is found to be the connection between Vierverlaten and Eemshaven in the Netherlands, which is congested in 5,111

[26]The Ten Year Network Development Plan (ENTSO-E (2010)) as implemented in the analysis assumes grid extensions between the countries of the CWE region, Austria and Switzerland of 8.9 GW between the years 2010 and 2015.

[27]Congestion is hereby referred to as a 100% rate of utilization of the lines' available capacity, i.e. after the reduction by the security margin.

(57%) hours and has an average rate of utilization of 83%. In contrast to Vierverlaten, Eemshaven is a low-cost, net-exporting node connected to offshore wind farms and the high voltage direct current line to Norway. Only 15 of the said 68 lines are interconnectors between countries, which have an average utilization of 42% and of which at least one is congested in 2,954 hours (58%). This finding underlines that by 2015 internal congestion is of greater relevance than international bottlenecks.

The generation mix of the year 2020 is mainly characterized by increasing shares of RES-E and a crowding-out of hard-coal based generation. Furthermore, the CWE+ region becomes a net-importer by 2020 (net-imports 2015: -65 TWh, 2020: 63 TWh). The resulting changes in the marginal costs of supply are noticeable both in height and regional development. First, the AMC rise substantially in the core regions. Tauern does no longer account for the least marginal cost but observes a rise of 15 EUR/MWh between the model years. The associated rise in Austria's AMC is the strongest among all core regions and is due to higher exports which require a stronger utilization of conventional technologies and increase the opportunity costs of hydro power. In contrast, the in absolute terms stronger increase in French exports does lead to a smaller increase in AMC since the slope of the national merit order is less steep. Now Le Havre, an important node with regard to the connection of French offshore wind power plants, shows the lowest average marginal prices in 2020.[28] Overall, the heterogeneity of the CWE+ regions is increased compared to 2015. The spread between minimal and maximal AMC now amounts to 17.25 EUR/MWh and France accounts for the highest in-country variance (14.60 EUR/MWh).

Table 3.5: Average marginal costs (AMC) of electricity supply in 2020

[EUR/MWh]	AT	CH	DE	NL	BE	FR
Nodal Pricing						
AMC	64.08	62.24	60.75	61.63	62.21	55.66
Min. AMC	60.17	60.00	58.87	60.19	59.29	48.52
at Node	Tauern	Chamoson	Lauchstaedt	Eemshaven	Avelgem	Le Havre
Max. AMC	65.77	64.86	62.49	64.27	65.04	63.14
at Node	Wien	Sils	Eichstetten	Vierverlaten	Gramme	Sierentz
National Market Coupling (Copperplate)						
AMC	60.45	61.60	60.65	61.96	63.71	57.09

Source: Own calculation.

3.4.2 Cluster Analysis

The hourly locational marginal prices computed for 2015 and 2020 serve as an input for two runs of the clustering model described in section 3.3. The result of the model is a tree

[28]The installed offshore wind capacities connected to Le Havre rise from 1,560 MW in 2015 to 2,350 MW in 2020.

or dendrogram which illustrates the successive grouping of nodes into clusters, starting with 72 single-node zones and ending with one all-encompassing cluster. The first quarter of the 2015 dendrogram is dominated by groupings of German nodes which exhibit the smallest in group variance. Furthermore, the first Dutch and the first Austrian nodes are clustered. Although this result shows a preferred grouping of small nodes at the first stages which is due to the structural similarities within limited geographical areas, the first major French nodes (Paris, Le Havre and Avoine) are also clustered during the first 19 steps of the algorithm. After half of the clustering steps, the cluster size is still heterogeneous. Nonetheless, several big clusters are already observable, e.g. North-West Germany (9 nodes), Eastern Germany (8) and Northern France (4). Furthermore, the first cross-border cluster of the well connected (11.1 GW) nodes Herbertingen (DE), Buers (AT), Westtirol (AT) has been formed. In this case, international clustering is preferred to merging the two Eastern Austrian nodes with their western neighbors since the Austrian network and generation structure exhibits an east-west divide. After 3/4 of the clustering steps the dominant cluster comprises a corridor of 20 nodes from Central Germany to parts of the Netherlands. Other significant groups are formed by nodes of Eastern Germany (8), Southern Germany, Switzerland and Austria (8), the Netherlands and Belgium (6), North-West France (6), Southern France (5) and Eastern Switzerland (4).

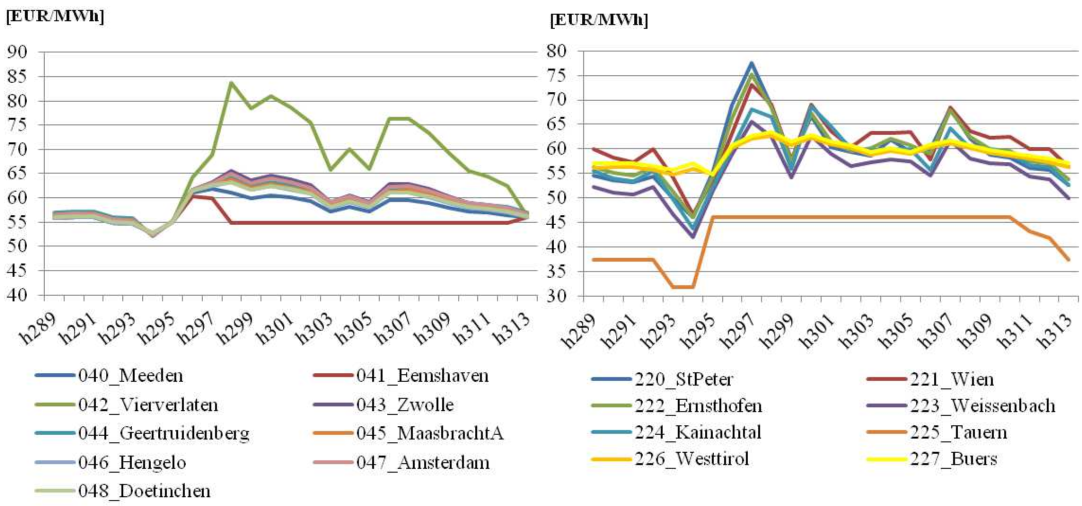
The differences in the quality of the clusters between the clustering stages (cf. equation 3.2) increases exponentially with the number of steps. Nonetheless, the test for the statistically optimal number of clusters (cf. equation 3.3) determines a small number of six zones as the optimal configuration for 2015. This equals the number of countries included in the core regions, except that the cluster analysis does not follow national borders. The cut of the dendrogram at this stage shows 4 big clusters and two single-node zones, namely Vierverlaten (NL) and Tauern (AT).

As discussed in the previous section, these outliers exhibit the overall highest and the lowest average marginal costs respectively. Figure 3.4 illustrates the particularities of the nodes in comparison to their neighbors: In the case of Vierverlaten, the node's marginal cost curve is strictly higher and more volatile than those of its neighbors. Thereby, the price spikes are driven by the volume of Vierverlaten's imports and the associated stress imposed on the network. The connection to Eemshaven is congested as of the early morning hours, which is reflected by the beginning of the price deviations within the Netherlands.[29] As opposed to Vierverlaten, the marginal cost curve of the outlier Tauern is more stable and strictly lower than those of its neighboring nodes

[29] As highlighted in table 3.4 and evident from figure 3.4, Eemshaven is also an extreme node, although no outlier at the given clustering stage. In contrast to Vierverlaten, Eemshaven is characterized by low and stable prices resulting from the yield of offshore wind power, the interconnector to Norway and positive external effects on the network.

due to the high availability of hydro power. Furthermore, the said east-west divide in Austria results in a separation of Tauern from both Eastern Austria and the western nodes Buers and Westtirol (also standing out in figure 3.4). In consequence, the cluster algorithm does not merge the outlier nodes with other clusters until the fourth to last (Vierverlaten) and second to last step (Tauern).

FIGURE 3.4: Marginal costs of a random day in the Netherlands (left) and Austria

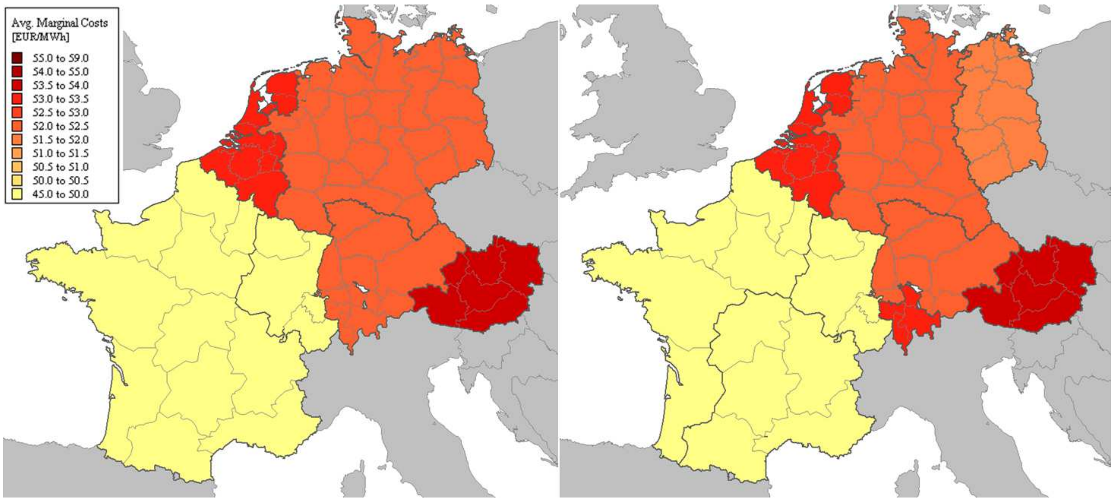


Source: Own calculation.

Since an extreme imbalance in the number of nodes per zone most-likely constitutes a political no-go, the two outlier nodes are added to the respective neighboring zone with the best network connection. In return, other clusters are split. This method is problematical for two reasons. First, the optimal splitting of clusters may produce new single-node zones and the more steps of the clustering have to be reversed, the more outliers by tendency appear. Second, the inefficiency created by the inclusion of extreme nodes is especially high (cf. section 3.3 and Stoft (1996)). Nonetheless, the strategy is kept due to the lack of a quantitative measure of minimum zonal size and leads to the six zones given in figure 3.5. Thereby, the only non-split country is Belgium. As sensitivity, a nine-zone example is also created. In the latter, France is divided among three zones, East Switzerland is separated from Southern Germany and an Eastern German zone is created.

Based on the nodal prices from 2020, the cluster analysis is repeated. Unlike in 2015, the heuristic test of the results gives five (instead of six) as the optimal number of zones. Although this configuration requires one additional aggregation step, the result does not imply that the market in 2020 is more homogeneous than five years before. On the contrary, the regional concentration of RES as well as overall demand growth lead to a higher degree of diversification in locational marginal prices in 2020 (cf. section 3.4.1).

Figure 3.5: Results of the cluster analysis for the model year 2015 with 6 (left) and 9 clusters



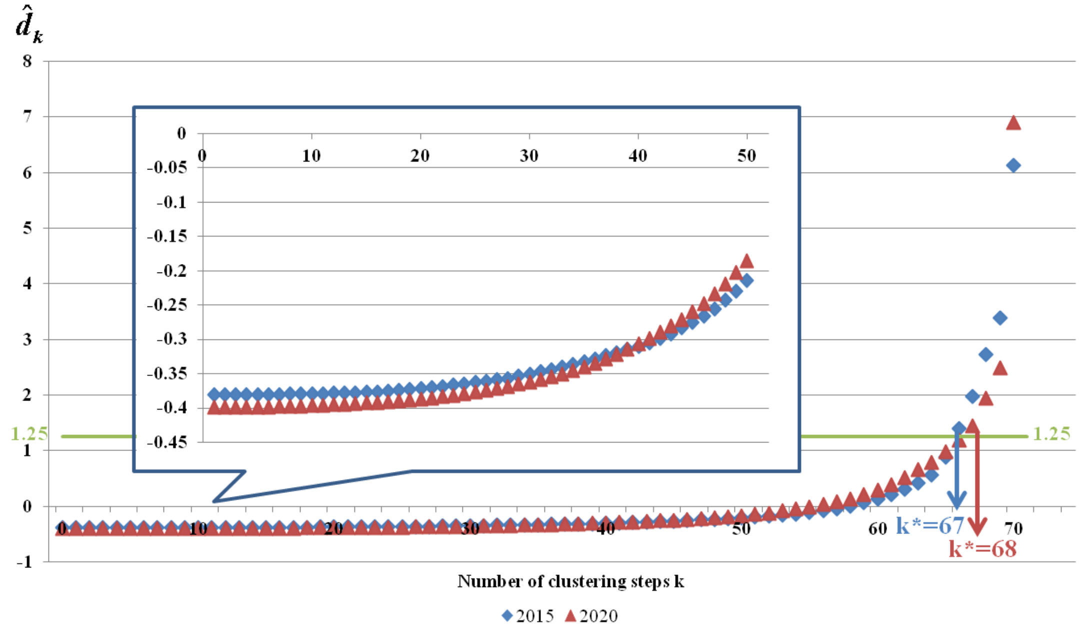
Source: Own illustration.

This is also reflected by the measure of heterogeneity d_k (cf. section 3.2.2) whose values at each clustering stage k are strictly higher in 2020 than in 2015. But since the heuristic according to Mojena (1977) and Milligan and Cooper (1985) relies on the normalized measure $\hat{d}_k$ (cf. eq. 3.3), this is not reflected in the choice of the optimal number of clusters. Instead, the heuristic identifies the point at which the normalized measure exceeds the predefined benchmark ($\hat{d}_k > 1.25$) and the *relative* increase in heterogeneity between steps is high. This is illustrated in figure 3.6.

The final five-zone design, which again requires a correction for outliers, is given in figure 3.7. In 2020, these outliers are Vierverlaten (NL) and the new minimum-price node Le Havre (FR) (cf. section 3.4.1).

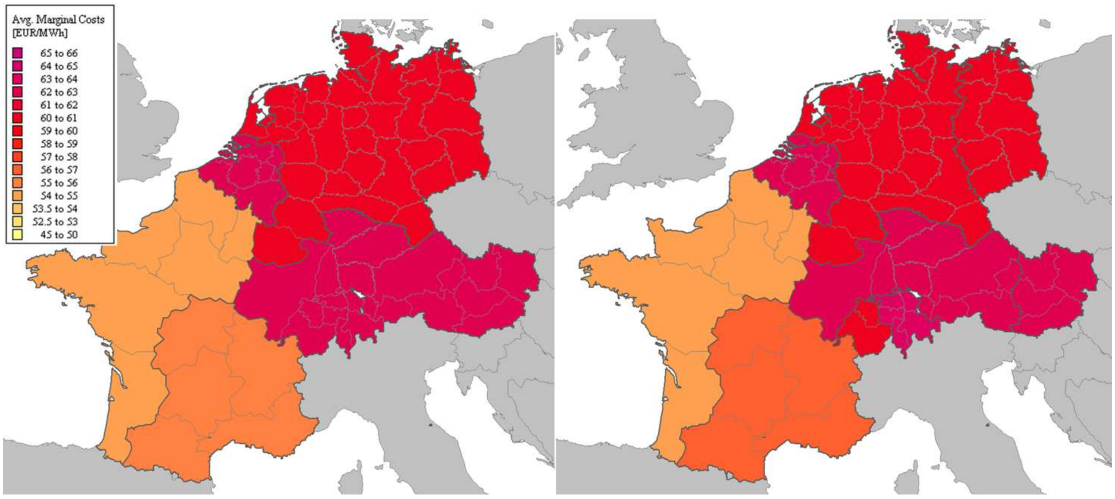
In comparison to 2015, the final configuration leads to two instead of one French zone, whereas the former zone consisting of Eastern France and Western Switzerland is merged with nodes of East-Switzerland, South-Germany and Western Austria. Furthermore, the border between the two Austrian-related zones is moved to the East. The latter development is due to the fact that Tauern has lost its outlier status and is now merged with West-Austrian, South-German and Swiss nodes at a relatively early stage. One driver for the French splitting is the development of offshore wind farms along the Atlantic Coast. Unlike in 2015, the division persists both with 5 and 9 zones. Again, the results concerning the grouping of Eastern Germany and Switzerland are sensitive to the number of bidding zones. A network related effect is e.g. observable in the northern Dutch regions, where a new connection between Eemshaven and Amsterdam leads to a merger of Amsterdam, Zwolle and Vierverlaten with the major Dutch-German zone.

FIGURE 3.6: Development of the normalized measure of heterogeneity in the cluster analysis of 2015 and 2020



Source: Own calculation.

FIGURE 3.7: Results of the cluster analysis for the model year 2020 with 5 (left) and 9 clusters



Source: Own illustration.

3.4.3 Zonal Dispatch with Re-dispatch

The bidding zones as described in section 3.4.2 define the network configuration which is provided for the zonal dispatch optimization with *NEULING*. In comparison to the nodal model runs, information on the network structure within a zone is removed and all included nodes are aggregated. Transmission lines between zones remain unchanged except for the definition of their start and end nodes which now correspond to the superordinate zone. The zonal dispatch provides information on locational marginal costs which only partly reflect costs of congestion. An overview of the results is given in table 3.6, where also the corresponding weighted average over the marginal costs of the zones' nodes as calculated in the nodal dispatch is given. Positive as well as negative deviations of zonal from nodal averages are observable due to the neglect of external network effects.

TABLE 3.6: Average marginal costs in zonal systems in 2015 and 2020

2015									
[EUR/MWh]	**A**		**B**		**C**	**D**	**E**		**F**
Zonal (6)	47.63		53.69		49.94	52.06	53.09		52.17
as in Nodal	51.42		53.72		52.65	52.84	53.56		51.54
A. FR, B. AT, C. FR/CH, D. DE/AT/CH, E. BE/NL, F. DE/NL									
[EUR/MWh]	**I**	**II**	**III**	**IV**	**V**	**VI**	**VII**	**VIII**	**IX**
Zonal (9)	47.20	47.96	53.88	53.11	49.66	52.00	53.45	51.67	52.05
as in Nodal	51.07	52.03	53.72	54.34	52.65	52.68	53.56	50.36	51.83
I. FR[NW], II. FR[S], III. AT, IV. CH[E], V. FR/CH, VI. DE/AT, VII. BE/NL, VIII. DE[E], IX. DE/NL									
2020									
[EUR/MWh]	**A**	**B**		**C**			**D**	**E**	
Zonal (5)	54.06	55.85		62.59			62.12	60.63	
as in Nodal	53.41	57.65		62.75			62.16	60.51	
A. FR[NW], B. FR[S], C. DE/AT/CH, D. BE/NL, E. DE/NL									
[EUR/MWh]	**I**	**II**	**III**	**IV**	**V**	**VI**	**VII**	**VIII**	**IX**
Zonal (9)	54.43	56.04	62.30	63.66	60.95	62.06	62.15	60.44	60.29
as in Nodal	53.41	57.65	64.83	63.43	60.55	62.22	62.16	60.79	59.05
I. FR[NW], II. FR[S], III. AT, IV. CH[E], V. CH[W], VI. DE/AT, VII. BE/NL, VIII. DE/NL, IX. DE[E]									

Source: Own calculation.

The information on the nodal net input under zonal pricing is used to calculate the resulting power flows over the full network. This implies that the utilization of the interconnectors between zones is calculated again, too. The re-dispatch algorithm now chooses the least-cost option to relieve congestion. Thereby, *NEULING* can access running power plants for downward re-dispatch with the exception of units with balancing market obligations. The generating units are ramped down in the order of decreasing cost savings and decreasing effectiveness with regard to congestion relief. No restrictions on the geographic distance between re-dispatchable plants and congested lines are imposed, such that perfect cooperation between the control areas is implied.[30] When the conventional potential for downward re-dispatch is exhausted, RES-E can be curtailed. This option is least attractive since curtailment of renewables does not yield

[30] Joint cross-border re-dispatch is currently not implemented in the CWE region, but envisioned as an element of the IEM (ETSO (2003)). At the moment, curative cross-border congestion management is performed via counter trade.

savings in variable generation costs. Concerning upward re-dispatch, the model may access spinning units with unused capacity, again under consideration of balancing market commitments. Furthermore, quick-starting units like open cycle gas-turbines (OCGT) may be activated.

In the 2015 six-zone case, congestion occurs in 7,678 hours of the year and requires a total amount of re-dispatch of 12,055 GWh. RES need to be curtailed in 1,954 hours to guarantee the stability of the network. In comparison to the flow-based coupling of national copperplates (CU), the proposed zonal model saves 741 GWh of re-dispatch and at the same time avoids 11.6 GWh of RES-E curtailment. Further reductions can be achieved by implementing the zonal configuration based on nine clusters which only requires 10,551 GWh of re-dispatch. Thereby, RES are used for supplementary downward re-dispatch in 1,709 out of a total 7,449 hours.

The same pattern is observable in 2020, although on a higher level: The lowest amount of re-dispatch is required in the nine-zone setup, where 20,895 GWh have to be rescheduled, including a RES-E curtailment of 2,405 GWh. In comparison to the nine zones of 2015, the necessary congestion management measures have thus almost doubled. Concerning the frequency of congestion, one or more lines of the CWE+ network are now overloaded in 8,213 hours of the year, whereas the feed-in of renewables is cut in 2,888 hours. Reducing the number of zones from nine to five further increases re-dispatch by 1,535 GWh up to 22,430 GWh, now requiring 2,562 GWh of downward re-dispatch from RES. Congestion occurs in 8,240 hours, curtailment in 3,039 of them. But again, the maximum re-dispatch occurs in the CU case, even though it contains one additional zone: Maintaining national bidding zones leads to a total of 24,469 GWh of re-dispatch (+91% compared to 2015) and to RES-E curtailment to the amount of 3,783 GWh.

The observed stepwise decrease in congestion management measures from national market coupling to the five- and six-zone set-ups and finally to the nine-zone models can be attributed to two effects. First, a higher level of detail in transmission system modeling reduces congestion. The more restrictions on electricity transmission are imposed on the dispatch, the less violations of line capacities are observed in the ex-post calculation of the flows over the entire network. This especially shows in the comparison of the zonal models. The second effect is not only related to the number of bidding zones but also to their delimitations: Since the endogenous aggregation of nodes implicitly considers bottlenecks in the grid, congestion is pushed to the borders of the resulting zones. In consequence, the 2015 six-zone dispatch does not necessarily account for *more* lines than the CU computation, but reveals the utilization of the *more critical* lines. This is underlined by the changing proportions of internal and external congestion. In the 2015 CU model, 4,116 GWh/a (given 369 GW of transmission capacities) are not transmittable within countries, whereas between countries the overload resulting from the wholesale market dispatch amounts to only 787 GWh/a (given 61 GW of network capacities).[31] Although the allocation of total transmission capacities within and between zones is not changed much in the six-zone configuration (368 GW and 61 GW respectively), the internal overload is reduced by almost 40% to 2,543 GWh/a while the excessive external flows rise up to 1,404 GWh/a.

3.4.4 Total System Costs

NEULING provides information on the total costs originating from the wholesale market dispatch and from ex-post re-dispatch. An overview of the total system costs for all market configurations analyzed so far is given for the model years 2015 and 2020 in table 3.7.

TABLE 3.7: Total system costs of electricity supply in 2015 and 2020

2015				
[Million EUR]	**Nodal**	**Zonal (9)**	**Zonal (6)**	**CU (6)**
Wholesale	95,977	95,955	95,892	95,822
(CWE+ only)	(37,676)	(37,271)	(37,202)	(37,291)
Re-dispatch	0	780	957	1,099
Total	95,977	96,735	96,849	96,922
(CWE+ only)	(37,676)	(38,051)	(38,158)	(38,390)
2020				
[Million EUR]	**Nodal**	**Zonal (9)**	**Zonal (5)**	**CU (6)**
Wholesale	114,828	114,635	114,553	114,507
(CWE+ only)	(44,286)	(43,423)	(43,817)	(43,778)
Re-dispatch	0	1,732	1,962	2,447
Total	114,828	116,367	116,516	116,954
(CWE+ only)	(44,286)	(45,155)	(45,779)	(46,225)

Source: Own calculation.

The comparison of annual wholesale market costs in the year 2015 shows only small deviations between nodal and zonal models. Only small "savings" (-22 million EUR/a) are realized by reducing the number of bidding zones from 72 to 9, whereas the cost difference between the nine- and six-zone models is slightly higher (-63 mio. EUR/a). Again, the decrease in dispatch-related costs is due to the softer constraints on power flows and the increasing neglect of local structural limitations. In 2020, the wholesale market costs also decrease from 114,828 mio. EUR/a in the nodal case to 114,635 and 114,553 mio. EUR/a in the nine- and five-zone models respectively. Although the first steps of the aggregation (72 to 9 nodes, -193 mio. EUR/a) now lead to higher cost reductions than the later (9 to 5 zones, -82 mio. EUR/a), the relative "savings" per step

[31]The first-stage dispatch is calculated under consideration of the reduced international or zonal network and guarantees the compliance with the associated constraints. Nonetheless, overloading of interconnectors may occur as soon as the nodal distribution of generation and load is revealed and the full network is considered. Therefore, lines between countries or zones may cause re-dispatch, too.

still increase in the course of the aggregation process. At this point, the development of the CWE+ wholesale market costs in the year 2020 is noteworthy: Unlike the total dispatch costs, the CWE+ costs on the wholesale level do not strictly decrease with advancing aggregation, thus indicating that the potential benefits of network extensions within CWE+ may partly be allocated in neighborring regions.

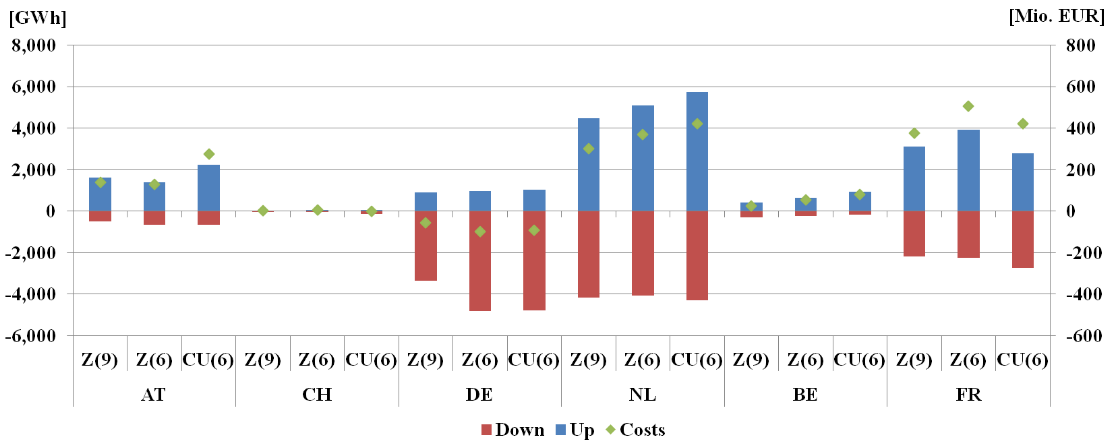
Regarding the costs caused by re-dispatch in the core regions, a higher number of zones is clearly preferable. Although the amount needed for re-dispatch in 2015 is only 14% higher in the six-zone than in the nine-zone configuration, costs increase by more than 23%. Analogously, the 7% increase in re-dispatch measures between 2020's nine- and five-zone models leads to 13% higher costs. This is due to the slope in the re-dispatch merit order which implies increasing marginal costs. The relative significance of the re-dispatch costs becomes slightly more apparent when comparing them to the wholesale market costs of the CWE region, Switzerland and Austria only. Given dispatch related costs of 37,271 mio. EUR/a and 37,202 mio. EUR/a in 2015's nine- and six-zone cases respectively, re-dispatch costs amount to 2.1% and 2.6% of the wholesale market costs of the core regions. A further increase in re-dispatch costs up to 1,099 mio. EUR/a or 2.9% of the respective wholesale market costs results from the CU model and the implementation of political instead of fundamental bidding zones. In 2020, the substantial increase in necessary congestion management measures as described in section 3.4.2 results in significantly higher re-dispatch costs, both in absolute and relative terms: Compared to the dispatch-related costs, additional 4% and 4.5% fall upon the five- and nine-zone re-dispatch respectively, while 5.6% are reached in the CU case.

In total, the nodal pricing model is - from a static, cost-based point of view - clearly preferable to the zonal options. Nonetheless, the increase in overall system costs remains small in relative terms, although the underlying aggregation is substantial. It also has to be kept in mind that a strict compliance with cluster analysis which allows for single-node zones would lead to lower total system costs of the zonal configurations and to even smaller differences in comparison to the nodal model. Furthermore, the results suggest that the level of physical market integration in the meshed CWE network is already high and that aggregation does not lead to significant cost increases until the very late stages. Nevertheless, a lower number of zones than tested for in this paper may still reveal critical losses in efficiency as soon as truly fundamental bottlenecks are disregarded or the last part of the exponentially increasing re-dispatch merit order is reached.

Another noteworthy insight generated from the comparison of total system costs is that not only the number of bidding zones but also their delimitations are decisive: As shown for 2015, refraining from the status quo of national borders (CU) and implementing a design derived from true structural barriers decreases overall costs even when keeping the number of bidding zones constant. Moreover, the 2020 example demonstrates that a reduction in overall system costs may even be achieved with fewer zones than countries, provided the bidding areas are chosen with respect to fundamental criteria.

Besides the quantitative effects, the definition of market zones also influences the spatial allocation of costs. Exemplary for 2015, figure 3.8 displays the variations in re-dispatch quantities and costs on a national level, which are derived from the respective nodal data. The absolute costs and quantities per country do not rise strictly from the nine-zone to the CU model but are shifted in accordance with the zonal delimitations. Furthermore, upward and downward re-dispatch are not allocated symmetrically since internal congestion does not need to be relieved by re-dispatch within the zones. Instead, the availability of re-dispatchable plants and their costs may turn cross-border congestion management into the more efficient option. In consequence, the national net costs are not necessarily positive. This observation adds another dimension to the issue of distribution effects: In addition to the differences in marginal costs (cf. section 3.4.1), the allocation of expenses and income from re-dispatch has to be taken into account and may lead to debates on source-related cost allocation.

FIGURE 3.8: Re-dispatch quantities and costs 2015



Source: Own calculation.

Finally, the disregard of dynamic effects in the given setup has to be considered. Due to the analysis of isolated scenario years, beneficial effects of system adaptation triggered by locational price signals are not included. Thus, the presented total system costs are not fully comprehensive.

3.5 Conclusion and Outlook

From the analyses of this paper useful insights into both methodological as well as real-world aspects of the debate on congestion management schemes have been gained. The calculation of the optimal nodal prices has highlighted the importance of in-depth modeling of generation and transmission systems for the identification of scarcities and unexploited potentials for increasing efficiency. At the same time, the model results show that nodal pricing in Europe comes with a noticeable heterogeneity in locational marginal prices which underlines the (political) relevance of distribution effects. Furthermore, the application of cluster analysis has given valuable insight into structural differences and similarities between regions and has eased the way to the identification of suitable bidding zones. Nonetheless, the instrument needs to be supplemented with information such as the desirable minimum zonal size and an ex-post test on the optimality of the results.

In this paper, no optimal zonal configuration has been defined. Especially, various important issues such as market concentration, liquidity and transaction costs have been excluded. Nonetheless, the comparative static analysis of total costs in European nodal and zonal systems allows for several relevant conclusions. First, the nodal-based delimitations of bidding zones in a strongly meshed network most often not coincide with national borders, even with relatively large zones. Second, even a dramatic reduction in the number of bidding zones yields only a relatively small increase in overall system costs. Third, nodes with extreme characteristics do exist and are worth identifying. The first two points suggest that efficiency gains from redefining market areas can be realized without compromising relevant factors such as liquidity. The third point leads to research questions related to dynamic effects of market design changes. Transparency on structural bottlenecks is indispensable for stimulating the adaptation of both generation and transmission systems. Nonetheless, the magnitude of price signals which is necessary to trigger changes in behavior has not yet been identified. This is especially true if zonal delimitations are dynamic themselves.

Chapter 4

On the Dynamic (In-) Efficiency of Re-dispatch

Re-dispatch is a widespread congestion management mechanism in Europe. Its popularity mainly stems from the possibility to adhere to uniform pricing on the national spot markets. Nonetheless, given the substantial delay in network expansions and increasing internal congestion, this approach has its limitations. The necessity to coordinate generation and transmission investments suggests an integration of local price signals into congestion management. With the help of theoretical models, this paper analyzes the short- and long-term efficiency of different re-dispatch designs and thus evaluates their ability to set regional incentives. The results show that although a well-designed re-dispatch is able to implement the optimal allocation of production, the mechanism does not induce dynamically efficient incentives for generators. Moreover, some designs may introduce additional distortions.

4.1 Introduction

Liberalized electricity markets with uniform pricing schemes are struggling with the coordination of power plant and transmission network investments. In spite of other well-known shortcomings, vertically integrated systems have the advantage of a simultaneous optimization of investments within the area of the regional monopolist.[32] Today, the obligation to connect supply and demand is generally imposed on the transmission system operators (TSOs) alone. Given the uniform wholesale market price within the bidding area, the choice of location on the part of the generator solely depends on the specific costs of the site, including the availability of cooling water and the transport

[32]Cf. Pollitt (2008), Höffler and Kranz (2011).

costs of primary fuels. In consequence, the individual costs of less favorable power plant sites are no longer weighed against the social costs of network extensions. As demonstrated in Dietrich et al. (2010) for the case of Germany, the locations of projected power plant investments thus deviate from the welfare maximizing siting.

Furthermore, an anticipation problem arises in the course of the network planning.[33] This problem is especially relevant due to the different leadtimes of generation and transmission investments. Accordingly, the process of long-term network planning is extremely complex. Given the important part of the transmission grid in the implementation of the Internal Electricity Market, noticeable efforts in network planning have been made both on international and national levels.[34] Despite this progress, the highly bureaucratic process of approving investments as well as the so-called NIMBY attitude (short for *not in my backyard*) prevail. Nonetheless, especially with regard to the high pace of the development of renewable energy sources (RES), network extensions advance slower than desirable. Overall, well-directed placing of new generation capacities could reduce the need for grid extensions.

Besides the long-term challenges, uniform pricing also complicates the day-to-day operation of the transmission network. In contrast to so-called electricity transmission pricing models such as locational marginal pricing (LMP, as developed by Schweppe et al. (1988)), the uniform wholesale market does not reveal the scarcity of internal network capacities and the associated costs of transmission to the market participants. Consequently, the resulting dispatch may overload the network. Therefore, uniform pricing systems come with the necessity to implement curative (sometimes also called corrective) congestion management mechanisms. Instruments such as re-dispatch resolve internal congestion by ex-post modifications of the generation schedules. In general, the TSO identifies the overloading of transmission lines and selects generators to increase or decrease their production. In the export-constrained region, the generation surplus is decreased by ramping down local units, whereas plants in the import-constrained deficit region are ramped up. Thereby, upward and downward re-dispatch have to be equal in volume, such that the balance between demand and supply is kept. The procedure of selecting generators for re-dispatch as well as their remuneration varies with the specific design.[35]

[33]Cf. Rious et al. (2011).

[34]Refer to ENTSO-E (2010) for the European approach and to 50Hertz Transmission GmbH et al. (2012) for the German Network Development Plan.

[35]Re-dispatch is sometimes differentiated from counter trade or counter purchases. The latter mechanisms are usually based on separate markets or auctions, in which the TSO acts as only buyer or seller of energy, again to the end that generation is increased and decreased locally. In this paper, all curative congestion management measures based on ex-post modifications of generation schedules are denominated as re-dispatch, irrespective of the procurement procedure.

Since in a uniform pricing system neither the social costs of network usage nor the social costs of location decisions are transparent for market participants, the question how to compensate the lack of locational signals is raised. Although locational marginal pricing (often called nodal pricing) provides a sophisticated alternative in theory, the political hurdle to the implementation of several price regions within one country will probably not be taken in the near future. Under the premise of uniform pricing, the attention is thus drawn to the existing congestion management scheme of re-dispatch. Given that re-dispatch (at least indirectly) reveals the location and costs of congestion as well as the nodes suitable for congestion relief, it is the only and thus the best available indicator of the relative quality of power plant locations.

In this paper, a joint analysis of the short- and long-term efficiency of re-dispatch is presented. Thereby, the focus is on the quality of the dynamic incentives for generators induced by the remuneration schemes of different designs. In addition to some general considerations, the two most common re-dispatch designs (so-called cost-based and market-based re-dispatch) as well as recently discussed variations using spot price-based remuneration are analyzed in detail.[36]

The first criterion of static efficiency defines the optimal allocation of re-dispatch volumes. The optimum is achieved when congestion is relieved and demand is satisfied at least cost under consideration of all network constraints. Bjørndal and Jørnsten (2007) state that optimal locational marginal prices implement this optimal allocation. The authors argue that the prices are unique in the sense that electricity is valued efficiently at each node. Bjørndal and Jørnsten (2007) therefore conclude that nodal pricing may be used as a reference in the evaluation of congestion management methods: In order to provide the optimal results, the methods have to be consistent with the optimal nodal values.

The static efficiency of the most common re-dispatch designs has been analyzed repeatedly, both qualitatively and analytically.[37] For example, De Vries and Hakvoort (2002) evaluate cost-based and market-based re-dispatch designs in a static framework of inelastic demand and perfect competition. By the means of theoretical models, the authors demonstrate that static efficiency is achieved through both mechanisms.

Provided that the efficient short-run result is achieved, the dynamic efficiency of re-dispatch may be assessed on the basis of the allocation of surpluses among the market participants. In order to identify the optimal level of re-dispatch remuneration, the divergence between the surplus from uniform pricing and an efficient benchmark has to

[36] The coupling of re-dispatch remuneration to spot prices is currently discussed in consultation processes of the German regulator Bundesnetzagentur (BNetzA), cf. BNetzA (2012b) and BNetzA (2012a).

[37] For a qualitative discussion, see Inderst and Wambach (2007). Analytical evaluations are presented in De Vries and Hakvoort (2002) and Hermans et al. (2011).

be determined. In contrast to the static case, the discussion of the dynamic efficiency of re-dispatch falls short of systematic analytical evaluations.

With the help of numerical examples, De Vries and Hakvoort (2002) demonstrate that consumer costs and generator surplus deviate under different re-dispatch mechanisms. However, they neither define a benchmark for the efficient distribution of surplus nor explicitly evaluate the effects analytically. In their brief discussion of long-term incentives of congestion management methods, the authors come to the conclusion that curative mechanisms do not set incentives to change the market participants' behavior and thus do not reduce congestion. In contrast, Inderst and Wambach (2007) state that market-based re-dispatch may send long-term signals to a certain degree, but do not elaborate further on the issue of dynamic efficiency.

Ding and Fuller (2005) primarily study the distribution of producer and consumer surplus for nodal, uniform and zonal pricing systems. In the latter cases, re-dispatch is shown to implement the efficient allocation of production. Assuming that re-dispatched generators are compensated for their incurred opportunity costs, the authors implicitly evaluate a cost-based re-dispatch design. By the means of theoretical models with demand and supply step functions, Ding and Fuller (2005) find that the total surplus is identical in all systems, but that the allocation of surplus among the market participants may differ substantially. Nonetheless, the authors argue that an adequate assessment of the magnitude of the differences requires quantification on the basis of realistic data and hourly model runs. Also Hermans et al. (2011) demonstrate analytically that although the generators' costs are identical in nodal pricing and uniform pricing with cost-based re-dispatch, the generators' surplus varies between the systems.[38]

Following the general line of argument from short to long term, the first part of this paper (section 4.2.1) defines the social planner benchmark for a statically efficient re-dispatch design. The applied setting is characterized by perfect competition, perfect foresight as well as by in-elastic demand. In the same section, the theoretical benchmark is analyzed with special regard to its practical limitations. Thus, the basic properties of a re-dispatch design which is both statically efficient and relatively robust can be identified. In section 4.3, the link between statically and dynamically efficient re-dispatch is established via considerations on the allocation of producer surplus. Again, an efficient benchmark has to be constructed. The discussion of the long-term incentives set by efficient short-run electricity prices reveals the necessity to further restrict the theoretical framework. Therefore, the assumptions of no economies of scale in generation and fixed network capacities are introduced. On this basis, three categories of re-dispatch mechanisms

[38]Hermans et al. (2011) use the term social welfare synonymously with producer surplus. This is misleading, since the net costs of re-dispatch ultimately borne by the consumers need to be included in a welfare analysis.

are tested with regard to their ability to introduce locational signals into electricity markets with uniform pricing. Section 4.4 then gives a critical acclaim of the underlying assumptions and discusses their influence on the quality of the results. The last section 4.5 concludes the analysis and identifies related issues in need for further research.

4.2 Static Efficiency of Re-dispatch

The analysis begins with some general considerations on statically efficient congestion management. Therefore, a theoretical social planner approach is consulted. Subsequently, the practical limitations of the model are discussed. On this basis, the characteristics of a statically efficient re-dispatch design are identified.

4.2.1 Efficient Allocation of Electricity Production

Per definition, the welfare maximization problem of the social planner leads to the efficient allocation of consumption and production under consideration of all relevant constraints. Evidently, this first-best solution also satisfies the criterion of Pareto optimality. According to the first welfare theorem, Pareto optimality is also reached in every competitive equilibrium. Then, utility maximizing producers and consumers base their individual decisions on market prices they take as given and achieve the same allocative efficiency as the benevolent planner.

In their seminal work, Schweppe et al. (1988) show that these principles also apply to the electricity market, provided that network constraints are explicitly taken into account. According to Kirchhoff's laws, power flows vary with voltage magnitudes and phases and largely depend on the network topology. Thus, the flows over a meshed network are never bidirectional but divide themselves among all lines connected to the node where the power is injected. As another consequence of the physical laws governing power flow, congestion on one line influences all flows within the transmission system. Accordingly, efficient market prices for electricity need to reflect the scarcity of the network and the external effects of its use.

The principle of locational marginal pricing (LMP) developed by Schweppe et al. (1988) therefore implies that in addition to the marginal costs of generation, also marginal costs of transmission losses and the opportunity costs of congestion are included in efficient spot prices. Hence, the prices paid by consumers depend on their location in the network and may vary on a nodal basis. The authors also state the duality of LMP and welfare maximization: The equilibrium prices resulting from the market may also be derived from the shadow prices of the social planner's dispatch problem and lead to the same allocation of production and consumption.

Under the assumption of a completely inelastic demand function, the minimization of production costs leads to maximal welfare.[39] Therefore, the optimal dispatch can be found as the solution to a problem minimizing the total cost of electricity supply TC in a (closed) system with N nodes.[40] Thereby, TC^N equals the sum of all nodal production costs, which are represented by functions $C_n(Q_n)$, $n \in \{1, \dots, N\}$ of nodal generation. The central balance constraint requires supply Q_n less net exchange to equal exogenous residual demand d_n for all nodes n at all times. The net exchange corresponds to the sum of power flows $F_{n,m}$ from all neighboring nodes m to node n. The flows may be positive or negative depending on their direction, thus resulting in negative net input when the flows entering node n exceed those leaving node n (and vice versa). Furthermore, dispatch and power flows are restricted by the capacity limits of generation $\bar{q}_n$ and transmission $\bar{l}_{n,m}$ between nodes n and m, $m \in \{1, \dots, N\}$. The optimization problem is given by

$$\min_{Q,F}! \; TC^N = \sum_n C_n \left(Q_n\right) \tag{4.1a}$$

$$\text{s.t. } Q_n - \sum_m F_{n,m} = d_n \tag{4.1b}$$

$$0 \leq Q_n \leq \bar{q}_n \tag{4.1c}$$

$$-\bar{l}_{n,m} \leq F_{n,m} \leq \bar{l}_{n,m} \tag{4.1d}$$

for all $n, m \in \{1, \dots, N\}$. The efficient solution is given by the allocation of generation Q_n^N and the corresponding flows $F_{n,m}^N$. Again, this outcome may be perfectly reproduced by the individual decisions of profit-maximizing producers in a competitive market under nodal pricing.

The key advantage of nodal pricing is the transparency of all network related constraints. The market clears under consideration of power flows and transmission capacities and thus manages congestion implicitly. In contrast, implementing a zonal or uniform pricing regime implies the aggregation of nodes into bidding areas, in which power flow constraints are neglected (or, equally, transmission capacities are set to infinity). Thus, internal congestion has to be relieved explicitly after market clearing by re-dispatch.

[39] Short-term demand inelasticity is not a necessary condition to prove the following, but simplifies notation considerably.

[40] The following formal representation does not include physical power flows, but resorts to the simple definition of bi-directional exchange between nodes. This has no impact on the economic intuition of the problem. A representation including the optimal power flow problem can be found in Hermans et al. (2011).

Just as for the dispatch, the optimal re-dispatch can be derived from a social planner approach, which is now deconstructed into a two-stage problem.[41] The first stage is represented by the dispatch problem. In comparison to the nodal model, the balance constraint is relaxed as to request the zonal equality of demand and supply only:[42]

$$\min_{Q}! \; TC^Z = \sum_n C_n\left(Q_n\right) \tag{4.2a}$$

$$\text{s.t.} \sum_n Q_n = \sum_n d_n \tag{4.2b}$$

$$0 \leq Q_n \leq \bar{q}_n \tag{4.2c}$$

for all $n \in \{1, \ldots, N\}$. In the presence of binding transmission constraints the optimal quantities Q_n^Z and Q_n^N at each node will differ and the zonal dispatch will overload the network given the corresponding $F_{n,m}^Z$. At the second stage, the social planner therefore restores the feasibility of the generation schedules by an ex-post adaptation R_n with flows $FR_{n,m}$:

$$\min_{R,FR}! \; RC = \sum_n \left[C_n\left(Q_n^Z + R_n\right) - C_n\left(Q_n^Z\right)\right] \tag{4.3a}$$

$$\text{s.t. } Q_n^Z - \sum_{m \neq n} F_{n,m}^Z + R_n - \sum_{m \neq n} FR_{n,m} = d_n \tag{4.3b}$$

$$0 \leq Q_n^Z + R_n \leq \bar{q}_n \tag{4.3c}$$

$$-\bar{l}_{n,m} \leq F_{n,m}^Z + FR_{n,m} \leq \bar{l}_{n,m} \tag{4.3d}$$

for all $n, m \in \{1, \ldots, N\}$. Since the optimal solution to a network constrained dispatch is Q_n^N, the statically efficient re-dispatch is given by $R_n^R = Q_n^N - Q_n^Z$. In consequence,

$$\begin{aligned} RC &= \sum_n \left[C_n\left(Q_n^N\right) - C_n\left(Q_n^Z\right)\right] \\ &= TC^N - TC^Z \end{aligned} \tag{4.4}$$

holds. Equation 4.4 thus reveals two important insights: First, "optimal" re-dispatch costs equal the dead-weight loss (DWL) in total welfare caused by the scarcity of transmission capacity, which is referred to as the costs of congestion (cf. Rious et al. (2009b)). Second, given a completely inelastic demand, the social planner achieves identical levels of total system costs in both the two-stage optimization and the integrated approach.

[41] Although the social planner has no reason to split the optimization, this representation allows for a more direct link to the real-world and the corresponding application of the first welfare theorem.

[42] In the following, the term "zone" refers to a bidding zone which contains more than one node and is prone to internal congestion. In this sense, a zone may be defined on a national level, too. Although the usage of the term zone commonly suggests the implementation of locational marginal pricing to some degree, whereas a national market with uniform pricing does not, no further differentiation between the designs is made in the remainder of the paper.

Consequently, the efficient re-dispatch does not impair total welfare either. However, these results can only be achieved if the deconstruction of the integrated problem does not cause any friction that further restricts the original solution space. Especially, the cost functions of dispatch and re-dispatch need to be identical.

Analogously to the duality of the social planner's one-stage dispatch and nodal pricing, the implementation of the efficient re-dispatch depends on the availability of an appropriate market-based mechanism. Whereas the competitive zonal wholesale market is assumed to reveal an efficient solution to the relaxed dispatch problem, the optimality of the second stage cannot be taken for granted. The next section therefore discusses the prerequisites for and the properties of a statically efficient re-dispatch design.

4.2.2 Implementing the Efficient Re-dispatch Allocation

The transfer of the social planner's two-stage problem to the real world comes with several pitfalls. The first is given by the previous assumption of a friction-free separation of dispatch and congestion management. The associated identity of the cost functions of day-ahead dispatch and intra-day re-dispatch implies full technical flexibility of generating units, such that congestion management on short notice does not lead to any additional costs. Most likely, this condition will not hold in reality: Due to the difference in the respective planning horizons and the available window for ramping, re-dispatch costs per unit will usually be higher than the costs of dispatching the same plant day-ahead.[43] Furthermore, intra-day trade and unplanned deviations from generation schedules or RES-E volumes lead to uncertainty of location and magnitude of congestion and may conceal the efficient re-dispatch allocation. Nonetheless, the assumption of cost identity and perfect foresight as a prerequisite for "perfect re-dispatch" will be kept in the following.

This said, the main requirement placed on a re-dispatch design is its ability to relieve overloaded transmission lines at least cost. The statically efficient allocation of re-dispatch is characterized by the optimal trade-off between the generators' marginal costs and the effectiveness of a change in their production level with regard to congestion relief. Since in a meshed network a variation in one node's demand and supply balance affects the power flows on all connected transmission lines, even a modification of production at the start or end node of a congested line will never translate in a relief to the same amount. Thereby, the effectiveness of a re-dispatch option is usually the smaller, the greater the distance between node and line. In consequence, the re-dispatch

[43] A similar line of argument is followed in Hermans et al. (2011).

of a costly but highly effective generator may be substituted by a cheaper but less effective option without diminishing efficiency. Although re-dispatch volumes will increase due to the smaller effect on the overloaded line, total re-dispatch costs will not change inevitably. Thus, choosing minimal re-dispatch volumes is neither a necessary nor a sufficient condition for static efficiency. Finally, optimal re-dispatch requires transparent information on the availability of generation capacities.

In practice, the calculation of the least-cost re-dispatch is highly complex and requires noticeable computational effort. Besides the extensive amount of data, numerous additional constraints have to be handled. First, reducing power flows on one line must not overload another one, such that a re-dispatch option may be infeasible unless counterbalanced by further measures. Second, the power flows have to respect (n-1)-security, i.e. the feasibility of power flows for a given set of nodal net inputs has to be maintained in the case of an outage of one random line. Third, congestion may occur simultaneously on several lines, such that the interplay between the re-dispatch options is of special importance.

Nonetheless, the crucial barrier to statically efficient re-dispatch is not the calculation itself but the availability of accurate data. In the unbundled electricity systems of Continental Europe, the transmission system operators (TSOs) are responsible for system security and therefore for adequate congestion management. Their key competence lies in the operation and management of the transmission system, thus providing the relevant information and methodology to perform load flow calculations. Therefore, the effectiveness of re-dispatch measures can be determined. Additionally, the coordinators of balance circles provide the TSOs with quarter-hourly schedules of generation and consumption, which could be easily extended to contain information on capacity available for re-dispatch. The information on the costs of re-dispatch options is thus most critical.

In the case of Germany, generators commit themselves in obligatory, bilateral grid connection or usage contracts with the regional TSO to provide information on their variable and ramping costs. On request by the TSOs, generators have to prove the adequacy of the indicated costs in a financial auditing process. Obviously, this process gives rise to problems associated with asymmetric information. Due to opaque, the statically efficient re-dispatch allocation may be missed. Furthermore, the limited incentives for generators to reveal their true costs are complemented by lacking incentives for TSOs to beat down the costs of re-dispatch, since the expenditures for congestion management are most commonly socialized via grid usage fees.

Nonetheless, the generators' scope to exploit their advantage may be reduced by increasing the credibility of cost control, either on behalf of the TSO or the regulator. This approach implies that an ex-post verification of the indicated re-dispatch costs is indeed possible, for example by checking the producers' accounts. What is not verifiable though, is the efficiency of the incurred cost.[44] The case of inefficient behavior of a regulatee is often brought forward with regard to the exaggerated assignment of general or administrative costs to positions subject to cost reimbursement. However, mixing the accounts of general with re-dispatch relevant variable costs is most likely difficult. Similarly, deliberate under-performance in power plant operation during re-dispatch seems to be of little relevance.

Alternatives to regulatory enforced cost control are market-based estimators or incentives for cost disclosure. Given perfect competition, the generators' spot market bids are an indicator of their marginal costs. If the TSO is granted access to the individual bids including information on the generator and her location, problems of information asymmetry are reduced to the identification of the ramping cost component, provided a well-designed re-dispatch mechanism is in place.[45] Such a mechanism will guarantee an efficient selection of generators on the basis of their bids, and at the same time ensure that the re-dispatch remuneration does not distort the spot market allocation. As soon as strategic behavior on the part of the generators is induced, their simultaneous optimization of spot and re-dispatch profits may diminish the quality of the bids as an indicator for marginal costs of production.

Under the assumption that true re-dispatch costs are revealed by cost control (or the threat thereof), so-called cost-based re-dispatch will achieve the efficient allocation of production. With this mechanism, the TSO re-dispatches the system under consideration of available capacity, variable costs and the effectiveness of congestion relief. Provided that the regulation encourages the TSO to minimize total re-dispatch costs, the operator will implement the efficient allocation. The remuneration scheme supports the TSO's behavior, since it merely reflects re-dispatch costs: Generators called for upward re-dispatch are compensated for the incurred variable costs and ramping. Generators reducing production during re-dispatch save variable costs, which they are obliged to transfer to the TSO. Given perfect information on the costs, both payments thus render the generators indifferent with regard to being re-dispatched and do not interfere with the individual surplus from wholesale market trade.

Whether the efficient outcome is also achieved on the basis of spot market bidding curves without cost control is not quite clear. Even under perfect competition, generators eligible for upward re-dispatch may raise their bids above marginal costs, if the forfeit spot

[44] This line of argument is for example followed in Shleifer (1985).

[45] In electricity markets managed by an independent system operator (ISO), the tasks of dispatch and congestion management are handled by the same institution, usually via implicit auctions. The ISO therefore has direct access to the bidding curves. However, the ISO depends on the transmission system owner to supply information on the network topology.

market revenues are compensated by increased expected re-dispatch remuneration.[46] The other way round, potential suppliers of downward re-dispatch may want to bid below their marginal costs. This behavior induces distribution effects and may conceal the least-cost re-dispatch. However, these strategies are not sustainable in a market without barriers to entry and with power plant sites available in the deficit region. In consequence, the potential for strategic behavior on the spot market under a cost-based re-dispatch regime is assumed to be small.

4.3 Dynamic Efficiency of Re-dispatch

Although the statically efficient allocation of production may be implemented in a zonal pricing system through re-dispatch, the quality of the associated long-term incentives remains to be assessed. Compared to the short-run perspective, the debate on dynamically efficient locational signals in electricity markets is more controversial. Hogan (1992) states that relying on a series of efficient short-run pricing decisions to achieve the optimal long-run outcome would only be possible in an ideal world with decreasing or at least constant returns to scale. In this sense, the lumpy transmission network makes it unlikely that electricity markets constitute an "ideal" case. Brunekreeft et al. (2005) further elaborate that since the production set of the network violates the requirements of the standard model of competitive pricing with respect to convexity (no economies of scale, proper pricing of externalities and public goods such as reliability), LMP will not reflect the marginal costs of the network adequately. In consequence, an investor's decision on location and plant type based on (future) nodal prices and the resulting present value of electricity only may be biased from a system-wide point of view.

Nonetheless, the extent of the bias also depends on the nature of generation investments. If the production set of generation is convex and thus exhibits no economies of scale, the investment decisions may be decentralized by competitive prices, provided that the network is planned efficiently by a central planner or TSO.[47] According to Brunekreeft et al. (2005), the variability of the capacity of combined cycle gas turbines (CCGT) and their small size in comparison to peak demands suggest that this assumption may not be overly critical. But the authors also highlight that the remaining assumptions of perfect foresight and competition put their own question mark on the applicability of

[46] This strategy is often denoted as economic capacity withholding. Examples are given in Inderst and Wambach (2007).

[47] Cf. Brunekreeft et al. (2005). Given the complex process of coordinated network planning (as recently observed in the case of the German network development plan) and its reliance on fault-prone forecasts of power plant (de-) commissionings, this is a highly demanding assumption.

the theoretical concept. Even so, the approach retains its charm since it limits the necessary locational differentiation to the spot prices, irrespective of further cost-recovering network charges.

In the following, the simplified framework, in which locational marginal prices are (apart from fixed and variable costs) the only indicator of a site's relative profitability, is used to derive a benchmark for dynamic efficiency. In this context, a generator's nodal surplus sets the optimal long-run incentives. Thus, interdependencies between power plant and network investments are excluded from her location decision. Furthermore, the assumptions on perfect competition and foresight are maintained in compliance with section 4.2.1. Despite the limitations of the setup, systematic deviations between this first-best outcome and the producer surplus from a zonal wholesale trade and re-dispatch can be identified and are likely to persist in more complex settings.

Although in a perfect world the total system costs do not change between the nodal benchmark and zonal models with re-dispatch, the distribution of rents between the market players may vary: First, the zonal aggregation leads to a neglect of external effects of network usage to some degree. Thus, the local distribution of surplus resulting from zonal wholesale trade will be biased in the presence of congestion. Second, re-dispatch may come with changes in the generators' revenues.[48] In this section, different re-dispatch designs will therefore be tested for their ability to compensate for the wholesale market bias, i. e. to internalize the opportunity costs of congestion ex-post. In addition to the present German system of cost-based re-dispatch, two remuneration schemes based on cost estimators derived from spot market prices as well as a market-based design are discussed.

4.3.1 Producer Surplus in Nodal and Zonal Systems

As preparation for the following evaluation of re-dispatch designs, some general considerations on the relationship between nodal and zonal producer surplus are of help. In the given setting of price-taking generators, the hourly producer surplus PS resulting from the respective dispatch can be written as

$$PS_n^N = p_n^N Q_n^N - C_n(Q_n^N), \tag{4.5}$$

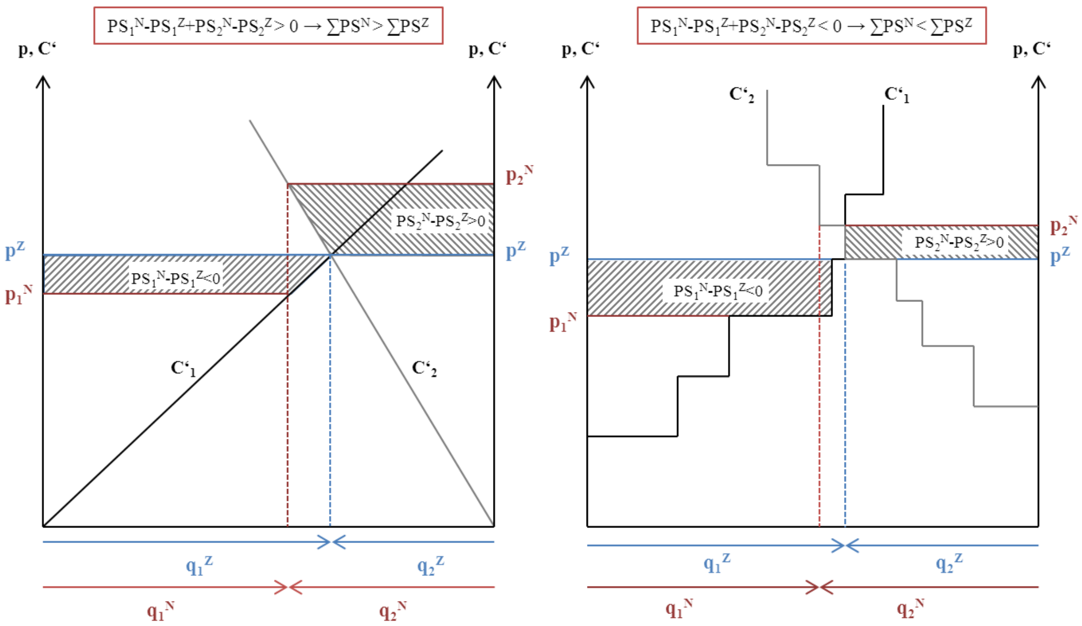
$$PS_n^Z = p^Z Q_n^Z - C_n(Q_n^Z). \tag{4.6}$$

Thereby, p_n^N and p^Z denote the hourly prices for electricity resulting from the nodal and zonal markets. As demonstrated in chapter 4.2.1, the zonal production costs differ from

[48] Also see De Vries and Hakvoort (2002).

the nodal costs provided that internal transmission constraints are binding. More precisely, the nodal restrictions on the solution space result in a costlier dispatch. Drawing conclusions from this result with regard to the total producer surplus in both systems is however not always possible. Figure 4.1 gives two examples.

FIGURE 4.1: Examples of diverging nodal and zonal producer surplus (PS)



Source: Own illustration.

In both diagrams, the ordinates depict the marginal costs C' and the market prices p at nodes 1 and 2. Furthermore, the length of the abscissa equals the total demand of both nodes, which may be served by production from either node (q_1, q_2). If both nodes belong to a single bidding zone, the market equilibrium leads to a price p^Z and production levels q_1^Z, q_2^Z. However, if nodal pricing reveals a binding transmission constraint, production levels adapt to q_1^N, q_2^N and the resulting nodal prices p_1^N, p_2^N diverge. In consequence, the nodal producer surplus PS changes in comparison to zonal pricing. The difference in their sum (area ruled in grey) may both be positive or negative. If in both markets the respective production costs and producer surplus are symmetric, e. g. in the case of linearly increasing cost functions with ordinate intercepts of zero (left diagram), the result will always be positive. However, the outcome is not self-evident in the more realistic case of asymmetric step functions (right diagram).

Nonetheless, propositions concerning the differences in producer surplus of a single generator g can be made. According to Ding and Fuller (2005), the following three main cases can be distinguished by the relationship between zonal and nodal production levels:[49]

(a) $Q^Z_{n,g} = Q^N_{n,g}$: $PS^Z_{n,g} - PS^N_{n,g} = \Delta PS_{n,g} = \left(p^Z - p^N_n\right) Q^N_{n,g}$.

(b) $Q^Z_{n,g} < Q^N_{n,g}$: $\Delta PS_{n,g} \leq 0$. If in addition $p^Z < p^N_n$ holds, then $\Delta PS_{n,g} < 0$.

(c) $Q^Z_{n,g} > Q^N_{n,g}$: $\Delta PS_{n,g} \geq 0$. If in addition $p^Z > p^N_n$ holds, then $\Delta PS_{n,g} > 0$.

The results indicate that generators in net exporting regions are by trend favored in zonal wholesale markets, while generators in net importing regions are most likely better off in nodal systems. However, the surplus of generators who are ultimately subject to re-dispatch (cases (b) and (c)) may be influenced by the congestion management mechanism in place.

4.3.2 Dynamic Incentives of Re-dispatch Designs

The degree to which congestion management is able to internalize external effects of network usage depends on the remuneration scheme. The first design to be analyzed is cost-based re-dispatch, followed by schemes with spot price-based remuneration. Finally, the incentives of market-based re-dispatch are assessed.

4.3.2.1 Cost-based Re-dispatch

Cost-based re-dispatch as described in 4.2.2 compensates the generators for their additional costs or charges them for their savings. Still, the information on the generators' opportunity costs of re-dispatch are assumed to be transparent. The associated payments $I_{n,g}(R_{n,g})$ thus lead to the following total producer surplus:

$$\begin{aligned} PS_{n,g} &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^Z_{n,g} + R_{n,g}\right) + I_{n,g}\left(R_{n,g}\right) \\ &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^Z_{n,g} + R_{n,g}\right) + \left[C_{n,g}\left(Q^Z_{n,g} + R_{n,g}\right) - C_{n,g}\left(Q^Z_{n,g}\right)\right] \\ &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^Z_{n,g}\right). \end{aligned} \tag{4.7}$$

Furthermore, if

$$R_{n,g} \neq 0 \text{ and } p^N_n \neq p^Z \tag{4.8}$$

[49] Ding and Fuller (2005) also list a fourth case, in which two generators at the same node are re-dispatched in different directions at the same time. Given least-cost zonal and nodal dispatch solutions, this case can only occur, when the re-dispatch is cost neutral and a benevolent planner would be indifferent concerning the dispatch of both generators. Then, zonal and nodal prices as well as the *sum* of the producers' surplus will be identical.

then

$$PS_{n,g} \neq p_n^N Q_{n,g}^N - C_{n,g}\left(Q_{n,g}^N\right). \tag{4.9}$$

The producer surplus of the re-dispatched generator remains on the zonal wholesale market level, such that the nodal benchmark is missed whenever zonal and nodal prices diverge. In consequence, the nodal allocation of production is implemented via re-dispatch without internalizing the costs of congestion.[50] Thus, no market participant is incentivized to deviate from the behavior induced by zonal pricing.

However, the most prevalent criticism passed on the current German cost-based system is the opaque of the bilateral contracts between generators and TSOs. Furthermore, the implemented design only allows for quarter-yearly updates of re-dispatch costs, which prevents the exploitation of short-term fluctuations in variable costs. Alternative designs therefore either define objective, time-variant estimators of variable re-dispatch costs which reduce problems of information asymmetry, or rely on a market mechanism to reveal the generators' costs. Their performance with respect to dynamic efficiency is analyzed in the following.

4.3.2.2 Spot Price-based Remuneration

The simplest approach to the definition of a general cost estimator is to make use of the information contained in the hourly spot price. This can be done by fixing the re-dispatch remuneration to the current price plus or minus a given percentage, depending on the direction of re-dispatch. The rate is then multiplied by the individual generator's re-dispatch quantity.[51] As a starting point for the formal representation, it is assumed that the given re-dispatch scheme does not influence the spot market outcome. In a general case of this "fixed-rate" approach, where the percentage value is denoted as δ, the resulting producer surplus thus amounts to

$$\begin{aligned} PS_{n,g} &= p^Z Q_{n,g}^Z - C_{n,g}\left(Q_{n,g}^Z + R_{n,g}\right) + I_{n,g}\left(R_{n,g}\right) \\ &= p^Z Q_{n,g}^Z - C_{n,g}\left(Q_{n,g}^N\right) + \delta p^Z R_{n,g} \\ &= p^Z\left(Q_{n,g}^Z + \delta R_{n,g}\right) - C_{n,g}\left(Q_{n,g}^N\right). \end{aligned} \tag{4.10}$$

Furthermore, if

$$\delta = \frac{p_n^N Q_{n,g}^N - p^Z Q_{n,g}^Z}{p^Z R_{n,g}} \tag{4.11}$$

[50] This corresponds to the findings in Ding and Fuller (2005) and Hermans et al. (2011).

[51] This remuneration scheme has been debated in a currently ongoing consultation process of the German regulator Bundesnetzagentur (BNetzA), cf. BNetzA (2012b). During the process, a percentage of 10% has been proposed.

then

$$PS_{n,g} = p_n^N Q_{n,g}^N - C_{n,g}\left(Q_{n,g}^N\right). \tag{4.12}$$

At the first glance, the generated equality between zonal and nodal surplus appears to be promising. Under the given assumptions, the implementation of the nodal surplus would set the first-best investment incentives for the long run. Given a closer look, equation 4.10 however reveals several flaws of the fixed-rate approach. First, an arbitrary percentage will most likely not do the trick since δ corresponds to the ratio between the surplus difference and the (zonal) spot market value of re-dispatch. Thus, an administratively set δ needs to depend on the zonal price level, the severeness of congestion (which influences the difference between zonal and nodal prices), as well as on the generator's individual re-dispatch level.

Therefore, any simplification in the form of a uniform δ will most likely lead to distortions. These inefficiencies for example show in the symmetry of payments for upward and downward re-dispatch, which ignores the increasing slope of the merit order (also see figure 4.1). Furthermore, a cost-minimizing TSO will select generators according to their effectiveness only, such that static efficiency is jeopardized: Since every generator is remunerated with the same rate, differences in variable costs are no longer a criterion of choice. The generators thus face a risk of being under-payed or over-charged for re-dispatch, since there is no link between the spot market merit order and the individual costs of the most effective producers. Last but not least, infra marginal generators needed for upward re-dispatch are always better off if they do not bid in the spot market, just as the dominant strategy for extra marginal producers is to bid below cost if they are being paid to ramp down afterwards. The simplicity of the remuneration scheme may thus induce significant inefficiency.

Some of the drawbacks of a fixed-rate approach can be avoided by a modification of the link between remuneration of the re-dispatched generators and the spot market price. The advanced model relies on an individual marginal cost estimator that is derived from the observed spot market behavior of a generator. In the expectation that producers bid their marginal costs, either the lowest market price at which the generator is called or the lowest price at which the generator is no longer called is used as an indicator for the re-dispatch costs. In a perfectly competitive environment, the prices will eventually deliver information on the true variable costs of starting up and turning off a power plant.[52]

[52] This estimator has also been discussed in the BNetzA consultation, cf. BNetzA (2012a). In the proposal, the spot market behavior of the last four weeks is suggested as an adequate basis for the estimation.

The following equation gives a general description of the effect of a marginal cost estimator ϵ on the producer surplus:

$$\begin{aligned} PS_{n,g} &= p^Z Q_{n,g}^Z - C_{n,g}\left(Q_{n,g}^Z + R_{n,g}\right) + I_{n,g}\left(R_{n,g}\right) \\ &= p^Z Q_{n,g}^Z - C_{n,g}\left(Q_{n,g}^Z + R_{n,g}\right) + \epsilon_{n,g} R_{n,g}. \end{aligned} \tag{4.13}$$

Furthermore, if

$$\epsilon_{n,g} = \frac{C_{n,g}\left(Q_{n,g}^Z + R_{n,g}\right) - C_{n,g}\left(Q_{n,g}\right)}{R_{n,g}} \tag{4.14}$$

then

$$PS_{n,g} = p^Z Q_{n,g}^Z - C_{n,g}\left(Q_{n,g}^Z\right). \tag{4.15}$$

Since ϵ is a punctual estimator, its value is independent of the re-dispatch quantity R. Thus, the estimator will only reflect the costs of re-dispatch, if the marginal costs of production are constant themselves. For a single generator, the assumption of constant marginal costs may not be overly critical, although it neglects part load losses etc.[53] However, a correctly determined ϵ never allows for a re-dispatch margin different from zero, such that the final producer surplus remains on the zonal level. Hence, no locational incentives are set.

Whether the estimator is able to capture the marginal costs also depends on the definition of the reference price. The proposition to derive separate estimators for upward and downward re-dispatch, i. e. on the respective prices at the time of starting or suspending production, has for example been made in BNetzA (2012a). The underlying motivation stems from the fact that the respective reference prices may differ, since the price at which a plant begins operation needs to cover additional start-up costs, whereas the variable costs of ramping down are in general negligible. However, this approach will systematically over-price the positive re-dispatch of spinning units. This is especially true if an additional compensation of ramp-up costs is allowed for.[54] Nevertheless, this bias can easily be avoided by using a single estimator only, which equals the minimum of the former reference prices. Then, ramp-up costs may e. g. be set to the difference between the reference prices and can be compensated separately. In this modified form, the estimator accurately reveals a generator's (constant) marginal costs.

In practice, not variable start-up but opportunity costs pose the biggest threat to the accuracy of the estimator. For example, the opportunity costs of ramping as well as of balancing reserve provision may lead to deviations in the spot market bids from variable costs (for empirical evidence, cf. Nicolosi (2010)). Especially in the latter case, the

[53] On the market level, the assumption implies a step-wise merit order, which is a common simplification.

[54] This is e. g. suggested in BNetzA (2012a).

obligation to keep the power plant spinning may lead to continuous production in times of prices below costs. Since the losses are compensated by the reserve market's capacity prices, this behavior is completely rational. However, in the presence of an estimator ϵ, re-dispatch costs may be underestimated. As a remedy, a minimum payment for re-dispatch can be introduced. This floor may lower the risk of faulty estimations, if it is specified on the basis of long-term observations or a technology-specific benchmark, and if it holds both for positive as well as for negative re-dispatch payments.[55] Nonetheless, it needs to be shown whether the floor constantly dominates the estimator due to the day-to-day presence of opportunities.

4.3.2.3 Market-based Re-dispatch

Instead of using spot market proxies, the pricing and procurement of re-dispatch may be organized with the help of a separate market. As before, all markets are assumed to be perfectly competitive. On the re-dispatch market, generators bid quantities and prices in auctions. The TSO then selects producers for re-dispatch according to costs and effectiveness. In the following, the market is defined as to remunerate energy only, such that no capacity payments are made. One possible auction design is uniform pricing, in which all winning generators are remunerated with the price bid of the marginal generator. The dominant strategy in this type of auction is to bid one's marginal costs, as this maximizes the probability of a call without diminishing the potential revenue.[56] In such auctions for positive and negative re-dispatch, the generators therefore reveal their marginal costs of increasing or decreasing production. If the market performs efficiently, the last winning local generator will correspond to the marginal generator under nodal pricing. In consequence, the marginal costs of re-dispatch equal nodal prices, such that $p_n^R = p_n^N$.[57] Under uniform pricing, all selected generators are remunerated adequately with $p_n^N R_n$. The payment is either positive or negative, depending on the sign of the

[55] In BNetzA (2012a), a minimum payment of 25 EUR/MWh is suggested for positive re-dispatch only.

[56] Cf. Grimm et al. (2008). In contrast to uniform pricing, pay-as-bid auctions remunerate the winners according to their individual bid. In this design, no incentives to reveal marginal costs exist, since it is most profitable to set one's bid to the expected price paid to the marginal generator. In an ideal world, pay-as-bid pricing leads to the same calls and payments as uniform pricing. However, given uncertainty and bounded rationality, the efficient outcome is often missed in practice, cf. Grimm et al. (2008).

[57] This implies that re-dispatch prices are calculated per node, or else that the surplus and deficit regions are separate copperplates.

re-dispatch. This leads to the following producer surplus:

$$\begin{aligned} PS_{n,g} &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^Z_{n,g} + R_{n,g}\right) + I_{n,g}\left(R_{n,g}\right) \\ &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^Z_{n,g} + R_{n,g}\right) + p^N_n R_{n,g} \\ &= p^Z Q^Z_{n,g} - C_{n,g}\left(Q^N_{n,g}\right) + p^N_n\left(Q^N_{n,g} - Q^Z_{n,g}\right) \\ &= \left(p^Z - p^N_n\right) Q^Z_{n,g} + p^N_n Q^N_{n,g} - C_{n,g}\left(Q^N_{n,g}\right) \end{aligned} \tag{4.16}$$

This equation reveals important insights into the nature of the re-dispatch market, especially with regard to the interplay with the zonal spot market. In the case of positive re-dispatch, the relevant generators are situated at import-constrained nodes. Thus, the zonal market price will be lower than the nodal price paid for re-dispatch. Accordingly, the volumes sold at the spot market reduce the generator's total surplus.

$$PS_{n,g} = \overbrace{\left(p^Z - p^N_n\right)}^{<0} Q^Z_{n,g} + p^N_n Q^N_{n,g} - C_{n,g}\left(Q^N_{n,g}\right) \tag{4.17a}$$

$$\Rightarrow \arg\max_{Q^Z_{n,g}} PS_{n,g} = 0 \tag{4.17b}$$

$$\Rightarrow PS_{n,g} = p^N_n Q^N_{n,g} - C_{n,g}\left(Q^N_{n,g}\right) \tag{4.17c}$$

In consequence, the dominant strategy of generators in the deficit region is not to participate in the spot market in times of congestion. This aggravates the congestion such that all previously infra-marginal generators can rely on being called for re-dispatch. In the extreme, all relevant generators migrate to the re-dispatch market and are remunerated as under nodal pricing.[58] This is both statically and dynamically efficient. Nonetheless, this strategic behavior induces substantial distribution effects.

These incentives also influence the remaining market players. The gap left by the generators of the deficit region at the spot market has to be filled by producers located at export-constrained nodes. Thus, previously extra marginal generators now win in the spot market auction and the market clearing price increases. After the closure of the spot market, all of the previously extra marginal generators have to be constrained-off additionally. On the negative re-dispatch market, the generators located at surplus nodes bid their avoided marginal costs, since this behavior never renders them worse off than before re-dispatch. Again, the re-dispatch market yields prices which equal the nodal prices at export-constrained nodes. All winning generators are remunerated with the price of the local marginal re-dispatch generator, such that (in analogy to the positive re-dispatch market) infra marginal generators are left with additional margins. But, in the case of the negative market, this is problematic since from a system-wide

[58]This implies that sufficient capacity is available in the surplus region, which can fill the gap at the spot market.

point of view the surplus of generators with $Q^Z > Q^N$ is already too high after dispatch and thus even higher after re-dispatch. Even if an auction design ensuring that each generator is remunerated individually according to her bid could be implemented, the surplus after re-dispatch would never be lower than after zonal dispatch.

$$PS_{n,g} = \overbrace{\left(p^Z - p_n^N\right)}^{>0} Q_{n,g}^Z + p_n^N Q_{n,g}^N - C_{n,g}\left(Q_{n,g}^N\right) \tag{4.18a}$$

$$\Rightarrow \arg\max_{Q_{n,g}^Z} PS_{n,g} = Q_{n,g}^{max} \tag{4.18b}$$

$$\Rightarrow PS_{n,g} > p_n^N Q_{n,g}^N - C_{n,g}\left(Q_{n,g}^N\right) \tag{4.18c}$$

The negative re-dispatch market thus invokes dynamic inefficiency by overshooting the nodal pricing level of revenues. In the long run, this result would lead to a build-up of overcapacities in the export-constrained region. As the inefficiency takes the form of excess producer surplus, it is however difficult to counteract. Given that spot market trade has already rewarded the constrained-off generators, a market mechanism to skim this profit margin can hardly be found. In the end, it would need to leave the generator as if he had not participated in the spot market at all.

4.4 Discussion

So far, three classes of re-dispatch designs have been analyzed with respect to their static and dynamic performance. Under the central assumptions of perfect competition and foresight, inelastic demand, fixed network capacities and no economies of scale in generation, the allocation of production and the distribution of producer surplus serves as an indicator for the mechanisms' economic efficiency. Although short-run allocative efficiency may be achieved in any well-designed system, none of the designs shows promising results with regard to dynamic efficiency.

Both cost-based re-dispatch and individual spot price-based estimators of re-dispatch costs have been shown to implement the optimal allocation of production. Whereas cost-based re-dispatch systems may struggle with information asymmetry and delayed cost updates, the intention of the developed estimators is to reduce asymmetries and to allow for time-variant payments. Spot price-based designs thus have the potential to increase static efficiency in practice, as long as the basis of calculation is designed with due diligence. However, neither design influences the producers' surplus from wholesale trade. Accordingly, the opportunity costs of congestion cannot be internalized.

In the case of market-based designs, the biggest practical obstacle to static efficiency is strategic behavior. Nonetheless, strategic behavior in itself does not prevent an efficient allocation of production in theory. Moreover, market-based re-dispatch is shown to be the only one of the analyzed designs which at least partly achieves an efficient distribution of producer surplus. Since all generators appointed for upward re-dispatch are remunerated with the marginal costs of the last required nodal supplier, their surplus is raised to the nodal level. However, the positive effect of a single nodal price for re-dispatch cannot be transferred to the market for downward re-dispatch. In order to reach the efficient level of surplus, the generators appointed for negative re-dispatch would need to hand over their profit margin from wholesale trade. Instead, the downward re-dispatch market leaves winning generators with additional margins. In the end, no free market sets incentives to bid below one's opportunity costs.

A further limitation to the dynamic efficiency of all re-dispatch designs is the restriction of payments to a limited group of market participants. Even if a mechanism that induces the optimal producer surplus could be found, all generators not appointed for re-dispatch would still be remunerated with the inefficient zonal spot market price. Hypothetically, the optimal design could indicate the necessary adjustment payments for those generators who are already dispatched efficiently after the clearing of the spot market. As in the optimum the marginal costs of re-dispatch equal nodal prices, the difference between marginal costs and zonal prices may be used to derive the difference in nodal and zonal surpluses. However, if structural congestion calls for comprehensive local incentives for power plant investors, re-distributing potentially large rents by the means of re-dispatch seems to be a far-fetched plan.

Given the strict assumptions imposed in the analysis, the performance of the re-dispatch mechanisms need to be challenged further in a more realistic setting. The case of market power and congestion management has a prominent place in the literature. For example, Green (2007) highlights that the inefficiency resulting from neglecting transmission constraints on the dispatch level rises in the presence of market power. An extensive analysis of strategic behavior in the case of market-based re-dispatch is provided in Harvey and Hogan (2000). The authors demonstrate the incentive for market players to provoke congestion in order to profit from the later re-dispatch remuneration. This so-called inc-dec game has amongst others been observed in the UK and in the California ISO system. The problem is aggravated, when congestion creates pockets of local market power. However, cost-based re-dispatch usually performs better in the presence of limited competition. In a comparative analysis of congestion management mechanisms, Inderst and Wambach (2007) show that cost-based re-dispatch mitigates the abuse of regional market power, especially in the case of a small number of stable bottlenecks. Similarly, the potential for the abuse of market power in spot price-based re-dispatch systems is assumed to be small, provided that the wholesale market is competitive. The persistence of local market power finally depends on the barriers to entry. In contrast to the wholesale market level, the regional barriers are largely determined by the availability of new power plant sites.

The assumption on demand (in-) elasticity is presumably less critical. However, Green (2007) indicates that the difference in generator surplus between nodal and uniform pricing with cost-based re-dispatch decreases with rising demand elasticity, whereas the welfare loss increases. Concerning the efficiency of re-dispatch in particular, the participation of the demand-side in congestion management is decisive. If demand responds to price signals, the limitation of re-dispatch to generators will prevent the implementation of the nodal pricing result and hence will increase the associated costs.

The role of perfect foresight in the given analysis is twofold. On the one hand, it allows for statically efficient re-dispatch. On the other hand, uncertainty diminishes the quality of locational marginal pricing as a benchmark for dynamic efficiency. According to Brunekreeft et al. (2005), the lumpiness of transmission investments may lead to large deviations between present nodal prices and their long-run equilibrium. The uncertainty of network extensions may therefore complicate the price forecast on which a power plant investment decision is based. In this context, Brunekreeft et al. (2005) emphasize the importance of hedging opportunities such as financial transmission rights. Furthermore, the defined benchmark requires the network to be planned centrally and efficiently. However, Inderst and Wambach (2007) state that due to the long planning horizons for generation and network capacity investments, the alternating expectations on investments are likely to effect capacity developments. This is confirmed by Rious et al. (2011), who show that the costs of anticipating power plant investments may determine the degree to which the TSO takes new generation into account when planning the network.

Smeers (2006) further elaborates the challenge of developing long-term signals in the presence of discrete investment decisions. The author derives pricing schemes which rely on nodal pricing to induce efficient dispatch, but also invoke payments related to the choice of location. Thus, the mechanisms explicitly account for the lumpiness of generation and transmission investments. In the basic pricing scheme, the fixed payment is made when the generator or consumer decides to connect to a specific node. The resulting two-part tariff is dynamically efficient, but discriminatory and not yet cost-reflective. Smeers findsthat the mechanism can be further developed to be cost-reflective, whereas non-discrimination comes with a loss of efficiency.

Also Rious et al. (2009a) develop a two-part tariff in the context of lumpy transmission investments. The pricing scheme relies on nodal pricing to send short-run signals, whereas long-run incentives are set by an average participation tariff. The authors find that implementing locational network tariffs even has a higher priority than the implementation of nodal pricing in the process of coordinating network and generation investments. However, the optimal allocation of new generation capacities cannot be guaranteed by the given approach.

The presented considerations reveal the limitations of the LMP benchmark applied in the presented analysis. Nonetheless, the literature suggests that the optimal nodal allocation of production and surplus is still worth striving for, such that LMP remains a valuable indicator in the evaluation of congestion management schemes. Given that uniform pricing will still dominate most of the European markets in the next few years, the focus of future research should be on the evaluation of the potential second-best combination of preferably efficient re-dispatch and local charges for network cost recovery. Besides the approach suggested in Rious et al. (2009a), other forms of locally differentiated network tariffs (so-called G- and L-components) may be worth considering.

4.5 Conclusion and Outlook

The theoretical analysis presented in this paper reveals the limited ability of re-dispatch to induce efficient long-run incentives for generators in a uniform pricing system. With the help of analytical models, formal representations of the impact of different remuneration schemes on the surplus of re-dispatched generators are given. Thereby, the nodal producer surplus of a locational marginal pricing system serves as a benchmark for efficient long-run signals. Accordingly, systematic deviations from the point of reference are identified.

In the case of cost-based and market-based mechanisms, the analysis complements the qualitative discussions on the long-term inefficiency of both designs. Whereas cost-based re-dispatch does not yield any revenues for re-dispatched generators, market-based congestion management may come with benefits for suppliers. However, not all of the benefits contribute to a more efficient distribution of producer surplus. In contrast, the remuneration of generators providing negative re-dispatch even aggravates the divergence of the total zonal surplus from the nodal outcome in the respective locations. Furthermore, two recent variations of spot price-based remuneration schemes are discussed. The theoretical analysis reveals structural deficits that prevent an efficient allocation of producer surplus and may even jeopardize static efficiency.

Despite the strict assumptions which limit the analysis to an ideal framework, the results suggest that re-dispatch is an inadequate tool for internalizing the external effects of congestion. The presented discussion already hints the relevance of issues related to information asymmetries, strategic behavior and the selective nature of re-dispatch mechanisms, which further impair the performance of re-dispatch in practice. In this context, regional market power is of special importance for some re-dispatch designs.

Overall, the selection of a robust re-dispatch mechanism that does not introduce additional distortions seems to be more rational than aiming for a re-dispatch design which sets local incentives. This draws the attention to cost-based and well-designed spot price-based mechanisms. With regard to the latter, the designs' practical performance needs to be analyzed in greater detail. Especially the trade-off between the mechanisms' transparency and accuracy is worth evaluating. However, the central question that remains to be answered concerns the original bias of the uniform pricing system. Ultimately, the pressure to introduce regionally differentiated signals and to enforce network extensions rises with the magnitude of the divergence between the outcome of the national and the efficient nodal market.

Due to the limited scope of the analysis, other instruments to improve the coordination of generation and network investments have not been addressed. Besides measures which aim at power plant investors, the central role of the TSO needs to be considered. Especially, the interaction of network user and network operator is of interest in the analysis of incentive schemes.

Chapter 5

Quantifying the Economic Effects of Congestion Management - The Case of Germany

The design of congestion management has a significant impact on the efficiency of electricity markets and influences the allocation of costs and surpluses. Using the example of Germany, this paper quantifies the associated effects. The impact of congestion management on the wholesale market is demonstrated by a comparison of the current uniform pricing system to nodal pricing as a benchmark for short-term efficiency. Both approaches deviate in their ability to internalize the opportunity costs of congestion and thus in the allocation of generation. In consequence, the presented analysis reveals significant distribution effects within Germany as well as differences in the overall wholesale market costs. The analysis of the uniform pricing system is complemented by the evaluation of three re-dispatch designs, which resolve internal congestion after the clearing of the spot market. Since even a well-designed re-dispatch mechanism will most likely miss the efficient allocation of generation in practice, the analysis indicates the magnitude of the associated bias. The results show that the details of the re-dispatch design largely determine the degree to which additional distortions are introduced.

5.1 Introduction

Much has already been said on the efficiency of electricity transmission pricing. In the short run, the optimal use of the transmission system can be induced by locational marginal prices which reflect the marginal costs of generation as well as the opportunity costs induced by congestion (cf. Schweppe et al. (1988)). This market design thus manages congestion implicitly on the wholesale market level. In the long-run, the associated local signals may contribute to a beneficial allocation of new generation capacities and load centers (cf. Smeers (2006)). Nevertheless, locational marginal pricing (often called nodal pricing) in its full spatial resolution has not been implemented in Europe so far. Besides the introduction of zonal designs in the Nord Pool spot market and in Italy, national uniform pricing is still the dominant market design.

As demonstrated in chapters 3 and 4, electricity market designs based on uniform pricing come with losses in efficiency of two origins. First, the national wholesale market neglects internal congestion. The resulting dispatch may thus overload the transmission network. Furthermore, the allocation of wholesale market costs and surpluses will not signal the external effects of network usage at a given node. In consequence, individual location decisions will not consider the scarcity of network capacities. Second, uniform pricing will require the management of internal congestion after the clearing of the wholesale market. Besides network-related measures such as topology optimization, the re-allocation of generation by the means of re-dispatch is often used to relieve overloaded lines. However, the characteristics of the specific re-dispatch design will influence the efficiency of congestion management, both with regard to the allocation of production as well as to the distribution of costs and surpluses.

The analysis presented in this paper aims at the quantification of the impact of congestion management design choices using the example of Germany. Complementary to the theoretical approach presented in the previous chapter, the focus is on the magnitude of the bias induced by uniform pricing and re-dispatch, as well as on its geographical allocation. In analogy to the two levels of the issue at hand, the analysis is split. In the first part, the losses in efficiency are identified on the wholesale market level. Thereby, the distribution of generation and producer surplus under uniform pricing is compared to a nodal pricing benchmark for congestion management. In the second part, three re-dispatch models are tested for their relative cost efficiency and their impact on the generators' revenues. Hereby, the reference case is defined by the currently implemented cost-based design, which does not create any additional surplus but is most likely to achieve the least-cost solution to congestion (see chapter 4). All calculations are based on the fundamental electricity market model *NEULING* as described in chapter 2. For each scenario, 8760h of the year 2015 are modeled in a European context. Power flows resulting from dispatch and re-dispatch are calculated by the means of a DC load flow. As opposed to the ideal world of the theoretical re-dispatch model, some practical obstacles such as limited short-term flexibility are introduced in the model and enable a realistic evaluation of congestion management in Germany.

The nodal pricing model applied in part one (section 5.3) defines the first-best congestion management mechanism. This benchmark is used to identify the efficient allocation of electricity production and generator revenues in Germany. Thereby, an approximation of local producer surplus is derived from hourly marginal cost-based prices, variable costs and production levels. As discussed in section 4.4, nodal pricing does not necessarily induce the optimal long-run level of producer surplus, especially in the presence of lumpy generation and transmission investments. Nonetheless, locational marginal pricing (LMP) usually is one building block of dynamically efficient pricing schemes.[59] Therefore, assessing the magnitude of the uniform pricing bias in comparison to a nodal benchmark may give a first indication of the distortion of local investment incentives.

This approach is for example followed in Green (2007). The author quantifies the welfare effect of changing from uniform pricing with re-dispatch to nodal pricing for a 13-node DC load flow model of England and Wales. Green (2007) calculates average prices, generators' profits and the change in consumer surplus with responsive demand. Re-dispatched generators are remunerated according to their opportunity costs, such that no additional profit from re-dispatch is made.[60] The input data is taken from the years 1996 and 1997. Ten sets of demand curves per winter and summer seasons represent different demand levels. The weighted results give the yearly values, which indicate that welfare under uniform pricing is (measured in percent of the generators' revenue) 1.3% lower than under nodal pricing. This figure results from a decrease in consumer surplus by 3.4% and an increase in generator profit by 2.1%. Thereby, costs and generator profits are calculated under consideration of operational costs only. Green (2007) also highlights, that the gains from optimal nodal pricing are market-specific.

For the Italian market, Ding and Fuller (2005) illustrate the divergence in producer and consumer surplus under nodal, zonal and uniform pricing regimes. The authors create artificial offer and demand curves consisting of four and five bids per node respectively. Ding and Fuller (2005) use a randomized procedure to match the bidding curves with historical data and further define three cases in which nodal demand is uniformly lowered, average or uniformly increased. For each case and each pricing scheme, one set of local surpluses is derived. The authors state that consumers benefit from uniform and zonal pricing in the low demand case compared to the nodal setting, but lose in the case of average and high demand. However, they question the robustness of their results, since the offer and bid data is only loosely related to reality.

Regarding the German market, an evaluation of the welfare gain from nodal pricing can be found in Weigt (2006). In the presented analysis, a DC load flow based on data of

[59] This refers to so-called two-part tariffs as discussed in Smeers (2006).
[60] This concept corresponds to a cost-based re-dispatch design.

the year 2005 is calculated for Germany and its neighboring countries. Weigt (2006) analyzes one winter and one summer day with 24 consecutive hours each and derives a total benefit of 90 mEUR/a. This result comes with an increase in consumer surplus and a decrease in producer surplus. Per winter day, the change for consumers amounts to +0.79%, whereas producers lose 3.55%.

However, the literature on the quantitative effects of re-dispatch mainly focuses on cost-based designs. For example, Nüßler (2012) evaluates the development of re-dispatch costs for the case of Germany under consideration of the current cost-based mechanism. Thereby, the focus is on the influence of different fundamental drivers such as wind power feed-in and local consumption. To this end, Nüßler (2012) calculates the re-dispatch for several scenario years on the basis of power transfer distribution factor (PTDF) matrices. Thereby, the scenarios are represented by 12 type-days with 24 hours each. A different angle is introduced in Kunz (2011), where the benefit of combining cost-based re-dispatch with network topology optimization is assessed for the case of Germany. The analysis is based on a DC load flow model, which is used to compute nine single hours per scenario year. The re-dispatch model introduced in Linnemann et al. (2011) is based on a methodology that allows for the iterative optimization of (n-1)-secure congestion management. However, the model still equals cost-based re-dispatch in its economic properties.

The analysis presented in this paper adds an in-depth analysis of congestion management within the German electricity market to the existing literature. Especially, the high temporal resolution as well as the detailed consideration of international power flows contribute to a robust basis for the evaluation of the current uniform pricing system. Furthermore, the second part of the analysis allows for a profound evaluation of the impact of re-dispatch on the overall performance of the German market. Besides the current cost-based design, two re-dispatch mechanisms using spot price-based remuneration schemes are analyzed in detail. Overall, a wide range of alternative congestion management mechanisms is put to the test. As stated by Bjørndal and Jørnsten (2007), the variation in the costs of congestion across different congestion management schemes may well be substantial.

This paper is structured as follows. In section 5.2, the data and the assumptions underlying the quantitative analysis are presented. Furthermore, the dispatch and re-dispatch scenarios are defined, including a description of the corresponding model setup. Section 5.3 constitutes the first part of the central analysis, which focuses on the impact of congestion management on the wholesale market. The second part (section 5.4) is dedicated to the identification of internal congestion resulting from the German uniform pricing dispatch and to the comparison of re-dispatch mechanisms. Section 5.5 closes with a general discussion and remarks on the need for further research.

5.2 Data and Scenarios

The quantitative analysis presented in this paper is based on calculations with the fundamental electricity market model *NEULING*. As described in chapter 2, the model computes the least-cost dispatch and re-dispatch under consideration of inelastic demand, exogenous electricity production from RES as well as from combined heat and power plants (CHP). Thereby, the associated power flows are subject to DC load flow constraints and network transfer capacity (NTC) limits. The temporal resolution of the dispatch model allows for an inter-temporal optimization across 8760 consecutive hours of a given scenario year, in this case 2015. The re-dispatch model also optimizes congestion management for all hours of the year, but neglects inter-temporality.

5.2.1 Data and General Assumptions

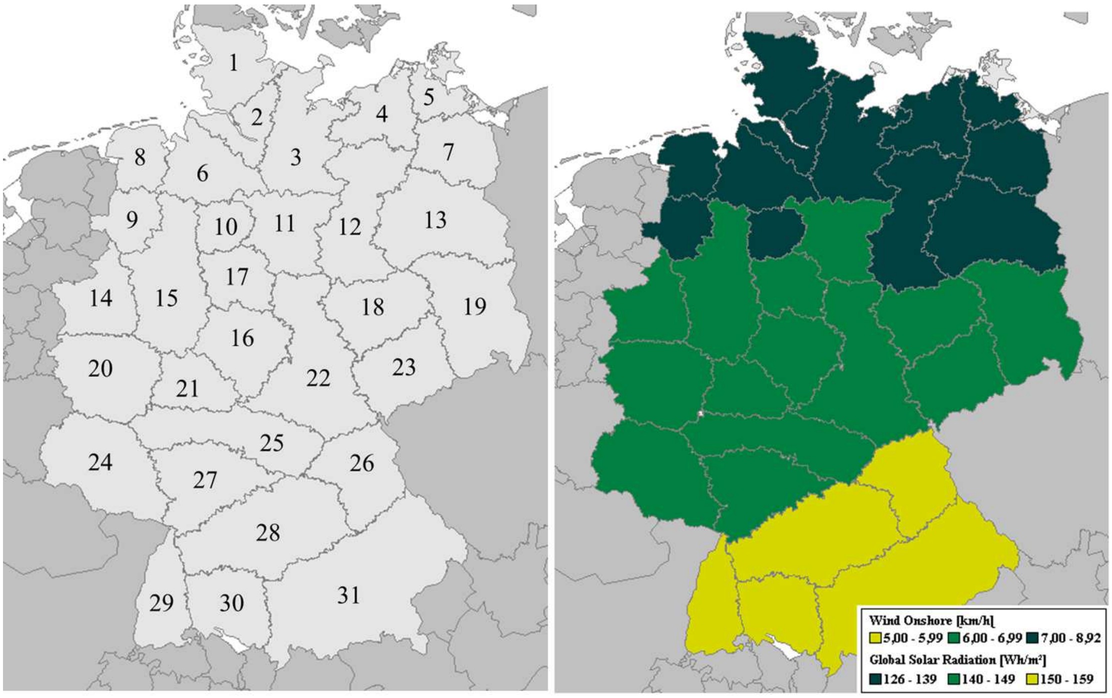
Although the focus of the analysis is on Germany, the model regions cover Central Western Europe (CWE, including France, BeNeLux and Germany) plus Switzerland and Austria, their direct neighbors as well as Great Britain and Scandinavia. The high number of considered power markets ensures an accurate representation of inter-regional trade and power flows. Depending on the scenario, the spatial resolution of the model is increased as to reveal nodal regions within CWE, Switzerland and Austria (in the following denoted as CWE+ or core regions).[61] These nodal regions are designed to represent the basic structure of the high-voltage transmission network, such that within the regions all consumers and suppliers are assumed to be connected to one central node. The 31 German nodal regions are displayed in figure 5.1.[62]

The data on the European 220 and 380 kV transmission network is kindly supplied by the Institute for Energy Systems, Energy Efficiency and Energy Management (ie^3) at TU Dortmund University. The considered transmission capacity expansions comply with the Ten-Year Network Development Plan provided by the European Network of Transmission System Operators for Electricity (ENTSO-E (2010)). In order to compensate for the lack of (n-1)-security constraints, the loss-less DC power flow over the transmission

[61] The regions are identical to those modeled in chapter 3. For a graphical illustration, refer to figure 3.1 on page 38.

[62] The delimitations of the German regions were first defined in Nüßler (2012) on the basis of the ie^3 network model. The original definition has been changed slightly in the case of region 24, which now covers Luxembourg as well. Given the high integration of the transmission networks of Luxembourg and the German TSO Amprion GmbH, this is a legitimate simplification.

FIGURE 5.1: German model regions with average wind speeds and solar radiation



Source: Own illustration.

lines is restricted to 80% of the lines' thermal capacity.[63] The network model is used to calculate the DC load flow (as introduced in Schweppe et al. (1988) and discussed in chapter 2) within and between the countries of CWE+, as well as between CWE+ and its continental European neighbors. The DC load flow model is complemented with ENTSO-E data on the interconnectors to and between satellite regions, including high voltage direct current (HVDC) lines to Great Britain and Scandinavia. The exchange via these interconnectors is restricted by NTC values.

The assumptions on the development of CHP and conventional power plant capacities in Europe are based on the database of the Institute of Energy Economics at the University of Cologne (EWI). The power plant database contains information on the units' location, such that the capacities can be assigned to the corresponding model region. Furthermore, expected decomissionings and commissionings of power plants until 2015 are taken into account.[64] The assumptions on fuel and CO_2 costs are taken from EWI (2011) and are displayed in table 5.1. The national electricity production of CHP plants is based on EURELECTRIC (2011), which is allocated among the regions in proportion to their CHP capacity. The exogenous feed-in is finally derived from hourly heat demand profiles.

[63]This is a standard assumption, e. g. applied in Weigt (2006) and Dietrich et al. (2010).
[64]Detailed data can be found in appendix B.

Table 5.1: Fuel and CO_2 price assumptions

[EUR/MWh$_{th}$]	Uranium	Lignite	Hard Coal	Nat. Gas	Oil
2015	3.60	1.40	13.20	25.70	47.20
CO_2 2015: 22.00 EUR/tCO_2					

Source: EWI (2011).

Concerning the development of RES, the national capacities as well as the total electricity production are set to the targets specified in the National Renewable Energy Action Plans (NREAP, cf. EC (2010)). A bottom-up analysis of the current distribution of installed RES capacities, regional potentials and historic capacity developments has been conducted for the CWE+ region and allows for the allocation of the forecasted installations. In the case of Germany, the data is based on Nüßler (2012). The feed-in structure of wind and solar power is derived from regional hourly data on wind speeds and solar radiation of the year 2008 (cf. EuroWind (2011)). Thus, a pattern of RES-E production which is consistent over time and space is developed.[65,66]

The assumptions on total electricity consumption (including network losses) are based on EURELECTRIC (2011), whereas hourly demand profiles are derived from historical data provided by ENTSO-E.[67] Total regional consumption is specified on the basis of information on regional electricity demand or on population and its future development. Again, the assumptions on the regional allocation of total consumption in Germany stem from Nüßler (2012).[68]

5.2.2 Scenario Definition and Model Configuration

In order to quantify the deviations in wholesale market costs, quantities and revenues from the efficient level, two dispatch scenarios are defined. The nodal pricing scenario (NP) sets the benchmark for efficiency and is characterized by the highest spatial model resolution available. In contrast, the second scenario implements national power markets with uniform pricing (CU) and thus represents the current market design in the CWE+ region. Both scenarios thus differ in the quality and quantity of the network constraints imposed upon the dispatch. Otherwise, the model setup is identical.

[65] Detailed data can be found in appendix B.

[66] Although the regional distribution of RES-E capacities in Germany is consistent with Nüßler (2012), the methodology of calculating wind and solar power production is different. First, the meteorological data is not identical. Second, the calculation in Nüßler (2012) is based on type days, whereas the work presented in this paper is based on 8760 hours. Thus, the regional in-feed is allocated differently.

[67] Refer to https://www.entsoe.eu/resources/data-portal/consumption/.

[68] Detailed data can be found in appendix B.

In the NP scenario, each core model region of CWE+ constitutes one bidding area. In the end, the dispatch of 72 nodal regions and 11 one-node regions is optimized. Out of the total 83 model regions, 79 are connected by the 434 lines of the DC network model. The optimal DC power flow resulting from the nodal dispatch thus respects all associated capacity limits and guarantees the regional balance of supply and demand.

In the CU scenario however, all internal network constraints are neglected. Hence, only interconnectors between countries restrict power exchange. Electricity transmission between the countries of the CWE+ region as well as between those countries and their continental neighbors is still modeled by a (reduced) DC load flow, now considering only 102 lines. In consequence, the framework resembles a flow-based coupling of national markets. In this setup, the model's balance constraints only guarantee the equality of demand and supply on a national level. The regional origin of domestic supply is therefore no longer relevant.

Although the focus of the analysis is on Germany, in-depth modeling of inter-regional exchange increases the quality and plausibility of the results. This also motivates the implementation of nodal pricing throughout the entire CWE+ region in the benchmark scenario. Overall, a coordinated change in the European market design will yield greater benefits than an isolated reorganization of a national market. Furthermore, a joint implementation of nodal pricing in Central Western Europe is much more plausible. In the end, the highest level of efficiency obtainable within the framework of the presented analysis is used as a reference to evaluate the German uniform pricing system.[69]

The dispatch scenarios are evaluated with a special focus on the allocation of supply and producer surplus in Germany. However, as demonstrated in chapter 3, a thorough analysis of a uniform market should include an assessment of the required internal congestion management. Since congestion management most certainly affects the allocation of supply and may also influence the generators' surplus, three re-dispatch scenarios based on designs presented in chapter 4 are analyzed for the case of Germany.

In addition to the present German cost-based re-dispatch design, two remuneration schemes that couple the remuneration to spot market prices are analyzed. Whereas a fixed-rate remuneration rewards or charges generators with a given percentage of the hourly spot price, individual marginal cost estimators can be derived from the generator's production schedules and the corresponding price curves. The latter options are

[69]One may argue that a scenario with nodal pricing in Germany only would simplify the comparison of the two market designs as well as the identification of the effects of internal congestion. However, also in the case of national nodal pricing scenario the exchange between German and neighboring regions would differ from the CU results. Therefore, a perfect isolation of the effects of national network constraints will not be possible in either nodal setup.

presently discussed by the German regulator Bundesetzagentur (cf. BNetzA (2012b) and BNetzA (2012a)).

All three designs rely on (more or less standardized) bilateral contracts between TSO and generators and resign auction-based re-dispatch procurement. As discussed in chapter 4, the selection of plants for re-dispatch and the associated costs will however vary between the designs. In each scenario, the re-dispatch model of *NEULING* calculates the least-cost congestion management in accordance with the respective remuneration scheme. Thus, the model's objective can be interpreted as a minimization of the TSO's expenditures. Consequently, the potential hidden costs of the designs which stem from the true variable costs of the re-dispatched generators have to be determined subsequently.

The DC load flow-based re-dispatch model optimizes congestion management on an hourly basis, such that no inter-temporal restrictions are imposed. However, the hourly availability of generators for re-dispatch is restricted due to balancing market obligations as well as by the plants' operating status after dispatch. The configuration of the re-dispatch model applied in this paper limits the start-up of standing capacities to flexible technologies such as combined cycle and open cycle gas turbines (CCGT, OCGT), pumped hydro storage plants and hydro reservoirs.[70] The usage of hydro power plants is further restricted to the generator units. Additionally, measures compensating for the lack of inter-temporal storage constraints are taken. The corresponding assumptions and their impact on the scenario results is discussed further in section 5.4.2. Furthermore, the production of RES may be decreased in the course of re-dispatch as a last resort.

In the presented analysis, the re-dispatch calculation is limited to Germany and its internal lines. Furthermore, only domestic plants may be used to relieve congestion. This national approach reflects the status quo in Germany. So-called joint cross-border re-dispatch would however reduce the overall costs of re-dispatch. Although an international approach to re-dispatch is aspired by the European TSOs (cf. ETSO (2003)), their cooperation is mostly limited to the management of international congestion. The relief of overloaded interconnectors is not considered in the presented analysis, such that only a part of the total congestion management measures is evaluated.

[70]While OCGTs are well known to start up in less than an hour, CCGTs may need one to five hours for start-up, depending on the standstill time, cf. Kasper et al. (2012). Since most of the congestion is already revealed after the clearing of the day-ahead market by the TSO's load flow calculations, it is assumed that standing CCGTs may be noticed in time. However, some congestion may result from short-term fluctuations of the feed-in of RES and from intra-day trade. The latter effect is assumed to be small, since the German TSOs have the right to reject intra-day schedules that endanger system security, cf. §5 Stromnetzzugangsverordnung (StromNZV, engl. Act on the Access to the Electricity Network).

5.3 Surplus and Costs under Nodal and Uniform Pricing

In this section, the focus of the analysis is on the wholesale market level. Nonetheless, the comparison of uniform and nodal pricing reveals the economic effects of neglecting or including congestion management into the optimization of the dispatch. Thus, the spot market bias under uniform pricing can be identified with regard to the allocation of generation and surpluses.

5.3.1 Total Costs of Production and Allocation of Generation

The first finding from the dispatch calculations with *NEULING* is an increase in the German costs of electricity production under uniform pricing compared to the nodal case. Given nodal pricing costs of 14,813 mEUR/a, the additional costs of a uniform pricing system amount to 454 mEUR/a or roughly 3%. Knowing the basic theory, one would expect a contrary development. Since uniform pricing imposes fewer restrictions on the dispatch, the optimal solution should come at a lower price than on a nodal level. However, the German power market is not an island system, such that a change in its design influences the interaction with the surrounding markets. In consequence, the predicted effect first reveals itself on the international level. Taking all countries subject to nodal pricing into account, the total costs of electricity production are 385 mEUR/a higher than the corresponding dispatch costs under uniform pricing.[71] However, the allocation of costs and benefits of design changes depends on the fundamental structure of the regional markets. As will be demonstrated later on, this pattern repeats itself on the national level.

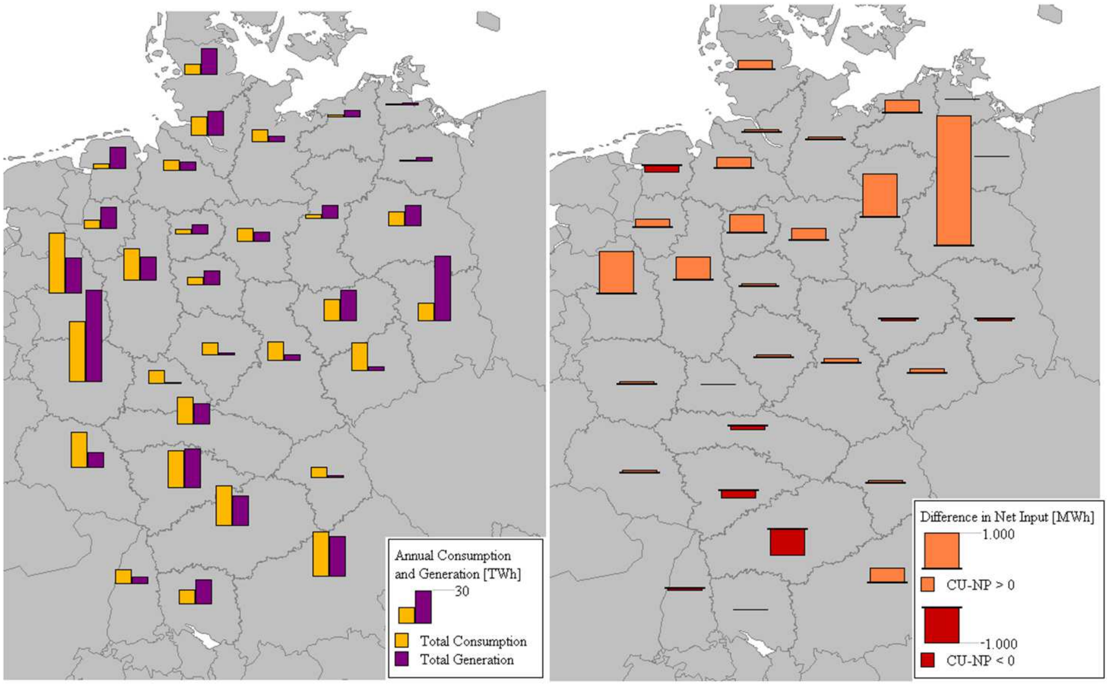
Getting back to the German case, the higher production costs under uniform pricing are mainly due to an increase in generation compared to the nodal pricing benchmark. Although Germany is a net-exporting region in both systems, domestic production is 8 TWh higher in the copperplate model. Since regional congestion limits the benefits of international trade, the neglect of internal network constraints in uniform pricing systems leads to deviations from the nodal pricing results. In the case of Germany, the efficient level of exchange is overshot when trade is determined on a national basis.

However, the quantitative effects of uniform pricing are not distributed evenly among the regions. On the left hand side of figure 5.2, the regional proportion of total consumption and total generation (including RES-E and CHP production) under uniform pricing is given. The figure's right hand side illustrates the divergence in the annual net input

[71] Considering all model regions, the wholesale market cost reduction of the uniform pricing systems amounts to only 155 mEUR/a. These results correspond to the aggregated values presented in section 3.4.4.

(defined as generation minus consumption) between the CU and the NP scenario. Since demand is identical in both scenarios, the change is attributed to the difference in local generation.[72]

FIGURE 5.2: Annual consumption and generation under uniform pricing (left) and difference in net inputs between uniform (CU) and nodal pricing (NP) (right) in 2015



Source: Own illustration.

The highest positive deviation from the efficient allocation of production is revealed in the north-eastern regions "Berlin" (no. 13) and "Wolmirstedt" (no. 12), which gain additional 241% and 158% in comparison to the respective nodal levels. This increase amounts to a total of 4.9 TWh over the whole year. Also the "Ruhr" regions (14 and 15) in (North-)Western Germany register a substantial absolute rise in generation by 1.2 (+5.7%) and 0.6 TWh/a (+4.8%) respectively. Further noteworthy net-increases take place in other regions situated in the northern half of the country. However, also the southern region "München" accounts for a positive effect of quantity under uniform pricing, which adds up to additional 411 GWh/a (+3.1%) of production. Since this observation is contrary to the previously described geographic pattern, the result suggests that the decrease is rather driven by cross-border network effects than by internal congestion.

Moreover, the net-effect in other southern regions is negative or zero, indicating that production in South Germany tends to be inefficiently low under uniform pricing. The

[72]Detailed results can be found in appendix B.

highest net-decreases of 724 GWh/a and 217 GWh/a can be observed in "Stuttgart" (28) and "Mannheim/Karlsruhe" (27) respectively. The nodal level of production is also higher than the corresponding CU result in "Frankfurt/Mainz" (no. 25, 118 GWh/a) and "Eichstetten" (no. 29, 26 GWh/a). However, three out of seven regions with negative net-effects under uniform pricing are situated in the North (no. 8 "Diele", 205 GWh/a) and in the East (no. 18 "Lauchstädt", 3.6 GWh/a, and no. 19 "Schwarze Pumpe", 13.5 GWh/a). Regions 8 and 19 are located at the Dutch and Polish borders respectively, such that the result may again be driven by cross-border effects.

As opposed to the spatial effects, the influence of the market design on the utilization of different technologies is less clear. Despite the increase of production under uniform pricing, the overall generation mix does not change notably in comparison to the benchmark scenario. However, regions which register lower domestic production in the CU scenario usually exhibit a lower utilization of local capacities with relatively high variable costs. In the case of the four southern regions, uniform pricing reduces the production by hard coal fired plants and older CCGT units in comparison to the point of reference, whereas the local nuclear power plants produce irrespective of the market design. The perceived lack of congestion in the CU scenario thus leads to a cheaper local dispatch in Southern Germany. On the contrary, high-cost generation by trend benefits in regions with a higher level of production in comparison to the benchmark. For example, this shows in the increase of production by CCGTs in "Berlin" (no. 13) and "Wolmirstedt" (no. 12) under uniform pricing, as well as in higher output of hard coal power plants in "Bremen" (no. 6) and "Landsbergen" (no. 10). Accordingly, the explicit consideration of limited transmission capacities will reduce the costs of production in the northern regions.

However, the deviations between the nodal and the national dispatch depend on more factors than variable costs of generation. Especially the impact of the respective nodal net-inputs on the underlying network will influence the efficient nodal dispatch. Furthermore, the local dispatch depends on the timing and magnitude of congestion. In an isolated system though, the trend towards a less expensive generation mix under uniform pricing will be more pronounced. In the presented analysis, this effect is overcompensated by the decrease in domestic generation and by the re-allocation of production within the CWE+ region.

5.3.2 Marginal Costs of Supply

Ultimately, the differences in the scenarios' dispatch as well as in the number and severity of network constraints result in diverging marginal costs of supply. In the CU scenario, the model is indifferent between generation of identical costs at any two German nodes. Due to the neglect of internal network constraints, the national merit order as well as the opportunity costs of international exchange define the marginal costs of supply. In consequence, electricity is valued equally at all German nodes. In contrast, nodal prices reflect both the local marginal costs of production as well as the influence of the local net-input on the opportunity costs of congestion throughout the entire network. Since a change in the net-input of a single node affects the flows on all (directly or indirectly) connected lines, a single congested line leads to a divergence in marginal costs of supply at all nodes.

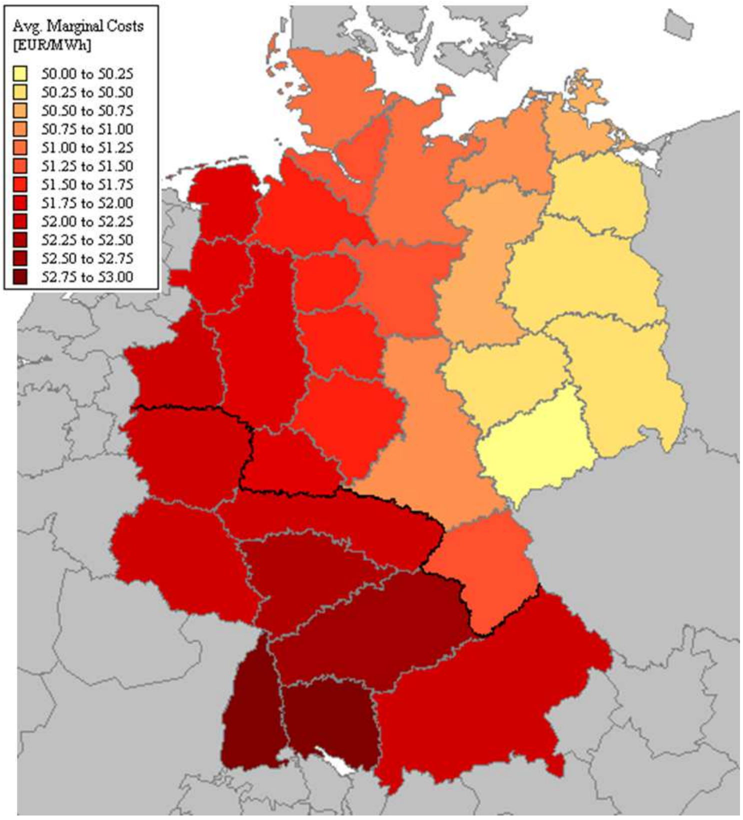
In the CU scenario, the uniform average marginal costs of supply in Germany amount to 52.04 EUR/MWh in the year 2015. Under nodal pricing, the demand-weighted average of the mean marginal costs at all German nodes of 51.74 EUR/MWh is slightly lower. Again, this effect is driven by the change in total domestic generation. However, just as local generation levels show both positive and negative deviations from the nodal outcome, the national average marginal costs (AMC) both overshoot and undercut the efficient nodal values in individual regions. In contrast to the slightly heterogeneous spatial distribution of generation in- and decreases, the differences in the AMC of both scenarios show a clear geographical pattern. Although the majority of the regions accounts for higher AMC under uniform than under nodal pricing, a cohesive area of eight nodes in South-West Germany exhibits lower AMC in the national setup. A graphical illustration of the average marginal costs in the nodal pricing scenario is given in figure 5.3. The black line separates the north-eastern nodes with higher AMC in the CU scenario from those with lower values.[73]

With regard to the 23 north-eastern regions, the average decrease in marginal costs under nodal pricing ranges from -1.99 EUR/MWh in "Röhrsdorf/Eula" (23) to -0.04 EUR/MWh in "Ruhr West" (14). In nine regions, the nodal reference level of the AMC is more than 1 EUR/MWh lower than the national value, and in another five regions the marginal costs still decrease by more than 0.50 EUR/MWh. In comparison, the AMC increases triggered by nodal pricing are less pronounced. The smallest rise can be observed in "Frankfurt/Mainz" (25), where average marginal costs only rise by 0.01 EUR/MWh. Out of the eight nodes with higher AMC, five regions exhibit an increase of less than 0.40 EUR/MWh. The highest differences between nodal and national AMC result in "Eichstetten" (no. 29, +0.83 EUR/MWh), "Herbertingen/Vöhringen" (no. 30, +0.82 EUR/MWh) and "Stuttgart" (no. 28, +0.51 EUR/MWh).

As stated before, the effects of the market design on local generation levels and local marginal costs not necessarily have the same sign. Despite the lower levels of local

[73] Detailed results can be found in appendix B.

FIGURE 5.3: Average marginal costs of nodal pricing in 2015



Source: Own illustration.

generation at the south-western nodes 20, 24, 30 and 31, the nodes' average marginal costs of supply increase under nodal pricing. Vice versa, the higher production level resulting from the nodal dispatch in the northern and eastern regions 8, 18 and 19 coincide with lower AMC. These examples demonstrate the relevance of network-related elements in the marginal costs of supply. The internalization of positive and negative external effects of network usage may thus overcompensate the change in the marginal costs of generation.

Furthermore, the regional distribution of demand is reflected in the pattern of AMC deviations. Five out of eight regions with inefficiently low AMC belong to the top-six nodes with the highest annual consumption. In the order of decreasing consumption, the said regions are "Köln" (20), "München" (31), "Stuttgart" (28), "Mannheim/Karlsruhe" (27) and "Weiher" (24). But also the remaining three nodes "Frankfurt/Mainz" (25), "Herbertingen/Vöhringen" (30) and "Eichstetten" (29) are under the top-fifteen demand regions. By trend, the change from a national merit order of supply to a local portfolio has a stronger effect on the average marginal costs of high-demand regions.

5.3.3 Producer Surplus

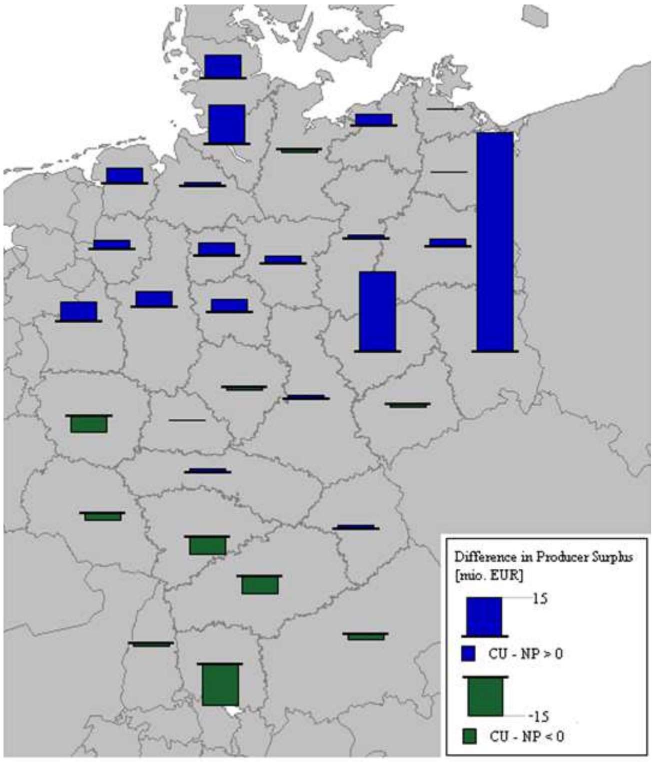
Finally, the scenarios' dispatch results can be used to derive an estimation of the respecitve producer surplus. Since the only available indicator for market prices is given by the marginal costs of supply, the practical relevance of the estimation is limited. Especially, (competitive) scarcity prices of generation cannot be captured by the model. However, the difference in the magnitude and in the allocation of producer surplus between nodal and uniform pricing indicates the potential relevance of the associated bias. Even though, the results should be interpreted as a short-term snapshot whose explanatory value with regard to dynamic efficiency is limited. In the following, the hourly marginal costs as well as the variable costs of production (fuel and CO_2 costs as well as other variable costs of operation) are used to calculate the producer surplus. Fixed operation and maintenance costs are neglected since they are identical in both scenarios. The analysis is therefore restricted to the part of the surplus influenced by variations in production levels and marginal costs.

In line with the findings on total generation and average marginal costs, the total German producer surplus under uniform pricing is found to be higher than in the nodal reference case. In total, the results of the CU scenario reveal an increase in producer surplus by 146 mEUR/a. Given the total surplus of 6,441 mEUR/a under nodal pricing, the short-run bias amounts to 2.3%. But again, the gains and losses resulting from the choice of a specific market design are not distributed evenly. While the majority of the regions still benefits from uniform pricing, some nodes reveal higher producer surpluses under nodal pricing.[74] Figure 5.4 illustrates the regional net-effects.

Almost all of the nodes which exhibit higher AMC in the NP scenario also register a higher producer surplus in comparison to uniform pricing. The largest absolute bias induced by uniform pricing is observable in "Herbertingen/Vöhringen" (30), where the producer surplus is 15.7 mEUR/a (2.5%) below the nodal reference point. The next largest deviations occur in "Mannheim/Karlsruhe" (no. 27, 7.2 mEUR/a or 1.7%), "Stuttgart" (no. 28, 6.5 mEUR/a or 1.8%) and "Köln" (no. 20, 5.7 mEUR/a or 0.4%). The nodes "Weiher" (24) and "München" (31) still account for deficits in comparison to the benchmark that amount to 2 and 1.6 mEUR/a. Among all nodes with negative deviations from the nodal surplus, "Eichstetten" (29) registers the highest relative bias of 29.2% (0.6 mEUR/a). In the regions 30, 24, 31 and 20 the negative price effect under uniform pricing thus dominates the corresponding effect of quantity, which is positive in the case of the last three regions and zero in the case of node no. 30.

[74] Detailed results can be found in appendix B.

FIGURE 5.4: Difference in producer surplus under uniform (CU) and nodal pricing (NP)



Source: Own illustration.

In the previously described south-western area, the only exception is "Frankfurt/Mainz" (25). At this node, the smallest difference in average marginal costs (-0.01 EUR/MWh under uniform pricing) is observed. Despite the lower level of production (-0.9%), local producer surplus is 0.7 mEUR/a (+0.2%) higher under uniform pricing. Although the observed relative differences are very small, this result indicates that the hourly constellation of production and marginal costs may be of greater relevance than the aggregate change of single influencing factors. Including "Frankfurt/Mainz", the total deviation in the surplus in South-Western Germany amounts to -38.6 mEUR/a (-1.1%) compared to the nodal benchmark.

At the north-western nodes however, the uniform pricing bias leads to additional surplus in comparison to the point of reference. In comparison to nodal pricing, the regions register a total producer surplus which is 184.8 mEUR/a (+6.6%) higher in the CU scenario. The discrepancy between the scenario results is the highest in "Schwarze Pumpe" (19), where the surplus under uniform pricing overshoots the nodal result by 86.3 mEUR/a (+8.4%). Further substantial deviations can be observed at "Lauchstädt" (no. 18, 31.2 mEUR/a or +7.5%), "Dollern" (no. 2, 15.5 mEUR/a or +15.9%) and "Brunsbüttel" (no. 3, 9 mEUR/a or +2.7%). The largest relative gains from uniform pricing occur in "Berlin" (no. 13, +176% or 2.7 mEUR/a) and "Wolmirstedt" (no. 12, +137% or 0.9 mEUR/a).

However, three nodes in the North-West also register lower surpluses under uniform pricing than under nodal pricing. The power plant mix in these regions is dominated by pumped hydro storage plants (PSP), which are the only available technology in "Hamburg" (3) and "Borken" (16) and provide 50% of the capacity in "Röhrsdorf/Eula". At all three nodes, the producer surplus from PSP is higher in the NP scenario, despite a lower level of production. This general pattern is repeated for PSP capacities at almost all German nodes. This observation suggests that while the number of profitable cycles is smaller under nodal pricing, the remaining opportunities yield higher profits from temporal price arbitrage. Since the network-related flexibility of the nodal system is diminished in comparison to the national model, the remaining flexibility options such as storage plants are more valuable.

With regard to other technologies, trends are less simple to identify due to the mixing of price and quantity effects. In the regions where the national AMC are below the local benchmark, some of the additional producer surplus from nodal pricing falls upon high-cost technologies such as old lignite and hard coal plants or less efficient CCGTs. These units reach a higher number of full load hours than under uniform pricing, since they are less frequently in merit on a national level. Ultimately, these differences mirror the direct costs of congestion. But also low-cost units such as nuclear power plants that are equally utilized in both scenarios benefit from higher nodal prices. A contrary effect can be observed in regions which show lower AMC under nodal than under uniform pricing. Although base-load capacities do not run less frequently, their surplus diminishes in the NP scenario due to the price effect.

5.3.4 Intermediate Conclusion

Overall, the comparative analysis reveals the influence of congestion management and market design choices on the short-term allocation of generation and producer surplus and thus indicates potential long-term impacts. First, the dispatch under uniform pricing leads to a sub-optimal allocation of production and an inefficient (if not infeasible) use of the network in the presence of congestion. Second, the remuneration of both inefficiently and efficiently dispatched generators does not reflect the opportunity costs of congestion in a uniform pricing system. In the long-run, the bias in the producer surplus may lead to a sub-optimal siting of new generation capacities from the network's perspective.

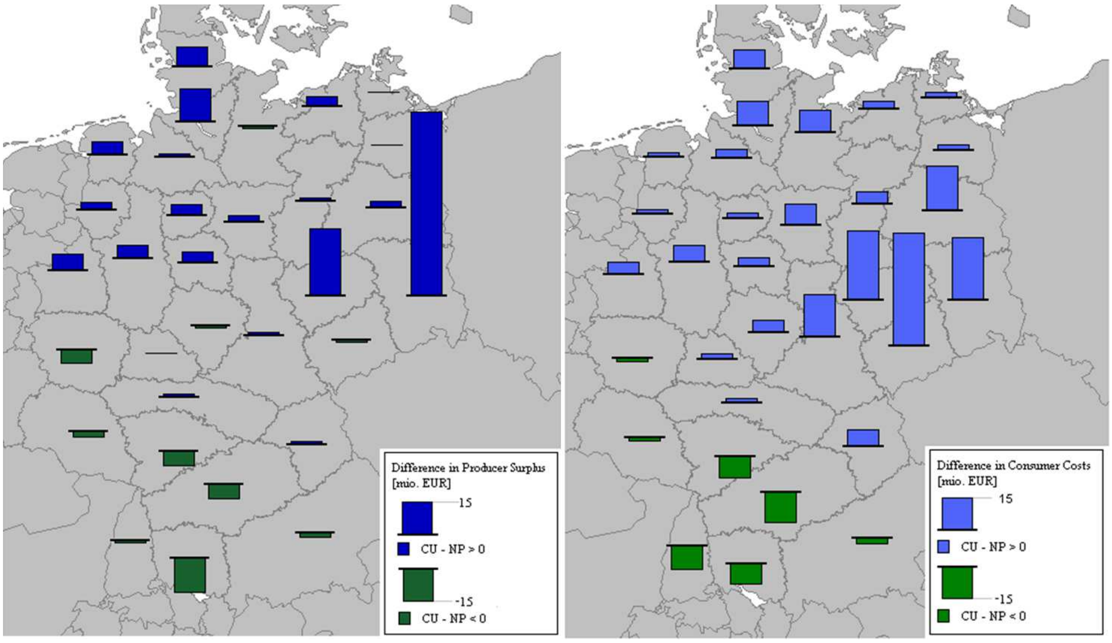
In the case of Germany, a systematic bias with regard to the spatial distribution of producer surplus is identified. While generation in the North-East shows to be over-priced, production capacities in the South-East are by trend under-valued in the given scenario. This relationship implicitly demonstrates the mismatch of local generation and network capacities. If nodal pricing was implemented, the drop in the surplus of generators situated in the North-West would by trend discourage local investors, whereas the increase in the revenues of southern producers would possibly encourage investments. To assess whether the demonstrated re-allocation of producer surplus would be sufficient to actually trigger the construction of new plants however requires a complex analysis. Besides investment and other fix costs, the expected profits would have to compensate potential disadvantages of the sites, for example with respect to primary fuel costs. Ultimately, the trade-off between the network extensions and the allocation of power plant capacities in high-cost regions should determine the investments on both sides. Especially with regard to the lifetime of power plants and transmission lines, the aggregate effects of location decisions can be substantial.

Although the magnitude of the long-term effects of market design choices cannot be assessed by the means of the presented analysis, the short-term distribution effects are shown to be notable. In the presented setup, the beneficiaries of uniform pricing gain 185.5 mEUR/a, whereas other generators forfeit 39.5 mEUR/a. With regard to the short-run surplus, producers can thus be expected to favor uniform pricing. However, the wholesale costs of consumption can be shown to behave differently. Under nodal pricing, 256 mEUR/a savings in consumer costs are realized at 24 nodes, whereas consumer cost increase by 49.6 mEUR/a in the remaining regions. Not surprisingly, the regional allocation of savings and losses for consumers exactly contrasts the spatial distribution of the producers' gains and losses (cf. figure 5.5).

In the presented framework, the wholesale market net-effect including changes in consumer costs and producer surplus amounts to 60.4 mEUR/a of benefits under nodal pricing. The benefits thus equal 0.4% of the total nodal pricing production costs in Germany. In line with the findings in Green (2007), the distribution effects are shown to be considerably higher than the total gain. However, this comparison is by no means comprehensive. First, nodal pricing also generates congestion rents, which account for 93.9 mEUR/a. Congestion rents are paid by market participants to the TSO. Although the payments are higher than the net-benefit for producers and consumers, this does not necessarily overturn the balance of costs and benefits under nodal pricing. Depending on the regulation, the TSO may use the rents to cover a part of its infrastructure expenditures.[75] Thus, the rents may finally reduce network tariffs, which also incur under uniform pricing but are not considered in the presented analysis.

[75] Cf. Brunekreeft (2005).

FIGURE 5.5: Difference in producer surplus (left) and consumer costs (right) under uniform (CU) and nodal pricing (NP)



Source: Own illustration.

Second, the calculation does neither account for the costs of implementing a new market design, nor for additional transaction costs associated to trade and market operation. Furthermore, the analysis does not cover issues related to market liquidity and market power. Both aspects are of special importance for small bidding zones.[76] A further issue not yet analyzed in this paper is the costs of congestion under uniform pricing. In the end, market participants have to bear the costs of curative congestion management that incur apart from the wholesale market. This aspect is discussed in further detail in the following section.

5.4 Evaluation of Re-dispatch Designs

The wholesale market perspective adopted in the previous section ignores the impact of internal congestion on the performance of the German uniform pricing system. In the following, the significance of internal transmission constraints is highlighted from the perspective of re-dispatch. First, the overload of the German high voltage network resulting from the dispatch is identified. Second, the performance of cost-based and fixed-rate re-dispatch as well as of spot price-based estimators of re-dispatch costs is evaluated quantitatively.

[76]Especially in comparison to a local re-dispatch *market*, nodal pricing may be less prone to the abuse of local market power. These issues are e. g. discussed in Harvey and Hogan (2000).

5.4.1 Power Flows and Congestion

As a preparation for the re-dispatch scenarios, the power flows resulting from the copper-plate dispatch have to be determined. Therefore, an additional DC load flow calculation is based on the local generation schedules resulting from the CU scenario. The calculation yields the true utilization of both national and international transmission lines, which may well exceed the thermal capacity of some lines. In the following, the analysis is limited to congestion occurring within Germany.

Within Germany, the network model represents 163 high and extra high voltage transmission lines which divide themselves among 58 routes. In the scenario year 2015, the lines account for 193.6 GW of available electricity transmission capacities after consideration of the 80% security margin. After the uniform pricing dispatch, the average absolute flows on the lines amount to 328 MW, which translates into an average capacity utilization of 28%. However, single lines register noticeably higher transmission. The connection between the regions "Lauchstädt" (no. 18) and "Erfurt" (no. 22) exhibits the highest average values per line, both in terms of absolute flows (1072 MW) and utilization (75%). Similarly high results (895 MW and 63%) can be observed for the lines connecting "Wahle" (11) "Wolmirstedt" (12).

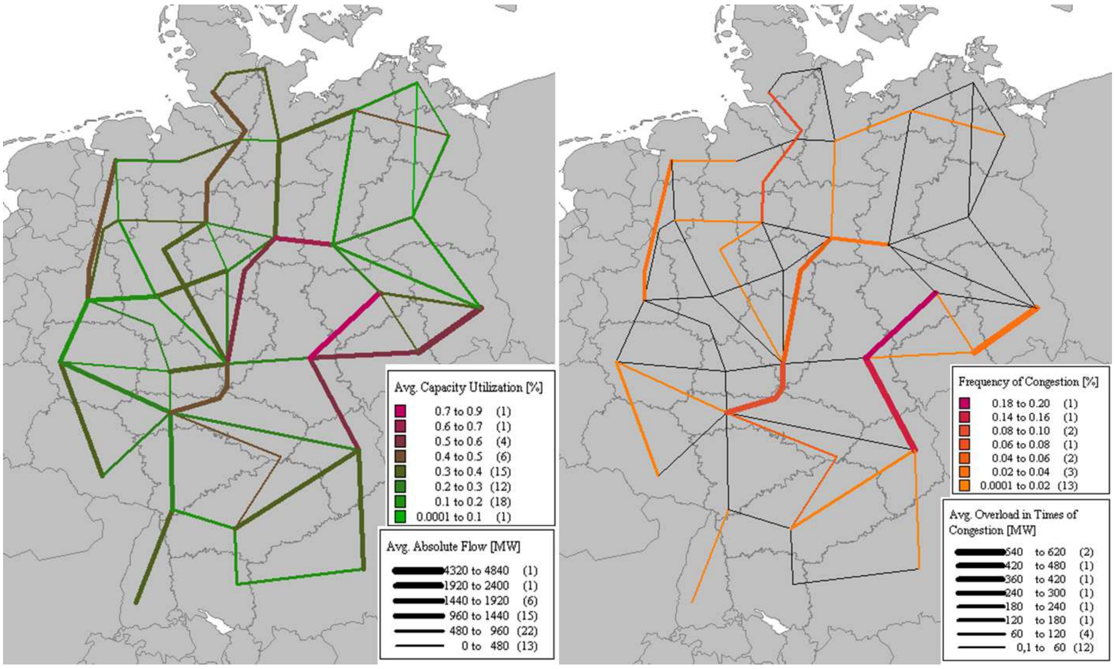
Since the indicated results refer to the flows resulting from uniform pricing, they include the line overload in times of congestion. In total, congestion within Germany occurs in 2,151 hours (25%) of the year 2015. The non-transmittable flows add up to 2,452 GWh and reach an hourly maximum of 10.7 GWh. Thereby, 53 lines or 23 routes are prone to congestion throughout the year. On average, each of the lines is overloaded in 302 hours, such that the average number of simultaneously congested lines amounts to seven.

With congestion in 20% of the hours, the most frequently congested connection again lies between "Lauchstädt" and "Erfurt", whereas the line between "Erfurt" and "Etzenricht/Raitersaich" registers the highest average magnitude of congestion (305 MW). Figure 5.6 illustrates the aggregate power flows between the German network regions as well as the corresponding frequency and magnitude of congestion.

5.4.2 Allocation of Re-dispatch Volumes, Remuneration and Costs

In the end, the failure of the network due to overloading has to be prevented by re-dispatch. For this purpose, the re-dispatch model of *NEULING* selects local generators to simultaneously increase and decrease their output (cf. chapter 2). The effects of these changes in the nodal net inputs on the transmission lines are again determined by a DC load flow. The optimal re-allocation of supply eventually relieves the overloaded

FIGURE 5.6: Power flows and congestion under uniform pricing in 2015



Source: Own illustration.

lines at least cost and guarantees the local balance of demand and supply at the same time. However, the definition of re-dispatch costs and hence the final allocation depends on the remuneration scheme. Given that the TSO minimizes her expenditures, the net-payments to the generators rather than the true variable costs will be the deciding factor.[77]

5.4.2.1 The Reference Case: Cost-based Re-dispatch

Cost-based re-dispatch is currently used to manage congestion of the internal transmission network in Germany. As discussed in sections 4.2.2 and 4.3.2.1, this design will implement the efficient allocation of generation provided that information on the true variable costs is available and that re-dispatch is friction-free (cf. section 4.2.2). In the setup of *NEULING*, the transparency of the costs is accounted for by setting the variable costs of re-dispatch to the hourly values of the corresponding dispatch parameters. Consequently, the equality of dispatch and re-dispatch cost functions, which is one property of a friction-free re-dispatch, is guaranteed *within* hours. However, the model's lack of intertemporality leads to an overestimation of ramping costs *in between* hours. Even when a unit is re-dispatched consecutively, ramping costs incur in every hour. Furthermore, the freedom of re-dispatch is limited by restricting the start-up of

[77]Detailed results of the following sections can be found in appendix B.

standing capacities to CCGTs, OCGTs and hydro power. This induces greater friction in comparison to the ideal world of chapter 4, but achieves more realistic results.

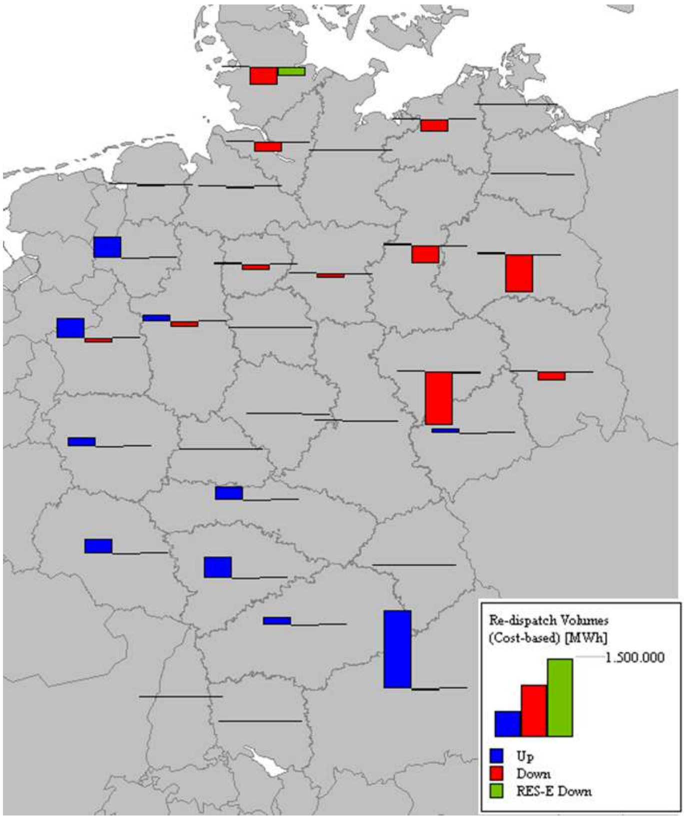
A further comment has to be made with regard to pumped-hydro storage plants (PSP) and hydro reservoirs, which are handled differently from conventional technologies in the re-dispatch model. Since the variable costs of hydro power are very small, the cost-based re-dispatch model would call these plants before all other types. To some degree, this can be prevented by using opportunity costs rather than variable costs to value the production of hydro power plants. Since stored water can only be used once, the generation of electricity during re-dispatch comes with a loss of spot market revenue. In the CU scenario, the average marginal costs at which hydro plants produce electricity are found to be EUR 57.17 (PSP) and EUR 56.44 (reservoir). However, using these values as a cost estimator would still lead to a frequent utilization of hydro plants in the course of re-dispatch. This is critical since the re-dispatch model does not account for intertemporal storage constraints. In consequence, the provision of positive re-dispatch by hydro power would often violate the storage constraints. For this reason, the costs for re-dispatching hydro plants are set to a dummy value of 100 EUR/MWh. The costs are therefore higher than for most other technologies (including the ramping costs of conventional plants). Accordingly, the utilization of hydro power for positive re-dispatch is most certainly underestimated, but most likely feasible. In the case of negative re-dispatch of hydro power plants, the savings are set to the (very small) variable costs just as for any other technology. Again, this makes hydro power a less favorable re-dispatch option.

All of the discussed characteristics of the re-dispatch model will lead to deviations between the allocation of generation implemented via re-dispatch and the results of the efficient nodal pricing benchmark. In addition, the geographical scope of the nodal model allows for the international coordination of congestion management, whereas re-dispatch is limited to Germany. As a result, a reduction of the overall level of generation as observed under nodal pricing cannot be achieved via re-dispatch. With national re-dispatch, the level of supply is kept constant, such that only the allocation of production is changed. In consequence, a direct comparison of both scenarios would be misleading.

Results

In the scenario year 2015, cost-based re-dispatch leads to a re-allocation of 3,691 GWh of generation within Germany. Considering the net value of upward and downward re-dispatch, downward re-dispatch is concentrated in the north-eastern part of Germany, whereas upward re-dispatch is mostly applied in the South-West. This pattern reflects the location of congested transmission lines, which are especially found between the said regions (cf. figure 5.6). However, almost all regions provide both negative as well as positive re-dispatch at some point of the year. This is due to the hourly variation in the flow pattern and the potential necessity to counterbalance flows induced by other re-dispatch measures. Figure 5.7 illustrates the aggregated re-dispatch volumes per node.

FIGURE 5.7: Re-dispatch volumes (cost-based) in 2015



Source: Own illustration.

The largest absolute re-dispatch volumes as well as the highest net volumes can be observed in "München" (no. 31) and "Lauchstädt" (no. 18). Whereas "München" mainly provides positive re-dispatch (1,360 GWh net), generation in "Lauchstädt" (no. 18) is primarily reduced (-999 GWh). The latter region is the start node of the most heavily congested connection in the model. Since "Lauchstädt" accounts for a positive net input (nodal exports are higher than imports), downward re-dispatch reduces the node's exports, which are mainly southbound. In comparison, the location of "München" in the network is more favorable, such that the node's additional generation supplies the southern deficit region. Further important nodes for positive re-dispatch can both be found in the South-West ("Mannheim/Karlsruhe", 373 GWh net) as well as in the North-West of Germany ("Emsland", 343 GWh net). In contrast "Berlin" (13) and "Brunsbüttel" mainly provide negative adjustments of generation (-645 GWh net and -491 GWh net).

Given that only extra-marginal capacities can be ramped-up during re-dispatch, mid- and peak-load plants supply most of the positive re-dispatch volumes. Gas fired plants provide 95% of the positive adjustments, supplemented by hard coal (4%), lignite and hydro power plants (less than 1%). Nuclear power plants are never used for positive re-dispatch since they already operate at full capacity in the relevant hours. The allocation of re-dispatch to power plant technologies changes in the case of negative re-dispatch, which can only be provided by spinning capacities. In consequence, the share of base- and mid-load plants is higher. Between 26% and 31% of the re-dispatch volumes are attributed to CCGTs, hard coal and lignite plants each. Now, also nuclear plants are ramped down to secure the network (7%).

If the (local) availability of conventional plants is insufficient to fulfill the re-dispatch requirements, RES-E can be curtailed. Since the reduction of electricity production from renewables does not save any variable costs, curtailment is the least favorable option. However, since there are no local differences in the savings, the efficient allocation of curtailment is identical to the most effective allocation. In total, 8% of the downward re-dispatch (286 GWh) are provided by RES. The observed curtailment is limited to the North-East of Germany and occurs no farther south than "Erfurt" (22) and "Borken" (16). The highest reduction (168 GWh or 59%) is however observed at the northernmost node of "Brunsbüttel" (1), followed by the regions "Lauchstäedt" (no. 18, 14%), "Schwarze Pumpe" (no. 19, 9%) and "Bertikow" (no. 7, 8%).

In contrast, RES cannot contribute to the provision of positive re-dispatch within the model, since they are assumed to operate at the hourly limit. In three hours in February and December, the available conventional capacities however prove themselves insufficient to serve local demand in all regions. The model nonetheless solves by using a so-called dummy-variable, which is activated at the most effective node. In all three hours, the dummy is located in the south-western region of "Eichstetten" (29) and supplies 89 MWh of additional generation in total. Since the dummy may be interpreted as a demand for cross-border congestion management or demand side management (DSM), this result does not indicate a failure of the network in the real world.

Excluding the costs of procuring DSM or international re-dispatch, the costs of re-dispatch amount to 136.5 mEUR/a in the scenario year 2015.[78] This value mirrors the sum of the additional costs of positive re-dispatch and the savings of negative re-dispatch. Although the volumes of upward and downward adjustments are in absolute terms identical, re-dispatch will rarely be cost-neutral. This is due to the fact that infra-marginal generators are substituted by extra-marginal units. Concerning the remuneration of

[78]Thereof, 2.2 mEUR/a are associated to the positive re-dispatch of hydro storage plants, priced at roughly 100 EUR/MWh.

re-dispatched generators, cost-based designs ensure that the induced changes in the producers' variable costs are exactly compensated, either by payments or charges. Thus, the producers' surplus from the wholesale market is not changed (section 5.3.3).

In consequence, cost-based re-dispatch is not able to internalize the external effects of network usage and congestion. However, within the limited scope of the re-dispatch model, the design implements the least-cost re-dispatch. This solution is optimal in the sense that all true costs are taken into account. Thus, no hidden costs lead to deviations between the expenses of the TSO and the generators' opportunity costs. Although the inefficiency in the allocation of producer surplus under uniform pricing is not reduced, no additional distortions are introduced in the market through cost-based re-dispatch. In the following, the design is used as a point of reference in the evaluation of alternative re-dispatch schemes.

Classification of Results

As stated in the monitoring reports published by the German regulator BNetzA for the years 2007 to 2010, the maximum congestion management costs up to now amount to 45 mEUR/a (2008).[79,80] Given the (expected) expansion of renewable energy sources and the reduction of conventional surplus capacities between the years 2008 and 2015, a triplication of congestion management costs does not seem to be an unrealistic result.

A comparison of the calculated re-dispatch volumes (+/- 3,691 GWh) with real-world data is much more difficult, since the BNetzA has so far only published the quantities for the year 2010. In the corresponding monitoring report, the total increase in generation arranged by the German TSOs in the course of congestion management is stated as 141 GWh. The total decrease is indicated with 1,996 GWh.[81] No explanation is given concerning the divergence of the two values, which may be due to international congestion management. Furthermore, the *NEULING* model does not allow for congestion management through network topology optimization. In consequence, the need for the re-allocation of generation may be overestimated (cf. Kunz (2011)). This effect is however opposed by the spatial resolution of the network model, which neglects large parts of the transmission grid.

In the literature, the case of cost-based re-dispatch in Germany has been studied by Nüßler (2012) and Kunz (2011). In Nüßler (2012), roughly the same data set for Germany as in the presented analysis is used. However, the methodology applied in Nüßler

[79]The reports (German: Monitoringberichte) are published online at www.bundesnetzagentur.de.

[80]In this paper, the meteorological data of the year 2008 has been used to calculate the hourly feed-in of RES-E. In this respect, a comparison with the scenario year 2015 is not overly farfetched.

[81]Both values include re-dispatch and counter-trading volumes. The regulator defines the latter as purchases and sales of electricity across control zones. Since it serves the exact same end as re-dispatch, the differentiation is irrelevant in this context.

(2012) differs in various aspects. First, the use of type-days hinders the representation of extreme constellations of local demand and RES-E feed-in, which come with especially high transmission requirements. Furthermore, load flow calculations are restricted to Germany and its interconnectors and are based on power transfer distribution factor (PTDF) matrices. Thereby, the security margin is set to 90% of the thermal line capacities, which is a less strict assumption than the one applied in this paper (80%). Overall, the calculated re-dispatch volumes and costs of the year 2015 are lower than in the presented analysis (608 GWh/a and 35.5 mEUR/a).

Kunz (2011) analyzes the combination of cost-based re-dispatch with congestion management through network topology optimization (switching lines on or off). The author conducts a comparative static analysis for Germany, which is based on a European scenario of the year 2008. Within this framework, the development of conventional and wind power capacities, of load and internal network capacities is modeled for Germany only. On this basis, DC load flow-based dispatch and re-dispatch are calculated for nine single hours of the scenario years. The findings of Kunz (2011) indicate that the management of congestion by the means of re-dispatch alone leads to an increase in German congestion management costs by factor six between the years 2008 and 2020. Kunz (2011) uses this base case to highlight the relevance of network topology optimization, which reduces the respective costs to 0 in 2008 and by 98% in 2020. With respect to the analysis presented in this paper, the findings in Kunz (2011) highlight that the costs of congestion management by the means of re-dispatch only will most certainly be overestimated.

5.4.2.2 Fixed-rate Re-dispatch Remuneration

The advantages of fixed-rate re-dispatch remuneration as described in BNetzA (2012b) and section 4.3.2.2 are its simplicity and the avoidance of problems rooted in information asymmetries. According to a transparent rule, the payments to re-dispatched generators are set to the hourly spot market price plus a fixed percentage, whereas charges are set to the spot price minus the same amount. This mechanism is based on the assumption that the national merit order can be used as an indicator for the variable costs of re-dispatched generators. Since this ignores the geographical component of congestion management which influences the selection of generators for re-dispatch, fixed-rate re-dispatch will most likely prevent an adequate remuneration. Furthermore, the fixed rate does not reflect the non-linear slope of the merit order, such that the suppliers of positive and negative re-dispatch face different risks of insufficient remuneration. However, the intention of the design is to lower transaction costs and to increase transparency. Putting strategic behavior on the generators' part aside, for example by assuming that the unpredictability of congestion prevents a systematic advantage of gaming, the magnitude of the mechanism's bias is therefore analyzed in the following. Exemplarily, the fix percentage is set to +/-10%, as proposed in BNetzA (2012b).

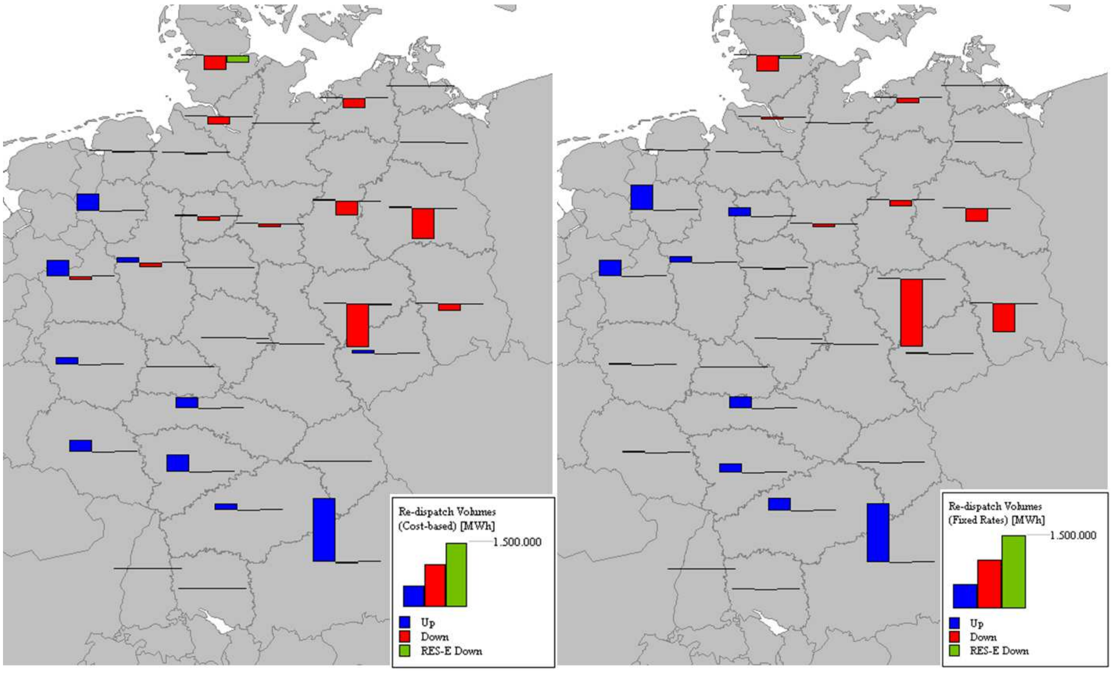
As described in chapter 4.3.2.2, the remuneration of all generators at a fixed rate leaves the TSO indifferent with regard to the selection of power plant technologies. Under the assumption that the TSO always minimizes her expenditures, the optimization problem is reduced to one of volume minimization. The TSO therefore selects the most effectively located generators only. In the *NEULING* model, this is reflected by setting all cost parameters included in the original objective function to one and by considering the absolute values of the variables only. In consequence, ramping costs are excluded from the calculus and need to be compensated separately.[82] The assumptions on the technological flexibility remain unchanged. With regard to the re-dispatch of hydro power plants, the feasibility of the results as well as the comparability to the cost-based re-dispatch scenario is maintained by introducing a similar scaling factor for upward re-dispatch. In the case of fixed-rate re-dispatch, the factor is not directly coupled to the payments but exerts the same influence. Again, the factor leads to a preferred re-dispatch of fossil technologies such that the deployment of hydro plants is the less favorable option. Additional measures to restrict the downward re-dispatch of spinning hydro generators are not taken, since the spill of surplus water is assumed to be possible at all times. In consequence, hydro power plants are handled as every other technology with regard to negative re-dispatch.

Results

In line with the intuition described above, the total re-dispatch volumes are reduced by 7.5% (276.5 GWh/a) in comparison to the cost-based reference case. Furthermore, the allocation of the re-dispatch volumes changes notably. Although the availability of physical capacities still limits the selection of generators, the results of the fixed-rate re-dispatch indicate the relevance of single nodes for the transmission network. In the case of positive re-dispatch, the adjustments are now provided at 19 instead of 24 nodes. Due to the standardized rate, the trade-off between costs and effectivity is no longer relevant. In consequence, suppliers which are re-dispatched in the reference case because of their relatively low costs are disregarded in the fixed-rate scenario. The opposite is observed in the case of negative re-dispatch. Whereas the cost-based model selects generators at 22 different nodes, now five additional nodes provide downward adjustments. Thus, the neglect of differences in the generators' savings leads to a finer geographical differentiation. An illustration of the regional re-dispatch volumes in direct comparison to the cost-based results is given in figure 5.8.

[82] This is in line with the proposal of the German regulator, cf. BNetzA (2012b).

FIGURE 5.8: Comparison of re-dispatch volumes (cost-based left, fixed rate right) in 2015



Source: Own illustration.

The higher geographic concentration of upward re-dispatch especially shows in a cluster in the North-West and in the South of Germany. In the North-East, three nodes register substantially higher volumes, namely "Emsland" (no. 9, +177 GWh/a or 48%), "Landsbergen" (no. 10, +150 GWh/a or 340%) and "Ruhr Ost" (no. 15, +15 GWh/a or 12%). In exchange, the positive adjustments in neighboring regions decrease. In the South, "Stuttgart" (no. 28) and "Frankfurt/Mainz" (no. 25) register an increase in positive re-dispatch of 133 GWh/a (+97%) and 23 GWh/a (+10%) respectively. Instead, suppliers in the regions "München" (31), "Mannheim/Karlsruhe" (27) and "Weiher" (24) are called less. Another noteworthy effect of fixed-rate re-dispatch is observable in the North-East of Germany. In contrast to the cost-based scenario, the nodes "Wolmirstedt" (12) and "Berlin" (13) no longer provide positive re-dispatch. This amounts to a local decrease of 33 GWh/a and 46 GWh/a. The same effect occurs in "Brunsbüttel" (1), "Schwarze Pumpe" (19) and "Lauchstädt" (18), although to a smaller extent.

Concerning the allocation of negative re-dispatch, the highest changes under fixed-rate re-dispatch occur in Eastern Germany. Especially, additional negative adjustments in "Schwarze Pumpe" (19) and "Lauchstädt" (18) replace downward re-dispatch in "Wolmirstedt" (12) and "Berlin" (13). Thus the measures are taken in a greater proximity to the critical lines connecting the East and the South. In general, the more direct aim at the congested lines thus decreases the overall need for adjustments. This also holds with regard to the necessity to curtail the feed-in of RES. Since the smaller volumes of fixed-rate re-dispatch require less conventional capacities, supplementary curtailment can be avoided more often. In comparison to cost-based re-dispatch, 179 GWh/a or 63% of RES-E curtailment can thus be saved.

Regarding the selection of power plant technologies, the logic of the fixed-rate remuneration directly translates in a shift towards high-cost technologies for upward and towards low-cost technologies for downward re-dispatch. Whereas the provision of additional generation by lignite is completely suspended (-6.5 GWh/a), the share of hard coal fired plants in upward re-dispatch is reduced from 4.3% to 1.3% (-114.7 GWh/a). In contrast, older gas fired units provide more upward re-dispatch in the fixed-rate scenario. Although the absolute volumes supplied by CCGTs and OCGTs also diminish due to the overall reduction of re-dispatch, their share rises from 92% to 98%. Because of the corresponding parameterization, the deployment of hydro power plants does not change significantly. Nonetheless, the effect of quantity also reduces the positive re-dispatch volumes provided by pumped storage plants by 360 MWh/a. In contrast, the share of gas and hard coal plants in downward re-dispatch decreases notably in the fixed-rate scenario. In return, lignite and nuclear power plants are ramped-down more often in the course of re-dispatch. Their shares now amount to 64% and 11% respectively, despite the low savings in variable costs. Especially in the case of lignite plants, this development is driven by their location in the North-East of Germany. Furthermore, the provision of downward re-dispatch by spinning hydro power plants is increased in comparison to the reference scenario. Since hydro power plants offer the lowest savings per reduced MWh apart from curtailment, the technologies are seldom selected for downward adjustments under cost-based re-dispatch. Now, the fixed rate leads to the deployment of hydro power plants at effective nodes, such as "Erfurt" (22) and "Röhrsdorf/Eula"' (23).

The expenses of the TSO finally amount to 187.9 mEUR/a including the payments for ramping, which are assumed to be revealed truthfully and to be remunerated accordingly.[83] Excluding hydro power plants, whose remuneration is defined by the fixed-rate as well, the expenses are slightly reduced to 187.5 mEUR/a. Both values are higher than the corresponding costs of the reference scenario (136.5 mEUR/a incl. hydro power, 134.2 mEUR/a excl. hydro). Even though the re-dispatch volumes decrease, the fixed-rate design does not come with a reduction in the TSO's expenses. However, the discrepancy is even more pronounced when the true variable re-dispatch costs are taken into account. Under consideration of the generators' hourly variable and ramping costs as applied in the cost-based scenario, total re-dispatch costs of 264.4 mEUR/a (253.6 mEUR/a excl.

[83]Necessary payments to loads or international suppliers which are associated to the use of the dummy variable are not included. The remuneration scheme has no impact on the dummy variable and its allocation, such that the corresponding values do not change in comparison to the cost-based reference case.

hydro) are revealed. In consequence, the loss in efficiency triggered by a fixed-rate design can be valued at -127.9 mEUR/a (or -119.4 mEUR/a).

However, with regard to different technologies, the fixed-rate remuneration has mixed effects. In the case of positive re-dispatch, technologies with variable costs within the range of the marginal system cost plus 10% benefit from the TSO's payments. In the given scenario, especially hard coal power plants are remunerated above their true costs. Their additional revenues from re-dispatch amount to 252,200 EUR/a and to an average of 5.60 EUR/MWh. In contrast, effective generators with relatively high variable cost are most likely in an inferior position. This holds true for gas fired power plants, which in total suffer losses from re-dispatch to the amount of 16.2 mEUR/a or 19.46 EUR/MWh. However, the rate of 10% appears to be sufficient for modern CCGTs, although their average benefit of 1.24 EUR/MWh is lower than for hard coal technologies. Due to the steeper slope of the merit order towards its end, the capacities which fall within the pre-defined range will be smaller at high hourly marginal costs than in the middle of the merit order. Over all fossil technologies, the shortfall in compensatory payments amounts to 15.9 mEUR/a.

Concerning negative re-dispatch, the pattern is reversed. In the case of low-cost technologies, the probability that the true savings are below the charges of the TSO are greater than for costlier power plants. In the given scenario, nuclear and lignite plants pay 11.7 mEUR/a (29.62 EUR/MWh) and 41.3 mEUR/a (17.50 EUR/MWh) more to the TSO than covered by their savings in variable costs. In contrast, hard coal and gas fired plants generally benefit from downward re-dispatch under a fixed-rate regime (2.35 EUR/MWh and 5.57 EUR/MWh). Nonetheless, the charges of the TSO exceed the true savings of fossil-fuel plants by a total of 50.1 mEUR/a.

Overall, the error of the fixed-rate remuneration is observed to be significantly higher in the case of negative re-dispatch. However, as stated in chapter 4 and already hinted above, a 10% markup of the hourly marginal system costs will cover less capacities along the merit order than a 10% reduction. Thus, the probability that a plant is insufficiently remunerated is higher in the course of upward re-dispatch than during downward re-dispatch. Nonetheless, this pattern does not dominate the presented results. This is due to the fact that the theoretical example does not account for the plants' location. In consequence, the error may well be higher for generators providing negative re-dispatch if the variable costs of the most effective plants happen to be considerably lower than the system marginal costs.

Furthermore, no geographical pattern of additional revenues or losses can be observed. Since both upward and downward re-dispatch can generate benefits and losses at the same node at the same time, the regional distribution depends on the local capacity mix rather than on the nodes' position with respect to the bottleneck. In accordance with chapter 4, this demonstrates that a well-aimed compensation for inefficiently low or excessively high regional producer surpluses from uniform pricing is thus not possible by the means of fixed-rate re-dispatch. Instead, the design introduces further distortions into the market. Given that the associated inefficiencies roughly double the true congestion management costs, the potential benefits from saving transaction costs or reducing information asymmetries are most likely insufficient to justify the implementation of such a design.

5.4.2.3 Spot Price-based Re-dispatch

The use of a less simple but possibly more accurate spot price-based remuneration scheme may however reduce the inefficiency of a fixed-rate design while still offering the possibility to mitigate information asymmetries. In this section, the performance of a generator-specific marginal cost estimator as discussed in section 4.3.2.2 will be tested. The estimator equals the lowest price at which a given generator is called at the wholesale market. Assuming that all market participants bid according to the principles of perfect competition, the estimator indicates the generators' marginal costs. In order to minimize the impact of start-up costs on the estimator, the minimum marginal system costs are used to price both positive as well as negative re-dispatch provided by a given generator. This is a slight variation of the proposal made in BNetzA (2012a). In addition, ramping costs are compensated separately.

In the presented analysis, the results of the dispatch model applied in the CU scenario are used to derive technology-specific estimators. Since the variable costs of power plants within one vintage class are identical and since the order in which the local plants are called during dispatch is not justified by fundamental differences, the estimator is not differentiated locally. In reality, the estimator would rarely be identical for any two plants. However, the definition of the estimator allows for a variation in time. Its hourly value is thus defined by the minimum marginal system price at which a vintage class was in operation during the previous four weeks. Should a technology not have been used during the last four weeks, the estimator is set to its last positive value rather than to zero. The variable costs of technologies that never run are set to their true variable costs. The case of hydro power is once again handled by setting the variable costs of positive re-dispatch to roughly 100 EUR/MWh. All remaining assumptions of the cost-based reference case are left unchanged.

In the presented scenario, no floor is introduced such that no artificial lower bound of the estimator is provided. This gives room to the effects of opportunity costs, which may push the estimator below variable costs. In the applied model setup, the opportunity costs incurring during dispatch mainly stem from ramping costs.[84] Thus, a first indication of the relevance of opportunity costs for the remuneration of re-dispatched is given.

Results

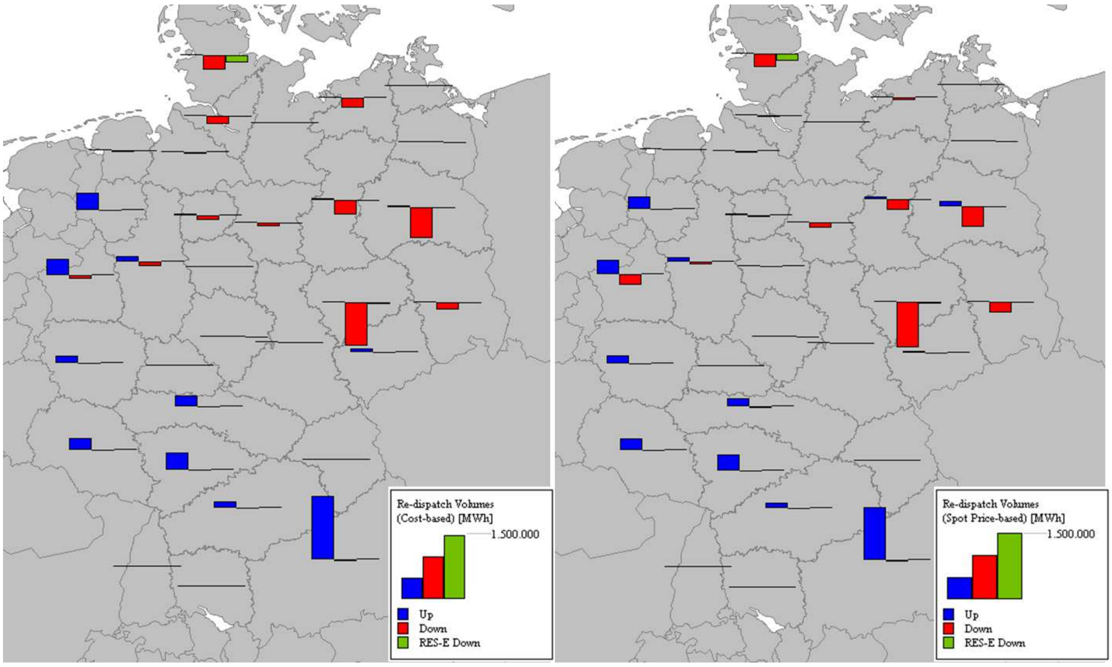
The first effect of the estimator shows in the overall re-dispatch volumes which rise by 35 GWh/a in comparison to the reference case. This observation indicates that the trade-off between the variable costs and the effectivity of available re-dispatch options has changed. Given the rising volumes, the change in the relative costs of effective and less effective generators apparently shifts the balance towards low-cost options at weaker nodes. In the case of upward re-dispatch, some nodes which have been identified as especially effective during the analysis of the fixed-rate scenario now register smaller volumes than under cost-based re-dispatch. This for example holds true for the southern nodes "München" (31), "Frankfurt/Mainz" (25) and "Stuttgart" (28), which respectively provide 64 GWh/a, 36 GWh/a and 9 GWh/a less than in the reference case. Analogously, the northern regions "Emsland" (no. 9, -58 GWh/a) and "Ruhr Ost" (no. 15, -24 GWh/a) account for smaller positive adjustments.

In the case of downward re-dispatch, the effect is less clear. While in Eastern Germany a shift of re-dispatch volumes towards more effective nodes such as "Lauchstädt" (no. 18, +204 GWh/a) and "Schwarze Pumpe" (no. 19, +102 GWh/a) can be observed, also less prominent nodes now provide additional re-dispatch. This is for example the case in the north-western region "Ruhr West" (no. 14, +188 GWh/a). However, increasing adjustments at more remote nodes can be both attributed to a change in the perceived local costs as well as to the overall higher re-dispatch volumes. The general development of regional re-dispatch volumes is illustrated in figure 5.9 in comparison to the reference case. Overall, the geographical diversification of re-dispatch increases slightly in the spot price-based scenario.

The use of the estimator has a technology-specific effect on the selection of generators for re-dispatch. With regard to positive adjustments, especially hard coal fired plants and modern CCGTs provide additional volumes. The increases to the amount of 13 GWh/a and 382 GWh/a also compensate for a reduced provision of upward re-dispatch by lignite (-4 GWh/a) and other gas fired plants (-356 GWh/a). Furthermore, a minimal change (+54 MWh) in the supply of positive re-dispatch by PSP can be observed due to slight changes in the technologies' relative costs. In contrast, the estimator leads to a stronger

[84] In the given model set-up, positive balancing reserves are mainly provided by quick-starting OCGTs. Furthermore, sufficient capacities are usually online for the provision of negative reserve. Imposing more severe balancing market restrictions would increase opportunity costs and the difference between marginal cost-based prices and variable costs.

Figure 5.9: Comparison of re-dispatch volumes (cost-based left, spot price-based right) in 2015



Source: Own illustration.

preference for low-cost plants in the course of downward re-dispatch. In contrast to the reference case, nuclear power plants account for additional negative adjustments to the amount of 43 GWh/a. Furthermore, lignite plants provide 320 GWh/a more downward re-dispatch. Both technologies thus compensate the decrease in volumes provided by hard coal and CCGT units (-152 GWh/a and -196 GWh/a, respectively). Furthermore, the production from hydro reservoirs is slightly more often subject to downward re-dispatch (+22 MWh/a). The overall increase in re-dispatch volumes also affects the curtailment of RES, which is increased by 19.7 GWh/a. The additional reductions mainly take place in the North-East.

Concerning the total costs of re-dispatch, the presented spot price-based remuneration scheme comes at total expenses of 207.1 mEUR/a for the TSO, which is the highest net-payment observed so far. Subtracting the payments to hydro power plants, which are remunerated for upward re-dispatch at a fixed price of 100 EUR/MWh, the expenses amount to 204.9 mEUR/a. However, also the estimator induces hidden costs of re-dispatch. Under consideration of the generators' true variable costs, the total costs of congestion management amount to 215 mEUR/a (212.7 mEUR/a excluding hydro power). The error of the pricing scheme is thus considerably smaller than with a fixed rate (7.9 mEUR/a instead of 76.5 mEUR/a), despite the lack of a floor price.

Again, the error of the estimator is observed to affect the suppliers of upward and downward re-dispatch asymmetrically. In the case of positive re-dispatch, the TSO pays a total of 334.8 mEUR/a to fossil-fuel plants, including ramping costs. The true costs of increasing local generation by conventional plants however amount 355.8 mEUR/a. Since ramping costs are assumed to be remunerated adequately, the bias of 21 mEUR/a is restricted to the estimation of the variable fuel and CO_2 costs plus other variable operating costs. For downward re-dispatch, ramping costs are assumed to be negligible. Based on the estimator, the charges imposed on generators providing negative re-dispatch amount to 129.9 mEUR/a. Unlike in the case of upward re-dispatch, the true savings in variable costs register above the estimated value. In consequence, 13.1 mEUR/a of savings remain with the re-dispatched generators. Both results indicate that the estimator by trend underestimates the true variable costs. Whereas this yields losses for producers subject to positive re-dispatch, it generates additional revenues for generators ramped-down. With regard to the inefficiency of the local producer surplus induced by uniform pricing, the observed pattern aggravates the deviations from the efficient level.

The effects of the estimator are however not homogeneous across all technologies. While the average bias in the remuneration of suppliers of positive re-dispatch amounts to -5.63 EUR/MWh, the underestimation is especially high for hard coal plants with a deficit in the remuneration of 2,576 mEUR/a or -14.05 EUR/MWh. This is due to the original dispatch of hard coal plants which often requires operation at marginal system costs below variable costs. This is optimal from a system-wide point of view since the dispatch mirrors the opportunity costs of ramping. However, this translates in an inefficiently low estimation of the plants' variable costs. In the extreme case of modern hard coal plants, the estimator is thus constantly lower than the variable costs. This does not mean that the plants constantly operate below costs, but that the opportunity costs of ramping set the price at least in one hour within the four weeks. In this case, using a shorter time frame as the basis for deriving the estimator may be an appropriate remedy. The same principle applies to modern CCGTs which register an error of -11.31 EUR/MWh on average. However, some older gas fired plants yield slight profits of 0.52 EUR/MWh. This is due to the rule that the estimator is set to its last positive value in case a plant has not been running since more than four weeks. If in the mean time the variable costs of the said plants have been updated to account for seasonal fluctuations in fuel costs, the estimator may be overestimated in short time periods.

With regard to downward re-dispatch, the underestimation of the costs of hard coal plants and modern CCGTs now works in the opposite direction. Since the true savings exceed the charges of the TSO, the respective plants obtain additional revenues of 9.7 mEUR/a (avg. +11.86 EUR/MWh) and 5.2 mEUR/a (avg. +4.56 EUR/MWh). On average, also lignite plants benefit from inefficiently low estimators. In sum, their profits amount to 0.9 mEUR/a. However, some modern lignite technologies as well as nuclear power plants are charged for more than their savings. Especially nuclear power plants lose on average 9.16 EUR per MWh downward re-dispatch. This indicates that the base-load plants not necessarily set the price in hours in which they are the only spinning unit. Instead, network effects resulting from the DC load flow may cause opportunity costs which push the marginal system costs beyond the marginal costs of the last spinning domestic unit.

Whereas errors resulting from underestimated variable costs may be cured by time-variant and technology-specific floors, the error underlying this last observation cannot be cured by the means of a lower bound. Instead, a ceiling would need to be introduced. However, setting bounds in every direction would finally narrow the estimator down to the generators' true marginal costs. Although this would indeed be efficient, it would also implement cost-based re-dispatch once again, leading the original concept of the estimator ad absurdum. The problem of guessing the variable costs of re-dispatch on the basis of information provided by the producers would again dominate the mechanism.

In the presented design without any bounds except for hydro power, the true re-dispatch costs in a spot price-based regime are however substantially higher than in a cost-based system. In total, the presented design leads to additional costs of 78.5 mEUR/a. Given the transaction costs of constantly updating the estimator for every generator subject to re-dispatch, potential benefits will be thus be limited to the said effects of mitigated information asymmetries.

5.4.3 Intermediate Conclusion

The comparison of the three different re-dispatch mechanisms highlights the impact of design choices on the efficiency of internal congestion management. Even though no re-dispatch design can be expected to implement the allocation of generation that results from nodal pricing, considerable differences in the relative performance of individual approaches can be observed.

In the given framework, cost-based re-dispatch proves to be clearly preferable to mechanisms with spot price-based remuneration schemes. First, cost-based re-dispatch achieves the least-cost solution. Although the magnitude of the re-dispatch costs is small in comparison to the production costs under uniform pricing (0.9% or 136.5 mEUR/a in a cost-based system), the relative increases induced by the use of a spot price-based cost estimator (+78 mEUR/a) or by fixed-rate re-dispatch (+127.9 mEUR/a) are substantial.

Second, cost-based re-dispatch is found to be the only one of the designs which aligns the expenses of the TSO with the generators' true costs. Although the hidden costs are relatively small in the estimator-based design (7.9 mEUR/a), the difference between the true costs and the expenses amount to substantial 76.5 mEUR/a in a fixed-rate design. In the end, this discrepancy may induce evasive behavior on the part of the generators which could further increase the system's inefficiency.

The results also reveal the sensitivity of the allocation of re-dispatch to changes in the proportion of the local costs. In the case of the estimator, the local distribution of the perceived variable costs indicates a cost minimum which comes at additional re-dispatch volumes in comparison to the cost-based reference case. In contrast, the artificial leveling of the variable costs in the course of the fixed-rate approach lowers the re-dispatch volumes. Although this minimizes the TSO's interference with the dispatch, it leads to a particularly inefficient management of congestion.

Furthermore, fixed-rate and estimator-based re-dispatch rather introduce technology-specific than region-specific effects on the generators' revenues. Thus, the ex post internalization of external effects of network usage cannot be achieved by re-dispatch. In contrast, additional distortions are introduced. Accordingly, the revenue-neutral cost-based approach is the best available option.

However, the scope of the analysis does not cover an analysis of transaction costs and the effects of information asymmetry. The necessity to update the generator-specific cost data exists both in cost-based and estimator-based designs and will probably not induce significant differences in transaction costs. The impact of information asymmetries is probably more difficult to assess. Given the substantial differences in the mechanisms' re-dispatch costs, it may nonetheless be the best strategy to enforce cost-control in a cost-based system instead of changing the design.

5.5 Discussion and Final Conclusion

The analysis presented in this paper highlights the relevance of congestion management for a market with structural bottlenecks such as Germany. Depending on the choice of the design, the impact of congestion on the market is either revealed during dispatch or in the course of re-dispatch. The choice of nodal pricing leads to the efficient utilization of the transmission network and internalizes the opportunity costs of congestion. However, nodal pricing comes with the challanges of limited local liquidity and higher regional market concentration. Furthermore, the presented results reveal significant distribution effects within the country. Uniform pricing on the other hand is able to reduce the relevance of local liquidity and avoids regional discrimination of market participants. Depending on the re-dispatch design, the abuse of local market power can futher be limited. However, even a well-designed re-dispatch mechanism will most likely miss the efficient allocation of generation in practice, especially in the presence of wide-spread and severe congestion. Moreover, the details of the re-dispatch design largely determine the degree to which additional distortions are introduced.

This paper demonstrates the complexity of the issue at hand and highlights the interdependency between the regional and the economic structure of the market. However, the results have to be viewed in the context of the applied methodology. First, the analysis is limited to one scenario year. Although some of the fundamental factors shaping the German market can be assumed to persist in the mid-term, a sensitivity of the results with regard to structural changes can generate valuable insights.[85] However, the high temporal resolution of the model delivers robust results for the scenario year itself.

Furthermore, the dispatch model provides short-run marginal costs only, which could be interpreted as market prices under certain assumptions, such as perfect competition and overcapacities. In particular the assumption on overcapacities can only occur temporarily. Therefore, the short-run marginal costs cannot be interpreted as long-run equilibrium prices in an energy-only market. In consequence, the producer surplus and consumer costs derived on the basis of the dispatch results have limited explanatory value. However, the calculations give a first indication of the regional impact of market design choices. In addition, the analysis is restricted to a setting of perfect competition.

The analysis could among others be refined by introducing a regional differentiation of fuel costs and by considering demand elasticity. Taking local fuel costs into account would most likely increase the divergence between the nodal and the uniform pricing model, especially with regard to marginal costs. Furthermore, an impact on the local producer surplus can be expected. On the other hand, the price effect of nodal pricing is by trend reduced in the presence of demand response, as demonstrated e. g. in Green (2007).

With regard to the re-dispatch model, the lack of intertemporality complicates the representation of hydro power plants and leads to an overestimation of re-dispatch costs by trend. In contrast, the variable costs of operation (excluding ramping costs) are set to the dispatch-level and may thus be underestimated. A more important factor however is the neglect of network topology optimization. Introducing this congestion management option would decrease the costs of re-dispatch.

[85] See chapter 3 and Nüßler (2012).

Furthermore, the representation of power flows and of congestion is limited to the aggregate network model. Thus, the need for re-dispatch may be underestimated. Two additional effects are induced by the limitation of the re-dispatch calculation to transmission lines within Germany. First, the consideration of cross-border congestion management will reduce the costs of re-dispatch. Second, some of the analyzed internal re-dispatch measures may increase the stress of the interconnectors and may not be feasible in an international context.

With regard to future research, the analysis of interdependencies between generation and network investments may yield valuable insights concerning the evaluation of pricing systems. Furthermore, quantitative analyses on the impact of local load pockets with market power potential may help to set the issue of market concentration into perspective. Overall, the importance of a holistic approach to electricity market studies including both generation and the network may be emphasized by the presented work.

Appendix A

General Parameters of *NEULING*

Table A.1: Transmission line parameters per voltage level

	Thermal Capacity [MW]	Resistance [Ohm]	Reactance [Ohm]
380 kV	1,777	0.025	0.25
220 kV	286	0.23	1.16

Source: ie^3 TU Dortmund.

Table A.2: Average economical and technical power plant parameters per technology

	Nuclear	Lignite	Hard Coal	CCGT	OCGT	Oil
Fixed O&M Costs [EUR/kWa]	70.00	40.70	29.06	23.15	10.26	8.08
Other Variable Costs [EUR/MWh_el]	9.00	3.30	3.30	1.60	1.60	1.10
Start Attrition Costs [EUR/MWh_th]	1.70	3.00	4.97	10.00	10.00	10.00
Start Time [h]	6	2.9	3	2	0.4	1
Minimum Load [%]	53	41	39	37	23	40
Efficiency [%]	34	40	43	49	34	37

Source: Own assumptions.

Appendix B

Supplementary Material to Chapter 5

TABLE B.1: Generation capacities

No.	Node	Nuclear	Lignite	Hard Coal	Natural Gas	Oil	Pumped Storage	Hydro Reservoir	CAES	TOTAL
1	Brunsbüttel	1,410	0	323	0	0	0	0	0	1,733
2	Dollern	0	0	2,617	0	0	0	0	0	2,617
3	Hamburg	0	0	0	0	0	120	0	0	120
4	Rostock/Güstrow	0	0	509	51	0	0	0	0	560
5	Lubmin	0	0	0	0	0	0	0	0	0
6	Bremen	0	0	766	0	0	0	0	321	1,087
7	Bertikow	0	0	0	0	0	0	0	0	0
8	Diele	0	0	1,506	0	0	0	0	0	1,506
9	Emsland	1,329	0	709	1,818	0	0	0	0	3,856
10	Landesbergen	0	0	1,288	330	0	0	0	0	1,618
11	Wahle	0	352	690	96	0	0	0	0	1,138
12	Wolmirstedt	0	0	0	812	0	0	0	0	812
13	Berlin	0	0	0	3,420	0	0	0	0	3,420
14	Ruhr West	0	0	7,086	1,820	0	153	0	0	9,059
15	Ruhr Ost	0	0	3,650	1,116	0	147	25	0	4,939
16	Borken	0	0	0	9	0	620	0	0	629
17	Grohnde	1,360	0	0	0	0	220	0	0	1,580
18	Lauchstädt	0	2,644	0	123	0	0	0	0	2,768
19	Schwarze Pumpe	0	6,723	0	56	0	40	0	0	6,819
20	Köln	0	9,232	13	4,307	0	0	30	0	13,582
21	Gießen	0	0	0	0	0	0	0	0	0
22	Erfurt	0	0	0	0	0	1,603	4	0	1,607
23	Röhrsdorf/Eula	0	0	0	1,200	0	1,050	0	0	2,250
24	Weiher	0	0	2,192	576	0	1,296	0	0	4,064
25	Frankfurt/Mainz	1,275	0	1,088	1,425	0	160	0	0	3,948
26	Etzenricht/Raitersaich	0	0	0	0	0	284	0	0	284
27	Mannheim/Karlsruhe	1,392	0	2,429	899	0	0	0	0	4,720
28	Stuttgart	1,305	0	1,769	633	0	90	0	0	3,797
29	Eichstetten	0	0	0	0	0	1,740	1	0	1,741
30	Herbertingen/Vöhringen	2,572	0	0	0	0	0	0	0	2,572
31	München	1,410	0	449	2,082	0	108	174	0	4,223
	GERMANY	12,053	18,951	27,084	20,772	0	7,631	234	321	87,047

Source: EWI power plant database.

TABLE B.2: Consumption, generation, costs and surplus

No.	Node	Consumption [GWh/a]	Generation RES & CHP [GWh/a]	Conventional Generation [GWh/a] CU	NP	Avg. Marginal Costs [EUR/MWh]	Consumer Costs [mEUR/a] CU	NP	Producer Surplus [mEUR/a] CU	NP
1	Brunsbüttel	9,764	12,505	11,007	10,762	51.24	518.6	509.5	339.6	330.6
2	Dollern	17,272	4,305	17,976	17,959	51.46	914.7	903.3	112.8	97.3
3	Hamburg	10,887	5,304	22	16	51.20	577.7	567.4	0.1	0.1
4	Rostock/Güstrow	2,682	3,226	2,703	2,367	50.81	141.6	138.1	13.3	8.8
5	Lubmin	1,915	2,603	0	0	50.61	101.2	98.3	0.0	0.0
6	Bremen	9,090	7,012	867	567	51.64	482.8	478.0	1.6	1.1
7	Bertikow	1,686	4,023	0	0	50.48	89.0	86.3	0.0	0.0
8	Diele	5,075	10,340	9,066	9,272	51.81	269.6	267.7	53.0	47.0
9	Emsland	8,286	5,580	14,429	14,220	51.94	438.9	437.2	338.4	335.1
10	Landesbergen	4,899	3,437	5,311	4,814	51.59	260.2	257.5	23.4	18.7
11	Wahle	11,646	5,597	3,374	3,059	51.29	618.5	608.5	52.7	50.2
12	Wolmirstedt	4,008	9,785	1,963	762	50.70	211.7	206.0	1.6	0.7
13	Berlin	12,720	13,385	5,224	1,532	50.50	671.9	651.1	4.3	1.6
14	Ruhr West	53,561	9,929	21,868	20,689	52.01	2,831.2	2,825.2	93.2	86.0
15	Ruhr Ost	28,630	7,808	13,491	12,868	51.85	1,517.5	1,509.5	77.3	71.6
16	Borken	11,424	2,426	120	100	51.61	606.3	600.3	0.5	0.5
17	Grohnde	6,817	2,146	10,169	10,161	51.59	362.0	358.2	326.8	322.0
18	Lauchstädt	19,505	7,681	20,143	20,147	50.50	1,030.3	998.5	444.7	413.6
19	Schwarze Pumpe	16,377	6,440	51,223	51,237	50.36	865.1	836.2	1,112.5	1026.1
20	Köln	53,991	9,683	71,528	71,491	52.12	2,860.3	2,860.6	1,476.1	1481.8
21	Gießen	12,075	1,351	0	0	51.93	641.1	638.8	0.0	0.0
22	Erfurt	17,254	5,183	337	231	50.97	913.2	893.4	2.3	2.1
23	Röhrsdorf/Eula	25,440	3,973	309	199	50.05	1,343.8	1,291.0	1.0	1.2
24	Weiher	31,954	5,527	8,599	8,597	52.09	1,691.4	1,693.2	28.9	30.9
25	Frankfurt/Mainz	24,311	6,497	12,659	12,778	52.05	1,290.5	1,289.2	319.8	319.2
26	Etzenricht/Raitersaich	9,125	2,282	54	33	51.28	485.9	478.1	0.2	0.2
27	Mannheim/Karlsruhe	32,980	11,142	23,725	23,942	52.43	1,750.6	1,760.9	410.6	417.8
28	Stuttgart	35,801	8,928	18,260	18,984	52.55	1,904.4	1,919.0	352.2	358.7
29	Eichstetten	13,530	5,726	356	382	52.88	719.7	730.7	1.5	2.1
30	Herbertingen/Vöhringen	13,730	2,697	19,144	19,144	52.86	730.3	739.7	617.7	633.3
31	München	40,215	22,270	13,485	13,074	52.19	2,138.2	2,140.4	381.4	383.0
	GERMANY	546,650	208,790	357,410	349,387	-	28,978.1	28,771.7	6,587.4	6,441.4

Source: Own calculation.

TABLE B.3: Re-dispatch of conventional capacities

		Re-dispatch of Conventional Capacities [MWh/a]					
		Cost-based		Fixed-Rate		Spot Price-Based Estimator	
No.	Node	Upward	Downward	Upward	Downward	Upward	Downward
1	Brunsbüttel	470	-323,520	0	-351,172	1,106	-342,291
2	Dollern	21,252	-183,635	8,387	-55,075	24,106	-49,371
3	Hamburg	0	0	0	-368	0	0
4	Rostock/Güstrow	4,527	-226,683	6,588	-115,336	3,473	-63,941
5	Lubmin	0	0	0	0	0	0
6	Bremen	1,047	-41,983	715	-4,276	1,537	-55,532
7	Bertikow	0	0	0	0	0	0
8	Diele	7,038	-39,400	1,356	-16,846	9,470	-14,332
9	Emsland	371,977	-28,591	549,049	-5,664	313,655	-22,136
10	Landesbergen	44,207	-103,582	193,762	-13,926	38,500	-35,923
11	Wahle	9,564	-74,767	11,417	-84,905	7,377	-127,636
12	Wolmirstedt	32,506	-320,908	0	-132,639	68,056	-273,132
13	Berlin	45,698	-674,547	0	-295,787	135,055	-520,851
14	Ruhr West	354,246	-75,038	352,792	-6,813	361,069	-262,969
15	Ruhr Ost	128,001	-90,045	142,988	-9,890	103,841	-69,113
16	Borken	1,451	0	580	-502	1,263	0
17	Grohnde	0	0	0	-36,204	0	-6,795
18	Lauchstädt	2,828	-960,379	0	-1,489,689	250	-1,164,244
19	Schwarze Pumpe	4,186	-169,644	0	-632,309	3,143	-271,642
20	Köln	160,161	-3,682	32,929	-3,761	210,927	-8,101
21	Gießen	0	0	0	0	0	0
22	Erfurt	0	-99	0	-10,482	0	-121
23	Röhrsdorf/Eula	73,054	-5,595	40,991	-2,676	56,571	-4,877
24	Weiher	261,996	-17,392	37,363	-2,354	296,398	-19,224
25	Frankfurt/Mainz	230,485	-9,029	253,741	-11,295	194,690	-39,699
26	Etzenricht/Raitersaich	1,744	0	1,744	-364	1,744	0
27	Mannheim/Karlsruhe	383,134	-10,577	201,945	-292	415,289	-22,713
28	Stuttgart	138,105	-9,254	271,453	-5,628	129,319	-3,623
29	Eichstetten	15,974	0	15,616	0	15,980	0
30	Herbertingen/Vöhringen	0	0	0	-9,088	0	0
31	München	1,397,143	-36,860	1,290,872	-10,426	1,333,025	-42,234
	GERMANY	3,690,792	-3,405,211	3,414,288	-3,307,766	3,725,842	-3,420,498

Source: Own calculation.

TABLE B.4: Curtailment of RES-E and upward dummy re-dispatch

		Curtailment of RES-E and Upward Dummy Re-dispatch [MWh/a]					
		Cost-based		Fixed-Rate		Spot Price-Based Estimator	
No.	Node	RES-E	Dummy	RES-E	Dummy	RES-E	Dummy
1	Brunsbüttel	-167,563	0	-83,173	0	-174,818	0
2	Dollern	-4,402	0	-315	0	-5,933	0
3	Hamburg	0	0	0	0	0	0
4	Rostock/Güstrow	0	0	0	0	0	0
5	Lubmin	0	0	0	0	0	0
6	Bremen	0	0	0	0	0	0
7	Bertikow	-21,437	0	-1,067	0	-20,968	0
8	Diele	-22	0	0	0	-22	0
9	Emsland	0	0	0	0	0	0
10	Landesbergen	0	0	0	0	0	0
11	Wahle	-337	0	-1,908	0	-79	0
12	Wolmirstedt	-2,374	0	0	0	-2,609	0
13	Berlin	-16,605	0	-369	0	-17,160	0
14	Ruhr West	0	0	0	0	0	0
15	Ruhr Ost	0	0	0	0	0	0
16	Borken	-461	0	-681	0	-819	0
17	Grohnde	0	0	0	0	0	0
18	Lauchstädt	-41,339	0	-5,539	0	-45,465	0
19	Schwarze Pumpe	-26,850	0	-13,504	0	-28,054	0
20	Köln	0	0	0	0	0	0
21	Gießen	0	0	0	0	0	0
22	Erfurt	-4,281	0	-55	0	-9,506	0
23	Röhrsdorf/Eula	0	0	0	0	0	0
24	Weiher	0	0	0	0	0	0
25	Frankfurt/Mainz	0	0	0	0	0	0
26	Etzenricht/Raitersaich	0	0	0	0	0	0
27	Mannheim/Karlsruhe	0	0	0	0	0	0
28	Stuttgart	0	0	0	0	0	0
29	Eichstetten	0	89	0	89	0	89
30	Herbertingen/Vöhringen	0	0	0	0	0	0
31	München	0	0	0	0	0	0
	GERMANY	-285,670	89	-106,610	89	-305,434	89

Source: Own calculation.

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