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

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From Nodal to Zonal Pricing - A Bottom-Up Approach to the Second-Best[☆]

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Abstract

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 redispatch 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.

JEL classification: C38, C63, L51, Q41

Keywords: Cluster Analysis, Electricity Market Modeling, Nodal Pricing, Redispatch, Zonal Pricing

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Nomenclature

$\bar{d}$	Mean of d_k
$\bar{p}_{i,k}$	Mean vector of prices in cluster i at stage k
$b_{n,m}$	Binary parameter indicating neighboring nodes n, m
$C_{i,k}$	Cluster i at step k
d_k	Critical distance at clustering step k
$E_{i,k}$	Sum of squared Euclidean distances of cluster i at step k
I_k	Feasible set of clusters at step k
k	Clustering step $k \in [1, \ldots, N-1]$
n	Node $n \in [1, \ldots, n, m, \ldots, N]$
p_n	Price vector of node n
s_d	Standard deviation of d_k

1. Introduction

On the way to the internal electricity 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 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 locational 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 redispatching costs" (cf. ACER (2011), p. 7). Especially, the TSOs' analysis of zonal delimitations shall be based on detailed data on redispatching 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 2 while section 3 describes the data basis and relevant assumptions. In section 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 redispatch 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 5.

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.

2.1. The NEULING Model

The New European Linear Investment and Grid Model (*NEULING*, cf. Burstedde (2012)) is used to calculate the cost-minimal generation dispatch and redispatch 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.

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).

2.1.2. Redispatch

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 redispatch in case of violations of network constraints can be calculated based on the plants' operating status and their utilization.

The optimal flow-based redispatch 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 redispatch are given by its variable fuel and ramping costs, while the marginal savings of its downward redispatch 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 redispatched.

In theory, the nodal injections after cost-based redispatch 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 redispatch (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 redispatch the technical restrictions on the latter are tighter, thus increasing the variable costs of generation. Furthermore, intraday trade requires costly adjustments of the redispatch schedule on short notice.

In the presented approach, redispatch 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 redispatch by trend. However, redispatch 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 redispatch.

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 result 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 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. At the beginning of each step, the sum of squared Euclidean distances $E_{i,k}$ between the price vectors p_n of each 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 $C_{i,k}$ representing the i$^{\text{th}}$ cluster at stage k:

$$E_{i,k} = \sum_{n \in C_{i,k}} (p_n - \bar{p}_{i,k})'(p_n - \bar{p}_{i,k}). \tag{1}$$

$E_{i,k}$ 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 i at stage k. In consequence, the optimal configuration of clusters is chosen as the combination that yields the minimal decrease in quality:

$$\arg\,\min_{I_k} \Delta := \sum_{i \in I_k} E_{i,k} - \sum_{j \in I_{k-1}} E_{j,k-1}. \tag{2}$$

Here, I_k represents a feasible cluster set at the kth stage of the algorithm. Thereby, only combinations of neighboring nodes give valid clusters. The latter 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, i.e. the sum of all optimal $E^*_{i,k}$ over i. These distances are denoted by d_k. In order to identify the ideal level of aggregation, Mojena (1977) proposes a benchmark based on the normalized measure

$$\hat{d}_k = \frac{d_k - \bar{d}}{s_d} \tag{3}$$

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.

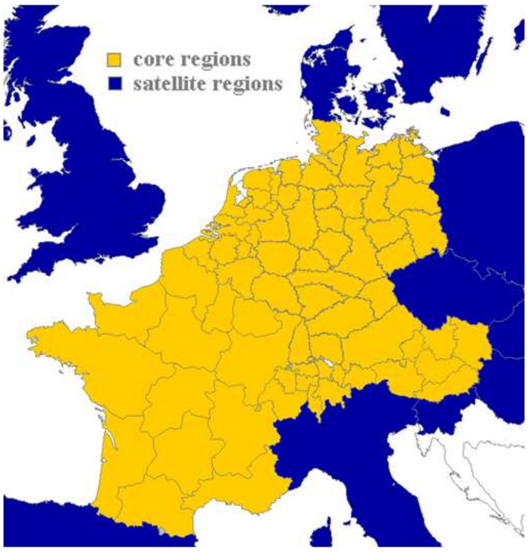
3. Data and Parametrization

The regional coverage used in the model runs is given in figure 1. The core regions Austria, Switzerland, Germany, the Netherlands, Belgium and France are divided into 72 basic regions, which each represent one node of the DC network. The shape of the regions is chosen to best reflect the grid structure, but also considers the boundaries of national administrative areas. Adjacent 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 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)). In total, *NEULING*'s DC load-flow simulates the optimal power flow between 79 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.

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 1. Fuel and CO_2 price assumptions are based on EWI (2011) and given in table 2.

Figure 1: Regional coverage of *NEULING*



Source: Own illustration.

The data on conventional 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. 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 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. Total demand includes network losses and is assumed according to EURELECTRIC (2011). Aggregated data on RES and demand is given in table 3.

Table 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.

Table 2: Fuel and CO_2 Price Assumptions

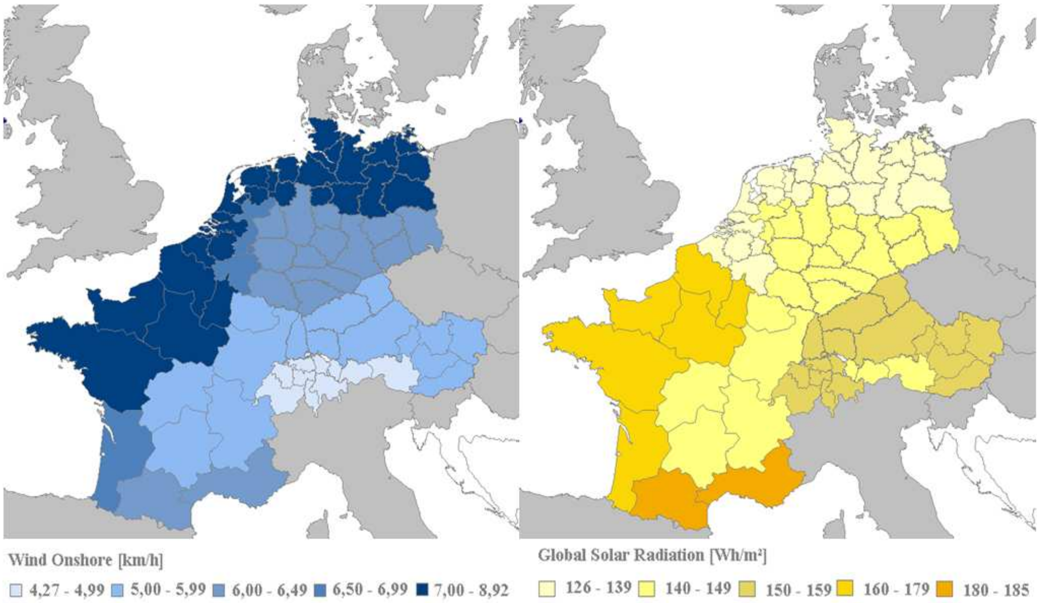
[EUR/MWh$_{th}$]	Uranium	Lignite	Hard Coal	Nat. Gas	Oil
2015	3.60	1.40	13.20	25.70	47.20
2020	3.60	1.40	13.40	28.10	50.25
CO_2 2015: 22.00 EUR/tCO_2, **2020:** 35.00 EUR/tCO_2					

Source: EWI (2011).

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.

Figure 2: Regional wind speeds onshore and global solar irradiation in the core regions



Source: Own illustration based on EuroWind (2011).

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, 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 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 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 is implemented. In contrast, the underlying assumption in the national model is that network capacities within countries are abundant.

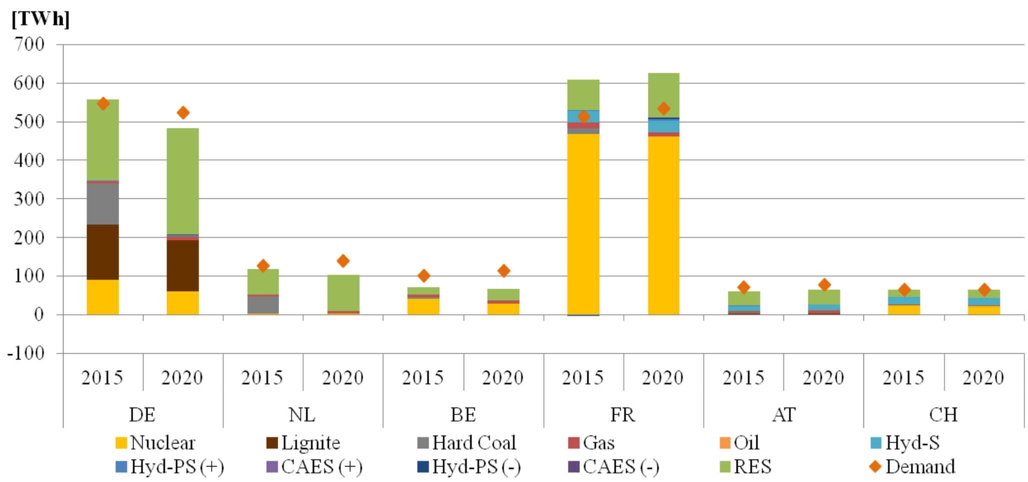
On a national level, both the demand-weighted average nodal costs as

Table 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).

Figure 3: Annual electricity generation in the nodal model in the years 2015 and 2020 per country and technology



Source: Own calculation.

well as the average marginal costs of the copperplates are rather homogeneous such that the maximum difference between countries amounts to no

Table 4: Average marginal costs (AMC) of electricity supply in 2015

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

Source: Own calculation.

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.[1] 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 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

[1]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.

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.[2] 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 (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

[2] 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.

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.[3] 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 5: Average marginal costs (AMC) of electricity supply in 2020

[EUR/MWh$_{\mathbf{th}}$]	**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.

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. The result of the model is a tree 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

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

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).

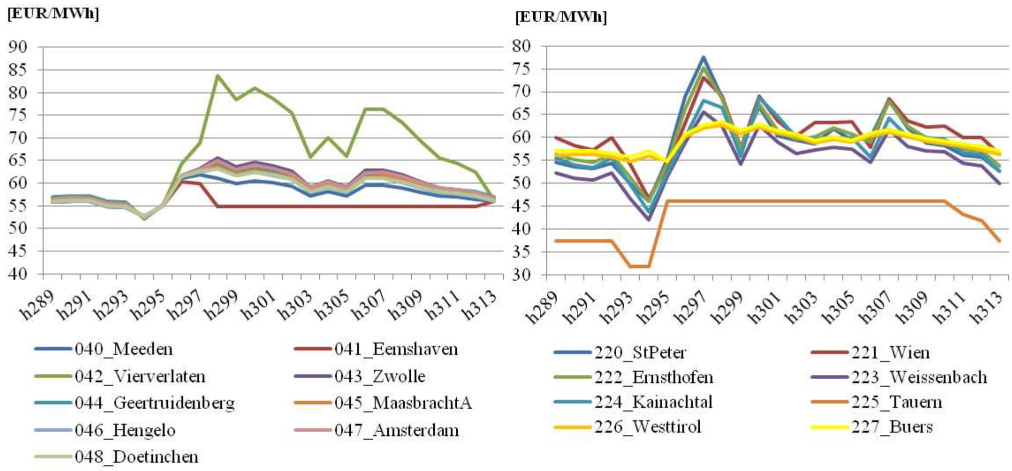
The differences in the quality of the clusters between the clustering stages (cf. equation 2) increases exponentially with the number of steps. Nonetheless, the test for the statistically optimal number of clusters (cf. equation 3) determines a small number of six zones as the optimal configuration for 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 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.[4] As opposed to Vierverlaten, the marginal cost curve of the outlier Tauern is more stable and strictly lower than those of its neighboring nodes due to the high availability of hydro power. Furthermore, the said east-west divide in Austria results in a separation of Tauern from both

[4]As highlighted in table 4 and evident from figure 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.

Eastern Austria and the western nodes Buers and Westtirol (also standing out in figure 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 4: Marginal Costs of a Random Day in the Netherlands (left) and Austria

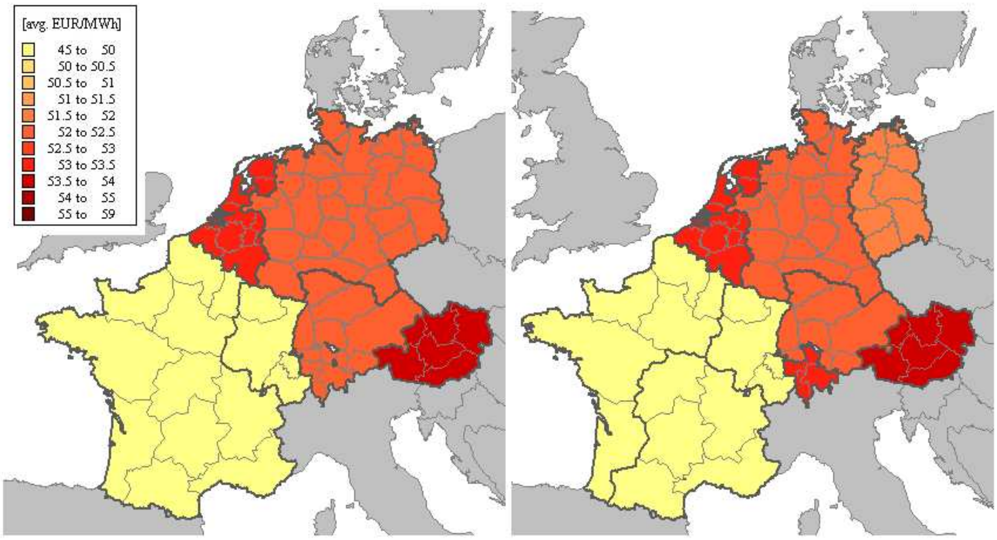


Source: Own calculation.

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 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 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)

Figure 5: Results of the cluster analysis for the model year 2015 with 6 (left) and 9 clusters



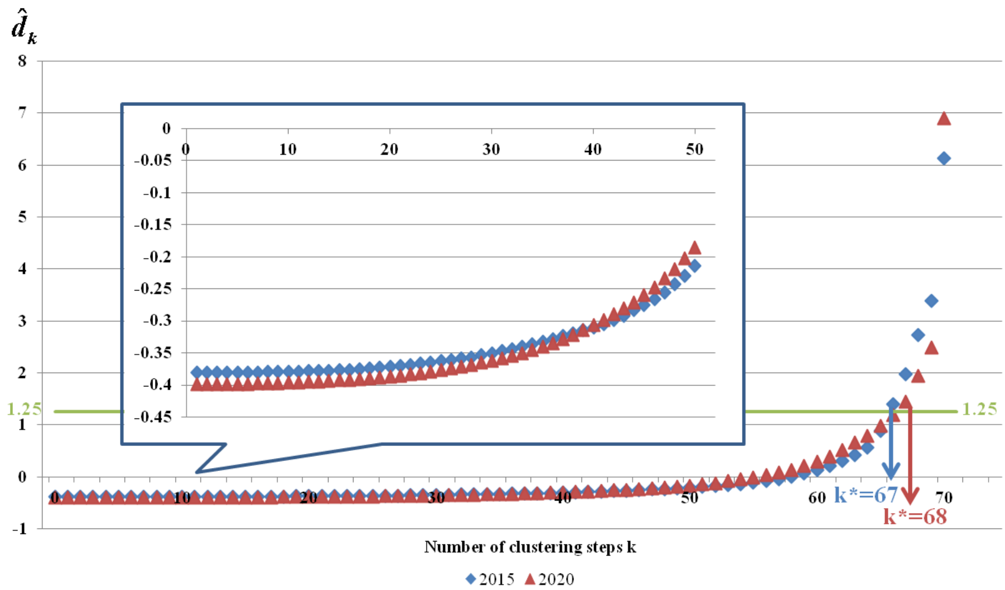
Source: Own illustration.

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 4.1). This is also reflected by the measure of heterogeneity d_k (cf. section 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), 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 6.

The final five-zone design, which again requires a correction for outliers, is given in figure 7. In 2020, these outliers are Vierverlaten (NL) and the new minimum-price node Le Havre (FR) (cf. section 4.1).

In comparison to 2015, the final configuration leads to two instead of one

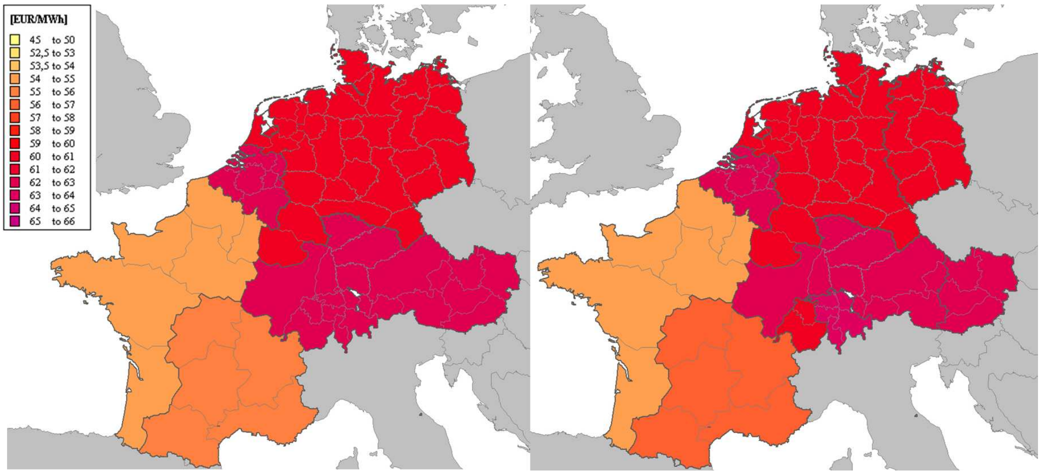
Figure 6: Development of the normalized measure of heterogeneity in the cluster analysis of 2015 and 2020



Source: Own calculation.

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



Source: Own illustration.

4.3. Zonal Dispatch with Redispatch

The bidding zones as described in section 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 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.

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 redispatch algorithm now chooses the least-cost option to relieve congestion. Thereby, *NEULING* can access running power plants for downward redispatch with the exception of units with balancing market obligations. The generating units are ramped down in the order of decreasing cost sav-

Table 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.

ings and decreasing effectiveness with regard to congestion relief. No restrictions on the geographic distance between redispatchable plants and congested lines are imposed, such that perfect cooperation between the control areas is implied.[5] When the conventional potential for downward redispatch is exhausted, RES-E can be curtailed. This option is least attractive since curtailment of renewables does not yield savings in variable generation costs. Concerning upward redispatch, 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 redispatch 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

[5]Joint cross-border redispatch 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.

model saves 741 GWh of redispatch 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 redispatch. Thereby, RES are used for supplementary downward redispatch 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 redispatch 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 redispatch by 1,535 GWh up to 22,430 GWh, now requiring 2,562 GWh of downward redispatch from RES. Congestion occurs in 8,240 hours, curtailment in 3,039 of them. But again, the maximum redispatch 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 redispatch (+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).[6] 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.

4.4. Total System Costs

NEULING provides information on the total costs originating from the wholesale market dispatch and from ex-post redispatch. 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 7 .

Table 7: Total system costs of electricity supply in 2015 and 2020

2015				
[Million EUR]	**Nodal**	**Zonal (9)**	**Zonal (6)**	**CU (6)**
Wholesale	302,962	302,940	302,876	302,807
(CWE+ only)	(144,462)	(144,057)	(143,988)	(144,077)
Redispatch	0	780	957	1,099
Total	302,962	303,720	303,833	303,906
(CWE+ only)	(144,462)	(144,837)	(144,944)	(145,176)
2020				
[Million EUR]	**Nodal**	**Zonal (9)**	**Zonal (5)**	**CU (6)**
Wholesale	293,349	293,156	293,075	293,028
(CWE+ only)	(139,072)	(138,209)	(138,603)	(138,564)
Redispatch	0	1,732	1,962	2,447
Total	293,349	294,888	295,037	295,475
(CWE+ only)	(139,072)	(139,940)	(140,565)	(141,011)

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

[6] 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 redispatch, too.

models is slightly higher (-64 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 293,349 mio. EUR/a in the nodal case to 293,156 and 293,075 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 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 neighbouring regions.

Regarding the costs caused by redispatch in the core regions, a higher number of zones is clearly preferable. Although the amount needed for redispatch in 2015 is only 14% higher in the six-zone than in the nine-zone configuration, costs increase by more than 23%. Analagously, the 7% increase in redispatch measures between 2020's nine- and five-zone models leads to 13% higher costs. This is due to the slope in the redispatch merit order which implies increasing marginal costs. The relative significance of the redispatch 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 144,057 mio. EUR/a and 143,988 mio. EUR/a in 2015's nine- and six-zone cases respectively, redispatch costs amount to 0.5% and 0.7% of the wholesale market costs of the core regions. A further increase in redispatch costs up to 1,099 mio. EUR/a or 0.8% 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 4.2 results in significantly higher redispatch costs, both in absolute and relative terms: Compared to the dispatch-related costs, additional 1.25% and 1.42% fall upon the five- and nine-zone redispatch respectively, while 1.77% are reached in the CU case.

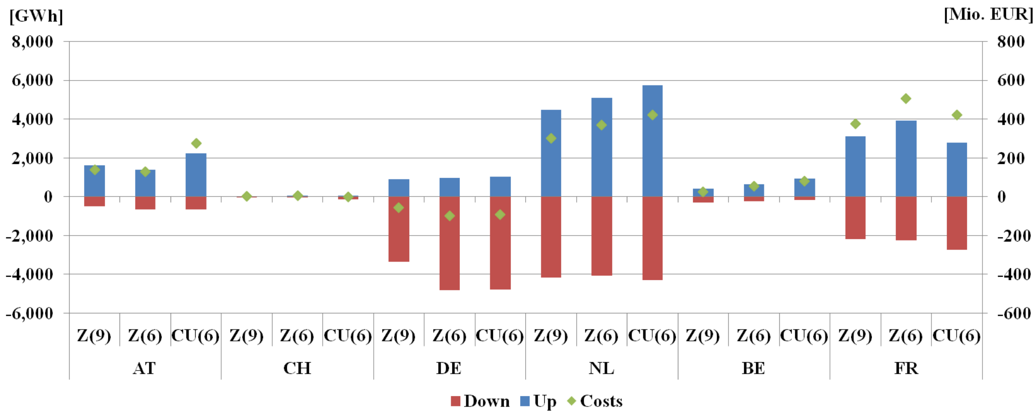
In total, the nodal pricing model is - from a static, cost-based point of view - clearly preferable to the zonal options. Nonetheless, the increase in overall system costs remains negligible in relative terms, although the underlying aggregation is substantial. It also has to be kept in mind that a strict 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 redispatch 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 less 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 8 displays the variations in redispatch 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 redispatch are not allocated symmetrically since internal congestion does not need to be relieved by redispatch within the zones. Instead, the availability of redispatchable 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 4.1), the allocation of expenses and income from redispatch has to be taken into account and may lead to debates on source-related cost allocation.

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.

Figure 8: Redispatch quantities and costs 2015



Source: Own calculation.

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.

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