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Transmission capacity reduction in international power systems: economic incentives and welfare effects

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Abstract

We consider a transmission system operator (TSO) in a zonal international power market and investigate potential economic incentives for reducing transmission capacities on existing interconnectors. We show that, under certain conditions, a TSO that aims to maximize the domestic total welfare has an incentive to reduce the transmission capacity on the international transmission cables to neighboring countries. In contrast with the (limited) literature on this subject, which focuses on incentives through the avoidance of future balancing costs, we show that incentives can exist even if one ignores balancing and focuses solely on the day-ahead market. Our analysis consists of two parts. In the first part, we develop an analytical framework that explains why these incentives exist. Moreover, we distinguish two particular incentive mechanisms: one based on price differences with neighboring countries and one based on the internal electricity price. In the second part, we perform numerical experiments using a model of the Northern-European power system, focusing on the Danish TSO. In 84% of the scenarios tested, we indeed observe economic incentives for capacity reduction, leading to a significant welfare gain for Denmark and welfare loss for the system as a whole. All in all, our paper suggests that economic incentives for capacity reduction may well exist in practice and, if acted upon, can have significant welfare effects.

Keywords: Transmission system operators, transmission capacity reduction, economic incentives, welfare effects

1. Introduction

Electricity transmission cables that connect the electricity grids of different countries or regions are highly valuable elements of the electricity system because they enable regional trade in electricity. Due to differences between regions, mainly in supply conditions associated with differences in, e.g., weather patterns and environmental conditions, electricity may be abundantly available in one region while at the same time being scarcely available in another region. Transmission cables enable electricity to flow from the abundant region to the scarce region. This electricity trade results in the typical welfare gains associated with international trading. In the coming decades, the importance and value of transmission cables will likely even increase, given the electrification trends (e.g., of transport and buildings) as well as the increasing variability of electricity supply associated with the transition to renewable sources like wind and solar. The latter will mean that the differences in scarcity between regions will further increase, tending to increase the welfare gains from trade and, hence, the value of transmission cables.

To realize the welfare gains from electricity trade, the transmission cables need to be utilized efficiently. A key requirement for efficient utilisation is that, beyond physical constraints in the electricity network, all technically available capacity on a transmission cable should be made available for trading. However, it is not evident that transmission cables are always utilized efficiently in this way. European transmission cables are typically jointly owned by the two Transmission System Operators (TSO) operating the regional electricity grid at both ends of the cable. As such, the TSOs have the capability to limit the available import or export capacity at their end of the cable. While existing regulations state that such constraints are only allowed in the case of technical restrictions,¹ it is hard to verify claims of technical restrictions because key information about the network (e.g., regarding expected electricity flows, outages, maintenance) often resides in the private domain of the TSOs.²

The capability to impose inefficient restrictions does not

¹For instance, internal bottlenecks in the regional grid or unscheduled “loop” electricity flows that enter the regional grid from another region.

²In addition, TSOs, including, e.g., the Swedish, Danish and Finnish TSOs, are at times hesitant or reluctant to share network information with (trans-national) regulators (e.g. ACER in Europe), citing, e.g., national confidentiality legislation as motivation [1].

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immediately imply that TSOs also have an incentive to actually impose them. However, there are signals that inefficient restrictions may in fact be implemented in practice. For instance, the Norwegian TSO recently pointed out that the Swedish TSO is applying export restrictions on the cable connecting the southern regions of the two countries and the Norwegian TSO and regulators appear to question to some degree whether these restrictions are strictly necessary for physical constraints [2, 3, 4, 5]. In response to the Swedish export restrictions, while citing reasons of “transparency, reciprocity, and common understanding”, Norway implemented export restrictions at their end of the same cable. Shortly after, both TSOs agreed to partly alleviate these export restrictions again [6, 7]. This example raises the question whether TSOs may benefit from applying inefficient restrictions on the transmission capacity that are not necessary for physical reasons.

The existing literature on the efficiency of TSOs in utilizing transmission capacity is scarce. Many papers investigate (in)efficient behaviour of electricity producers, sometimes with particular attention for the role of transmission capacity [8, 9, 10]. However, very few have focused on the behaviour of TSOs in providing transmission capacity efficiently. We are aware of [11] and [12]. Glachant and Pignon [11] point out that TSOs under the Nordic market regulations have the capability to restrict transmission capacity and, using a stylized model, argue that such restrictions increase the congestion rent earned by the TSO and reduce the national balancing costs. Horn and Tangerås [12] develop a theoretical framework to analyze the incentives of TSOs to reduce transmission capacity under the assumption that TSOs maximize national welfare. Their analysis focuses mostly on the role of the balancing market and includes a proposal for a new market design that eliminates the incentives for TSOs to limit capacity that arise from the current balancing market design.

This paper adds to this scarce strand of literature and investigates whether TSOs have an incentive to apply inefficient restrictions on interconnectors. Specifically, we analyze whether TSOs can increase national welfare, including through congestion rents, by restricting transmission capacity on interconnectors. Rather than focusing on the avoidance of balancing costs, as is done in the literature, we focus on the day-ahead market and explore the potential for increasing national welfare by manipulating domestic and foreign prices through capacity reductions on interconnectors. In addition, we analyze the impact of such restrictions on the distribution of welfare over domestic and foreign consumers, producers and TSOs. Another novelty of our paper is that we study these restrictions numerically, using a realistic model of the Northern-European power system, based on historical data on consumption, production, and price levels, as well as actual interconnection capacities between price zones.

Our analysis consists of two parts. In the first part we provide an analytical framework that illustrates that national welfare-maximising TSOs may have economic incen-

tives to restrict transmission capacity. Using simple illustrative examples, we illustrate two mechanisms through which a TSO can increase national welfare by restricting capacity, one based on creating price differences and inducing congestion rent, and one based on changing the local price and increasing the sum of producer and consumer surplus. In the second part we perform numerical experiments using a model of the Northern-European power system. Based on actual historical data, this power system includes the supply and demand and cross-border transmission grid characteristics of eleven countries that form a meshed electricity network in practice. In the experiments we focus on investigating the incentives for reducing transmission capacity by the Danish TSO, who occupies a central position in the geographical area we consider.

The remainder of this paper is organized as follows. Section 2 provides the analytical framework and discusses mechanisms through which TSOs may increase national welfare with capacity restrictions. Section 3 describes the model of the representative power system as well as the experimental design to analyze the presence and magnitude of the welfare impact of TSO restrictions. The results are discussed in Section 4. Section 5 concludes the paper. Finally, Appendices A and B provide a detailed description of the mathematical model and the data used in the case study, respectively.

2. Analytical framework

This section presents two stylized examples of electricity trade between regions in order to illustrate the potential impact of transmission capacity restrictions on national welfare. In Section 2.1, the first example describes the welfare effects of electricity trade in a setting with two electricity zones. We highlight the standard result that trading increases total welfare of the system as a whole and show that the common EU practice of 50%-50% sharing congestion rents between TSOs on interconnectors can introduce incentives for TSOs to impose trade restrictions that increase the national welfare of their hosting country, while reducing the overall welfare of the system as a whole. The latter is because restrictions may increase price differences and thus congestion rent and this may outweigh reductions in the sum of domestic consumer and producer surplus. Section 2.2 adds a third region to the previous setting and discusses two additional examples. The first example is brief and describes that the mechanism of the two-zone case still applies with three regions. The second describes another mechanism by which capacity reductions can increase local welfare in a zone, based on reducing local prices and increasing consumer surplus through preventing one neighbor from exporting through the zone to another neighbor.

2.1. Two-zone case

This example assumes that two zones $i = 1, 2$ exist with distinct electricity grids consisting of electricity producers

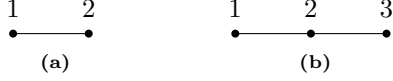


Figure 1: Schematic illustration of two-node and three-node electricity systems.

and electricity consumers, represented respectively by the linear supply and demand curves $S_i(p_i)$ and $D_i(p_i)$ (S and D are the quantity of supply and demand, respectively, and p is the price). Figure 1a displays this electricity system schematically whereas Figure 2 displays the supply and demand curves in the two zones. Furthermore, we assume that the market is characterized by perfect competition.

Without trade, the equilibrium market outcome is determined by the point of intersection of the local supply and demand curves. Define the equilibrium price and quantity for zone i by $p_i = p_i^*$ and $q_i = q_i^*$, respectively. Notice in Figure 2 that $p_1^* > p_2^*$. This price difference implies that producers in zone 2 would happily supply electricity to zone 1 and consumers would happily buy from them, provided this was possible.

A transmission cable connecting the two zones enables trade between suppliers and consumers in the different regions. The willingness of consumers in zone 1 to import from zone 2 can be represented by an import curve $I_1(p_1) = D_1(p_1) - S_1(p_1)$. For each price, this curve provides the quantity I_1 that consumers in zone 1 are willing to consume in excess of what local producers are willing to supply, i.e. import. In an equivalent fashion, the willingness of consumers in zone 2 to export to zone 1 can be represented by an export curve $E_2(p_2) = S_2(p_2) - D_2(p_2)$. This curve provides the quantity E that suppliers are willing to produce after domestic demand has been satisfied, i.e. export. Figure 3 displays these import and export curves. In line with the common practice on interconnectors in the EU, we assume here that the direct financial benefit associated with electricity trade, i.e. the congestion rent CR , is divided equally among the two TSOs that operate the grids in the connected zones. CR is equal to the difference in the market price between two connected zones, multiplied by the quantity exported through the cable.

The market equilibrium with unrestricted trade – i.e., assuming that a transmission cable with unlimited capacity connects the two zones – is given by the point of intersection of the import and export curves, i.e., $I_1 = E_2$, yielding a price and trade quantity of \bar{p} and \bar{y} , respectively. Unrestricted trade implies full market integration with $\bar{p} = p_1 = p_2$, for otherwise arbitrage opportunities would remain. Notice that, with unrestricted trade, the price difference between the zones is zero, implying $CR = 0$.

Trade increases total welfare in the combined electricity system, as can be illustrated with Figures 2 and 3. As per convention, define consumer surplus (CS) as the difference

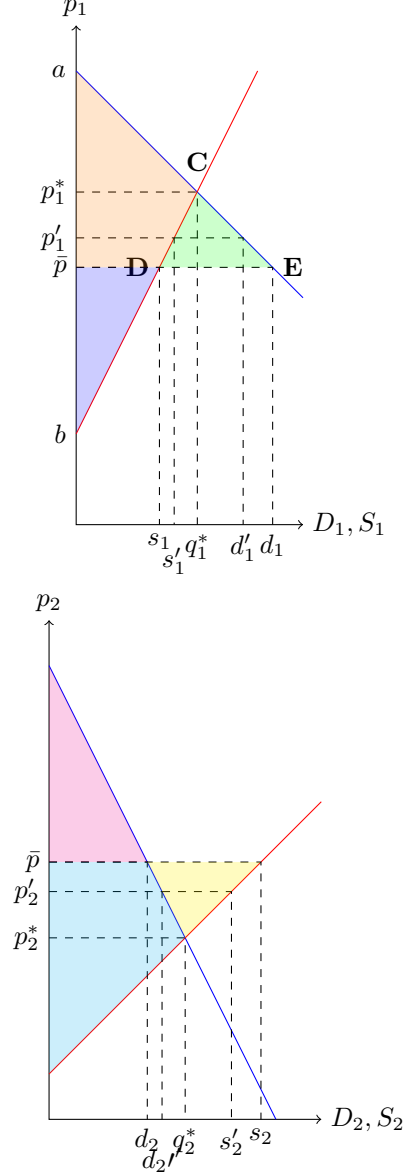


Figure 2: Supply and demand curves and economic surplus in the two-node case.

between consumer willingness to pay and the market price aggregated over consumption (i.e. the area below the demand curve and above the market price in Figure 2); define producer surplus (PS) as the difference between the minimally-required producer price and the market price aggregated over production (i.e. the area above the supply curve and below the market price); and define total welfare in zone i (TW_i) as $TW_i = PS_i + CS_i + CR_i$. In zone 1, unrestricted trade decreases the local market price from p_1^* to \bar{p} , which increases consumer surplus (the area below the demand curve and above the price, i.e., to the orange and green areas) and decreases producer surplus (the area above the supply curve and below the price, i.e.,

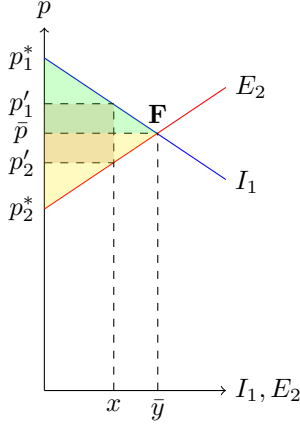


Figure 3: Import/Export graph for the two-node example.

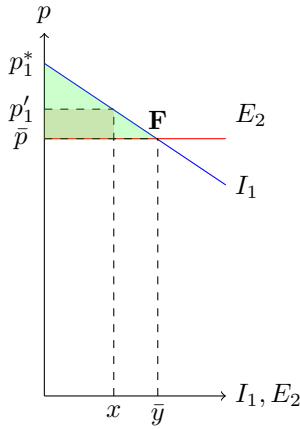


Figure 4: Import/Export graph for the two-node example with a horizontal export curve.

to the blue area).³ The increase in CS_1 is greater than the decrease in PS_1 , as the decrease in the latter fully transfers to the former, and CS_1 rises beyond that. The ‘excess’ increase in CS_1 is in the graph represented by the green triangle and this equals the increase in TW_1 and thus to the benefits from trade in zone 1. In Figure 3, the increase in TW_1 is equivalently represented by the area below the import curve and above the market price, i.e., the same green triangle.

The mechanisms in zone 2 are identical but the effects differ. Here, the local market price increases such that PS_2 increases and CS_2 decreases. In similar fashion as in zone 1, the increase in PS_2 outweighs the decrease in CS_2 , thereby increasing TW_2 . In the figures, this welfare increase is represented by the yellow triangle. With both TW_1 and TW_2 increasing, aggregate system welfare also increases as a result of trade through the interconnector.

If the capacity on the interconnector is reduced such that the capacity of the cable becomes a binding constraint

and prices cannot equalize, aggregate system welfare is unequivocally reduced. This can be most easily illustrated with Figure 3. Suppose that one of the TSOs decides to limit the capacity on the interconnector, say to x . The interconnector capacity then becomes a binding constraint and prices cannot equalize between the two zones, implying that local prices p'_1 and p'_2 emerge. This reduces the sum of CS and PS in both zones. In Figure 3, for zone 1 (zone 2), the reduction equals the shaded green (yellow) area plus the green (yellow) triangle to the right of the shaded green (yellow) area. Part of this reduction in welfare, however, is ‘recouped’ in the form of an increase in congestion rent, which increases from zero to $(p'_1 - p'_2)x$. This is reflected by the two shaded rectangles, of which both TSOs obtain half. The reduction in system welfare, or deadweight loss, is equal to the triangle in between the import and export curves and to the right of the shaded rectangles.

In the current case with symmetrical import and export curves, for both zones, the increase in the congestion rent that they obtain (half of the brown rectangle) is smaller than the decrease in the sum of local consumer and producer surplus. This means that local welfare decreases in both zones and both TSOs can thus not increase local welfare by reducing capacity on the interconnector. This last point, however, is not always true.

To illustrate that local welfare can increase from a capacity reduction on the interconnector, imagine that E_2 is a flat horizontal curve at level \bar{p} , corresponding to a zone 2 supply curve with constant marginal costs and infinite production capacity.⁴ Figure 4 shows the import and export curves in this new situation. Without restrictions, the efficient level of trade is still given by \bar{y} with an integrated price level of \bar{p} . Note that, in this case, trade over the interconnector improves welfare in zone 1 but leaves it unaffected in zone 2.

Consider the same capacity restriction as before on the interconnector, to level x . This would result in a price increase in zone 1 to p'_1 , while the price in zone 2 remains \bar{p} . Hence, while $CS_2 + PS_2$ remains unaffected, $CS_1 + PS_1$ is reduced due to the constraint. In Figure 4, this reduction is equal to shaded rectangle and the green triangle to the right of it. Part of this reduction in welfare is again compensated by an increase in aggregate CR , from zero to $(p'_1 - \bar{p})x$. Both TSOs obtain half of this, meaning that total welfare decreases in zone 1, as well as in the aggregate system, but increases in zone 2. Hence, the TSO in zone 2 has an incentive to reduce capacity from the efficient level, thereby creating a difference in prices between the zones and increasing congestion rent and local welfare.

We point out that reducing capacity (under the prevailing profit-sharing rules) in this mechanism can only

³Specifically, CS_1 decreases from the triangle ap_1^*C to the triangle $\bar{p}Ea$, and PS_1 decreases from the triangle bCp_1^* to the triangle $bD\bar{p}$.

⁴The mechanism could equivalently be illustrated with a flat horizontal import curve. However, as this requires consumers to be willing to consume infinite amounts of electricity at a certain price threshold, this appears less likely in practice than a flat horizontal export curve.

increase local welfare if 50% of the induced congestion rent exceeds the decrease in the sum of local of consumer and producer surplus. This depends on the supply and demand conditions and the resulting import and export curves. In principle, reducing capacity by a TSO will tend to increase local welfare as long as the change in the local price is relatively small (implying small changes in local PS and CS) and the change in the foreign price is relatively large (inducing a large price difference and thus high CR). This mechanism hinges on creating price differences with neighboring zones. While this mechanism only pertains to certain supply and demand conditions, a key lesson is that equal profit sharing on interconnectors can introduce incentives for TSOs to impose capacity restrictions that harm aggregate system welfare.

2.2. Three-zone case

Next we use a setting with three zones to show that a more complicated network can introduce additional incentives for limiting transmission capacity. It is not hard to show that the mechanism based on increasing price differences illustrated in the two-zone case can still hold in the three-zone case. Here, we focus on different incentives that only exist in a network with more than two zones, based on manipulating the domestic price and increasing the local sum of producer and consumer surplus.

The next example illustrates that causing price differences and inducing congestion rent is not the only relevant mechanism through which restrictions can increase local welfare. Here, a restriction by the TSO also reduces the local price, thereby increasing local consumer surplus.

This example assumes that a region located between two other (otherwise isolated) regions imports from one region and exports to the other region. In terms of Figure 1: region 1 is an export region without local demand and with supply that is characterised by increasing marginal costs. Specifically, its supply curve is given by $S_1 = p_1$, where S is the quantity supplied. Regions 2 and 3 are identical consuming regions with no supply, characterised by the demand curves $D_2 = 5 - \frac{1}{2}p_2$ and $D_3 = 5 - \frac{1}{2}p_3$, respectively. Given its location, region 2 may export its imports from region 1 to region 3.

In the initial situation with unrestricted trade, electricity can flow freely between regions. The three regions essentially form an integrated market with a single price ($p = p_1 = p_2 = p_3$), where supply is given by S_1 and aggregate demand $D = D_1 + D_2 = 10 - p$. The market equilibrium is given by the solution to $S = D$, which yields an equilibrium price $p = 5$ and quantity $S = D = 5$ with $D_1 = D_2 = 2\frac{1}{2}$.

Suppose now that region 2 imposes a binding restriction on the capacity of the interconnector to region 3, say to a capacity of 2. This implies that, at prices below 6, the point where $D_3 \geq 2$, the cable becomes congested and the markets disintegrate into two zones with separate prices, one formed by regions 1 and 2 (with $p_1 = p_2 = \tilde{p}$) and one by region 3. While aggregate market demand faced by the

producer in region 1 is still given by $D = D_2 + D_3$, this now consists of two segments: $D = 10 - \tilde{p}$ when $\tilde{p} \geq 6$ and $D_3 \leq 2$, and $D = D_2 + 2 = 7 - \frac{1}{2}\tilde{p}$ when $\tilde{p} \geq 6$ and $D_3 \geq 2$. From the unrestricted case, we know that the equilibrium outcome to $S = D$ does not satisfy the constraints pertaining to the first segment. Focusing on the solution pertaining to the second segment, $S = D$ implies $\tilde{p} = 7 - \frac{1}{2}\tilde{p}$ for the (still integrated) regions 1 and 2. This yields an equilibrium price and quantity of $\tilde{p} = 4\frac{2}{3}$ and $S = D = D_2 + D_3 = 2\frac{1}{3} + 2 = 4\frac{2}{3}$. In region 3, with the cable congested and thus $D_3 = 2$, the local price becomes $p_3 = 6$. Summarizing, the restriction reduces consumption region 3 and increases consumption in region 2. On an aggregate system level, the restriction results in a reduction in consumption/production. Regarding prices, in line with the local quantity changes, the price in regions 1 and 2 decreases while it increases in region 3. Furthermore, the price difference results in congestion rent on the interconnector between regions 2 and 3 of $CR = (p_3 - \tilde{p})D_3 = (6 - 4\frac{2}{3})2 = 2\frac{2}{3}$ on aggregate, and $CR_2 = CR_3 = 1\frac{1}{3}$.

The welfare effects of region 2's restriction are the following.⁵ In the supply region 1, $\Delta TW_1 = \Delta PS_1 = -(5 - 4\frac{2}{3})4\frac{2}{3} - \frac{1}{2}(5 - 4\frac{2}{3})(5 - 4\frac{2}{3}) = -\frac{3}{2} = -1.5$. Hence, local welfare in region 1 is reduced. In region 2, $\Delta TW_2 = \Delta CS_2 + \Delta CR_2$. $\Delta CS_2 = (5 - 4\frac{2}{3}) + \frac{1}{2}(4\frac{2}{3})(2\frac{1}{3}) = \frac{31}{36}$. Hence, $\Delta TW_2 = \frac{31}{36} + 1\frac{1}{3} \approx 2.19$. Local total welfare in region 2 is thus higher than before the restriction. In region 3, $\Delta TW_3 = \Delta CS_3 + \Delta CR_3$. $\Delta CS_3 = -(6 - 5)2 - \frac{1}{2}(6 - 5)(2\frac{1}{2} - 2) = -2\frac{1}{4}$. Hence, $\Delta TW_3 = -2\frac{1}{4} + 1\frac{1}{3} = -\frac{11}{12} \approx -0.92$. Local total welfare in region 3 is also lower than before the restriction. $\Delta TW = \Delta TW_1 + \Delta TW_2 + \Delta TW_3 \approx -1.5 + 2.19 - 0.92 = -0.23$. As a consequence of the restriction, total welfare in regions 1 and 3 increases whereas it decreases in region 2. This thus illustrates that the TSO in region 2 can successfully increase local welfare by restricting capacity on the interconnector with region 3. The increase in welfare is partly due to higher congestion rent, much in line with the mechanism from the previous example, but also to a considerable extent due to a lower local price and higher associated consumer surplus. The higher welfare in region 2 goes at the expense of local welfare in the other regions and total welfare in the aggregate system, illustrating the undesirability of unnecessary capacity restrictions on interconnectors.

3. Case study

In this section we study capacity reduction incentives and corresponding welfare effects in a case study of the Northern European electricity market. The purpose of this case study is to provide a numerical illustration of

⁵Graphical support for this example in the form of conventional supply and demand schedules is not yet included in this draft and will be added.

the theoretical mechanisms outlined in Section 2. We are interested to see if the capacity-reducing behavior we theorized is observed in a model using realistic data. Moreover, if so, we are interested in analyzing the welfare effects such capacity restrictions have.

3.1. Model description

In order to describe the model used in our case study we first describe the situation we aim to model. We consider part of the Northern European transmission network. Specifically, we consider the twelve countries (Austria, Belgium, Czech Republic, Denmark, France, Finland, Germany, the Netherlands, Norway, Poland, and Sweden) colored green in Figure 5. These countries are integrated into the European electricity market, which is based on a zonal market structure. Each country is made up of one or several price zones. In each price zone electricity is traded in the day-ahead market at a single zonal price. Every time period, market participants log orders in the day-ahead market indicating how much they are willing to buy or sell at all potential prices. These orders are translated into an aggregate supply and demand curve per price zone. Matching these curves in all zones simultaneously, taking into account the possibility of transmitting electricity through interconnectors between different price zones, a market solution is found with a corresponding market clearing price in each price zone. Every actor in the market that indicated a willingness to buy or sell at this price is then bound to do so.

Our model (which is heavily based on the model in [13]) is aimed to be an accurate reflection of this day-ahead market. First, we define a graph, illustrated in Figure 6 that represents the underlying geographical network. Every node in the graph corresponds to a price zone in the day-ahead market, while every edge represents interconnector capacity between neighboring price zones. The actors in the day-ahead market are modeled as follows. Buyers on the market are represented by a representative consumer that tries to maximize its consumer surplus, defined as the area under its demand curve. The relevant demand curves are estimated based on historical consumption and price data. Sellers on the market are modeled as individual profit-maximizing generating companies. The profit-maximization problem determines how much each generating company is willing to supply at each price, i.e., it implicitly determines a supply curve. Adding a market coupling constraint that matches net supply and net demand in each node (and adding a “dummy” market operator that sets the flows on the interconnectors), these consumer and producer optimization problems together constitute an equilibrium model. Clearing the day-ahead market is equivalent to solving this equilibrium problem.

To solve the equilibrium problem, we first formulate it as a so-called mixed-complementarity model (MCP) [14] by combining the Karush-Kuhn-Tucker optimality conditions of all individual optimization models. It turns out that this MCP can be reformulated as a single quadratic

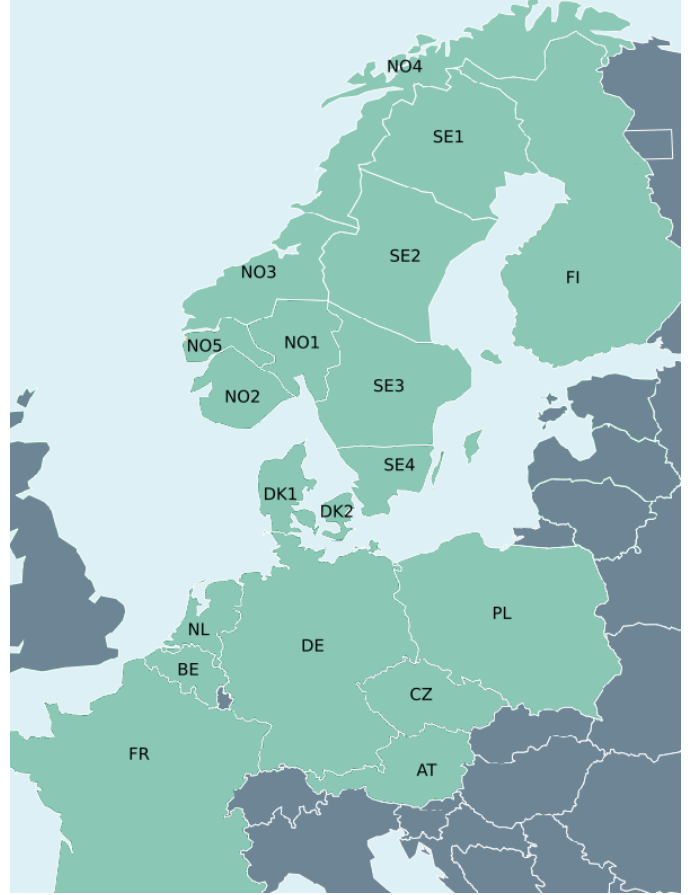


Figure 5: Map of all price zones considered in the case study.

optimization model, which can be solved using standard optimization packages such as Gurobi. When a solution is obtained, market-clearing prices are generated and corresponding welfare statistics can be computed straightforwardly. Here, we assume that the congestion rent earned on a line connecting two nodes is equally distributed over the two nodes, in line with typical agreements used in practice [15]. See Section A in the appendix for a detailed description of our mathematical model and its reformulation.

To obtain a realistic representation of the Northern European power market, we use historical data from this region as input data for our model. Specifically, we use historical data to (1) determine physical capacities of interconnectors, (2) determine production capacities of dispatchable generators, (3) obtain production patterns for solar and wind power, and (4) estimate demand curves based on estimated price elasticities and historical consumption and prices. For parameters that vary over time (e.g., renewable production), scenarios have been generated based on historical weeks. For a full description of the data used in the case study, see Section B in the appendix.

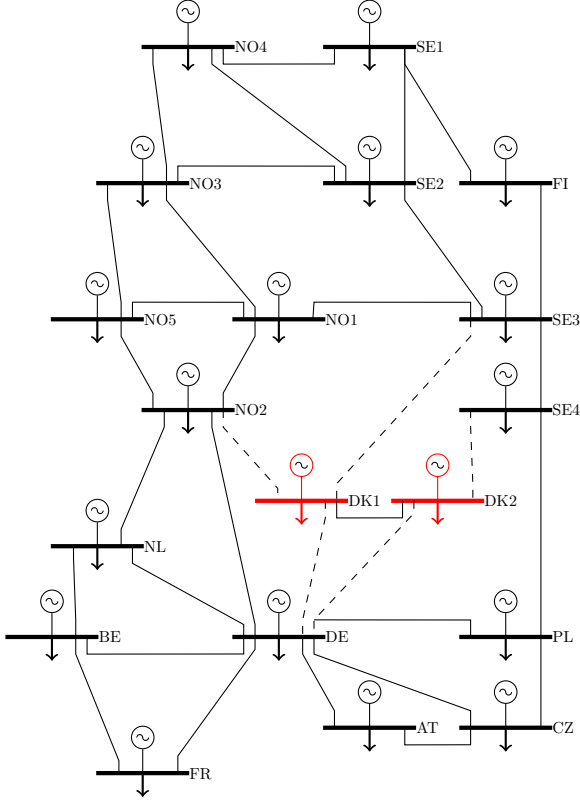


Figure 6: Underlying graph representation of the power system used in the case study. Danish nodes are colored red; interconnectors from Danish nodes to neighboring nodes are indicated by dashed lines.

3.2. Model validation

We now shortly discuss the validity of our model. From a structural point of view our model very closely resembles the actual Northern-European electricity market. The zonal division and interconnectors exactly match the actual market. Moreover, the market dynamics as modeled in our mathematical formulation closely resembles the design of the actual European electricity market: producers and consumers bid their supply and demand curves, respectively, after which a central market authority clears the market by picking prices that equate supply to demand in every node. Hence, structurally, we are quite confident in the validity of our model.

The main structural difference between our model and the real power system is the fact that we only include a selection of European countries. However, as we focus on Denmark in our analysis, we made sure to include all of Denmark’s neighboring countries and most of its neighbors’ neighbors. Thus, we believe the resulting network to be a reasonable representation of the power market around Denmark.

Accurate parametrization of our model is a somewhat more challenging task. While demand curves can be estimated based on available consumption and price data and estimates for the price elasticity of demand (see Section B in the appendix for more details), estimation of producers’

supply curves (i.e., their marginal costs) is harder, since we are not aware of data on historical supply curves bid in the market. Instead, we used estimates of marginal costs, partially based on historical prices of coal and gas (again, see Section B in the appendix for more details). Though we made use of the most accurate data available, these estimates inevitably lead to some errors in the parametrization of the model.

However, for our purposes we don’t need an *exact* representation of the historical power system. We only need to populate our model with *realistic* scenarios, in the sense that they represent the overall dynamics in the power market to a sufficient degree. To test this, we plot so-called *price-duration curves*. These curves show, for a given node, the distribution of the price over all scenarios (sorted from high to low). In Figure 7 we present the price-duration curves for the most relevant nodes in our model: the Danish nodes (DK1, DK2) and its neighboring nodes. We observe that in all nodes, the historical and the model price-duration curve are reasonably close. The only significant differences are observed in the tails of the distribution: in most nodes, the tails of the distribution are somewhat more extreme in the historical data than in our model. We believe that a main reason for this is the fact that in reality there is likely more variability in marginal costs than we capture in our data. All in all, however, we believe the price-duration curves do show a good fit, which gives us confidence that our model provides a realistic representation of the Northern-European energy system.

3.3. Experimental design

We give one country in the network the option of reducing the export capacities on its international interconnections. In this case study, we choose Denmark, consisting of bidding nodes DK1 and DK2 (colored red in Figure 6). The reason for choosing Denmark is its interesting location, between Scandinavia and mainland Europe. Denmark functions as a bottleneck for transmission between these two regions. Hence, it could potentially show both types of capacity reduction behavior described in Section 2: monopolist behavior and middle-man behavior. This makes Denmark an interesting candidate to consider in our numerical study.

We run various experiments to investigate whether the Danish TSO has incentives for capacity reduction and what the corresponding welfare effects are. In total, we run 100 experiments, each corresponding to a scenario based on one week of historical data from the years 2016–2020. The scenarios are divided into four seasons (“spring”: Mar–May, “summer”: Jun–Aug, “autumn”: Sep–Nov, “winter”: Dec–Feb) with 25 associated scenarios each. Each scenario is divided into hours, such that every experiment consists of $7 \times 24 = 168$ time periods.

In every experiment, Denmark has the option of reducing the capacity on each of the lines connecting Denmark with foreign price nodes: DK1-NO1, DK1-NO2, DK1-SE3,

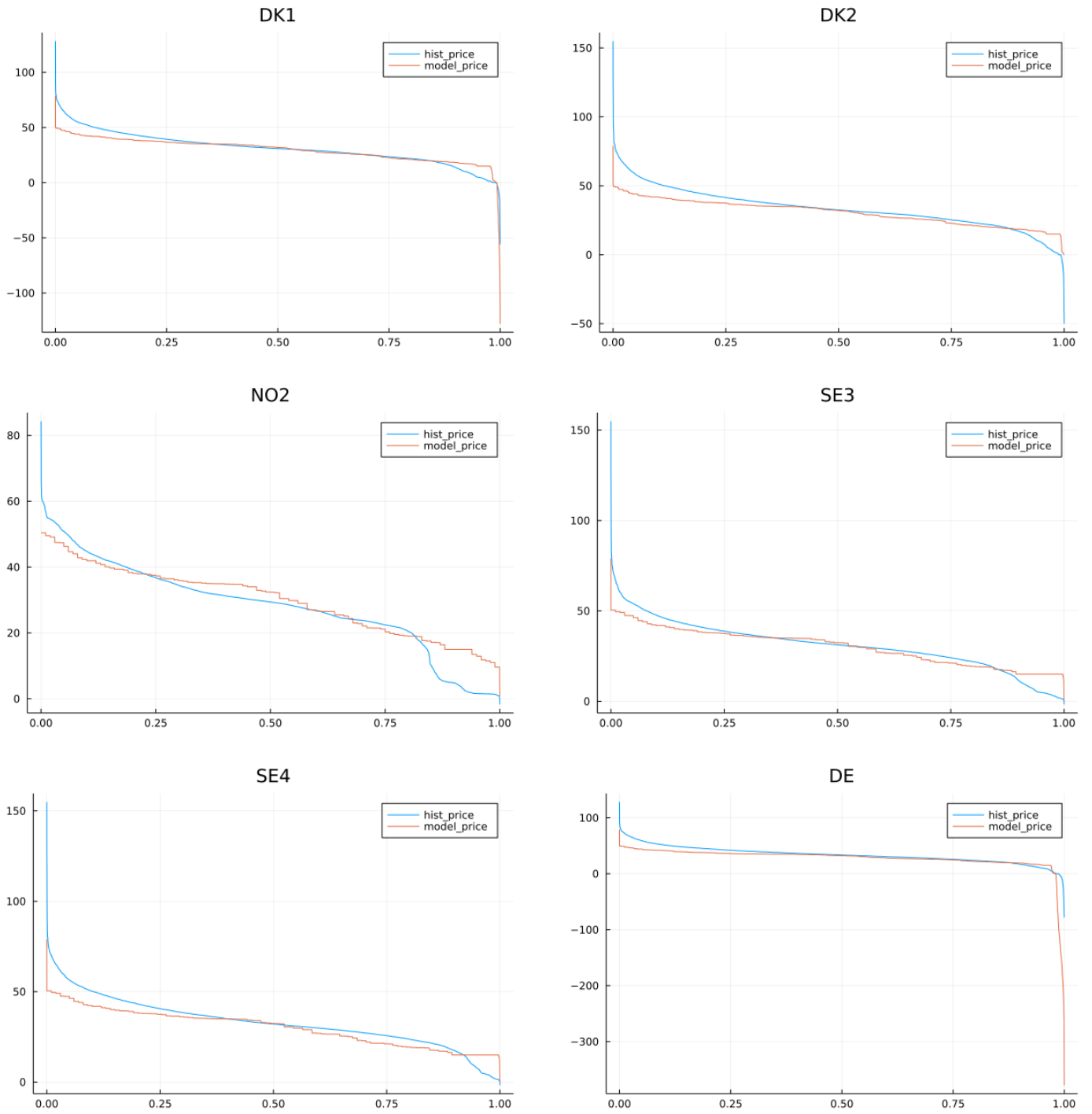


Figure 7: Price-duration curves for several nodes.

DK1-DE, DK2-DE, DK2-SE4 (the dashed lines in Figure 6). A capacity reduction limits both import and export capacity simultaneously. The purpose of this assumption is to keep the search space limited. As the planning horizon is limited (one week), we expect flow through a given cable to be flowing in the same direction in most periods, as the relative scarcity of power in different nodes are strongly temporally correlated. Hence, we expect the effect of this assumption to be mild, and in any case to lead to an *underestimation* of incentives for capacity reduction.

For each connection, we consider three possible capacity levels: 0%, 50%, and 100% of the maximum capacity. Note that a capacity reduction of 50% is of the same order of magnitude as the reductions observed in the Sweden-Norway conflict motivating this research. We do not consider a higher number of capacity levels for computational reasons: in our computations we perform a full enumeration of all possible capacity combinations, which grows exponentially in the number of capacity levels considered. With five connections and three capacity levels, we have $3^5 = 243$ combinations, which is computationally feasible.

In every experiment, we run the model for each of the possible combinations of capacity levels. We then compute the corresponding welfare measures for all countries and pick the capacity reduction combination that results in the highest total welfare for Denmark. Note that this assumes that the Danish TSO has full information of the upcoming week. This may lead to an overestimation of Denmark’s ability to adjust its capacity reduction levels to the observed market conditions. However, this effect is mitigated by a number of factors. First, we only allow a *single* level of capacity reduction for each interconnector for the entire planning horizon. This is a great limitation compared with reality, where capacity reductions can differ every hour. Thus, in our model, Denmark can only use *aggregate* information about the planning horizon to make its decision. We believe that with this restriction, the advantage of having full information is greatly mitigated: it is not unreasonable to assume that in reality, the aggregate market situation in the upcoming week can be predicted quite accurately. Second, the fact that we only allow three capacity reduction levels for each interconnector also limits the Danish TSO’s ability to adjust the capacity reduction levels to the information it has. All in all, we believe it is reasonable to think that the restrictions put on the Danish TSO outweigh its advantage of having full information of the future. Hence, we do not expect our results to exaggerate the economic incentives for capacity reductions.

4. Results

This section discusses the results of our numerical experiments. First, we focus on our main question: does the Danish TSO have economic incentives to reduce transmission capacities on its international interconnectors? The short answer is: in most cases, it does. Out of the 100

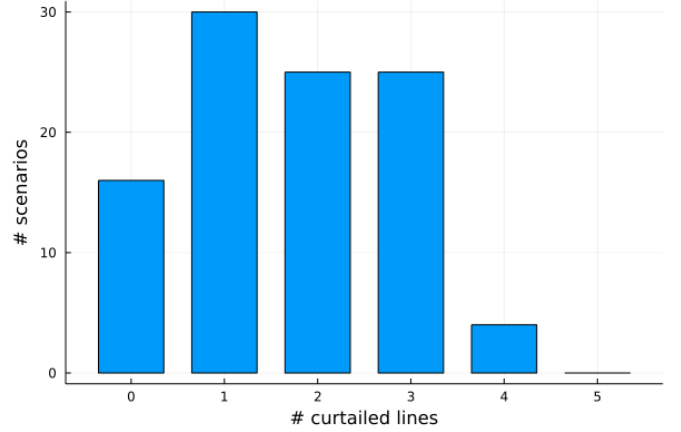


Figure 8: Histogram of the number of curtailed lines in each scenario.

Table 1: Average capacity usage over all scenarios for each line connected to Denmark.

Line	Avg. capacity usage
NO2-DK1	72%
SE3-DK1	75.5%
SE4-DK2	82%
DK1-DE	77%
DK2-DE	46.5%

weekly scenarios tested, in 84 scenarios the TSO was able to increase the Danish total welfare by means of capacity reductions. Hence, in the majority of cases, the TSO does have economic incentives for at least some level of transmission capacity reduction. This statistic alone provides evidence that the theoretical incentives outlined in Section 2 may indeed be present in real-life energy markets. An interesting next question is how significant these incentives are. We will answer this question in two ways.

First, we investigate the *levels* of capacity reduction. In Figure 8 we plot a histogram of the number of curtailed lines: interconnectors that have some amount of capacity reduction. We already noted that in 16 out of the 100 scenarios, the best choice for the Danish TSO is to operate all interconnectors at their maximum level, i.e., to curtail zero lines. In most scenarios, however, it is optimal to curtail either 1, 2, or 3 lines by some amount, while in a few scenarios curtailing 4 lines is optimal.

How these curtailments are distributed over the five interconnectors is illustrated in Figure 9. We observe that while most lines are curtailed in about a quarter of the scenarios, the line from DK2 to DE is curtailed in over half the scenarios. These findings are also reflected in Table 1, which shows that most lines are used at approximately three quarters capacity on average, while DK2-DE is used at less than half of its capacity on average.

Another insight from Figure 9 is that if some amount of curtailment of a line is desired, then in most cases a

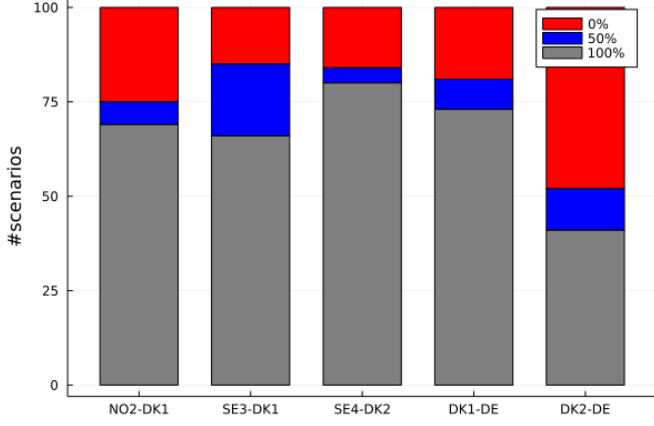


Figure 9: Plot of the level of curtailment of each line over all scenarios.

Table 2: Table of average welfare changes over all scenarios per country (in thousands of euros).

Country	ΔTW	ΔCS	ΔPS	ΔCR
DK	444	148	224	71
NO	-141	-5148	4969	37
SE	-655	-5044	4349	39
FI	-399	-686	538	-250
DE	25	803	-818	40
NL	58	22	-26	62
BE	-21	-74	57	-5
FR	-23	-170	185	-37
AT	5	108	-104	1
CZ	-11	-3	2	-10
PL	131	-85	84	133
Total	-587	-10128	9460	81

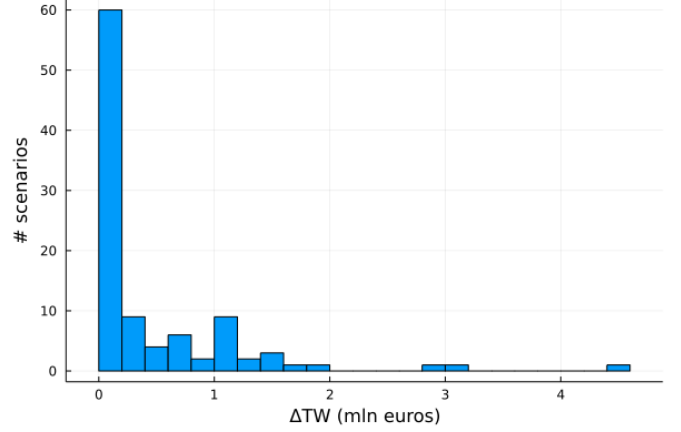


Figure 10: Histogram of the increase in total welfare for Denmark in each scenario.

reduction to 0% capacity is preferred over a reduction to 50% capacity. Hence, whenever incentives for curtailment exist, they tend to steer towards extreme levels of curtailment. This suggests that these incentives, if acted upon, may have significant effects on the resulting power market.

Second, we study the *welfare effects* of the optimal capacity reductions. Focusing on Denmark first, we see in Table 2 that on average, the possibility of reducing transmission capacities leads to a total welfare increase for Denmark of 444 thousand euros per scenario (i.e., per week). To put this number in perspective, we compare it with economic value of all power traded in Denmark⁶. We compute this value by multiplying all production and consumption in Denmark by the corresponding zonal prices, aggregating this over the entire week, and dividing it by two (to correct for double counting of production and consumption). The Danish total welfare increase then amounts to 2.72% of this economic value. We believe this could be significant enough in practice to catch the attention of a TSO and potentially cause it to change its behavior.

Figure 10 provides insight into the distribution of the Danish welfare increase. It shows that, while in most scenarios the welfare gain is modest (less than 200 thousand euros per week), in the tail of the distribution the welfare gains may go up to over 4 million euros per week. Hence, in a small, but non-negligible amount of cases, the TSO has an especially significant incentive to reduce transmission capacity.

⁶We prefer this approach over expressing the welfare change as a percentage (i.e., compared to the total welfare itself) for the following reason. To express the welfare change as a percentage, one would need to compute the total welfare. Part of this is the consumer surplus, which has two issues: first, it is extremely large due to the essential nature of the electricity (i.e., due to the low price elasticity); second, to compute it, one would need to estimate the entire demand curve, which is very hard. Our approach estimates the demand curve around a historical price-quantity point. This provides a reasonable *local* estimation of the demand curve (which is all we need for our purposes), but is unreliable for estimating the entire demand curve.

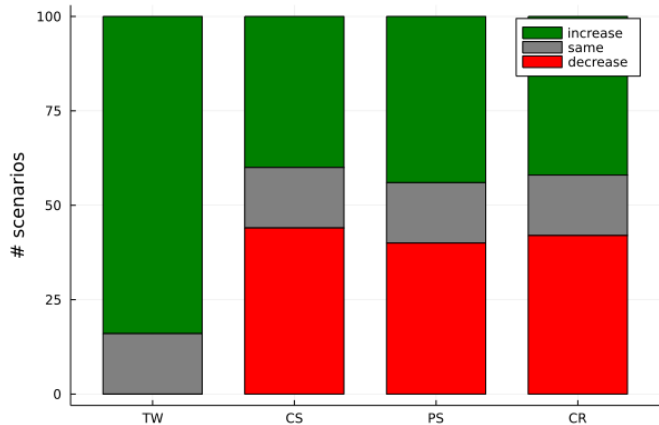


Figure 11: Plot indicating the direction of change for four Danish welfare measures over all scenarios.

Returning to Table 2, we now focus on the welfare effects on *other countries*. We find that the Danish capacity reduction especially affects the welfares of the Nordic countries Norway, Sweden, and Finland. These countries are all negatively affected by the capacity reductions, mostly due to decreased consumer surplus (i.e., due to higher prices). Most other countries are only moderately affected, except for Poland, which profits in terms of congestion rent earned by exporting to SE4 in periods where Nordic countries have excessively high prices. In sum, the entire market suffers from the capacity reductions. The total welfare loss in all countries combined is larger than the welfare gain in Denmark. This shows that this behavior is indeed detrimental to the system as a whole.

Finally, we move to the question of what *mechanisms* cause the welfare increases in Denmark. In Section 2 we discussed two main types of mechanisms: those based on internal prices (related to consumer surplus and producer surplus) and those based on price differences with neighboring nodes (related to congestion rent). In Figure 11 we plot the direction of the change of welfare and its constituent parts for Denmark. While the total welfare increases in most scenarios, the direction of change of its constituent parts is approximately split 50/50. This suggests that the mechanism for welfare increase (through a higher internal price, lower internal price, or higher price differences with external nodes) differs per scenario. So none of the incentive mechanisms dominates the others, but the particular mechanism driving incentives for capacity reduction depends on the situation at hand.

This finding is confirmed when we study individual scenarios. In Figure 12–14 we present the results of three different scenarios that each achieve a welfare increase through different means. In Figure 12 a welfare increase is achieved by a lower internal price, leading to a higher consumer surplus (while producer surplus and congestion rent are lower). In contrast, in Figure 13 a welfare increase is achieved through a higher internal price, with the

other two measures being lower, and in Figure 14 there is a larger price difference with external nodes, leading to a higher congestion rent, but lower producer and consumer surplus. We conclude that indeed, different mechanisms for welfare increase may occur in different scenarios.

5. Conclusion

We consider a zonal international power market and investigate potential economic incentives for TSOs to reduce transmission capacities on interconnectors. In contrast with the (limited) literature on this topic, which focuses on the possibility of TSOs to avoid balancing cost by reducing transmission capacities, we ignore operational uncertainty and focus exclusively on the day-ahead market.

First, we present an analytical framework that explains the mechanisms by which capacity reduction incentives may arise. We show that, in contrast with the conventional insight from the trade literature, with cross-border electricity transmission, individual TSOs/country’s have an incentive to implement restrictions on interconnectors with neighbors. This is primarily due to the prevailing practice of equally splitting congestion rent between neighboring TSOs. Furthermore, we distinguish two mechanisms that result in incentives for capacity reductions: one based on price differences with neighboring nodes (related to congestion rent) and one based on the internal electricity price (related to the sum of producer and consumer surplus).

Second, we run numerical experiments on a case study with realistic data from the Northern European power market to investigate whether we can actually observe these economic incentives. Taking the Danish TSO as an example, we find that in most scenarios, the TSO indeed has an incentive to reduce the transmission capacity on its interconnectors. Most lines are limited to about three quarters of their capacity on average, with one line (from DK2 to DE) limited to less than half of its capacity. On average, this leads to an average welfare gain of 444 thousand euros per week, and up to over 4 million in individual scenarios, while negatively affecting the system as a whole. The mechanism that is responsible for the Danish welfare gain turns out to depend heavily on the specific scenario at hand.

All in all, our paper provides evidence both from a theoretical and from an experimental point of view for the existence of incentives for transmission capacity reduction on interconnectors by TSOs in the day-ahead market. In conjunction with existing results in the literature, that point to additional incentives based on avoiding future balancing cost, this suggests that these incentives should be taken seriously by market regulators and more research should be aimed at better understanding the significance of the problem and finding measures to counteract the potential negative effects.

We see several specific future research directions for deepening our understanding of the problem at hand.

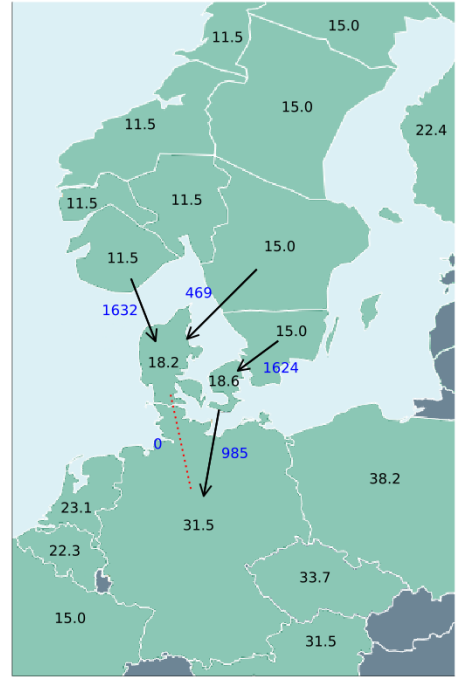
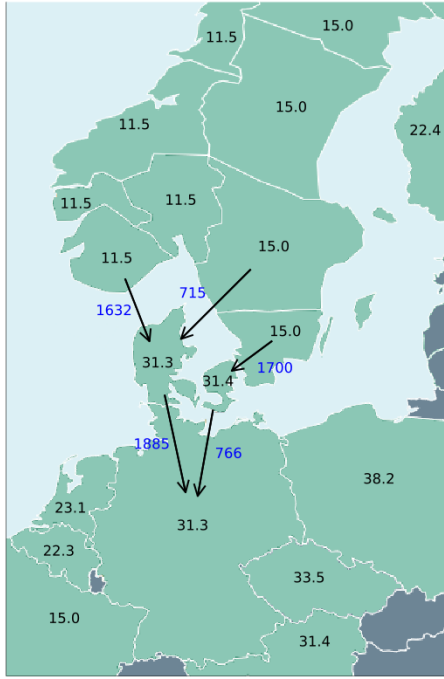


Figure 12: Plot of the average flows and weighted average prices for summer scenario 1, without (left) and with (right) curtailment. (Lower internal price, higher consumer surplus.)

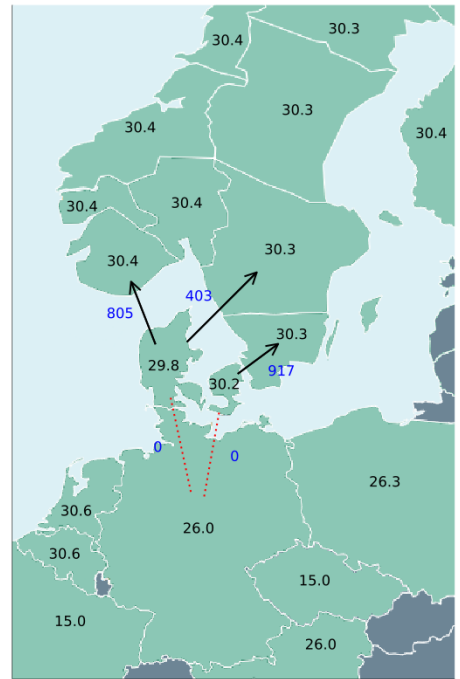
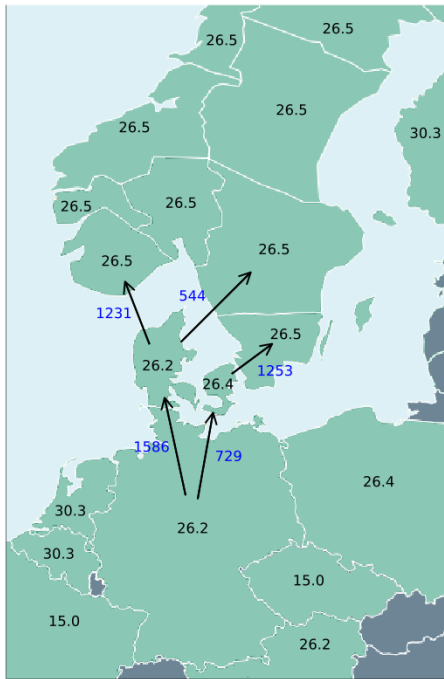


Figure 13: Plot of the average flows and weighted average prices for spring scenario 2, without (left) and with (right) curtailment. (Higher internal price, higher producer surplus.)

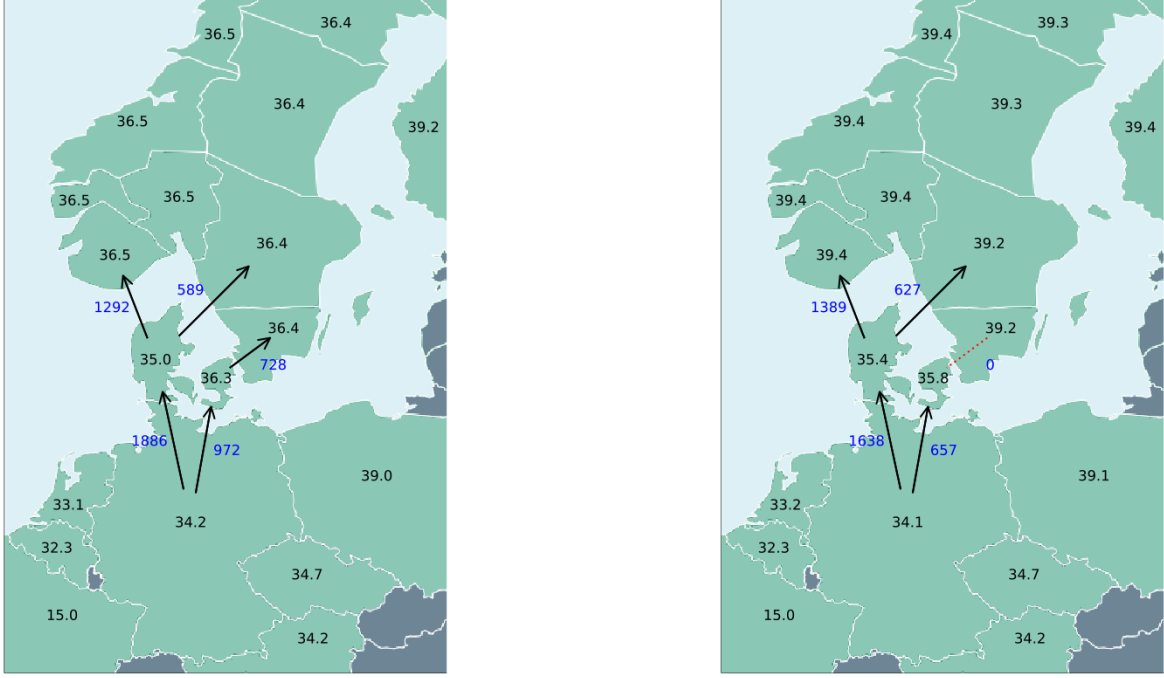


Figure 14: Plot of the average flows and weighted average prices for winter scenario 15, without (left) and with (right) curtailment. (Higher price differences, higher congestion rent.)

First, it would be interesting to investigate the problem using more sophisticated models that can take more aspects of the problem into account. In particular, one might run numerical experiments in a setting where multiple TSOs have the ability to *simultaneously* limit transmission capacity on interconnectors. The interactions in such equilibrium problems may lead to new behavioral patterns, and requires more advanced methodological approaches, such as an equilibrium problems with equilibrium constraints (EPEC) [14]. Second, it would be interesting to *empirically* investigate whether incentives not only exist in theory, but are also acted upon in practice. Since the motivations for TSO behavior are not directly observable, smart methodologies should be developed to find reliable estimates.

Another avenue for future research is to develop policy measures to counteract the negative effects of the incentives described in this paper. For instance, one might investigate the effectiveness of the European “70% rule”, which states that at least 70% of the capacity on an interconnection should be made available to the market [12]. Alternatively, novel policy measures might be proposed that more effectively mitigate the negative effects of economic incentives for transmission capacity reduction, while avoiding some of the drawbacks of the 70% rule [16], and while retaining the ability of TSOs to reduce transmission capacities for the purpose of safeguarding network reliability.

bility.

Appendix A Mathematical formulation

In this section we describe the mathematical model used for our numerical experiments in Section 3. The model, as well as its description in this section, is heavily based on the model from [13]. The main difference is the fact that in our paper, dispatchable production capacities and physical capacities of transmission cables are assumed to be fixed, while these are decision variables in the model in [13].

A.1 Notation

Sets:

- \mathcal{N} Set of nodes (indexed by n)
- \mathcal{L} Set of lines (indexed by l)
- \mathcal{G} Set of dispatchable generator types (indexed by g)
- \mathcal{T} Set of time periods (indexed by t)

Parameters:

R_{nt}	Production from renewables in node n in period t [MWh]
C_{gt}	Marginal cost for dispatchable generation of type g in period t [€/MWh]
G_{ng}	Generation capacity for generator type g in node n [MW]
Q_{ng}	Production limit for generation of type g in node n over the planning horizon [MWh]
A_{nl}	Node-line incidence matrix entry for node n and line l
F_l	Maximum line capacity for line l [MW]
D_{nt}^A	Slope of inverse demand function for node n in time period t
$D_{\omega nt}^B$	Intercept of inverse demand function for node n in time period t

Variables:

q_{ngt}	Production by generator type g in node n in time period t [MWh]
f_{lt}	Flow in line l in time period t [MWh]
d_{nt}	Demand in node n in time period t [MWh]
π_{nt}	Price in node n in time period t [€/MWh]

A.2 MCP formulation

As explained in Section 3, our model is a mixed-complementarity model (MCP) consisting of the Karush-Kuhn-Tucker (KKT) conditions of the individual optimization problems of all market participants. We assume perfect competition with all actors acting as price takers. Rather than presenting the MCP itself, we present the individual optimization problems whose KKT conditions define the MCP.

A.2.1 Dispatchable energy producer problem

In every node $n \in \mathcal{N}$, all dispatchable energy production resources are aggregated to a single profit-maximizing producer. The producer can freely choose its generation levels to maximize its profits. Eq. (1) describes the optimization problem for generator $g \in \mathcal{G}_n$ located in node $n \in \mathcal{N}$, where the constraints are defined $\forall g \in \mathcal{G}, t \in \mathcal{T}$.

$$\underset{q_{ngt}}{\text{maximize}} \quad \sum_{g \in \mathcal{G}} \sum_{t \in \mathcal{T}} (\pi_{nt} - C_{gt}) q_{ngt} \quad (1a)$$

subject to

$$q_{ngt} \leq G_{ng}, \quad (1b)$$

$$\sum_{t \in \mathcal{T}} q_{ngt} \leq Q_{ng}, \quad (1c)$$

$$q_{ngt} \geq 0 \quad (1d)$$

The objective function in Eq. (1a) consists of maximizing the expected revenue minus production cost, which are both assumed to be linear in the production level $q_{\omega gt}$. Eq. (1b) states that the production of each generation type must not exceed the corresponding capacity. Eq. (1c) states that the total production over the planning horizon must be no more than the available quantity. The purpose of this constraint is to model the amount of available water for hydropower production. Finally, Eq. (1d) states that the generation quantities must be non-negative.

A.2.2 Consumer problem

In every node $n \in \mathcal{N}$, the preferences of the consumers are represented by a linear demand curve. The fact that the consumers' behavior follows the demand curve can equivalently be stated by saying that the consumers maximize the consumer surplus [13]. Eq. (2) represents the corresponding maximization problem for the consumers located in node n .

$$\underset{d_{nt}}{\text{maximize}} \quad \sum_{t \in \mathcal{T}} \left(\frac{1}{2} D_{nt}^A d_{nt} + D_{nt}^B - \pi_{nt} \right) d_{nt} \quad (2a)$$

Eq. (2a) is the objective function for the consumers, representing the consumer surplus.

A.2.3 Market operator problem

We assume a single market operator that determines the flows on all interconnectors between nodes. The market operator maximizes the expected congestion rent for all lines, and sets the line flows accordingly. By assuming that the market is a price taker, it will not use its market power to influence prices and hence, it will act as a dummy player that simply sets line flows to those levels that satisfy the market clearing condition presented below [13]. The optimization problem for the market operator is given by Eqs. (3), where the constraints are defined $\forall l \in \mathcal{L}, t \in \mathcal{T}$.

$$\underset{f_{lt}}{\text{maximize}} \quad - \sum_{n \in \mathcal{N}} \sum_{l \in \mathcal{L}} \sum_{t \in \mathcal{T}} A_{nl} f_{lt} \pi_{nt} \quad (3a)$$

subject to

$$f_{lt} \leq F_l, \quad (3b)$$

$$f_{lt} \geq -F_l \quad (3c)$$

The objective function in Eq. (3a) consists of the expected congestion rent earned from all lines. Eqs. (3b) and (3c) state that the flow in a line must not exceed its capacity.

A.2.4 Market clearing

The market clearing constraint is used to connect the market actors' decisions together. It guarantees that the market clears, i.e., that supply meets demand. For every $n \in \mathcal{N}$ and $t \in \mathcal{T}$, it is given by

$$d_{nt} + \sum_{l \in \mathcal{L}} A_{nl} f_{lt} = \sum_{g \in \mathcal{G}} q_{ngt} + R_{nt} \quad (4)$$

In particular, Eq. (4) states that the sum of demand and net outgoing flows must be equal to the total amount of power generated from both conventional and renewable sources. The market price is the dual variable π_{nt} corresponding to this constraint.

A.3 Quadratic programming reformulation

In line with the classical result by [17], it can be shown that the MCP formed by the KKT conditions corresponding to (2)–(3) in conjunction with the market clearing constraint (4) is equivalent to a central planner quadratic optimization problem in which total welfare is maximized. The proof of this equivalence, which we omit for brevity, is through the observation that the KKT conditions to the quadratic program, which are necessary and sufficient, are equivalent to the MCP defined above. The quadratic program is given by Eq. (5), where the constraints are defined $\forall n \in \mathcal{N}, g \in \mathcal{G}, l \in \mathcal{L}, t \in \mathcal{T}$.

$$\begin{aligned} \underset{q_{ngt}, d_{nt}, f_{lt}}{\text{maximize}} \quad & \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(\frac{1}{2} D_{nt}^A d_{nt} + D_{nt}^B \right) d_{nt} \\ & - \sum_{n \in \mathcal{N}} \sum_{g \in \mathcal{G}} \sum_{t \in \mathcal{T}} C_{gt} q_{ngt} \end{aligned} \quad (5a)$$

subject to

$$q_{ngt} \leq G_{ng}, \quad (5b)$$

$$\sum_{t \in \mathcal{T}} q_{ngt} \leq Q_{ng}, \quad (5c)$$

$$d_{nt} + \sum_{l \in \mathcal{L}} A_{nl} f_{lt} = \sum_{g \in \mathcal{G}} q_{ngt} + R_{nt}, \quad (5d)$$

$$f_{lt} \leq F_l, \quad (5e)$$

$$f_{lt} \geq -F_l, \quad (5f)$$

$$q_{ngt}, d_{nt} \geq 0 \quad (5g)$$

Here, the objective function in Eq. (5a) consists of the sum of the objective functions of all market participants' optimization problems less investment cost in new transmission lines. The constraints in Eqs. (5b)–(5g) are a concatenation of the constraints from all market actors' individual optimization problems and the market clearing constraint.

Appendix B Data

In this section we describe the data used to parametrize the model from Section A in the numerical experiments in Section 3. While various new sources have been used, part of the data is based on the data used in [13]. The data set spans the period 2016–2020 and contains a mixture of hourly, daily, monthly and annual series.

The underlying network (illustrated in Figure 6) is based on the actual structure of the electricity market in Northern Europe, with a limited number of connected price zones. The aggregate physical capacities of the transmission cables between price zones come from the following

sources: the EMPIRE model in [18], Nordpool [19], Fingrid [20] and [21]. These capacities are based on the net transfer capacity, i.e. the maximum capacity after taking account for 'technical uncertainties on future network conditions' [19]. In practice, the capacity at a given point in time frequently needs to be limited below the net transfer capacity by TSOs for technical reasons. However, we do not model the factors causing such technical reasons explicitly (e.g. detailed characteristics of the national grids) and since capacity restrictions are the key decision variables in our model, we use the net transfer capacities.

Generation capacities of dispatchable generators for each zone are based on annual data from ENTSO-E [22], except for the Swedish zones, which are taken from the database of [13]. We distinguish between the following six types of dispatchable generation: hydropower, nuclear power, combined-cycle gas turbines (CCGT), peaking gas turbines, coal-fired plants and lignite plants. ENTSO-E does not distinguish between CCGT and peaking gas plants but reports single figures for natural gas plants. The model assumes a $\frac{2}{3}$ - $\frac{1}{3}$ split between CCGT and peaking gas plants, respectively. To account for the fact that generators are not always available (due to (un)planned maintenance, for instance), we multiply the ENTSO-E capacities by the following availability factors: 85% for coal and lignite plants, 92% for nuclear plants, 95% for CCGT and gas plants. These availability factors are based on [23]. For hydropower plants, the model contains an additional limit on the total amount of power that can be produced during the planning period (one week). This production limit is calculated by aggregating the historical production over all periods in the corresponding week. That way, the total amount of production remains the same as in the historical sample, while the distribution over the hours in the planning horizon may be changed by the model.

The marginal costs of dispatchable generation are determined in the following manner. For hydropower plants, we assume that the marginal costs are zero. For nuclear power plants, in line with [13], we assume fixed marginal costs of €15/MWh. For coal, lignite and natural gas plants, the marginal costs consists of fuel costs and CO₂ costs. We discuss these in turn by fuel type. Regarding fuel costs, for CCGT plants and gas peaking plants, we assume that gas is converted to electricity with an efficiency of 55% and 39%, respectively (based on IEA [24]). We use the daily day-ahead TTF price as reported by Refinitiv Eikon as proxy for the input price of gas.⁷ For coal and lignite plants, we respectively assume electrical efficiencies of 39% and 38% (based on Eurostat [25]). For coal plants, the coal input price is proxied by the daily month-ahead ARA (Amsterdam Rotterdam Antwerpen) API2 CIF coal price, as reported by Refinitiv Eikon. For lignite plants, because

⁷For gas and coal plants, the model assumes that generators offer their bids in the day-ahead market, implying that the input prices that were established on yesterdays day-ahead market for inputs are relevant for the electricity market of today.

there does not exist a liquid market for lignite, we assume fixed fuel costs of €10/MWh [26]. Regarding CO₂ costs, gas and coal plants have to buy EU ETS permits for their emissions, which are determined by the CO₂ intensity of the respective fuel and the permit price. Based on [27], we assume the following CO₂ intensities (in tCO₂/MWh of fuel input): 0.359 for coal, 0.364 for lignite and for 0.201 natural gas. The EU ETS price is based on the daily spot EU EUA price as reported by Refinitiv Eikon. We point out that our assumptions imply that the marginal costs for a given type of dispatchable generation do not differ between regions.

The hourly production from variable renewable sources (wind and solar) are based on actual historical production in each zone, which is extracted from ENTSO-E [28]. This production is taken as exogenously given. We assume a corresponding marginal cost of zero.

Linear demand curves are constructed using hourly electricity consumption and day-ahead electricity price data in each zone. Prices are extracted from ENTSO-E [29],⁸ while consumption is extracted from ENTSO-E [30] for all countries except for the Swedish zones, which comes from the Swedish TSO [31].⁹ Assuming that the inverse demand curve is written as $\pi = ad + b$, and using a fixed price elasticity of demand of $\varepsilon = -0.05$ (which is in line with estimates from, e.g., [32]), the parameters of the inverse demand curve are calculated as

$$a = \frac{1}{\varepsilon} \frac{|P|}{D}, \quad b = \left(1 - \frac{1}{\varepsilon}\right) |P|,$$

with P and D the historical price and consumption for a particular hour, respectively. We use the absolute value $|P|$ to account for historical prices with negative prices. This method ensures that demand is downward sloping with an elasticity close to -0.05 in cases when model outcomes are close to historical outcomes.

Most parameters described above vary per scenario used in our experiments. The only exceptions are the physical capacities of interconnectors and the availability factors for dispatchable generation, which are both fixed. Among the scenario-dependent parameters, dispatchable generation capacities vary annually (i.e., for every scenario the capacity from the corresponding year is taken), marginal costs of dispatchable generation vary daily, and all other variables vary hourly.

⁸Missing values for electricity prices have been manipulated in two ways: (i) in case of six or fewer consecutive missing observations, the observations have been replaced by the average of the last and next known observation; and (ii) in case of more than six consecutive missing prices, the observations have been replaced with the price for the same hour of the zone with the highest correlation coefficient in the sample (e.g. missing prices in SE2 are replaced by the prices from SE2).

⁹Missing value for consumption have been replaced by one of the following: (a) consumption in the zone on the same hour on the previous day, (b) consumption in the zone on the same hour on the next day, or (c) consumption in the zone on the same hour on the same day in the next week. Option (a) is used when available; if not available, (b) is used; if both (a) and (b) are unavailable, (c) is used.

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