# Is an inefficient transmission market better than none at all?

## On zonal and nodal pricing in electricity systems


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# Is an inefficient transmission market better than none at all?

## On zonal and nodal pricing in electricity systems

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In this paper, the trade-off between inefficient transmission forward markets (in nodal pricing regimes) and the inefficiency induced by hiding transmission constraints from the market (in zonal pricing regimes) is analyzed. First, a simple two node model formalizing the general trade-off is developed. Then, comparative statics are performed with a stochastic equilibrium model including more nodes, loop flows and an energy and transmission forward market. Inefficiency in the transmission forward market is introduced via a bid-ask-spread and risk aversion of market participants. The welfare impacts for a broad range of supply, demand, grid and inefficiency parameters are analyzed numerically. For efficient spot and forward markets, the results of the literature of nodal pricing being the efficient benchmark are confirmed. With inefficient transmission forward markets, however, zonal pricing proves advantageous in situations with little congestion and low costs. The results imply that the trade-off between the pricing regimes should be considered carefully when defining the geographical scope of bidding zones.

JEL classification: D47, Q40, L10

Keywords: Electricity, Market Design, Transmission Forward Markets, Inefficient Markets

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## 1 Introduction

Liberalization in electricity markets has led to an unbundling of formerly vertically integrated utilities. Consequentially, electricity generation and grid operation are tasks performed by separated entities. Still, since the balance of electricity production and consumption is crucial for system stability, generator schedules must respect the physical constraints of the transmission infrastructure to circumvent any imbalances caused by congestion. Different approaches for dealing with the transmission constraints have therefore been proposed and implemented. In some parts of the USA nodal pricing was introduced (e.g. by PJM or NYISO) providing one price for every grid node and hence explicit scarcity signals for transmission in the price differences between these nodes. Meanwhile, several countries in Europe opted for a national zone with a uniform price where transmission constraints are invisible in the market. Possible violations of the intra-zonal transmission constraints in these zones is usually being handled administratively by a Transmission System Operator (TSO). E.g., by reallocating the production of power plants (a so-called redispatch) after the market clearing with respect to congestion.

In the process of creating an internal European market for electricity, the European TSOs are obligated to deliver a review of these zones with respect to their performance. In this context, the umbrella group of the European regulators, ACER, issued a report which states that the "*European electricity target model envisages* [...] *properly defined bidding zones*", but recognizes that "[...] *the meaning of 'properly defined bidding zones' is not straightforward and needs deeper consideration.*"(ACER, 2014).

The scientific literature focusing on this topic (e.g. Harvey and Hogan (2000), Bjørndal and Jørnsten (2001)), however, essentially *is* rather straightforward, stating that the only properly defined bidding zones are actually nodes. It is argued that such a nodal pricing is superior over any zonal pricing approach, because hiding transmission scarcities from the market leads to inherent inefficiencies. A zonal aggregation could not be as efficient as a nodal pricing approach wherein the real value of transmission capacities is visible to market participants. Considering complete and competitive markets, Green (2007) provides empirical evidence for this argument for England and New Wales, and Bertsch et al. (2015) for the Central Western European region.

A more efficient market due to a larger market area with more participants is an opposed argument brought up in favor of zonal pricing. A larger market area should increase liquidity and reduce market power (e.g. CAISO (2000)). For the spot market however, Harvey and Hogan (2000) and Hogan (1999) show exemplarily that nodal pricing handles market power issues efficiently, while a zonal pricing approach might lead to perverse incentives and increasing congestion. Possible market power, but also liquidity, i.e., the possibility for traders to quickly buy or sell an asset while having a minor impact on price, is determined by the physical constraints in the spot market. A zonal pricing regime pretends more intense competition or better liquidity by allowing physically infeasible trades within a zone. Resolving these physically not viable trades brings up the need for curative measures, e.g. redispatch. In the end, market power is shifted from the spot market to the redispatch and infeasible trades, simulating liquidity, have to be administratively undone. It is not clear, why this should be (more) efficient in any case. Hogan (1999) states that an administrative pricing rule, i.e., neglecting transmission scarcities by averaging prices, does not alter the physical realities, which in the end determine the characteristics of the spot market - an argument also recognized in ACER (2014).

Empirical work (e.g. Bartholomew et al. (2003), Kristiansen (2005), Siddiqui et al. (2005), Deng et al. (2010), Adamson et al. (2010)) however, has shown that nodal pricing regimes can lack efficiency in forward markets for transmission rights. In a nodal pricing regime, energy forwards are usually traded at central hubs, while (financial) transmission rights are defined from every node to this hub. The market for these transmissions rights might not be efficient if market participants have poor expectations about the prices, transaction costs are high or liquidity is low due to few participants. If the forward market for these transmission rights is not efficient, an aggregation of nodes to zones and hence, a reduced number of transmission rights to be traded, might be advantageous. An aggregation of nodes to bidding zones implicitly hedges all risks of transmission constraints and socializes the costs via the curative measures in the spot market. The remaining question and the issue addressed in this paper is therefore: Under which circumstances does the inefficiency of a transmission forward market (in a nodal pricing regime) matter more than the inefficiencies induced by neglecting transmission (in a zonal pricing regime)?

To show the general effects of the two inefficiencies of the different pricing regimes, a simple two node model with two producers, a retailer and a transmission system operator with a spot and forward market is developed. On the forward market a transmission right for hedging against the risk of congestion can be traded, while on the spot market only energy is considered. The TSO clears the market in a welfare optimal way while ensuring physical feasibility. For performing comparative statics of nodal and zonal pricing, a more complex model incorporating more nodes, loop flows as well as energy and transmission forwards is used. The spot and forward market model by Bessembinder and Lemmon (2002) and de Maere d'Aertrycke and Smeers (2013) serves as a base. The stochastic equilibrium model by de Maere d'Aertrycke and Smeers (2013) incorporates missing liquidity in a nodal pricing system via a volume constraint for forward transmission contracts. I extend their model by a zonal pricing approach and a producer-only redispatch. Furthermore, an exogenous bid-ask-spread to model effects of inefficiencies such as missing liquidity, transaction costs etc. is implemented. Compared to a volume-constrained approach, this allows to solve for unique prices of transmission forward contracts and hence, a unique equilibrium, which is essential for comparing the two pricing regimes. A consistent numerical setting (proposed by Chao and Peck (1998)) is chosen and a systematic numerical analysis performed by varying the influencing fundamental factors such as grid restrictions, supply and demand properties as well as the bid-ask spread and risk aversion.

The contribution to the literature is twofold: First, a consistent model for comparing the effects of inefficiencies in nodal and zonal pricing regimes is developed. Second, comparative statics for an established numerical framework is performed to identify relevant circumstances regarding the comparison of both pricing regimes.

With no inefficiencies in transmission forward markets, the arguments of the theoretical literature can be confirmed and it can be concluded that nodal pricing performs always better than zonal pricing. The relative performance of zonal pricing improves with decreasing congestion and is equal to nodal pricing in case of no congestion at all. In addition, smaller supply cost differences and a more inelastic demand work in favor of zonal pricing. In the case of an inefficient transmission forward market, situations appear wherein zonal pricing performs better than nodal pricing. The total number of such cases increases with increasing bid-ask-spread and risk aversion.

The results show that efficiency of transmission right markets does in fact matter. Hence, for finding 'properly defined bidding zones', the efficiency of forward markets for transmission should be one criterion. With a zonal pricing in place this could mean that, e.g., the geographical coverage of a zone should be defined as a trade-off between the inefficiencies of a zonal pricing and a nodal pricing regime. The respective measure or a possible change of pricing mechanisms, however, has to include political considerations and transaction costs of system adaption.

The paper is organized as follows: Section 2 introduces a simple model. The model used for comparative statics, the numerical framework and results are presented in section 3. Section 4 concludes.

## 2 A simple model

Within this section, a simple two node model for comparing a zonal pricing regime with a redispatch of producers and a nodal pricing regime with an inefficient transmission forward market is established. This allows to identify some general effects, which also apply to larger models. At first, the differences in the spot market outcomes with and without congestion are shown. Next, the differences considering a an additional forward market are analyzed.

### 2.1 Spot market outcomes without congestion

Consider an electricity system with two nodes and a single time period. A producer with constant marginal costs of $c_1$ is located at node 1 and a producer with constant marginal costs of $c_2$ is located at node 2. Both producers have infinite production capacities, but producer 2 has higher costs, i.e., $c_1 < c_2$. The final consumer demand is located at node 2 and represented by some demand function $D^l(p^r)$ with $\frac{\partial D^l(p^r)}{\partial p^r} < 0$. A retailer buys electricity at price $p^s$ from the producers and sells it to the final consumers at price $p^r$, which is the (weighted) average price of all possible spot market realizations $p^r = E(p^s)$.[1] Producers and retailers are considered as price-takers. The transmission capacity between the nodes $k$ is considered to be larger than the maximum demand, i.e., no congestion occurs. With no congestion, the market outcomes for nodal (NP) and zonal pricing (ZP) are the same as indicated in figure 1. Only the producer at node 1 is dispatched, the spot price is $p^s = c_1$ and the retail price is $p^r = p^s = c_1$ resulting in a demand of $q^* = D^l(c_1)$.

[1] In this case there is only one realization and therefore $p^r = p^s$, but generally there is more than one possible spot market outcome as will be shown later.

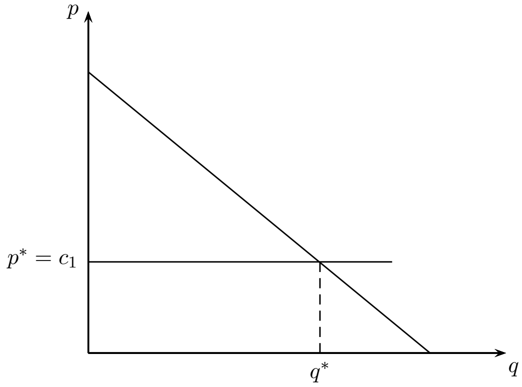


Figure 1: Spot market result without congestion

Profits are zero for producers and the retailer. Hence, total welfare for the case with no congestion (*noc*) is determined only by the consumer rent:

$$W^{NP,s}_{noc} = W^{ZP,s}_{noc} = \int_{c_1}^{\infty} D^l(p^r)dp^r \tag{1}$$

### 2.2 Spot market outcomes with congestion

Now consider that transmission capacity is limited due to a higher demand (i.e., $k < D^h(c_2)$). For ensuring physical feasibility, a benevolent transmission system operator (TSO) is introduced. In the zonal pricing regime, the TSO performs a redispatch of the producers after the market outcome until the transmission constraints are fulfilled. In the nodal pricing regime, the TSO clears the market considering the transmission constraint. The spot market outcomes now differ for the pricing regimes.

#### 2.2.1 Nodal pricing outcome

The TSO clears the market with a cost-minimal dispatch considering the transmission constraint. The producer at node 1 now generates electricity up to $k$, whereas the producer at node 2 produces from $k$ to $q^* = D^h(c_2)$ (figure 2). The prices reflect the marginal costs at the respective nodes with $p^s_1 = c_1$ and $p^r = p^s_2 = c_2$.

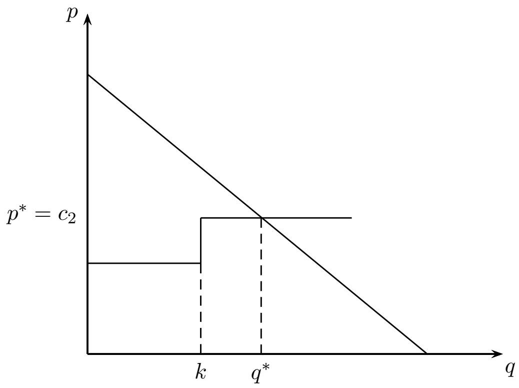


Figure 2: Spot market result for nodal pricing with congestion

It is assumed that the TSO receives the profit resulting from the price difference between the nodes and the quantity transmitted from node 1 to node 2. Profits of the TSO and welfare in this congested case ($con$) are

$$\pi_{tso}^{NP,s} = (c_2 - c_1)k \tag{2}$$

$$W_{con}^{NP,s} = \pi_{tso}^{NP,s} + \int_{c_2}^{\infty} D^h(p^r)dp^r \tag{3}$$

### 2.2.2 Zonal pricing outcome

In the zonal pricing regime, the market outcome is calculated as in the case of no congestion, i.e., prices are $p^r = p^s = c_1$, demand is $q^* = D^h(c_1)$ and profits are zero for producers and the retailer. However, this outcome is technically not feasible, because the producer at node 1 would export more than $k$ to node 2. The TSO now redispatches the two producers until technical feasibility is achieved. For this, the TSO reduces the quantity of the producer at node 1 to $k$ and increases the production of the producer at node 2 to $D(c_1) - k$. In figure 3 the left graph shows the spot market outcome and the right graph shows the real dispatch. For the quantity from $k$ to $q^*$ the producer at node 2 is dispatched, but still, electricity is traded at $p^s = c_1$.

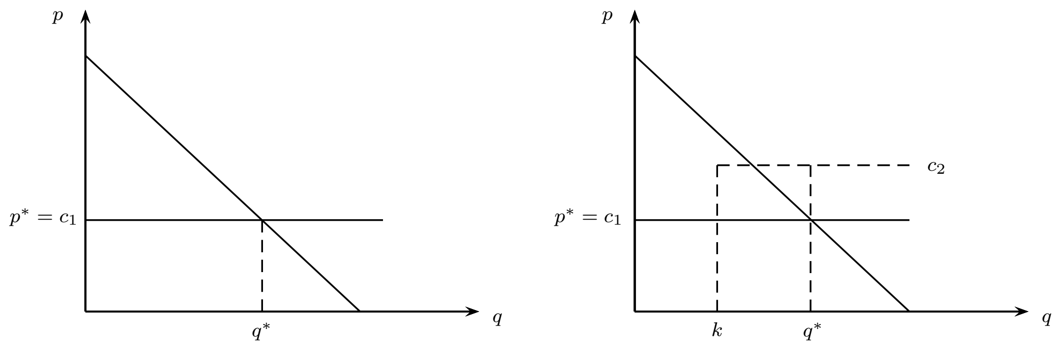


Figure 3: Spot market result for zonal pricing with congestion

The additional costs result in a negative TSO profit. Profit and welfare are

$$\pi_{tso}^{ZP,s} = (c_1 - c_2)(D^h(c_1) - k) \tag{4}$$

$$W_{con}^{ZP,s} = \pi_{tso}^{ZP,s} + \int_{c_1}^{\infty} D^h(p^r)dp^r \tag{5}$$

### 2.2.3 Comparing the spot market outcomes

Comparing $W_{con}^{NP,s}$ and $W_{con}^{ZP,s}$ yields:

$$\begin{aligned}
\Delta W_{con} &= W_{con}^{NP,s} - W_{con}^{ZP,s} \\
&= (c_2 - c_1)k + \int_{c_2}^{\infty} D^h(p^r)dp^r - (c_1 - c_2)(D^h(c_1) - k) - \int_{c_1}^{\infty} D^h(p^r)dp^r \\
&= \underbrace{\int_{c_2}^{c_1} D^h(p^r)dp^r}_{<0} + \underbrace{(c_2 - c_1)D^h(c_1)}_{>0}
\end{aligned} \tag{6}$$

and see immediately that $\Delta W$ has to be always larger than zero if $\frac{\partial D^l(p^r)}{\partial p^r} < 0$, i.e., if demand decreases in price. In the zonal pricing market outcome demand is too high due to neglecting the transmission capacities. This inherent inefficiency is induced by only allowing producers for redispatch. In figure 4 the striped area marks the welfare delta induced by the inefficiency.

If demand is allowed for redispatch, both regimes would lead to the same outcome. The same would be the case, if demand is inelastic. This means the more inelastic demand and the more negligible the cost differences of the nodes, the smaller is the welfare delta between the two regimes.

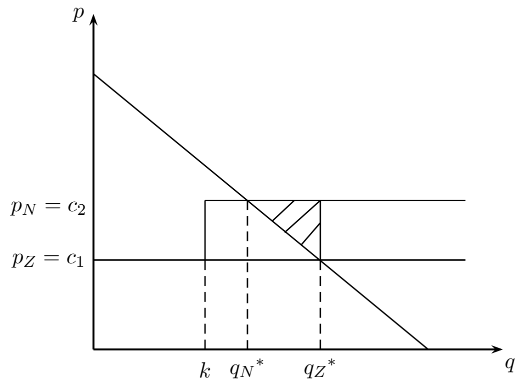


Figure 4: Comparison of spot market results with congestion

## 2.3 Forward market outcome

A forward market is considered, on which a transmission forward can be traded. The transmission forward or financial transmission right (FTR) is defined as the right to collect the congestion rent, i.e., the price differences, between two nodes or zones. There are two possible spot market outcomes at the time trade takes place at the forward market, namely the ones described above with either no congestion (*noc*) (probability $\mu$) or congestion *con* (probability $1-\mu$). Empirical literature (e.g. Viehmann (2011)) has found that market participants in electricity markets show risk averse behavior. Hence, producers and and the retailer are assumed to be risk averse in the sense that they require additional capital for possible losses. The TSO is considered to be risk neutral.[2]

In zonal pricing, the market participants do not see any transmission capacity in the spot market outcome and hence, there is no forward market for transmission. The prices $p^s$ and $p^r$ are always the same, regardless of congestion. Producers and retailers -despite being risk averse- have no desire to hedge any possible spot market realization due to the variance of their profits being zero. Overall welfare in the forward market for zonal pricing is:

$$W^{ZP,f} = \mu W_{noc}^{ZP,s} + (1-\mu) W_{con}^{ZP,s} = \mu \left[ \int_{c_1}^{\infty} D^l(p^r) dp^r \right] + (1-\mu) \left[ \pi_{tso}^s + \int_{c_1}^{\infty} D^h(p^r) dp^r \right] \tag{7}$$

In the nodal pricing regime, the forward market outcome is different. The producer

[2]Of course, also a risk averse TSO could be assumed. The reason for the assumption of risk neutrality is due to making the pricing regimes comparable: In the zonal pricing regime, neglecting transmission capacities could be interpreted as a risk neutral administrative hedge against congestion risks. Hence, an equivalent assumption becomes necessary in the nodal pricing regime.

at node 1 gets always the same price regardless of congestion. The producer at node 2 and the retailer however, face two possible price realizations. The expectation value of the profits are still zero, but the retailer has a loss with probability $1-\mu$ due to the fixed retail price. Risk aversion of the retailer is indicated by some function $U(\pi)$ describing the additional capital requirements of losses with $U(\pi) < \pi \ \forall \ \pi < 0$ and $U(\pi) = \pi \ \forall \ \pi \geq 0$. Hence, the retailer is willing to give up some profit from the case of no congestion to hedge against the possible losses. This can be done with the TSO offering a FTR $x$ at price $p^{f,bid}$ which allows the consumption of the congestion rent. The retailer can buy this FTR at price $p^{f,ask}$. The profit functions change to

$$\pi_r^{NP,f} = \mu U(\pi_{r,noc}^s) + (1-\mu)U(\pi_{r,con}^s) + p^{f,ask}x \tag{8}$$

$$\pi_{tso}^{NP,f} = (1-\mu)\pi_{tso,con} - p^{f,bid}x \tag{9}$$

The FTR is independent of the realization of either the congested or the uncongested case since it is an option to consume the congestion rent in case of congestion. The risk averse retailer is willing to give up some profit from the uncongested case in order to reduce her losses in the congested case. The risk neutral TSO will take over all risk of the retailer, if $p^{f,ask} = p^{f,bid}$. The bid-ask-spread is equal to zero if there are no transaction costs and the traded contract is fully liquid. However, it can be greater than zero if the asset lacks liquidity or transaction costs occur, i.e., $p^{f,ask} < p^{f,bid}$. In this case, the TSO is not able to fully take over the risk of the retailer, who is left with some unhedged losses.

Overall welfare in the forward market for nodal pricing is:

$$\begin{aligned} W^{NP,f} =& \mu \left[ U(\pi_{r,noc}^s) + \int_{c_1}^{\infty} D^l(p^r)dp^r \right] \\ &+ (1-\mu) \left[ U(\pi_{r,con}^s) + \pi_{tso}^s + \int_{c_2}^{\infty} D^h(p^r)dp^r \right] - p^{f,bid}x + p^{f,ask}x \end{aligned} \tag{10}$$

The comparison of the welfare in the forward markets yields:

$$\Delta W^f = W^{NP,f} - W^{ZP,f} = \Delta W_{con} + \underbrace{(1-\mu)\left[U(\pi_{r,con}^{NP,s}) + \pi_{tso,con}^{NP,s}\right]}_{\text{Costs of unhedged risks}} - \underbrace{(p^{f,bid} - p^{f,ask})x}_{\text{Bid-ask-spread inefficiency}} \tag{11}$$

In addition to the spot market welfare delta, there are two new parts stemming from the possibly unhedged loss of the retailer and the possible bid-ask-spread. Both terms work in favor of zonal pricing since they can at largest be zero, if $p^{f,ask} = p^{f,bid}$. In case the bid-ask-spread is larger than zero, the retailer cannot fully hedge the losses by buying FTRs from the TSO. Hence, both terms become negative and reduce the delta between nodal and zonal pricing. In case of a positive bid-ask-spread the question which regime performs better depends on whether this inefficiency is larger than the inefficiency induced by the producer-only redispatch of the zonal pricing regime, included in $\Delta W_{con}$.

From the analysis of the spot market outcome it was already obtained that smaller cost differences and a more inelastic demand improve the relative performance of zonal compared to nodal pricing. From the forward market analysis it can be concluded that a higher bid-ask-spread and higher costs of unhedged risks work in the same direction and may even (over)compensate the inefficiencies of zonal pricing in the spot market.

# 3 Comparative statics

In order to further investigate the trade-off obtained in the simple model, more details of the electricity grid are now considered. There are two main characteristics which deserve special consideration, namely the spatial distribution and correlation of demand as well as different grid configurations. Flows in electricity grid can usually not be directed from node to another and hence, an injection of electricity anywhere in the grid impacts electricity flows on all lines. This becomes especially relevant in combination with changing demand patterns. Therefore, a model incorporating more nodes, the spatial distribution of demand, loop flows, more possible spot market outcomes and a forward market for transmission rights *and* energy is developed. With this model, a numerical analysis with a broad variation for the named characteristics is performed. The often applied setting by Chao and Peck (1998) is used as consistent numerical base.

## 3.1 A slightly more complicated model

For the general formulation of the model I follow Bessembinder and Lemmon (2002) and de Maere d'Aertrycke and Smeers (2013) and extend their nodal pricing formulation to incorporate zonal pricing with a producer-only redispatch. Furthermore, an alternative modeling approach for inefficency of the transmission forward market is chosen by implementing a bid-ask-spread instead of constraining the trading volume of transmission forwards.

### 3.1.1 Market participants and TSO

The market participants are denoted by $N$ consisting of producers $N_P$ and retailers $N_R$. There is either one producer or one retailer at any node $\nu$. Furthermore, an arbitrary number of nodes can be in one market area $m, n$ of all markets $M$. Producers have a cost function consisting of a fixed component $a$ and variable costs $b$ depending on the quantity sold in the spot market area. In line with Bessembinder and Lemmon (2002) a quadratic cost function is assumed.

$$c_\nu(q_\nu) = a_\nu q_\nu + \frac{b_\nu}{2} q_\nu^2 \tag{12}$$

Producers sell their production in the spot market at price $p_m^s$ and hence their profit is

$$\pi_\nu^s = p_m^s q_\nu - c_\nu(q_\nu). \tag{13}$$

Retailers buy production at the spot market price $p_m^s$ and sell it to the consumers at a fixed price $p_m^r$. Their profit is

$$\pi_\nu^s = (p_m^r - p_m^s) q_\nu. \tag{14}$$

The linear inverse demand function $p_\nu(q_\nu)$ of the consumers at node $\nu$ is subject to an exogenous shock caused by, e.g., changing weather conditions.[3] The shocks are indicated in the demand function by realizations $\omega$ of the exogenous random variable $a_\nu$.

$$p_\nu(q_\nu) = a_\nu^\omega - b_\nu q_\nu. \tag{15}$$

The fixed price $p_m^r$ is assumed to be the average price resulting from the market clearing with all possible realizations of $a_\nu$ plus some markup, i.e., $p_m^r = \sum_\omega^\Omega prob^\omega p_m^\omega + \mu$ with $\sum_\omega prob^\omega = 1$. The markup is the profit the retailer gets from selling electricity to the final consumers. To a certain extent the markup works as an insurance for having a fixed retail price and a volatile spot price. Retailer profit can be negative for some realizations $a_\nu^\omega$ depending on the properties of the random variable $a_\nu$ and the markup. To hedge themselves against the volatility of the spot market and possible losses, producers and retailers have the possibility to buy or sell contracts $c \in C$ with a price $p_c^f$ and a quantity $x_{c,\nu}$ on the forward market.[4] The underlyings of the forward contracts can either be based on energy sold in the spot market $(p_m^s, q_m^s)$ or on the right to collect congestion

[3]This basically corresponds to the different cases in the simple model.

[4]Note that the prices are the same for all market participants while the quantities are individual.

rent, which is defined as the price difference and the traded quantities between two spot markets $(\Delta p^{s}_{m,n}, \Delta q^{s}_{m,n})$.[5] The right to collect congestion rent corresponds to a financial transmission right. The forward prices are $p_c^{f,bid}$ for going long and $p_c^{f,ask}$ for going short. The corresponding forward contract quantities $x^{bid}_{c,\nu}$ and $x^{ask}_{c,\nu}$ are not dependent on the realization $\omega$. The difference between the prices indicates the bid-ask-spread. This differs from the formulation in de Maere d'Aertrycke and Smeers (2013), where the tradeable volume was limited to represent an inefficient transmission forward market. Treating this inefficiency as a bid-ask-spread yields the nice property that the forward price of each contract for bid or ask is equal for all players. For the later solution this implies that only one equilibrium exists, which is then arbitrage free if the bid-ask-spread is exogenous.[6]

The profit of a producer or retailer in the forward market for one possible realization of the spot market is

$$\Pi^{\omega}_{\nu} = \sum_{c=1}^{C} ((p_c^{s,\omega} - p_c^{f,bid}) x^{bid}_{c,\nu} + (p_c^{f,ask} - p_c^{s,\omega}) x^{ask}_{c,\nu}) + \pi^{s,\omega}_{\nu} \tag{16}$$

The profit realization $\Pi^{\omega}_{\nu}$ in the forward market depends on the loss or profit in the spot market $\pi^{s,\omega}_{\nu}$. Possible losses in the spot market is costly in the sense of some sort of additional capital requirement. Hence, market participants try to hedge against losses in the spot market by giving up some possible profits.[7] A producer or retailer optimizes the overall profit in the forward market by buying forward contracts considering the additional costs of possible losses indicated by $U^{\omega}_{\nu}(\Pi^{\omega}_{\nu})$:[8]

$$\max_{x_\nu} \left\{ \sum_{\omega} \mathrm{prob}^{\omega} \left[ (1-\beta_\nu)\Pi^{\omega}_{\nu} - \beta_\nu \alpha_\nu^{-1} U^{\omega}_{\nu}(\Pi^{\omega}_{\nu}) \right] \right\} \tag{17}$$

The weight $\beta$ defines the relative importance of expected losses versus the additional capital requirements needed for the average losses above some value at risk (specified by the quantile above $\alpha$). This means a lower $\alpha$ requires more risk capital and a higher $\beta$ puts more emphasis on these capital requirements.

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[5] Due to loop flows the traded quantities are not necessarily the physical flows!

[6] This is not shown analytically, but the numerical analysis and the behavior of the solution algorithm for a wide range of starting points indicate that the equilibrium is unique.

[7] For modeling this, de Maere d'Aertrycke and Smeers (2013) propose a weighted sum of the expectation of losses and a conditional value at risk (CVaR) as a coherent risk measure (E-CVaR). The conditional value at risk defines the expected value above some value at risk. I follow their definition, but drop the time variable since only one time period is considered: $\text{E-CVaR}_{\alpha,\beta} = (1-\beta)\mathbb{E}[-\Pi_\nu] + \beta \mathrm{CVaR}_\alpha(\Pi_\nu)$.

[8] Function $U^{\omega}_{\nu}(\Pi^{\omega}_{\nu})$ is defined as in the simple model, i.e., $U^{\omega}_{\nu}(\Pi^{\omega}_{\nu}) < \Pi^{\omega}_{\nu} \ \forall \ \Pi^{\omega}_{\nu} < 0$ and $U^{\omega}_{\nu}(\Pi^{\omega}_{\nu}) = \Pi^{\omega}_{\nu} \ \forall \ \Pi^{\omega}_{\nu} \geq 0$.

As stated in the simple model, the TSO has some profit in the spot market due to the collected congestion rent, i.e., the price differences times the traded energy minus the redispatch costs $R$.

$$\pi^s_{tso} = \frac{1}{2}\sum_m^M \sum_n^M |\Delta p^s_{m,n}||q_{m,n}| - R. \tag{18}$$

Considering the forward market, the TSO has the additional role to emit financial transmission rights and to act as the ultimate counter-party for trading these contracts. Emission is limited by the actual transmission capacities available in the spot market. The TSO is only allowed to trade FTRs but no energy forward contracts, leading to the profit for each realization of the spot market:

$$\Pi^\omega_{tso} = \sum_{c=1, c\notin c_e}^{C} ((p_c^{s,\omega} - p_c^{f,bid})x^{bid}_{c,tso} + (p_c^{f,ask} - p_c^{s,\omega})x^{ask}_{c,tso}) + \pi^{s,\omega}_{tso} \tag{19}$$

The optimization problem for the TSO is the same as for the other market participants, stated in equation 17.

### 3.1.2 The spot market

The forward and spot market are sequential. Producers, Retailers and the TSO do not know the exact market outcome of the spot market, but do know all possible outcomes and the respective probability distribution. Furthermore, a competitive spot and forward market is considered, with producers and retailers as price takers and the TSO as the welfare-maximizing market clearer. This allows to first compute all possible spot market outcomes and then solve for the equilibrium on the forward market.

**Spot market clearing**

$$\max_{q_\nu} \left[ \sum_{\nu \in N^R} \int_0^{q_\nu} p_\nu(q_\nu) dq_\nu - \sum_{\nu \in N^P} \int_0^{q_\nu} c_\nu(q_\nu) dq_\nu \right] \tag{20a}$$

$$\text{s.t.} \sum_{\nu \in m} q_\nu + \sum_{-m} (q_{m,-m} - q_{-m,m}) = 0 \qquad \forall m \in M \tag{20b}$$

$$f(q_{m,-m}) \leq k_{m,-m} \qquad \forall m \in M \tag{20c}$$

$$q_\nu \geq 0 \tag{20d}$$

The spot market clearing is done by the TSO by maximizing the welfare over quantities $q$ (Equation 20a) subject to the market balance (Equation 20b) and the transmission constraints (Equation 20c). If $\nu$ is identical to $m$ (implying that real transmission scarcities are visible in the market), the spot market outcome is at the same time the optimal dispatch and the problem is physically feasible. This setting corresponds to a nodal pricing regime. The function $f$ then maps power injections and withdrawals to load flows on lines. If $\nu$ is not identical to $m$ and hence, transmission scarcities are only incompletely considered, $f$ represents trade flows, restricted by some trading capacity offered to the market. This corresponds to a zonal pricing regime, wherein the zone definition depends on the mapping of nodes to markets. A subsequent optimization to ensure physical feasibility has to be performed.[9] The problem is formulated as cost minimization representing a redispatch of power plants which does *not* alter the profits obtained in the spot market. One implicit assumption is that the TSO has full information about the cost functions of the producers.

**Redispatch**

$$\min_{q_{\nu \in N^P}} R = \left[ \sum_{\nu \in N^P} \int_0^{q_\nu} c_\nu(q_\nu) dq_\nu \right] \tag{21a}$$

$$\text{s.t.} \quad \sum_{\nu \in N^P} q_\nu - \sum_{\nu \in N^R} q_\nu = 0 \tag{21b}$$

$$f(q_\nu) \leq k_{\nu,\nu'} \tag{21c}$$

The system balance constraint (equation 21b) is defined over all zones, i.e., implying a coordinated cross-border redispatch. Equation 21c now represents the real transmission constraints by indexing over $\nu$ instead of $m$. The objective value of this cost minimization is given by the redispatch costs $R$, which are part of the TSO's profit function (Equation 18).

The total welfare of the spot market is computed as the sum of producer, retailer and TSO profits plus the end consumer rent retrieved over the demand function.

$$W^s = \sum_{\nu \in N} \pi_\nu^s + \pi_{so}^s + cr^r \tag{22}$$

### 3.1.3 The forward market

The forward market is cleared before the realization of the spot market. On the forward market the market participants optimize their profits as stated before. The TSO emits FTRs and acts as the ultimate counterparty for transmission forward contracts. The market is cleared if no further forward quantity is traded, i.e., retailers, producers and

[9] The sequential optimization approach ensures that the TSO has no means to actively profit from redispatching power plants.

the TSO have optimized their forward contracting. The forward market clearing can be defined by the sum of the single optimization problems plus some market clearing and bid-ask-spread constraint. Index $\nu$ is slightly abused by including the TSO to reduce the complexity of the formulation.

**Forward market clearing**

$$\max_{x_\nu} \sum_{\nu \in \{N,TSO\}} \left\{ \sum_{\omega} \mathrm{prob}^{\omega} \left[ (1-\beta_\nu)\Pi_\nu^\omega - \beta_\nu \alpha_\nu^{-1} U_\nu^\omega \right] \right\} \tag{23a}$$

$$\text{s.t.} \quad \sum_{\nu} x_{\nu,c}^{bid} - \sum_{\nu} x_{\nu,c}^{ask} = 0 \tag{23b}$$

$$f(x_{tso,c}^{bid} - x_{tso,c}^{ask}) \leq k_{m,n} \tag{23c}$$

$$p_c^{bid} - p_c^{ask} \geq \chi_c \tag{23d}$$

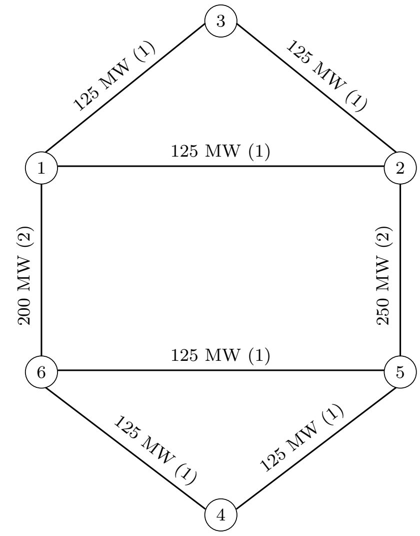
While equation 23a simply sums up the optimization problems of the single players, equation 23b represents the market clearing condition for all forward contracts. Equation 23c guarantees feasibility of the transmission constraints in the spot market, i.e., restricts the TSO's emission of FTRs to feasible quantities. As in the spot market, the function $f$ describes a mapping of traded quantities to physical flows, which depends on the nodal or zonal pricing regime. Considering nodal and zonal pricing the main difference between the regimes lays in the different number of forward contracts needed. If in the nodal pricing regime some hubs corresponding to the zones in the zonal pricing are defined, the number of energy contracts might be the same. The number of transmission contracts however, is different. In a nodal pricing regime, there are as many transmission contracts as nodes minus the hub. With zonal pricing, the number of transmission contracts corresponds to the number of connected zones. Equation 23d introduces a bid-ask-spread, exogenously defined by some value $\chi$.

Total welfare of the forward market can be computed considering the profit, the additional capital requirement from unhedged risk and the consumer rent:

$$W^f = \sum_{\omega} \mathrm{prob}_\omega \left[ \sum_{\nu \in \{N,TSO\}} (\Pi_{\nu,\omega} - \alpha_\nu^{-1} U_{\nu,\omega}) + cr^{r,\omega} \right] \tag{24}$$

## 3.2 Numerical analysis

For the numerical analysis the six-node spot market model introduced by Chao and Peck (1998) is applied. For the forward market the general setting from de Maere d'Aertrycke and Smeers (2013), who also use the Chao-Peck model as a basis, is taken. The spot market model has 3 production and 3 retailer nodes. The structure and the standard supply and demand functions for these nodes can be seen in figure 5.




| Node | Supply functions $C_v(q_v)$ |
|---|---|
| 1 | $10 + 0.05q$ |
| 2 | $15 + 0.05q$ |
| 4 | $42.5 + 0.025q$ |

| Node | Demand functions $p_v(q_v)$ |
|---|---|
| 3 | $37.5 - 0.05q$ |
| 5 | $75 - 0.1q$ |
| 6 | $80 - 0.1q$ |

Figure 5: Basic spot market model (Chao and Peck, 1998), taken from de Maere d'Aertrycke and Smeers (2013)

In the nodal pricing regime, each node represents a spot market, while trading between these markets is restricted by transmission constraints. For the zonal pricing regime all nodes are aggregated into one spot market. This allows us to ignore transmission capacity allocations, which is a rather difficult issue. Due to loop flows the available transmission capacity depends on the actual dispatch. Hence, the transmission capacity offered to the market has to be valid for all possible dispatch situations. Furthermore, contingencies are included when assessing the possible transmission capacity, making it even more difficult to come up with a reasonable value. One should keep in mind that this configuration is the worst possible case for zonal pricing and could be relaxed by, e.g., defining two zones. For our purpose this means that if zonal pricing performs better in any case, this could also happen with better configuration of bidding zones. To ensure physical feasibility, a cost-based redispatch of power plants -as described above- is applied, which does not affect the profit of the market participants. A risk-neutral TSO is assumed, i.e, $\beta = 0$. This means that in the zonal pricing regime, all congestion costs are present in the actual redispatch (and do not appear in the forward market).

Drivers for the behavior of market participants in the forward market are costs of risk, prices and profits. The latter two depend fundamentally on supply and demand characteristics, grid configuration and markup. Furthermore, the bid-ask-spread impacts the achievable welfare of any market. All the mentioned parameters are varied as shown in table 1.

Table 1: Parameter variations

| | **Parameter** | **Variation** | **Steps** | **Scenarios** |
|---|---|---|---|---|
| Demand | $a_\nu^\omega$ | fully correlated, semi-correlated and non-correlated (with different variance) | | 4 |
| Supply | $a_\nu$ | between 20% and 180% at each node | 40% | 5 |
| Grid | $k$ | Line 1-6 between 0 and 400 Line 2-5 between 50 and 450 | 50 | 9 |
| Markup | $\mu$ | between 0 and 20% for each retailer | 0.05 | 5 |
| Risk aversion | $\alpha$ | 0.1, 0.2, 0.4 and 0.8 | | 4 |
| | $\beta$ | 0.1, 0.5 and 0.9 | | 3 |
| Bid-ask-spread | $\chi$ | 0, 0.1, 0.25, 0.5, 1, 2, 4, 6 | | 8 |

For each scenario, different dispatch realizations (indicated by $\omega$, $\sum_\omega prob^\omega = 1$) with a varying demand $a_\nu^\omega$ are calculated. In the dispatch realizations, the axis intercept of the demand function is varied between 75% and 125% (respectively 70% and 130% for the high variance - no correlation scenario) in steps of 12.5 % (30 % for the high variance - no correlation scenario) at each demand node. The correlation of demand levels at nodes is differentiated in four demand scenarios, leading to 202 different dispatch situations in total.[10] Beside the demand correlation, additional scenarios consist of variation of supply costs and grid capacities. There are 180 spot market scenarios with a total of 9,090 different dispatch realizations. For the forward market, scenarios with variation of the markup of retailers, the costs of risk ($\alpha$,$\beta$) and the bid-ask-spread are calculated. Together with the spot market scenarios this adds up to 86,400 scenarios in total.

The dispatch realization can be computed via an integrated maximization approach for the nodal pricing regime, while for the zonal pricing regime, the additional redispatch has to be calculated. For solving the forward market, I follow the solution algorithms suggested by de Maere d'Aertrycke and Smeers (2013). They solve the forward market as an iterative linear problem by fixing the forward price and updating it with the marginal

[10] For each demand scenario, a different number of dispatch realizations is needed, but their probability always adds up to 1. In the no correlation case, all 125 possible combinations are considered, in the no correlation - high variance case all 27 combinations are considered. The semi-correlated scenario adds up to 45 and the fully correlated scenario to 5 dispatch situations.

of the equilibrium constraint. The iterative solution algorithm allows us to introduce the bid-ask-spread $\chi$ as the difference between the bid and the ask price in the updating of the forward prices. With (bid and ask) prices being equal for all market participants the resulting equilibrium is a global optimum.[11] The global optimum property enables the comparison of the two pricing regimes. The solution algorithm starts with the initialization of the forward prices, which are then fixed in the forward market clearing. If the sum $\epsilon$ over the marginal of the forward quantities market clearing condition $\eta_c$ (equation 23b) is smaller than some pre-defined solution accuracy $\delta$, the algorithm stops.

---

Initialize $p_c^{f,bid} = 0, p_c^{f,ask} = 0$
**While** $(\epsilon \geq \delta)$ **do**
Forward market clearing
$p_c^{f,bid} = p_c^{f,bid} + \eta_c$
$p_c^{f,ask} = p_c^{f,bid} - \chi$
$\epsilon = \|\eta_c\|$
**end while**

---

## 3.3 Results

### 3.3.1 Efficient transmission forward market

The numerical simulation with the variations presented above confirms the general insights from the previous section. Figure 6 shows the delta performance of nodal to zonal pricing with respect to overall welfare. A positive (negative) number indicates better performance of nodal (zonal) pricing. For every parameter variation, the minimum and average of all scenario combinations are given. The numbers should be interpreted with care, because the absolute numbers depend highly on the chosen parameter setting. The shape and behavior of the different parameter variations however, can be used to gain general insights.

The average welfare lays in between 34,120 € for nodal pricing and 25,229 € for zonal pricing. In all considered scenarios, the delta is at least zero and clearly positive in most of the cases. For the varying grid configuration, which implicitly indicates the severity of bottlenecks, the relative performance of zonal pricing decreases with increasing grid capacities. Logically, with no bottlenecks both regimes have the same outcome. With increasing bottlenecks nodal pricing performs better. This is due to the increased costs

[11] The convergence of the algorithm with different starting values indicates that the equilibrium is unique.

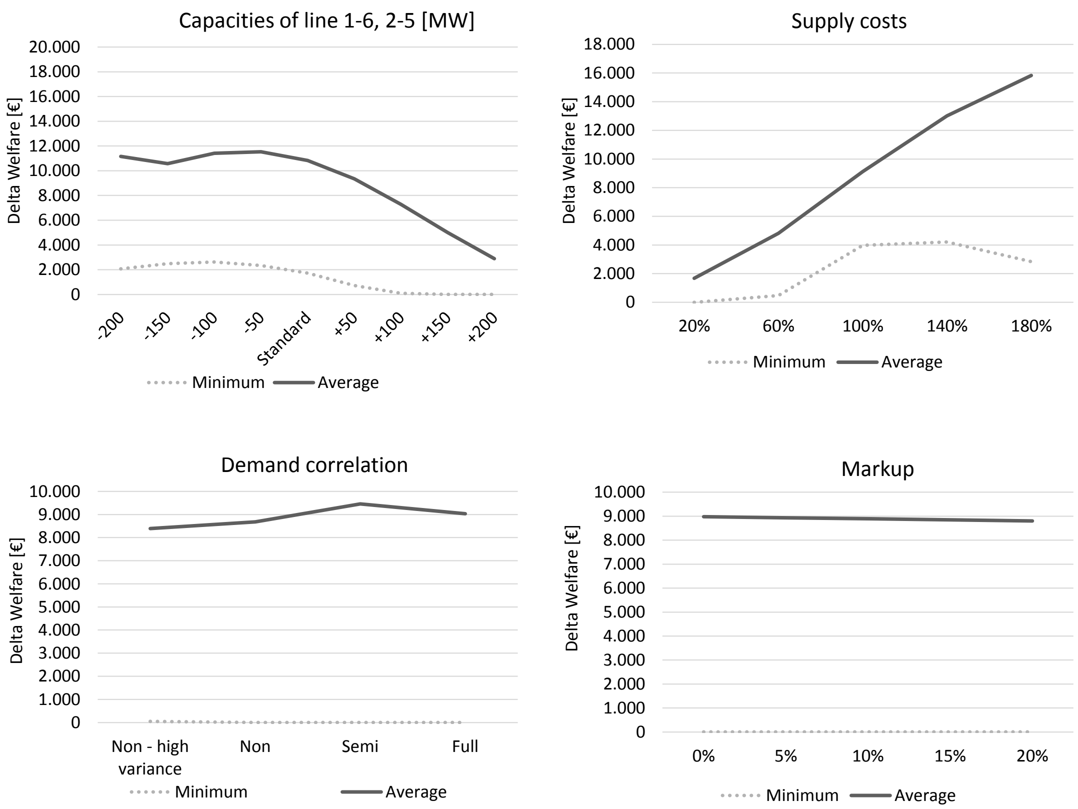



Figure 6: Delta performance of nodal to zonal pricing in the spot market

of redispatch measures in the zonal pricing regime.[12] This effect is similar for the cost variation. If supply is cheaper, the severity of bottlenecks in terms of costs decreases due to reduced overall system costs and hence costs of redispatch. If supply becomes more costly, a decline of the delta can be observed. This effect stems from reduced quantities due to decreasing demand. If the supply costs increase further, the delta would decline to zero at the moment when the demanded quantities become zero. The delta between nodal and zonal pricing depends slightly on the demand volatility, with a higher correlation of demand increasing the performance of nodal pricing. An increasing markup has no significant effect on the relative performance of the two pricing regimes.[13]

[12] The decline in the scenario with 150 MW below the standard can be explained by the supply and demand curves as well as the power flows. For the lines 1-6 and 2-5, transmission capacity is reduced simultaneously. This impacts the welfare or more precisely the delta welfare between nodal and zonal pricing in a non-linear way, e.g., due to one node not being supplied any more in the nodal pricing regime or a different redispatch in the zonal pricing regime.

[13] Some dispatch situations occur, where total welfare is higher for zonal pricing than for nodal pricing. This is due to the calculation method of the surplus: The profit of the retailer is added ex-post, not part of the optimization and furthermore depends on the quantities and volatility. In some cases

As for the spot market, the numerical simulation for the forward market yields the same overall outcome. Nodal pricing performs better in any parameter combination supporting again the general insights from before. Figure 7 shows the parameter variation for the forward market. Not very surprisingly, the fundamental parameters of the spot market have the same influence in the forward market. The reason for most minima indicating $\Delta W^f = 0$ can be explained by the effect of the increased grid capacities. At some point in the variation +150 MW and +200 MW grid capacity, there is no more congestion and hence the welfare converges. The two additional parameter variations impact the costs of risk. A smaller $\alpha$ indicates higher costs and a higher $\beta$ more impact of these costs in relation to the expectation value. The variation of $\alpha$ does not have much influence, which can be explained by the possibility of all market participants to find a counterpart to hedge their risks. Retailers can perfectly hedge their risks with the producers. The variation of $\beta$ seems to affect the delta between the regimes. However, as for the cost factor, this is mainly due to the variation in the overall welfare measure.

this causes (minimally) higher welfare for zonal pricing. However, this effect is due the calculation method and not dependent on the dispatch system. This partly not precise result is ignored in the further analysis.

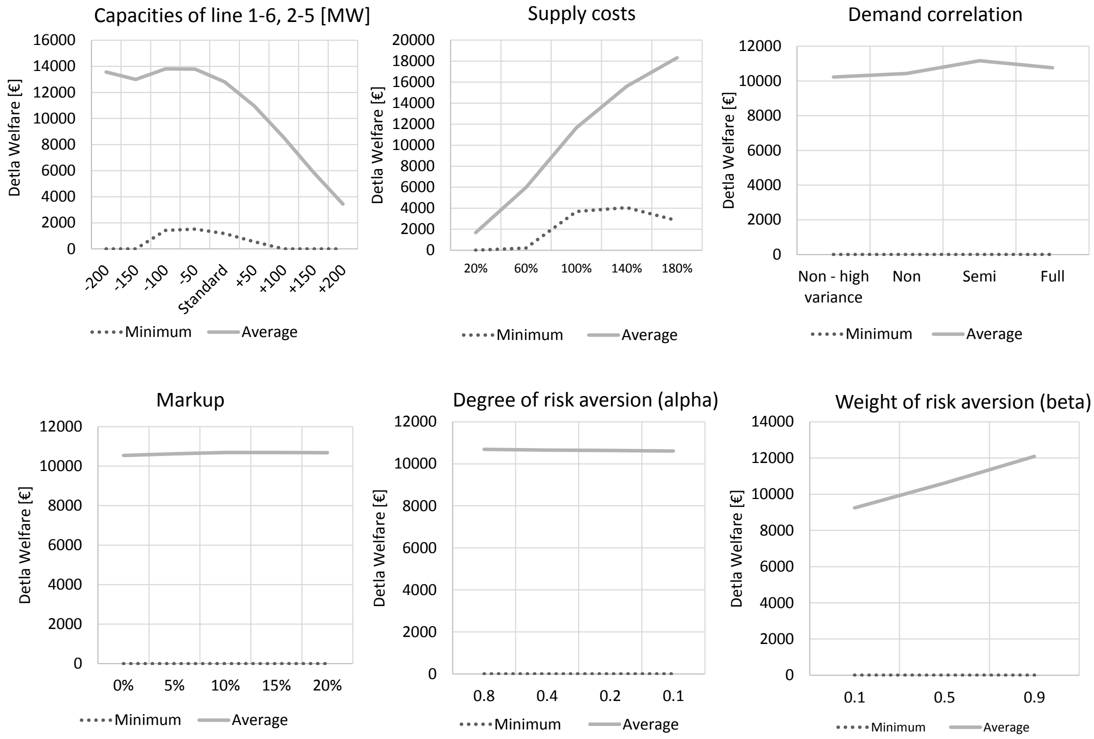



Figure 7: Relative performance of nodal to zonal pricing in the forward market

### 3.3.2 Inefficient transmission forward market

Now the case of an inefficient forward market for transmission is considered. Inefficiency in this context means that the forward contracts for transmission are not fully tradeable due to a positive bid-ask-spread. Hence, market participants are not able to hedge their risks up to the desired level. Obviously, an inefficient transmission forward market reduces the overall welfare in a nodal pricing regime. Unhedged risks of market participants cause additional capital requirements. The impact on welfare then depends on the nodal price volatility in the spot market which causes the risks in the first place. Furthermore, the level of the additional capital required reduces the overall welfare level. In addition, the reduced traded quantity of transmission forward contracts possibly impacts the traded quantity of energy forwards and intensifies the welfare reduction (also shown by de Maere d'Aertrycke and Smeers (2013)). If this welfare reduction is larger than the inefficiencies in the zonal spot market, a zonal performs better than a nodal pricing regime. This trade-off might appear to be simple, but it is influenced by several factors, which are fundamental for both effects. The final trade-off then depends on the structure of demand, cost differences, severity of congestion as well as the level of inefficiency in the forward transmission market and the capital requirement.

Figure 8 shows the number of scenarios wherein zonal pricing performs as good as or better than nodal pricing for the fundamental factors. The overall number of zonal pricing performing better is small compared to the overall number of scenarios.

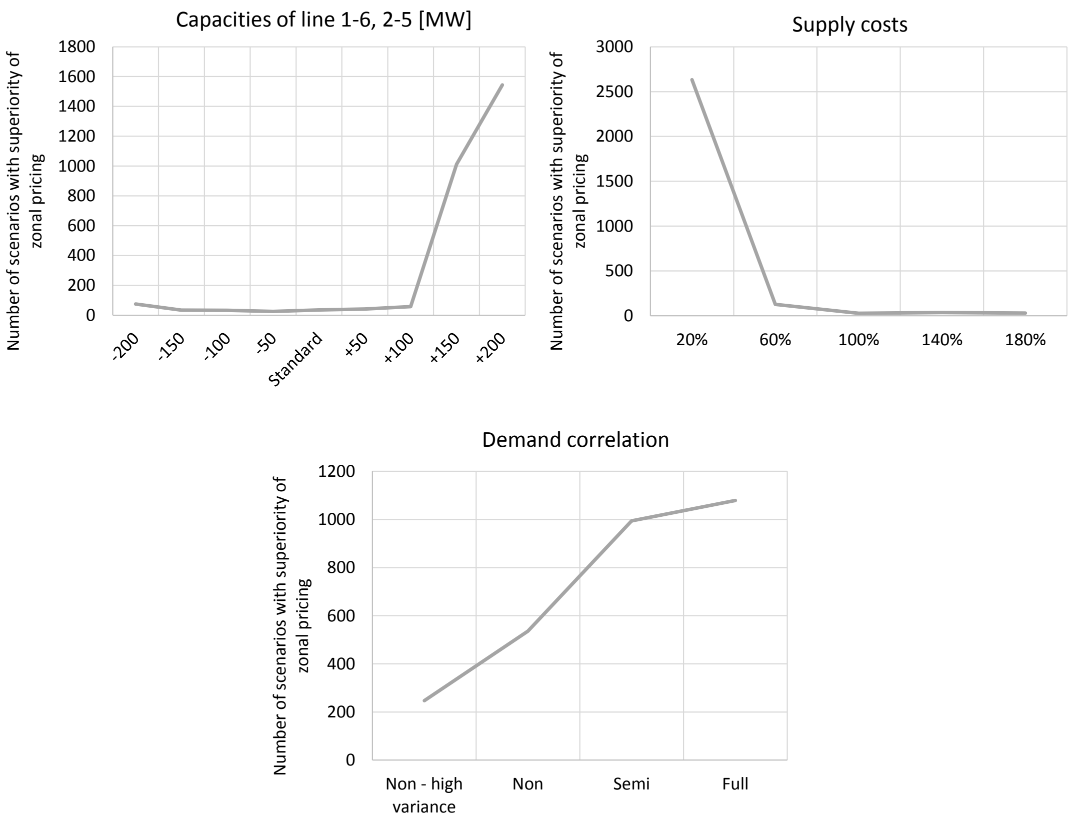



Figure 8: Number of scenarios with zonal pricing performing equally or better than nodal pricing dependent on parameter variation

Despite the total percentage of zonal pricing being advantageous is small, some scenarios could still be highly relevant. Interesting are the general trends where zonal pricing performs better than nodal pricing. For the grid variation, it can be seen that zonal pricing comes closer or performs better than nodal pricing, if there is little congestion. On the one hand this is due to the overall convergence of the pricing regimes in case of no congestion. On the other hand with little congestion, redispatch costs become smaller while costs from inefficiency become more relevant. For the costs variation, small costs induce low redispatch costs and therefore make the inefficiencies of zonal pricing cheaper.

For demand correlation, the results are somehow counter-intuitive at first sight, since the relative performance of zonal pricing seems to be increasing with correlation. This can again be explained by the convergence of the market outcomes if congestion is low which is the case for higher correlation.

Figure 9 shows the relative performance between the pricing regimes for each parameter variation relevant for the inefficiency of the forward transmission market. Increased markups reduce losses and hence the needs for hedging, leading to the straightforward result of a stabilized performance of zonal relative to nodal pricing. An increasing bid-ask-spread leads to a more inefficient market and hence, zonal pricing performance improves. Also straightforward are the results for risk aversion. With increasing risk aversion and increased weight put on this risk aversion, more hedging is required and it is more expensive in terms of welfare not to be able to hedge.[14]

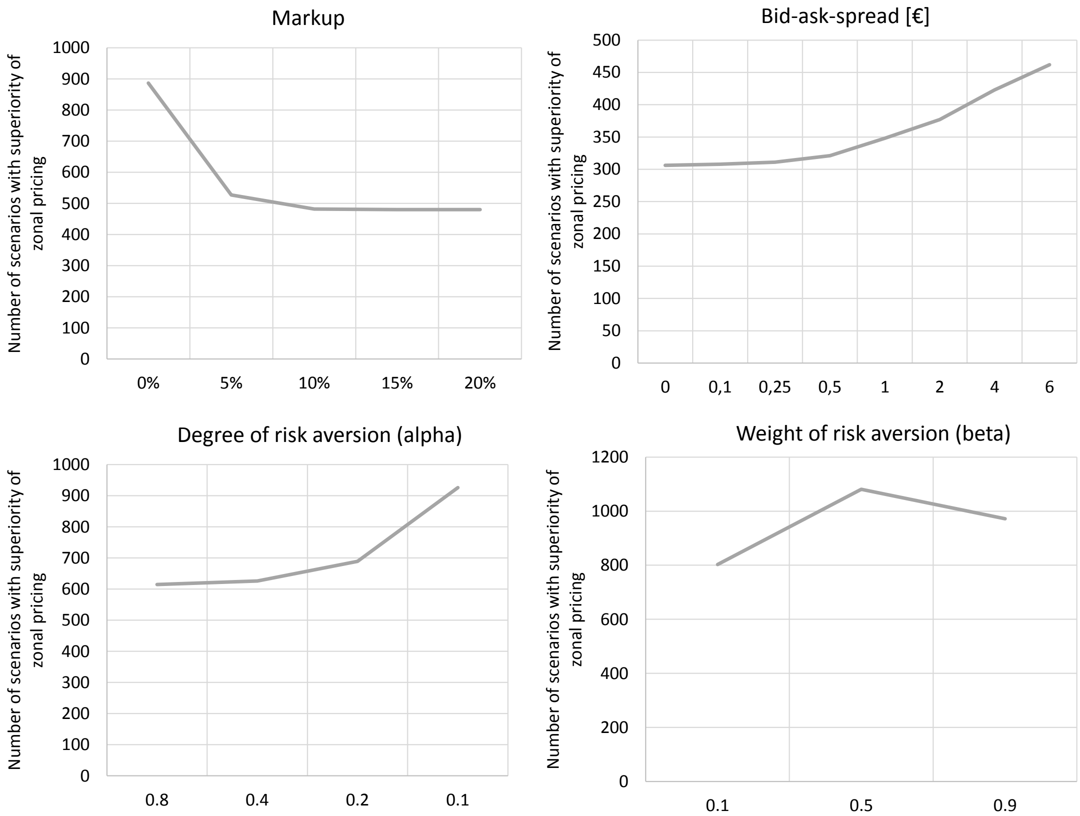



Figure 9: Number of scenarios with zonal pricing performing equal or better than nodal pricing dependent on parameter variation

[14] The slight peak of $\beta = 0.5$ can again be explained by non-linearities caused by the underlying fundamental values.

Even a small increase of the bid-ask-spread reduces traded quantities drastically.[15] Furthermore, the impact of an inefficient transmission forward market on the traded quantity of the energy forward can be seen in figure 10. A reduced volume of forward transmission trades induces a lower quantity of energy forward trades. Retailers try to hedge their local risk, for which they have to buy an energy forward at the hub and a transmission forward. If transmission forwards become less attractive due to an increased bid-ask-spread, they also reduce the number of energy forwards for their hedging.

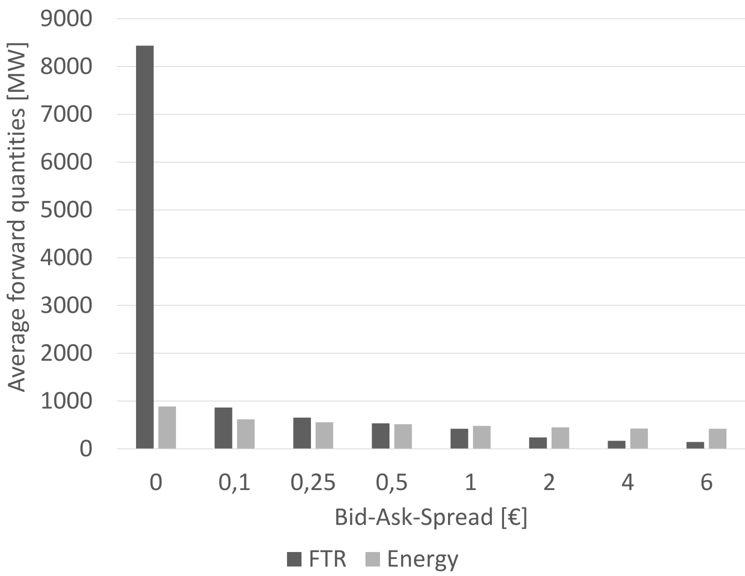



Figure 10: Average forward quantities of nodal pricing

While the reduction of volumes is drastic when introducing a bid-ask-spread, the impact on prices is lower as shown in table 2.[16] Prices increase slightly with decreasing efficiency. Of course, this stems partly from averaging the values. Simulations with higher risk aversion induce higher price reductions, e.g. for $\alpha = 0.1, \beta = 0.9$ an energy price difference of 5 occurs between the efficient transmission market and a bid-ask-spread of 4. No shifting from one FTR to another seems to take place when looking at the prices. The reason for this however is that the bid-ask-spread is equal for all FTR, keeping the general relationships stable.

[15] The quantities in the liquid case are significantly higher as in de Maere d'Aertrycke and Smeers (2013) which is due to a high trading activity of the TSO, which is assumed to be risk neutral.

[16] The negative value for FTR4 from node 4 to node 6 indicates that with a higher bid-ask-spread the direction of the FTR changes.

| | Bid-Ask-Spread | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **0,0** | **0,1** | **0,25** | **0,5** | **1,0** | **2,0** | **4,0** | **6,0** |
| **Energy (6)** | 44,4 | 44,4 | 44,4 | 44,5 | 44,5 | 44,7 | 44,9 | 45,1 |
| **FTR1 (6-1)** | 20,9 | 21,0 | 21,1 | 21,2 | 21,3 | 21,7 | 22,1 | 22,5 |
| **FTR2 (6-2)** | 16,7 | 16,8 | 16,8 | 17,0 | 17,1 | 17,5 | 18,2 | 18,8 |
| **FTR3 (6-3)** | 19,1 | 19,2 | 19,3 | 19,4 | 19,6 | 19,9 | 20,6 | 21,1 |
| **FTR4 (4-6)** | 1,8 | 1,8 | 1,7 | 1,6 | 1,4 | 1,0 | 0,4 | -0,1 |
| **FTR5 (6-5)** | 4,1 | 4,1 | 4,2 | 4,3 | 4,4 | 4,7 | 5,4 | 5,9 |

Table 2: Average prices for forward contracts with nodal pricing [€]

# 4 Conclusions

The literature has shown the theoretical superiority of nodal pricing compared to zonal pricing in efficient markets. Zonal pricing is inherently inefficient due to hidden scarcities of transmission constraints. Empirical work, however, showed that forward markets for financial transmission rights in nodal pricing regimes might lack efficiency impacting the performance of nodal compared to zonal pricing.

In this paper, a zonal and nodal pricing regime were compared and the impacts of an inefficient transmission forward market were analyzed. The general effects have been shown in a simple two node model. The conclusions for efficient markets were confirmed. The trade-off between an inefficient transmission forward market (in a nodal pricing regime) and the inherent inefficiencies of redispatch (in a zonal pricing regime) have been formalized. Comparative statics were performed with a model incorporating more nodes, loop flows as well as energy and transmission forwards. For this, the nodal pricing spot and forward market model by de Maere d'Aertrycke and Smeers (2013) was extended by a zonal pricing approach and a producer-only redispatch. Furthermore, the volume constraint reducing efficiency was replaced by a formulation via a bid-ask-spread.

The relative performance of the pricing regimes has been tested for a wide range of scenarios with varying demand volatility, supply costs, grid configurations, markups and risk aversion. The results for the spot market showed that nodal pricing is always performing at least as good as zonal pricing (and better in nearly all considered cases). This holds also for the case of an efficient forward market, regardless of the parameter setting. Inefficiencies in the forward transmission market, in terms of a positive bid-ask-spread and risk aversion of market participants, lead to situations wherein zonal pricing outperforms nodal pricing. Given all considered parameter variation this happens only in a relatively small number of cases. Nevertheless, this matters if these cases are the most relevant ones. It seems plausible that each pricing regime performs better, if the respective weaknesses, i.e., the inefficiency of the forward transmission market or the inherently inefficient redispatch, are highly relevant: A nodal pricing regime performs better, if congestion within a zone is severe and costly. In turn, a zonal pricing regime performs better, if the bid-ask-spread and the risk aversion are high.

The results imply that the trade-off between the respective weaknesses of the pricing regimes should be considered carefully. In larger electricity systems such as the European one, some sort of in-between solution might be favorable, i.e., by properly defining bidding zones by considering the respective inefficiencies. However, other factors such as market adaptation to newly defined zones and transaction costs have to play a role within such considerations.

Further research should clarify whether or not the findings of the rather simple numerical setting can be transferred to a more complex one. In addition, the effects of strategic behavior, different preferences, portfolio effects or uncertainty are worthwhile considering.

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