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FTR Allocations to Ease Transition to Nodal Pricing: An Application to the German Power System

Friedrich Kunz¹, Karsten Neuhoff², Juan Rosellón³

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Abstract

A shift from zonal pricing to smaller zones and nodal pricing improves efficiency and security of system operation. Resulting price changes do however also shift profits and surplus between and across generation and load. As individual actors can lose, they might oppose any reform. We explore how free allocation of financial transmission rights to generation and load can be used to mitigate the distributional impact. In a three node network we explore the fundamental effects with regard to reference node/hub for FTRs, the share of FTRs to be allocated for free and the metric to determine the proportion of rights allocated to different generation and load. We test the results in a more realistic setting based on hourly modelling of the German power system at nodal representation.

Keywords: Electricity market, Financial transmission right, Congestion management, Market design, Germany

JEL-Codes: L52, L94, Q40, D47

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1 Introduction

Among academics, but now every time more among policy makers in many countries, it has become increasingly accepted that nodal pricing is the most secure and efficient way of operating a power system. However, one major obstacle for implementation of nodal prices or the definition of smaller pricing zones is their implied distributional impacts. For instance, generators in low-price and loads in higher-price zones might lose out with the new pricing system.

Therefore, a central element for the successful implementation of nodal pricing has been the parallel allocation of financial hedges, such as Financial Transmission Rights (FTRs) (e.g., in the electricity markets in the Northeast of the USA). Such a process has allowed: (i) to compensate losers, and (ii) to reduce the risk for players since they become protected against potential price impacts. The latter point is particularly relevant since most market participants are risk averse, particularly towards risks that are partially attributed to regulators like a power-market design choice. Such risks are naturally difficult to assess.

Notwithstanding, the *initial* allocation of FTRs in a newly created nodal-price system has in particular been one of the most highly disputed parts of market liberalization processes (e.g., New Zealand and Australia). After all, an initial provision of FTRs boils down to sharing the pie of congestion rent among the various market participants.⁴ In the United States, for instance, the early implementation of an FTR market in the NYISO had to deal with “grandfather” contracts. That is, long-term hedging contracts which were to be respected during the allocation of new FTRs within transformation of the system to nodal prices. In New Zealand, the adoption of nodal prices dates back to 1989, but hedging contracts were not immediately implemented. Discussions on FTR implementation takes place, both at the inter- and intra-regional levels. In Australia, a zonal pricing system developed that has complicated the initial allocation of FTRs. There are discussions to evolve in Australia to a fully nodal-pricing scheme (which has proven to support FTR contracts more firmly) but, again, the implied sharing of rents among economic agents is a serious obstacle.

In Europe transmission rights between pricing zones had been grandfathered as physical transmission rights between pricing zones (usually countries) to match commercial contractual arrangements at the time of liberalization of the power markets, These long-term transmission rights

⁴ One proven advantage, however, has been that through the introduction of nodal pricing in liberalized markets, the overall level of network utilization increases, and therefore also the volume of FTRs that are available for allocation.

have been largely phased out, and as of 2014 most transmission rights between pricing zones are auctioned for a year and shorter time periods. Financial transmission rights are only present in the Nordic area, but are exclusively bilateral contractual arrangements with limited liquidity as the transmission system operator does not issue transmission rights backed by congestion revenue like in the other markets.

In this paper, we develop a model to explore how an initial free allocation of FTRs at the time of a transition to nodal pricing could be designed so as to avoid revenue or cost shocks for generation and load. We first analyze a simplified three-node network to illustrate the basic dynamics of the model, and then we obtain simulated results for the German power system so as to quantify the merits of different FTR allocation approaches. In all approaches, the allocation remains independent from sub-sequent operational choices by generation and load so as to avoid distorting effects. The modeling effort is focused on the distributional aspects and does not quantify the impact on efficiency savings or system security.

In our three node network we address the optimal allocation of FTRs – assuming that the regulator has full information across the entire system—so as to investigate to what level the FTR allocation may dampen volatility. However, in practice it might be difficult to replicate an optimal allocation scheme that, for example, could minimize the welfare losses for changing from a uniform-pricing system to a nodal one. In particular, how could a European regulator agree on the necessary parameterization for a corresponding EU power system model that would be the basis for such an optimal FTR-allocation approach? We thus subsequently consider simplified FTR allocation methods that could be available in practice, and simulate the results to compare across such allocation methods.

The rest of the paper is organized as follows. In section 2 we review some international experiences on allocations of FTRs. In section 3 we present our models for uniform pricing, nodal pricing and for the optimal allocation of FTRs. In section 4 we study in a three-node network how different FTR allocation methods compare, while in section 5 we do the same thing but using real data from the German power market. Section 6 concludes.

2 FTR Allocation: International Experiences

FTRs have mainly being implemented during the last decade. The technical characteristics of an electricity grid (as represented by the Kirchhoff’s laws) has led economists to create markets for transmission property rights (Hogan, 1992). FTR markets were implemented in the northeast US

power markets during the late nineties. In other countries, there have been intense discussions on the need of congestion hedging from transmission price risk, such as the case of New Zealand where nodal prices were implemented as early as 1989.

An FTR is typically defined according to: i) an injection node or zone and a withdrawal node or zone that permit to characterize the point-to-point direction of the electricity flow and the contract, ii) a megawatt (MW) award that remains invariable for the length of the contract, and iii) a life term. FTRs are typically of two types: FTR-obligations and FTR-options. With an FTR obligation the holder has the right to collect payment (when congestion takes place) or the requirement to pay (when congestion in network occurs in the opposite direction as originally defined in the FTR contract). The payment is given by the difference in prices between the injection node and the withdrawal node times the accorded contractual amount of MW. In contrast, FTR options grant only the non-negative gains to its owner since there is no charge when congestion occurs in the opposite direction of the FTR

In practice, a popular way to allocate FTRs is through auctions run by an ISO. In such processes, the ISO typically has to ensure that only *feasible* FTRs are issued. That is, the associated transmission flow should not violate the capacity constraints in a power-flow model. Hogan (1992) shows that if such FTRs are obligations, then the revenue from congestion rent in the spot market is adequate to cover all payments in the FTR contracts.

In this paper, we are interested in the process of *initial* allocation of FTRs in a recently restructured market. Such a process is usually characterized by intricate negotiations among the different market players since all of them would like to preserve rent privileges. We analyze how these negotiations took place in various countries in the following paragraphs.

2.1 NYISO

One of the earliest FTR markets arose in the US State of New York, operated by the New York Independent System Operator (NYISO). Transmission congestion contracts (TCCs) are FTRs that periodically started to be auctioned since 1999 at the NYISO market. TCCs are defined as point-to-point transmission-right obligations (i.e, they might be negative⁵) that act only as financial swaps (Adamson and Parker, 2013). Market participants include generators, utilities, marketers and financial firms such as banks and hedge funds. TCCs are usually sold for periods from 1 month up to 2 years, and they are auctioned previous to the month they will be covering.

⁵ Reverse auctions are carried out to allocate TCCs with negative value.

Typically, utilities and retailers in the NYISO market purchase FTRs to hedge congestion risk, while hedge funds and trading groups generally buy FTRs as speculative capital. Generators, marketers and banks obtain FTRs both for hedging and speculative purposes. Since their inception in 1999, the total volume of FTRs awarded substantially grew between 2000 and 2001, and remained stable since then. Retailers acquired FTRs in great deal during 2000-2005, but since then financial agents (banks and funds) have become increasingly important. The amount of FTRs acquired by utilities has remained relatively large and constant over time.

In the early days of the NYISO's operations, "grandfathered" TCCs were awarded to market agents. These rights replaced previously existing *physical* rights over the grid. Various these rights were of very long duration, and were owned by New York utilities who later converted them into FTRs directly. That is, FTRs were initially allocated according to the previous transmission capacity rights of utilities (and not through an explicit auction). This of course represented an initial condition for the later formal implementation of FTR auctions. Adamson and Parker (2013) analyze the efficiency implications of the FTR auction system in the NYISO market, and conclude that after an initial relative inefficiency market participants over time learned the rules so that nowadays the forward-looking allocative efficiency of the NYISO's FTR market design is pretty robust.

2.2 New Zealand

The electricity market of New Zealand is in turn one of the first full nodal-pricing markets. Naturally, it was also one of the first places where the FTR concepts were discussed, but after more than 20 years no formal FTR market has been implemented. It is only now that a limited FTR market might be implemented. According to Read and Jackson (2013), such a long delay might partly be explained by the special characteristics of the New Zealand's market which is mainly dominated by hydro generation, with a sparse network, and where reserve support is typically more important than network capacity constraints. When the nodal pricing system was initially established, the introduction of FTRs was also proposed. However, at that time this was deferred due to little existing transmission congestion (which in turn implied less urgency in the allocation of rents), and also due to the impossibility of reaching any consensus in a market with a recently reform regarding ownership and vertical disintegration of public utilities.

In 2002, a proposal for a full FTR market was carried out (Transpower, 2002). However, Read and Jackson (2013) explain that it was opposed by many agents that feared that such proposal would imply losses of rents that they earned from their captive local markets. Joskow and Tirole (2000) have demonstrate that FTRs could enhance the level of competition by allowing outside parties to

offer energy contracts. In recent years, as congestion rents have increased, further discussions on the creation of an FTR market have again gained attention. Still, Read and Jackson (2013) argue that many market participants once more oppose an FTR market due to the potential rent redistribution that it might imply. For instance, it could reduce the market power of incumbents in small regions.

Read (2009) then proposed a smart way to carry out *initial* allocations of rents to loads in such a way that it approximates those allocations of an efficient FTR market: the Locational Rental Allocation (LRA). The FTR/LRA regime would hedge loads in an island to its generation weighted average hub price (GWAP). Inter-island trade would then take place between GWAP hubs. As Read (2009) explains, a system like this would however still be difficult to implement under FTR *obligations* due to the “tidal-flow” nature of the New Zealander electricity system: South-to-North flows in a wet year, and North-to-South flows in a dry year. Therefore, the FTR market should preferably rely on *options*.⁶

2.3 Australia

Compared to New Zealand, the Australian electricity market is a zonal-price market facing quite different design issues. The impacts of congestion constraints depend on whether the constraints involved are intra-regional or inter-regional. Regions correspond to states, which are centered around a major city. Little cross-border network developments have taken place among states. Within regions, market participants face a regional reference price given by the marginal cost minus a loss factor that is fixed annually. The Australian market then operates as if there were interconnection linking these reference nodes into a *loop-less* “tree structure” (Read and Jackson, 2013). Market clearing is achieved imposing constraints that assure that generator dispatch is feasible, given the loads and available network capacity. However, this is not done in a sort of power-flow model (which would include constraints on line flows) since there is no nodal pricing. Rather, thousands of constraints are applied for each particular case on loads and network condition.

Intra-regional congestion occurs rather rarely, so that inter-regional congestion and hedging have more relevance. Therefore, a sort of congestion rent -the interregional settlement residue (ISSR)—was made available to providers of hedging products, such as swaps or other financial instruments. The ISSRs were auctioned aiming to resemble a *flow-gate* right design (as in Chao et al., 2000).

⁶ Of course another implementation issue would be the achievement of the required *revenue adequacy* in such a system. For example, some market participants argue that it is not clear to them why rents generated in the Southern Island system should support FTRs traded in regions that do not utilize any part of the Southern Island network.

However, a complication arose since rents collected for the flow-gates did not always match the hedging requirements of participants because of the insufficient representation of the full network with a limited number of flow-gates. Therefore, the auctions of ISSRs have not been perceived as providing a reliable risk management tool.

Thus, there have recently been more alternative proposals in Australia to provide revenue-adequate hedging to market participants. One of them is of course the implementation of a full nodal-price system. However, many market players oppose the change (and involved transaction costs) in a new system implied by nodal pricing. Read (2008) then proposes an intermediate alternative where all market participants (generators, loads, network capacity and ancillary-service providers) are selectively exposed to nodal pricing, but provided with FTRs to hedge the risk implied. Given the many vested interests involved, the major implementation obstacle to such a proposal is (once more) how congestion rents would be allocated among market participants, such as between generators and interconnector flows, and between new and old market players.

2.4 Europe

de Maere d'Aertrycke G. and Smeers (2013) analyze the potential introduction of FTRs in the European *market-coupling* system (MC). MC was first implemented in the Central-West-Europe region comprising Belgium, France, Germany and The Netherlands, and is gradually expand to neighboring countries. MC relies on zones, rather than on nodes. It can be based either on *Transfer-Capacity* (TC) model or on a *Flow-Based* model (the latter replaces the transfer capacities of zone interconnections by PTDF relations). The MC system has no real-time market but a day-ahead one, and it is in the process of implementing an *intraday* market.

Given the MC system under the TC and FB models, de Maere d'Aertrycke G. and Smeers (2013) use two and three-zone stylized topologies to explore the potentiality of creating a European FTR market as suggested in ACER (2011). In doing so, they assume that in the MC region FTRs rely on zonal-price differences (as opposed to nodal-price differences, as in a nodal-pricing system). They show with various examples that –both for the TC and FB models– FTRs under the MC system would not lead to simultaneous feasibility and, hence, would not be revenue adequate. That is, the zonal-pricing nature of the MC system, together with the lack of real-time markets, lead to lack of firmness of FTRs and thus make the ACER's foreseen transmission-right framework guidelines unlikely.

In this paper we explore a different (but related) issue as the one discussed in de Maere d'Aertrycke G. and Smeers (2013). Namely, we compare different FTR initial-allocation methods

that seek to hedge market participants from a transition from uniform pricing to nodal pricing. We carry out this analysis first in a three-node network, and then we obtain simulated results for the German power system.

3 Optimization Models

For our simulations we specify three optimization models. The underlying nomenclature of indices, parameters and variables is given in Appendix 8.1. The first model characterizes the current German electricity market clearing approach with a uniformly priced national spot market fully abstracting from physical transmission limits and a subsequently following congestion management based on curative power plant redispatch (Kunz, 2013). The second model follows the idea of nodal pricing and combines the economic dispatch of power plants in the spot market and the optimal operation of the physical transmission network. Both models, the uniform and nodal pricing model, differ in the way congestion in the transmission network is handled. The uniform pricing model relies on curative methods (re-dispatch), whereas preventive congestion management is applied in the nodal pricing. Finally, we specify a third optimization model which deals with the allocation of Financial Transmission Rights to market participants based on the results of the uniform and nodal pricing market models. Herein, the feasibility and the revenue adequacy of the FTR allocation are checked out.

3.1 Uniform Pricing Model

3.1.1 Market Clearing

The uniform pricing model starts with the optimization of the generation dispatch (Equation 1) subject solely to the energy balance of demand and supply (Equation 2), and the maximum generation restriction (Equation 3). Thus, restrictions stemming from limited transmission capacity of the network are not taken into account which results in a uniform price for the entire electricity market.⁷

$$\min_G \sum_{p,t} mc_p G_{p,t} \quad (1)$$

$$\sum_n d_{n,t} - \sum_p G_{p,t} - \sum_n g_{n,t}^{RES} = 0 \quad (2)$$

$$0 \leq G_{p,t} \leq g_p^{max} \quad (3)$$

⁷ The dual of the energy-balance constraint (2) provides such a uniform price.

3.1.2 Congestion Management

Given the optimized generation dispatch of the market clearing model, network restrictions due to limited transmission capacity are considered in the congestion management model. Herein, the generation dispatch is adjusted in order to ease overloading of transmission lines. The congestion management model minimizes the congestion management cost consisting of upward G_p^{UP} and downward regulation G_p^{DOWN} of generation enumerated at their marginal cost (Equation 4). The approach reflects the cost-based redispatch. Again, the energy balance (Equation 5) has to be ensured as well as maximum and minimum generation restrictions (Equation 6 and 7). The parameter g_p reflects the optimized generation of the market clearing model. Finally, the feasibility of the transmission flows is ensured in Equation 8 and 9 using a DC load flow approach (Leuthold et al., 2012).

$$\min_{G^{UP}, G^{DOWN}, \Delta} \sum_{p,t} mc_p (G_{p,t}^{UP} - G_{p,t}^{DOWN}) \quad (4)$$

$$d_{n,t} - \sum_{p \in A(n)} (g_{p,t} + G_{p,t}^{UP} - G_{p,t}^{DOWN}) - g_{n,t}^{RES} - \sum_{nn} b_{n,nn} \Delta_{n,t} = 0 \quad (5)$$

$$0 \leq G_{p,t}^{UP} \leq g_p^{max} - g_{p,t} \quad (6)$$

$$0 \leq G_{p,t}^{DOWN} \leq g_{p,t} \quad (7)$$

$$\left| \sum_l h_{l,n} \Delta_{n,t} \right| \leq p_l^{max} \quad (8)$$

$$\Delta_{n',t} = 0 \quad (9)$$

3.2 Nodal Pricing

In contrast to the uniform pricing model, the nodal pricing model combines the optimization of the generation dispatch and the transmission usage. Thus, the previously specified market clearing model of the uniform pricing model is extended by transmission network restrictions (Equation 8 and 9) to form a nodal pricing approach. The model minimizes generation costs (Equation 10) subject to the nodal energy balance (Equation 11), generation capacity limitations (Equation 3), and DC load flow restrictions (Equation 8 and 9).⁸

$$\min_{G, \Delta} \sum_{p,t} mc_p G_{p,t} \quad (10)$$

$$d_{n,t} - \sum_{p \in A(n)} G_{p,t} - g_{n,t}^{RES} - \sum_{nn} b_{n,nn} \Delta_{n,t} = 0 \quad (11)$$

⁸ The dual of the energy-balance constraint (11) provides the nodal prices.

3.3 FTR Allocation

In the following we define two approaches, *volume-* and *capacity-based*, for an initial allocation of FTR obligations. We define a reference bus, as demand weighted average of all nodal prices, thus following the typical definition of trading hubs in US systems. FTRs are issued from generation nodes to the reference bus and from the reference bus to nodes with load. As any trading relation can be hedged with such a pair of FTRs, point-to-point FTRs are not necessary and not considered.

As we are focusing on the distributional effects, we do not model any re-trading of the FTRs or auctioning of FTRs not issued for free that would be motivated by market participants that aim to more closely hedge exposure to congestion costs with FTRs. Such re-trading, would under the assumption of perfect competition have a distributional impact.

The first approach allocates FTRs to conventional (FTR_p^G) and renewable (FTR_n^{RES}) generators based on historical production⁹ (*volume-based approach*), whereas the second approach relies on installed generation capacities (*capacity-based approach*) to determine the amount of FTRs. These measures are applied for the allocation of FTRs to conventional and renewable generation. On the demand side, FTRs (FTR_n^D) are allocated relative to consumption given the total amount of FTRs allocated to generation. For both allocation approaches, we explore different levels or amounts of total FTRs ranging from 0% to 100% of historical generation or installed capacity, respectively.

For each allocation approach, the feasibility as well as the revenue adequacy is checked. Feasibility means that FTR allocation is feasible with the underlying physical transmission network and their capacities (Equations 8, 9, 12, and 13). On the other hand, revenue adequacy requires that the payments resulting from FTR obligations do not exceed the congestion rent cr_t^{TSO} earned by the TSO (Equation 14). If the initial allocation is feasible in these terms, the implications on market participant's surplus are quantified as additional revenues stem from holding an FTR due to nodal price differences. The price at the reference bus ($price_{slack,t}$) where all FTRs are related to is defined as the demand weighted average of all nodal prices.

$$\sum_n FTR_n^D - \sum_n FTR_n^{RES} - \sum_p FTR_p^G = 0 \quad (12)$$

$$FTR_n^D - FTR_n^{RES} - \sum_{p \in A(n)} FTR_p^G - \sum_{nn} b_{n,nn} \Delta_{n,t} = 0 \quad (13)$$

⁹ Historical production refers to generation quantities realized under uniform pricing over a specified time horizon from the past. Therefore, it is assumed that market participants can not alter their generation in order to impact the FTR allocation. In the following calculations, we use the generation quantities of the uniform pricing setting for the FTR allocation.

$$cr_t^{TSO} - \sum_p (price_{slack,t} - price_{A(n),t}) FTR_p^G - \sum_n (price_{slack,t} - price_{n,t}) FTR_n^{RES} - \sum_n (price_{n,t} - price_{slack,t}) FTR_n^D = 0 \quad (14)$$

4 FTR Allocation in a Three-Node Network

In a first step, we consider a simple three-node network setting in order to examine the implications of the different initial FTR allocation approaches on the different market participants. Generally, we consider two time steps reflecting off-peak and peak load, two conventional generators with different marginal generation cost, as well as two load locations. The underlying transmission infrastructure is characterized by equal technical characteristics and only one particular line has limited capacity. The setting is summarized in Figure 1.

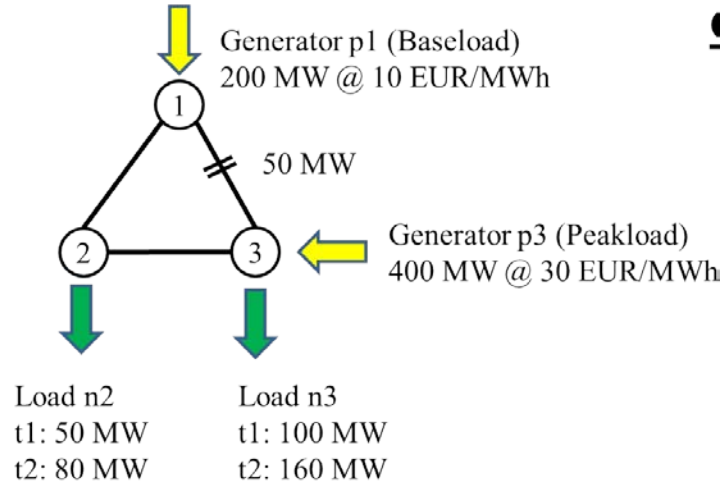


Figure 1: Three-node network setting with two time periods (t1,t2), symmetric resistance of lines and a transmission constraint of 50MW on line 13.

Table 1 depicts the surplus of the considered market participants for the uniform and the nodal pricing regime. Due to the different ways of managing network constraints, market prices differ and hence the surplus of load and generation. Furthermore, the transmission part faces congestion management cost in the uniform pricing for shifting production from cheap to expensive generation assets to correct for violations of the transmission constraint (re-dispatch) and revenues in the nodal pricing stemming from an implicit allocation of network capacity. Further on, we assume in a first step that the transmission surplus is redistributed or socialized to load as part of the network

tariffs.¹⁰ Thus, loads at nodes 1 and 2 are left with an overall benefit of 2200 EUR and 1800 EUR, respectively. On the other hand, generation p1 is negatively affected and faces a loss in surplus by -4000 EUR for the two considered time periods.

Table 1: Summary of market participant's revenue, costs, and surplus in different pricing regimes

	Uniform pricing	Nodal pricing	Surplus change including socialized transmission surplus
Load			
n2			
Revenue	0	0	--
Costs	3800	2600	--
Surplus	-3800	-2600	+2200
n3			
Revenue	0	0	--
Costs	7600	7800	--
Surplus	-7600	-7800	+1800
Generation			
p1			
Revenue	6150	2150	--
Costs	2150	2150	--
Surplus	4000	0	-4000
p3			
Revenue	5250	5250	--
Costs	5250	5250	--
Surplus	0	0	0
Transmission			
Revenue	1350	3000	--
Cost	4050	0	--
Surplus	-2700	3000	Socialized to load

So far, we have considered a full redistribution of transmission surplus to load which results in overall profits for them. In the following, we relax this assumption and apply an initial FTR allocation which then allocates transmission surplus in particular the congestion rent of the nodal pricing to all market participants thus including also generators. Figure 2 depicts the implications of an increased amount of FTRs allocated to market participants based on either their installed capacity or the historical production of the uniform pricing regime. If not all congestion rent is

¹⁰ The transmission surplus is socialized to load in each node according to their share on the entire load. Furthermore, the distribution of transmission surplus solely to load instead of generation or a combination of both reflects the current approach of most European countries.

allocated through FTRs, the remaining rent is again socialized to load. The allocation is undertaken as long as the feasibility of the FTR allocation is ensured.

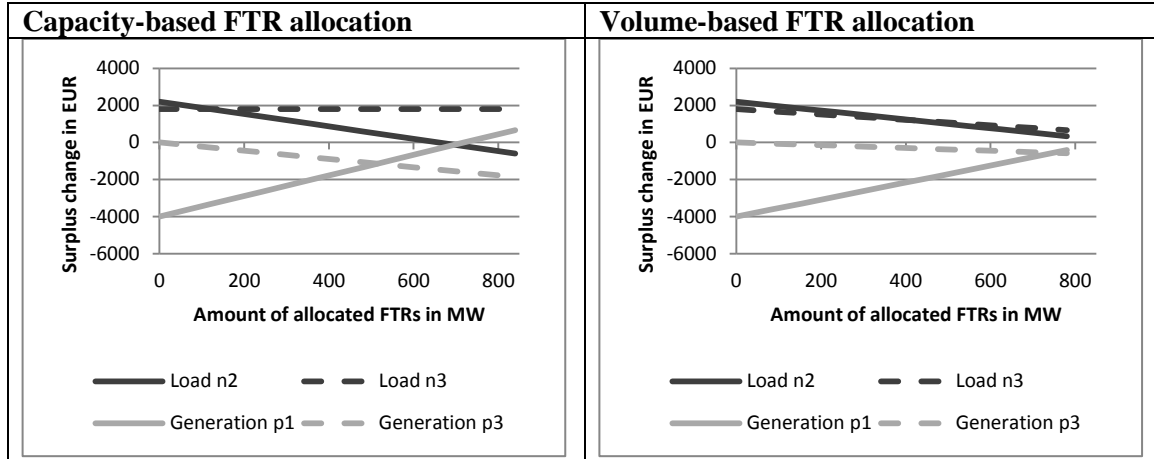


Figure 2: Change of market participant's surplus between uniform and nodal pricing considering different initial FTR allocation regimes in the three-node setting

As can be seen in Figure 2, both allocation approaches initiate a redistribution of congestion rents and bring down the loss or profit through a pricing change for most market participants. This is particularly true for the volume-based allocation where the loss experienced by generation is nearly compensated. On the other hand, the initial gain of load is decreased and redistributed to generation. If we consider instead an allocation of FTRs based on installed capacity, the general result remains true. The peak generator located at n3 obtains with a capacity based allocation more FTRs than in the allocation based on historic (modelled) production. As the price at n3 is higher than at the reference node, the allocation of the FTR requires a payments from the FTR holder, hence the declining surplus of the peak generation at n3.

If we adjust the optimization problem described in Section 3.3 to minimize the absolute difference between surpluses of both pricing regimes, we can easily determine an optimal initial FTR allocation which minimizes the surplus variance.¹¹ Within this approach, the FTR allocation is not determined by capacity or production, and can be optimized with respect to the defined objective. Using this setting, an optimized FTR allocation is determined which allocates 75 MW FTRs to generation located at node n1 and load located at node n3. All other market players do not receive an FTR. With this FTR allocation the initial loss of generation at node n1 of -4000 EUR can be reduced to -1500 EUR, while the significant positive surplus of load, taking the socialized congestion rent into account, is reduced.

¹¹ See Appendix 8.2 for the detailed model formulation.

An intriguing result from the exercise was for us, that the choice of the reference point for financial contracts does matter. In order to avoid the need to issue FTRs between each pair of nodes, typically a reference node or weighted set of nodes (reference hub) is defined. Market participants thus require only FTRs to and from each node to the hub. Market participants with an FTR from the origin of a power transfer to the hub, and a subsequent FTR from the hub to the destination, are indifferent to the definition of the hub. However, if the initial free FTR allocation is for contracts from the location of load/generation to the reference location (node or hub) only, then the definition of the hub matters. To minimize the effect, the reference location of FTRs should reflect average rather than extreme prices and location (See Olmos and Neuhoff 2006 for a similar calculation at European level).

Real networks, generation and load patterns are obviously far more complex than our three node example. The large number of nodes and linkages could – in principle – moderate the impact of any one constraint, and thus reduce some of the large variations that have been demonstrated for the three node network, thus enhancing the value of FTRs to address distributional impacts of nodal pricing implementation. To the contrary, the specific circumstances of nodes, generation and load could reduce the value of using FTRs to address distributional impacts. To assess this trade-off, we quantify the role of FTR allocation proportional to annual generation/load and proportional to installed generation capacity/peak load in the following application to the German power system.

5 FTR Allocation for the German Power System

In a second analysis, we now apply the described methodology to a dataset of the German power system reflecting the year 2012. A detailed description of the dataset and the underlying data sources is given in Egerer et al. (2014). The dataset covers an entire year, but we focus on three characteristic weeks to limit computational requirements. The weeks are selected due to their different load and renewable generation pattern covering one week in summer with high solar generation and two weeks in winter which are characterized by high load and low or high wind generation, respectively. For these three weeks we determine the uniform and nodal pricing solution, both for the off-peak and the peak periods, and apply the different FTR allocation approaches.

In the following, the implications on load, conventional and renewable generation are analyzed in detail. First, the absolute changes in surplus between nodal and uniform pricing are shown in Figure 3 for the analyzed three weeks. The transmission congestion costs occurring in the uniform pricing due to necessary redispatch of generation as well as the transmission congestion rent of the nodal

pricing are socialized to load as in the three node setting. Thus, they are implicitly considered in the results and therefore not listed explicitly in the following graphs.

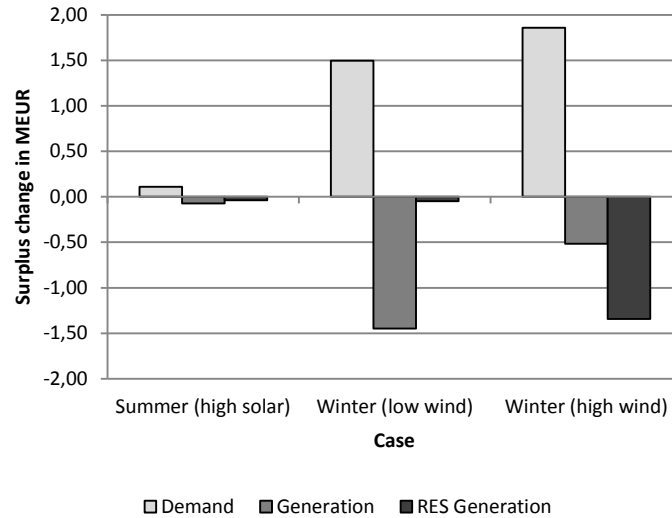


Figure 3: Change of surplus between uniform and nodal pricing

As can be seen in Figure 3, the changes are significant in the winter weeks with a significant amount of network congestion. In the summer week, the congestion is low and therefore both pricing regimes yield nearly identical results. In particular, demand wins in all three cases from a switch to nodal pricing as firstly the price level decreases due to explicit pricing of network congestion and, secondly, the socialization of congestion rents in the nodal pricing regime to electrical load. On the other hand, the lower price level decreases the generation revenues in all three cases. In particular the last case with high wind generation in the winter week indicates higher losses for renewable generation than other cases. Due to high wind generation in the northern part of Germany, significant congestion occurs on the north-south corridor resulting in lower prices in the northern part and higher prices in the southern part of Germany compared to the uniform pricing. As most of the conventional as well as renewable generation is located in the northern part this results in a negative effect of nodal pricing for generation. Furthermore, the congestion and henceforth congestion rents strengthen the position of the demand resulting finally in profits compared to the uniform pricing regime. It is important to note, that the level of congestion in the

German power system is relatively low. For instance, in the winter week with high wind generation, congestion rent in the nodal pricing amounts to 1.6 mEUR or 0.2% of electricity cost for demand¹²

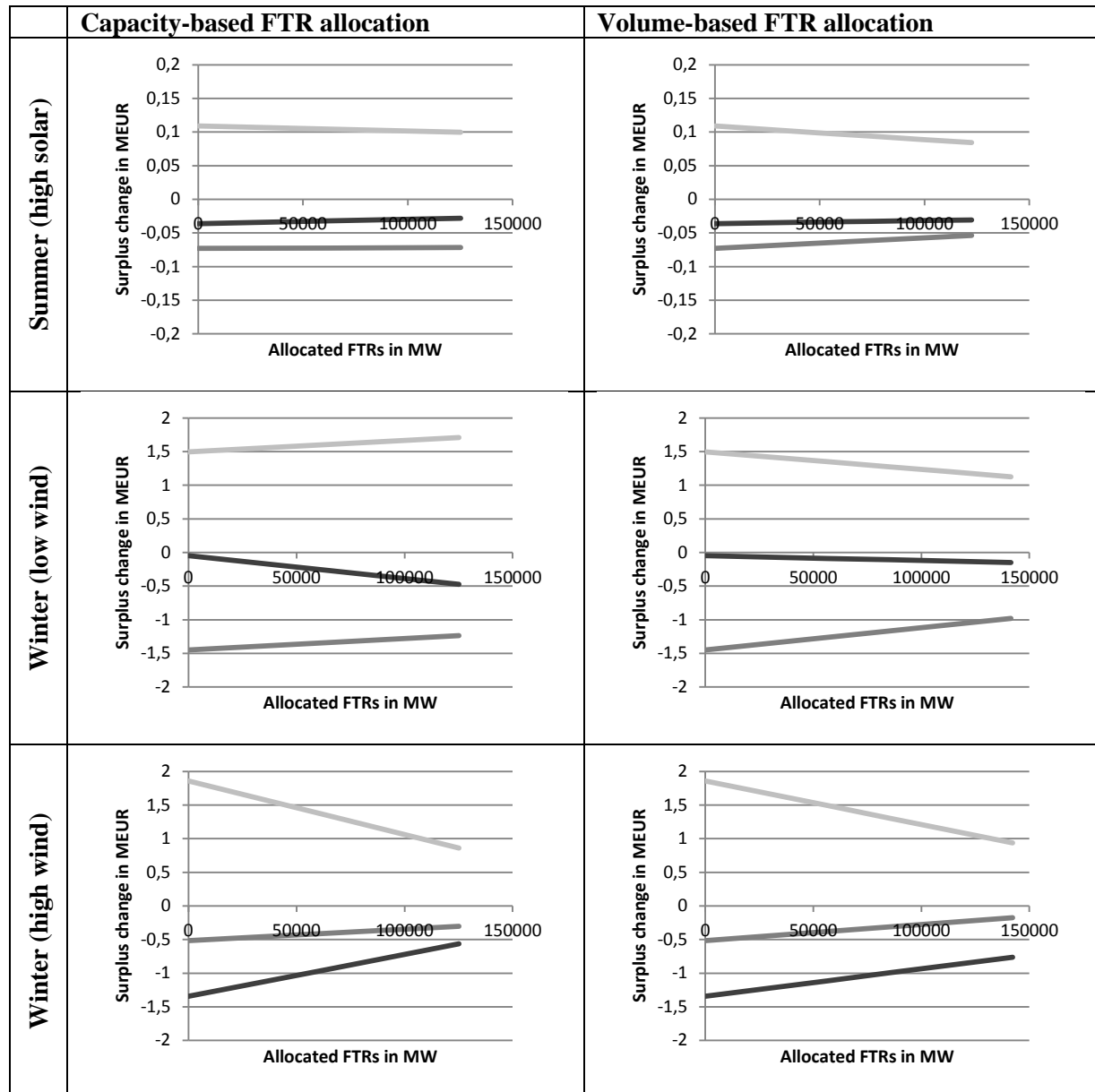


Figure 4: Change of market participant's surplus between uniform and nodal pricing considering different initial FTR allocation regimes (Light grey: load; Grey: conventional generation; Black: renewable generation)

Comparing now the different FTR allocation approaches, Figure 4 depicts the surplus changes for the capacity-based (left side) and the volume-based allocation approach (right side) for the three considered weeks. Furthermore, each graph visualizes the implications for an increasing amount of

¹² Electricity cost of demand amount to 675 mEUR in the windy winter week. It represents the sum of hourly nodal load times nodal price. Thus it can be interpreted as market volume.

FTRs to be allocated as long as the FTR allocation remains feasible. Thus, on the Y-axis in each graph no FTRs are allocated, which reflects the initial situation as shown in Figure 3, whereas on the X-axis in each graph the FTRs to be allocated to market participants are represented up to their maximum feasible value. Furthermore, it is important to note, that the distribution of FTRs differs for each week in the volume-based approach as the uniform pricing production in the week is used as distribution measure. For the capacity-based approach the distribution is constant as the installed generation capacities are the same.

Figure 4 shows that both FTR distribution approaches yield qualitatively comparable. The FTR allocation yields the expected benefit of reducing the distributional impact of the introduction of nodal pricing. The calculations also illustrate that both allocation regimes can only reduce the changes in surplus, but cannot precisely compensate all market participants. Comparing both allocation regimes, the volume-based approach achieves a favorable distribution in all three weeks. This can be attributed to the fact that the generation of the uniform pricing regime is taken as proxy for FTR allocation and thus varies between the three weeks. Thus, the low production of renewable generation in the first winter week is considered in the FTR allocation yielding in a higher allocation to conventional generation. Contrarily, the share of FTRs allocated to renewable generation in the windy winter week is higher than conventional generation due to a higher production share. On the other hand, the FTR allocation in the capacity-based approach is by definition constant in all three weeks. Thus, if renewable production is low and the price at the nodes of renewable generation is below the reference value (e.g. because of large conventional generation), the negative value of FTRs reduces the surplus.¹³ The scale of the overall effect is small, but illustrates the challenge of using FTR obligations to hedge output of intermittent renewable sources. FTR options would in principle avoid negative payments, but do not allow for netting as in the case of FTR obligations and thus reduce the volume of obligations that can be allocated.

Additionally, as the German power system is characterized by a regionally diversified generation as well as load structure a closer look at the regional level is necessary to analyze the effectiveness of the allocation regimes. On an aggregated level as presented here, the results are promising and may provide an argument for a switch of the pricing regime towards nodal pricing.

¹³ As renewable generation faces costs from FTR obligations, the congestion rent increases accordingly. Through socialization of the remaining congestion rent (initial congestion rent minus cost from FTR obligations) demand faces a positive effect in the winter week with low wind.

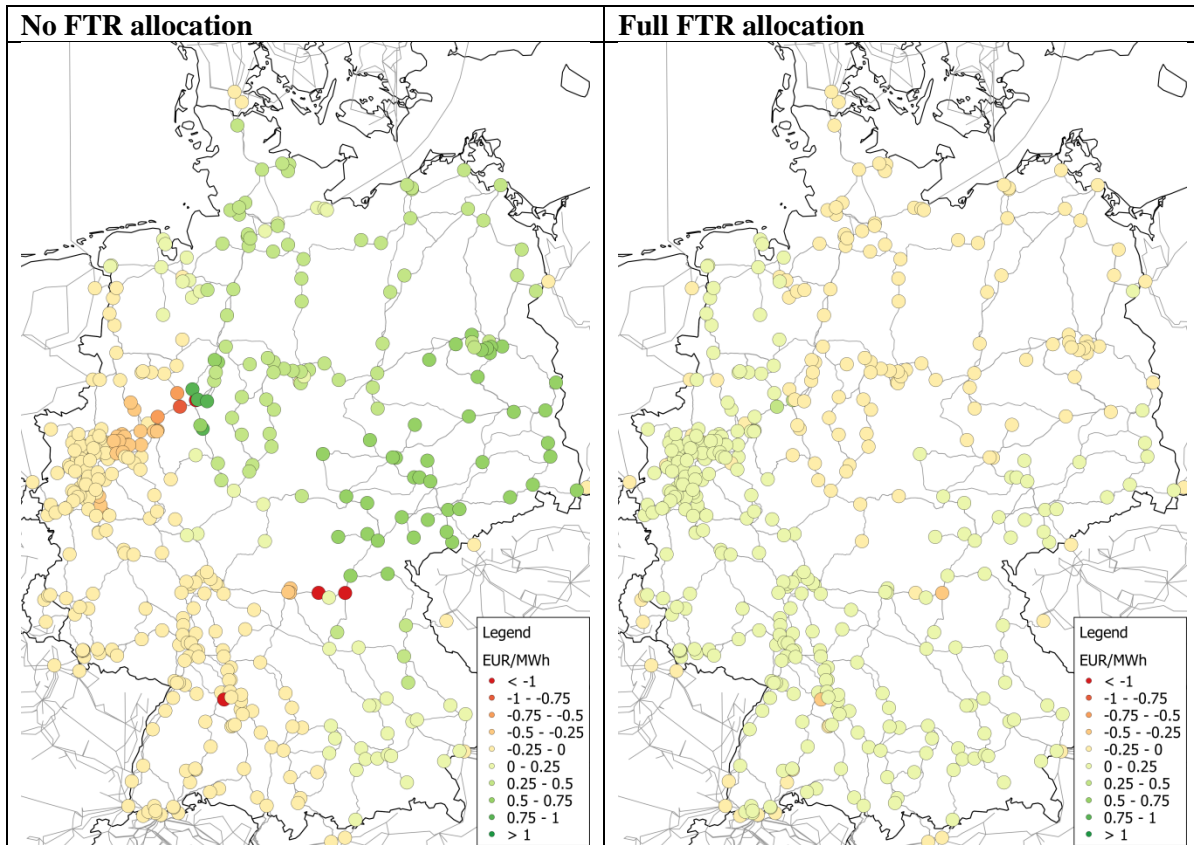


Figure 5: Average change in surplus of demand in the high wind winter week under volume-based allocation approach

In the following we analyze the results at the regional level for load, conventional, and renewable generation. We focus our analysis on the winter week with high wind as it shows the highest level of congestion among all considered weeks. Figure 5 depicts the average change of demand's surplus at the regional level differentiated between the initial situation without any FTR allocation (left side) and the situation with full volume-based FTR allocation (right side). As can be seen, congestion within the transmission network divides Germany into two parts: an export constrained north-eastern part with lower average prices and an import-constrained south-western part with higher average prices than in the uniform pricing regime. This development could partially be compensated should solar deployment volumes in the South further increase.

Henceforth, demand in the export-constrained region profits from lower electricity prices, whereas other regions face higher electricity costs and loose from a change in the pricing regime. Through an allocation of FTRs, as depicted on the right side in Figure 5, the demand in south-western Germany is compensated for the loss and vice versa for the benefits in north-eastern part. Through the allocation of FTRs the changes of surplus resulting from the introduction of nodal pricing is significantly reduced.

To assess this effect in more detail, Figure 6 and Figure 7 depict the histogram of average surplus changes differentiated by considered market participants. Figure 6 presents the initial situation, which is characterized by a higher variation of participant's surplus, in particular of demand and renewable generation.

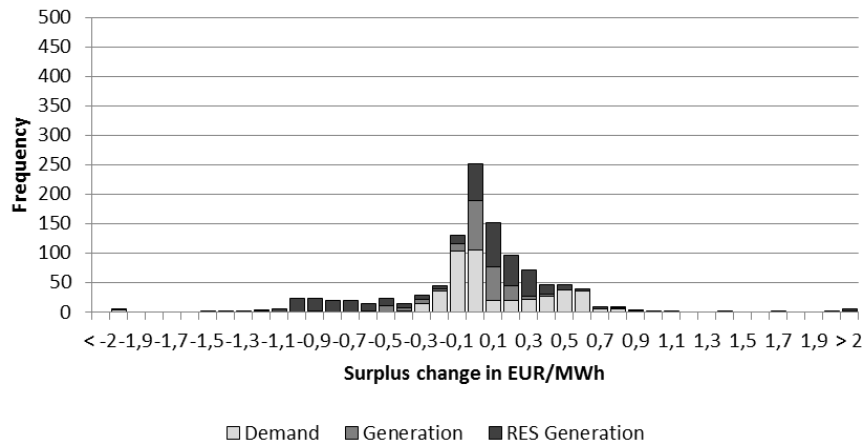


Figure 6: Histogram of average nodal surplus changes in the high wind winter week without FTR allocation

As shown in Figure 7, the demand side with the allocation of FTRs can compensate for the surplus changes and thus mitigates the impacts of an introduction of nodal pricing with both allocation methodologies.

In the case of generation (both renewable and conventional) an allocation based on installed capacity can result in instances of significant increase or decrease of surplus (exceeding 2 Euro/MWh). This results where generation is located at nodes with significant price changes and at the same time production volume is significantly below installed capacity. Thus the effect only occurs in the capacity based allocation method. The effect is furthermore linked to specific network circumstances (one generator in a generation pocket). We thus need to further assess the numerical results to assess to what extent this effect is material or a result of model calibration so as to then inform a debate about implications for allocation methodologies or other responses like local market power mitigation procedures.

However, for wind power in practice output will deviate in any hour from historic production volumes and therefore additional (hourly) variations will have to be anticipated that will not necessarily balance out across the year. This again points to the difficulties of using FTR obligations as hedging instruments for wind power generation.

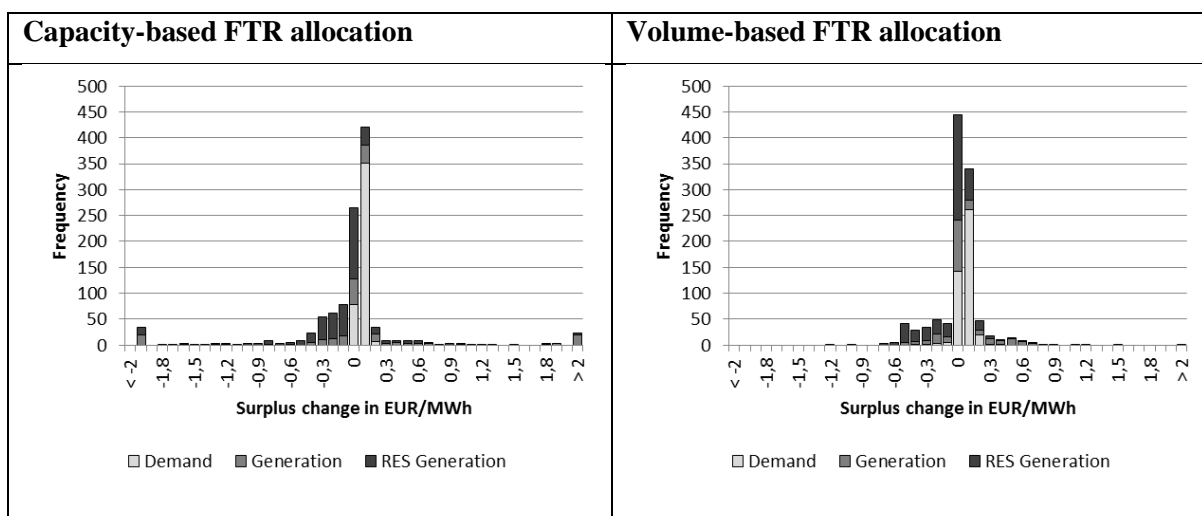


Figure 7: Histogram of average nodal surplus changes in the high wind winter week with capacity-based (left side) and volume-based FTR allocation (right side)

Figure 8 depicts the standard deviation of surplus changes as function of the volume of FTR allocation. It confirms the point that for demand and conventional generation the allocation of FTRs can reduce most of the surplus change linked to the introduction of nodal pricing. It also illustrates that in case of conventional generation the maximum allocation of FTRs results in an overcompensation of generation and thus the optimal volume of FTR allocation is below the maximum possible allocation. This result is linked to the use of FTR obligations that allow for netting and thus for a larger overall volume of FTRs to be allocated.

For renewable generation assets the allocation of FTR obligation reduces only about half the standard deviation of surplus changes linked to nodal pricing introduction. If instead FTR options would be allocated, then the allocation can only increase the surplus, and not compensate for winners. It also would result in a significantly lower volume of FTRs available for allocation, as netting is not possible, thus reducing the ability to compensate any of the market participants.

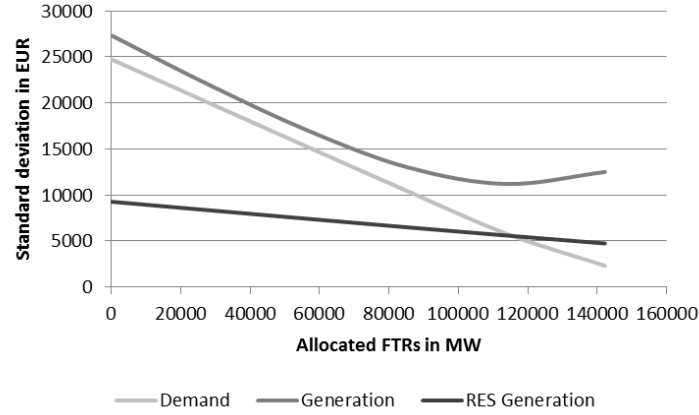


Figure 8: Standard deviation of market participant's surplus in volume-based approach in the high wind winter week (based on demand and generation at each node)

Further work would be needed to better explore alternative FTR designs. These could involve splitting of FTR options so as to for example compensate renewable generation for the price difference up to a strike price at the reference node (Newbery and Neuhoﬀ 2008, Biggar and Hesamzadeh, 2013).

To date a more pragmatic solution has been prominent in the US. Utility companies run tenders for renewable generation that oﬀer a long-term oﬀ-take contract at the node of the generation asset. Thus the transmission price risk is pooled within a larger portfolio. Feed-in tariffs typically oﬀer a similar long-term oﬀ-take contract at the point of production, and thus avoid exposure of renewable projects to such long-term contracts. A new paradigm suggests that such feed-in tariffs should be replaced by (floating) market premium systems. Floating premiums provide a payment between an average system price and a strike price, but leave the renewable project investor exposed to any congestion risk linked to introduction of zonal or nodal pricing. This was not considered to be a relevant risk by the proponents of such a transition as they typically assume the feasibility of a single pricing zone at country level or beyond.

6 Conclusions

A major challenge for the adjustment of pricing zones and for the implementation of nodal pricing is the distributional impact of price changes facing generation and load in diﬀerent locations of the system. The sum of changes to proﬁts by individual generators and changes to costs faced by individual load of the price changes are typically several times higher than the eﬃciency savings delivered by an eﬃcient congestion pricing mechanism.

In order to ensure that all (or most) parties benefit from and support the early shift to an improved congestion management system before system security risks of inappropriate congestion management become apparent, it is therefore necessary to mitigate the distributional impact. The implementation of nodal pricing has often been accompanied with the free allocation of FTRs to market participants in proportion to their prevailing trading relationships (contracts or transfers within vertically integrated utilities) with the objective to mitigate the distributional impact. Such an approach is no longer suitable in the European context, as most longer-term contracting arrangements between generation and load have expired.

Given the very political nature of rent allocation, we anticipate that an FTR allocation would have to be based on a clearly specified and transparent methodology. The purpose of this paper is to explore possible allocation alternatives, their representation in numerical models, and their relative merits based from the model results.

In a three node network we found that allocation in proportion to modelled annual production volume allows to better compensate the distributional impact than allocation in proportion to installed capacity. This effect is dominated by the large discrepancy between available and used capacity of one generator in our stylized model.

Hence we were interested to explore the situation in a more realistic setting, and for this purpose modelled the FTR allocation for the German power system based on full nodal representation. Our first results show that FTR allocation can mitigate almost all distributional effects for the demand side and the large share of the distributional effects for conventional generation. For intermittent renewables the allocation of FTR obligations can mitigate fewer of the distributional effects, as the allocation profile will not match generation and could thus at times also increase the surplus change linked to the introduction of nodal pricing. This points to the need of either more complex FTR designs (option contracts), or contractual arrangements (long-term off-take contracts) or legal framework (fixed feed-in tariffs) that insulate the revenue stream from the introduction of additional zones or nodal pricing.

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8 Appendix

8.1 Nomenclature

8.1.1 Sets

$A(n)$	Mapping of plants to nodes
l	Transmission lines
n, n'	Nodes, Slack bus
p	Power plants
t	Time period

8.1.2 Parameters

$b_{n,nn}$	Nodal susceptance matrix
cr_t	Congestion rent
$d_{n,t}$	Load
ds_n^{NP}, ds_n^{UP}	Economic surplus of load in nodal pricing (NP) or uniform pricing (UP)
$g_{p,t}$	Generation of market clearing model in uniform pricing regime
g_p^{max}	Generation capacity
$g_{n,t}^{RES}$	Renewable generation
gs_p^{NP}, gs_p^{UP}	Economic surplus of generation in nodal pricing (NP) or uniform pricing (UP)
$h_{l,n}$	Branch susceptance matrix
p_l^{max}	Transmission capacity
$price_{n,t}$	Nodal price
mc_p	Marginal generation cost

8.1.3 Variables

FTR_n^D	FTR allocated to load
FTR_p^G	FTR allocated to generation
FTR_n^{RES}	FTR allocated to renewable generation
$\Delta_{n,t}$	Voltage angle
$G_{p,t}$	Generation
$G_{p,t}^{UP}$	Positive redispatch of generation
$G_{p,t}^{DOWN}$	Negative redispatch of generation

8.2 Model for Optimized FTR Allocation

$$\min_{FTR, \Delta} \sum_p (gs_p^{UP} - gs_p^{NP} - \sum_t (price_{slack,t} - price_{A(n),t}) FTR_p^G)^2 + \sum_n (ds_n^{UP} - ds_n^{NP} - \sum_t (price_{n,t} - price_{slack,t}) FTR_n^D)^2 \quad (21)$$

$$\sum_n FTR_n^D - \sum_p FTR_p^G = 0 \quad (22)$$

$$FTR_n^D - \sum_{p \in A(n)} FTR_p^G - \sum_{nn} b_{n,nn} \Delta_n = 0 \quad (23)$$

$$cr_t^{TSO} - \sum_p (price_{slack,t} - price_{A(n),t}) FTR_p^G - \sum_n (price_{n,t} - price_{slack,t}) FTR_n^D = 0 \quad (24)$$

$$\left| \sum_l h_{l,n} \Delta_{n,t} \right| \leq p_l^{max} \quad (25)$$

$$\Delta_{n',t} = 0 \quad (26)$$

$$FTR_{p,t}^G, FTR_{n,t}^D \geq 0 \quad (27)$$