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A Combined Merchant-Regulatory Mechanism for Electricity Transmission Expansion in Europe

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Abstract

This paper provides a new mechanism on how to overcome transmission expansion in the specific European context. We test the Hogan-Rosellón-Vogelsang (2007) (HRV) incentive mechanism for different network topologies. The HRV mechanism is based on redefining the output of transmission in terms of point-to-point transactions or financial transmission rights (FTRs), and applies the incentive-regulation logic in Vogelsang (2001) that proposed rebalancing the variable and fixed parts of a two-part tariff to promote the efficient long-term expansion of the grid. We analyze three main topics: first, the behavior of cost functions is analyzed for distinct network topologies; second, the HRV regulatory approach is incorporated in a MPEC Problem and tested for a three node network, and, finally, we apply the mechanism to a simplified network in Northwestern Europe. The results suggest that the mechanism is generally suited as an incentive tool for network extensions.

Resumen

Este documento proporciona un nuevo mecanismo sobre cómo llevar a cabo la expansión de la transmisión en el contexto específico europeo. Probamos el mecanismo de incentivos Hogan-Rosellón-Vogelsang (2007) (HRV) para diferentes topologías de redes. El mecanismo HRV se basa en redefinir el producto de la transmisión mediante transacciones punto-a-punto de derechos financieros de transmisión (FTRs), y en aplicar la lógica de regulación por incentivos de Vogelsang (2001) quien propone rebalancear las partes variable y fija de una tarifa en dos partes para promover la expansión eficiente de la red en el largo plazo. Analizamos tres temas principales: primero, el funcionamiento de la función de costos es analizada para distintas topologías de red; segundo, el enfoque regulatorio HRV es incorporado a un problema MPEC y probado para una red de tres nodos, y, finalmente, aplicamos el mecanismo a una red simplificada de transmisión en el noroeste de Europa. Los resultados sugieren que el mecanismo es generalmente apropiado como una herramienta por incentivos para extensiones de la red.

Introduction

This paper provides a new mechanism on how to overcome transmission expansion in the specific European context. We test the Hogan-Rosellón-Vogelsang (2007) (HRV) incentive mechanism for different network topologies within a real European network. The HRV mechanism is based on redefining the output of transmission in terms of point-to-point transactions or financial transmission rights (FTRs), and applies the incentive-regulation logic in Vogelsang (2001) that propose rebalancing the variable and fixed parts of a two-part tariff to promote the efficient long-term expansion of the grid. Roughly speaking, Vogelsang (2001) is by its nature relevant for radial networks only, while HRV is designed to deal with expansions within meshed networks.

The relevance of network extension is especially urgent in the European electricity market. Due to the liberalization processes initiated in the late 1990s, former national electricity networks with only limited cross border capacities are now supposed to form the backbone of an emerging European wide energy market. However, ten years after the first liberalization efforts the network is still segmented into several regional and national sub networks with little to no competition between countries. Furthermore, the network is subject to several congestion issues. The diverging approaches on how to handle network regulation and congestion management further complicates the development of a functioning European market. How to ensure efficient and sufficient network extensions particularly cross border capacities are therefore one of the cornerstones of the future progress of liberalization.

Another urgent topic regarding network extension is the increased production of electricity from renewable energy sources particularly wind. The expected capacity increase in off (and on)-shore capacities requires large investment projects to transport energy from offsite locations to demand centers. Several studies have then proposed ambitious extension schedules for the existing grid (*e.g.* Dena, 2005). However, up to now a consistent economic technical approach that can cope with the increasing need for extensions and that, simultaneously, takes welfare effects into account has not been designed. We tackle the theoretical and practical discussion on this topic by applying the HRV mechanism to the European grid.

After a brief theoretic overview our paper is divided into three main parts. The first part carries out a theoretical analysis of the cost function behavior of transmission expansion with simple structures (such as three-node meshed networks), and extends them to more complex topologies. For this analysis we focus on two basic cases. In first place only line capacities are adjusted, but nodes, lines, impedances and thus the PTDFs do not change. Secondly, we single out the effect of loop flows on costs by considering switched networks of the same topology (allowing for changes in line impedances that are correlated with line capacities) under several scale assumptions. This evolves into insights on the relationship between PTDFs, and the network topology size and shape.

In the second part of our work, we proceed to apply the HRV incentive mechanism to the theoretic network used for the first part of the analysis to derive its general behavior. The same differentiations made for the cost function analysis are tested under the regulatory regime. In the last part we apply the mechanism to a simplified grid connecting Germany, the Benelux and France to testify whether the obtained theoretic conclusions are consistent with the application of the mechanism to a real word situation.

1. State of the Literature

There are two disparate approaches to transmission investment: one employs the theory based on long-run financial rights to transmission (LTFTR, merchant approach), while the other is based on the incentive-regulation hypothesis (regulatory approach). The first approach is based on LTFTR auctions by an independent system operator (ISO). This approach is also known as a merchant mechanism because participation of economic agents in auctions is voluntary. This method deals with loop-flow externalities by having the ISO retain some unallocated transmission rights (or *proxy* FTRs) during the LTFTR auction to protect FTR holders from negative externalities due to transmission expansion projects (Kristiansen and Rosellón, 2006). This is equivalent to having the agents responsible for externalities pay back for them (Bushnell and Stoft, 1997) so that when FTR contracts exactly match dispatch, welfare cannot be reduced through the gaming of certain agents. Under the approach, "merchants" would invest in new transmission capacity and finance their investments through the sale of LTFTRs.

The second approach to transmission expansion relies on regulatory mechanisms for a Transco. The transmission firm is regulated through benchmark regulation or price regulation to provide long-term investment incentives, while avoiding congestion. Some mechanisms suggest comparing the Transco performance with a measure of welfare loss (Léautier, 2000; Grande and Wangesteen, 2000; Joskow and Tirole, 2002). Another alternative is the two-part tariff cap proposed by Vogelsang (2001) where incentives for investment in expanding the grid derive from the rebalancing of the fixed and the variable parts of the tariff. Vogelsang postulates transmission cost and demand functions with fairly general properties and then adapts known regulatory adjustment processes to the electricity transmission problem. For instance, under well-behaved cost and demand functions, appropriate weights (such as Laspeyres weights) grant convergence to equilibrium conditions.[1] A particular criticism of this approach has been that the properties of transmission cost and demand functions are little known but are suspected to differ from conventional functional forms. Hence the assumed cost and demand properties in Vogelsang (2001) may actually not hold under loop-flows. Furthermore, a conventional linear definition of the transmission output is in fact difficult since the physical flow through a meshed transmission network is complex and highly interdependent among transactions (Bushnell and Stoft, 1997; Hogan, 2002a, 2002b).

The HRV model combines the merchant and regulatory approaches in an environment of price-taking generators and loads. This model is an extension of Vogelsang (2001) for meshed projects. It is designed for Transcos but —as in the Vogelsang (2001) model— it could also be applied under an ISO institutional setting. Transmission output is redefined in terms of incremental LTFTRs so as to be able to apply the Vogelsang's incentive mechanism to a meshed network. The Transco maximizes profits intertemporally subject to a price cap constraint on its two-part tariff, and having as choice variables the fixed and the variable fees. The fixed part of the tariff plays the role of a complementary charge. The variable part of the tariff is the price of the FTR output, and is then based on nodal prices. Pricing for the different cost components of transmission is such that they do not conflict with each other (fixed costs are allocated so that the variable charges are able to reflect nodal prices). Thus, variations in fixed charges over time partially counteract the variability of nodal prices giving some price insurance to the market participants.

The preliminary results of the HRV profit-maximizing regulatory model show convergence to marginal-cost pricing under idealized weights, while under Laspeyres weight there is evidence of such a convergence under more restrictive conditions.[2,3] Likewise, transmission cost functions are shown to have very normal economic properties under a variety of circumstances. This holds, in particular, if the topology of all nodes and links is given and only the capacity of lines can be changed, which implies that unusually behaved cost functions require a change in the network topology.

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1 For an application of the Vogelsang (2001) model to an electricity network with no loop flows see Rosellón (2007).

2 Chained Laspeyres weights and idealized weights. Laspeyres weights are easily calculated and have shown nice economic properties under stable cost and demand conditions. Idealized weights correspond to perfectly predicted quantities and posses strong efficiency properties (see Laffont and Tirole, 1996, and Ramírez and Rosellón, 2002).

3 Under Laspeyres weights--and assuming that cross-derivatives have the same sign-- if goods are complements and if prices are initially above to marginal costs, prices will intertemporally converge to marginal costs. When goods are substitutes, this effect is only obtained if the cross effects are smaller than the direct effects. If prices are below marginal costs the opposite results are obtained.

2. Cost functions

2.1. What we do

In this section we derive properties for electricity transmission cost functions. We identify types of network topologies where the expansion project derives on well (or ill) behaved transmission cost functions. This is done for two cases. In the first case, the expansion is such that only line capacities are adjusted, but nodes, lines, impedances and thus the PTDFs do not change. In the second case, the expansion considers switched networks of the same topology, allowing for changes in PTDFs and under several scale assumptions.

Our analysis of cost functions relies on a "translation" of the HRV's theoretical cost model into an empirically testable model. The HRV's cost model defines as cost function the minimum costs necessary to produce each level of the FTR output, subject to constraints on feasibility and on the relationship between FTR obligations and net injections. That is:

$$C(FTR) = \min_{k_i} \sum_{i,j} f_{ij}(k_{ji}) \quad (1)$$

$$s.t. \quad -H^*q \leq k \quad (2)$$

$$q = FTR^*e \quad (3)$$

With

FTR= $[q_{ij}]$ matrix of balanced point-to-point FTRs

q= vector of net injections

k= vector of line capacities

$f_{ij}(k_{ij})$= cost of extending the capacity k_{ij} of the line connecting i and j[4]

e= a vector of ones

H= PTDF matrix

$-H^*q$= vector of line flows

In the first approach only line capacities are changed while line impedances and thus the PTDF do not change. The objective of the model is to satisfy a given combination of FTRs by estimating the least cost capacity extension. Due to the loop flow characteristic of electricity networks an increased injection at one node may result in a decreased capacity requirement for specific lines.

In a second approach a capacity extension is always linked to a change in the lines impedance resulting in a change of the grids PTDF. Thus whenever the capacity value of one line is changed the whole power flow within the grid changes and may result in congestion on other lines.

[4] Hereafter referred to as "extension function" whereas $C(FTR)$ is referred to as "cost function".

The aim is to derive a "global" cost function in terms of the individual-line costs. This is at first achieved by letting one FTR output move while the other are kept constant for various assumptions on the shape of individual-line cost functions. The numeric results provide some insights on the general behavior of costs functions in meshed networks.

2.2. Model

The above described approach is incoporated as a non linear minimization problem into GAMS with the overall grid extension expanses as objective function. For the second step of the analysis the DC Load Flow model is used for power flow calculations. Based on the assumption that real power flows are determined according to the differences of the voltage angles between two nodes, one can model the real power flow by focusing on voltage angle differences only. This approach allows us to avoid the complete recalculation of the PTDF matrix when changing one single line parameter as the line reactance is already part of the flow formulation:[5]

$$P_{ij} = B_{ij} \cdot \Theta_{ij} \tag{4}$$

With

P_{ij}= real power flow between i and j

Q_{ij}= voltage angle difference between i and j

B_{ij}= line series susceptance $\left(B_{ij} = \frac{X_{ij}}{X_{ij}^2 + R_{ji}^2}\right)$, with X_{ij} line reactance and R_{ij} line resistance.[6]

For the specific capacity extensions, represented by the functions $f_{ij}(k_{ij})$, three different forms are tested which correspond to constant, increasing and decreasing returns to scale, respectively:

Linear function:	$f_{ij} = a_{ij}\, k_{ij} + c$
Quadratic function:	$f_{ij} = a_{ij}\, k_{ij}^2 + c$
Logarithmic function:	$f_{ij} = \ln\left(a_{ij} + b_{ij}\, k_{ij}\right) + c$

The values of *a* and *b* have been varied for different scenarios, c is assumed to be 0. A realistic line extension function may be a combination of the three modeled cases. Furthermore, lumpiness of investments and jumps

5 A more detailed reperesentation of the DC Load Flow model is given in Stigler and Todem (2005) and Schweppe *et al.* (1988).

6 As line resistance values are significant smaller than the reactance values, only the latter are used within the model simplifying the line susceptance to: $B_{ij} = \frac{1}{X_{ij}}$

within the extension functions (*e.g.* due to a change in the voltage level) may be possible.

The initial basic grid topology consists of a three node network with two generation nodes and one demand node (Figure 1). Two FTRs are defined: one from node 1 to 3 and one from node 2 to 3. Both are varied between 1 MW and 10 MW respectively to estimate the resulting global cost function. For the first part of the analysis a green field approach is chosen. The lines reactances are given and fixed but the lines have no starting capacity values. Thus, for each incremental FTR the necessary capacity amount has to be fully constructed.

For the second part when capacity and reactances are linked this approach is altered. The functional connection between capacity extensions and line characteristics $B_{ij}(k_{ij})$ is derived from the laws of parallel circuits.[7] We assume that a doubling of capacity results in a bisection of a line reactance. Thus, starting values for the line capacities k_{ij} with a value of zero would result in an impossibility of any extension. We chose basic values of 2 MW per line thus allowing a relatively high initial level of congestion which are further reduced in the alternative case to 1 MW per line. Thus, the starting grid is only capable to cover small amounts of FTRs.

To further analyze the impact of loop-flow lines a second grid configuration consisting of a meshed six node networks is used (Figure 2) Accordingly, the FTRs have been adjusted. Due to the numerical nature of the model, we cannot claim general predictions for cost functions applicable to any electricity network configuration. Nevertheless, by applying different scenarios for two different FTRs we want to derive the functional behavior of extensions that might support general conclusions. An overview of the undertaken simulation is given in Table 2.

[7] In a parallel circuit the total resistance of the system is defined by $R_{total} = \frac{1}{\sum_i \frac{1}{R_i}}$.

FIGURE 1: THREE NODE NETWORK

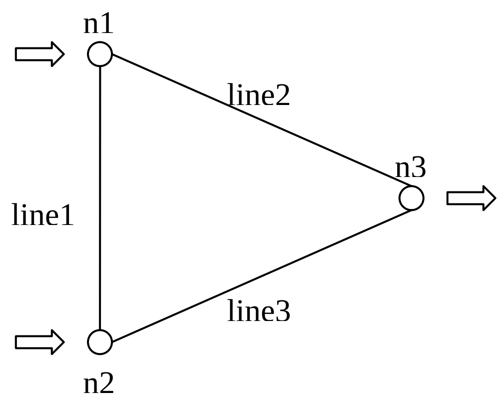


FIGURE 2. SIX NODE NETWORK

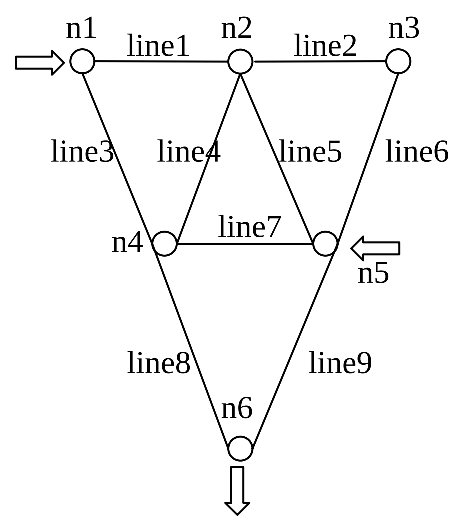


TABLE 1. SCENARIO OVERVIEW FOR COST FUNCTION CALCULATION

	FIXED LINE REACTANCES	VARIABLE LINE REACTANCES
THREE NODE NETWORK		
CONSIDERED FTR RANGE	FTR 1 to 3: 1 MW to 5 MW FTR 2 to 3: 1 MW to 10 MW	
CONSIDERED LINE EXTENSION FUNCTIONS	Linear quadratic logarithmic	
CONSIDERED LINE EXTENSION FUNCTIONS PARAMETERS	Base values: $a_{ij} = b_{ij} = 1$ Asymmetric case: a_{12} or $b_{12} = 3$	Base values: $a_{ij} = b_{ij} = 1$ Asymmetric case 1: a_{12} or $b_{12} = 3$ Asymmetric case 2: a_{23} or $b_{23} = 3$
STARTING CAPACITY VALUES	$k_{ij} = 0$	Base values: $k_{ij} = 2$ Alternative values: $k_{ij} = 1$
SIX NODE NETWORK		
CONSIDERED FTR RANGE	FTR 1 to 6: 1 MW to 5 MW FTR 5 to 6: 1 MW to 10 MW	
CONSIDERED LINE EXTENSION FUNCTIONS	Linear quadratic logarithmic	
CONSIDERED LINE EXTENSION FUNCTIONS PARAMETERS	Base values: $a_{ij} = b_{ij} = 1$ Asymmetric case: a_{12} or $b_{12} = 3$ a_{23} or $b_{23} = 3$ a_{25} or $b_{25} = 3$ a_{35} or $b_{35} = 3$ a_{45} or $b_{45} = 3$	Base values: $a_{ij} = b_{ij} = 1$ Asymmetric case 1: a_{12} or $b_{12} = 3$ a_{23} or $b_{23} = 3$ a_{25} or $b_{25} = 3$ a_{35} or $b_{35} = 3$ a_{45} or $b_{45} = 3$ Asymmetric case 2: a_{14} or $b_{14} = 3$ a_{24} or $b_{24} = 3$ a_{46} or $b_{46} = 3$ a_{56} or $b_{56} = 3$
STARTING CAPACITY VALUES	$k_{ij} = 0$	Base values: $k_{ij} = 2$ Alternative values: $k_{ij} = 1$

2.3. Results

2.3.1. Fixed line reactances

The first part of the cost function analysis only considers the capacity extension while the grid's topology is fixed in terms of line reactances and available connections. Thus, varying the FTRs has an exogenously determined impact on the power flow pattern. Hence, the model only calculates the minimum capacity amount needed to exactly fulfill this pattern. The outcomes therefore resemble the loop flow nature of electricity networks.

In the symmetric three node case, line 1 (between nodes 1 and 2) is subject to power flows in opposite directions depending on the value of the two FTRs. Thus given a fixed level of one FTR an increase of the second FTR will first lead to a decrease in the flow on line 1 towards zero until both FTRs have the same value. Afterwards, the flow will again increase, although in opposite direction. Thus, the resulting cost for increasing the FTR value will have a kink at the level of the fixed FTR (Figure 3) which might imply some problems as the resulting function is not smooth. Furthermore, the resulting global cost function for increasing two FTRs simultaneously shows that the costs when moving from one FTR combination to another can even decrease (Figure 4).

This result is a specific case for the decreasing-returns extension function, as for the linear and quadratic functions the cost always increases with increasing FTR values. The asymmetric case allowed distinguishing the outcomes more clearly as the costs dependence of the loop flow can be represented more clearly. However, this does not significantly affect the outcome.

FIGURE 3. COST FUNCTION, THREE NODE NETWORK, FTR 1>3 FIXED AT 2.5 MW

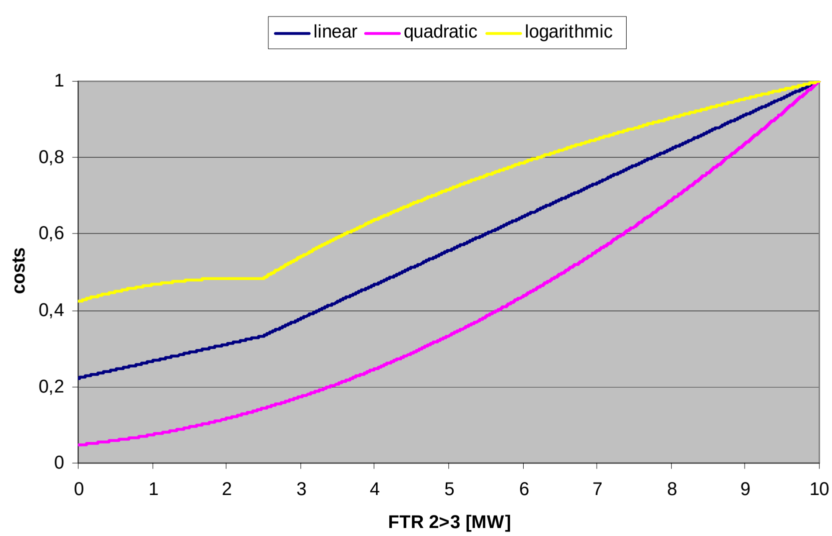
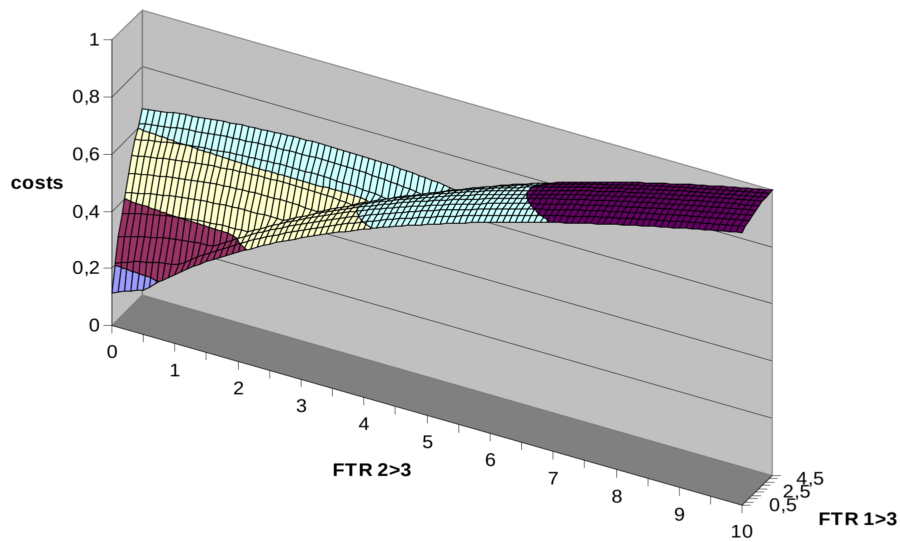
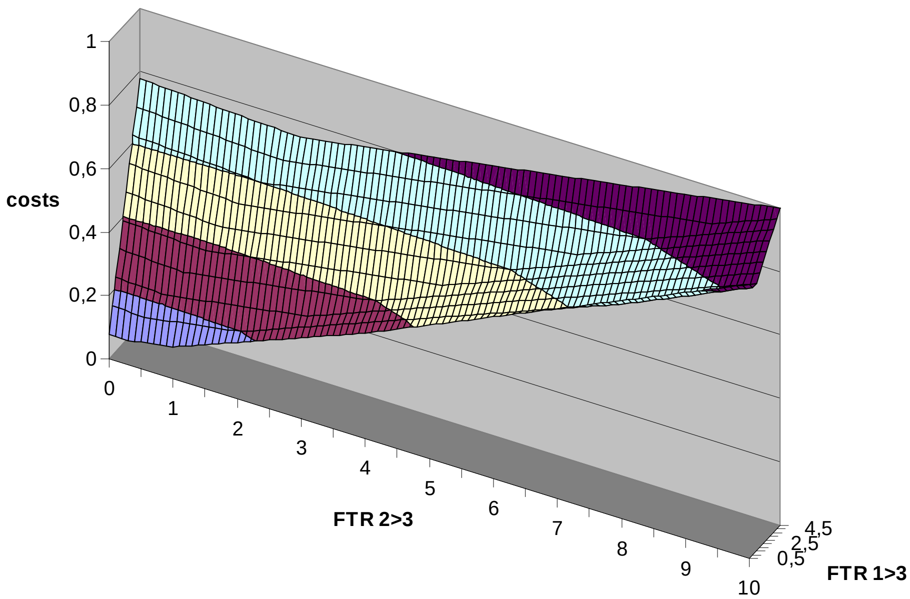


FIGURE 4. GLOBAL COST FUNCTION, THREE NODE NETWORK, LOGARITHMIC EXTENSION FUNCTIONS



Extending the model to six nodes introduces more than one line with opposing flow direction according to the FTR combination. In total, five lines are subject to counter flows whereof line 2, 5 and 6 are symmetric and thus have their counter flow kink at the same level. The resulting global cost function can therefore have three kinks according to the FTR combinations. Comparing the six and the three-node network the quadratic extension function still results in an always increasing feasibility range, while the logarithmic function has a decreasing global cost function according to the FTR combination. However, the linear extension function now also has decreasing elements (Figure 5) in the global costs function especially when increasing the cost parameters for loop flow lines (asymmetric case). Thus, when extending a specific FTR the simultaneous increase of different FTRs can reduce the overall costs in meshed networks. However, this can not always be achieved as the necessary counter flow generating FTRs may not be needed and, hence, the positive effect of the additional net injections would not be obtained.

FIGURE 5. GLOBAL COST FUNCTION, SIX NODE NETWORK, LINEAR EXTENSION FUNCTIONS, ASYMMETRIC CASE



2.3.2. Variable line reactances

The model so far has only considered a fixed network topology in terms of line reactances. In a real-world grid the possibility to extend a line's capacity without altering its further technical characteristics is rather limited. Thus normally a capacity extension is linked to a change in the lines reactance. We assume for the second part of the analysis that a doubling of a line's capacity results in a reduction of the lines reactance by the factor 0.5. Therefore starting values of the lines' capacities are necessary but prevent a direct comparison to the first model approach with fixed line reactances.

Starting with the simple three node case, and a starting capacity of 2 MW on each line, the resulting cost functions when keeping one FTR fixed do not necessarily have a kink as in the fixed-reactance part of our analysis. Furthermore, all lines start with 0 extension costs as the first part of the FTR increase can be accomplished with the existing grid (Figure 6). However, the cost function can still have significant kinks but these are not necessarily related to one loop flowed line. Of course, a loop flow on one line can still cause the cost function to decrease until the flows cancel out and increase again afterwards resulting in a kink. Another possibility for discontinuities could result from changing grid conditions. Instead of a fixed grid like in the first part of our analysis, the same FTR combination can be obtained by different grid conditions. Thus, when extending two lines simultaneously in small amounts becomes more expensive than just extending one line significantly (*e.g.* due to decreasing line extension costs) the optimal solution will have a shift at a specific FTR amount, and possibly an additional kink.

The global cost function for extending both FTRs no longer shows a clear correlation to the number of loop flowed lines like in the fixed-reactance part of the analysis. Furthermore, all line extension functions show decreasing elements for certain FTR combinations (Figure 7). As the simulation needs starting values for line capacities, an alternative approach with reduced capacities has been calculated. However, when decreasing the starting capacity from 2 MW to 1 MW the resulting cost functions show a similar behavior. The functions are slightly shifted to the left and, in particular, outcomes of higher FTR levels vary accordingly.

Increasing the costs function parameters of the loop flowed line does not alter the results at all. Thus in the optimal solution of the three node network an extension of line 1 seems to be avoided. When the costs parameters of another line are changed, the outcome changes although the general functional form remains similar. The logarithmic extension function yields particularly different results as the trade-off between extensions of one or two lines becomes more evident as large extensions are relatively cheaper.

FIGURE 6. COST FUNCTION, THREE NODE NETWORK, FTR 1>3 FIXED AT 2.5 MW, VARIABLE LINE REACTANCES

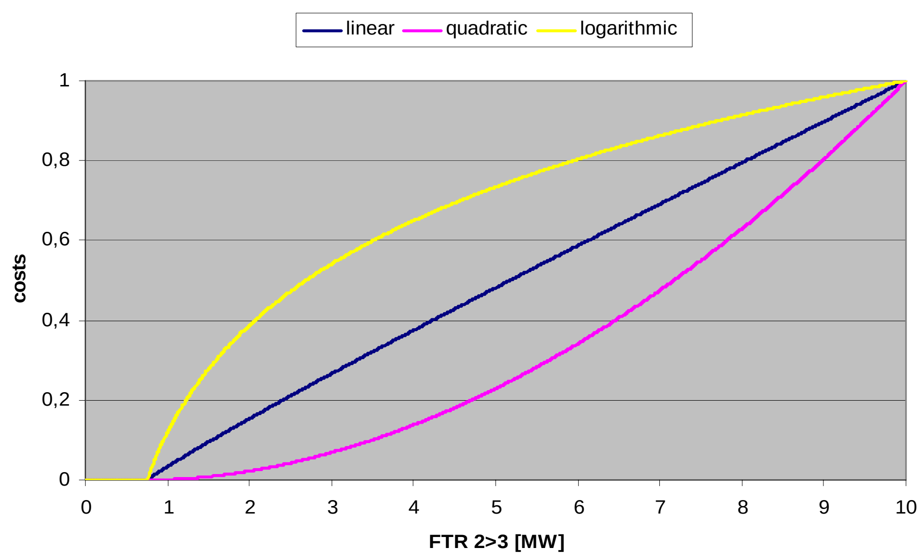
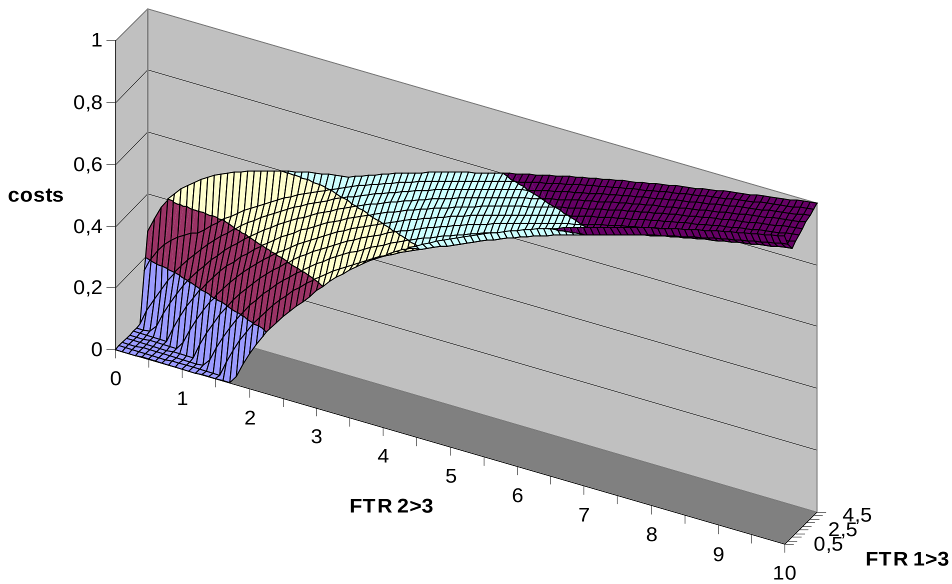


FIGURE 7. GLOBAL COST FUNCTION, THREE NODE NETWORK, LOGARITHMIC EXTENSION FUNCTIONS, VARIABLE LINE REACTANCES

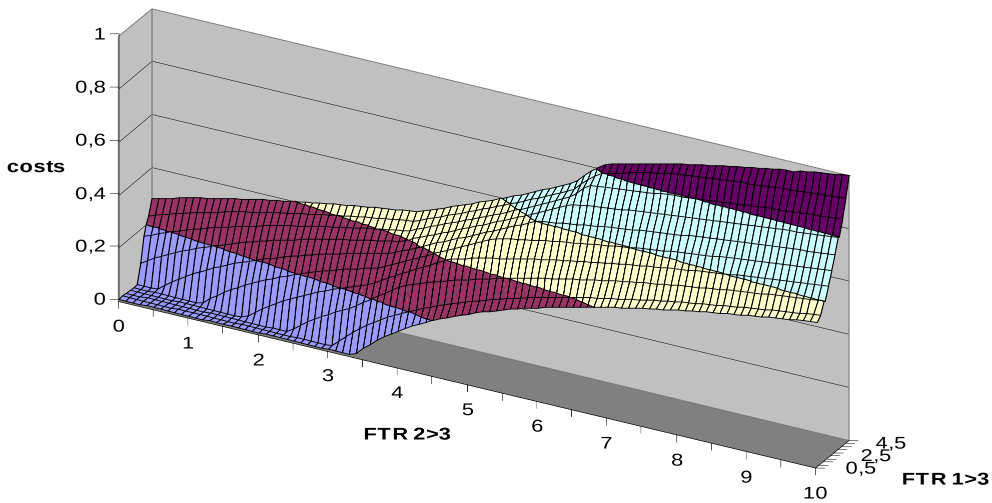


As in the fixed-reactance part of the analysis, the model is extended to six nodes and nine lines in order to estimate the impact of more loop flowed lines on the cost functions. Like in the three node simulations the obtained cost function do not show a clear correlation to the number of loop flow lines. Furthermore the results for linear and quadratic extension functions show a generally increasing cost function with a relatively smooth outline. However the logarithmic extension function results in a global cost function with significant slope changes (Figure 8). The model had further problems to obtain a consistent solution in the logarithmic case resulting in cost spikes which occurred in three of the six scenario runs.

Reducing the starting capacity of the lines to 1 MW does not significantly change the results of the linear and quadratic extension functions. The global cost function in the logarithmic case also resembles the same form but the slope changes are less sharp. Likewise, a shifting of the line parameters for loop flowed and non loop flowed lines does not alter the general results although the absolute values differ.

The comparison of the results with the fixed network case shows that the introduction of variable line reactances significantly changes the possible outcomes. In particular, for linear or quadratic extension functions the introduction of a linkage between capacity and reactance seems to lessen the impact of loop flows in terms of significant kinks. However the logarithmic extension function shows a highly non linearity in the global cost function making it hard to predict the outcome of a planned extension measurement in terms of cost minimization.

FIGURE 8. GLOBAL COST FUNCTION, SIX NODE NETWORK, LOGARITHMIC EXTENSION FUNCTIONS, VARIABLE LINE REACTANCES



The results of the cost function analyses show the difficulties that electricity networks present when applying standard economic approaches. Due to loop flows within the system even rather simplistic extension functions can lead to mathematical problematic global cost function behavior. Furthermore, the linkage between capacity extension and line reactances, and thus the flow patterns, leads to highly complex results that are highly sensitive to the underlying grid structure. None of the three tested extension functions is able to reproduce realistic extension structures, as these are subject to lumpiness and external influence like geographic conditions that may result in functional behavior with sudden slope changes. However, for modeling purposes the logarithmic behavior seems to lead to a high degree of nonlinearities with non-smooth behavior thus making it demanding with respect to calculation effort and solver capability. Quadratic functions show a generally continuous behavior that makes them suitable for modeling purposes. Linear extension functions are in between the logarithmic and quadratic cases. However, the piecewise linear nature of the resulting global costs function makes the derivation of global optima feasible which, in combination with the advantages of keeping linear functions, makes them preferable for modeling purposes.

3. The regulatory two-part tariff model

3.1. What we do

In this section we analyze the implementation of the HRV regulatory model. The price cap restriction on two-part tariffs is analyzed to find out whether this system provides incentives for efficient transmission expansion. We estimate the impact of different assumptions regarding grid parameters and topology, again with and without PTDF changes. As in section 3, we carry out translation of the HRV's theoretical regulatory model (Hogan, Rosellón and Vogelsang, 2007, pp. 13-19) into an empirically testable model.

The HRV regulatory model uses FTRs as the definition of output. By employing such a critical output definition, the regulatory logic of a price cap constraint on two-part tariffs of Vogelsang (2001) —based on the appropriate rebalancing of the variable and fixed parts of the tariff using some set of weights— is linked to the merchant model. The HRV model assumes stable costs and demand conditions, and considers the repeated application of the incentive mechanism of a myopic Transco optimizing profit in each period. Likewise, there are various established agents (generators, Gridcos, marketers, etc.) interested in the transmission grid expansion that do not have market power in their respective markets.

There is a sequence of auctions at each period *t* where participants buy and sell long-term FTRs (LTFTRs), culminating in a real time auction at which time all FTRs are cashed out. LTFTRs are assumed to be point-to-point balanced financial transmission right obligations. The Transco maximizes expected profits at each auction subject to simultaneous feasibility constraints, and a two-part-tariff cap constraint. The transmission outputs are the incremental LTFTRs between consecutive periods. The model first defines the least cost solution for the network configuration that meets a given demand. Over the domain where $\iota^t q = 0$ (*i.e.*, no losses):

$$c^*\left(q, K^{t-1}, H^{t-1}\right) = \underset{K^t \in \mathrm{K}, H^t \in \mathrm{H}}{Min} \left\{ c\left(K^t, K^{t-1}, H^t, H^{t-1}\right) \middle| H^t q \le K^t \right\}. \tag{5}$$

Where:
q^t = the net injections in period t (FTRs are derived from:

$$\sum_j \tau_j^t = q^t \, ; \tau_j^t = \begin{bmatrix} -x \\ 0 \\ 0 \\ . \\ . \\ +x \\ 0 \end{bmatrix}$$)[8]

K^t= available transmission capacity in period t
H^t= transfer admittance matrix at period t
ι^t = a vector of ones
$c\left(K^t, K^{t-1}, H^t, H^{t-1}\right)$ is the cost of going from one configuration to the next. For a DC load approximation model, the Transco's profit maximization problem is then given by:

$$\underset{t^t, F^t}{Max}\ \pi^t = \tau^t\left(q(\tau^t) - q^{t-1}\right) + F^t N^t - c\left(K^t, K^{t-1}, H^t, H^{t-1}\right) \tag{6}$$

subject to

$$\tau^t Q^w + F^t N^t \leq \tau^{t-1} Q^w + F^{t-1} N^t \tag{7}$$

Where:
t^t= vector of transmission prices between locations in period t
F^t= fixed fee in period t
N^t= number of consumers in period t
Q^w= $(q^t - q^{t-1})^w$
w= type of weight

Note that the proposed price cap index (7) is defined on two-part tariffs: a variable fee τ^t and a fixed fee F where the output is incremental LTFTRs. The weighted number of consumers N^t is assumed to be determined exogenously. When the demand and optimized cost functions are differentiable the first order optimality conditions are:

$$\nabla q(\tau - \nabla_q c^*) = Q^w - (q(\tau) - q^{t-1}) \tag{8}$$

[8] 'q' refers to net injections of the form q_i, while the FTRs are of the form q_{ij}. The FTRs form a matrix Q= $[q_{ij}]$ so that the vector of net injections is q= Qe, where e is a unit vector. Since we are assuming that FTRs are point-to-point obligations, we can indistinctively use net injections or FTRs as output (see Hogan, 2002b).

3.2. Model

We implement this incentive-regulatory mechanism as an maximization problem with complementarity constraints (MPEC) model with a profit-maximizing Transco subject to the two-part tariff constraint, and a perfectly competitive wholesale nodal pricing market. The Transco's revenue consists of the collected congestion rents and the fixed part of the tariff, and its expenses are the network investment costs. By choosing a specific extension level, the Transco has an impact on flow patterns and thus on market prices and, consequently, on his own revenue.

For a first application of the HRV regulatory model the approach has been slightly altered to allow for a straightforward implementation into GAMS. The objective function of the Transco covers the collectable congestion rent in terms of point to point price differences (Δp_{ij}) in a nodal pricing market and its fixed fee minus the extension costs for the grid:

$$\max_{k,F} \quad \pi = \sum_{t} \Delta p_{ij}^{t} q_{ij}^{t} + F^{t} N^{t} - c\left(k_{ij}^{t}\right) \tag{9}$$

The sum of variable and fixed revenues is subject to a Laspeyere weighted price cap as proposed in equation 7. The time horizon for the analysis is assumed to be ten periods. The first period is considered to define the starting values for the price cap. Thus, no extension measurements are allowed in the first period. Furthermore, we assume that the starting value of *F* has an impact on the outcome.

The Transco's maximization problem is subject to a market equilibrium, which defines defining the outcome of the underlying nodal pricing market. We assume a welfare maximizing ISO that balances demand and generation given the network constraints:

$$\max\ W = \sum_{i,t} \left(\int_{0}^{d_i^{t^*}} p(d_i^t)\, \mathrm{d}d_i^t - \int_{0}^{g_i^{t^*}} c(g_i^t)\, \mathrm{d}g_i^t \right) \tag{10}$$

s.t. $\left|P_{ij}^{t}\right| \leq P_{ij}^{t,\max}$ line flow constraint between i and j (11)

$g_i - d_i - q_i = 0$ energy balance constraint at node I (12)

$g_i^t \leq g_i^{t,\max}$ generation constraint at node I (13)

Where:
t= time period
d_i= demand at node i
$p(d_i)$= linear price function at node i
g_i= generation at node i
P_{ij}= real power flow between *i* and *j*

Demand and generation result in pairs of net inputs (q_i and q_j) that translate into specific FTRs between these nodes. Power flows are again calculated based on the DC-Load-Flow approach following equation (4). The power-flow welfare maximization problem is transformed into an equilibrium problem by deriving the first order conditions of the Lagrange formulation and their dual variables respectively. The wholesale market therefore is assumed to be fully competitive and the only influence that the Transco has on the market outcome is to decide on the extensions of existing lines.

Similarly to the cost function analysis, we use a three-node network to test the HRV regulatory model under different conditions, firstly for a fixed-PTDF grid and secondly for a linkage of line capacities and reactances. To mathematically simplify the analysis, we introduce linear demand functions at each node with a slope of -1 and a maximum demand of 10 at a price of 0. To resemble the situation of the cost function analysis, node 3 is still assumed to have no own generation capacities and thus depends on the grid capacities so as to be supplied. Generation capacities at node 1 and 2 are assumed to be unrestricted and have no marginal generation costs. Thus the demand at these nodes is supposed to be always at maximum level supplied by local generation and, therefore, has no impact on the general outcome. As the first period is used for the price cap definition, we expect that the results strongly depend on the chosen starting conditions in particular the starting capacities of the lines. In a real electricity network, generation capacities have different marginal costs, thus the market equilibrium has to take the merit order into account. To test the impact of this factor on the model a second approach using asymmetric generation costs is considered. Table 2 summarizes all calculated scenarios.

TABLE 2. SCENARIO OVERVIEW FOR MPEC MODEL

	FIXED LINE REACTANCES	VARIABLE LINE REACTANCES
TIME PERIODS	$t = 10$	
DEMAND FUNCTION at i	$p(d_i) = 10 - d_i$	
CONSIDERED LINE EXTENSION FUNCTIONS	linear quadratic logarithmic	
CONSIDERED LINE EXTENSION FUNCTIONS PARAMETERS	$a_{ij} = b_{ij} = 1$ $c_{ij} = 0$	
STARTING CAPACITY VALUES	Base values: $k_{ij} = 2$ Alternative values: $k_{ij} = 1$	
GENERATION COSTS at i	Base values: $c_i = 0$ Alternative values: $c_1 = 1$	
STARTING VALUE FOR FIXED TARIFF PART IN t_1	Base values: $F^{t1} = 0$ Alternative values: $F^{t1} = 20$	

3.3. Results

3.3.1. Fixed line reactances

At first the fixed network is analyzed. When using symmetric generation facilities, the obtained results of linear, quadratic, and logarithmic extension functions do not differ significantly. Prices at node 1 and 2 remain zero thus equaling the marginal generation costs. The price at node 3 starts from either 6 €/MWh or 8 €/MWh depending on the starting line capacities and drops to about 5 €/MWh for all the remaining periods. With the exception of the quadratic function, only one extension measurement is undertaken in period 2. In the quadratic case, extensions take place in each period although strongly decreasing in absolute values. However, the sum of the extended capacity is nearly equal for all three extension cases. It is not evident why the quadratic case shows a significant different behavior than the other two cases. A further non-intuitive result is that increasing the starting value for the fixed-part of the tariff does not alter the results.

In the asymmetric case, when the cost parameters of generation are changed the results differ accordingly. The price at node 1 remains at its marginal costs level for all scenarios. Thus, the modeled Transco finds no incentive to increase line capacities to allow for a price reduction due to cheaper generation at node 2. Prices at node 3 again change according to the extended capacities. However, the extension patterns differ from the symmetric generation-cost case. The quadratic extension function still results in a generally decreasing extension over all periods. The linear and logarithmic functions result in one, two or three price jumps and according extension measurements. Thus the price at node 3 can drop as low as to a value of 2 €/MWh for some cases. The total sum of extensions therefore is not constant as in the symmetric case. This varying outcome may be a result of the highly non linearity resulting from asymmetric generation and non smooth extension functions. Furthermore time is not taking into account at full economic scale as no discount factor is considered. Thus, the Transco is indifferent about revenues in present or future periods which might influence the obtained results. Again introducing a starting fixed tariff part does not alter the general outcome.

3.3.2. Variable line reactances

In the second part of the simulations, the line's capacity and reactance are linked. Under base case conditions with 2 MW starting line capacities, symmetric generation and no fixed-part of the tariff in the first period the resulting price and extension patterns resemble the expectations of a price decrease towards marginal costs. While price tend towards marginal generation cost due to increasing line extensions, the loss of congestion rent is compensated by increasing the returns of the fixed-part of the tariff (Figure 9). The results for linear and logarithmic extension functions show only small differences whereas the quadratic case has a slightly different functional form towards the last periods with a further steady decrease whereas the other two remain somehow stable The outcome when reducing the starting capacity remains the same although absolute values differ. The extension schedule for the quadratic case is symmetric throughout all periods whereas for linear and logarithmic extension functions the values vary, being mainly either symmetric or focused on one line's capacity.

Introducing asymmetric generation costs leads to a significant divergence in the functional form of the quadratic extensions case whereas the other two remain rather stable (Figure 10). The price at node 1 with its higher marginal generation costs decreases in addition to the price at node 2. In the linear and logarithmic case the price at node 2 moves towards zero starting in period 3. However in the quadratic case the price decrease starts in period 7 but reaches the same value level in period 10. Altering the starting value of the fixed-part of the tariff does not change the results again, and decreasing the starting capacity does change the absolute value but not the general behavior. The extension schedule of the quadratic case is more consistent as it continuously extends lines 1 and 2. In the linear and logarithmic extension case, capacities are increased more bulky with larger amounts in the first periods which explains the divergence of the price figures. The total amount of extension is rather similar in all three cases.

The main difference between the static line rectanaces and the variable ones is the non existent price movement in the first case. Furthermore, the fixed-part is not altered during the periods thus the Transco only extends in such a way that the initial congestion rent value is not altered although more energy is transported. The missing possibility of changing the flow pattern within a grid reduces the effective degrees of freedom for the Transco's choices, limiting it to the observed ones. As capacity extension in real electricity networks generally are linked to changes in its flow characteristics, the second part of the analysis is the practical relevant one. Altering the myopic assumption the Transco may also bias the results as a Transco which only maximizes in one period repeatedly might have significant different incentives. However, transposed to realistic situations a more periodic approach may still be more appropriate. Furthermore, one has to consider that MPEC models are still complicated to solve and the high degree of nonlinearity in the used functions and the resulting non-smooth behavior increases the possibility that the obtained solutions are local optima which could be far away from the global one.

FIGURE 9. VARIABLE PART OF THE TARIFF PRICE AT NODE 3 AND FIXED-PART OF THE TARIFF, VARIABLE LINE REACTANCES AND SYMMETRIC GENERATION

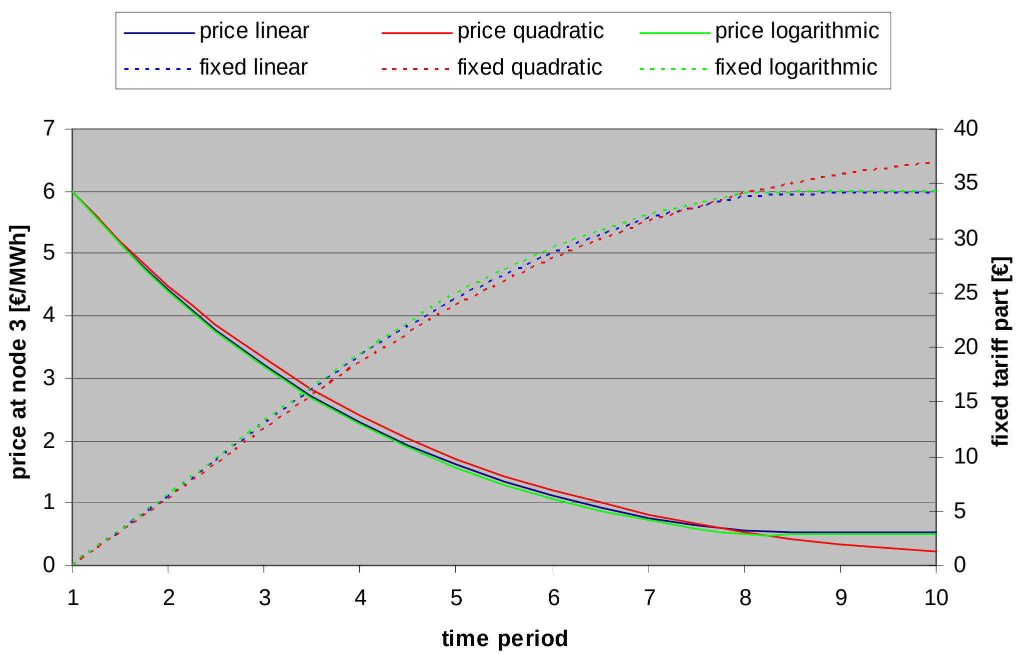
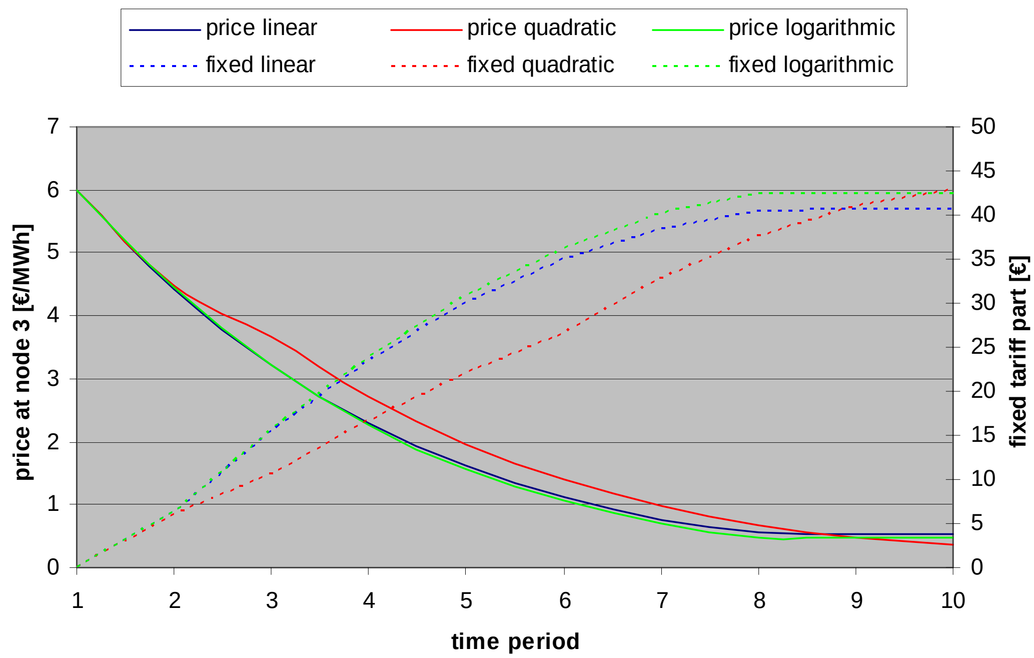


FIGURE 10. VARIABLE PART OF THE TARIFF AT NODE 3 AND FIXED-PART OF THE TARIFF, VARIABLE LINE REACTANCES AND ASYMMETRIC GENERATION

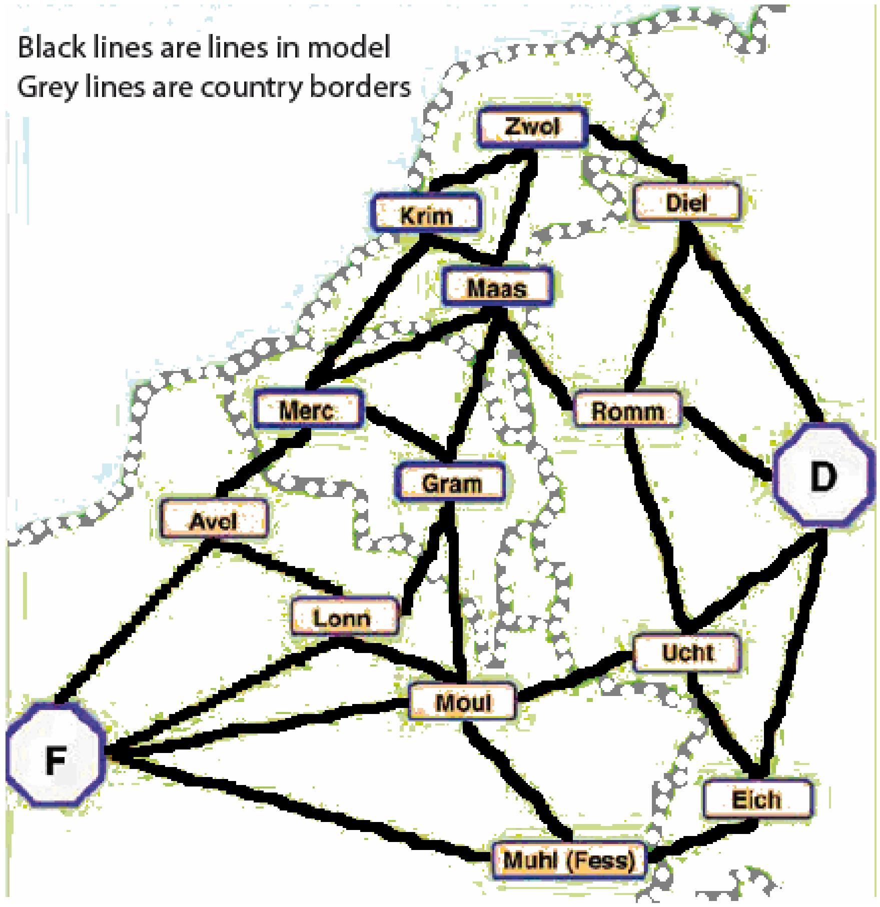


4. Application to a European Network

4.1. What we do

In the last part of our work, we proceed to apply the HRV incentive mechanism to a real network. The obtained insights from the theoretical part of the paper will be tested in a real world situation. The analysis is based on a simplified grid connecting Germany, the Benelux and France as presented in Ehrenmann *et al*. (2006) (Figure 11). The modeled market is designed as a nodal pricing system which is an approximation of the current country wide uniform pricing system in use. The modeled market system is characterized by high prices in the Benelux, intermediate prices in Germany, and relatively low prices in France. Thus, the transmission network of this system supplies simplified congestion problems of the European market where the HRV mechanism might be tested.

FIGURE 11. SIMPLIFIED GRID OF NORTH WEST EUROPE



4.2. Model and Data

The mathematical implementation of the model follows the approach presented in section 0 with variable line reactances. The only difference is the introduction of plant types to differentiate several plants at one node *i*. Furthermore, the data set has been adjusted to represent the simplified grid of Northwestern Europe. The network consists of 15 nodes and 28 lines. The nodes connecting France and Germany with its neighboring countries are auxiliary nodes without associated demand or generation. The lines connecting the German and French country nodes with these auxiliary nodes are assumed to have unlimited capacities, and are not allowed to be extended by the Transco.

Each country node has a number of generation capacities, and a reference demand level. Generation capacities are classified in eight types to further simplify the calculation. For each generation type, a marginal cost level has been assumed which is equal in all countries. Table 3 gives an overview of the used types, installed capacities and marginal generation costs. A linear demand behavior at one node is derived from the average load level and an assumed elasticity of -0.25.

The line extension costs are assumed to behave linearly. Following Brakelmann (2004) and DENA (2005), a value of 100 € per km per MW has been chosen. This value is derived from upgrade costs for additional lines of the same voltage level, and upgrades from 220 kV to 380 kV. However, in reality, network investments are lumpy as adding one further line adds a specific amount of capacity to the system. The derived results for one time period represent an hour; thus the obtained Transco revenue has been multiplied by 8760 for each of the 10 periods to resemble yearly incomes. Due to the average nature of both the load level and the generation structure, the varying nature of electricity systems is not yet covered in the model.

TABLE 3. POWER PLANT FLEET OF THE EUROPEAN MODEL

PLANT TYPE	INSTALLED CAPACITY	MARGINAL GENERATION COST	PLANT TYPE	INSTALLED CAPACITY	MARGINAL GENERATION COST
Nuclear	83 500 GW	10 €/MWh	Steam	28 000 GW	45 €/MWh
Lignite	21 000 GW	15 €/MWh	Gas turbine	5 500 GW	60 €/MWh
Coal	51 250 GW	18 €/MWh	Hydro	17 000 GW	0 €/MWh
CCGT	18 500 GW	35 €/MWh	Pump Storage	13 000 GW	28 €/MWh

4.3. Results

Only one case has been considered for the application using the above described data. The starting conditions in the market are classified by a high price level in the Netherlands (Krim, Mass, Zwol), a divided price structure in Belgium (Grim, Merc), modest price in Germany, and low prices in France. Thus, congestion occurs between Belgium and France as well as between Germany and the Netherlands. The ten period model run resulted in an extensive network extension program that finally leads to price convergence at marginal costs level of coal units (Figure 12). The fixed-part of the tariff increases in a similar way to the cases presented in section 0. The Transco's profit increases significantly during the periods, starting at 950 mn € per year, and reaching 2.5 bn € in the last period. Thus the chosen Laspeyres weights allow a significant revenue increase for the Transco.

The total extension amount sums to additional 14.2 GW which is nearly 43% of the initial line capacity in the system. The total investment sum is about 140 mn €. The relatively low investment amount can be explained by the assumption that the extension cost functions represent system upgrades, and no new line construction. The geographic extent of the measurements

(Figure 13) resembles expectations drawn from the nodal price differences, particularly between France and Belgium. However, some of the measurements seem to represent necessary back up extensions to allow for specific flow patterns, particularly between France and Germany, and within Germany.

The consumer surplus in the system also changes according to the price development. Due to the large demand levels in France which has to face higher prices after the extensions, the surplus decreases about 1%. Thus, even though the overall congestion is nearly vanished, the increased consumer surplus in the Benelux is not sufficient to offset the decrease in France. However, looking at the social welfare including consumer and producer surplus of the wholesale market an increase of 1.7% can be observed equaling about 1.6 bn € per year.

These first results show that the HRV mechanism has the potential to foster investment into congested networks in an overall desirable direction. However, further analyses are necessary to estimate impacts of externalities like wind input, and generation extensions on the Transco's behavior. Furthermore, the extension functions and restrictions have to be adjusted for a better representation of real world conditions, particularly with regards to the lumpiness of investments. As presented in the above sections, these adjustments may result in serious modeling problems due to the non-linear and non-smooth nature of the impacts. Besides technical and theoretical issues, other political and administrative issues have to be addressed. These include property-right issues, and existing long term transaction contracts.

FIGURE 12: PRICE DEVELOPMENT IN THE EUROPEAN MODEL

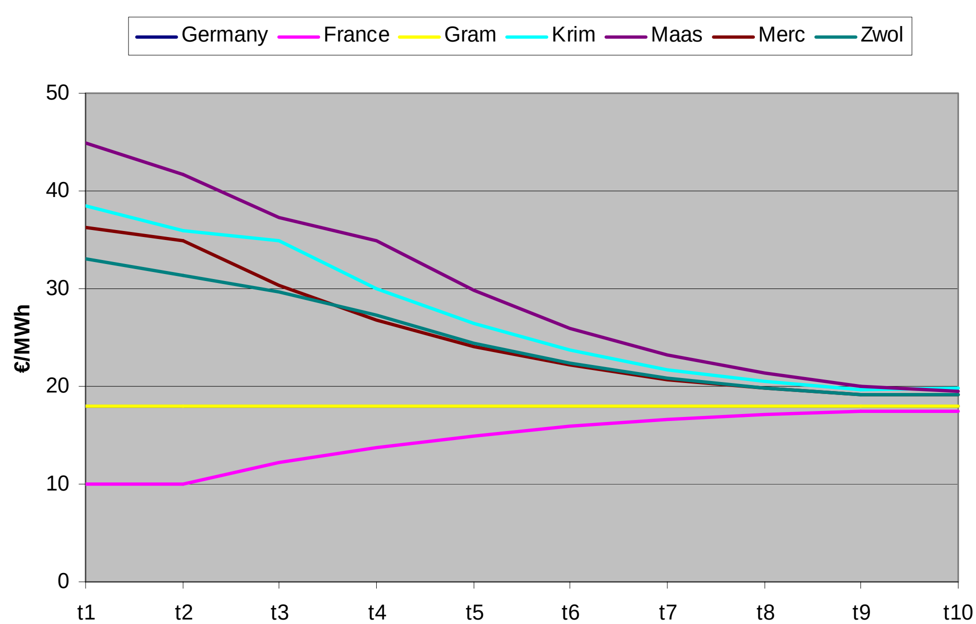
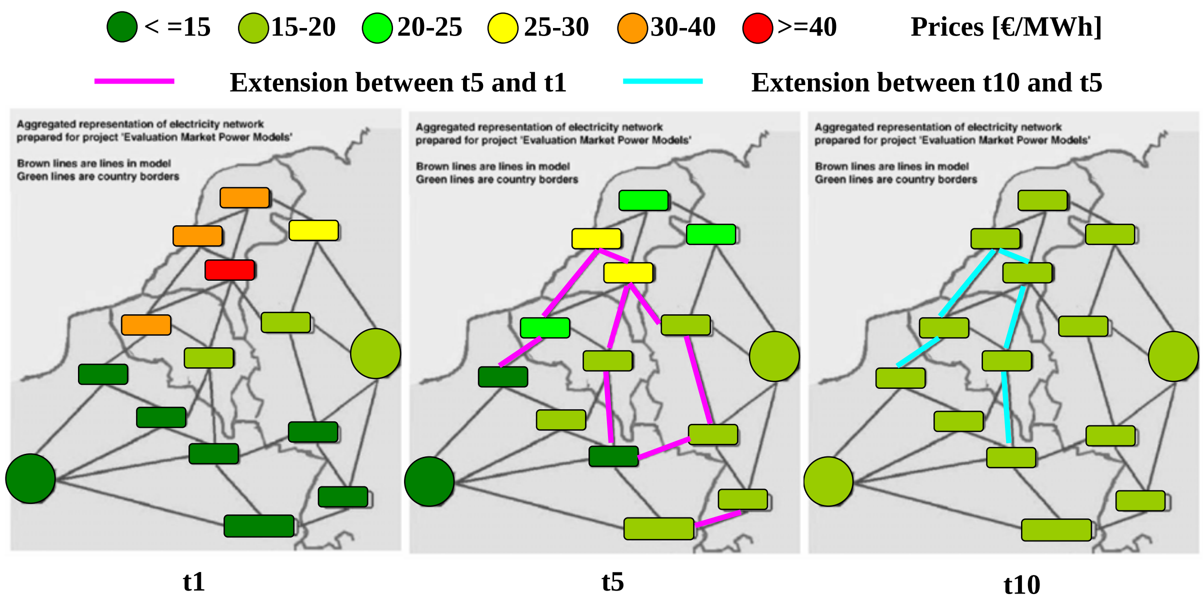


FIGURE 13. GEOGRAPHICAL PRICE STRUCTURE OF THE MODEL



Conclusion

This paper presents a combination of the merchant-FTR approach with the regulatory approach to electricity transmission expansion in an environment of price-taking generators and loads. Our results contribute in a continuing effort for further research to explore the use of practical incentive mechanisms, and their compatibility with merchant investment in organized electricity markets with FTRs.

The paper takes up three distinguish topics and develops first results towards a more detailed analysis. First, the general cost function behavior in electricity networks is analyzed. Due to the loop-flow nature of meshed networks a high level of complexity, non linearity and discontinuities exist. By testing increasing, linear and decreasing extension functions for lines within a network the global cost function behavior when increasing the FTR amount in a system is derived. The results indicate that the high level of kinks resulting from loop flows on lines is relaxed when line capacity extensions are linked to line reactances thus changing the flow pattern within the network whenever it is extended. However, the resulting global costs functions still show a high level of nonlinearity making the derivation of global optima in model approaches complicated.

In the second part, the regulatory mechanism is implemented as MPEC problem with a profit maximizing Transco and a fully competitive wholesale market on nodal pricing basis. Starting with a congested grid the Transco is free to choose grid extensions that influence its own profit which consists of the congestion rent and a fixed fee. The Transco's profits are subject to a price cap with Laspeyres weights. The results show that the Transco extends the network finally leading to a price development in the direction of marginal costs.

These last results are also confirmed in the last part of the paper where the MPEC approach is tested using a simplified grid of Northwestern Europe with a realistic generation structure. This first application of the HRV mechanism to a real world situation yields similar outcomes to the theoretical analyses. The nodal prices that were subject to a high level of congestion in the first place converge towards a common price level representing the marginal generation costs.

Further in depth analyses are necessary to verify the obtained results and draw general conclusion that can be applied to a large number of specific cases. These include an improvement of the underlying model structure with respect to myopic behavior, different weights in the price-cap constraint, different time periods, different pricing mechanisms particularly zonal pricing, and the impact of more Transcos within one network. Likewise, other practical questions need to be addressed such as property-right problems and specific implementations.

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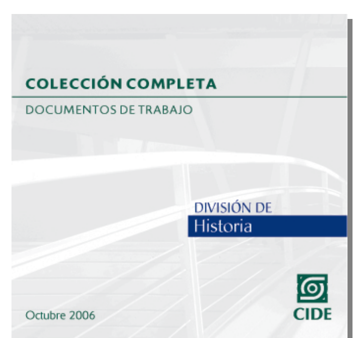

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