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Power System Transformation toward Renewables: An Evaluation of Regulatory Approaches for Network Expansion

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Abstract

We analyze various regulatory regimes for electricity transmission investment in the context of transformation of the power system toward renewable energy. Distinctive developments of the generation mix are studied, assuming that a shift toward renewables may have temporary or permanent impacts on network congestion. We specifically analyze the relative performance of a combined merchant-regulatory price-cap mechanism, a cost-based rule, and a non-regulated approach in dynamic generation settings. We find that incentive regulation may perform better than cost-based regulation but only when appropriate weights are used. While quasi-ideal weights generally restore the beneficial properties that incentive regulatory mechanisms are well-known for, pure Laspeyres weights may either lead to overinvestment or delayed investments as compared to the welfare-optimum benchmark. Laspeyres-Paasche weights, in turn, seem appropriate under permanently or temporarily increasing network congestion. Thus, our analysis provides motivation for further research in order to characterize optimal regulation for transmission expansion in the context of renewable integration.

JEL codes: Q40; Q42; L51

Keywords: Electricity transmission; incentive regulation; renewable integration; Laspeyres-Paasche weights; ideal weights.

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1 Introduction

The transformation toward a low carbon economy is one of the most ambitious projects of the European Union (EU) in the first half of the 21st century. To promote this pathway, the EU formulated binding reduction targets through 2020 with the "20-20-20" goals.[5] On a long-term perspective, the implementation of proposed emission reduction targets of 80% (or more) by 2050 is less concretely defined. The principle sectors for potential emission reductions are found in the energy system, with electricity being of special importance. In the electricity sector, fossil fuels are increasingly being replaced with renewable generation technologies. It is broadly accepted that the power system will have to integrate an increasing share of renewables as most EU members are making investments in new generation capacity based on wind, solar, biomass and hydro. However, the role of conventional power generation facilities, both existing and new, during the renewable integration process is less clear. In Europe, lignite, coal and natural gas, as well as nuclear in some countries, might build a bridge to the large-scale integration of non-conventional renewable technologies.

Regarding infrastructure, the transformation toward a low carbon economy requires new transmission capacity different to the historically existing one. However, network planning is increasingly complex when integrating renewable electricity. The role of network regulation in a dynamic renewable-integration process is a challenging task. The owning transmission system operators (TSOs) carry out operations within the system while investments and decommissioning in renewable and conventional generation capacities, respectively, is taking place. In a system with centralized planning, the regulator should ensure that the transmission company (Transco) carries out the proposed transmission expansion. Under a more decentralized market structure, the regulator should provide investment incentives through regulatory mechanisms, such as cost-plus or incentive regulation. In any case, the regulator will require market information to carry out their responsibilities. Typical regulatory challenges include the implied impacts on network development, as well as potential under- or overinvestments by network operators during the renewable integration process.

In this paper, we address the rationale for transmission investment under a renewable integration process. We isolate some basic characteristics and drivers of transmission investment in an energy transformation process characterized by network capacity expansion under the gradual substitution of conventional power (e.g., coal) with renewable energy sources (e.g., wind). In particular, we compare the relative performance of a combined merchant-regulatory price-cap mechanism, using different weights, with cost-based regulation as well as with a non-regulated approach in a dynamic system that assumes a transformation toward a power generation system with high renewable penetration.

[5] The 20-20-20 goals for 2020 refer to (*i*) a reduction in EU greenhouse gas emissions of at least 20% below 1990 levels; (*ii*) 20% of EU energy consumption to come from renewable resources; and (*iii*) a 20% reduction in primary energy use compared with projected levels, which is to be achieved through improving energy efficiency.

The remainder is structured as follows. In section 2 we carry out a literature review on the regulation of transmission investment under market and renewable integration. In section 3 we present a bi-level model for transmission investment with different regulatory schemes for the Transco in a changing market-setting under an intertemporally process of renewable integration. In section 4, we provide fundamental stylized examples helpful to understand possible drivers of network congestion changes in the context of the transformation toward renewable power. For a simple two-node network, three distinctive developments of the generation mix with different implications on network congestion are presented. In section 5, we present and discuss the results of the relative performance of a combined merchant-regulatory price-cap mechanism, a cost-based rule, and a non-regulated approach under the dynamic generation settings. The final section concludes with a discussion on avenues for further research on the appropriate definition of weights for incentive regulation under renewable integration.

2 Literature Review

This paper analyzes the role of electricity transmission on the integration of renewable energy sources. This presupposes a possibility of the regulator of focusing on incentivizing investment from a independent Transco through adequate price regulation (see Vogelsang, 2001). This approach has gained importance, both in theory and practice, due to liberalization processes in various electricity systems that prioritize vertical separation, mainly between generation and transmission activities. Such unbundling measures are shown to promote investment. Pollitt et al. (2007) review the econometric evidence and the international experience with generation and transmission unbundling (New Zealand, Australia, Chile, Argentina, Nordic Countries, and the USA), concluding that, as opposed to other market architectures, the unbundling of electricity generation and transmission – together with well-regulated independent transmission system operators (ITSOs) – can deliver highly competitive energy markets and facilitate timely transmission investments. Newbery (2005) finds similar conclusions for the UK electricity market. Using OECD measures of product market reform, Alesina et al. (2005) also find that electricity investment increases as vertical integration decreases.

The role of transmission investment as an important factor in the transformation of the whole electricity market via appropriate price signals from liberalization and regulatory reform processes is also recognized in most studies. Brunekreeft et al. (2005) and Rubio and Pérez-Arriaga (2000) point out the importance of a nodal-pricing system (and complementary capacity charges) to signaling the efficient location of generation investment. That is, establishing appropriate measures for incentivizing an efficient development of transmission networks is crucial not only for the development of the grid but also for power generation, marketing, distribution, and system operation itself. Likewise, transmission planning both in centralized systems as well as incentivized transmission expansion in decentralized market architectures have relevant impacts on consumer surplus and generator surplus (see Sauma and Oren, 2007, and Rosellón and Weigt, 2011).

A regulator has several alternatives to regulate the transmission price of a Transco in liberalized market environments. Cost-of-service (or cost-plus) regulation has been traditionally used in the practice of electricity utilities. It implies setting prices to equalize average cost, and usually goes along with a restriction on the rate of return on capital. It has a basic advantage in that it provides certainty and long-run commitment by the regulator – two crucial elements for long-run investments of utilities. However, incentives for cost minimization are almost nonexistent since the complete restitution of costs does not promote monetary expenditures for the improvement of efficiency. The other extreme of regulation, price-cap regulation, usually provides more incentives for cost minimization but at the cost of less certainty for the investing firm. This explains that price-cap schemes are usually combined in practice with cost-plus regulation.[6]

Regarding regulation for electricity transmission investment of an independent Transco in meshed networks, there are several alternatives. Two are especially interesting for the approach used in this paper: one based on financial transmission rights (FTRs; merchant approach), and another based on the incentive price-cap regulation. The merchant approach is based on FTR auctions within a bid-based security-constrained economic dispatch with nodal pricing of an independent system operator (ISO). The ISO runs a power-flow model that provides nodal prices derived from shadow prices of the model's constraints. FTRs are subsequently calculated as hedges from nodal price differences. The ISO retains some capacity or FTRs in order to deal with externalities caused by loop-flows, so that the agent expanding a transmission link implicitly pays back for the possible loss of property rights of other agents (Bushnell and Stoft, 1997, Kristiansen and Rosellón, 2006). FTR auctions have mainly been implemented in Northeast USA (NYISO, PJM ISO, and New England ISO).

The incentive approach relies on a price-cap on the two-part tariff of an independent Transco (Vogelsang, 2001).[7] Incentives for efficient investment result in expansion of the transmission grid through the over-time rebalancing of the fixed and variable charges of the two-part tariff. Convergence to steady state Ramsey-price equilibrium relies on the type of weights used. Transmitted volumes for each type of service are used as weights for the corresponding various prices so that the Transco's profits grow as capacity utilization and network expansion increase. In equilibrium, the rebalancing of fixed and variable charges depends on the ratio between the output weight and the number of consumers. There are two basic ways to regulate price structure: one with fixed weights (tariff-basket regulation) and another with variable weights (average revenue regulation). Under the former regime, a price cap is established over the weighted sum of prices for different products. Weights might be

[6] For example, an initial price cap (P_0) might be decided by the regulator and fixed for a first period of, say, five years (regulatory lag). P_0 is only adjusted during these first five years by inflation and efficiency indexes ("RPI-X" factor). After the initial five-year regulatory lag, a cost-of-service revision of the regulated company is carried out by the regulator. A second price cap (P_1) is determined and adjusted by a new RPI-X factor for the next five years. This process is repeated going forward (see Ramírez and Rosellón, 2002). In Germany, incentive regulation is complemented with cost-based elements like the so-called investment budgets for transmission expansion.

[7] A Transco needs to be regulated since it is a natural monopoly. Vogelsang (2001) concentrates on incentive regulation of natural-monopolistic activities of the Transco, independently from power generation.

output (or throughput) quantities of the previous period (chained *Laspeyres*), quantities of the current period (*Paasche*), intertemporally fixed quantities (fixed *Laspeyres*), or projected quantities that correspond to the steady state equilibrium (ideal *Laffont-Tirole* weights, as in Laffont and Tirole, 1996).[8] Variable (endogenous) weights are usually associated with average-revenue regulation, which sets a cap on income per unit but does not set fixed weights that limit the relative variation of prices. Compared to tariff-basket regulation, this confers the firm greater flexibility in tariff rebalancing but lack of convergence to a welfare-maximizing equilibrium.[9] The literature proves that, under non-stochastic (or stable) conditions of costs and demand and myopic profit maximization (that is, when the firm does not take into account future periods in its current profit maximizing behavior), the use of the chained Laspeyres index makes the prices of the regulated firm intertemporally converge to Ramsey-Boiteaux pricing (Vogelsang, 2001, Vogelsang, 1989, Bertoletti and Poletti, 1997, Loeb and Magat, 1979, and Sibley, 1989). The chained Laspeyres structure simultaneously reconciles two opposing objectives: the maximization of social welfare and the individual rationality of the firm (i.e., non-negative profits). Social surplus is redistributed to the monopoly in such a way that long-run fixed costs are recovered but, simultaneously, consumer surplus is maximized over time.[10]

Tanaka (2007) also proposes various incentive mechanisms: a Laspeyres-type price-cap on nodal prices, a two-part tariff cap also based on Laspeyres weights, and an incremental surplus subsidy, where the regulator observes the actual cost but not the complete cost function. These mechanisms are shown to achieve optimal transmission capacity from the effects of capacity expansion on flows and welfare. However, both Tanaka (2007) and Vogelsang (2001) abstract from technical electricity transmission constraints (loop-flows), and assume well-behaved transmission capacity cost functions, which appear to be very strong assumptions for loop-flowed meshed electricity networks.

A combination of the merchant and the incentive-regulation approaches was developed by Hogan, Rosellón, and Vogelsang (Hogan et al. 2010, HRV). A crucial aspect here is the redefinition of the transmission output in terms of incremental FTRs in order to apply the same regulatory logic of Vogelsang (2001) to real-world networks within a power-flow model. The HRV model deals with loop-flows in meshed networks and achieves well behaved transmission cost functions (Rosellón et al. 2012). The Transco intertemporally maximizes profits subject to a cap on its two-part tariff, but the variable fee is now the price of the FTR output based on nodal prices. Although immersed in an inter-temporal regulated profit-maximizing environment, the bi-level HRV model really assumes a static

[8] The steady state equilibrium is characterized by prices whose optimal distance from marginal cost is inversely proportional to the elasticity of demand. These are referred in the literature as Ramsey-Boiteaux prices (see Armstrong et al. 1994, chapter 3).

[9] More specifically, average-revenue regulation is a price-cap regime that sets an upper limit on revenues per unit and is the preferred way of regulating prices of firms whose costs depend on total production and whose products are commensurable. Compared to tariff-basket regulation, average-revenue regulation does not fix weights that limit variation among relative prices (see Armstrong et al. 1994, chapter 3). Sappington and Sibley (1992) prove in a two-part tariff model that by setting the usage charge at a low level the average-revenue restriction might be relaxed in future periods and thus allows the firm to increase future prices. This means that the regulated firm has incentives to set its tariffs strategically so that both consumer surplus and total surplus are lowered.

[10] The social surplus is made up by consumer, producer, and government surpluses (if present).

market setting in the sense of identical output behavior during each period. The Transco is actually a player enabled to alter the market result over time as it decides investments in transmission infrastructure (upper-level problem). Additional transmission lines change the constraints on the network (flow pattern and capacity), and therefore typically allow for an improved market dispatch with higher welfare (lower-level problem). The Transco is allowed to get a share of the welfare gains due to its two-part tariff structure. The fixed fee of the tariff inter-temporally rebalances (with respect to the variable fee) to make up for lost congestion rents, and convergence to steady state equilibrium is achieved through the use of proper weights (typically, Laspeyres weights). The approach also applies to more general situations including more realistic electricity flows like DC load-flow with loop-flows. The HRV model has already been successfully tested in simplified grids of Western Europe, Northeast USA, and South America (see Rosellón and Weigt, 2011, Rosellón et al. 2011, and Ruíz and Rosellón, 2012).

With the HRV mechanism, the regulator promotes welfare-beneficial network developments through an increased regulated return in the two-part tariff. This mechanism works as long as the welfare changes in the system can be directly linked to transmission investment. In previous HRV research, however, the complex issue of intertemporal interactions between generation, transmission, and demand has not been considered.[11]

Naturally, other incentive mechanisms for transmission investment exist in the literature. For instance, Léautier (2000) and Joskow and Tirole (2002) propose mechanisms based on a measure of welfare loss with respect to the Transco's performance. The regulator rewards the Transco when the capacity of the network is increased so that congestion rents are decreased. The regulator also might punish the Transco for taking advantage of a congested network by charging increasing fees, and accumulating higher congestion rents.[12] Alternatively, Contreras et al. (2009) propose an incentive scheme for transmission expansion based on a cooperative-game model where the Shapley value is used to reward investors according to their value added to social welfare.[13]

One common feature across all of the above incentive regulation mechanisms is that they rely on a market-integration economic rationale, that is, on the efficient expansion of the transmission network to the nodes with cheapest generation technologies (but possibly with high carbon emissions). Policy making based on such criteria is usual in practical network-expansion planning decisions, even under

[11] See Ruiz and Rosellón (2012), Rosellón et al. (2011), Rosellón and Weigt (2011), and Schill et al. (2011).
[12] Another variation is an "out-turn" based regulation. "Out-turn" is defined as the difference between the price for electricity actually paid to generators and the price that would have been paid absent congestion (Léautier, 2000). The Transco is made responsible for the full cost of out-turn, plus any transmission losses.
[13] The Shapley Value is an *a priori* evaluation of the prospects of a player in a multi-person game consisting of a set N of players and a coalitional function v that associates to every subset S of N (the "coalition") a real number $v(S)$, which is the maximal total payoff the members of S can obtain (the "worth" of S). The Shapley value associates to each player in that game a unique payoff—his "value" and turns out to be exactly his *expected marginal contribution to a random coalition* (see Winter, 2002).

an associated process of large-scale integration of renewable generation, as is the case of development of the transmission grid in Germany (50Hertz et al. 2012).

Schill et al. (2011) study the performance of various regulatory mechanisms under transmission market integration with both varying demand and wind generation. Specifically, they compare the HRV mechanism to a cost-based and a non-regulated approach with hourly time resolution in demand and fluctuating wind power. They show that HRV regulation leads to welfare outcomes far superior to the other modeled alternatives. The analysis by Schill et al. (2011) is carried out assuming intertemporal stability on the power generation mix. However, a system with increasing shares of generation from renewable energy will need to be combined at least temporally with conventional base-, mid-, and peak-load generation. Therefore, network extensions for combined integration of carbon-intensive base-load and renewable generation might face the risk of excessive stranded transmission investments in the medium term.[14] In this paper, we study this basic issue with a simple model presented in the following section.

3 The Model

We follow the approach of Schill et al. (2011). Table 4 in the Appendix lists all model sets and indices, parameters, and variables. We assume a market design with nodal pricing based on real power flows. A single Transco holds a natural monopoly on the transmission network. The Transco decides on network extension. Accordingly, we assume that just the Transco maximizes profit, which consists of congestion rents and – depending on the regulatory regime – a fixed income part. As the Transco is not involved in electricity generation, an independent system operator (ISO) manages the actual dispatch in a welfare-maximizing way. The ISO collects nodal payments from loads and pays the generators. The difference between these payments is the congestion rent, which is assumed to be transferred to the Transco. We model three different regulatory cases in which we assume the Transco to be unregulated regarding network expansion (*NoReg*), cost-regulated (*CostReg*), or *HRV*-regulated. We compare these regulatory cases to a baseline case without any network expansion (*NoExtension*) and to a welfare-maximizing benchmark (*WFMax*), in which a social planner makes combined decisions on network expansion and dispatch. The problem formulation entails two decision levels (bilevel programming). In the regulatory cases, the Transco's profit maximization constitutes the upper-level optimization problem. In the welfare-maximizing benchmark, the upper-level program represents the social planner's maximization problem. On the lower level, we formulate the ISO's welfare-maximizing dispatch as a mixed complementarity problem (MCP).[15] The combination of

[14] We assume perfect foresight regarding the changing generation mix. Van der Weijde and Hobbs (2012) study the economics of electricity transmission planning under uncertain economic, technological, and regulatory conditions.

[15] An MCP allows formulating economic equilibrium models as systems of nonlinear equations, complementarity problems or variational inequalities. These extensions accommodate market and game-theoretic equilibrium models (Rutherford, 1995).

lower and upper level problems constitutes a mathematical program with equilibrium constraints (MPEC).[16]

We assume a standard linear demand function (0):

$$p_{n,t,\tau} = a_{n,\tau} + m_{n,\tau} q_{n,t,\tau} \tag{0}$$

where $p_{n,t,\tau}$ is the electricity price at node n in regulatory period t and hour τ,[17] whereas $q_{n,t,\tau}$ describes the corresponding electricity demand. Given (0), the lower level dispatch problem consists of equations (0)-(0). These represent an MCP formulation of the ISO's constrained welfare maximization problem, which is provided in the Appendix. We model real load flows between single nodes with the simplified DC load flow approach (Schweppe et al. 1988, Leuthold et al. 2012). Equations (0)-(0) must be satisfied in every single hour τ.

$$a_{n,\tau} + m_{n,\tau} q_{n,t,\tau} - p_{n,t,\tau} \leq 0 \qquad \perp q_{n,t,\tau} \geq 0 \tag{0}$$

$$-c_s + p_{n,t,\tau} - \lambda_{4,n,s,t,\tau} \leq 0 \qquad \perp g_{n,s,t,\tau} \geq 0 \tag{0}$$

$$-\sum_{l \in L} \frac{I_{l,n}}{X_{l,t}} \lambda_{1,l,t,\tau} + \sum_{l \in L} \frac{I_{l,n}}{X_{l,t}} \lambda_{2,l,t,\tau} - \sum_{nn} p_{nn,t,\tau} B_{nn,n,t} - \lambda_{5,n,t,\tau} slack_n = 0, \quad \Delta_{n,t,\tau} \quad free \tag{0}$$

$$\sum_{n} \frac{I_{l,n}}{X_{l,t}} \Delta_{n,t,\tau} - P_{l,t} \leq 0 \qquad \perp \lambda_{1,l,t,\tau} \geq 0 \tag{0}$$

$$-\sum_{n} \frac{I_{l,n}}{X_{l,t}} \Delta_{n,t,\tau} - P_{l,t} \leq 0 \qquad \perp \lambda_{2,l,t,\tau} \geq 0 \tag{0}$$

$$\sum_{s} g_{n,s,t,\tau} - \sum_{nn} B_{n,nn} \Delta_{nn,t,\tau} - q_{n,t,\tau} = 0 \qquad , \quad p_{n,t,\tau} \quad free \tag{0}$$

$$g_{n,s,t,\tau} - \overline{g}_{n,s,t} \leq 0 \qquad \perp \lambda_{4,n,s,t,\tau} \geq 0 \tag{0}$$

$$slack_n \Delta_{n,t,\tau} = 0 \qquad , \quad \lambda_{5,n,t,\tau} \quad free \tag{0}$$

Equations (0)-(0) represent the partial derivates with respect to $q_{n,t,\tau}$, $p_{n,t,\tau}$, and the voltage angle $\Delta_{n,t,\tau}$. $I_{l,n}$ is the incidence matrix of the network, which provides information on how the nodes are

[16] Hobbs et al. (2000) are among the first to apply an MPEC approach to power market modelling. See also Gabriel et al. (2013).

[17] In the numerical application in section 4, we do not make use of the hourly resolution of the model formulation. Instead, we rely on stylized average values.

connected by transmission lines l. The parameter $X_{l,t}$ describes the reactance for each transmission line. $B_{n,nn}$ is the network susceptance between two nodes. Equations (0) and (0) ensure that the power flows on each line do not exceed the respective line's capacity $P_{l,t}$. (0) ensures nodal energy balance: generation minus net outflow has to equal demand at all times. Equation (0) constrains generation of technology s to the maximum available generation capacity at the respective node and the respective time period. Finally, (0) establishes a point of reference for the voltage angles by exogenously setting the parameter $slack_n$ to 1 for one node in the network. For all other nodes, $slack_n$ equals 0.

Where the lower-level problem (0)-(0) must be solved for every single hour τ, the upper-level problem needs to be inter-temporally optimized over all regulatory periods t.[18] For the three regulatory regimes, the upper level problem is represented by (0):

$$\max \Pi = \sum_{t \in T} \left(\left(\sum_{\tau \in \mathrm{T}} \sum_{n \in N} \left(p_{n,t,\tau} q_{n,t,\tau} - \sum_{s \in S} p_{n,t,\tau} g_{n,s,t,\tau} \right) + fixpart_t - \sum_{l \in L} \sum_{tt < t} ec_l ext_{l,tt} \right) \frac{1}{\left(1+\delta^p\right)^{t-1}} \right) \qquad (0)$$

The Transco's decision variable is capacity extension of transmission lines $ext_{l,t}$, which incurs extension costs ec_l (annuities). Both future revenues and future costs are discounted with a private discount rate δ^p. In the *NoReg* case, transmission investments have to be fully recovered by congestion rents, i.e. the fixed part is constrained to zero ($fixpart_t = 0$). Accordingly, the Transco will only invest in lines if it leads to increases in congestion rent that are larger than extension costs. In the *CostReg* case, we assume that the Transco not only receives congestion rents, but may also charge an additional fixed tariff part that reimburses the line extension cost and grants an additional return on costs ("cost-plus" regulation). Equation (0) shows that the fixed part of a given period includes the costs (annuities) of all network investments made so far plus a return on costs r. With positive r, the Transco may find it optimal to expand all transmission lines infinitely. We thus include an upper limit for line extensions in the *CostReg* case such that no single line capacity is allowed to exceed the optimal level as determined by the welfare-maximizing benchmark.[19] In the *HRV* case, the Transco may also charge a fixed tariff part, for which equation (0) sets a cap. It includes current and previous period quantity weights $q_{n,t+1,\tau}^{weight}$, $q_{n,t,\tau}^{weight}$, $g_{n,s,t+1,\tau}^{weight}$, and $g_{n,s,t,\tau}^{weight}$. In its general form, it also includes a retail price index RPI and an efficiency factor X. We set both RPI and X to zero in the model application, as we assume real prices and neglect efficiency gains. Summing up, in both the *CostReg*

[18] This implies that the Transco has perfect foresight over all periods.

[19] Note that this requires the regulator to have sufficient knowledge about which lines should be increased. In the numerical simulations, line extensions in the *CostReg* case are substantially smaller than welfare-optimal extension levels in most cases because the marginal benefit of cost-plus regulation would not compensate for the Transco's marginal congestion rent loss. An exception is the case of temporarily increased congestion, in which the Transco invests nearly optimally under *CostReg* because this allows a temporary increase of congestion rents (see section 5.1). In the case of permanently decreasing congestion, no line extension takes place regardless of the regulatory regime.

and the *HRV* cases, the Transco is able to recover network extension costs by the fixed tariff part. In contrast, this is not possible in the *NoReg* case.

$$fixpart_{t+1}^{CostReg} = \sum_{l \in L} ec_l ext_{l,t} (1+r) + fixpart_t^{CostReg} \tag{0}$$

$$\frac{\sum_{n \in N} \sum_{\tau \in T} \left(p_{n,t+1,\tau} q_{n,t+1,\tau}^{weight} - \sum_{s \in S} p_{n,t+1,\tau} g_{n,s,t+1,\tau}^{weight} \right) + fixpart_{t+1}^{HRV}}{\sum_{n \in N} \sum_{\tau \in T} \left(p_{n,t,\tau} q_{n,t,\tau}^{weight} - \sum_{s \in S} p_{n,t,\tau} g_{n,s,t,\tau}^{weight} \right) + fixpart_t^{HRV}} \leq 1 + RPI - X \tag{0}$$

Table 1 provides an overview of the different types of weights used in the analysis. (Quasi-)Ideal weights are derived from welfare-optimal results (indicated by an asterisk).

Table 1: Overview of weights

	Laspeyres	Paasche	Average Laspeyres-Paasche	(Quasi-)Ideal[20]
$q_{n,t+1,\tau}^{weight}$	$q_{n,t,\tau}$	$q_{n,t+1,\tau}$	$\frac{1}{2}(q_{n,t+1,\tau} + q_{n,t,\tau})$	$q_{n,t+1,\tau}^{*}$
$q_{n,t,\tau}^{weight}$	$q_{n,t,\tau}$	$q_{n,t+1,\tau}$	$\frac{1}{2}(q_{n,t+1,\tau} + q_{n,t,\tau})$	$q_{n,t,\tau}^{*}$
$g_{n,s,t+1,\tau}^{weight}$	$g_{n,s,t,\tau}$	$g_{n,s,t+1,\tau}$	$\frac{1}{2}(g_{n,s,t+1,\tau} + g_{n,s,t,\tau})$	$g_{n,s,t+1,\tau}^{*}$
$g_{n,s,t,\tau}^{weight}$	$g_{n,s,t,\tau}$	$g_{n,s,t+1,\tau}$	$\frac{1}{2}(g_{n,s,t+1,\tau} + g_{n,s,t,\tau})$	$g_{n,s,t,\tau}^{*}$

In the baseline and in the welfare-maximizing benchmark case, the upper level problem does not represent a Transco's profit-maximization, but rather a social planner's maximization of social welfare, which is described by (0). The social planner uses a social discount rate δ^s, which may be smaller than the private discount rate δ^p used by a Transco.[21]

$$\max wf = \sum_{t \in T} \left(\left(\sum_{\tau \in T} \sum_{n \in N} \left(a_{n,\tau} q_{n,t,\tau} + \frac{1}{2} m_{n,\tau} q_{n,t,\tau}^{\ 2} - \sum_{s \in S} c_s g_{n,s,t,\tau} \right) - \sum_{l \in L} \sum_{tt < t} ec_l ext_{l,tt} \right) \frac{1}{\left(1+\delta^s\right)^{t-1}} \right) \tag{0}$$

[20] Following Laffont and Tirole (1996), ideal weights would require using, in each period, the predicted fixed q^* and g^* prevailing in the steady state welfare-optimal equilibrium, not period-specific (also predicted) equilibrium quantities. However, in a dynamic generation setting with an exogenously changing generation mix, in which there may be no smooth convergence to a steady state, our quasi-ideal period-specific weights prove to perform better.

[21] In the model application, we assume δ^s = 0.04 and δ^p = 0.08. Evans and Sezer (2004) present empirical estimates of social discount rates for different countries. Private discount rates are typically higher due to various factors including risk premia.

In all regulatory cases, network extension leads to inter-period constraints on line capacity (0), line reactance (0) and network susceptance (0).

$$P_{l,t+1} = P_{l,t} + ext_{l,t} \tag{0}$$

$$X_{l,t} = \frac{P_l^0}{P_{l,t+1}} X_l^0 \tag{0}$$

$$B_{nn,n,t+1} = \sum_l \frac{I_{l,n} I_{l,nn}}{X_{l,t+1}} \tag{0}$$

The problem is implemented in the General Algebraic Modeling System and solved using the commercial solver NLPEC. As the feasible region of the MPEC problem is non-convex, a large number of different starting points are used in order to find good local optima.[22] First, the welfare-optimal benchmark and all regulatory cases are solved using the case without expansion as a starting point. Second, all cases are repeatedly solved with the solution of *WFMax* serving as a starting point. Afterwards, all cases are repeatedly solved in varying order, using the (feasible) solution of one case as a starting point for the next case. We find that local optima converge to some characteristic values during this solution procedure. After several iterations, solutions do not improve any more. The best available solutions are then considered as good approximations of global optima.

4 Test cases

The locations of renewable power generation usually differ from the ones of conventional power plants. For example, lignite plants are always located near lignite mines in order to minimize transportation costs. Likewise, hard coal plants are usually built where the coal can easily be shipped. In contrast, wind power plants are usually constructed at places where their natural potential is greatest, for example at coast lines or even offshore. Solar power is often installed near the load, for example on roof tops. Thus both (centralized) wind power and (decentralized) solar power may lead to very different transmission requirements compared to conventional power plants. Accordingly, an energy system transformation toward renewable power supply may either increase or decrease congestion in existing transmission systems.

Exactly how network congestion changes in the context of such an energy transformation depends very much on the existing transmission system, the choice of renewable technologies (for example, wind or solar power), and the timeframe considered. We thus analyze four stylized cases of changing generation capacities in a simple two-node network (n1, n2) over a timeframe of 20 years.[23] Both nodes are connected by a capacity-constrained transmission line with a bi-directional capacity of 50 MW in the initial period. Figure 1 shows the network setting in the initial period.

[22] Non-convexity is not a major issue given the small size of our stylized model.
[23] There is only one representative hour, τ .

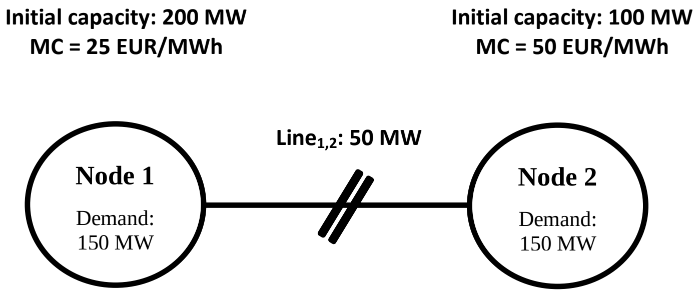

Figure 1: The network setting in the initial period

Demand at both nodes is characterized by a linear demand curve with a reference demand of 150 MW at a reference price of 30 EUR/MWh. The price elasticity of demand is -0.25 at the reference point. There are two conventional generation technologies (base, peak) with marginal costs of 25 EUR/MWh and 50 EUR/MWh, respectively. The cheap conventional technology is assumed to be located at node 1, the expensive technology at node 2. Renewable power is dispatched without marginal costs, which is true for both wind and solar power.[24] For reasons of simplicity, we abstract in our model of section 3 from fluctuations in demand and in renewable generation. The four stylized cases (see Figure 2) with changes in generation capacity are:

1: **The static case**: There are no changes in generation technologies over time.

2: **Temporarily increased congestion**: Renewable generation capacities increase over time at node 1. This could be interpreted as wind power replacing hard coal plants in coastal areas. There is an overlap of renewables phasing in and conventional generators phasing out, such that congestion is temporarily increased.

3: **Permanently increased congestion**: Growing renewable capacities at node 1 over-compensate the phase-out of conventional power plants at this node, giving rise to permanently increased congestion.

4: **Permanently decreased congestion**: Renewable power generation increases equally at both nodes, for example wind power at node 1 and solar power at node 2, such that conventional generation is completely phased out. Consequently, transmission congestion vanishes.

[24] We implicitly assume full spot market integration of renewables. Under the assumption of a feed-in tariff for renewables, our analysis could be applied to any renewable technology including biomass, because variable costs under such a regime do not matter for renewable dispatch.

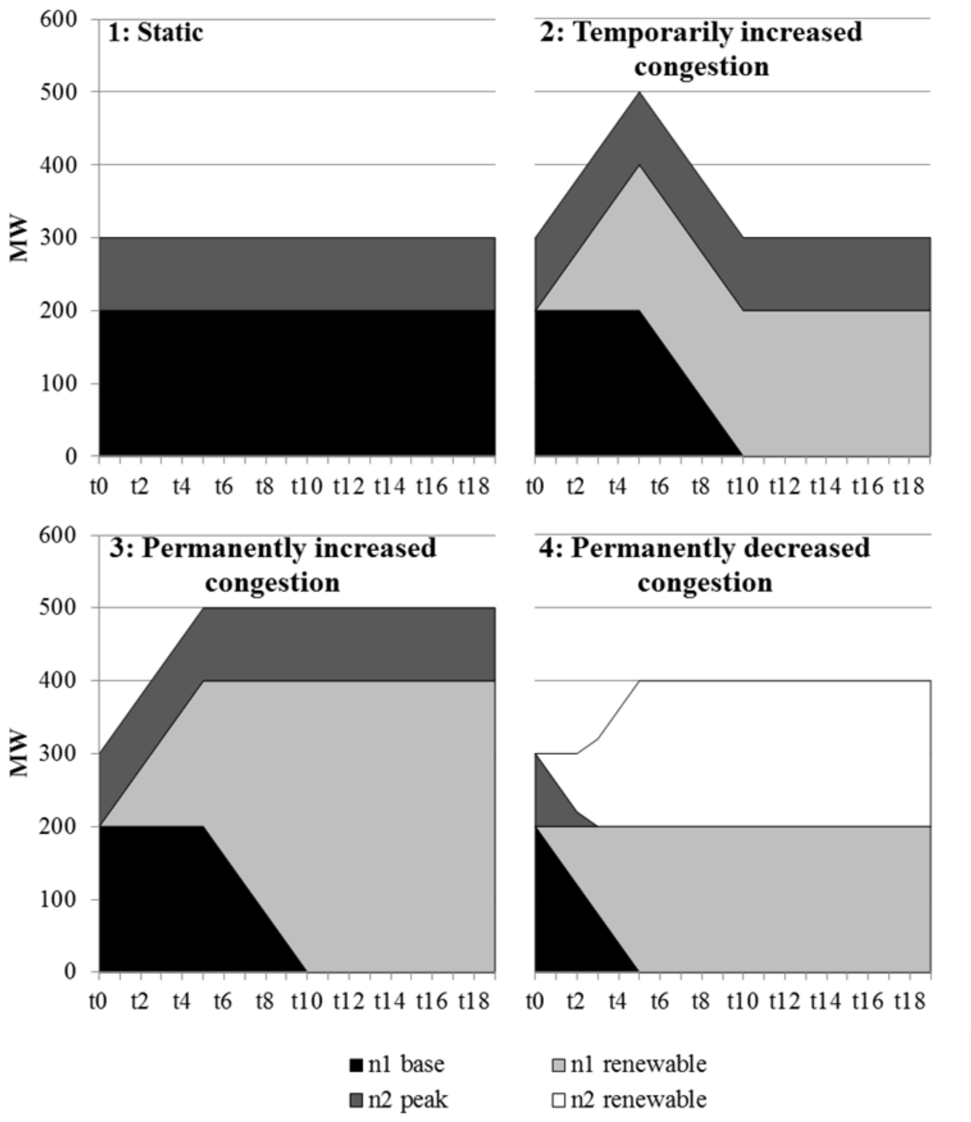

Figure 2: Exogenous development of generation capacities in different cases

Figure 3 provides more intuition on the transmission congestion implications of the assumed intertemporal changes of the generation mix. It shows how network congestion rent develops in all cases due to the exogenous changes in generation capacity discussed above, assuming that no network expansion takes place in any period. Accordingly, congestion rent does not change in case 1. Note the temporally increased congestion between t1 and t9 in case 2 due to the delayed phase out of conventional generation in node 1, compared to the two jumps in congestion rent in period t1 and t6 in case 3, which is the result of conventional capacity phasing out at node 1 and zero cost renewables setting the price at this node. In case 4, network congestion vanishes completely from t3 on. The values have been computed with the model described in section 3, with the network expansion variable fixed to zero.

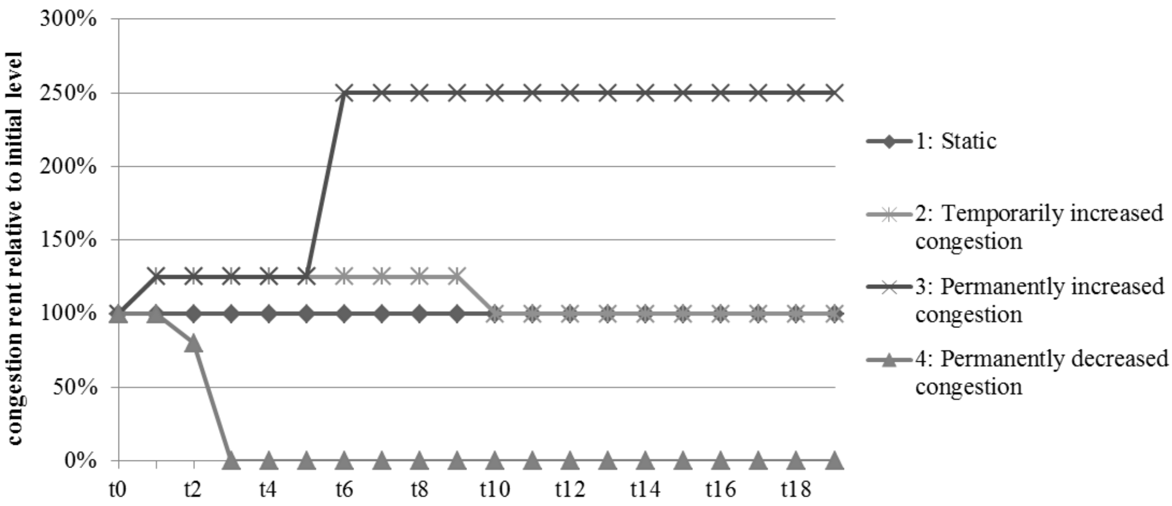

Figure 3: Development of the congestion rent (without network expansion)

In section 5, we analyze the effects of the three regulatory regimes on transmission expansion and welfare in all of the above cases. We compare them to the baseline without expansion and the welfare-maximizing optimum. First we do so using Laspeyres weights in the *HRV* model. Then, we try out other possibilities such as Paasche weights, average Laspeyres-Paasche weights and ideal weights.

5 Results

5.1 Laspeyres weights

Figure 4 shows network expansion results for the two-node cases. In the static case – in which generation capacities do not change over time – line expansion under *HRV* regulation converges to the welfare-optimal level over time. The Transco compensates extension-related congestion rent losses with a corresponding increase in the fixed tariff part. Vogelsang (2001) shows that the rebalancing of the variable and fixed fees will lead to a slow convergence to a steady state equilibrium. In contrast, both the cost-regulatory case and the scenario without regulation do not lead to network expansion. These findings confirm the results of previous numerical simulations.[25] The slowness in convergence is because Laspeyres weights reflect the previous-period state of demand only, so that the compensating increase in the fixed part of the two-part tariff falls somewhat short of the actual increase in consumer surplus in the current period.

[25] See Rosellón and Weigt (2011), Rosellón et al. (2011), Schill et al. (2011), and Ruiz and Rosellón (2012).

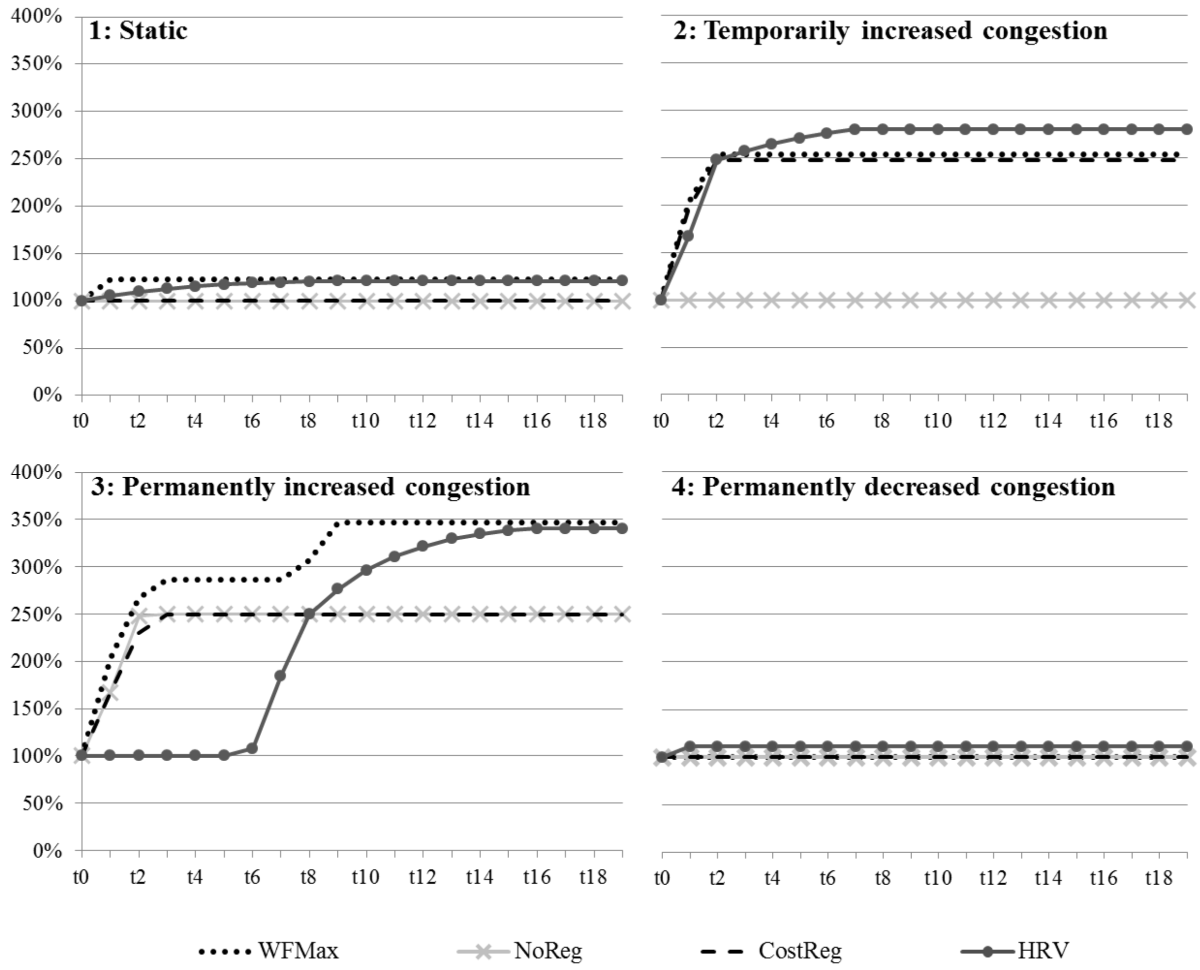

Figure 4: Line extension results (relative to initial line capacity, Laspeyres weights)

In the cases with exogenously changing generation capacities, however, these results do not necessarily hold any longer. In case 2, which assumes temporarily increased network congestion due to growing renewable capacities, *HRV* leads to over-investments as compared to the welfare-optimal benchmark. When rebalancing the fixed and variable tariff parts according to the regulatory cap, the Transco is rewarded for stranded investments. The main reason for this finding is that the chosen Laspeyres weights (previous period quantities) are not optimal, as they do not reflect exogenous decreases in congestion rents in future periods and they incorporate gains in congestion-rents arising both from the transmission expansion process as well as from the change in the generation mix. Laspeyres weights have been previously described to adjust too slowly to a changing environment since the weights only reflect the past state of demand or costs (see Neu, 1993, and Fraser, 1995). In our model, the convergence speed seems to be slower than the exogenous change in network congestion. In contrast, the cost-regulatory approach leads to a nearly optimal network expansion. This is because a moderate line extension results in temporarily higher flows and accordingly increased congestion rents, which together with the cost-plus revenues, given by equation (0), outweigh the (discounted) congestion rent losses in later periods (see analysis of congestion rents below and Figure 5). Without the cost-plus revenues, no extension takes place (*NoReg*).

In case 3, with permanently increased congestion, *HRV*-triggered network expansion approaches optimal levels in the final periods. However, the Transco finds it optimal not to invest before the seventh period, as it benefits much of increased congestion rents in the first periods, which are rebalanced against growing fixed parts later on. In contrast, both the cost regulatory case and *NoReg* lead to substantial line capacity extension in early years because these allow the Transco to permanently increase congestion rents; however, both *CostReg* and *NoReg* do not provide incentives to the Transco to expand capacity to optimal levels in later periods, as congestion rent losses would be too high.

In case 4, we do not find any network investments in the welfare-optimal case, as congestion decreases exogenously and vanishes completely after period 3. *CostReg* and *NoReg* also do not lead to any network investment. Yet under *HRV* regulation, some over-investment occurs, because the regulatory cap rewards the Transco for removing congestion in the first periods.

As a consequence of the line investments shown in Figure 4, we find (nominal) congestion rents to develop as shown in Figure 5. While *HRV* regulation largely removes congestion rent over time in the static case, it leads to overly reduced congestion in case 2, in which the exogenous congestion shock is only of temporary nature. A related observation can be made in case 4. Yet, in case 3, we find that the Transco's delay of investments enables it to benefit from relatively very high congestion rents around the ninth period, which it is then able to rebalance with the fixed part in the following periods. As shown in Figure 6, the Transco is even willing to choose a negative fixed part in the first periods in order to "make room" for even higher fixed parts in future.[26]

[26] The provision of absolute numbers on the ordinate (in Euro) would not be meaningful due to the stylized nature of our 2-node example.

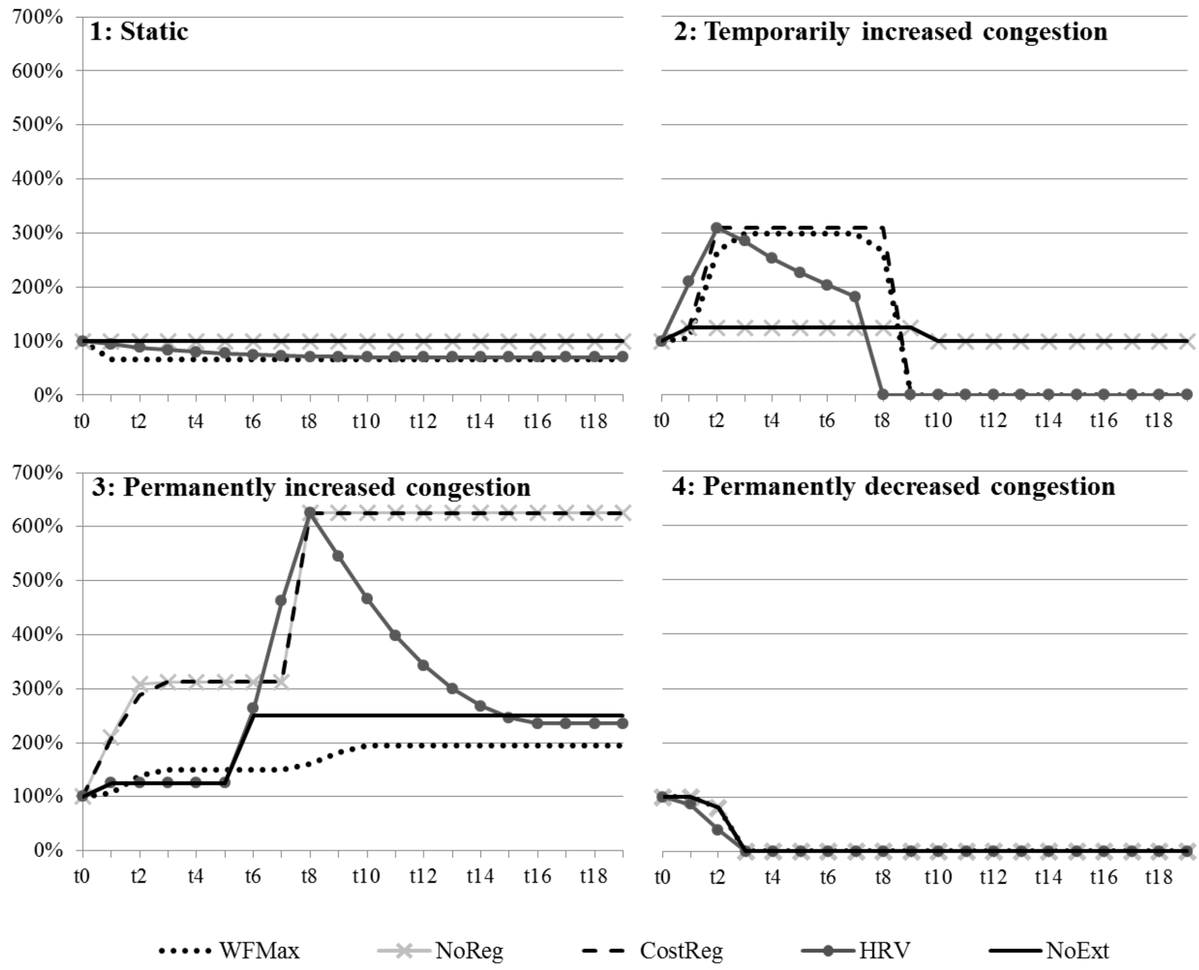

Figure 5: Congestion rents (nominal values relative to initial value)

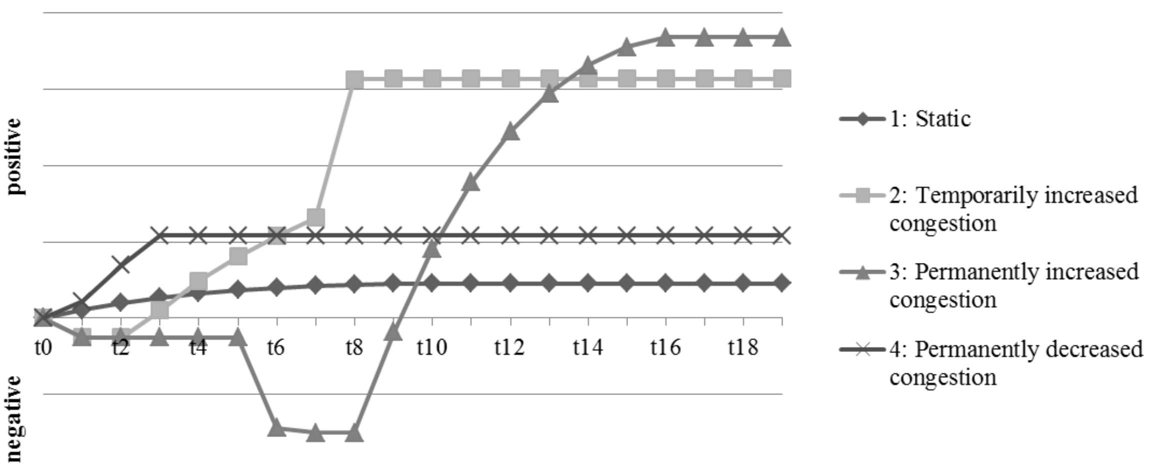

Figure 6: Development of the fixed part in case of HRV regulation

5.2 *Other Types of Weights*

The results presented so far show that some of the properties of the combined merchant-regulatory incentive regulation, as established in the literature, may no longer hold in the context of exogenous changes of generation capacities when Laspeyres weights are used. In the next sub-sections, we study the effects of using other type of weights in the *HRV* regulatory-cap formula.

5.2.1 Paasche weights

Paasche weights use same-period quantities as weights in the regulatory constraint. They are theoretically shown in the literature to lead to overinvestment under incentive regulation (Vogelsang, 2001). The main logic is that the Transco tends to set a variable price in the two-part tariff (and an implied Paasche weight quantity) that relaxes the price cap in such a way that the fixed part can be excessively increased in relation to the consumer surplus of network users. Compared to Laspeyres weights, Paasche weights typically lead to too much investment and, consequently, to divergence from the steady state equilibrium. In fact we confirm this in our simulations. Figure 7 depicts network expansion results for the modeled cases. In all cases, line expansion under *HRV* regulation notably exceeds the welfare-optimal level over time. Paasche weights do not reflect exogenous decreases in congestion rents in future periods, which has an even larger effect on extension results than in case of Laspeyres weights. Another difference to Laspeyres weights refers to the fact that total network extension is carried out in the first period in cases 1 and 4. This contrasts to gradual line extension in the Laspeyres case.

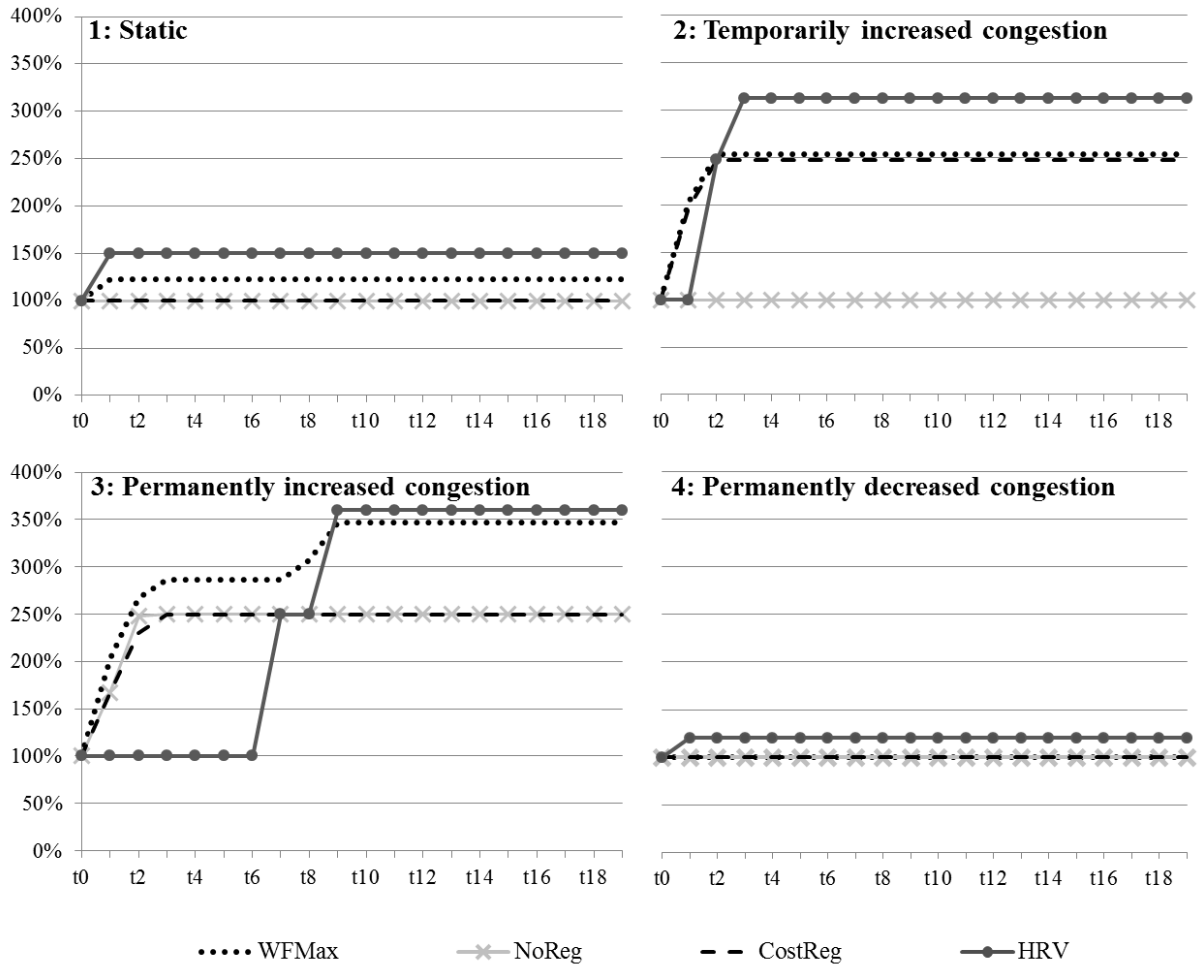

Figure 7: Line extension results (relative to initial line capacity, Paasche weights)

5.2.2 Average Laspeyres-Paasche weights

A simple average of Laspeyres and Paasche weights is used in the literature as a linear approximation of idealized weights (Vogelsang, 2001). They are exact only for linear demand curves and may, in theory, lead to strategic behaviour (cycles) if demands are nonlinear, but this has limited practical significance (Vogelsang, 1988). The average Laspeyres-Paasche weight is optimal only in a stationary environment with linear demand because in that case the fixed fee of the two-part tariff defined by the price cap is equal to the change in consumer surplus of network users. Thus, the price cap equals the incremental surplus subsidy (Sappington and Sibley, 1988). In a dynamic scenario when demand differs between periods, the average Laspeyres-Paasche weight makes the fixed fee no longer equal to the change in consumer surplus because the Laspeyres part belongs to consumer surplus in the past period and the Paasche weight to consumer surplus in the current period.[27] In our simulations, we confirm that, under *HRV* regulation, this type of weight actually leads to less overinvestment in cases 2 and 3 compared to pure Paasche weights. Noticeably, in the static case total network extension is carried out in the first period, as was also observed in the case of Paasche weights. This once again contrasts to the Laspeyres case, in which lines are extended gradually.

[27] We thank a referee for this insight.

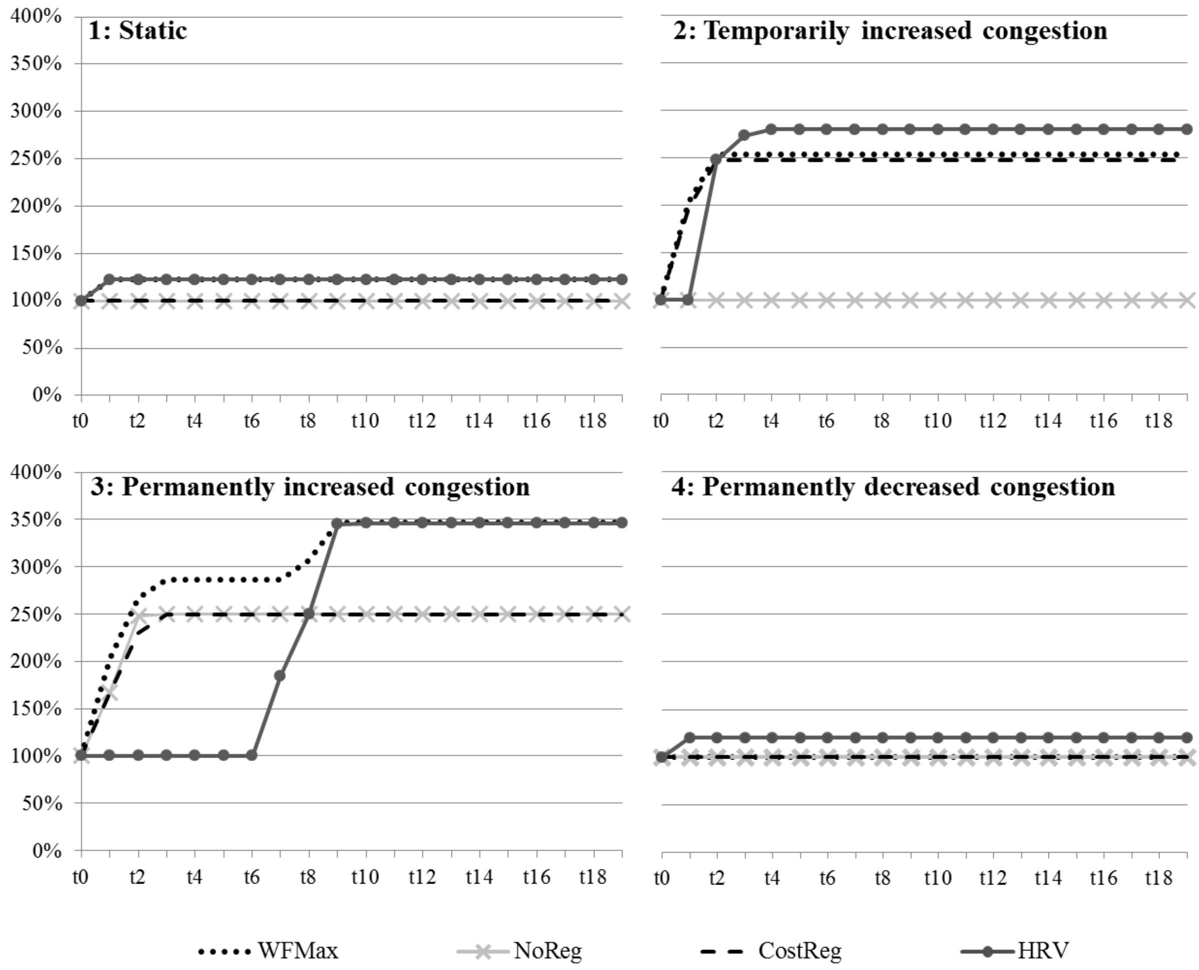

Figure 8: Line extension results (relative to initial line capacity, average Laspeyres-Paasche weights)

5.2.3 Ideal weights

Ideal weights are quantities corresponding to the steady state equilibrium and are analytically shown to grant convergence of incentive mechanisms to such equilibrium in just one period (Laffont and Tirole, 1996). In the following simulation, we use quasi-ideal weights defined as the period-specific quantities of the welfare-optimal runs for each case.[28] Figure 9 confirms the theory of incentive regulation under renewable integration. The *HRV* incentive mechanisms nicely converge early to the welfare-optimal benchmark investment in all cases. Introducing the quasi-ideal weights isolates the investment incentives from the effects of the changing generation mix.

[28] Ideal weights serve as benchmarks. In practice, they may not be available to the regulator as they cannot be observed from market outcomes. Compare section 3.

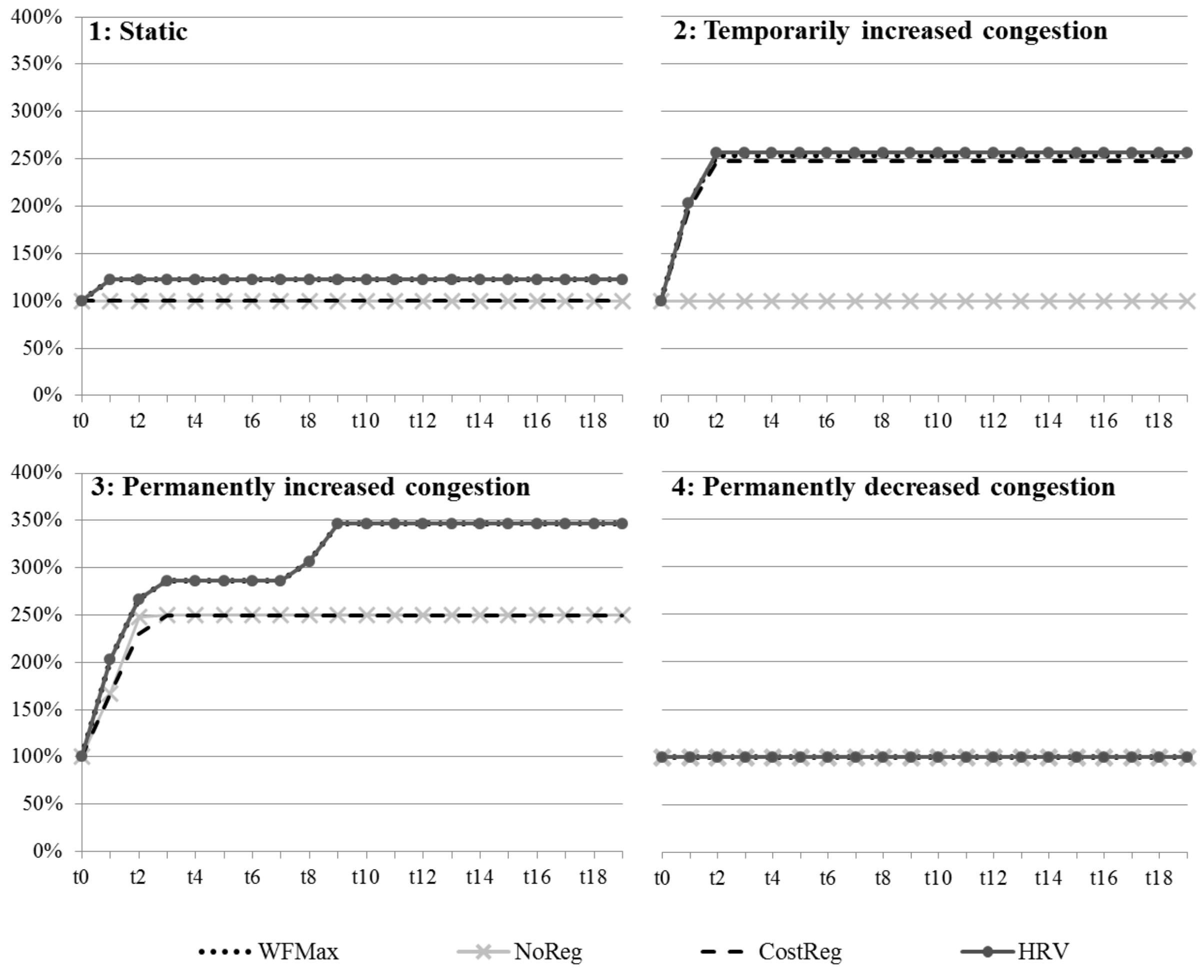

Figure 9: Line extension results (relative to initial line capacity, ideal weights)

5.3 *Welfare Effects*

As a consequence of the expansion results discussed above for each type of weight, we find the welfare results as summarized in Table 2. In the static case, the incentive regulatory scheme with Laspeyres weights leads to a welfare improvement close to the welfare-optimal benchmark, because transmission capacity converges to the optimum over time. Yet, in the other cases, this is no longer true due to over-investment (cases 2 and 4) or delayed investment (case 3). The cost-regulatory case even leads to slightly better outcomes in these cases.

For Paasche weights, the incentive regulatory scheme leads in the static case to less extension-related welfare compared to the welfare-optimal benchmark, as a result of heavily diverging transmission over-investment. The same is true for the other cases; except 3, in which the negative effect of slight overinvestment is more than compensated by quick expansion, compared to slower network upgrades in the Laspeyres case.[29] Cost-plus regulation still noticeable leads to better welfare outcomes in cases

[29] This feature of Paasche weights may be beneficial in the case of lumpy network investments.

1, 2, and 3. So, even though Paasche weights are easy to obtain for the regulator, they seem to be relatively inappropriate for incentive regulation in the context of a changing generation mix.

Combining Paasche weights with Laspeyres weights provides diverse outcomes. In the static case, the use of average Laspeyres-Paasche weights leads to welfare-optimal results. However, welfare effects are between Laspeyres and Paasche weights for cases 2 and 3, and similarly bad as under Paasche weights in case 4. Incentive regulation under ideal weights provides the best welfare results in all cases as expected.

Table 2: Welfare changes relative to the case without extension

	Weights	1: Static	2: Temporarily increased congestion	3: Permanently increased congestion	4: Permanently decreased congestion
WFMax		0.29%	1.28%	11.62%	0.00%
NoReg		0.00%	0.00%	9.25%	0.00%
CostReg		0.00%	1.27%	9.22%	0.00%
HRV	Laspeyres	0.25%	1.01%	9.02%	-0.17%
	Paasche	-0.11%	0.38%	9.39%	-0.32%
	Average Lasp.-Paasche	0.29%	0.89%	9.21%	-0.32%
	Ideal	0.29%	1.28%	11.62%	0,00%

Thus, incentive regulation might still provide relatively adequate outcomes in terms of welfare convergence, as long as proper types of weights are used. Ideal weights always lead to convergence to the welfare optimum, but are not available for the regulator in complex networks. Accordingly, the regulator might actually choose the best practically available weights that can be observed from market outcomes under incentive regulation for each assumed congestion behavior:

- No exogenous change of network congestion: Average Laspeyres-Paasche weights provide the best results due to quick network expansion, but Laspeyres weights also work well.
- Temporarily-increased-congestion case: Laspeyres weights work best, average Laspeyres-Paasche weights fall somewhat short.
- Permanently-increasing-congestion case: Paasche weights work best, while average Laspeyres-Paasche weights provide the second best outcome.
- Permanently-decreasing-congestion case: Incentive regulation with other than ideal weights does not lead to desirable outcomes, as the Transco is rewarded for network investments that are obsolete in later periods (stranded investments).

Regarding questions of real-world renewable integration, cases 2 and 3 appear to be most relevant. Whereas Laspeyres weights work best in case 2 and Paasche weights are preferable in case 3, average Laspeyres-Paasche weights appear to be an appropriate choice in both cases. That is, the regulator may choose average Laspeyres-Paasche weights if it is not clear if the expected exogenous increase in network extension is a permanent or a transitory one.

6 Conclusions

In this paper we address transmission investment in the context of a renewable integration process. That is, transmission capacity expansion is driven by the adoption of new and zero variable cost renewable generation which is increasingly replacing conventional generation. We compare incentive price-cap, cost-of-service and non-regulated regulatory approaches in dynamic systems that assume different transformation paths toward a renewable-based system. In previous research, the complex issue of interaction between generation, transmission and demand is not considered in the regulation of transmission expansion. In real world, transmission investment is not the only source of welfare change; another possible source is the shift toward renewables in the power plant fleet, which is considered exogenous here.

We consider two sources of welfare change: (i) network expansion; and (ii) the shift in generation technologies. In our stylized settings this means more wind and solar as opposed to conventional base-load generation. Compared to the welfare-optimal solution, this, in turn, may translate into either (stranded) overinvestments or substantially delayed investments in the transmission network for incentive price-cap (HRV) regulation if standard Laspeyres weights are used. This is due to excessive rents accruing to the Transco, some of them purely originating from an exogenously changing generation mix. Cost-of-service regulation in contrast can trigger investments close to the welfare-optimal levels. This suggests that, in order to capture the full gains of incentive regulation, the regulator should seek to differentiate the changes in congestion rents, so as to efficiently guide the transmission expansion process and minimize welfare losses.

Under a renewable integration process the definition of appropriate weights that lead to welfare convergence with HRV regulation is the challenge for regulators. In our stylized application, Laspeyres weights only reflect the above mentioned non-differentiated sources on welfare, and therefore over-compensate the Transco that may over- or under-invest in network expansion. The complexities in real-world renewable integration would then need the regulator to precisely differentiate between the sources of welfare change in the transmission expansion process. In our simulations, the use of quasi-ideal weights (related to Laffont and Tirole, 1996) achieves this goal and allows for early convergence in investment and welfare values of incentive regulation to the welfare-optimal benchmark. However, the actual implementation of ideal weights seems challenging in regulatory real-world practice.

The challenge would be finding a practically obtainable new type of weight that provides the required incentives under renewable integration. None of the evaluated weights (except for ideal ones) are able to incentivize welfare-optimal network investments. Yet our results indicate that different weights are favorable, depending on the permanent or transitory nature of exogenously increasing network congestion attributable, for example, to the build-up of renewable generation capacity. We conclude that average Laspeyres-Paasche weights may be an appropriate choice in case of an assumed exogenous increase in network congestion, the duration of which may not be known. In addition, these weights lead to earlier investments compared to Laspeyres weights, which may be beneficial if a requirement of substantial future network investment for renewable integration is anticipated, or if investments are lumpy. In any case, the choice of weights depends on the regulator's expectations on the exogenously driven development of congestion rents.

Our analysis thus motivates further research on weight regulation aimed to characterize optimal regulation for transmission expansion under a transformation toward a renewable-based power system. This task may be more complex in the context of meshed loop-flowed networks, since the welfare effects from transmission expansion and a changing mix in generation technologies may be more difficult to isolate. Although our analysis is motivated by renewable energy integration, our findings may be interpreted in a more general context. Exogenous congestion changes may not only originate from renewable integration, as assumed here, but also from other developments in the generation mix, or from changes in power demand.

7 Appendix

Table 4: Sets and indices, parameters, variables

Symbol	**Description**	**Unit**
Sets and indices:		
n, nn $\in$ N	Nodes	
l $\in$ L	Line	
s $\in$ S	Generation technology	
t $\in$ T	Regulatory time periods	years
$\tau \in$ T	Dispatch time periods	hours
Parameters:		
$m_{n,\tau}$	Slope of demand function	
$a_{n,\tau}$	Intercept of demand function	
$\overline{g}_{n,s}$	Maximum hourly generation capacity	MWh
c_s	Variable generation costs	EUR/MWh
ec_l	Line extension costs	EUR/MW
ε	Price elasticity of demand at reference point	
P_l^0	Initial line capacity	MW
$I_{l,n}$	Incidence matrix	
X_l^0	Initial line reactance	Ω
$B_{n,nn,t}$	Network susceptance matrix of period t	1/Ω
$slack_n$	Slack node (1 for one node, 0 for all others)	
δ^s	Social discount rate	
δ^p	Private discount rate	
r	Return on costs (in case of cost-based regulation)	
Variables:		
wf	Overall welfare	EUR
Π	Transco profit	EUR
$q_{n,t,\tau}$	Hourly demand	MWh
$g_{n,s,t,\tau}$	Hourly generation	MWh
$p_{n,t,\tau}$	Hourly electricity price	EUR/MWh
$\Delta_{n,t,\tau}$	Voltage angle	
$\lambda_{1,l,t,\tau}$	Shadow price of positive line capacity constraint	EUR/MWh
$\lambda_{2,l,t,\tau}$	Shadow price of negative line capacity constraint	EUR/MWh
$p_{n,t,\tau} = \lambda_{3,n,t,\tau}$	Shadow price of market clearing constraint (electricity price)	EUR/MWh
$\lambda_{4,n,s,t,\tau}$	Shadow price of generation capacity constraint	EUR/MWh
$\lambda_{5,n,t,\tau}$	Shadow price of slack constraint	EUR/MWh
$ext_{l,t}$	Line extension	MW
$P_{t,t}$	Line capacity of period t	MW
$X_{l,t}$	Line reactance of period t	Ω
$fixpart_t^{CostReg}$	Fix tariff part in case of cost-based regulation	EUR
$fixpart_t^{HRV}$	Fix tariff part in case of *HRV* regulation	EUR

ISO's constrained welfare maximization problem

$$\max_{\substack{q,g,\Delta,\\ \lambda_1,\lambda_2,p,\\ \lambda_4,\lambda_5,}} \sum_{t\in T}\left(\left(\sum_{\tau\in \mathrm{T}}\sum_{n\in N}\int_0^{q^*_{n,t,\tau}} p_{n,t,\tau}(q_{n,t,\tau})dq_{n,t,\tau} - \sum_{s\in S} c_s g_{n,s,t,\tau}\right)\frac{1}{(1+\delta_s)^{t-1}}\right)$$

$$\begin{aligned}
s.t.\quad & \sum_n \frac{I_{l,n}}{X_{l,t}}\Delta_{n,t,\tau} - P_{l,t} \le 0 && (\lambda_{1,l,t,\tau}) && \forall l,t,\tau\\
& -\sum_n \frac{I_{l,n}}{X_{l,t}}\Delta_{n,t,\tau} - P_{l,t} \le 0 && (\lambda_{2,l,t,\tau}) && \forall l,t,\tau\\
& \sum_s g_{n,s,t,\tau} - \sum_{nn} B_{n,nn}\Delta_{nn,t,\tau} - q_{n,t,\tau} = 0 && (p_{n,t,\tau}) && \forall n,t,\tau\\
& g_{n,s,t,\tau} - \bar{g}_{n,s} \le 0 && (\lambda_{4,n,s,t,\tau}) && \forall n,s,t,\tau\\
& slack_n \Delta_{n,t,\tau} = 0 && (\lambda_{5,n,t,\tau}) && \forall n,t,\tau
\end{aligned}$$

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