Regional versus Bilateral Cost Sharing in Electricity Transmission Expansion*

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Abstract

The costs of cross-border transmission links have traditionally been shared equally between the two involved countries. However, capacity expansions are likely to create positive and negative externalities on a larger scale for all countries in a meshed electricity network. In this paper we compare a regional cost sharing framework (i.e., proportional allocation) to the traditional bilateral framework (i.e., equal allocation) with respect to the effects on welfare and grid capacity. The analysis combines a numerical optimisation model of the electricity market and a game-theoretical representation of the choices made by TSOs on capacity expansions. The model includes a stylised electricity system representing six European countries. Results show that the consideration of load-flow patterns compared to directed flows reduces the number of stable outcomes. The expansion game does not converge to one unique outcome, but to a set of stable outcomes. Regional cost sharing by the proportional rule gives stable outcomes that on average include more investments and are closer to the system-wide welfare optimum compared to bilateral equal sharing. A regional framework for cost sharing of transmission investments should therefore be considered as part of the solution to the problems of insufficient cross-border transmission capacity, which has been identified as a major issue in the development of the European electricity market.

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1. Introduction

The planning and expansion of electricity transmission grids have mainly been done from national perspectives because the investment costs of new capacity are paid nationally, or shared between two countries when building a new cross-border link. This is despite the facts that benefits of new grid capacity often spreads to several neighbouring countries and that grid planning from a supranational perspective could bring higher overall benefits. This topic is of increased importance since the liberalisation of electricity sectors around the world and the progression of system transformation towards renewable generation. It is particularly relevant for Europe where insufficient cross-border capacities have been identified as one obstacle to the on-going integration of national electricity markets to a single European market. The EU initiated the process by Directive 96/92/EC (EC, 1996), followed by Directive 2003/54/EC, which concludes that the 'experience in implementing this Directive [96/92/EC] shows the benefits that may result from the internal market in electricity, in terms of efficiency gains, price reductions, higher standards of service and increased competitiveness' (EC, 2003: p.37). In the last years the focus has shifted towards infrastructure. The need for additional cross-border infrastructure, which is unlikely to come about in nationally planned systems, resulted in several initiatives. EC (2009) accelerated the unbundling between generation/supply and the Transmission System Operator (TSO) and initiated the ten-year network development plans. In addition, EC (2010) addresses the issue of cost allocation for transmission investments.

The cost structure of electricity transmission systems generally consists of high fixed costs and low variable costs. Transmission tariffs are the main source of cost recovery. Depending on market design, some rents are also collected as congestion rent on capacity between price areas. While these rents may cover some of the costs they are generally not sufficient (Perez-Arriaga et al. 1995). In the European interconnected electricity system, the costs are not shared system-wide but within some entity, such as the transmission system operator's (TSO) control area (which is typically nation-wide). Thus, the agents benefitting from transmission capacity may not always coincide or be limited to the ones paying for the capacity. From this perspective, transmission infrastructure in multinational markets has some public goods characteristics (see Nylund (2013) for a discussion). There exists an inter-TSO compensation mechanism (ITC) for transit of electricity (EC, 2010), but it is currently not designed to provide financial compensation for new capacity. The problem of cost allocation in electricity transmission has been studied by game theory models for the national context

(Rudnick and Zolezzi, 2002; Contreras and Wu, 1999). However, with a social planner trying to maximise social welfare of one single country, the transmission investment diverges from the welfare optimal investment for the entire multi-national system (Buijs and Belmans (2012), Meeus and Saguan (2011)). To what extent can the sharing of investment costs between several countries help to overcome this issue?

In Europe, the investment costs of cross-border links are traditionally shared equally between the two countries making the expansion. The sometimes wide-spread regional effects of grid expansions have motivated discussions on regional cost sharing according to benefit distribution, as for example in the proposed EU policy for projects of common interest (PCI) (EC, 2011). Real world examples of regional cost sharing are also present with the case of the "Priority Cross-sections" program by the (former) regional TSO group Nordel (Nordel, 2004). Since each country/TSO has decision power over their own investments, cooperation on expansions needs to be incentive compatible and rational for each participant. Within EU policy and regulatory framework it is possible to envision the formation of a general agreement for cost sharing in transmission expansions with regional benefits. An intuitive and transparent way to allocate the investment costs in such an agreement is in proportion to the benefits received, defined by joint cost-benefit analyses (CBAs). Nylund (2013) analyses different allocation rules for regional cost sharing in transmission expansions and recommends the proportional rule. An important question to answer is therefore what the effects on expansions would be if the traditional bilateral cost sharing was replaced by a regional cost sharing agreement.

The purpose of this paper is to analyse the outcomes on transmission capacity and economic welfare when investment decisions are made under bilateral cost sharing by the equal rule, compared to regional cost sharing by the proportional rule. The expansion decisions of the TSOs are modelled by non-cooperative game theory and a numerical optimisation model of the stylised electricity systems of six European countries. The paper is outlined as follows. Section two presents the theoretical framework and the applied methodologies. Section three describes the application of the numerical optimisation model to the electricity systems of six European countries. The results of the optimisation and the game theoretic analysis are presented and discussed in section four. Section five concludes.

2. Methodology

This section describes the theoretical background, the defined framework, and the applied methodologies on the non-cooperative investment game played by several countries.

2.1 Theoretical background

The economic analysis is based on welfare theory applied to an electricity spot market with short-term marginal cost pricing. The welfare term is defined as the consumer and producer surplus as well as network congestion rents. The market price is determined by the intersection of the inverse demand function and the supply curve defined by the marginal costs of the suppliers. Exchange capacity between different price zones is implicitly auctioned into the market dispatch to maximise system welfare.

This setting represents the prevailing market design in Central and Western Europe. It also indicates that the market dispatch of the entire system is optimised without considering implications at the national level. As soon as limited inter-zone capacity becomes binding, electricity prices deviate across different national price zones. While additional cross-border capacity is required for the on-going integration of national electricity markets, these investments also affect the national welfare level. Thus, national regulators and TSOs might have second thoughts on investments which provide this additional exchange capacity.

The two deviating objectives of integration and national welfare are illustrated in Figure 1. The problem formulation separates the decision on transmission investments in the upper-level (leader) from the market dispatch in the lower-level (follower) into a bi-level optimisation problem. The central-planner with the objective of welfare optimisation is a special case of investment planning with a single objective. As the leader and the follower have the same objective value the bi-level model can be simplified to a common linear optimisation problem (Kirschen and Strbac, 2004).

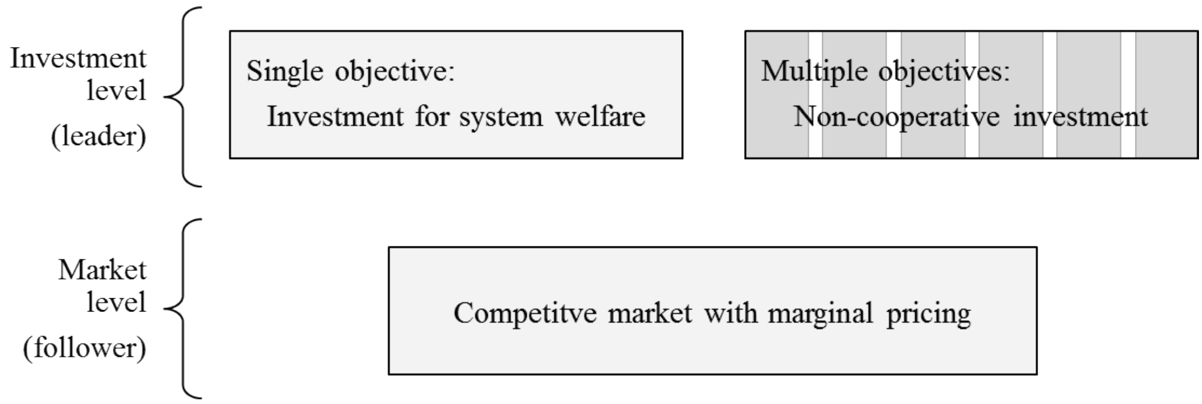

Figure 1: Bi-level optimisation problems

More generally, the objective of the leader diverges from the optimisation of system welfare in the market dispatch. The formal representation results in a mathematical problem with equilibrium constraint (MPEC). Buijs and Belmans (2012) argue that the benchmark for transmission planning should be a Pareto-planner rather than a central-planner. In this case only investments that do not decrease any country's welfare remain possible. They apply the bi-level optimisation model with a Pareto-planner as well as single profit seeking countries as leaders in the upper-level. Other examples of applications of bi-level models to electricity transmission can be found in Garces et al. (2009), Jenabi et al. (2013), and Drondorf et al. (2010). Compared to one leader, this paper assumes an interaction of several nationally motivated transmission planners. Consideration of not only the market effects of transmission planning, but also the interaction of multiple national transmission planners, results in a generalised Nash equilibrium. These models with multiple objectives (leaders), so called equilibrium problems with equilibrium constraints (EPECs), are very difficult to handle. Thus, this paper does not formulate an optimisation problem to find optimal strategies. Rather, it examines the payoff matrix for a set of possible expansion strategies with a game theory model for stable outcomes.

Due to the complexity of the game, the other parameters of the market level (e.g., generation capacity) are assumed to be constant, and the focus is instead on national strategies in the expansion of cross-border transmission capacity. In the analysed framework, countries try to increase their national welfare value by strategic decisions on investment in their own cross-border links. Obviously, all players involved in the investment have to agree for the realisation of the expansion. We also make the assumption that players can decide on the investment only once. The existing exchange capacity is available in the electricity market and cannot be reduced by holding back capacity by any player. The framework combines two models in consecutive order:

(i) A numerical mixed-integer optimisation model to calculate the optimal network expansion strategy for the entire system as well as the payoff matrix with national welfare results for every combination in the set of possible network expansions.

(ii) A game theory model to derive stable outcomes for the pre-defined cost allocation schemes.

The framework applies these models in the following steps:

1) The welfare optimal network expansion strategy for the entire system is determined by a mixed-integer expansion model with endogenous decision on transmission capacity.
2) The payoff matrix of national welfare values for the short-term system operation is derived by running the model for welfare maximisation with every predetermined set of possible network expansions.
3) The payoff matrix is tested for stable outcomes with respect to nationally rational network expansions. This is done for both of the discussed allocation rules for network investment costs (equal and proportional).

2.2 Optimisation models

The problems are implemented in the General Algebraic Modelling System and solved using the commercial solver CPLEX.

Transmission investment model

The first step of the framework uses a bi-level optimisation model to calculate the optimal network investment strategy for the entire system. It maximises system welfare from the market dispatch minus the network investment costs. As the central-planner has the same objective of welfare maximisation the model is simplified to a mixed-integer linear problem with integer variables on transmission capacity. The resulting expansion strategy does not consider national welfare outcomes at this stage.

All model equations are included in Appendix A. The objective value is the system welfare (w). It is represented in the objective function (Eq. 1) by the area below the inverse demand function[1] minus generation costs, summed up over all countries (c), hours (t), and technologies (s), minus infrastructure costs.[2] The endogenous integer decision to invest in network capacity requires a positive integer variable ($build$) for every network link (l) and the parameter for investment costs ($CostL$).

$$\max w_{strategy} = \sum_{c,t}\left[A_{c,t}d_{c,t} + 0.5 * M_{c,t}d_{c,t}^2 - \sum_s\left(g_{c,s,t} * C_{c,s}\right)\right] - \sum_l\left(build_l * CostL_l\right) \quad \text{(Eq. 1)}$$

[1] The inverse demand function is defined by the prohibitive price (A) and the negative slope of the demand function (M).

[2] The notation uses capital letters for parameters and small letters for endogenous variables and sets.

Additional constraints of the model are the generation constraint (Eq. 2) which limits the hourly output for every generation technology to the installed capacity (*Gmax*) multiplied by an hourly availability factor (*Ava*). Four constraints describe the hydro pumped storage plants. They include their maximal capacity (*GStor*) which limits *pspG* and *pspD*, the variables for generation and pumping (Eq. 3/4). The storage is also constrained (Eq. 5) by the maximum storage level (*LStor*) on the energy content (*level*). In Eq. 6, the storage level of the hour (*t*) depends on the usage of the storage, its cycle efficiency, and the level in the previous hour (*t-1*). Except for the free objective value all other variables are defined as positive variables.

One special characteristic of electricity flows is their physical flow patterns, which include loop-flows throughout the network. In the transmission expansion game both transport-flows and load-flows are examined. The transport-flow approach assumes that electricity can be allocated freely on the direct links between two countries without the occurrence of loop-flows. The transmission capacity of the link remains the only limiting factor. The load-flow approach describes how electricity injected in the network takes both direct and indirect paths to the location of consumption. This characteristic has implications for the transmission expansion game as it can cause positive as well as negative externalities on the level of available transmission capacity.

The constraints of the transport-flows include the energy balance and three constraints for electricity flow. The energy balance (Eq. 7a) requires generation to equal demand and network in- and outflows for every hour and country. The positive and negative capacity constraint (Eq. 8a/9a) limits the flows (*f*) on each link to a maximum exchange capacity (*Cap*) in both directions. Network expansion relaxes these constraints. The value of the parameter *MW_Step* defines the step size for the expansion of exchange capacity and is multiplied with the integer variable for network investment (*build*). The connection between the links and the countries is included in the incidence matrix (Eq. 10a).

To consider loop-flows in the network we implement the DC load-flow simplification (Schweppe et al., 1988), which requires two additional constraints (Leuthold et al., 2012). The consideration of loop-flows includes the same capacity constraint on line flow and network expansion (Eq. 8b/9b). Instead of the free flow variable (*f*) the network flow is constraint by the angle difference times the network transfer matrix (*H*) which reflects the physical network characteristics. To enforce unique solutions for the flow angles (*delta*) the value for delta is forced to zero for one reference country with a value for the slack parameter not equal to zero (Eq. 12b). The energy balance (Eq. 7b) is similar to the transport approach but network in- and outflows also depend on the flow angles and the physical network characteristics (*B*).

The additional constraints in the load flow approach provide a more restricted solution space. As the flow allocation on individual lines relies on the entire network, capacity expansion between countries might not be available to full capacity without additional investments in indirect routes between the two countries.

Dispatch model

The second step of the framework calculates the national welfare outcomes for the two cost sharing frameworks. To limit the number of possible investments the solution space of the game is restricted to combinations of capacity up to the level in the welfare optimal solution, plus one additional step for every transmission link. For each combination a reduced linear version of the mixed-integer model with fixed integer variable is solved.

2.3 Game theory model

The third step of the framework applies non-cooperative game theory. The decision makers in transmission expansions are assumed to be the TSOs, which by game theoretic terminology are labelled as the players in the game. A fundamental assumption on the behaviour of the players is that they will make rational choices among the different payoff options available to them. The relevant payoffs are defined to be the national welfare outcomes of different expansion options, given by step two in the optimisation model and specified as the level of consumer and producer surplus plus congestion rent and minus the investment cost. A TSO is thereby assumed to represent the interest of its country when making expansion decisions, and the terms “TSO”, “Country” and “Player” can therefore be interpreted as interchangeable entities in the following analysis. The expansion game will be analysed under two different cost allocation rules for the investment costs of expansions: (*a*) bilateral sharing between two connecting countries based on the equal rule; and (*b*) regional sharing between all countries that benefit based on the proportional rule (in proportion to the benefits received).

Expansions in cross-border links require the cooperation of at least two TSOs. When modelling the decisions on expansions it is therefore relevant to consider that an expansion choice cannot be realised independently by one player, but needs to be matched with the choice of at least one more player. The interdependencies in grid expansions that underlie the national welfare outcomes are incorporated in the payoff matrix from the optimisation model. In order to identify the outcomes that are likely to result from the game, it is assumed that players have exclusive decision rights on expansions connecting to their own territory. A player is thereby defined as a veto player for the own expansions that it can block. An outcome is defined as stable if it is not blocked by any player. To derive the stable outcomes it is therefore important to know who has the decision right for a particular expansion.

The procedure to identify the stable outcomes includes: (1) The optimisation model that derives the payoff matrix for all technically feasible outcomes using a step-wise procedure that increases trade capacities in pre-defined steps. The step-wise procedure starts from a baseline grid and continues up to pre-defined maximum capacities. (2) The set of outcomes is refined to the stable outcomes by using the following assumptions and procedure. For each incremental capacity step on a specific trade link, and conditional on the capacity on other trade links, a player's payoff can either be increased, decreased or remain unchanged compared to the previous step. A veto-player is assumed to block capacity steps that have a lower payoff compared to the previous or following step. All non-blocked outcomes can thereby be derived by checking all capacity expansion steps and their combinations for each player with this procedure. The stable outcomes are then defined as the non-blocked outcomes with the highest payoffs for each player (the dominated strategies are eliminated) and are equal to the Nash equilibriums in pure strategies for the game (Varian, 1992). This means that in the stable outcomes each player makes an optimal choice given the expectation of what the other players will choose.

Will the game have a unique stable outcome? The answer to this question depends on the payoff distributions and the veto rights of players in the different outcomes. If there is a single outcome with the highest payoffs for all players, it will be a unique outcome of the game. However, in games where veto-players prefer different outcomes it is not possible to predict a unique outcome without additional assumptions on how the players resolve conflicts. In practice this may depend on many factors, which in turn are difficult to formalise. Yet, without any further assumptions we can characterise the set of stable outcomes for the different cost sharing frameworks and flow representations by how close they are to the optimal welfare outcome, and by the number and range of the outcomes. It is also interesting to characterise each outcome by dividing the players into those who make expansions and those who do not. This is conveniently formalised by coalition structures that partition the set of players into to expanding and non-expanding players for each outcome. The results section will present and analyse the stable outcomes in this way (see section 4).

The players' choices on expansions can be summarised as a multinational expansion plan, which remains fixed for a given time-period. The players' farsightedness in choosing strategies is therefore limited to the development of the given plan, and does not take into account any strategic implications for future negotiations of expansion plans. The assumptions on the game are summarised in Appendix B.

3. Application on European countries

The framework is applied to a set of six countries, illustrated in Figure 2. The model data provide a general representation of the real world electricity market setting with some assumptions where necessary. The stylised network represents the national electricity systems of Belgium and the Netherlands combined (BN), France (FR), Germany (DE), Switzerland (CH), Austria (AT), and Italy (IT). The connections represent lines with existing trade capacity for electricity between the countries.

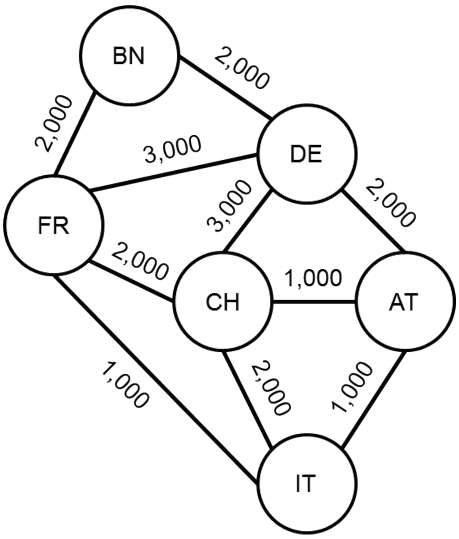

Figure 2: Stylised network with six countries and exchange capacity in MW

The model is run for 672 operational hours (4 weeks) composed of 168 hours (1 week) from each season of the year 2012. The four weeks allow representing the strong seasonal and daily variation in hourly demand and renewable generation levels. The welfare results are then aggregated to annual values to make them easier to interpret and evaluate.

The data set includes parameters of yearly and hourly character for the reference year of 2012. The infrastructure data (parameters on the network and the generation capacity) is kept constant for all hours of the year. The level of demand and availability of renewable generation varies on an hourly basis. The initial trade capacities between the six countries represent realistic net transfer capacities (ENTSO-E, 2011). All transmission lines are considered to be equal in their physical characteristic (length, and impedance in the load-flow model). Rosellón and Weigt (2011) use a line expansion cost of 100 € per km per MW. Since the stylised model applied here only includes the capacity and not the line lengths, a general hourly cost of 10 € per MWh is used. This is high for an individual line, but is chosen to also reflect the required upgrades of the hinterland networks which are not represented in the scope. It also addresses the issue of social acceptance for new transmission lines. Both these aspects increase the real cost of additional cross-border trade capacity.

The hourly demand function for electricity is derived for each country with an hourly reference demand for every country (ENTSO-E, 2013), a reference price (45 €/MWh) and the short-run elasticity of demand (-0.10).[3] The data set includes eleven different generation technologies. Figure 3 shows the installed capacity on national level.

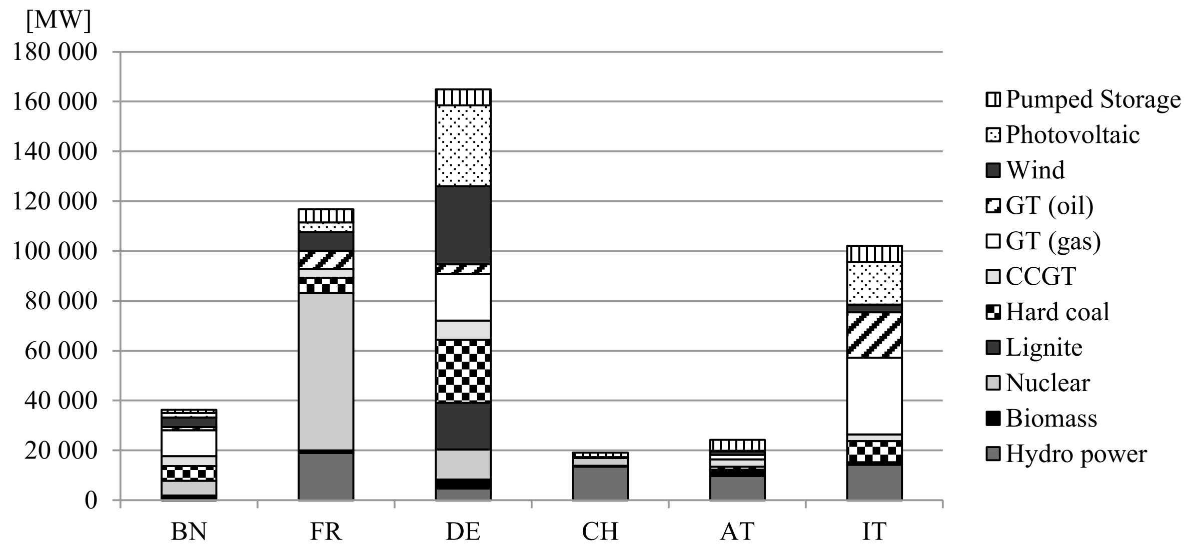

Figure 3: National generation capacities for each generation technology[4]

Sources: Platts, 2012; EWEA (2013); Eurobserver (2013).

Approximated values for the variable generation costs of the technologies are stated in Table 1. The power plants are assumed to be available with a fixed percentage over the entire year. Exceptions are wind and photovoltaic (PV) with an hourly availability factor based on regional data for 2012.[5] Storage capacity is implemented to operate throughout one model

[3] As the elasticity of demand has strong implications the results section includes a sensitivity test with an elasticity of -0.25. Dahl (2011) provides a survey of estimated electricity demand elasticities and presents a median short-run elasticity of -0.14 and an average of -0.21.

[4] The generation capacities are aggregated from detailed power plant data (Platts, 2012) and additional sources for renewable generation capacity EWEA (2013) and Eurobserver (2013).

[5] The regional time series include data by the following TSOs: 50Hertz (2013); Amprion (2013); Tennet (2013); Terna (2013); TransnetBW (2013); and RTE (2013); as well as by EEX (2013). In case no data is available for one

week, has a storage size equal to seven times its generation capacity, and runs with a cycle efficiency of 0.75.

Table 1: Variable costs for each generation technology[6]

Technology	Cost	Technology	Cost	Technology	Cost
Hydro power	0 €/MWh	Nuclear	12 €/MWh	Open gas turbine	80 €/MWh
Biomass	10 €/MWh	Lignite	15 €/MWh	Open oil turbine	140 €/MWh
Photovoltaic	0 €/MWh	Hard coal	40 €/MWh		
Wind	0 €/MWh	Combined cycle (gas)	50 €/MWh		

4. Results and discussion

4.1 System welfare optimal expansion

Before presenting and comparing the results of the expansion games, we give a brief description of the optimal system welfare level for the load-flow (transport-flow) model. The welfare maximising expansion strategy provides an annual net increase of 3.33 (2.65) billion €. The gain with additional capacity is higher in the load-flow model due to the more constrained network setting. The additional cross-border capacity is also greater with 20,000 (17,000) MW and requires 1.75 (1.49) billion € of annualised capital expenditures. Figure 4 displays the welfare optimal expansion strategy. In the load-flow model, the expansions of cross-border capacity are located between IT and all its neighbours and in the triangle of BN, FR, and DE. Due to the unconstrained flow distribution in the transport model (less externalities by loop-flows), the investments increase from FR to BN and IT and decrease on the other lines. The welfare distribution between the countries has no effect on the welfare optimal investment decision.

country and technology the time series of the neighbouring country is applied. For a more realistic representation (revision downtime, etc.) the availability factors for conventional capacities are fixed to 0.85 and to 0.60 for biomass.

[6] The calculation of variable generation costs assumes resource prices of 2 €/MWh for lignite, 12 €/MWh for hard coal, 26 €/MWh for natural gas and 47 €/MWh for oil, efficiency values of 35% for gas turbines, 40% for steam turbines and 56% for combined cycle turbines, and a CO_2 price of 10€/t. The assumed prices are in the range of market prices for the last years. The variable costs are rounded to the stated values.

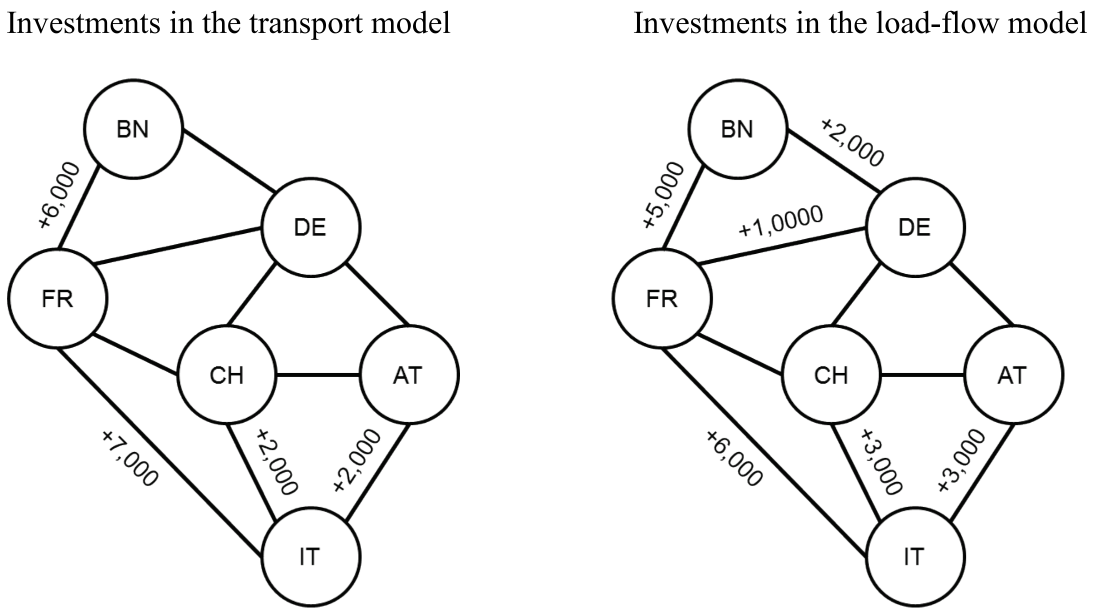

Figure 4: Welfare optimal transmission investments for transport and load flow in MW

4.2 Non-cooperative results

The outcome of the strategic interaction between TSOs on grid expansions is defined by the set of stable outcomes for each cost sharing framework and flow representation.

Transport-flow model

With equal sharing, the game for the transport-flow model results in 28 stable outcomes. The average capacity expansion is 11,900 MW (70% of the optimum) and the average welfare gain is 2.1 billion € (79% of the optimum). The aggregations to national level (Table 2) indicate a wide range of possible welfare changes for each country. Except for AT, the average welfare results are below those given by the system welfare optimum. Yet, the stable outcomes give a strong incentive for gaming as most countries could get national welfare gains of up to several 100 million € compared to the system welfare optimum.

According to the system welfare benefits, the outcomes can be aggregated into two general categories in this case. The first category of 17 outcomes include strategies with a 1,000 MW expansion between FR and DE but only limited upgrades of the links from FR to BN and IT (at most 5,000 MW in combined capacity). The second category of 11 outcomes excludes the expansion to DE, and the links from FR to BN and IT are expanded with at least 12,000 MW in combined capacity. In the second category the average expansion increases from 8,700 MW to 16,800 MW and the average welfare gain from 51% to 98% of the welfare optimum. In a game with such a broad distribution of possible outcomes it could be difficult to decide on a common expansion plan and there is a high risk to have a joint planning with insufficient investments.

Table 2: National welfare changes for equal cost allocation (Bilateral)

[M€]	AT	BN	CH	DE	FR	IT
Minimum	137	-112	122	-801	475	84
Maximum	440	772	710	-293	1,451	1,139
Average	323	363	362	-559	925	703
Optimum	239	410	390	-754	1,380	985

In case of regional cost sharing the number of stable outcomes is reduced to eight as the redistribution of costs according to benefits creates more balanced national payoffs. The average welfare gain is 2.5 billion € (94% of the optimum) and the average capacity increase is 19,900 MW (117% of the optimum). The over-investment in the average case, compared to the welfare optimum, is partly due to an over-investment of 1,000 MW between DE and BN or FR in all but one outcome, and an over-investment of 1,000 MW between IT and AT as well as CH. In this case it is clear that regional cost sharing will give a better outcome from a welfare perspective compared to bilateral sharing.

Table 3: National welfare changes for proportional cost allocation (Regional)

[M€]	AT	BN	CH	DE	FR	IT
Minimum	118	462	310	-837	1,164	876
Maximum	282	551	373	-690	1,378	1,051
Average	233	505	346	-786	1,286	959
Optimum	227	468	332	-754	1,356	1,021

Load-flow model

The coalition structures in Table 4 are denoted by grouping the investing TSOs as one coalition and the non-investing TSOs as separate players. In the payoff columns the non-investing TSOs' payoffs are market in grey. With equal sharing, the game for the load-flow model results in six stable outcomes. While the overall number of stable outcomes is lower than in the transport-flow model, their relative performance to the welfare optimum is similar. The average capacity expansion is 12,300 MW (62% of the optimum) and the average welfare gain is 2.7 billion € (82% of the optimum). The stable outcomes also include two types: (1) two strategies (excluding BN/DE or CH) with lower average welfare gains (64%) and capacity investments (50%) and; (2) four strategies (including all countries except for one without DE) closer to the system optimum (91% welfare and 68% capacity increase).

Table 4: Stable states for the DC load-flow model

Coalition structure	Expansions, MW	AT	BN	CH	DE	FR	IT	%
		Payoffs, M€						
Bilateral cost sharing		**AT**	**BN**	**CH**	**DE**	**FR**	**IT**	%
{AT, CH, FR, IT}, {BN}, {DE}	3,000: CH-IT 4,000: AT-IT, FR-IT	436	26	93	-261	384	1,397	62
{AT, BN, DE, FR, IT}, {CH}	1,000: AT-IT, DE-FR 3,000: FR-IT 4,000: BN-FR	291	685	-460	87	1,129	448	65
{AT, BN, CH, FR, IT}, {DE}	3,000: AT-IT, BN-FR, CH-IT 5,000: FR-IT	348	535	-21	-246	1,151	1,443	96
{AT, BN, CH, DE, FR, IT}	1,000: DE-FR, CH-IT 2,000: AT-IT 3,000: BN-FR 4,000: FR-IT	441	558	-182	-40	1,097	817	81
	1,000: BN-DE 2,000: AT-IT, CH-IT 3,000: BN-FR 4,000: FR-IT	306	666	159	-181	1,052	1,054	92
	1,000: BN-DE 3,000: BN-FR, CH-IT 4,000: AT-IT 5,000: FR-IT	414	605	115	-259	1,025	1,276	95
Regional cost sharing								
{AT, BN, CH, DE, FR, IT}	1,000: DE-FR 3,000: BN-DE, CH-IT 4,000: AT-IT, BN-FR 5,000: FR-IT	431	721	145	-384	1,120	1,158	96
	1,000: DE-FR, CH-IT 3,000: AT-IT, BN-DE, CH-IT 4,000: BN-FR 6,000: FR-IT	413	687	57	-371	1,190	1,283	98

With regional sharing, only two outcomes remain stable. Both are close to the welfare optimum (96% and 98%) and include 20,000 MW in capacity increase (with a slightly different distribution on lines than in the welfare optimum). Also, individual countries have similar payoffs for both options. In this application the regional cost allocation combined with a load-flow representation is able to provide good results both for welfare and capacity. The lower number of stable outcomes indicates the reduced possibilities of gaming for specific outcomes as the loop-flows make them more reliant upon each other.

Sensitivity analysis

The short-run demand elasticity is of central importance as it determines the effect of price changes on consumer surplus. Thus, in addition to an inelastic demand (elasticity of -0.10), the sensitivity of the results is tested using a demand elasticity of -0.25.

In the system optimal outcome of the transport-flow model the overall welfare gain decreases by 30% and the expansion capacity decreases on three lines by 1,000 MW each to 14,000 MW. With equal sharing the average welfare gain is 91% of the optimum and capacity expansion 75% of the optimum, with regional sharing it is 95% for welfare and 111% for capacity.

In the load-flow model the optimal outcome is 27% lower in welfare and has 4,000 MW lower capacity (16,000 MW in total). All lines (except IT to AT/CH) decrease by 1,000 MW. For equal sharing the average welfare gain is at 82% and capacity expansion at 69%, while regional sharing yields an average of 90% for welfare and 98% for capacity.

5. Conclusions

This paper has analysed transmission expansion in cross-border electricity networks and how it is affected by the way that investment costs are shared between countries. Two cost sharing frameworks have been compared: traditional bilateral cost sharing by the equal rule between connecting countries only; and regional cost sharing by the proportional rule according to benefits received for all countries that benefit. The analysis was conducted using a numerical optimisation model applied to an exemplified network with six European countries, in combination with a game theoretical model that predicts the results of strategic interaction between countries in expansion decisions.

Results show that several possible stable outcomes can result under both cost sharing frameworks. The outcomes are fewer and much less spread out with regional sharing, indicating that the uncertainty of the outcome under this framework is lower. In the best cases the bilateral outcomes are on par with the best of the regional outcomes, but on average the outcomes differ significantly. Regional sharing gives an average capacity increase equal to the system welfare optimum, whereas bilateral sharing reached 62% of the optimum on average, using a load-flow representation of the grid. The corresponding increase in total welfare is 97% of the optimum with regional sharing and 82% with bilateral. Comparing the two shows that regional sharing gives 18-19% larger welfare on average and 62-67% more capacity. Average investment costs increase by the same percentage as capacity since a standard cost per MW capacity is used in the models. With a transport-flow representation there are more stable outcomes for both sharing frameworks, while the average welfare gains are similar to the load-flow results. The difference in welfare gain between the two cost sharing frameworks is reduced when demand elasticity is changed from -0.10 to -0.25, but regional sharing still gives around 10% higher welfare on average.

Regional sharing gives better results because it makes more investments profitable by allocating the costs to more players, and also prevents players that receive positive spill-over benefits from expansions to free-ride on others. It thereby reduces the risk that expansion options are blocked by some countries due to negative welfare effects. In absence of a supranational planner that can impose the first-best solution, it appears that regional cost sharing is a close second best. A regional agreement of the type presented in this study imposes new rules on the interactions between TSOs in their grid planning. However, it does not imply that grid planning must be done by a supranational planner, rather it gives TSOs the economic incentives (in terms of national welfare) to pursue expansions that are closer to a supranational planner's choice. A regional cost sharing framework is in this sense a middle-way between bilateral cost-sharing and the idealised supra-national planner. Still, the realisation of a regional cost sharing agreement on a European scale may face serious opposition since it could involve a large number of countries with diverging priorities with regards to infrastructure investments. In this sense it is reassuring that bilateral sharing gives at least on average a reasonably good welfare outcome.

It is also possible to consider combinations of the two separate cases studied here. Regional sharing could be limited to particular investments that are difficult to realise under bilateral sharing. This seems to be the reasoning behind the EU's proposal for regional cost sharing of special "Projects of Common Interest" and the Nordic TSOs' "Priority Cross-sections" program. In a real world application of regional sharing it could also be relevant to include some internal expansions since the trade capacities on cross-border links can be limited by the capacity of internal grids.

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Appendix A: Optimisation model for network investments

$$\max w_{strategy} = \sum_{c,t}\left[A_{c,t}d_{c,t} + 0.5 * M_{c,t}d_{c,t}^2 - \sum_s\left(g_{c,s,t} * C_{c,s}\right)\right] - \sum_l\left(build_l * CostL_l\right) \quad \text{(Eq. 1)}$$

$s.t.$

$$g_{c,s,t} \leq Gmax_{c,s} * Ava_{c,s,t} \qquad \forall c,s,t \qquad \text{(Eq. 2)}$$

$$pspG_{c,t} \leq GStor_c \qquad \forall c,t \qquad \text{(Eq. 3)}$$

$$pspD_{c,t} \leq GStor_c \qquad \forall c,t \qquad \text{(Eq. 4)}$$

$$level_{c,t} \leq LStor_c \qquad \forall c,t \qquad \text{(Eq. 5)}$$

$$level_{c,t} - Eff * pspD_{c,t} + pspG_{c,t} = level_{c,t-1} \qquad \forall c,t \qquad \text{(Eq. 6)}$$

Transport-flow equations:

$$d_{c,t} + pspD_{c,t} = g_{c,t} + pspG_{c,t} + netinput_{c,t} \qquad \forall c,t \qquad \text{(Eq. 7a)}$$

$$f_{l,t} \geq -Cap_l - build_l * MW\_Step \qquad \forall l,t \qquad \text{(Eq. 8a)}$$

$$f_{l,t} \leq +Cap_l + build_l * MW\_Step \qquad \forall l,t \qquad \text{(Eq. 9a)}$$

$$netinput_{c,t} = \sum_l\left(Incidence_{l,c} * f_{l,t}\right) \qquad \forall l,t \qquad \text{(Eq. 10a)}$$

DC load-flow equations:

$$d_{c,t} + pspD_{c,t} = g_{c,t} + pspG_{c,t} + netinput_{c,t} \qquad \forall c,t \qquad \text{(Eq. 7b)}$$

$$f_{l,t} \geq -Cap_l - build_l * MW\_Step \qquad \forall l,t \qquad \text{(Eq. 8b)}$$

$$f_{l,t} \leq +Cap_l + build_l * MW\_Step \qquad \forall l,t \qquad \text{(Eq. 9b)}$$

$$netinput_{c,t} = \sum_{cc}\left(delta_{cc} * B_{c,cc}\right) \qquad \forall c,t \qquad \text{(Eq. 10b)}$$

$$f_{l,t} = \sum_n\left(delta_{l,c} * H_{l,c}\right) \qquad \forall l,t \qquad \text{(Eq. 11b)}$$

$$slack_c * delta_{c,t} = 0 \qquad \forall c,t \qquad \text{(Eq. 12b)}$$

Appendix B: Assumptions on the non-cooperative game

Assumptions on the game

- Static game with simultaneous moves, described in strategic form with: Players=TSOs; Strategies=Transmission expansion choices; Payoffs=National welfare.
- Complete information, meaning that the complete payoff matrix is known to all players.
- Each player has exclusive decision power over grid expansions on its own territory.
- The number of expansion options is finite.
- The stable outcomes of the game are defined by Nash equilibriums in pure strategies.
- The strategic considerations include blocking of expansion by single players and preferring different stable outcomes:
  - If any player has the power to increase its own welfare, given a particular outcome, by reducing or increasing investment on one of its own lines the outcome is not considered to be stable.
  - Also the incentive to diverge to a different expansion path can result in a non-stable outcome if all players involved in changed planning are better off compared to the initial outcome.

Assumptions on the local objective function

- Players are rational and seek to maximise their own welfare.
- Welfare is defined as the sum of consumer surplus, producer surplus and congestion rents minus costs for transmission investments. The congestion rent is shared equally between the two adjacent players.

Assumptions on the market design

- Short-term marginal pricing with implicit auctioning of exchange capacity defines the market outcome.
- Static setting for generation capacities, their variable costs, and the demand functions.
- Transfer flows are modelled with the two approaches a) transport-flows and b) load-flows (DC load-flow approximation).

Assumptions on cost sharing

- *Bilateral game:* Expansion costs for cross-border links are shared equally (50/50) between the two TSOs involved only.
- *Regional game:* Players have signed a general agreement stating that the investment cost of expansions will be shared in proportion to benefits received for each player, including players that receive positive spill-over benefits. There is no compensation for negative spill-overs, with the motivation that it may induce strategies for gaining compensation instead of participating in building new expansions.