Efficient Allocation of Monetary and Environmental Benefits in Multinational Transmission Projects: North Seas Offshore Grid Case Study

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ABSTRACT

There are multiple countries involved in, or affected by, multinational grid investments. Although cooperative investment strategies always result in nonnegative aggregate net-benefits, the national distribution of those might be asymmetric and, in some cases, negative. In order to ensure the most cost-efficient investment strategies for systems such as the European one, it is crucial to provide strong incentives at national level. Using a capacity-planning model for transmission and generation expansion under perfect competition, in combination with cooperative game theory, we present a generic framework to determine an efficient and fair allocation of benefits arising from multinational transmission projects in the North Sea region, considering three cross-border transmission corridors. We verify numerically that our case study yields a convex cooperative game, meaning that the computed allocation is in the core and, consequently, provides a higher payoff to all countries than under any other possible subcoalition.

Keywords: Cooperative game theory, Cost-benefit allocation, Energy policy, North Seas Offshore Grid, Shapley Value, Transmission expansion planning

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1. INTRODUCTION

Several countries in the European Union plan to incorporate large shares of generation from renewable energy technologies—particularly solar and wind power—in the coming decades (European Commission, 2011). Unlike conventional generation technologies, the variability and unpredictability of renewable resources result in higher needs for flexibility in order to maintain the reliability of a power system (Denholm and Hand, 2011). One source of flexibility is the possibility of balancing distinct generation resources and demand across large geographical areas through high-voltage transmission lines (Munoz et al., 2012; Konstantelos and Strbac, 2015). Distant wind farms, for instance, can present synergistic effects by geographic diversification (Hasche, 2010), which can reduce the need for other sources of flexibility such as storage of fast-ramping generation units. It is for this reason that the EU Commission has identified the North Seas Offshore Grid (NSOG) as one of the strategic trans-European energy infrastructure priorities in the EU Regulation No 347/2013.

The NSOG is a particularly interesting case since it involves multiple countries, a large amount of both onshore and offshore wind resources that are unevenly distributed in the region, no centralized planner, and decentralized incentives for multinational transmission projects (ENTSO-E, 2014). The latest development plan by the European Network of Transmission System Operators for Electricity (ENTSO-E) states that nearly €150bn worth of investments will be needed in pan-European infrastructure to meet projections of demand and environmental goals at minimum cost by year 2030 (ENTSO-E, 2016), which is more than 1,000 times higher than the current annual budget of €100m for inter-TSO compensations in the region (Hirschhausenm et al., 2012).[1] However, most of the investments in new transmission infrastructure identified as necessary by ENTSO-E are multinational projects, which is a challenge since these will only be realized if all the countries involved in their development reach an agreement on how to split benefits and costs. Alternatively, these transmission projects could be developed by merchant investors, but only if congestion rents from the arbitrage of power between countries provide sufficient revenues to cover their capital costs. This is in contrast to the challenge of developing inter-ISO or interstate transmission projects in the US, where there exist rules that require regional planners to coordinate interregional projects if they could lead to cost-effective solutions for mutual transmission needs (e.g. , FERC order 1000 (FERC, 2012)). Thus, adequate cost and benefit allocation schemes could be crucial for stimulating national support for the

[1] The inter-TSO compensation mechanism is designed to compensate for hosting cross-border flows, i.e. additional costs that occur in national transmission systems due to losses and facilitation of infrastructure.

most cost-efficient investment options—yielding the largest, aggregate benefits for the system.

The NSOG has already proven to be beneficial at system level due to lower operating costs, higher efficiency, lower CO_2 emissions, and increased security of supply (ENTSO-E, 2016). However, it is not clear if the current cost-allocation mechanism will provide the right incentives to develop all the needed transmission infrastructure identified by the ENTSO-E for the coming decades. In this article we present an alternative compensation scheme to the current framework of the EU to support socially-optimal investments in transmission infrastructure for a NSOG. We apply the Shapley Value (SV) from cooperative game theory to quantify fair allocations of benefits that arise under the so called *grand coalition*, which is when full cooperation is achieved among all participating countries. We then compute side payments between countries that will be necessary to support the grand coalition, which under assumptions of perfect competition and information yields the same results of a centrally-planned system (Contreras and Wu, 1999). This, together with a series of desirable properties of the SV, gives stronger incentives for multinational cooperation than under other alternative allocation methods. Moreover, we verify that in this case the cooperative multinational transmission planning problem yields a convex game, which allows us to guarantee that under the allocation computed using the SV all countries are better off than in any other possible subcoalition.

We illustrate the proposed allocation method on a 25-bus network that simulates power production and trade among six countries in the North Seas region in 2030. We consider all the possible realizations (i.e. , built or not built in 2030) of the three following offshore projects planned in this region (ENTSO-E, 2016): the North Sea Link from Norway to Great Britain, the NordLink from Norway to Germany, and the Viking cable from Denmark to Great Britain. We determine benefits and costs of each possible realization of these transmission projects using a detailed capacity planning model that captures generators' response to transmission investments. Our numerical examples show that large-scale grid investments can have mixed effects on metrics such as welfare, total cost, CO_2 emissions, and share of renewables in countries that are part of or adjacent to the NSOG, which highlights the need for more sophisticated allocation mechanisms to support large-scale, multinational grid projects.

We structure the rest of the paper as follows. In Section 2 we overview existing literature on transmission planning models with a focus on allocation mechanisms. In Section 3 we show two examples where expanding the capacity of a transmission line could lead to asymmetric, or even negative, net-benefits as a result of grid investments between two or more interconnected areas. Section 4 presents a capacity-planning model, formulated as a mixed-integer linear program (MILP), which is used to find optimal investment strategies for the case study of the NSOG presented in Section 5. Under perfect competition, this model is equivalent to a bi-level equilibrium model where transmission projects are developed first and generation investments and operations occur afterwards. Finally, in Section 6 we conclude.

2. LITERATURE

Large and non-divisible multinational grid projects can have a significant impact on future electricity prices, making it particularly important to assess cost-benefit allocation schemes that could help in supporting projects with potentially conflicting incentives (Bushnell and Stoft, 1996; Hogan, 2011; Munoz et al., 2013). Transmission expansion planning (TEP) models are used to identify cost-efficient investment opportunities in power systems and they become increasingly more complex and difficult to solve when trying to simulate current, and future, market characteristics (Lumbreras and Ramos, 2016). However, it is not the complexity of identifying the most cost-efficient investments in a multinational setting that limits their deployment. Instead, it is that their development is strongly dependent on the incentives of the participating regions or countries to support them (Sauma and Oren, 2007; Perez et al., 2016). One occurring challenge of multinational TEP is the need for tighter coordination of electricity markets to take advantage of new transmission infrastructure, which can result in an uneven distribution of benefits and costs between the countries involved in the development of new transmission projects. In addition, these multinational projects might cause negative or positive externalities on surrounding countries with transmission networks that are not directly connected to the projects in question (Bushnell and Stoft, 1996, 1997).

Cost-benefit studies are, indeed, a pressing issue for multinational investments as stated in a state-of-art NSOG case study review by Gorenstein Dedecca and Hakvoort (2016). One metric that is commonly used to quantify the impact of multinational investments is the change in national welfare—the sum of producer surplus, consumer surplus, and in some cases a fraction of congestion rents—as a result of the development of a new transmission project. This metric can be used, for instance, to determine how transmission costs could be allocated among countries on multinational projects in proportion to estimated welfare changes (e.g. , countries that benefit more bear a larger fraction of transmission costs). However, the aforementioned approach does not consider information regarding the economic value that results from a country's support for one or a group of projects (e.g. , welfare changes for all countries if one nation decides not to support a project), which potentially serves as a key benchmark in order to create stronger incentives for national support of those projects

(Nylund, 2009; Hogan, 2011).

In practice, there is a variety of much simpler transmission pricing schemes, including postage-stamp rates and flow-based charges, among many others. However, since these are mostly used to recover transmission costs within a unique dispatch region it is unlikely that they could provide the right economic incentives to support transmission projects in multinational settings, such as in the NSOG. For instance, since the standard postage-stamp allocation method is based on a uniform distribution of transmission costs within a region, it fails at supporting correct incentives for the development of transmission projects that provide positive aggregate benefits for a group of regions, but potentially negative ones for some (Bravo et al., 2016). Benefit-based allocation methods splits costs between the agents that benefit from the project, e.g. by equal share. Konstantelos et al. (2017b) argues that the Positive Net Benefit Differential (PNBD) is the most appropriate benefit-allocation method since it internalizes negative externalities—i.e., impact on surrounding regions (Bushnell and Stoft, 1997). Unfortunately, the methods mentioned above do not capture the value of that a single country or region offers to the system. For instance, countries with abundant flexible generation, such as hydro in Norway, may be responsible for a large fraction of the cost savings that result from an integrated NSOG network. Thus, it unlikely that such countries will agree to participate in an integrated NSOG unless they are compensated in proportion to their contribution to the rest of the system.

Nylund (2009) states that an allocation scheme should be simple and, ideally, hold the property of monotonicity in order to be implementable in practice. This means that more cooperation, in terms of larger coalitions, should yield increased added value in a system to be allocated among the participating countries. Although the proportional methods mentioned above are intuitive, they still fall short under some criteria. The first is that they do not capture the marginal contribution from each participant within a coalition, i.e. how much a country contribute in terms of added value (e.g. cost savings through more efficient dispatch). Secondly, they ignore the strategic aspect for cooperation, meaning that they do not consider the incentives that each region or country might have to form smaller subcoalitions—which could give them higher payoffs, but that could yield less efficient solutions from a system-wide perspective. Finally, proportional methods ignore how the sequence of development of transmission projects affect the value of other projects in the same network (Banez-Chicharro et al., 2016) (e.g., incremental value of a project for the system if it is considered first or last in a sequence of developments). Similar methods that take into account how the sequence of development of transmission projects, such as Take Out One at a Time (TOOT) and Put In one at a Time (PINT), do not value the marginal contribution of all possible sequences of individual projects. However, the Shapley Value (SV) (Ferguson, 2014) from cooperative game theory copes with all the aforementioned shortcomings, which makes the SV superior to its competing methods.

The application of cooperative game theory in TEP dates back to Contreras and Wu (1999) where they present the idea of studying outcomes of strategic games in order to allocate costs or benefits in a fair way, rather than focusing on strategic decisions in a given game. The concept of using SV from cooperative game theory fits well with TEP where the grand coalition will be formed by full cooperation in a multi-agent system, in our case countries, which is when it is possible to achieve the most cost efficient investments for all agents combined. Computational challenges are overcome by using the Bilateral Shapley Value for larger systems, and advancements are made in studying value functions that are in the core (Contreras and Wu, 2000; Yen et al., 2000).[2] The aforementioned papers calculates SVs for each bus in stylized networks, in terms of producer surplus and consumer surplus, while Zolezzi and Rudnick (2002) and Erli et al. (2005) calculate the cost allocation to loads. Moreover, the majority base their analysis on one market state and IEEE test systems, while Ruiz and Contreras (2007) use a hourly market clearing for different market states in order to calculate more accurate value functions.

Another widespread branch in game theory is normal form games, also called strategic form games, that makes it possible to study strategic decisions in hierarchical forms. This is in contrast to cooperative game theory that focuses instead on the outcomes of the game. Although this does not provide information regarding cooperative cost allocations, it is a useful tool to quantify national-strategic plans and compare those to a centralized planning (grand coalition), where the gap will reflect the value of a well functioning allocation scheme (Tohidi and Hesamzadeh, 2014; Huppmann and Egerer, 2015). This means that such models can be used to simulate what we believe is realistic and quantify the value of an efficient allocation scheme for multinational, cooperative investments using the SV.

Limited research has been pursued for multinational allocation schemes in TEP, particularly applied to case studies with the unique characteristics that the NSOG region posses. Konstantelos et al. (2017a) investigate full cooperation and market integration for a NSOG under different policy choices and deployment scenarios for offshore wind's location, sizing, and timing. However, their analysis

[2]The core refers to cooperative solutions that are stable, equivalent to the concept of Nash equilibria in non-cooperative games. If a solution is in the core, agents to deviate from the grand coalition by forming smaller sub-coalitions. For some cooperative games the core can be an empty set, whereas for others the core can have more than one possible solution. However, if the cooperative game is convex, the core is non-empty and the SV is in its center of gravity (Ferguson, 2014).

is not rooted in cooperative game theory concepts; instead, they model cooperation as changes in grid topology, i.e. from conventional radial solutions to fully integrated, meshed infrastructures.[3] A comprehensive analysis of national welfare is presented in their paper quantifying the asymmetric impact of a fully integrated network, which serves as the base in the discussion of a regional ISO and compensation mechanisms. In this paper, we aim at extending the discussion of possible compensation mechanisms with a corresponding numerical example of the NSOG.

Our main contribution is the development of a bottom-up framework for an efficient allocation of monetary and environmental benefits that arise from multinational investments. A stylized and illustrative example of asymmetric welfare impact, in combination with a real case study of a planned project portfolio in the NSOG, will together give more insight to the cost-benefit allocation problem. We cope with some of the aforementioned shortcomings in TEP by using a capacity-planning model, equivalent to a bi-level investment model under perfect competition, where generators are allowed to respond to transmission investments with a detailed market dispatch in order to capture a variety of flow patterns and seasonal variation in the hydro-dominated systems that borders the NSOG. In contrast to the majority of the reviewed literature, we extend the application of SV in TEP to consider more than only welfare metrics to assess possible trade-offs. For instance, some countries might see a beneficial trade-off in e.g. increased share of renewables, or reduced CO_2 emissions, despite weak monetary welfare effects. Finally, we discuss how multinational TEP problems might always yield convex cooperative games where the SV is in the center of the core—yielding a stable solution.

3. COMPARATIVE STATICS ON TWO- AND THREE-NODE SYSTEMS

In this section we present some counterintuitive effects of transmission investments on welfare at aggregate and regional (i.e., nodal) levels using two stylized networks. We show that although more trading of electricity between regions, as a result of new transmission capacity at congested lines, always result in nonnegative changes of welfare and net welfare[4] in aggregate terms, changes in benefits or costs as a consequence of more trading can be unevenly distributed among regions. In fact, transmission capacity that is optimal from a system-wide perspective (i.e., that maximizes aggregate welfare for all regions) could leave some regions worse off, which can create difficulties for the development of new projects that are not centrally planned since the involved parties might not have

[3] A radial grid consists of point-to-point connections, while a meshed infrastructure allows offshore nodes to be connected with two, or more, transmission cables. A meshed solution requires advanced power electronics at a higher capital costs than conventional technologies, but the potential cost savings in terms of e.g. less cable investments could make a meshed NSOG more cost-efficient than a radial NSOG (Trötscher and Korpås, 2011; Konstantelos et al., 2017a).

[4] Net welfare is welfare (i.e., the sum of consumer and producer surplus) plus congestion rents.

incentives to support them.

In this section total costs are comprised of transmission and long-run operation costs, but they can also include generation capital costs separately as we show in the next section. For simplicity, we assume inelastic demand functions (i.e., the demand does not respond to changes in price) in all nodes with a high price ceiling equal to the value of lost load ($VOLL >> 1$). Moreover, we assume linear long-run supply functions and perfect competition. The analysis is static, meaning that we look at one representative market state, with and without additional transmission capacity. Finally, we choose to isolate the impact of congestion rent (CR) on welfare metrics in both two- and three-node systems because the share of CR and investment cost level each other out in nodal welfare for cooperative investments under ideal conditions (e.g., no increasing returns to scale, no market power, efficient nodal prices, free entry, etc.) (Hogan, 2011; Bushnell and Stoft, 1996, 1997). For further analyses on this topic and merchant investments under more realistic conditions please refer to Joskow and Tirole (2005).

3.1 Asymmetric benefits in a two-node system

Consider first a system composed of nodes (countries) 1 and 2, with demands d_1 and d_2, respectively, such that $d_1 < d_2$, and a transmission line with capacity K. We denote generation levels at each node q_1 and q_2 and assume linear supply functions, $c_1(q_1) = c_0 + a_1 q_1$ and $c_2(q_2) = c_0 + a_2 q_2$, which represent the long-rung marginal cost of generation at each node. Node 2 comprise a generation mix with higher marginal cost for electricity generation than Node 1, thus, we assume $a_2 > a_1$. Since $VOLL >> 1$, demand is never curtailed and $d_1 + d_2 = q_1 + q_2$. For simplicity, we only consider transmission capacities K that result in a congested line between nodes 1 and 2. This is true if $c_1(d_1 + d_2) < c_1(d_1 + K) + c_2(d_2 - K)$, where $0 \leq K \leq d_2$. Consequently, the equilibrium quantities and prices are $q_1 = d_1 + K$, $q_2 = d_2 - K$, $p_1 = c_1(d_1 + K)$, and $p_2 = c_2(d_2 - K)$.

Figure 1 shows changes in nodal welfare (W_i), consumer surplus (CS_i), producer surplus (PS_i), and congestion rent (CR) when increasing the capacity of the line from $K = 0$ to $K > 0$, disregarding any transmission cost. The consumer surplus is the area below the VOLL and above the price, p_i, i.e. the surplus that the consumers see in terms of their maximum willingness to pay for electricity. Contrary, the producers see a surplus between their marginal cost of production and the price, p_i. The CR is determined by the price difference and trade/capacity between two, or more, connected nodes. CR is therefore zero when the trade-capacity is zero.

The following assertions are true for this system, based on the fundamental derivations found

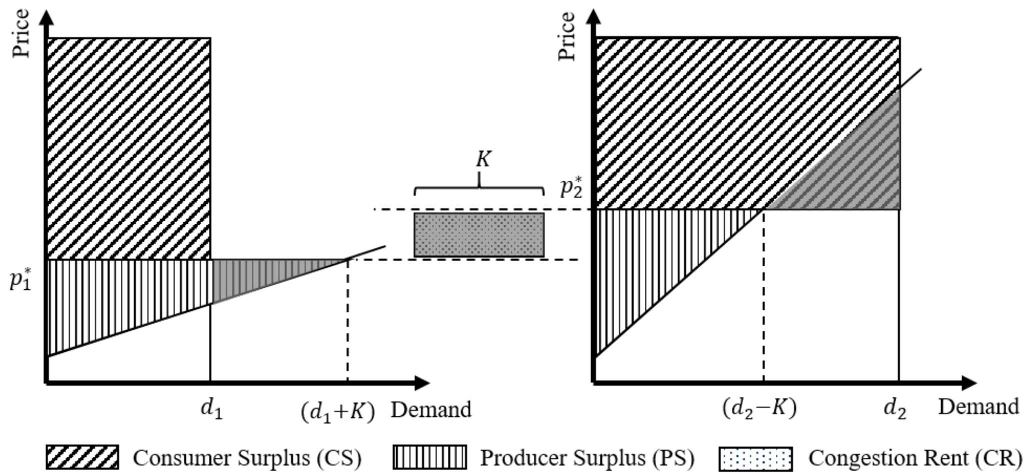

Figure 1: Net welfare effects (dark shaded areas) of new transmission capacity between a low price area (Node 1) and a high price area (Node 2).

in Table 4 in the Appendix:

1. *Consumer surplus:* An increase in K benefits consumers at the importing node ($\frac{dCS_2}{dK} = a_2 d_2 > 0$) since the price declines ($\frac{dp_2}{dK} = -a_2 < 0$). In contrast, consumers at the exporting node are worse off as a result of an increase in the transmission capacity between nodes 1 and 2 ($\frac{dCS_1}{dK} = -a_1 d_1 < 0$) since exports drive local prices up ($\frac{dp_1}{dK} = a_1 > 0$).

2. *Producer surplus:* The producers at Node 1 will benefit from an increase in K ($\frac{dPS_1}{dK} = a_1(d_1 + K) > 0$) as the nodal price increase (see 1.). Some production at Node 2 falls out of the market when the price decreases due to cheaper import from Node 1, which reduces producer surplus ($\frac{dPS_2}{dK} = a_2(K - d_2) < 0$).

3. *Congestion rent:* $CR = (p_2 - p_1)K$ is a concave and quadratic function on K. The level K^M maximizes CR and is equal to the optimal investment level for a single merchant investor (assuming $I(K) = 0$). The level $K^* = 2K^M$ solves $CR(K) = 0$ and is equal to the socially optimal investment level, which could be achieved under full cooperation between nodes. Thus, $\frac{dCR}{dK} > 0$ for $0 < K < K^M$ and $\frac{dCR}{dK} < 0$ for $K^M < K < K^*$.

4. *Welfare:* If we disregard CR, welfare at Node 1 increases ($\frac{dW_1}{dK} = a_1 K > 0$) when the transmission capacity K increases. Welfare does also increase at Node 2 ($\frac{dW_2}{dK} = a_2 K > 0$) but at a higher rate than in Node 1 ($\frac{dW_2}{dK} > \frac{dW_1}{dK}$) since $a_2 > a_1$. Say CR is split between nodes 1 and 2 in proportions $\alpha_1 \geq 0$ and $\alpha_2 \geq 0$, respectively, such that $\alpha_1 + \alpha_2 = 1$. For $0 < K < K^M$, a marginal increase in transmission capacity always increases net welfare for both nodes, i.e.

$\frac{dW_i}{dK} + \alpha_i \frac{dCR}{dK} > 0$ for $i \in \{1, 2\}$.[5] In contrast, for $K^M < K < K^*$ it is possible that a marginal increase in transmission capacity could reduce net welfare in one node for some allocation rule (i.e., α_1 and α_2) of CR. Yet, since $\frac{dW_1}{dK} + \frac{dW_2}{dK} + \frac{dCR}{dK} > 0$,[6] it is always possible to split the benefits of adding a marginal amount of transmission capacity to both nodes (e.g., through some form of side payments) such that the marginal change in net welfare is strictly positive at both locations.

When ignoring the allocation of investment costs and CRs in a perfectly competitive market, we see from Figure 1 and the analytical assertions that the aggregated welfare and net welfare always increases when adding capacity to a congested line. However, the nodal benefits are unlikely to be evenly distributed since $\frac{dW_2}{dK} > \frac{dW_1}{dK}$, $PS_1 \leq PS_2$, and $CS_1 \geq CS_2$. Furthermore, it is possible that net welfare at one node could decrease for some combination of parameters and allocation rule of congestion rents. Hence, it is possible that some form of compensation would be required since agents from one node could unilaterally block the development of a transmission project. For instance, if we consider investment costs, one could compensate for unevenly distributed benefits by adjusting the cost allocation of the transmission line in proportion to the benefits that result from its development (Hogan, 2011). However, under ideal conditions this would be neutralized by an equivalent fraction of CRs (see 3.). Moreover, as mentioned in Section 2, such cost-allocation schemes does not incorporate the value that each node (or country) adds to the cooperative and socially-optimal plan.

3.2 Asymmetric and negative benefits in a three-node system

We now add a medium price node to the previous example, as shown in Figure 2. The parameter K_{23} denotes the transmission capacity between nodes 2 and 3. Assume that the given prices reflect the connected system under operation and that there is a bilateral, voluntary, agreement to build a new transmission line between Node 1 (low price) and Node 2 (high price). Node 3 (medium price), with marginal costs equivalent to $c_3(q_3) = c_0 + a_3 q_3$ and energy balance $q_3 = d_3 + K_{23}$, is still connected to Node 2 after the new transmission line is built. With more transmission capacity between Node 1 and Node 2 the system is re-dispatched to utilize more of the cheap generation capacity available at Node 1, meaning that the power flow from Node 3 to Node 2 (K_{23}) decreases towards zero as K increases.

The dark shaded areas in Figure 2 shows the initial welfare effects of the transmission

[5] This is because for $0 < K < K^M$, $\frac{dCR}{dK} > 0$.

[6] By definition, $a_2 d_2 - a_1 d_1 > 0$, thus $\frac{dW}{dK} + \frac{dCR}{dK} = \frac{K}{2}(a_1 + a_2) + a_2 d_2 - a_1 d_1 > 0$ for $K < K^*$.

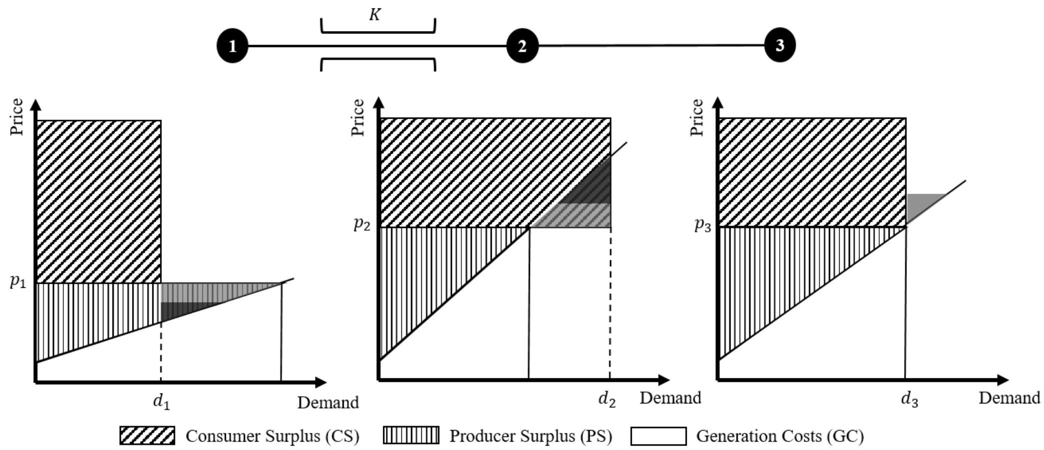

Figure 2: Three-node example where new transmission capacity is added between Node 1 (low price) and Node 2 (high price). Dark shaded areas illustrate the case where it already exists some capacity between Node 1 and 2, while the light shaded areas are the final effects when new capacity is added.

capacity between Node 1 and 2. When additional transmission capacity (K) is introduced between Node 1 and Node 2, the system is re-dispatched and welfare increases in these two adjacent nodes, illustrated with the light shaded areas in Figure 2. Simultaneously, as K increases, Node 3 suffers a welfare loss due to less export to Node 2 over K_{23}, since Node 2 imports cheaper electricity from Node 1, i.e. $q_3 = d_3 + K_{23} - K$. Moreover, the CRs between Node 2 and Node 3 decrease due to less trade.

As in the two-node example, the marginal changes in welfare in this three-node is highly dependent on the slopes of the supply curves. Node 2 has the steepest supply curve, thus, it experience the largest deviation as a result from an increment in the transmission capacity between nodes 1 and 2. Since Node 3's exports gets substituted by new trade capacity between Node 1 and 2, the marginal change in welfare in Node 3 becomes negative, despite the fact that $a_1 \leq a_3 \leq a_2$. This results in $\frac{dW_2}{dK} \geq \frac{dW_1}{dK} \geq \frac{dW_3}{dK}$, where $\frac{dW_3}{dK} = a_3(K - K_{23} - d_3) \leq 0$ as long as $K \leq K_{23} + d_3$.

For the three-node system we see that not only may benefits by unevenly distributed, but also shifted across the system leaving one node worse off due to negative externalities (Bushnell and Stoft, 1997). The value of existing transmission rights can potentially decrease to zero value after a voluntary, bilateral investment between two other nodes in the same system. The example from the three node system could be analogous to countries forming a coalition within a given system, since their aggregated benefits are greater than the investment costs. It could also be comparable to cooperative investments that are optimal on system level, but asymmetric and potentially negative at a nodal level. [7]

[7] Note that the findings presented in these two analytical examples are based on a stylized model. For instance, if we consider a larger system with alternating currents (AC), the material impact on expected prices would be more complex

The case study of the NSOG that follows in the next sections illustrates numerically the fundamental findings presented here. We find that benefits of developing a series of transmission projects in the NSOG will be unevenly distributed between countries. Consequently, some individual nations might have incentives to impede cross-border transmission investments without any form of side payments in order to reallocate benefits and costs. Moreover, we show that the value of an individual transmission project is also dependent on the sequence of deployment of all planned transmission investments in a portfolio. We will illustrate how the SV could be used to achieve an efficient allocation scheme with side payments that covers missing incentives among the participants and that considers all possible transmission deployment sequences.

4. NORTH SEAS OFFSHORE GRID MODEL DESCRIPTION

This section describes the transmission and generation expansion planning model used for offshore grid expansion in the NSOG. The model assumes inelastic demand and a centralized planner for multinational grid and generation investments. It is targeted for the system characteristics of the North Seas region where both offshore grid technology costs and hydro representation play an important role. The presented model is inspired in Trötscher and Korpås (2011), Munoz et al. (2014) and Svendsen and Spro (2016). Under the assumption that transmission plans are developed proactively (i.e., before generation) and a perfectly competitive market in generation investments, this planning model is equivalent to a bi-level equilibrium model (Munoz et al., 2017b). The upper level determines optimal transmission investment plans subject to generators' response to such investments. The lower level is an open-loop equilibrium in generation investment and operation decisions in a perfectly competitive market (Samuelson, 1952; Munoz et al., 2017a). This allows generators to react to transmission investments, as the grid investments have a considerable material impact on expected market prices (Hogan, 2011).

4.1 Optimization problem

The mathematical formulation is adapted to the 25-bus NSOG case study for six countries in total, namely, Norway (NO), Denmark (DK), Germany (DE), The Netherlands (NL), Belgium (BE), and Great Britain (GB). We describe some notation in this section, a full description is provided in Table 6

since a re-dispatch in the system could cause loo-flow effects due to Kirchhoff's Voltage Law. However, for the high-voltage direct current (HVDC) system presented in our case study the intuition behind those analytical examples might be directly transferable.

in the Appendix. By minimizing the net present value (NPV) of total system costs (i.e., capital cost of transmission and generation as well as operation costs) we find the socially optimal solution that would be attained under full cooperation among all involved countries. Total costs (1a) sums over the investment costs (1b) and operational costs (1c). Operational costs are calculated for one representative year, multiplied with an annuity factor a in order to convert annual costs to NPV.

Transmission infrastructure investments are represented with both fixed (1d) and variable costs (1e). We determine fixed costs based on mobilization costs B and cable distance $B^d D_j$, in addition to voltage transformers and/or power electronics needed at each end of the cable (CL is the cost for land-based stations and CS is the cost for offshore-based stations). Fixed costs are multiplied by an integer variable that reflects the number of cables, y_b^{num}. Moreover, in the expression that describes the variable costs (1e) there is a power-distance dependent cost-parameter $B^{dp} D_j$ and a power dependent cost-parameter for the end-points of the branch (CL^p is the cost for land-based stations and CS^p is the cost for offshore-based stations), which is multiplied by new branch capacity, y_b^{cap}. In cases where a node facility does not exist, e.g. an offshore node/platform, a binary variable, z_n, is used to reflect installation costs C_n^{bus} for such a node facility which is forced to be implemented by restriction (1l). We ignore Kirchhoff's voltage laws since the majority of the system consist of high voltage direct current (HVDC) branches that are fully controllable, yielding a transport model with no loop flows as shown in Equation (1j) and (1k). However, linear losses for power flows f_b are incorporated to reflect both the transmission distance and use of necessary voltage transformers and power electronics (1f).

The variability of wind, solar, hydropower, and load is incorporated using full-year hourly profiles from both historical and simulated weather data, where the latter source is particularly relevant for offshore locations with limited historical information (Kristiansen et al., 2016). We model the hourly variability of these resources using factors γ_{it} in (1h) ranging from 0 to 100% inflow/availability and multiplied by the maximum existing capacity, P_i^e, plus any additional capacity investments, x_i (1c). We use an agglomerative hierarchical clustering technique (Härtel et al., 2017) in order to reduce the hourly resolution from 8760 hours to 500 representative ones, where each hour is weighted by ω_t (number of hours in a cluster) in (1c) and (1i), while maintaining multi-variate correlations between the different technologies and geographical coordinates.

Variables g_{it} denote generator dispatch levels with marginal cost MC_i and emission cost CO_2 for technologies that use fossil fuels. Load shedding, s_n , is allowed at a cost equivalent to the value of lost load $VOLL$. The market clearing, or energy balance, for each time step is given by

Equation (1f) for a projected demand profile, D_{lt}. We determine long-run electricity prices from the dual variables of Equation (1f) after fixing all transmission investment variables (binaries) and resolving the remaining generation investment and dispatch problem that yields a linear program.

$$\min_{x,y,z,g,f,s} \quad IC + a \cdot OC \tag{1a}$$

where

$$IC = \sum_{b \in B}(C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} C_n^{bus} z_n + \sum_{i \in G} CX_i x_i \tag{1b}$$

$$OC = \sum_{t \in T} \omega_t (\sum_{i \in G}(MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL s_{nt}) \tag{1c}$$

$$C_b^{fix} = B + B^d D_b + 2CL/CS \qquad \forall b \in B \tag{1d}$$

$$C_b^{var} = B^{dp} D_b + 2CL^p/CS^p \qquad \forall b \in B \tag{1e}$$

subject to

$$\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{1f}$$

$$s_{nt} \leq \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{1g}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i, t \in G, T \tag{1h}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \qquad \forall i \in G \tag{1i}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b, t \in B, T \tag{1j}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{1k}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{1l}$$

$$x_i, y_b^{cap}, g_{it}, f_{bt}, s_{nt} \geq 0, \quad y_b^{num} \in \mathbb{Z}^+, \quad z_n \in \{0, 1\}$$

5. NORTH SEAS OFFSHORE GRID CASE STUDY - YEAR 2030

We study a portfolio of three projects that are planned in the North Seas area. Table 1 gives an overview of this project portfolio, comprised of the following cross-border cables; North Sea Link (NO-GB), NordLink (NO-DE), and Viking (DK-GB). We assume that the transmission cables are

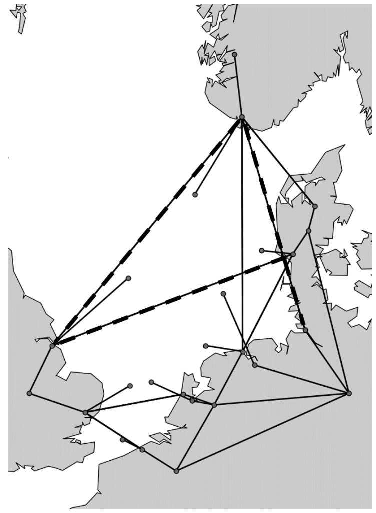

Figure 3: Illustration of the data set used for this North Seas 2030 case study. It depicts all transmission lines to be in operation by year 2030, candidate branches are shown as dashed lines.

scheduled to be in operation by year 2030 under ENTSO-E's scenario Vision 4 (ENTSO-E, 2014).[8] An overview of the key input data is found in Table 5 in the Appendix. An illustration of the geographical scope of the system is depicted in Figure 3.

Table 1: Project portfolio considered in this case study. Costs include operation and maintenance.

Project	From	To	Capacity [MW]	Cost [bn€]
North Sea Link	NO	GB	1400	2.73
NordLink	NO	DE	1400	2.16
Viking	DK	GB	1400	2.5

Each possible outcome of this transmission game is solved as an open-loop generation dispatch and capacity planning problem for the whole system. This means that generators can react to transmission expansion, but we limit generation capacity investments limited to 5000 MW per technology in each country in order to from the projected scenario outlined by ENTSO-E.

In order to assess this cooperative game, the eight possible outcomes (see Table 2) are used to determine the characteristic functions[9] for the $2^6 = 64$ possible investment coalitions, since there will be no other optimal solutions than the eight different combinations of three projects ($2^3 = 8$). This is assuming that two adjacent countries have to agree on investment decisions, in addition to the assumption of no merchant, third party investor.

[8]ENTSO-E's Vision 4 is a top-down scenario developed at European level and it is designed to meet the objectives of the European Commission on market integration and on climate mitigation. It is considered to be the most ambitious scenario in terms of share of renewable generation capacity.

[9]The characteristic functions represent gains achieved by a given coalition in a cooperative game and it is later used to calculate the marginal contribution of a player entering the grand coalition, in different sequences, yielding the SV as an average value of all those marginal contributions (Contreras and Wu, 1999; Ferguson, 2014).

Table 2: Aggregate results for the eight different outcomes. Values are shown in relative terms to the Base case. The combinations are based on the following ordering (NorthSeaLink, NordLink, Vinking).

Outcome -	Total costs bn€	Price €/MWh	CO_2 emissions m€	New branches bn€	New generators bn€	Renewables % of generation
Base case	660.47	41.32	4419.4	0	28.02	61.6800
(0, 0, 1)	-14.05	-0.15	-19.71	2.5	-0.73	0.2070
(0, 1, 0)	-4.87	-0.09	-66.25	2.16	-0.09	0.2000
(0, 1, 1)	-18.95	-0.25	-84.82	4.66	-0.53	0.4194
(1, 0, 0)	-15.24	-0.12	-26.14	2.73	-1.69	0.1967
(1, 0, 1)	-28.14	-0.27	-41.96	5.23	-2.4	0.4298
(1, 1, 0)	-20.08	-0.22	-84.14	4.89	-0.59	0.3252
(1, 1, 1)	-32.99	-0.39	-103.64	7.4	-1.26	0.5793

Total costs in Table 2 reflect the objective function that is being minimized for the system, i.e. investment and operational costs. Prices are calculated as a load-weighted average for all time steps, meaning that areas with high electricity consumption a have larger impact on the average load-weighted system price than areas with low demand. The environmental cost of CO_2 emissions is incorporated using a CO_2 tax (45 €/ton). Capital costs (CAPEX) for investments are separated into branches and generators, under the columns new branches and new generators, respectively. The column named renewables is the share of renewable energy generation which is calculated with respect to total energy production. Note that we use ENTSO-E Vision 4, a very ambitious scenario for 2030 in terms of renewable penetration. This explains why the share of renewables in all cases is relatively high.

The same values are also calculated per country in order to quantify their initial benefits from a specific project, combination of projects, or all projects. Other metrics on national level includes welfare, consumer surplus, producer surplus, congestion rent from new projects, consumer costs, generation costs, and total costs. The latter consists of 50 % of relevant branch CAPEX and 100 % generator CAPEX and dispatch costs. For consumer costs we assume that consumers bear 100 % of the grid investment costs (from the 50 % allocation to one country), according to the postage stamp method, in addition to the cost of consumed energy. Welfare is computed as in the analytical examples in Section 3.

Based on the eight different outcomes of the cooperative game, and the 64 different characteristic functions those represent, the SV is calculated as shown in Equation 2, where $v(\cdot)$ is the characteristic function. A short summary of how to calculate the SV is given for illustrational purposes, whereas a more thorough explanation of the similar format can be found in Gately (1974) and Ferguson (2014).

$$\phi_i(N,v) = \frac{1}{|N|!}\sum_{S\subseteq N\setminus\{i\}} |S|!(|N|-|S|-1)![v(S\cup i)-v(S)] \tag{2}$$

Equation 2, i.e. the SV, weight different ways where country i can add value to a coalition S, which is a subset of the grand coalition N. This captures the marginal contributions from country i for different sequences, $[v(S\cup i)-v(S)]$, weighted by the $|S|!$ different ways the coalition S could have been formed prior to country i joining it and by the $(|N|-|S|-1)!$ ways the remaining countries could join the same coalition, summed over all combinations of subsets excluding i ($S\subseteq N\setminus\{i\}$) and averaged by it dividing by $|N|!$, where $|N|!$ is the number off possible orderings of all countries. The resulting payoff vector, in our case allocation, is given by $\phi_i(N,v)$ to each country i.

5.1 Standard allocation framework (shares/proportions)

In this section we assess the impact of using the standard allocation procedure that consists of splitting the capital costs of transmission expansion and congestion rents between countries at the end of the lines equally (50% to each country). We first impose building all the projected lines in Table 1, which is the solution that minimizes total system cost, and allocate transmission expansion costs and congestion rents 50/50 between connecting countries at each end of a transmission line. The left plot in Figure 4 shows the resulting costs (CAPEX+O&M) and welfare for each country. For illustrational purposes we also include a second allocation rule that splits transmission cost and congestion rents in proportion to the estimated benefits as a result of the development of the socially-optimal transmission investments. The results of this second allocation rule are depicted in the right plot of Figure 4.

Figure 4 shows that the countries that are directly involved in the expansion plan, i.e. the ones who are physically connected to the new transmission lines, all will experience a positive net-benefit in terms of welfare (white bars). However, the third parties, BE and NL, will suffer a decrease in welfare due to less trade with surrounding countries, which also was the case in one of the analytical examples in Section 3. For BE the welfare loss amounts to €79 m (see Table 3).

The suggested project portfolio will most likely be accepted assuming that third parties, such as BE and NL, have no rights to impede the investment decisions if the asymmetric distribution of benefits does not affect the involved countries and their decisions. If, for instance, DK is unsatisfied with the distribution of costs and benefits (i.e. welfare) it can exercise its right to block the development of the project. One solution in such a cases could be to allocated the costs in proportion to the benefits,

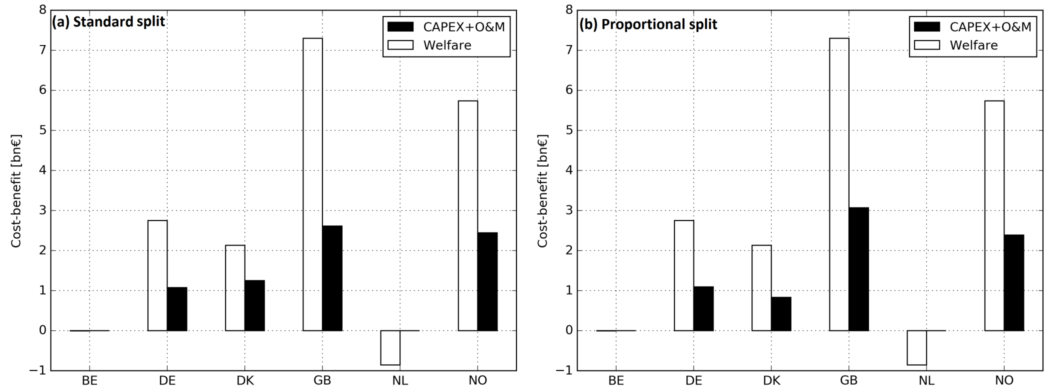

Figure 4: Final allocation of costs (CAPEX+O&M) and welfare for all countries in the NSOG with respect to the base case (i.e., no transmission investments). The left plot (a) shows an equal split of costs, while the right plot (b) shows a proportional cost allocation with respect to the estimated benefits. All transmission lines are assumed to be in operation simultaneously.

as shown in the right part of Figure 4. However, this does not guarantee strong enough (i.e., fair) incentives as the net present value of the aggregate welfare is much larger than the associated costs.

On the other hand, if third parties have the ability to block the development of the transmission expansion project, they will, since their net benefits are negative under these cost and benefit allocation schemes. Moreover, one could argue that the incentives for joining the grand coalition with the standard and proportional allocation schemes in Figure 4 are somewhat imprecise, since it is simply based on cost-sharing and simultaneous deployment, while at the same time, ignoring strategic incentives for countries to form smaller coalitions in order to maximize their gains.

Table 3: Strategic incentives to deviate from grand coalition (1,1,1) under a standard allocation scheme (50/50 allocation of transmission costs and congestion rents). Monetary values are net benefits measured with respect to (1,1,1). The combinations are based on the following ordering (NorthSeaLink, NordLink, Viking).

	NO	DE	DK	BE	NL	GB
Preferred portfolio	(1,1,0)	(0,1,1)	(1,0,1)	(0,0,0)	(0,1,0)	(1,1,1)
Monetary incentive to deviate [m€]	338	130	70	79	675	0

From a strategic perspective, the suggested allocation schemes are not stable since some countries have incentives to form sub-coalitions that would result in higher net benefits for them. Table 3 shows an overview of the project portfolio that give the highest net benefits (i.e., welfare) to each country in comparison to what they would get under the grand coalition (1,1,1). For instance, we see that under the standard 50/50 split of transmission costs and CRs NO would be better off if only the North Sea Link (NO-GB) and NordLink (NO-DE) were developed, i.e. solution (1,1,0), since national welfare would increase in €338m compared to what this country would get if all three transmission lines were developed (1,1,1). Hence, it is unlikely that all countries will agree to join the grand coalition, which contradicts with the EU commissions objectives to incentivize the development of transmission projects that will yield most cost-efficient system and highest aggregate benefits.

How can we make sure that the allocation of costs and benefits is fair? How can we account for possible sequences of project deployment? And how can we use side payments to make everyone better off in the grand coalition? The next subsection will present one alternative payment scheme to accomplish these goals.

5.2 A fair allocation framework based on cooperative game theory

Under the standard and proportional allocation schemes presented in previous subsection we found that net benefits among countries were i) asymmetrically distributed, ii) in some cases negative, iii) based on simultaneous deployment of individual transmission cables, and iv) unstable due to national incentives to deviate from the socially-optimal grand coalition. This is, to a large extent, analogous to the findings in the illustrative examples in Section 3. We now show how the SV can be used in combination with side payments between countries to design a cooperative planning scheme that addresses all the aforementioned shortcomings.

The SV has a series of desirable properties that appeals to cooperative expansion planning such as efficiency, symmetry, additivity, and zero players (Ferguson, 2014). Respectively, this means that the SV supports the welfare optimal solution and that the total gains is distributed to the players, that players with equal contributions to the cooperative solution receive the same payoff, that the sum of two cooperative games is equal to the combined payoff of both games, and finally, that players that do not contribute to the cooperative solution are allocated zero benefits (in our case third-party countries). Additionally, under certain circumstances, the SV is part of the core, meaning that no country will have incentives to deviate from the grand coalition and form a sub-coalition (Ferguson, 2014).

Figure 5 shows the final allocation of costs and benefits under the SV. At first sight, we see that the distribution of benefits with the SV looks more even than with the standard allocation method in Figure 4 since we allow for transferable utility (i.e., side payments) in order to re-distribute benefits. Secondly, the distribution of benefits is still asymmetric for two reasons: i) to level out strategic incentives to deviate from grand coalition, and ii), to compensate for for the value added to the system as a whole by a country, in all the possible sequences of development.

If we compare the SV, which can be viewed as a fair benchmark for benefit allocation, with the strategic incentives in Table 3 we notice that the SV suggests that BE and NL should end up

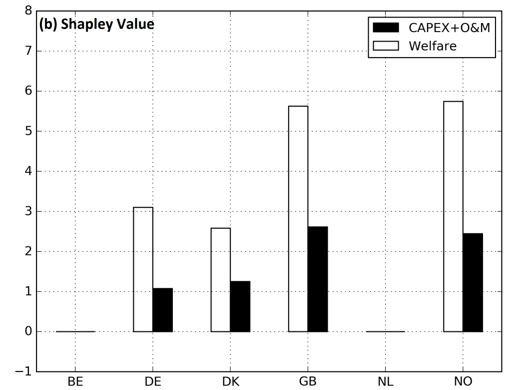

Figure 5: Final allocation of costs (CAPEX+O&M) and welfare for all countries in the NSOG with respect to the base case (i.e., no transmission investments) using the the Shapley Value, which takes into account the sequence of deployment of transmission projects.

with zero net benefits as a consequence of their impact on the development of three transmission projects. In other words, BE and NL will now be indifferent to the projects given an efficient side payment scheme which is depicted in Figure 6. On the other hand, if BE and NL were ignored in the final side payment scheme (Figure 6), there would be more benefits to be allocated among the direct beneficiaries, but this could give BE and NL incentives to undertake actions to reduce or potentially eliminate the negative impact of the transmission projects on their national welfare. For instance, they could react by imposing strict import tariffs[10] or by blocking all future developments of grid and generator capacity expansion projects within their jurisdiction that would benefit neighbouring countries, which would ultimately reduce the net benefits of any transmission project that is not fully supported by all countries.

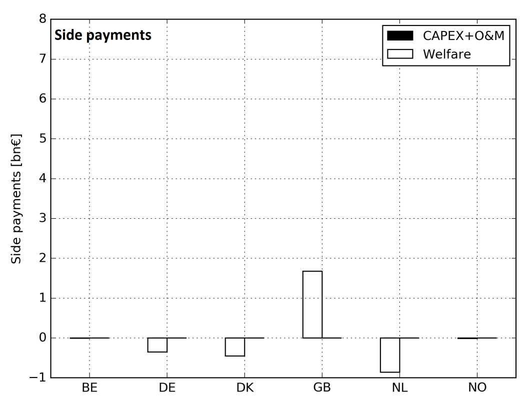

Figure 6: Necessary side payments in order to achieve the benefit allocation suggested with the Shapley Value. Positive values represent expenses, while negative values are gains. All side payments sum to zero.

The side payments, shown in Figure 6, are used to achieve the allocation of benefits

[10]Note that so called "border tariffs" are illegal in Europe, but it could be relevant for other countries and systems.

determined using the SV. These are computed as the difference between the allocation of benefits using the SV and the estimated market impact of developing all transmission projects based on a standard cost-allocation method (left part (a) in Figure 5). For instance, under a standard cost-allocation scheme GB would get larger welfare gains through operational savings than what is determined to be fair under the SV. Consequently, GB would have to pay in order to join the grand coalition. This side payment would then be distributed among the other countries that receive less welfare gains compared to what they deserve according to the SV. Since the aggregated welfare gains are the same for the standard (Figure 4) and SV (Figure 5) allocation schemes, the side payments add up to zero, i.e., they are only a re-allocation of benefits.

On particularly interesting observation from Figure 6 is that NO gets about the same level of benefits with the SV as with the standard allocation method. While Table 3 suggests that NO should be compensated with monetary incentives to join the grand coalition, this is not the case. The issue is that the alternative sub coalition (1,1,0) for NO is actually not preferred by the other two parties involved, neither GB nor DE. Consequently, NO's options in this transmission game are reduced to either impede the development of all projects or to participate. Since the latter provides significantly higher benefits, NO would still prefer to join the grand coalition and, at the same time, still get compensated for its marginal contribution to cooperative welfare gain (amounting to €10m). This illustrates one of the key advantages of using the SV.

5.3 Stability in multinational cooperative TEP games

As we mentioned earlier, the allocations computed using standard rules do not necessarily lead to a stable solution. In Table 3 for instance, we showed that some countries would have incentives to block the socially optimal plan (1,1,1) and form subcoalitions that would result in higher welfare. This indicates that under the standard allocation rule, a fully cooperative expansion plan without side payments would be unstable since countries will have monetary incentives to deviate from the grand coalition. On the other hand, the allocation computed using the SV suggest a more fair benefit allocation among countries than under a standard allocation rule, which yields stronger incentives for a cooperative solution (e.g., no country is worse off than in the base case). Yet, there is no guarantee that the SV will always result in an allocation of benefits that is in the core of a cooperative game, meaning that some countries might still have incentives to form subcoalitions and receive a higher payoff than under the grand coalition if the SV is used to compute the side payments.

One alternative to assess the stability of the solution proposed using the SV is to check whether the game is supermodular or not (Schweizer, 1989). A cooperative game is supermodular (or convex) if the incentives for agents to join a coalition increase with the size of the coalition. If that is the case, then the SV is in the core (Ferguson, 2014). Equation 3 shows the supermodular property of a cooperative game where the marginal value for country i entering coalition S is less than for joining coalition T, where $S \subseteq T$ meaning that coalition T is at least as large as coalition S.

$$v(S \cup \{i\}) - v(S) \leq v(T \cup \{i\}) - v(T) \qquad \forall S \subseteq T \subseteq N \backslash \{i\}, \forall i \in N \tag{3}$$

By applying the characteristic functions from the previous subsection to Equation 3 for all countries, we find that the cooperative game presented in this paper holds the property of supermodularity. We can therefore conclude that the SV is in the core, which means that the proposed allocation is both fair and stable. Therefore, it is not necessary to apply other methods that search for solutions that are in the core such as the Nucleolus, described in Contreras and Wu (2000). Although we do not provide a general proof that multinational transmission planning problems always result in supermodular or convex cooperative games, verifying whether this property holds or not in real-world applications should be relatively simple since these usually have a very limited number of transmission investment alternatives.

5.4 Evaluation of multi-attribute benefit allocation

We now analyze alternative value attributes with the SV in order to show how this can be useful for highlighting possible trade-offs. In the previous sections, we showed that the SV gave stable allocation payoffs where all countries where better off compared with not cooperating, or by forming smaller coalitions. We considered gains in national welfare as characteristic functions, but will now extend the same methodology to evaluate multiple SVs calculated with respect to additional value attributes such as consumer costs, renewable energy production and CO_2 emissions.

The procedure is the same. We first calculate the estimated benefits retrieved from market operations. Then, we calculate a fair benefit allocation with the SV. Finally we use side payments—assuming that they are possible—to bridge the gap between the benefits from market operation and the benefits calculated with the SV.

5.4.1 Initial benefits from the standard allocation scheme

The initial benefits are calculated per country for different metrics using the same methodology used for the results in Figure 4. Figure 7 shows the relative portion of four different benefit metrics a country gets by joining the grand coalition (see solution (1,1,1) in Table 2). The considered metrics include increased electricity production from non-dispatchable renewable energy sources (RES), such as solar and wind, in addition to reduced CO_2 emissions, welfare gains, and cost savings to consumers. Values are given in relative terms, since the different value attributes have different units. For instance, CO_2 reductions are given in ton, while renewable generation is given in MWh and welfare in bn€. Hence, the figure shows the relative allocation of each attribute to all countries, where one value attribute adds up to one over all countries.

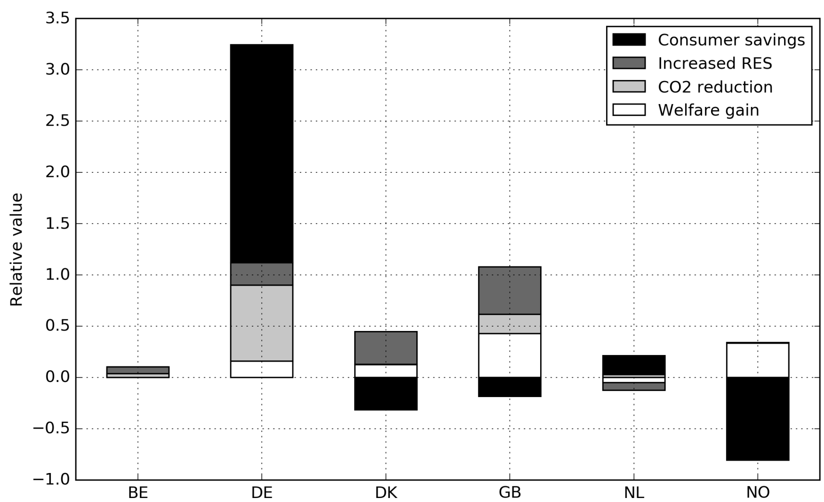

Figure 7: The relative benefit distribution for the grand coalition without any form of side payments. Each metric is given in relative terms to the total benefit gains for that particular value attribute, meaning that the allocation to all countries adds up to one.

There are countries in Figure 7 that are worse off as a consequence of the development of the three transmission projects in other terms than just welfare. For instance, compared with no transmission expansion (0,0,0), NO experience a relatively large increase in consumer costs due to more exports that result in higher electricity prices, in addition to the fact that we assume that investment costs are allocated 100% to the consumers within a country (note that consumers in NO are responsible for financing a fraction of two interconnections in this case). The increase in producer surplus through exports of electricity dominates this cost effect and the net effect on welfare is therefore positive in NO. The same is the case for GB, financing two interconnectors, which in turn gives a positive consumer surplus—hence the small negative proportion of consumer costs in the system. In contrast, we see that consumers in DE obtain significantly lower electricity prices as a result of trades through the new transmission lines. DE does also benefits in terms of energy policy-related metrics that are not fully quantified in our model, including the environmental and health benefits of reductions in greenhouse gas emissions (beyond the ones accounted for through a CO2 tax) and higher shares of RES (Cifuentes et al., 2001; Akella et al., 2009).

Third party countries, such as NL and BE, experience minor cost savings for consumers. What used to be exports is now substituted by competitive power flows from NO through the new interconnector capacities, which is the reason why we see some cost reductions for consumers in those countries. However, the net impact on welfare is still negative, as we already saw in the previous subsection.

Without any side payments, Figure 7 would represent the final estimated effects of the planned investment portfolio. One could question whether this is a fair allocation of benefits, or not. For instance, why should NO and DK increase their costs to consumers in order to shift benefits over to other countries? Are there any underlying drivers other than just costs, e.g. CO_2 emissions and utilization of RES, that represent a trade-off? The next subsection will quantify each country's deserved benefits by calculating the SV for all metrics, individually.

5.4.2 A fair benchmark for benefits using cooperative game theory

The SV is used in order to quantify a fair benchmark for the same value attributes as in previous subsection, and the resulting payoff vectors are illustrated in Figure 8. Again, the allocation of benefits are given in relative terms and each metric adds up to one when added over all countries.

Recall from the initial results in Figure 7 that consumers in NO bear the largest share of costs among all countries, with positive benefit repercussions elsewhere in the system. The value of those repercussions is not reflected in the initial benefits, nor would it be reflected in conventional proportional methods for benefit allocations (Hogan, 2011). The payoff vectors in Figure 8 does, however, incorporate the positive effect of NO taking a larger piece of consumer costs for the greater good. The results shows that NO should end up with a positive impact on consumer savings since it contributes to consumer savings elsewhere in the system. Moreover, NO plays an important role for the value creation in the other metrics as well, particularly due to its cheap and flexible hydropower capacity that becomes available to surrounding countries with new interconnectors.

Environmental metrics shifts benefits towards those causing the initial benefits in Figure 7. Take for instance NO. This country gets rewarded in Figure 8 for its impact on reduced CO_2 emissions

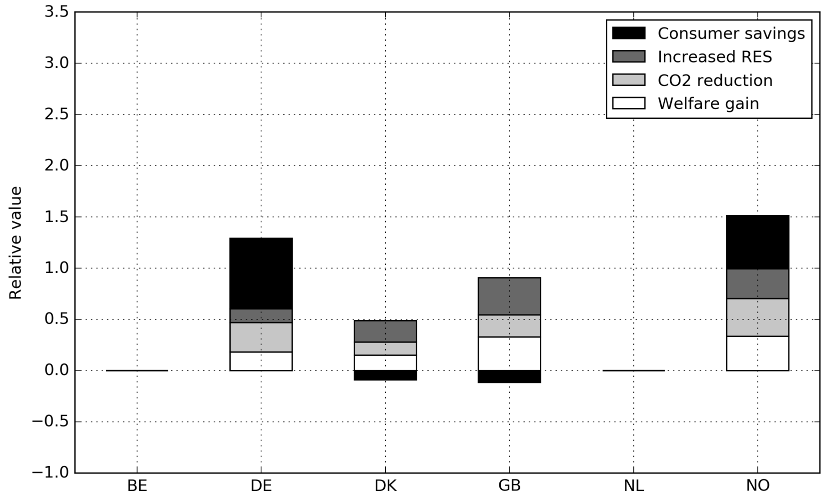

Figure 8: The relative benefit distribution for the grand coalition based on the SV. Each metric is given in relative terms to the total benefit gains for a particular value attribute, meaning that the allocation to all countries adds up to one. This allocation is only achievable assuming some form of side payments to compensate for features such as RES generation and reductions in greenhouse gas emissions.

on system level, in addition to its impact on a higher share of renewable generation, where the curtailed energy is reduced by 0.6 % on a system level. This was not reflected with the initial allocation depicted in Figure 7.

Consistent with the result in the previous subsection, third party countries (BE and NL) will not be considered in the SV allocation since they do not contribute to system benefits by making any decisions regarding the development of the transmission expansion projects. Once again, the allocation of benefits computed using the SV indicates a fair distribution of benefits for many attributes and can be used to determine a series of side payments needed to achieve such allocation if the optimal transmission plan is developed.

5.4.3 Resulting side payments

Figure 9 depicts the resulting side payments for each country and metric in order to achieve the allocation suggested by the SV, assuming full cooperation. Note that the suggested side payments are based on the isolated impact of each metric, and not a combination of them all, since they might be partly incorporated into each other. For instance, more efficient use, and trade, of renewables is highly correlated with welfare gains, and increased utilization of RES yields reduced CO_2 emissions. However, their relative distribution could still be used to reveal possible trade-offs that are useful in both the decision and allocation process in the real world.

First note that under certain metrics third parties should receive side payments to level out the impact from changes in investments and in market operations (Figure 7). DK, for instance, should be compensated for an increase in the amount of CO_2 emissions as a consequence of the construction of the optimal transmission projects. On the other hand, countries that are directly involved in the development of these transmission projects have different side payments depending on the impact of these projects on each metric. Consumers in NO, for example, should be compensated for their relative loss in surplus with respect to the base case with no investments in transmission projects. This compensation would come mainly from consumers in DE since they are the ones that would benefit the most (in relative terms) from the development of the three offshore interconnectors.

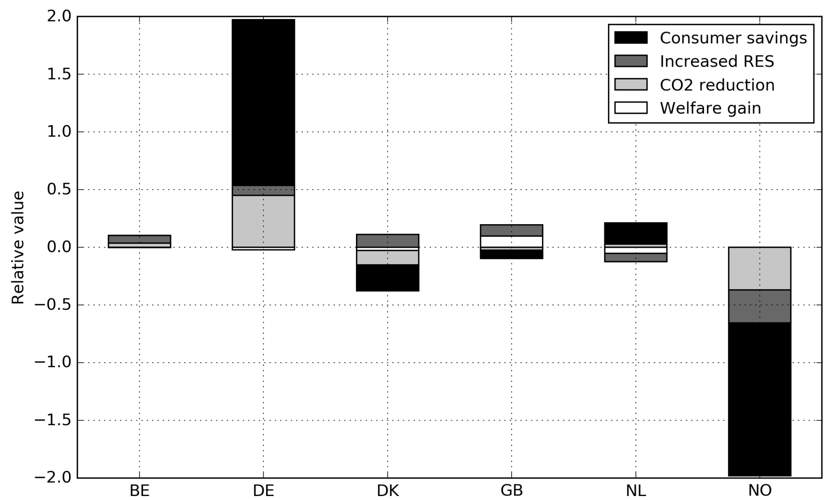

Figure 9: The relative distribution of side payments to achieve the SV allocation (Figure 8) taking the standard allocation as the initial endowment of benefits (Figure 7). The side payments are given for different metrics and sums to zero for that particular value attribute. Positive values represent expenses, while negative values are gains.

Recall from our previous analysis focused on national welfare in Figure 7 that NO should receive a relatively small side payment. This is because the fair level of welfare in NO based on the SV is very similar to what this country would receive under the standard allocation rule. However, if we were to consider consumer savings, instead of welfare, NO would require significant compensation in order to join the grand coalition (1,1,1). The same would be the case for increased RES and reduced CO_2 emissions, since NO provides flexible hydropower to the system which allows for more efficient utilization of renewable resources and cost-efficient generation. Without NO, the rest of the countries would not be able to achieve the same magnitude of benefits for those metrics.

6. CONCLUSION

In this paper we address the challenge of computing a fair allocation of the costs and benefits that result from the development of multinational transmission projects. We focus on this subject inspired by the goal of the EU Commission to integrate markets and increase the economic efficiency and security of supply in the aggregate system, in conjunction with reductions of greenhouse gas emissions. Unlike federal transmission rules in the US enforced by FERC, the EU Commission has no legal power to impose the development of new transmission projects between countries, meaning that these will only be developed if all independent parties (i.e., countries) agree to do so. To this end, we present a generic methodological framework for cost-benefit allocations that could support system-optimal cross-border investment decisions and which has a series of desirable properties that more common cost-allocation frameworks do not possess (e.g., 50/50 split of transmission costs and congestion rents).

We first develop simple two- and three-node examples to show that investments that are socially optimal from a system-wide perspective (i.e., that maximize total aggregate welfare or minimize total system cost) can result in asymmetric and potentially negative benefits for some countries in neighboring regions. The analytical observations are carried over to a real case study of a planned project portfolio for the North Seas Offshore Grid (NSOG) in 2030. We use a transmission and generation planning model in combination with cooperative game theory to evaluate different allocation schemes. The model accounts for generators' response to transmission investments assuming a perfectly competitive electricity market and includes a fine-grained hourly resolution that captures demand and renewable resource variability across all regions.

We use the Shapley Value (SV) to compute a fair allocation of the benefits acquired by the grand coalition, which is when all countries make decisions cooperatively, as if all investments were centrally planned. The results from the SV are benchmarked against simpler and more common allocation rules, including a) an equal split of transmission costs and congestion rents between connecting countries and b) a rule that shares transmission costs and congestion rents in proportion to estimated benefits. Our results show that both a) and b) yield allocations that are significantly different than what would be obtained under the SV. Furthermore, under a) and b) countries that are not directly connected to the transmission projects in question end up with lower welfare than without them. Consequently, such countries would not support the development of an efficient transmission portfolio and, although they could not unilaterally impede its development, they will have incentives to respond in some other form that could ultimately affect aggregate benefits in the long term (e.g., high wheeling charges on existing links or blocking future transmission projects that they are part of). However, under the SV, all countries are better off or at least equal in terms of welfare to a scenario where no transmission project is developed, thereby facilitating a multinational agreement to support socially-optimal projects. In addition, we show that the SV can be used to compute a fair allocation of other alternative objectives, including consumer surplus, reductions of greenhouse gas emissions, and renewable energy generation.

Finally, we verify numerically that in this case the cooperative game between countries is convex since the incentives to join a coalition increases with its size. This results in a supermodular characteristic function to compute the SV, which means that this allocation resides in the core of the game. This is a rather strong result since it guarantees that no coalition of countries could receive a larger payoff than what they would get under the grand coalition. Although we do not provide a general proof for a generic case, we claim that supermodularity should be easily verifiable in most real-world applications of multinational transmission planning since investment alternatives are often very limited.

Nevertheless, our analyses have a series of limitations. We assume that it is of all the countries interest to cooperate and to reach energy and environmental targets by 2030, which is why we do not study the strategic form of this transmission game. Evaluating the strategic form would allow us to quantify the value of a well-functioning allocation scheme to reach a cooperative solution (i.e., the cost of anarchy). Moreover, we do not study political, legal and/or market design mechanisms for the actual side payments necessary for this allocation method to work. One occurring observation was that the discussion of results were highly dependent on the legal framework in place that would ultimately determine which projects will be developed (i.e., the agents that decide the type, size, and location of projects). Hence, future work should focus on the two latter shortcomings in order to gain better insight to potential real-life applications of the proposed allocation framework.

Moreover, the investment portfolio considered in this study consists of point-to-point HVDC interconnectors only. A potential advancement could be to study the proposed allocation framework on a meshed grid with AC power flows. National preferences with respect to radial versus meshed solutions would be also an interesting contribution. In addition, a natural followup to our illustrative analysis on multi-attribute benefit allocation is to consider attributes such as system reliability, which could be measured as reductions in (expected) demand curtailment. Moreover, additional benefits can be captured by incorporating sequential resolution of uncertainty and dynamic decisions (i.e., the option value of a postponed investment decision).

7. APPENDIX

Table 4 shows the underlying derivations for the two- and three node analytical example in Section 3. The mathematical model notations are given in Table 6, and Table 5 summarize the data input used for the case study presented in this paper.

Table 4: Derivations for welfare calculations in Section 3. Note that transmission investment costs are disregarded. For cooperative investments; $\alpha_1 + \alpha_2 = 1$, e.g. $\alpha_1 = \alpha_2 = 0.5$.

Metric	Node 1	Node 2	System
Dispatch	$q_1 = d_1 + K$	$q_2 = d_2 - K$	$q_1 + q_2 = d_1 + d_2$
Price	$p_1 = c_1 = c_0 + a_1 q_1$	$p_2 = c_2 = c_0 + a_2 q_2$	$-$
Producer Surplus (PS)	$\frac{1}{2}(p_1 - c_0)q_1$	$\frac{1}{2}(p_2 - c_0)q_2$	$PS_1 + PS_2$
Consumer Surplus (CS)	$(VOLL - p_1)d_1$	$(VOLL - p_2)d_2$	$CS_1 + CS_2$
Congestion Rent (CR)	$\alpha_1(p_2 - p_1)K$	$\alpha_2(p_2 - p_1)K$	$CR_1 + CR_2$
Welfare (W)	$PS_1 + CS_1$	$PS_2 + CS_2$	$PS + CS$
Net Welfare (W+CR)	$PS_1 + CS_1 + \alpha_1 CR_1$	$PS_2 + CS_2 + \alpha_2 CR_2$	$PS + CS + CR$

Table 5: Input model data: Marginal costs, generation capacity and peak load per country (ENTSO-E, 2014; Van Hulle et al., 2009). The economic lifetime of investments is assumed to be 30 years and the discount rate is 5 %.

Country	Costs	NO	DK	DE	NL	BE	GB	Sum
-	EUR/MWh	———	———	———	MW	———	———	———
Biomass	50	0	4 420	13 500	3 100	2 510	11 150	34 680
Coal	22	0	0	31 690	3 230	0	9 520	44 440
Natural Gas	52	900	2 010	39 300	20 710	15 130	39 190	117 240
Hydro	-	52 000	10	15 650	200	1 440	5 270	74 570
Nuclear	12	0	0	0	490	0	13 910	14 400
Oil	125	0	0	1 200	0	0	610	1 810
Solar PV	0	0	3 430	68 800	9 100	6 740	5 800	93 870
Wind Onshore	0	5 000	11 460	89 500	6 000	5 370	18 060	135 390
Wind Offshore	0	6 400	5 540	23 600	6 800	4 000	42 309	88 649
Total generator capacity	-	57 900	21 330	259 640	42 830	31 190	103 510	605 049
Peak load	-	22 400	8 130	108 160	22 980	15 790	64 640	243 100

Table 6: Notation for the generation and transmission planning model (PowerGIM).

Sets & Mappings	
$n \in N$	: nodes
$i \in G$	: generators
$b \in B$	: branches
$l \in L$	: loads, demand, consumers
$t \in T$	: time steps, hour
$i \in G_n, l \in L_n$	: generators/load at node *n*
$n \in B_n^{in}, B_n^{out}$	: branch in/out at node *n*
$n(i), n(l)$	: node mapping to generator *i*/load unit *l*
Parameters	
a	: annuity factor
ω_t	: weighting factor for hour *t* (number of hours in a sample/cluster) [h]
$VOLL$	: value of lost load (cost of load shedding) [€/MWh]
MC_i	: marginal cost of generation, generator *i* [€/MWh]
$CO2_i$	: CO_2 emission costs, generator *i* [€/MWh]
D_{lt}	: demand at load *l*, hour *t* [MW]
B, B^d, B^{dp}	: branch mobilization, fixed- and variable cost [€,€/km,€/kmMW]
CL, CL^p	: onshore switchgear (fixed and variable cost) [€,€/MW]
CS, CS^p	: offshore switchgear (fixed and variable cost) [€,€/MW]
CX_i	: capital cost for generator capacity, generator *i* [€/MW]
NL, NS	: onshore/offshore node costs (e.g. platform costs) [€]
P_i^e	: existing generation capacity, generator *i* [MW]
γ_{it}	: factor for available generator capacity, generator *i*, hour *t*
P_b^e	: existing branch capacity, branch *b* [MW]
$P_b^{n,max}$	: maximum new branch capacity, branch *b* [MW]
D_b	: distance/length, branch *b* [km]
l_j	: transmission losses (fixed + variable w.r.t. distance), branch *b*
E_i	: yearly disposable energy (e.g. energy storage), generator *i* [MWh]
M	: a sufficiently large number
Primal variables	
y_b^{num}	: number of new transmission lines/cables, branch *b*
y_b^{cap}	: new transmission capacity, branch *b* [MW]
z_n	: new platform/station, node *n*
x_i	: new generation capacity, generator *i* [MW]
g_{it}	: power generation dispatch, generator *i*, hour *t* [MW]
f_{bt}	: power flow, branch *b*, hour *t* [MW]
s_{nt}	: load shedding, node *n*, hour *t* [MW]

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