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Analyzing Brexit: Implications for the Electricity System of Great Britain

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Abstract: The UK's exit from the European Union (EU) has potential ramifications for the country's electricity sector, given its increasing interlinkage with other EU electricity systems. Brexit could hamper the development toward higher market integration and the realization of new interconnector projects. Moreover, a fall in the value of the Pound, resulting from Brexit in the medium term, could also affect the electricity trading structure. Combining a European electricity market model and a multi-criteria decision analysis tool, this study assesses the implications of Brexit for the electricity market of Great Britain (hereafter GB) for 2030, from the perspective of (i) political decision makers, (ii) electricity consumers, and (iii) producers. Results indicate that the implications of Brexit depend on the future development of the GB electricity system and on the objectives of the respective stakeholders. Possible opportunities brought by Brexit under a low-carbon trajectory contrast with greater challenges and tradeoffs between stakeholders under alternative power system development paths. Despite increased British autonomy in energy and climate matters, there remains interdependency between British and EU energy policy.

Keywords: Brexit; electricity markets; interconnectors; TOPSIS

1. Introduction

Britain's vote in June 2016 to leave the European Union (EU) represents a dramatic shift in the country's relationship with the rest of the EU, following over 40 years in the Union. There have been efforts to evaluate the impact of Brexit across various sectors of the British economy and society [1–5]. However, the potential results of a reduction in integration with the EU for these sectors, following Brexit, remain unclear.

One sector that could be influenced by Brexit is the Great Britain (GB) (In this paper, we only consider the power system of England, Scotland, and Wales, and not Northern Ireland. Northern Ireland and the Republic of Ireland share one electricity grid and engage in a single electricity market. Analyzing the impact of reduced expansion of interconnector capacity between the EU and GB on the joint Irish electricity system is beyond the scope of this paper) electricity sector, as it is a system that has experienced increasing integration with other electricity systems in the EU. Indeed, there has been attention in the literature on the implications of reduced integration for UK energy policy and security [6,7]: This integration has come e.g., in the form of interconnectors linking GB's electricity grid with those of neighboring EU countries, enabling the trading of electricity. The European Commission has set a target for net transfer capacities to equal 10% of all installed capacity by 2020 and 15% by 2030 [8], which means that the trade of electricity through interconnectors will form an important component in the ongoing transformation of the British and other EU member states' power systems toward 2030. Brexit could affect the integration of GB's electricity system into those of other EU member states and may have consequences for its future trajectory. This paper seeks to investigate the possible consequences of Brexit for the electricity system of GB.

The Brexit vote coincides with wider changes in the GB electricity system [9]. In relation to the composition of the electricity mix, there has been a shift away from coal: GB's aging coal power plant fleet will be phased out by the mid-2020s [10], and this has also been accompanied by a greater focus on combined cycle gas turbine (CCGT) plants, renewable energy sources (RES), nuclear power and imports of power through interconnectors [11]. Further interconnector projects with France and Ireland in addition to new interconnector projects with Belgium, Norway, Denmark [12], and even Iceland [13] are being developed. There is currently 4 GW of interconnection capacity installed between GB and its neighbors; a further 7 GW are planned between now and 2022 [12]. A total of 12 GW of interconnection capacity would amount to just over 12% of total generation capacity in relation to a total installed generation capacity of 81 GW at the end of 2017 [14]. This would represent progression toward the EU target for interconnection. Uncertainty caused by Brexit could raise doubts about these projects, and ultimately lead to lower interconnector capacity than anticipated. At the same time, the Brexit vote entailed a decline of the British Pound and it has never regained its pre-Brexit level [15].

Applying the Electricity Market Model for Europe (EMME), we address the question of the effects of Brexit on the GB electricity system by analyzing the implications of a reduced expansion of net transfer capacity (NTC) between the GB grid and EU neighboring grids combined with a fall in the value of the Pound. In this paper, the level of NTC is not modeled in the optimization; it is assumed that the NTC expansion is politically determined, and therefore exogenous to the model.

The model results will be categorized with respect to three different stakeholders within the electricity system: (i) political decision makers, (ii) electricity producers, and (iii) electricity consumers. The results for these three groups depend on the transition pathway that the GB electricity sector will follow up to 2030; therefore, we consider and discuss different conceivable pathways in our analysis. Applying the multi-criteria decision analysis (MCDA) tool TOPSIS (Technique for Order Preference by Similarity to Ideal Solution), the modeling results will be evaluated from the viewpoint of the three respective interest groups. MCDA techniques can complement other analytical tools. Both energy market modeling frameworks and MCDA methods are commonly used for scenario assessment and energy planning (see e.g., [16–18]). McKenna et al. [19] introduced an integrated participatory approach for energy generation scenarios for small communities. In doing so, they coupled an MCDA with a linear optimization modeling framework. Ribeiro et al. [20] electricity production scenarios for Portugal by ranking different development paths generated with an optimization model with an MCDA. Ram et al. [21] combined MCDA with scenario planning, as MCDA can be used to handle competing objectives whereas, unlike MCDA, scenario planning tools are effective at dealing with uncertainty. Energy scenario tools may offer a higher, more general level of analysis, aimed at strategic guidance and can be combined with MCDA approaches which, on the other hand, provide a detailed evaluation of a particular alternative from the perspective of different actors [22]. Furthermore, MCDA can act as an interface between complex models and practical decision problems. For instance, in evaluating future trajectories for the Portuguese power system, Ribeiro, Ferreira, and Araújo [20] coupled scenarios resulting from a mixed integer linear programming model with an MCDA tool. In doing so, they identified a willingness to increase the overall cost of the system among all the respondents as long as factors other than economic ones are integrated into the decision; MCDA, in this case, has revealed the importance of non-economic factors to the decision problem.

Furthermore, MCDA tools offer an alternative to the monetary evaluation of environmental aspects, as e.g., within the cost–benefit analysis or integrated assessment models (IAM) (see Ürge-Vorsatz, et al. [23]). Scholten et al. [24] compared the application of MCDA tools to IAM in the context of water supply planning. They found that both methodological frameworks identified the identical best alternative, even though the rankings among the alternatives differed.

Saarikoski et al. [25] and Browne and Ryan [26] compared CBA (Cost-Benefit Analysis) and MCDA approaches.

The structure of this paper is organized as follows: Section 2 will briefly present the related scientific literature dealing with possible implications of Brexit on the GB energy system. Particular focus will be paid to the structure of the GB energy landscape and its interlinkages with the European Internal Energy Market (IEM). In this context, the impact of international NTCs is highlighted. Furthermore, the literature review considers possible consequences of Brexit with regard to future British climate and energy policy. Subsequently, in Section 3, the methodological framework is presented, detailing the specifications of the dispatch model, the scenarios used in this analysis, and the indicators forming the basis of the assessment. The modeling results for the three main actors mentioned above and the MCDA results will be presented in Section 4. Finally, policy-oriented conclusions will be drawn in Section 5. The analysis presented here is differentiated according to three possible trajectories for the UK power system to 2030, based on scenarios from ENTSO-E (European Network of Transmission System Operators for Electricity) [11]: (i) a Blue and Yellow scenario that is closer to the status quo, and (ii) a Green scenario reflecting policy with a stronger focus on the development of renewable energy capacities.

2. The Trend toward Greater Integration of the EU's Electricity Systems

2.1. Interconnectors: Role in Single Electricity Markets

Increasingly, the European Union has been promoting a common energy policy, based on the three core priorities of energy security, affordability, and environmental protection [27]. The IEM underlies this common energy policy with the aim that electricity can be traded among EU member states without restrictions, creating a more competitive electricity market, benefiting from greater security of supply [28–31], which is made possible through physical interconnections between electricity grids [32].

With regard to the multifarious challenges of security of electricity supply, the role of interconnectors has been discussed frequently [9,33]. Historically, cross-border interconnectors were intended to reinforce the security of supply, as other countries could help, via electricity exports, if a member state's electricity system faced disruption [34]. However, increasingly, there has been a focus on how interconnection can increase trade among member states and, in doing so, improve the efficiency of markets and, ultimately, social welfare [35]. A crucial argument in favor of interconnectors is that they further the integration of intermittent power resources [35–37], as they can help to reduce the impact of renewable penetration on price volatility [38,39].

Connecting two electricity markets generally results in greater price convergence between the two markets and lower price volatility [39]. This, in effect, creates both "winners and losers", as the fall in electricity prices in one region, thanks to the interconnectors, penalizes electricity producers, whereas the rise in electricity prices in the other region adversely affects electricity consumers in that region [34,40]. Furthermore, interconnectors bring about technical benefits to the power system [41], especially in situations of high renewable power penetration [42,43]. For instance, Lynch, et al. [44] argue that interconnection reduces total system costs in cases where there is high wind penetration, as the total capacities of both conventional and renewable generation technologies can be reduced.

There has already been an ongoing discussion of the impact of interconnection on electricity markets and CO_2 emissions [45–47]. Mezősi, Pató, and Szabó [38] argued that the effect of interconnectors on CO_2 emissions is dependent on the carbon price and the ratio between coal prices and gas prices. Indeed, they found that complying with the 10% interconnection target by 2020 would lead to an increase in CO_2 emissions, if the low CO_2 price environment prevailed. Considering the UK's decision to introduce a CO_2 price floor (CPF), the question arises as to how a unilateral minimum price for carbon emissions interacts with electricity trade and the European Emission Trading Scheme (ETS). The CPF constitutes a minimum price for CO_2 emissions, with a fixed development corridor over the next years. It consists of two parts (see Hirst [48]): (i) the ETS certificate price and (ii) the Carbon

Support Price. The Carbon Support Price tops up the ETS price in accordance with the CPF corridor set by the British Government. In 2030, the CPF was originally set to be £70 [48].

Investments in interconnectors are long-term in nature (between 25–40 years), increasing the significance of uncertainty for the planning process of new projects [49]. Moreover, in general, there are insufficient incentives to invest in interconnectors, compounded by resistance from domestic firms to more competition in the domestic market [34,47]. Furthermore, investment in interconnectors is complicated by long planning and construction times, onerous permit procedures, and the possibility that interconnector capacities will be under-used and, therefore, become stranded [34]. Barriers to investment in interconnectors are exacerbated by the presence of a "regulatory gap" in which there is no regulator responsible for cross-border infrastructures [40]. The uncertainty arising from Brexit could increase the reluctance to invest in further interconnector projects. Therefore, this work offers a detailed analysis of possible implications of a reduced interconnection development for the GB power system.

2.2. Brexit: Implications for the GB Electricity System

It remains unclear what the UK's trading relationship with the EU will look like after Brexit. At the time of the Withdrawal Agreement, the will was expressed to develop a "framework" that would enable "technical cooperation between electricity and gas network operators" and ensure the security of supply and efficient trade over interconnectors; however, the British Parliament subsequently rejected the agreement [50]. If the Withdrawal Agreement is revived, it is not clear to what extent such a framework would emulate the conditions the UK enjoyed as a member of the IEM. Energy UK [51] emphasizes the importance of minimizing uncertainty, given the "long investment timelines" concerning energy assets, such as interconnectors.

Brexit has led to a decline in the value of the Pound, and this should be factored into any (medium-term) economic analysis of Brexit. In the weeks following the referendum, the Pound's value fell substantially, losing almost 15% and, in the months to October 2016, the nominal effective exchange rate of the Pound, measured against a selection of foreign currencies, depreciated by nearly 20% [52]. Since 48% of the UK's exports go to the European Single Market [53], the impact of restrictions and greater costs in trading with the EU would be considerable. There are indications that the Pound's loss in value could be sustained, as both trade between the UK and the EU in addition to foreign direct investment (FDI) are likely to be adversely affected by Brexit [54–56]. By 2030, Ebell and Warren [55] estimated that if the UK follows a Swiss arrangement with the EU, trade between the UK and the EU will be between 13–17% lower than it would have been, had the UK remained in the EU and, if the UK has a World Trade Organization (WTO) arrangement, then trade is estimated to be between 20–30% lower. These conditions would, in the long-term, depress the value of the Pound. A lower value of the Pound is likely to make imports of electricity more expensive, and conversely increase the competitiveness of GB electricity exports to the EU.

Both climate and energy policies have substantial links with EU policy, and could be affected by lower integration with the EU. In terms of climate policy, the UK's current CPF is contingent on the EU ETS—it tops up, essentially, the emission certificate price, and if the UK were to be out of the EU ETS, it would need to replace this with a UK ETS or a carbon tax [4]. Taking a more optimistic view of Brexit, Pollitt [5] suggested that the impacts on the GB energy sector will be rather contained, and that leaving the EU could bring opportunities for the sector. He refers to the fact that fossil fuel prices are set internationally, whilst the UK has diversified its suppliers of fossil fuels in addition to the interconnection capacities being currently low, as indicative of the limited negative impacts of Brexit. Outside of the EU, the UK would have greater freedom to pursue alternative options in market design that are inconsistent with EU policy, such as reconsidering the unbundling of generation from supply and the financing of nuclear generation over long-term contracts between generators and suppliers [5].

As regards the risks of Brexit, energy security is a concern. This is because there may be less cooperation in terms of exchanging electricity through the interconnectors. Furthermore, "increased coordination costs" between the UK and EU countries could lead to delays in interconnector investments and reduced NTC growth [5]. This would force GB to resort to more expensive domestic back-up capacity in order to meet security of supply needs. A reduced expansion of interconnectivity could weaken the taming effect that interconnection has on very high peak power prices and lead to potential revenue opportunities for operators of large-scale storage facilities; conditions for such facilities in Great Britain have been less attractive than expected in recent years [57]. Indeed, Pye, Mathieu, and Deane [58] warned that the uncertainty associated with Brexit may lead to nervousness on the part of investors as regards investing in interconnectors, with French regulators already re-examining the rationale behind a new French–British interconnector project.

In summary, a greater integration of EU electricity systems is considered advantageous for energy security, the competitiveness of power markets, and should lead, ultimately, to lower system costs. Trajectories of the UK's power system toward 2030 have taken into account greater levels of cross-border interconnection (see e.g., [11,59]), and since Brexit raises questions about future interconnection projects, the possible impacts of lower interconnection must be examined in the course of the evaluation of Brexit's impacts.

3. Research Approach

3.1. Model Specifications

The EMME is a dispatch model of the EU electricity market. This model, featuring 28 individual member states of the EU and Switzerland, is a linear optimization model. Power flows among member states are restricted by NTCs between the respective markets. The model features a full list of types of generation technologies, their respective capacities and vintage structures, as well as differentiated variable costs in each country. The generation capacities, energy carrier prices, CO_2 certificate prices and the power demand are exogenous model inputs and demand is given in hourly intervals. The availability of variable and non-dispatchable RES is determined by time series.

The model takes the following objective function as its basis:

$$\min Z = \sum_{h,i,d} [Pr(h,i,d) \cdot Cst(i,d)] + \sum_{h,d,k} Im(h,d,k) \cdot T \quad (1)$$

subject to:

$$\sum_{h,i,d} Pr(h,i,d) + \sum_{h,d,k} Im(h,d,k) = Dm(h,d) \quad (2)$$

$$Pr(h,i,d) \leq Cp(h,i,d) \quad (3)$$

$$Im(h,d,k) \leq NTC(d,k) \quad (4)$$

with:

- *i*: generation technology type
- *h*: specific hour of the year [-]
- *T*: transport costs for imports and exports [€/MWh]
- *d* and *k*: country indexes [-]
- *Cst*: variable generation costs [€/MWh]
- *Pr*: electricity production [MWh]
- *Cp*: generation capacity [MW]
- *Im*: electricity imports from country k to country d [MWh]
- *Dm*: electricity demand [MWh]
- *NTC*: net transfer capacity between two markets [MW]

Producers' surpluses are calculated as the spread between the wholesale price and variable electricity generation costs:

$$PS(i,d) = \sum_h ((X(h,d) - Cst(i,d)) \cdot Pr(h,i,d)) \tag{5}$$

with

- PS: producer surplus [€]
- X: wholesale price [€/MWh]

Changes in consumers' surpluses are expressed as the absolute change in average wholesale prices multiplied by electricity consumption. Prices in the Yellow scenario are used as a reference value when calculating the magnitude of differences in wholesale prices.

$$CS(d) = \left(X_{Ref}(d) - \frac{1}{8760} \cdot \sum_h X(h,d) \right) \cdot DM \tag{6}$$

with

- CS: change in consumers' surplus [€/a]
- X_{Ref}: average reference wholesale price of Yellow_100_0 [€/MWh]
- DM_{Ref}: overall electricity demand [MWh/a]

In a subsequent step, the model results will be used to determine the overall levelized costs of electricity (LCOE) of the UK generation fleet *avg_LCOE* with:

$$avg\_LCOE = \frac{\left(\sum_i ANF_{n,p} \cdot \frac{I}{t_{voll}} + \frac{O\&M_{fix}}{t_{voll}} + O\&M_{var} + FC + EC \right) \cdot Pr(h,i,d)}{\sum_i Pr(h,i,d)} \tag{7}$$

and:

$$ANF_{n,p} = \frac{(1+p)^n \cdot p}{(1+p)^n - 1} \tag{8}$$

with:

- I: overnight investment costs [€/MW]
- ANF: annuity [€]
- $O\&M_{fix}$: fixed operation and maintenance costs [€/MW]
- $O\&M_{var}$: variable operation and maintenance costs [€/MWh]
- t_{voll}: achieved full load hours [h]
- FC: fuel costs [€/MWh]
- EC: costs for emission certificates [€/MWh]
- p: interest rate [-]
- n: expected lifetime of power plant [a]

With respect to the electricity production of each power plant type, the respective environmental implications are calculated by:

$$Env_x(d) = \sum_i \left(LCA_{x,i} \cdot \sum_h Pr(h,i,d) \right) \tag{9}$$

with

- Env_x: environmental impact x
- $LCA_{x,i}$: specific environmental impact factor x for power plant type i

The calculation of environmental impacts is based on LCA (Life Cycle Analysis) data for power plant types in the UK provided by "probas", which is a database for environmental management systems made available by the German Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety.

3.2. Scenarios

The modeling approach in the paper studies three different scenarios for the power system in 2030, namely: Yellow, Blue, and Green. The scenarios are based on the capacity, CO_2 price, and fuel cost assumptions contained within European Transmission System Operators' Ten-Year Network Development Plan (TYNDP) data [11] (the data refer to 'Vision 1' and 'Vision 3', respectively). Adjustments were made to integrate the UK's goal for a complete coal phase out by 2022. The Climate Change Act (2008) and the introduction of the Carbon Price Floor are examples of the UK unilaterally adopting strong climate policies and indicate a "Green" trajectory. However, the UK would no longer participate in the EU ETS, with which the Carbon Price Floor is linked, and would no longer be subject to the EU Renewables Directive. Thus, the UK would have to replace these instruments [4]. This gives rise to the opportunity to deviate from the Green trajectory, and possible deviations are characterized by the Yellow and Blue scenarios.

The Yellow scenario is characterized by a lower carbon price of €30 per ton of CO_2, and a moderate expansion of renewable power. As discussed before, Britain introduced a minimum price for emissions certificates in the form of a CPF. In general, the Yellow and Blue scenarios show the same characteristics with the exception of greenhouse gas (GHG) certificate prices in the UK. Yellow assumes a weaker enforcement of British environmental policy, which results in a CPF lower than (or equal to) the overall EU market price (i.e., the EU ETS price will apply for British generators). Blue represents a stronger commitment toward national climate mitigation policies, and thus shows a CPF well above the EU market price for CO_2 emissions.

In the Green scenario, amid the higher price for emission certificates, there is a stronger deployment of low-carbon electricity generation units.

Figure 1 shows the exogenous input parameters of overall installed capacity in GW (left axis) and electricity demand in TWh (right axis) of the Yellow, Blue, and Green scenarios in 2030 compared with 2015 for the UK (based on [49], and [11]).

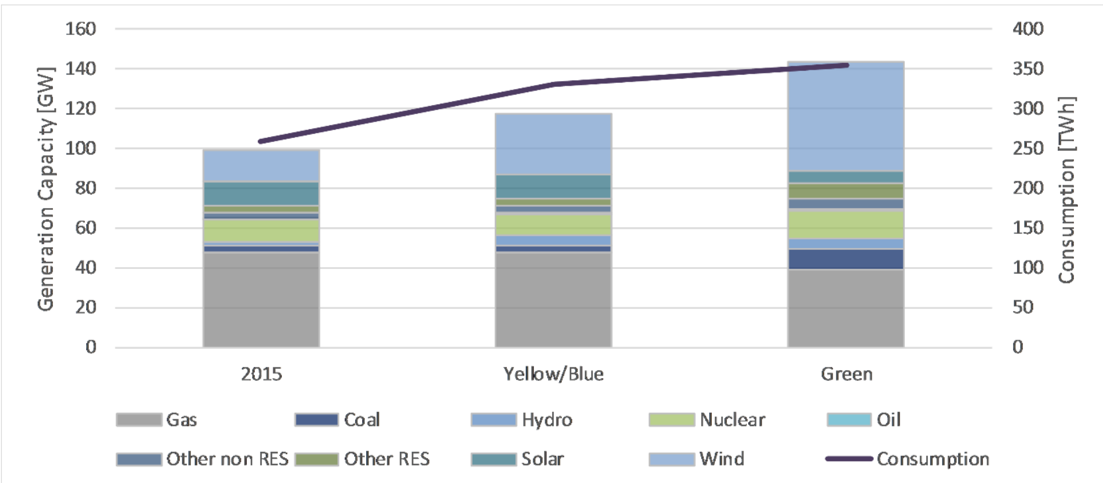

Figure 1. Assumptions on changes in installed capacity. Source: Own compilation based on [60] and [11].

Data relating to wind and PV profiles and capacity factors of different generation technologies were taken from internal data in the IEK-STE (Institute of Energy and Climate Research– Systems Analysis and Technology Evaluation). Information about the net transfer capacity of Great Britain was found in OFGEM (Office of Gas and Electricity Markets) data and ENTSO-E (European Network of Transmission System Operators of Electricity) sources.

As discussed in Section 1, this paper includes a differentiated analysis of a decreased development of the NTCs for the UK. While the already existing NTCs of 4 GW will be held constant, the 7 GW of NTCs planned for the future will be reduced by 50% or 35%, respectively (the capacity evaluation underlying the Green scenario did not allow for a reduction of NTC expansion by 50%. Section 4 will provide further details). Furthermore, the risk of a devaluation of the British Pound resulting from Brexit will be analyzed by introducing a devaluation of the Pound by 10%. This results in four different variations for each scenario, as depicted in Table 1.

Table 1. Scenario variations. Source: Own compilation.

Scenario Variations		**NTC Expansion**	
		As Planned	**Reduced Increase**
Devaluation of Currency	No	Yellow_100_0 Blue_100_0 Green_100_0	Yellow_50_0 Blue_50_0 Green_65_0
	Yes	Yellow_100_10 Blue_100_10 Green_100_10	Yellow_50_10 Blue_50_10 Green_65_10

Table 2 shows the key parameters for the scenarios applied.

Table 2. Key parameters for the scenarios. Source: Own compilation, based on ENTSO-E [11].

Factor	**Yellow**		**Blue**		**Green**	
	Yellow_100_0	**Yellow_65_10**	**Blue_100_0**	**Blue_100_0**	**Green_100_0**	**Green_100_10**
	Yellow_65_0	**Yellow_100_10**	**Blue_65_0**	**Blue_65_0**	**Green_65_0**	**Green_65_10**
Certificate price [Euro/t CO_2]	UK: 30, EU: 30		UK: 90, EU: 30		UK: 90, EU: 90	
Electricity demand UK [TWh]	330		330		355	
Fuel prices:						
Oil [Euro/GJ]:	57.87		57.87		41.73	
Coal [Euro/GJ]	12.53		12.53		7.96	
Gas [Euro/GJ]	37.00	39.54	37.00	39.54	28.48	30.44
Uranium [Euro/GJ]	1.36	1.42	1.36	1.42	1.36	1.42

3.3. System Performance and Evaluation of Modeling Results

MCDA approaches are commonly used for evaluating energy policies, scenarios, and technologies [61–63]. For the evaluation of the presented scenarios, TOPSIS will be applied, which is a variant of MCDA that has been used frequently in energy planning and analysis (see e.g., [64–66]) (in order to provide insights on the robustness of the MCDA results with regard to the chosen MCDA tool, Appendix C offers a system performance analysis using the Preference Ranking Organization Method for Enrichment Evaluation (PROMETHEE) method). MCDA offers a systematic approach to complex decision problems involving multiple perspectives, uncertainty, and competing goals [67]. Firstly, in the system performance assessment, each scenario is evaluated against a set of indicators, and the scores on each indicator are normalized to enable comparability. Secondly, an evaluation matrix (Table 3) is constructed, given the importance attached by each actor to each indicator. The weightings were derived from the judgment of the researchers informed by an understanding of the main issues for stakeholders in the energy sector. The actor-specific utility function results from the sum of actor-specific weightings for the indicators, which are given in Table 3, and the calculation of which is detailed in Equations (10)–(12), multiplied by the scores for each scenario on each indicator. As shown in greater detail in Appendix A, based on this utility function, it is possible to calculate, from the perspective of the particular actor, how far a scenario is from a positive ideal scenario and a negative ideal scenario. The highest scoring scenario (given by Equation (A5) in Appendix A) gives the highest utility for the particular actor, under the assumption that utility rises or falls at a constant level, according to changes in performance of a scenario on a given indicator [68].

Table 3. Relevance of parameters for each actor. Source: Own compilation. LCOE: levelized costs of electricity.

	Criteria Evaluation of Actor:		
Indicator	**Political Decision Makers**	**Electricity Producers**	**Electricity Consumers**
Net imports	3	2	1
Consumer surplus	2	1	3
Avg. wholesale price	1	2	3
LCOE	1	3	2
Avg. price spread	2	3	1
CO_2 emissions	3	1	2
Environmental impacts	2	1	3
Share of dom. production	3	2	1
Producer surplus	2	3	1

The system performance assessment will rely on the following indicators:

(1) Net imports
(2) Consumers' surplus
(3) Average wholesale price
(4) LCOE
(5) Average price spread
(6) CO_2 emissions
(7) Environmental impacts
(8) Share of domestic production
(9) Producers' surplus

TOPSIS evaluates the distance of a given alternative to a hypothetical positive-ideal and negative-ideal alternative [69] (see Appendix A for detailed information on the approach used to evaluate the scenarios). The TOPSIS tool has a wide range of applications [70]. TOPSIS is used in the main article, as it is a well-known technique [70] that is simple and considered more familiar to practitioners than the PROMETHEE method [71]. However, the PROMETHEE method is used in Appendix C to validate the results of the TOPSIS analysis. In the field of energy research, TOPSIS has been used, among other things, to evaluate energy and environmental policy [72], optimal sites for thermal power plants [73], electric vehicle charging stations [74,75], and for rating renewable energy sources [76].

In order to depict the objectives of different actors within the electricity system, we initially attached preferences for each actor in relation to each parameter. Table 3 shows the evaluation matrix, with a ranking of each actor group's interest in the respective MCDA criteria (the values provided in Table 3 are indicative and serve the purpose of illustration. Several studies provide a discussion on deriving such evaluations through applying other tools (e.g., the analytic hierarchy process) for certain stakeholder groups or panels (see e.g., [77–79])). The value 3 indicates highest interest of the stakeholder group in the specific criteria, whereas 1 indicates lowest interest.

From these preferences, five different weighting factors for each parameter and for each actor within the MCDA were derived: (i) 'Equal weights', (ii) 'Political decision makers' objective', (iii) Producers' objective, (iv) Consumers' objective, and (v) Average actors' weights. 'Equal weights' will assign a weighting factor of:

$$w_i = \frac{1}{m} \tag{10}$$

with w_i: the weighting factor for indicator i, and m: the number of indicators to every criterion. Due to the uncertainty of the assigned interests of the respective stakeholders, this weighting provides a benchmark to the other weighting factors.

The weighting approaches 'Political decision makers' objective', 'Producers' objective', and 'Consumers' objective' reflect the individual ranking of each stakeholder group. The weighting factors are calculated by dividing the criteria evaluation i of each actor a, as depicted, by the sum of actor-specific criteria evaluations:

$$w_i^a = \frac{r_i^a}{\sum_{i=1}^m r_i^a} \tag{11}$$

For 'average actors' weights', we sum up the stakeholder-specific weightings and divide the sum by the number of actors:

$$\overline{w}_i = \sum\nolimits_a^k \left(\frac{r_i^a}{\sum_{i=1}^m r_i^a} \right) / k \tag{12}$$

where k: the number of actors.

4. Results and Discussion

4.1. Computation of the Indicators

In 2030, the modeling results show that the volume of production and the relative share of different generation sources vary according to the scenario pursued and its respective variants regarding the NTC development and exchange rates (see Figure 2) (the dimensions "Full NTC" and "Reduced NTC" refer to an NTC expansion as planned, or a reduced NTC development, respectively. "Default" describes a default exchange rate, and "Devaluated" describes a devaluated currency. These abbreviations will be used throughout the text).

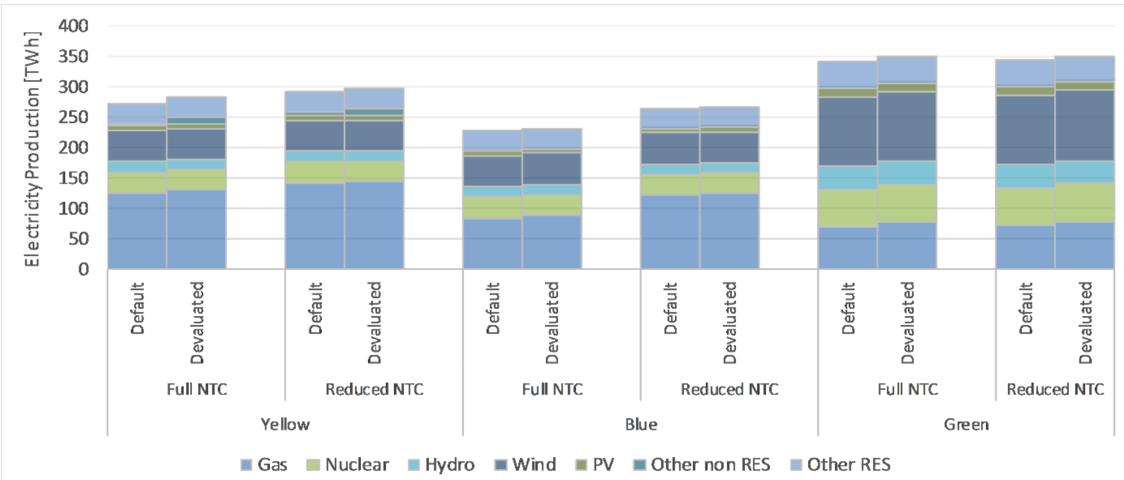

Figure 2. 2030 Power mix across scenarios and variants. Source: Own calculation.

In 2015, net imports of electricity accounted for 5.7% of domestic consumption (own calculation, based on [60] and [80]). For the Yellow scenario, this proportion increases to 15.5% in 2030. Due to the asymmetric financial burden for GB generators in the Blue scenario, net imports rise drastically, reaching 29.7% of domestic electricity consumption in 2030. Within the Green scenario, a general shift in the import–export ratio can be observed: while imports decrease drastically, exports to neighboring markets increase, leading to nearly balanced net imports. In all the scenarios under consideration, Norway plays a major role as an electricity exporter, which stems from its significant hydroelectric park and volume of hydro pump storage. For the Green and Yellow scenarios, it can be observed that there is a general shift in the import structure. In the Yellow scenario, Norway replaces the Netherlands as the second largest exporter to GB. Electricity imports from the Netherlands fall to less than 0.4% of overall imports (compared to just under 38% of all imports in 2017 [14]). In the Green scenario, Norway becomes the largest importer, followed by France; the Netherlands become a net importer of electricity from GB. Figure 3 depicts the changes in the electricity trade structure, with imports displayed on the positive ordinate axis and exports displayed on the negative ordinate axis.

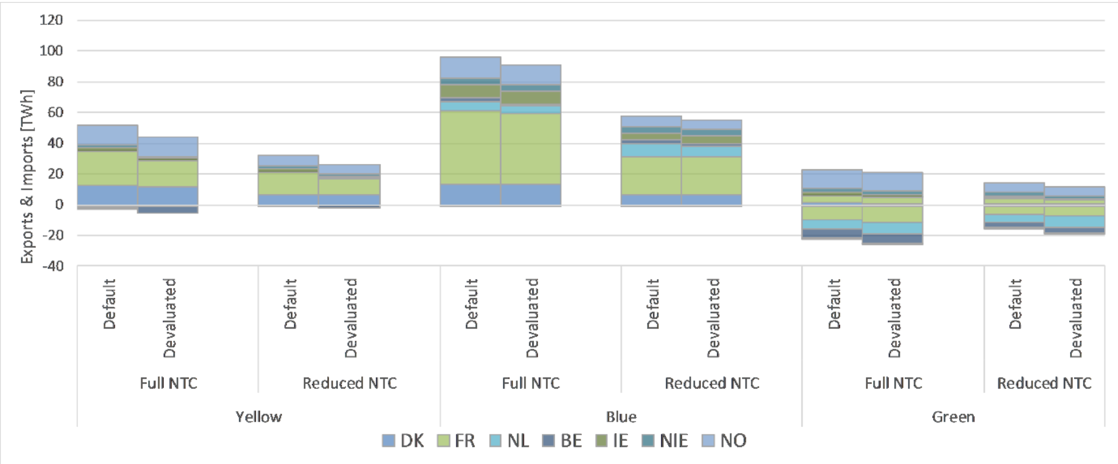

Figure 3. Electricity trade. Source: Own calculation.

In general, for the Blue scenario, a devaluation of the Pound does not significantly affect the overall electricity imports to GB. This is mainly attributable to the CPF, which increases the relative price at which GB (fossil) generators are able to supply electricity. Hence, the further increase in variable costs for fuel acquisition only marginally influences the cost structure. The Yellow scenario shows the strongest sensitivity to a devaluation of the Pound.

Green is only moderately affected by a devaluation of the Pound. Due to the high share of variable renewable energies in the system, imports are primarily used in periods of low wind and solar availability.

Although imports in the Green scenario represent only a fraction of the imports in the Yellow and Blue scenarios, modeling results indicate that electricity transfers represent a more critical role for the Green scenario; imports are characterized by an acute need for power transfers at certain hours in the year in which variable RES are unavailable. Whilst in the Yellow and Blue scenarios, a lower expansion of future NTCs in Great Britain by 50% is possible, for the Green scenario, the maximum feasible reduction is 35%. This indicates that in the Green scenario, in order to provide a sufficient security of supply, the GB electricity system relies on either a strong interconnection with neighboring electricity markets, or a significant deployment of further flexibility options (e.g., gas power plants, electricity storages, demand side management, etc.).

An examination of CO_2 intensity of electricity generation, displayed in Table 4, reveals that the significant reduction in emissions in the Blue scenario, compared to the Yellow scenario, derives partly from the general decrease of domestic electricity production. The reduced expansion of NTCs means resorting to a greater use of older power plants, leading to a rapid increase in CO_2 emissions. Likewise, under the devalued currency, domestic generation, including that from less efficient older plants, increases, leading to greater emissions. Due to the CPF, this effect is stronger in the Blue scenario than in Yellow. In absolute terms, greenhouse gas emissions in the Green scenario are quite stable and show no strong interrelation with changes in NTC or exchange rate volatility.

Table 4. Sensitivity of CO_2 emissions with regard to reduced net transfer capacity (NTC) expansion and depreciation of the Pound. Source: Own calculation.

	Expansion of NTC as Planned		**Reduced Increases in NTC Expansion**	
	Default Exchange Rate	**Devaluated Currency**	**Default Exchange Rate**	**Devaluated Currency**
CO_2 emissions Yellow	44.41 Mt	+14.28%	+15.47%	+27.43%
CO_2 emissions Blue	27.04 Mt	+5.86%	+46.92%	+50.00%
CO_2 emissions Green	23.42 Mt	+12.79%	+4.30%	+15.55%
CO_2 intensity Yellow	163.21 g/kWh	+10.06%	+8.07%	+16.46%
CO_2 intensity Blue	119.30 g/kWh	+3.71%	+25.88%	+27.52%
CO_2 intensity Green	68.42 g/kWh	+10.10%	+3.88%	+12.70%

Table 5 presents the average wholesale prices. Despite the high price of CO_2 certificates, the Green scenario shows the lowest market prices, which is predominantly due to the high share of renewables. Due to the low volume of overall imports, the sensitivity toward changes in the NTC development is marginal. In fact, wholesale prices show a small decrease as a result of reduced NTC growth. Especially in the Blue scenario, a decreased expansion of NTC leads to significant price increases. Due to the additional financial stress for British generators, which is caused by the higher carbon price level, imports represent a considerable share of the electricity supply. This is due to the loss of competitiveness of British fossil fuel generators. Consequently, a decrease in NTC growth necessitates a stronger integration of older, less efficient gas power plants. The high price for CO_2 emissions has a greater effect on those power plants, leading to the higher increase in the average wholesale price. For all the scenarios, the effect of the depreciation of the British Pound on wholesale prices is rather strong, which can be traced back to two main drivers. Overall expenses for fuel purchase for power plants will rise, increasing the marginal costs of fossil and nuclear power plants. Furthermore, imports from neighboring states become relatively more expensive. Due to the relatively costly imports, the utilization rate of older and less efficient gas-fired power plants rises, resulting in higher wholesale prices.

Table 5. Changes in wholesale prices. Source: Own calculation.

	Expansion of NTC as Planned		**Reduced Increases in NTC Expansion**	
Scenario	**Default Exchange Rate**	**Devaluated Currency**	**Default Exchange Rate**	**Devaluated Currency**
Yellow	72.96 [€/MWh]	+6.23%	+2.81%	+8.58%
Blue	88.14 [€/MWh]	+5.35%	+6.27%	+11.34%
Green	67.95 [€/MWh]	+6.03%	−0.22%	+5.38%

As shown in Figure 4, the Blue and Yellow scenarios show decreasing consumer surpluses under the reduced development of NTCs. The high share of RES in the Green scenario exerts downward pressure on the wholesale prices, and as a result leads to a slight increase in consumer surplus. Whilst rents show no significant sensitivity toward a reduced NTC development in the Green scenario, the Blue scenario is strongly affected by a reduced NTC growth. Due to the interrelation of a drop in the exchange rate and wholesale prices as described above, a depreciation of the Pound leads to a significant decrease in consumer surplus for all the scenarios.

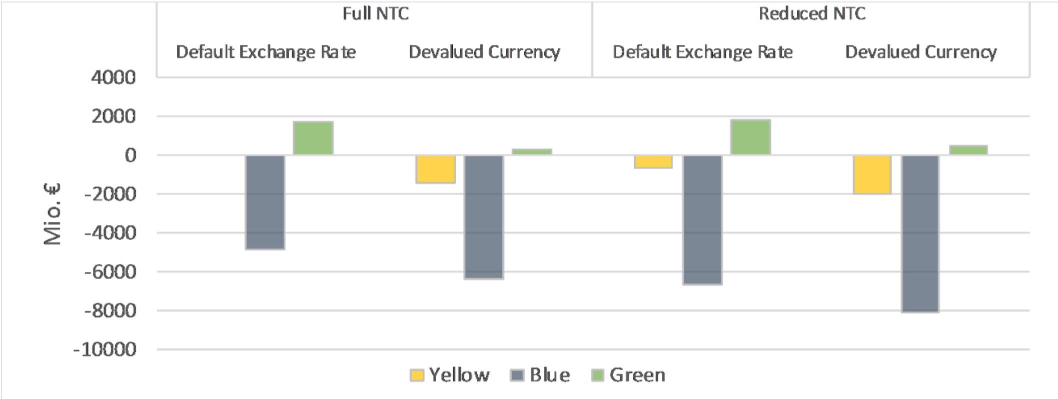

Figure 4. Changes in consumer surplus in comparison to the Yellow scenario. Source: Own calculation.

Assuming preferences as presented in Table 3, consumers will prefer electricity systems with a low environmental impact. The most notable emissions resulting from electricity generation include: sulfur dioxide (SO_2), ammonia (NH_3), and nitrogen oxides (NO_X). Compound indicators also highlight environmental or climatic damage, such as global warming potential (GWP), eutrophication (EP), and acidification potential (AP). Figure 5 shows the emissions of electricity generation in the UK in comparison to the Yellow scenario, with no reduction of net transfer capacities (indexed Yellow = 100%).

Figure 5. Environmental impacts from electricity generation in comparison to Yellow_100_0. Source: Own calculation.

In the case of no reduction in the NTC development, the Blue scenario shows the strongest reduction in emissions. However, this has to be considered in the light of the overall electricity generation structure in the Blue scenario, with a significant amount of the reduced environmental impact stemming from the overall reduction in electricity generation (see Section 4.1). This can be observed in the sharp increase between Blue_100_0 and Blue_50_0. Since the electricity generation structure for the Green scenario is relatively rigid (variable RES and nuclear power plants are at the lower end of the merit order, and operate nearly on their maximum utilization rate), emissions hardly change in the case of reduced NTC growth. While the Green scenario shows a significant drop in GWP, other emissions do not drop drastically. In order to adjust the emission data to the framework of this study, the emissions presented in Figure 5 will be condensed to a single indicator 'environmental impact' by applying TOPSIS with equal weights for the depicted impacts. This will allow for the subsequent evaluation of the scenario ranking in Section 4.2.

The average price spread gives an estimation of the difference between GB's and the connected electricity markets' wholesale prices, and indirectly, of the producers' opportunities to sell electricity to foreign markets. As discussed in Section 2.1, a higher level of interconnectivity should in general lead to a smaller divergence in prices. Indeed, observing the interaction between the average price spread of GB and the connected markets of Norway, Denmark, France, Belgium, the Netherlands, and Northern Ireland, this assumption holds for the Yellow and Blue scenarios (see Table 6).

Table 6. Average price spread in € per MWh. Source: Own calculation.

	Expansion of NTC as Planned		**Reduced Increases in NTC Expansion**	
	Default Exchange Rate	**Devaluated Currency**	**Default Exchange Rate**	**Devaluated Currency**
Yellow	13.94	13.04	16.58	15.31
Blue	28.08	26.97	34.65	33.29
Green	7.14	5.61	6.94	5.07

Prima facie, examining the changes of the price spread in the Green scenarios shows a counter-intuitive structure: a reduced expansion of NTC reduces the price spread between GB and the connected neighboring electricity markets. There are two effects that lead to this development. As discussed in the analysis of wholesale prices, Green_65_0 actually shows a decrease in wholesale prices in comparison to Green_100_0. Simultaneously, other markets in Europe show an increase in wholesale prices in case of a lower NTC development. The model results suggest that this stems from GB's function as the 'intermediary' between Norway and the markets in France, Belgium, and the Netherlands. As a result, the price spread between GB and the connected markets in continental Europe decrease in the Green scenario, in the case of a reduction in the growth of NTC.

Despite the higher import ratio of the Blue scenarios, producers' surpluses are significantly higher than in the Yellow scenarios (see Figure 6), and even more so at a devalued exchange rate (as depicted by the black bars).

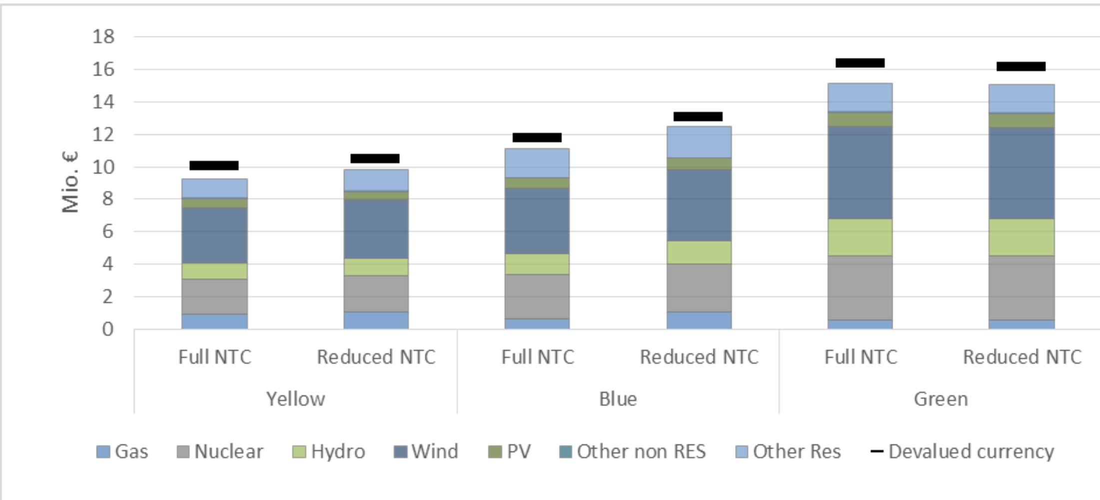

Figure 6. Interrelation of producer surplus and exchange rate volatility. Source: Own calculation.

In the Blue scenario, higher wholesale prices allow for increasing profit opportunities for low carbon generation technologies in particular. As a result, low carbon options, such as nuclear power plants, or wind farms show a significant increase in producer surpluses. On the other hand, the Green scenario reveals the highest level of producer surpluses. It should be noted that the Green scenario shows the highest level of consumer surpluses. Again, especially low-carbon generation technologies account for the major share of overall surpluses, while fossil fuel power plants do not create meaningful surpluses.

Figure 7 shows the average LCOE of the British electricity system, with the black bars indicating increases due to an additional devaluation of the exchange rate. The Yellow scenario shows the lowest LCOE for the scenarios under consideration and a moderate sensitivity toward changes in the NTCs.

In the case of no reduction of the NTCs, the implementation of a high CO_2 price in the Blue scenario leads to an increase of 9.6% in the average LCOE in comparison to the Yellow scenario. However, the LCOE in the Blue scenario drastically increases in the case of a reduced development of transfer capacities. As discussed in the previous section, the CPF shifts electricity production to neighboring countries. Whilst the increase of LCOE in the Blue scenario is almost exclusively driven by higher variable costs for CO_2 emissions, for the Green scenario, several drivers can be determined. First of all, the increase in LCOE stems partly from the higher overnight costs for RES. However, the higher LCOE in the Green scenario in comparison to the Yellow scenario cannot be explained by higher investment costs for RES capacities alone. There are two other drivers that show increasing effects. As in the Blue scenario, a high price for CO_2 certificates drives up variable generation costs. However, since the overall electricity system in the Green scenario is less CO_2 intensive, this effect is not as strong as in the Blue scenario. The merit order effect reduces the full load hours of gas-fired power plants. As a result, the digression of fixed costs (overnight investment and operation and maintenance (O&M) costs) for generation units drops, which increases the average LCOE.

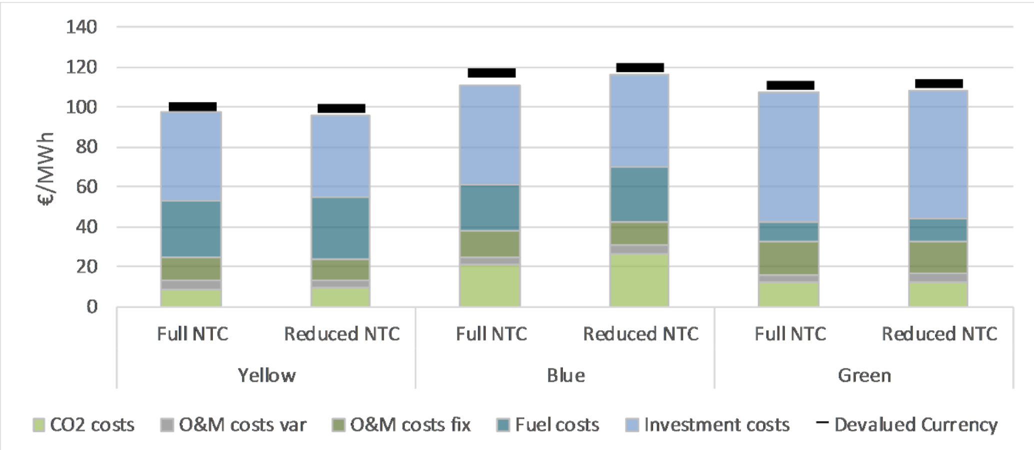

Figure 7. Average levelized costs of electricity generation. Source: Own calculation.

Within all the scenarios under consideration, a depreciation of the British Pound does not significantly impact the LCOE. Although domestic electricity production is stimulated by the depreciation of the British Pound and the average utilization rate of gas-fired power plants increases, the higher digression of fixed costs, driven by more full load hours, does not offset the higher costs for fuel supply and imported power plant components.

4.2. MCDA

This section will combine the results presented in the previous chapter and jointly evaluate them using the MCDA tool described in Section 3.1, with the indicators and their results listed in Table 7.

The weighting factors expressed by Equations (11)–(13) that were used for the MCDA analysis are shown in Table 8. Applying those factors, the TOPSIS method arrives at the rankings presented in Table 8.

Table 7. Compilation of multi-criteria decision analysis (MCDA) parameters. Source: own compilation.

	Expansion of NTC as Planned						Reduced Increases in NTC Expansion					
	Default Exchange Rate			Devaluated Currency			Default Exchange Rate			Devaluated Currency		
	Yellow	Blue	Green	Yellow	Blue	Green	Yellow	Blue	Green	Yellow	Blue	Green
Net Imports [TWh]	49.91	95.43	0.76	39.18	90.33	−4.72	30.99	57.19	−0.61	23.98	55.11	−6.87
Con. Surplus [Mio. €]	0.00	−4883.83	1730.28	−1463.04	−6400.05	312.17	−659.13	−6662.97	1780.89	−2014.77	−8099.56	465.22
Avg. wholesale price [€/MWh]	72.96	88.14	67.95	77.50	92.85	72.05	75.00	93.67	67.81	79.22	98.13	71.61
LCOE [€/MWh]	97.10	111.25	107.32	99.51	116.22	110.75	96.11	115.83	108.49	98.74	119.51	111.27
Avg. price spread [€/MWh]	13.94	28.08	7.14	13.05	26.97	5.61	16.58	34.65	6.94	15.31	33.29	5.07
CO_2 [Mio t]	44.41	27.04	23.42	50.75	28.63	26.42	51.28	39.73	24.43	56.59	40.56	27.06
Environmental impact [-]	0.53	1.00	0.44	0.31	0.95	0.37	0.37	0.66	0.44	0.22	0.65	0.37
Share of dom. Production [%]	0.85	0.70	0.99	0.88	0.72	1.01	0.90	0.82	0.99	0.93	0.83	1.01
Prod surplus [Mio. €]	9.27	11.13	15.17	10.01	11.77	16.35	9.81	12.52	15.10	10.47	13.05	16.18

Table 8. Sets for different weighting factors. Source: Own compilation.

Weighting Method Indicator	Equal Weights	Political Decision Makers' Objective	Producers' Objective	Consumers' Objective	Average Actors' Weight
Net imports	0.111	0.158	0.111	0.059	0.109
Consumers' surplus	0.111	0.105	0.056	0.176	0.112
Avg. wholesale price	0.111	0.053	0.111	0.176	0.113
LCOE	0.111	0.053	0.167	0.118	0.112
Avg. price spread	0.111	0.105	0.167	0.059	0.110
CO_2 emissions	0.111	0.158	0.056	0.118	0.110
Environmental impact	0.111	0.105	0.056	0.176	0.112
Share of dom. production	0.111	0.158	0.111	0.059	0.109
Producers' surplus	0.111	0.105	0.167	0.059	0.110

Table 9 shows the results of the TOPSIS analysis, with the colors corresponding to the scenarios as explained in the Color Key. They show a clear pattern with regard to the ranking of the three main scenarios. While the Green scenarios prevail for all the weighting approaches, the Blue scenarios rank last. However, the layout of this paper does not allow for a comprehensive comparison of the three scenario groups—Yellow, Blue and Green. In particular, the fact that the Green sub-scenarios only allow a 35% reduction in NTC expansion makes a ranking between the other scenarios with a reduction in expanded capacity of 50% less meaningful (however, even with a reduction of 35% of NTC expansion in all the scenarios, the pattern presented in Table 9 does not change significantly. Appendix B presents further information). Therefore, the conclusions provided in this section will focus more strongly on the patterns within the respective scenario groups.

The results reveal that the impact of a reduction in interconnectivity is nuanced in that it (i) depends on the transition scenario that the UK pursues, and (ii) is different for each stakeholder.

A reduced interconnectivity of the GB electricity market does not necessarily negatively impact the observed stakeholder groups; in the Green scenario, there can be advantages from reduced interconnection, with a positive effect on the overall evaluation (i.e., 'Equal' and 'Average actors' weight'). In case of a development of the electricity market in accordance with the Green scenario, producers do not necessarily prefer a full development of future NTC projects, but possible advantages from a devaluation of the Pound, do not offset their negative impacts, as both Green variants featuring devaluation rank last within their respective groups. In contrast, from the perspective of consumers, a full development of NTC and no devaluation constitutes the best option in all three scenario groups. Between the variants of the Green scenario with no devaluation and those with a devalued Pound, there is a considerable drop in the scenario valuation. This can be mostly explained by the reduction in consumers' surpluses that occur due to a devaluation of the Pound. Thus, from a consumer perspective, a devaluation of the Pound leads to a more severe decrease in the overall valuation than a reduction in the NTC development. However, under the Green scenario, reduced growth in NTC capacity leads to risks to the stability of the system, since although imports are lower overall, there are times of the year in which imports are more acutely important to meeting demand. This is why the power system is no longer viable in the Green scenarios when NTCs fall below 65% of their potential level. In the Green scenario, opportunities for lower overall reliance on imports (although there are points of time at which imports have greater importance than in the other scenarios) and opportunities for exports must be contrasted with this greater risk to the stability of the system resulting from reduced growth in NTCs.

Table 9. TOPSIS analysis of modeling results. Source: Own calculation.

Rank	Equal	Avg. Actors Weight	Actors' Perspective: Political Decision Makers	Actors' Perspective: PRODUCERS	Actors' Perspective: Consumers
1	0.785	0.783	0.811	0.850	0.738
2	0.784	0.782	0.811	0.850	0.735
3	0.752	0.750	0.789	0.846	0.679
4	0.748	0.745	0.785	0.843	0.673
5	0.596	0.599	0.573	0.593	0.666
6	0.581	0.581	0.552	0.582	0.590
7	0.540	0.540	0.543	0.580	0.531
8	0.530	0.528	0.527	0.562	0.483
9	0.376	0.379	0.344	0.266	0.468
10	0.337	0.339	0.322	0.262	0.390
11	0.294	0.293	0.318	0.260	0.285
12	0.272	0.270	0.309	0.258	0.237

Color Key:

Scenario	Expansion of NTC as planned		Reduced increases in NTC	
	Default	Devaluated	Default	Devaluated
Yellow				
Blue				
Green				

In the case of the Yellow scenario, Table 9 reveals that all the weightings with the exception of 'Actors' Perspective: Producers' and 'Actors' Perspective: Political Decision Makers' evaluate an environment with full NTC development and no devaluation of the Pound as the most favorable option. The producer-oriented weighting shows that from a generator's viewpoint, a development with reduced NTC expansion and devaluation would be preferred. A similar picture emerges when assessing the Blue scenario. However, in contrast to the Yellow scenario, the lower expansion in NTC has a stronger effect on the evaluation of the Blue scenario. As a result, the Blue scenarios with reduced NTC development rank last among those scenario variants, with the exception of the producers' viewpoint. The risks in the Blue and Yellow scenarios relate to loss of export opportunities for the producers, loss of electricity market competitiveness for the consumers, and loss of energy independence opportunities, from the point of view of political decision makers. Reflecting on the rationale behind interconnectors, Section 2.1 discussed their role in enhancing the competitiveness of electricity markets and in improving the stability within connected markets. It would appear that in the Green scenario, this role of ensuring stability is much more important, whereas for the Yellow and Blue scenarios, the contribution of interconnectors is chiefly to ensure price convergence between less competitive electricity markets (the GB market) and more competitive markets (EU markets).

5. Conclusions

By introducing the consideration of stakeholders' viewpoints to the assessment of quantified power system scenarios with an MCDA tool, this paper provides a differentiated analysis of the effects of Brexit on the GB power system. The applied methodology facilitates a versatile scenario analysis that takes into consideration the diversity of interests of the affected groups.

The analysis presented shows that Brexit is not inherently negative for the GB electricity market. At the same time, the results show that the effectiveness of future policy measures aiming at the attenuation of possible negative impacts strongly depend on the design of the power system. In the Green scenario, implications of Brexit could bring about positive developments for the GB power system, but the results indicate that the market is in need of additional flexibility options in case of a reduced NTC development. If the electricity system moves more strongly toward an energy landscape resembling the Yellow scenario, focus on currency stability could be more important than a strong drive toward further interconnection. On the other hand, the MCDA outputs show that conflicts of interest between the considered stakeholder groups may arise. This becomes especially apparent for producers' and consumers' interests in the Yellow scenario, where the ranking of the scenario variants diverges substantially.

In the Blue scenario, given that the higher carbon price (e.g., due to the CPF) leads to a considerable increase in costs, a tradeoff between environmental protection and consumer welfare emerges. In the longer term, in the Blue and Yellow scenarios, the UK may have to decide if it should build greater domestic power capacities to compensate for a reduced ability to import more competitively priced power. The impact of Brexit on the sustainability of the GB and EU power systems remains unclear. There is debate in Section 2.1 on the influence of interconnection on overall CO_2 emissions and, principally, the carbon leakage effect. In the Blue scenario, the domestic environmental impact of GB's power system is reduced the most, but this is due to the fall in domestic generation, so the emissions are likely to be produced elsewhere.

This work focuses on the implications of Brexit on the electricity market with consideration of different stakeholders' viewpoints. However, it excludes the extensive interactions of the economy-wide effects of Brexit with the power system. While econometric assessments already addressed issues concerning Brexit (see e.g., Raddant [81]), to the authors' knowledge, there exists no contributions that carry out a coupled approach of econometric modeling frameworks with a power system model. As a starting point for new research activities, this link could provide new valuable insights into the topic.

Further research avenues may include analyzing the implications of different forms of Brexit on the power system—i.e., comparing the impacts on the power system of a Brexit in which the UK retains a closer relationship with the EU compared to a Brexit in which the UK's relationship with the EU is more distant. The nature of possible advantages for the power system, which Brexit may entail, as referred to in Section 2.2, contrasted with potential wider challenges, such as the effects of changes in access to EU energy research and EU finance, also warrant further investigation. Pollitt [5] and Dutton and Lockwood [40] argued that Brexit might deliver attractive opportunities, which is to some degree congruent with the analysis presented in this work. Nevertheless, a higher level of autonomy in designing environmental and energy policy does not necessarily mean that British policies can be regarded as fully independent from European energy policy. This is exemplified by the Blue scenario: a CPF that strongly diverges from ETS prices may lead to asymmetric market conditions by preventing a level playing field for generators.

Author Contributions: This research article is a combined effort of TU Bergakademie Freiberg and Forschungszentrum Jülich. The contributions of the respective authors can be categorized as follows: Conceptualization and an initial literature review was done by C.B. and P.M. Together, they designed the original draft of the paper. A more extensive review and assessment of literature was conducted by C.B. The methodology can be separated into two parts. The modeling approach relies on the contributions of S.V. and P.M., while the resources for the modeling approach were provided by S.V. The MCDA results were computed by Ball and Mayer. The visualizations were processed by C.B. and P.M. The project was supervised by W.K. and D.R. Writing the article was a joint effort of all contributing authors. The final remarks and editing of W.K., D.R. and S.V. were used to finalize the article.

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Conflicts of Interest: The authors declare no conflict of interest.

Appendix A. TOPSIS Method

The approach follows the procedure presented by [69]. TOPSIS evaluates the MCDA alternative with regard to their distance to a positive-ideal and negative-ideal alternative. In order to do so, each performance indicator $d_{i,j}$ of all n criteria C_j with $j = 1, \ldots, n$ has to be transformed into a decision matrix M for each k alternative S_i, where $i = 1, \ldots, k$.

$$C_1 \;\; C_2 \;\ldots\; C_{j\ldots} \; C_n \tag{A1}$$

Due to the heterogeneity of the computed MCDA criteria, the matrix is normalized with:

$$p_{i,j} = \frac{d_{i,j}}{\sqrt{\sum_{i=1}^{k} d_{i,j}^2}} \qquad \forall\, d_{i,j} \neq 0,\ \forall\, j = 1, \ldots, n, \text{ and } \forall\, i = 1, \ldots, k \tag{A2}$$

or

$$p_{i,j} = 0 \qquad \forall\, d_{i,j} = 0,\ \forall\, j = 1, \ldots, n \text{ and } \forall\, i = 1, \ldots, k \tag{A3}$$

The normalized criteria are weighted with the factors described with Equations (10)–(12). This results in the normalized and weighted Matrix $\overline{M}$:

$$C_1 \;\; C_2 \;\ldots\; C_{j\ldots} \; C_n \qquad \overline{M} = \begin{array}{c} S_1 \\ S_2 \\ \cdots \\ S_i \\ \cdots \\ S_k \end{array} \begin{bmatrix} w_1p_{11} & w_2p_{12} & \cdots & w_jp_{1j} & \cdots & w_np_{1n} \\ w_1p_{21} & w_2p_{22} & \cdots & & \cdots & \\ \cdots & \cdots & & & & \\ w_1p_{i1} & w_2p_{i2} & \cdots & w_jp_{ij} & \cdots & w_np_{in} \\ \cdots & \cdots & & & & \\ w_1p_{k1} & w_2p_{k2} & \cdots & w_3p_{kj} & \cdots & w_np_{kn} \end{bmatrix} \tag{A4}$$

Table A1 shows the compilation of MCDA criteria after normalization.

Table A1. Normalized MCDA criteria. Source: own calculation.

Criteria/Scenario	Net Imports	Con. Rent	Avg. Wholesale Price	LCOE	Weightend Price Spread	CO_2 [Mio t]	GWP [Mio t]	Share of Dom. Production	Prod Surplus
Yellow_100_0	0.292	0.000	0.262	0.260	0.200	0.334	0.264	0.274	0.209
Blue_100_0	0.558	−0.356	0.316	0.297	0.403	0.203	0.501	0.228	0.251
Green_100_0	0.004	0.126	0.244	0.287	0.103	0.176	0.223	0.320	0.342
Yellow_100_10	0.229	−0.107	0.278	0.266	0.187	0.381	0.153	0.284	0.226
Blue_100_10	0.529	−0.467	0.333	0.311	0.387	0.215	0.477	0.233	0.265
Green_100_10	−0.028	0.023	0.259	0.296	0.081	0.198	0.186	0.328	0.369
Yellow_50_0	0.181	−0.048	0.269	0.257	0.238	0.385	0.187	0.292	0.221
Blue_50_0	0.335	−0.486	0.336	0.310	0.497	0.298	0.332	0.266	0.282
Green_65_0	−0.004	0.130	0.243	0.290	0.100	0.183	0.218	0.321	0.340
Yellow_50_10	0.140	−0.147	0.284	0.264	0.220	0.425	0.113	0.299	0.236
Blue_50_10	0.322	−0.591	0.352	0.320	0.478	0.305	0.324	0.268	0.294
Green_65_10	−0.040	0.034	0.257	0.298	0.073	0.203	0.185	0.328	0.365

Each scenario is evaluated with regard to a distance dimension A:

$$A_i = \frac{D_i^-}{D_i^- + D_i^+} \tag{A5}$$

where D describes the Euclidian distance toward both alternatives, with:

$$D_i^+ = \sqrt{\sum_{j=1}^{n} \left(w_ip_{ij} - w_ip_j^+\right)^2} \qquad \forall\, i = 1, \ldots, k \text{ and } \forall\, j = 1, \ldots, n \tag{A6}$$

$$D_i^- = \sqrt{\sum_{j=1}^{n} \left(w_i p_{ij} - w_i p_j^- \right)^2} \qquad \forall\, i = 1, \ldots, k \text{ and } \forall\, j = 1, \ldots, n \tag{A7}$$

where

- D_i^+: Euclidian distance to positive-ideal alternative
- D_i^-: Euclidian distance to negative-ideal alternative
- p^-: negative ideal reference point
- p^+: positive-ideal reference point

Table A2 presents the positive-ideal and negative ideal alternatives toward which the Euclidian distance of the scenarios under consideration is calculated.

Table A2. Positive-ideal and negative-ideal alternatives. Source: Own compilation.

	Net Imports	Con. Rent	Avg. Wholesale Price	LCOE	Weightend Price Spread	CO_2 [Mio t]	GWP [Mio t]	Share of Dom. Production	Prod Surplus
Positive Ideal	−0.002	0.023	0.043	0.030	0.004	0.021	0.088	0.019	0.022
Negative Ideal	0.033	−0.104	0.062	0.038	0.029	0.050	0.020	0.013	0.012

The Euclidian distance of the scenarios under consideration of the positive-ideal and negative-ideal solutions are presented in Figure A1:

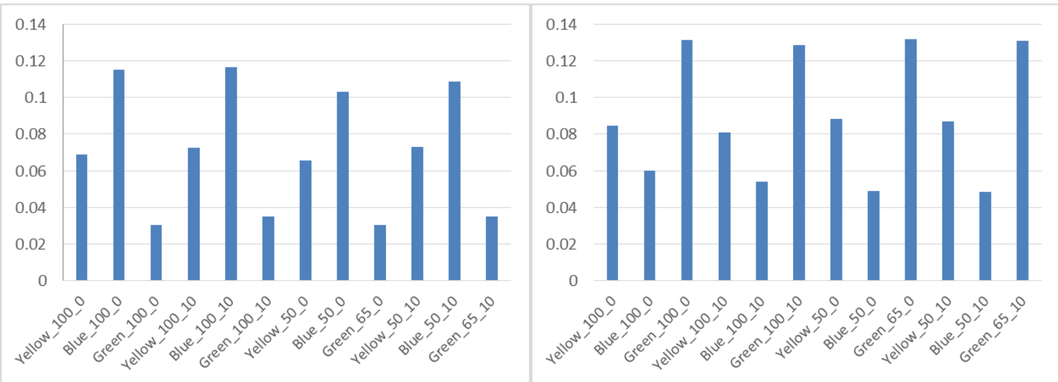

Figure A1. Euclidian distance of scenarios and their variants to positive-ideal (**left**) and negative-ideal (**right**) alternatives. Source: Own compilation.

Appendix B. Robustness of Results toward the NTC Development Assumptions

In order to provide insights on the robustness of the presented data and results, calculations were applied, with harmonized reductions of the future NTC expansions across all the scenarios and their variants. Table A3 shows the TOPSIS results for an extension of interconnectors reduced by 35%, with the colors corresponding to the scenarios as explained in the Color Key.

With respect to the sequence of Yellow, Blue, and Green, no change can be observed compared to a mixed reduction of the NTC expansion (Yellow and Blue scenarios by 50% and Green scenario by 35%), as presented in Table 9. In addition, the ranking of the respective variants across the different weighting factors do not show significant differences. The only exception is 'Actors' three scenarios shows a divergent pattern. However, this does not contradict the general conclusions presented in Sections 4 and 5.

Table A3. TOPSIS analysis of modeling results with 35% reduction of NTC expansion. Source: Own compilation.

Rank	Equal	Avg. Actors Weight	Actors Perspective: Political Decision Maker	Actors Perspective: Producers	Actors Perspective: Consumers
1	0.854	0.853	0.871	0.881	0.829
2	0.832	0.830	0.853	0.873	0.800
3	0.804	0.802	0.834	0.867	0.745
4	0.789	0.787	0.821	0.865	0.727
5	0.600	0.603	0.580	0.580	0.690
6	0.599	0.600	0.553	0.570	0.629
7	0.525	0.525	0.533	0.556	0.519
8	0.522	0.521	0.513	0.542	0.487
9	0.354	0.357	0.329	0.239	0.435
10	0.322	0.324	0.312	0.231	0.371
11	0.306	0.307	0.308	0.230	0.336
12	0.279	0.279	0.296	0.230	0.282

Colour key:

Scenario	Expansion of NTC as planned: Default	Expansion of NTC as planned: Devalued	Reduced increases in NTC: Default	Reduced increases in NTC: Devalued
Yellow				
Blue				
Green				

Appendix C. Robustness of Results in Comparison to the PROMETHEE Method

An alternative MCDA technique—the PROMETHEE method—is used to gain an impression of the sensitivity of the results from the TOPSIS method to the use of other decision analysis techniques. The PROMETHEE method (Preference Ranking Organization Method for Enrichment Evaluation) is based on outranking flows associated with a particular alternative (in this case, the different scenarios for the GB power system in 2030). The PROMETHEE method is a set of procedures that was developed in the 1980s by Brans, et al. [82] and Behzadia, et al. The authors of [83] conduct a review of different methodologies and applications of the PROMETHEE method.

Outranking flows are calculated from preference functions that evaluate the pairwise difference between the performance scores of scenarios on each criterion. These performance scores are then multiplied by the respective actor-specific weighting for each criterion. The following equation, which was adapted from Mareschal [84], gives the outranking relation:

$$\pi\ (S_a, S_b)\ =\ \sum\nolimits_{K=1}^{n} W_k \times P_k \tag{A8}$$

The outranking relation $\pi\ (S_a, S_b)$ assesses, for all the criteria (K), the extent to which scenario a (S_a) is outranked by scenario b (S_b), and corresponds to the sum of all the preference functions (P_k) (pairwise differences between scenarios in performance scores on the respective criteria) multiplied by the actor-specific weightings for those criteria (W_k).

Following the computation of the outranking relations, it is then possible to build the positive outranking flow and the negative outranking flow for each scenario. The positive outranking flow for scenario a, ($\varphi^+(a)$) consists of the instances in which scenario a performed better than another scenario overall (once all the criteria were considered), and the sum of the magnitude of those superior performances. Conversely, the negative outranking flow for scenario a, ($\varphi^-(a)$) consists of instances in which scenario a performed worse than another scenario overall (once all the criteria were considered) and the sum of the magnitude of those inferior performances. The positive and negative outranking flows, as reproduced from Brans and Mareschal [85], are depicted below:

Positive outranking flow (scenario a outperforming other scenarios):

$$\varphi^{+}(a) = \frac{1}{n-1}\sum \pi(a,x) \tag{A9}$$

Negative outranking flow (scenario a outperformed by other scenarios):

$$\varphi^{-}(a) = \frac{1}{n-1}\sum \pi(x,a) \tag{A10}$$

The net preference flow is computed from the positive outranking flow minus the negative outranking flow (($\varphi^{+}(a) - \varphi^{-}(a)$) [86]; the higher the net preference flow, the better the scenario, from the perspective of any particular actor.

This process was followed for the three weighting factors representing the stakeholders' perspectives, namely: (i) political decision makers, (ii) producers, and (iii) consumers, and the results are depicted in Table A4 below:

Table A4. Outranking flow results.

Outranking Flows (Political Decision Makers)				
	Positive Flow	**Negative Flow**	**Net Flow**	**Ranking (PDM)**
Yellow_100_0	0.048785448	−0.016063755	0.032721694	6
Blue_100_0	0.017168488	−0.07563523	−0.058466742	9
Green 100_0	0.073878944	−0.004282498	0.069596446	2
Yellow_100_10	0.044142223	−0.02168776	0.022454463	8
Blue_100_10	0.015248548	−0.081395048	−0.0661465	10
Green_100_10	0.120986423	0	0.120986423	1
Yellow_50_0	0.051555197	−0.014085363	0.037469834	5
Blue_50_0	0.000869473	−0.153290427	−0.152420955	11
Green_65_0	0.073089011	−0.004440485	0.068648526	3
Yellow_50_10	0.046594172	−0.018255031	0.028339142	7
Blue_50_10	0	−0.162854625	−0.162854625	12
Green_65_10	0.066356837	−0.006684543	0.059672294	4
Outranking Flows (Producers)				
	Positive Flow	**Negative Flow**	**Net Flow**	**Ranking**
Yellow_100_0	0.027006509	−0.0179437	0.00906281	7
Blue_100_0	0.004934607	−0.061701775	−0.05676717	9
Green 100_0	0.059216051	−0.001440161	0.05777589	3
Yellow_100_10	0.026363627	−0.018843734	0.00751989	8
Blue_100_10	0.004395798	−0.063318201	−0.0589224	10
Green_100_10	0.073953543	0	0.07395354	1
Yellow_50_0	0.028262983	−0.016910624	0.01135236	5
Blue_50_0	0.000240301	−0.084095685	−0.08385538	11
Green_65_0	0.059179629	−0.001452301	0.05772733	4
Yellow_50_10	0.027481087	−0.017469121	0.01001197	6
Blue_50_10	0	−0.086738998	−0.086739	12
Green_65_10	0.06013628	−0.001256115	0.05888017	2
Outranking Flows (Consumers)				
	Positive Flow	**Negative Flow**	**Net Flow**	**Ranking**
Yellow_100_0	0.05790375	−0.00389236	0.05401139	4
Blue_100_0	0.02450183	−0.03914444	−0.0146426	9
Green 100_0	0.0659491	−0.00139136	0.06455773	2
Yellow_100_10	0.03524032	−0.02046861	0.01477171	7
Blue_100_10	0.01785543	−0.05908365	−0.04122822	10
Green_100_10	0.0812541	0	0.0812541	1
Yellow_50_0	0.04564837	−0.01006055	0.03558782	6
Blue_50_0	0.0020616	−0.1380528	−0.1359912	11
Green_65_0	0.0645932	−0.00166254	0.06293066	3
Yellow_50_10	0.03057175	−0.02700461	0.00356713	8
Blue_50_10	0	−0.16073039	−0.16073039	12
Green_65_10	0.04583739	−0.00992554	0.03591186	5

In Figure A2, the scenario rankings for the different actors, resulting from the PROMETHEE process, are depicted.

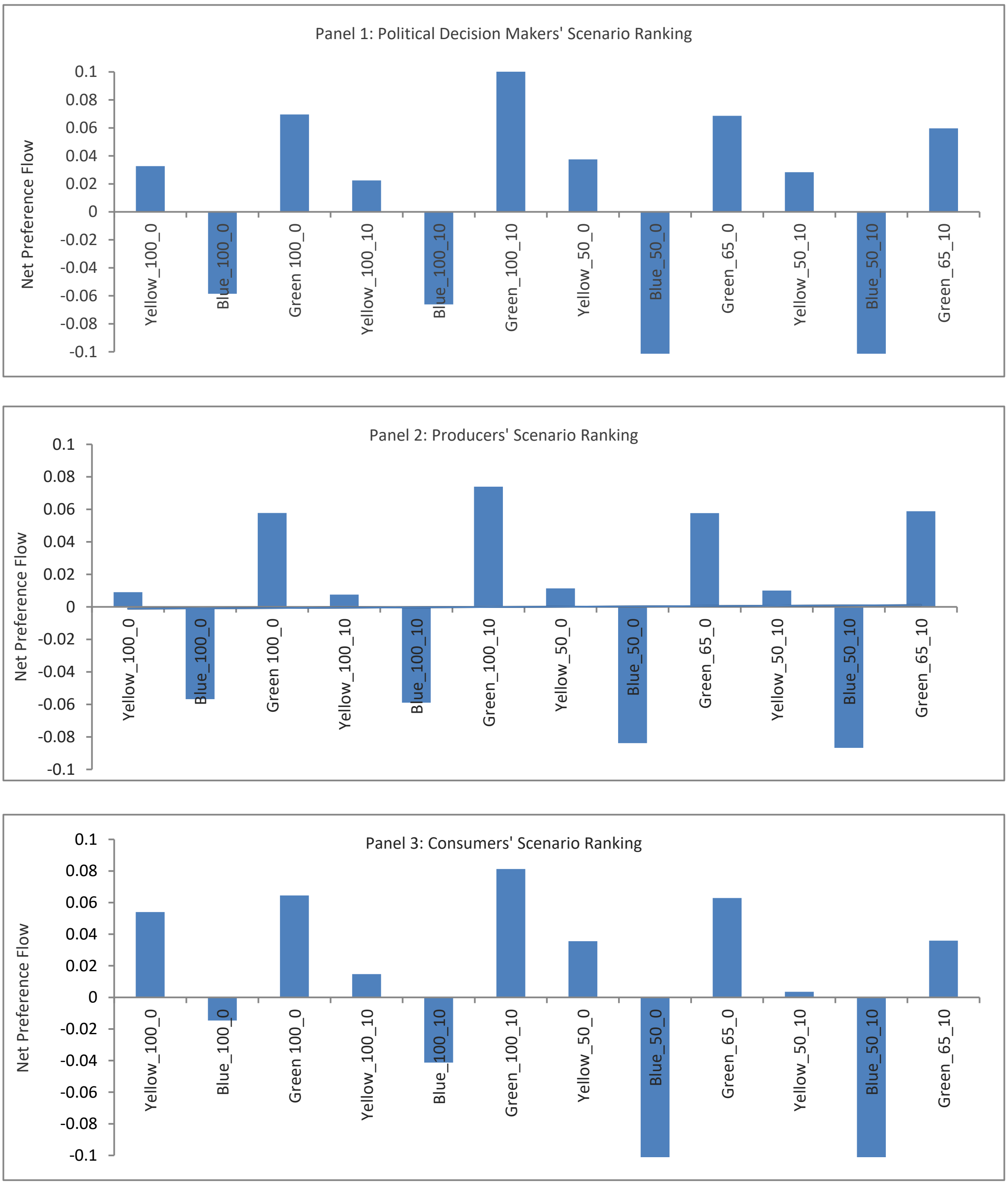

Figure A2. Scenario ranking for: (**i**) political decision makers (Panel 1), (**ii**) producers (Panel 2) and (**iii**) consumers (Panel 3).

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