Energy Economics 64 (2017) 131–148

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneeco

Coordination and uncertainty in strategic network investment: Case on the North Seas Grid

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ARTICLE INFO

Article history:
Received 16 February 2016
Received in revised form 13 March 2017
Accepted 20 March 2017
Available online 29 March 2017

JEL classification:
C61
E61
F42
O13
O18
O21

Keywords:
Onshore and offshore transmission investment
Cross-border interconnection
Offshore coordination
Min–max regret planning
Net benefit allocation

ABSTRACT

The notion of developing a transnational offshore grid in the North Sea has attracted considerable attention in the past years due to its potential for substantial capital savings and increased scope for cross-border trade, sparking a European-wide policy debate on incentivizing integrated transmission solutions. However, one important aspect that has so far received limited attention is that benefits will largely depend on the eventual deployment pattern of electricity infrastructure which is currently characterized by severe locational, sizing and timing uncertainty. Given the lack of coordination between generation and network developments across Europe, there is a real risk for over-investment or a premature lock-in to options that exhibit limited adaptability. In the near future, important choices that have to be made concerning the network topology and amount of investment. In this paper we identify the optimal, in terms of reduced cost, network investment (including topology) in the North Seas countries under four deployment scenarios and five distinct policy choices differing in the level of offshore coordination and international market integration. By drawing comparisons between the study results, we quantify the net benefit of enabling different types of coordination under each scenario. Furthermore, we showcase a novel min–max regret optimization model and identify minimum regret first-stage commitments which could be deployed in the near future in order to enhance strategic optionality, increase adaptability to different future conditions and hence reduce any potential sub-optimality of the initial network design. In view of the above, we put forward specific policy recommendations regarding the adoption of a flexible anticipatory expansion framework for the identification of attractive investment opportunities under uncertainty.

1. Introduction

Offshore wind power is expected to make a significant contribution towards the decarbonization of the European energy system. It is envisaged that today's installed capacity levels of about 5 GW of offshore wind generation may reach 150 GW by 2030, with approximately half of this capacity located in the North Seas. Currently, the business-as-usual case involves radial connections to shore and dedicated interconnectors with little scope for inter and intra-zonal coordination. Given Europe's goal of increased market integration, there is a significant opportunity to coordinate the large volume of impending offshore wind with cross-border interconnector projects in the North Sea. Accommodating offshore wind export capability and cross-border trade through a common meshed transmission network can provide substantial capital savings in the form of economies of scale. In addition, the formation of links that connect neighbouring offshore clusters can create new trade routes that will considerably expand the scope of cross-border arbitrage opportunities at a fraction of the cost compared to dedicated interconnection corridors. In specific cases, like the UK, such offshore–offshore links can also contribute to the resolution of internal congestion bottlenecks. In addition, integrated design configurations can increase security of supply for consumers as well as achieve reduced environmental and maritime impact due to coordinated construction efforts and commissioning of fewer assets.

In view of the multiple potential benefits described above, the European Commission has already recognized the development of a meshed North Sea offshore grid as one of the main infrastructure priorities for Europe (Directorate General for Energy, 2010). In this context, several studies have already been carried out to quantify the costs and benefits of various design alternatives (ENTSO-E, 2010). In general, study results indicate that a meshed grid design can bring significant financial, technical and environmental benefits at the European level. More specifically, OffshoreGrid (2011) concluded that clustering offshore wind farms in hubs and enabling hub-to-hub interconnection entail significant capital savings. Results published in NSCOGI (2012) indicate that adopting a meshed design philosophy by 2030 can be beneficial under large-scale deployment of offshore wind, resulting in capital savings in the order of 7%. In a similar vein, a recent report by Cole et al. (2014) quantified the system-wide savings associated with the

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http://dx.doi.org/10.1016/j.eneco.2017.03.022

development of a coordinated offshore grid in the Northern Seas to be in the range of 1.5 to 5.1 billion by 2030. A report published by EWEA (2014) states that annual savings stemming from coordinated offshore grid development in the Northern Seas can be 1.5 to 5.1 billion euros. In a similar vein, the NorthSeaGrid project (2015) focused on three specific case studies of meshed offshore networks in the North Sea, concluding that integrated solutions present significant scope for capital and operation cost savings. In addition, relevant regulatory and market barriers towards practical implementation were identified, while also investigating the impact of different benefit-sharing mechanisms on individual countries and stakeholders.

One key message of past studies is that coordination of offshore wind connections can entail significant benefits for Europe given the high capital cost of undersea cable installations and the substantial scope for economies of scale. However, all existing analysis have focused on coarse modelling approaches, where a basecase is compared to a system involving some integrated offshore projects defined a priori. In order to prioritize policy discussions, it is instructive to study in detail the effect of different levels of coordination between offshore developers and member-states. For example, it is important to separately quantify benefits stemming from inter-zonal coordination and benefits stemming from cross-border coordination, as they concern separate policy aspects and regulatory regimes. To this end, the present paper undertakes extensive cost–benefit analysis studies across five distinct policy choice setups. The selected policy choices cover the entire spectrum of coordination, from the current state of radial connections to shore to an extreme integrated-planning paradigm where generation and network investment decisions are taken on a global cost-minimization basis. Another well-recognized aspect is that the extent of integration benefits will largely depend on future offshore wind deployment patterns. However, existing efforts have largely considered transmission expansion as a static problem; cost benefit analysis is undertaken on the basis of an individual snapshot of the future European electricity system. Another common aspect of existing studies is that the integrated projects analysed have been defined a priori. Although informative, it is imperative to consider transmission expansion planning as a dynamic decision problem where the planner can optimize the timing, sizing and location of network investment while different potential future scenarios unfold. In this paper, four different scenarios of future offshore wind installation patterns are considered. The 2020–2044 horizon has been divided in five-year epochs and the optimal investment schedule for each scenario is presented.

In addition to the above, the valuation framework presented in this paper constitutes a radical departure from existing planning approaches due to the explicit consideration of uncertainty in the decision process. Given the lack of coordination that characterizes interactions between network planners and offshore developers, the assumption of perfect information about future system conditions must be relaxed. To this end, we construct scenarios that describe the uncertainty that characterizes the timing, location and amount of future offshore wind generation deployment. In addition, a suitable risk-averse decision criterion is adopted that minimizes the worst regret experienced across all scenarios considered. Under the suggested framework, an investment decision's agility for coping with adverse scenario realizations becomes an important consideration. In contrast, traditional approaches that assume perfect information about future deployments cannot identify openings for strategic action, inadvertently leading to premature project commitments with limited adjustability.

Finally, another point of interest is that of benefit distribution across member-states. Although all existing studies present a clear business case for integrated offshore networks, in practice we see little progress on such projects. We determine the asymmetric impacts of an integrated network at a market participant level (i.e., consumers and producers in a country), demonstrating significant imbalances. In this context, this study highlights the need for major developments in regional and European regulatory and market frameworks to enable the unhindered development of multi-purpose transmission projects. In view of the above, the present paper offers a three-fold contribution on the topic of offshore transmission grids:

- We investigate the value of different levels of coordination across a number of offshore wind scenarios. We show the importance of exploiting the economies of scale present in inter-zonal coordination for planning offshore clusters' connections to shore. In addition, we highlight the benefits of interconnecting different offshore clusters and explore this practice's potential to replace direct cross-border interconnectors.
- We study the value of flexibility by adopting a novel 'investment-under-uncertainty' framework. The proposed 'min–max regret' approach effectively retains the option of pursuing a wide range of future offshore wind deployment scenarios at least additional cost to consumers. In this context, offshore–offshore links are shown to possess significant strategic optionality. This finding is important in the context of developing much-needed policy and market frameworks for anticipatory offshore grid developments.
- We determine the asymmetric impacts of an integrated network at a market participant level (i.e., consumers and producers in a country), and discuss the creation of: (i) a regional ISO (or RTO) who can ensure efficient operation and planning of the North Seas grid, (ii) a adequate transmission charging regime based on 'beneficiary pays' principle, regardless of countries' boundaries (iii) harmonization of incentive mechanisms (i.e., subsidies) for offshore wind generation among North Seas countries, and (iv) a potential compensation mechanism that can facilitate transition to a more integrated and coordinated approach for network planning.

The paper is structured as follows: in Section 2 we present our modelling method including the compilation of different offshore deployment scenarios and policy choices subsequently analysed. In Section 3 we present the results of the analysis under perfect information and uncertainty, identifying and discussing the main investment patterns that emerge for each study. The overall aim is to quantify the benefit in terms of reduced cost of different levels of coordination, identify strategic investment options when facing uncertainty and examine the effects of asymmetric benefit allocation. In Section 4 we conclude and discuss policy recommendations stemming from the presented analysis. Appendix A includes the mathematical formulations for the optimization problems under perfect information and uncertainty (i.e., min–max regret investment problem).

2. Methods

The next sections outline the data, methods and models employed to identify the optimal transmission expansion strategies in the North Sea. Given the long-term nature of electricity transmission and generation infrastructure, the horizon of the undertaken study spans the years 2020–2045. This period has been split in five epochs, each lasting five years. Note that given the locational focus of the study in the surrounding area of the North Sea, the countries modelled are all North Seas Countries Offshore Grid Initiative (NSCOGI) members i.e., Belgium (BE), Germany (DE), Denmark (DK), France (FR), Ireland (IR), Netherlands (NL), Norway (NO), Sweden (SE) and the United Kingdom (UK). Luxembourg has been excluded from the analysis due to its reduced size and limited access to offshore resources.

2.1. System model

In order to capture the major cross-border flow patterns as well as local congestion bottlenecks that may impact trading possibilities, the modelled system representing state of the transmission network at 2020 comprises a total of 16 nodes and 28 transmission corridors. As

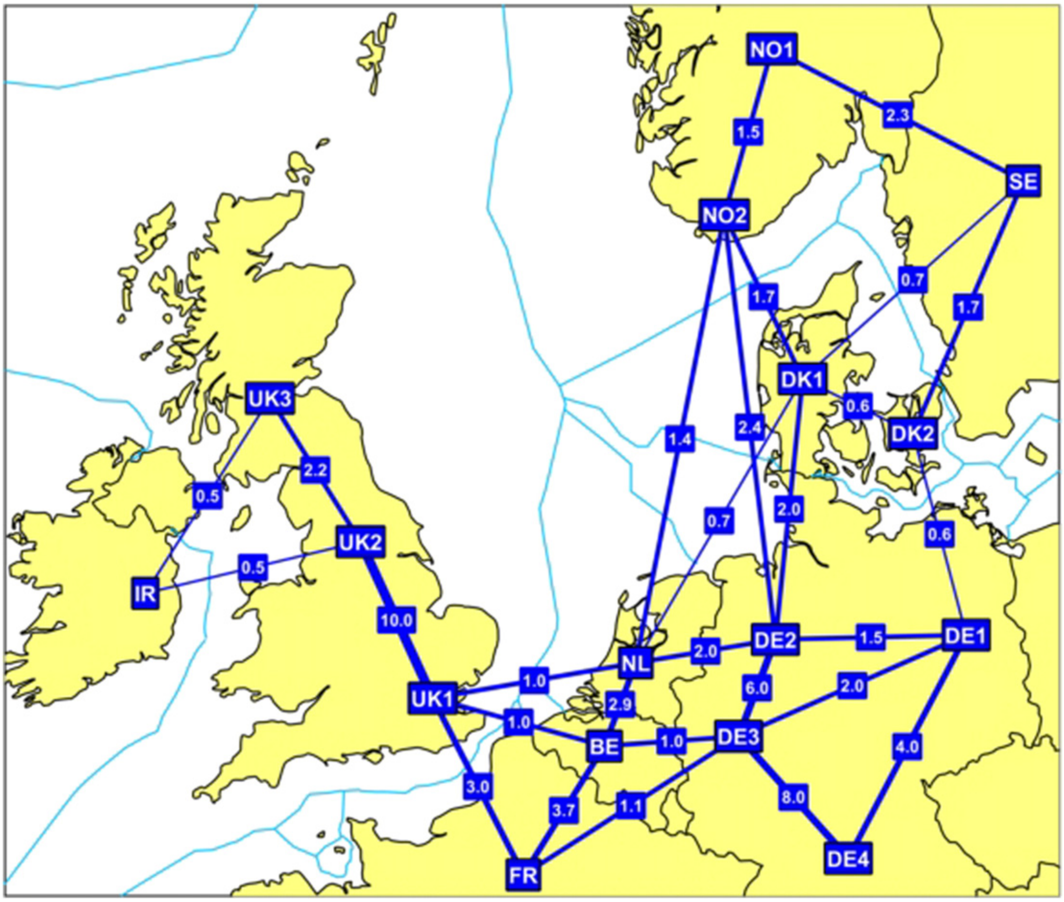


Fig. 1. Capacity of existing onshore–onshore links and cross-border interconnectors.

can be seen in Fig. 1, some countries consist of several nodes (e.g., Germany and UK comprise of 4 and 3 nodes, respectively) while others have been aggregated to a single node (e.g., Sweden and France). Transmission corridors represent the aggregate transfer capability between nodes due to existing interconnection and planned projects according to ENTSO-E (2012). Data pertaining to the existing topology as well as future generation mix and demand projections at each system node for the five epochs are similar to the ones used in (European Climate Foundation, 2010). The generation and demand scenario is shown in more detail in Fig. 2. Note that this scenario describes

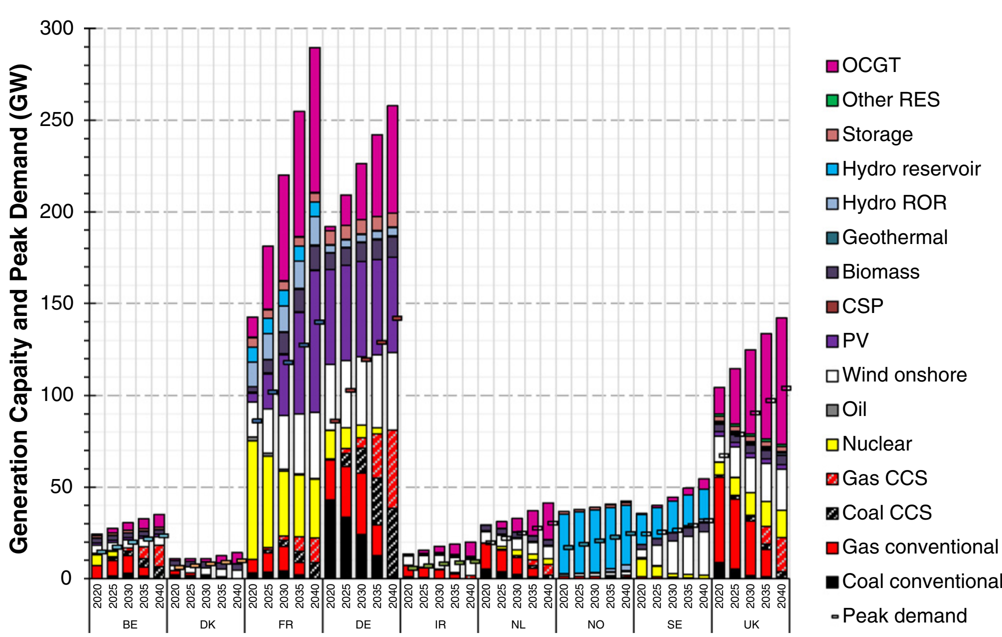


Fig. 2. Generation and demand background scenario for the modelled countries.

capacity evolution of conventional and renewable technologies while excluding deployment of offshore wind, which in this study is considered uncertain and four distinct scenarios have been developed to capture possible deployment trajectories.

2.2. Offshore wind deployment scenarios

While a single background is used to describe developments for demand and the installed capacity of different generation technologies, a scenario tree has been developed to describe the possible deployment patterns of offshore wind farms. A scenario tree is a coherent representation of possible future realizations of uncertainty; it comprises nodes that encapsulate possible states of the uncertain parameters at different times and arcs between nodes that capture the possible evolution paths. The use of a scenario tree enables us not only to explicitly consider a range of potential future system evolutions, but inherently enables the planner to identify the optimal recourse action for each, as permitted by the structure of inter-temporal uncertainty resolution. Note that for most of the analyses, generation patterns are assumed to be exogenous scenarios (so a scenario tree is appropriate), but that in the sensitivity analyses, a proactive planning approach is implemented in which offshore wind capacities are decisions and this is explained in detail later in Section 2.4.

The main source of information regarding future offshore wind developments has been the database developed by 4-C-Offshore (2014). A total of 421 North Sea offshore development projects with an aggregate capacity of 204 GW were deemed to be relevant and have been explicitly considered in the present study. The database contains extensive information on individual projects regarding geographical location (longitude, latitude), distance to shore, target wind farm size and current development status. More specifically, each project has been given one of the following status: 'Fully Commissioned', 'Under Construction', 'Permit Granted', 'Awaiting Permit', 'Early Planning' and 'Development Zone'. Information pertaining to each project's development status and its distance to shore can act as a suitable proxy towards inferring its position in a country's priority stack. For example, a project close to shore and labelled as 'Permit Granted' will most likely be developed earlier than a project currently designated as a prospective 'Development Zone'.

Following discussions with relevant stakeholders and system experts, four scenarios were developed to capture potential future deployment patterns in the North Sea. The scenario tree is shown in Fig. 3 along with the decision points regarding investment; note that investment decisions for the first epoch are coupled signifying the lack of full information (i.e., uncertainty) regarding future developments faced by the planner. Scenario 1 (S1) constitutes the high wind deployment scenario, where it is assumed that all currently identified prospective projects are eventually commissioned. Regarding the first epoch of S1, it is assumed that all projects listed as 'Commissioned', 'Under Construction' and 'Permit Granted' will be operational by 2020, totalling 25 GW. Conversely, scenario 4 (S4) represents the lowest deployment eventuality; it is less optimistic concerning developments by 2020 and only projects characterized as 'Commissioned' and 'Under Construction' are assumed to be operational by 2020, totalling 9 GW. Furthermore, to ensure a wide range of eventualities is covered, S4 has been defined with just 50 GW for total capacity deployment by 2044 to cover for the case that North Sea is eventually left largely unexploited. Targets for other scenarios and intermediate nodes have been drawn on a linear interpolation basis, with scenarios 2 and 3 (S2 and S3) representing upper and lower intermediate deployment levels respectively. Having defined aggregate deployment levels, country-specific levels were computed, excluding nodes that are already well-defined at the country level (i.e., nodes 1, 5 and 16), on the basis of country sharing ratios observed in the full deployment node 5 (i.e., last epoch of S1). The country-specific levels shown in Fig. 4 in conjunction with the 'priority stack' concept outlined earlier, allowed us to infer the precise deployment staging for each scenario at the individual project level. Deployment patterns for S1 across the five study epochs are shown in Fig. 5.

2.3. System topology model

Given the large number of individual projects in the North Sea area, their explicit inclusion in an optimization model would give rise to a prohibitively complex problem. For example, when considering the possibility for connections between offshore projects, the number of possible interconnection setups grows prohibitively large due to combinatorics. The approach taken to effectively reduce the number of possible connections is to group geographically adjacent projects into clusters; this way, only cluster-to-cluster connections need to be considered. This assumption is also more realistic from a network planning perspective since it would be inefficient to develop a North Seas network based on project-to-project connections. Naturally, there are many possible ways to cluster such a large number of points; the larger the number of clusters, the more complex the model becomes while a

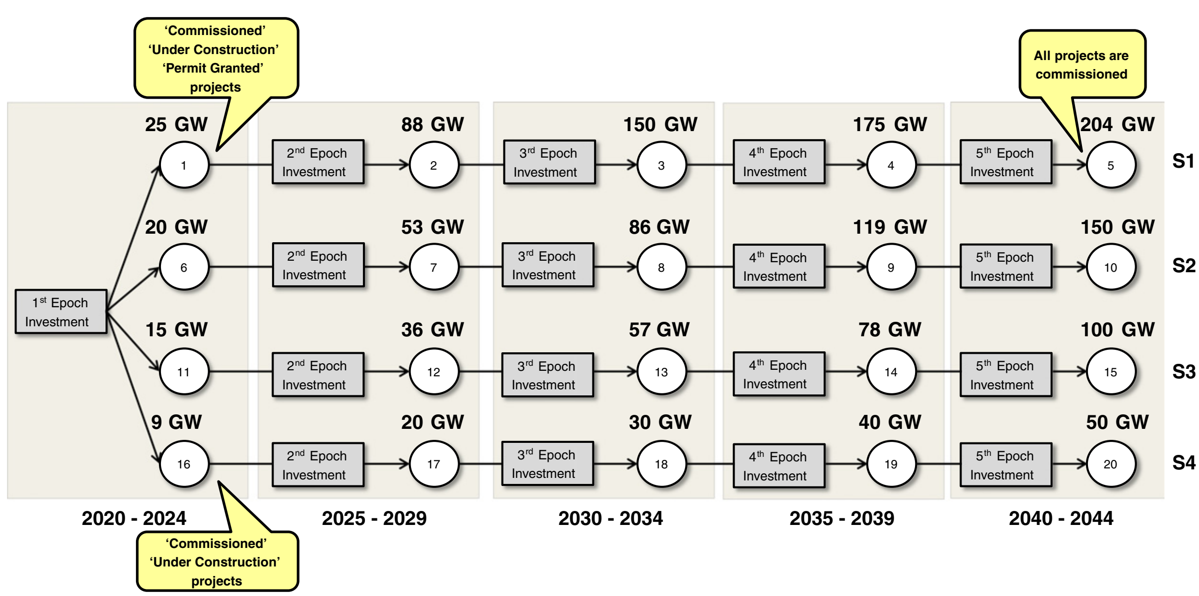


Fig. 3. Scenario tree capturing possible paths for future offshore wind deployment in the North Sea.

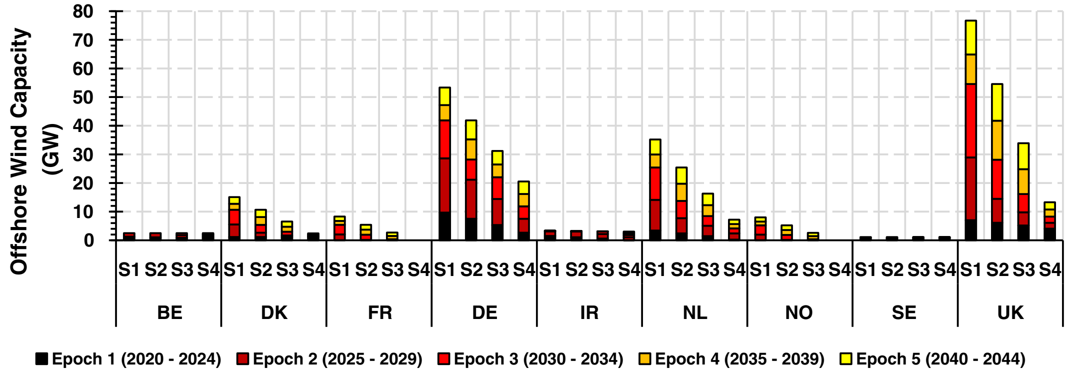


Fig. 4. North Sea offshore wind capacity deployment per country under each scenario.

small number of clusters may over-simplify the underlying reality by implicitly assuming the existence of connections between projects that belong to the same cluster. For the above reasons, a systematic way of geographically clustering the projects is essential.

K-means clustering is a widely-used unsupervised data mining method for partitioning a dataset in a pre-specified number of clusters so as to minimize within-cluster sum of distances. In this research, K-means clustering with a Euclidian metric has been applied to group geographically adjacent projects together for the purpose of rendering the model tractable while retaining a good representation of the geographical diversity of offshore projects. Note that the offshore clusters can only contain projects from the same jurisdiction so as to prohibit implicit resource sharing between projects that belong to different countries. Different clustering strategies were considered and the final clustering scheme consisting of 32 offshore clusters, shown in Fig. 6, was selected on the basis of minimizing the S_Dbw index, which is a widely-accepted validity indicator and has been shown to be a robust metric for unsupervised subgroup identification (Halkidi and Vazirgiannis, 2001).

Note that offshore projects of some countries can be accommodated in one or two clusters, while other countries like the UK require a large number of clusters due to the high locational diversity of offshore projects. By combining the scenario deployment patterns showcased earlier with the clustering scheme we calculate the capacity of the 32 offshore clusters, shown in Fig. 7. Cluster sizes range from as large as 30 GW in The Netherlands (cluster 15 is an area with very high project density) to small clusters of a few GW in Belgium and Sweden.

Having grouped offshore projects to a manageable number of offshore wind clusters, the next step is to define the set of candidate corridors to be considered in the optimization model. Existing and new transmission corridors can be classified in one of four types.

2.3.1. Onshore–onshore corridors (internal)

As already mentioned, some countries are modelled as a set of nodes instead of using a single bus model, enabling us to capture any material internal congestion that may limit trade opportunities, as is the case with the England-Scotland transfer boundary. There exist 8 internal links in continental Europe and Scandinavia that can be further reinforced.

2.3.2. Onshore–onshore corridors (cross-border)

These are the links that connect two different countries. The system has been initialised with 20 existing cross-border corridors; in addition, 11 new subsea cross-border paths have been defined, including several candidate connections between UK and the three Scandinavian countries.

2.3.3. Offshore–onshore corridors

These are the links that directly connect an offshore cluster to its parent country. Each one of the 32 clusters has been assigned with a single candidate connection to its parent country.

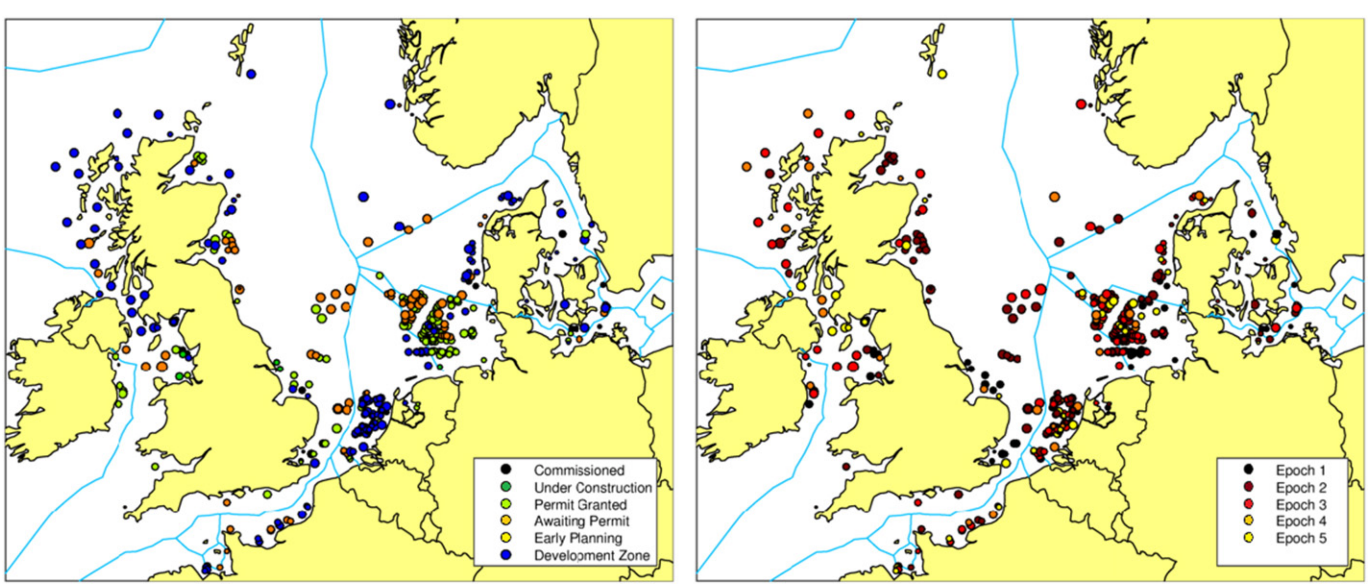
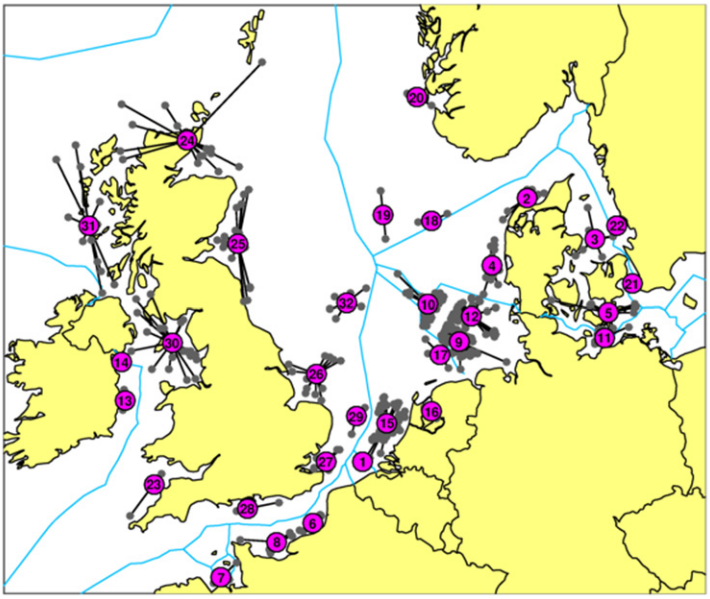


Fig. 5. Current development status of all projects considered (left). Deployment pattern at the individual project level for scenario 1 (right).



Country	Number of Projects	Number of Clusters
BE	11	1
DK	39	4
FR	22	3
DE	118	4
IR	7	2
NL	96	3
NO	9	3
SE	3	2
UK	116	10
Total	**421**	**32**

Fig. 6. Map of the 32 offshore wind clusters (magenta numbered circles) and corresponding individual projects (grey circles) (left panel). Clustering scheme for each country (right panel).

2.3.4. Offshore–offshore corridors

One of the main purposes of this project is to examine benefits of integrated connection strategies. To this end, it is necessary to define a large set of candidate corridors that link up clusters that belong to the same or different countries. Out of the possible 496 offshore-offshore links (i.e., all possible links among 32 nodes), 63 offshore-offshore corridors were evaluated as potentially beneficial and have been included in the present study. These links can lead to fundamental changes in network evolution and design because they enable a range of solutions that have traditionally been ignored. The most obvious possibility enabled by offshore-offshore links is increased inter-zonal coordination between different clusters, leading to reduced investment levels in the offshore grid. Furthermore, resolution of internal congestion can be achieved by building an offshore-offshore link that connects two clusters that belong to different onshore nodes (e.g., Scotland and South England); a new corridor that can directly accommodate energy exports and imports is created circumventing the congested onshore paths. In a similar manner, connecting two clusters that belong to different countries can essentially create a link that displaces the need for direct cross-border interconnection. Using a number of offshore-offshore links, it is possible to build a meshed offshore grid that connects multiple countries while integrating offshore wind export capabilities. Consideration of these links can have a profound effect on the amount of investment necessary to accommodate oncoming wind as well the design's exposure to stranding risks.

The set of existing and candidate transmission corridors is shown in Fig. 8. There is a total of 134 corridors; 28 existing links that can be further reinforced and 106 candidate corridors whose build-out and capacity is to be decided. The fixed and variable investment cost for all undersea cables is 70,000 €/km/yr and 115 €/MW/km/year, respectively. Reinforcements for onshore corridors only contain a variable cost component of 35 €/MW/km/year. This cost discrepancy has been introduced to render subsea options considerably more expensive than

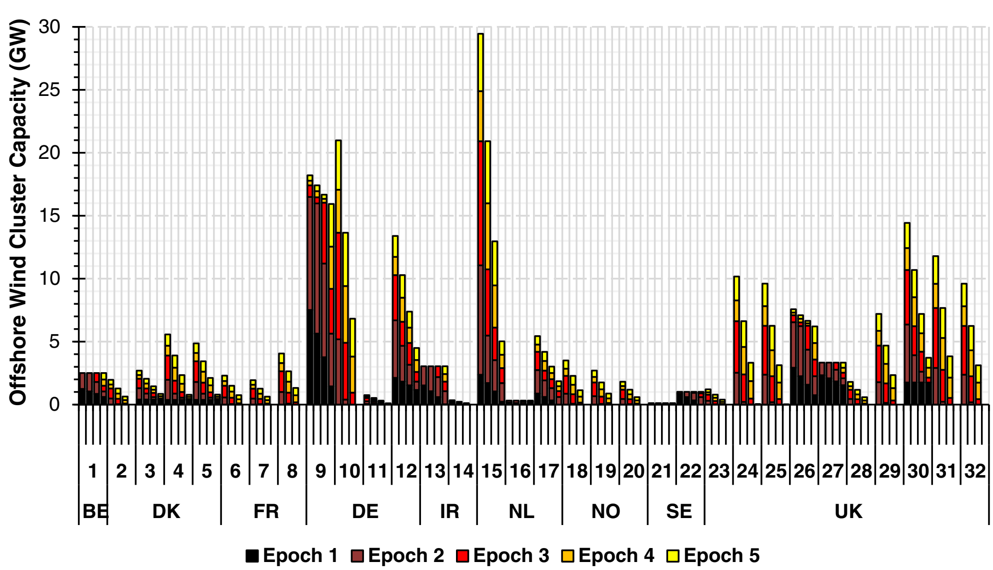


Fig. 7. Capacity of the 32 offshore wind clusters (GW) across all scenarios and epochs. Four bars are shown for each of the 32 clusters, the leftmost bar corresponding to scenario 1, followed by scenario 2 etc.

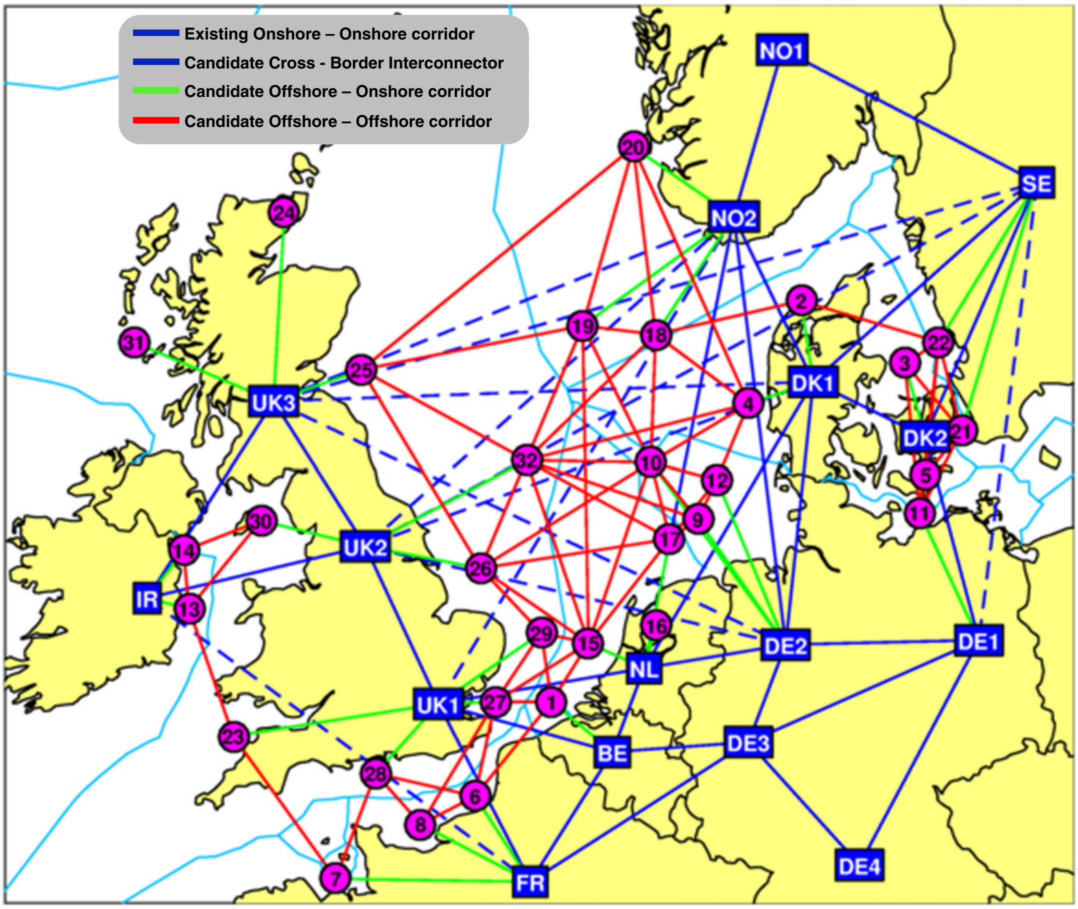
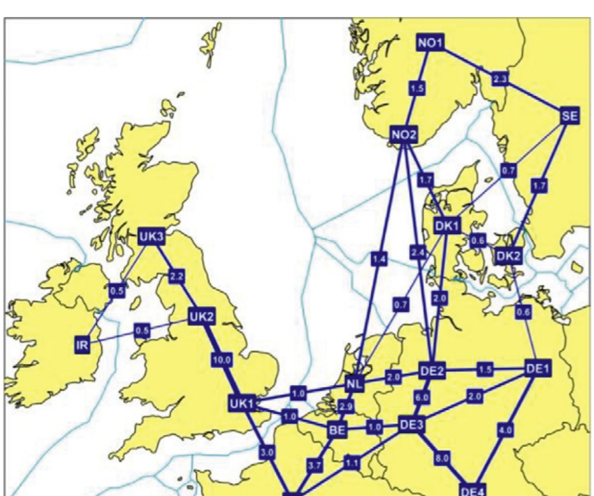


Fig. 8. Set of existing and candidate corridors in the North Seas.

onshore interconnection solutions, accurately capturing the large fixed costs associated with establishing a new subsea corridor.

The existing system topology, shown in Table 1, constitutes the starting point for all subsequent analysis. Along with the starting topology we also present the transfer capacity able to facilitate comparisons with subsequent evolutions of the system. All numerical entries refer to transfer capacities expressed in GW. Entries in blue represent internal (diagonal) or cross-border transmission capacity via direct onshore interconnectors. Entries in red represent cross-border capacity between two countries via offshore links. Diagonal entries in green represent the aggregate capacity of offshore-to-onshore links for each country. Cyan entries show the generation capacity of offshore wind deployed in each country. Crossed-out red cells correspond to combinations of non-neighbouring countries between which no direct trade route has been considered. Note that initially no offshore wind farms, onshore-offshore and offshore-offshore links exist.

Table 1
Existing system capacity in GW between different countries and offshore clusters.



	BE 0	DK 0	FR 0	DE 0	IR 0	NL 0	NO 0	SE 0	UK 0
BE 0	0								
DK 0		0.6 / 0							
FR 0	8.7 / 0		0						
DE 0	1.0 / 0	2.6 / 0	1.1 / 0	21.5 / 0					
IR 0			0 / 0		0				
NL 0	2.9 / 0	0.7 / 0		2.0 / 0		0			
NO 0		1.7 / 0		2.4 / 0		1.4 / 0	1.5 / 0		
SE 0		0.7 / 0		0 / 0			2.3 / 0	0	
UK 0	1.0 / 0	0 / 0	3.0 / 0	0 / 0	0.9 / 0	1.0 / 0	0 / 0	0 / 0	12.2 / 0

As can be seen above, the largest cross-border transfer capability pertains to the onshore connections between France–Germany and France–Belgium; subsea cross-border links have considerably less capacity. Significant further investment is needed across all scenarios to ensure that offshore resources and the changing generation background can be accommodated in a cost-efficient manner to maximize opportunities for cross-border trade and exploitation of inexpensive energy sources.

2.4. Policy choices

Currently, connection of offshore wind projects to shore is undertaken in an uncoordinated fashion, where each individual wind farm builds its own export link to the main electricity grid. In addition, despite several initiatives and discussions, no project combining cross-border links with offshore wind exports, namely multi-purpose projects (MPPs), has emerged yet under the current regulatory arrangements. Such advanced interconnection options have been ignored by private developers due to the stranding risks associated with the anticipatory investment elements that a strategic connection entails as well as the lack of clear cost and benefit allocation rules (Strbac et al., 2014). Note that anticipatory investment involves some additional assets or asset oversizing beyond what is needed in the immediate future so as to take advantage of the economics of scale that characterize transmission planning; for example, an investor may choose to install cables or transformers or larger capacity so as to enable the delivery of a future upgrade/addition at a reduced cost. Naturally, these anticipatory investments entail stranding risk since it is not fully certain that the projected upgrade/addition will actually materialize. However, enhancing coordination and integration can increase system-wide welfare as explained in (Gately, 1974). To this end, we adopt a social welfare maximization/cost minimization viewpoint across the entire North Seas region and investigate the benefits of increasingly integrated policy setups. Four policy choices, explained in detail below, have been analysed; each policy choice applies different investment and operation constraints to capture varying levels of resource and market integration.

2.4.1. Radial

The Radial policy choice represents the status quo and exhibits the least amount of offshore coordination and market integration. The incremental design philosophy prevails, with each wind farm developer building its own dedicated connection to shore and foregoing any opportunity for strategic coordination. To capture the increased cost of conducting technical studies, securing planning permissions, building cables and reinforcing offshore and onshore substations in a piecemeal manner, the planner is modelled to pay fixed costs for each new project connecting to shore in increments of 500 MW. Regarding market integration, although cross-border flows are allowed, net energy trades across a year are constrained so that each member-state is energy-neutral and self-secured. Due to the reduced levels of integration, the possibility for building offshore-offshore links is not considered. The 'Radial' policy choice constitutes the counterfactual against which the integration benefits of other choices are assessed.

2.4.2. Hub

The 'Hub' policy choice assumes that the planning process will take a strategic view towards the connection of future offshore wind resources. To this end, offshore wind generation projects are no longer connected on an individual basis while incurring fixed costs multiple times. Instead, the planner has to incur a fixed cost payment every time an onshore-offshore corridor is constructed or an already-existing corridor is upgraded. This renders investing beyond the current needs an attractive option, since taking advantage of the arising economies of scale can lead to substantial reductions in network costs. The possibility for building offshore-offshore links remains unconsidered.

2.4.3. Energy-neutral integrated

This policy choice allows the construction of offshore–offshore links between clusters that belong to the same or different jurisdictions, constituting a significant leap in the level of European system integration. However, similar to the 'Radial' and 'Hub' cases, energy neutrality and self-sufficiency is enforced at the member-state level. Under the energy neutrality condition each country is allowed to import and export power as long as the net annual energy import/export balance is zero. This allows countries to trade their excess power when available but also ensures that local generators remain profitable. The latter point is linked to the concept of self-sufficiency, where each country relies solely on its own generation resources to achieve the desired capacity margin. Similar sensitivities around cross-border trading have been employed in the past in other studies assessing the impact of new technologies at a European level; for example, see (Imperial College London and NERA, 2015) and (Strbac et al., 2012.).

2.4.4. Fully integrated

Under this option, the energy neutrality constraints have been relaxed. Electricity trading opportunities between different countries are unconstrained and can be fully taken advantage of, resulting in increased benefit for cross-border interconnectors and augmented trade volumes in order to exploit all available opportunities for arbitrage, reflecting the highest level of European integration and coordination.

2.4.5. Proactive

In all the policy choices described above, offshore wind developments are considered fully exogenous, i.e., dictated by the different scenario definitions and therefore outside of the network planner's control. A different approach is to co-optimize generation and network assets so as to maximize social welfare/minimize total cost in a coordinated fashion. Naturally, this approach is most suited in cases of vertically integrated utilities where the same entity undertakes planning of generation resources and networks. However, as pointed out in (Liu et al., 2013) co-optimization of generation and network investment can also be useful within unbundled environments by identifying grid reinforcements that encourage generation siting decisions that yield low overall system costs. As explained in (Van der Weijde and Hobbs, 2012), capturing the interactions between network and generators within a unbundled environment gives rise to bi-level problems that may require the deployment of sophisticated optimization methods such as Mathematical Programming with equilibrium constraints (Sauma and Oren, 2006). However, as shown in (Garces et al., 2009) under the assumptions of perfect competition and cost-reflective transmission pricing, this bilevel problem can be cast as a single social welfare maximization problem. Following the above assumptions, capacities of offshore clusters are introduced as a decision variable to be optimized by the model (subject to comply with a net installed capacity volume associated with each future scenario S1-S4), so as to take full advantage of any possible synergies between generation and network investment. This analysis provides useful insights regarding the benefit of encouraging further coordination between offshore developers through suitable market design and regulatory mechanisms.

2.5. Optimization model

Having fully defined the candidate corridors, demand and generation background, future offshore scenarios and the policy choices to be investigated, we need to establish the optimization framework that enables us to identify the optimal network topology and perform the various cost–benefit analysis. Our model assumes that operation takes place in perfectly competitive price-coupled markets, where the planner's objective is the minimization of investment and operation cost across the horizon 2020–2044. Note that cost minimization is equivalent to welfare maximization under the assumption of inelastic demand. The full mathematical formulations for the optimization problems under perfect information and uncertainty (i.e., min-max regret planning model) are given in detail in Appendix A.

3. Results and discussion

The objective of the presented studies is to explore the optimal network topology that arises under different scenarios and policy choices and thus provide evidence for policy decisions related to infrastructure deployment in the North Sea. More specifically, we aim to investigate the impact that trade limits have on social welfare, identify the major cross-border trade routes and explore the scope for network integration across the different scenarios. In Section 3.1 we perform deterministic analysis and assess the range of costs under different scenarios and policy choices. In Section 3.2 we present the min-max regret results for the 'Radial' and 'Fully Integrated' choices under uncertainty and we explore 'no-regrets' investment solutions and the extent to which they are facilitated by increased system integration. Finally, in Section 3.3 we explore the impact that asymmetric cost–benefit sharing between market participant in different countries can have on the commercial attractiveness of integrated projects and pinpoint potential mitigation measures.

3.1. Value of coordination

3.1.1. General results under perfect information

In Fig. 9 we present savings in operation and capital costs for all policy choices when compared to the 'Radial' basecase study.

As expected, all policy choices present significant potential for savings since the 'Radial' case captures the least amount of coordination; as opportunities for coordination are progressively introduced through the various policy choices, system cost reduces. What is also important to highlight is that the scope for savings depends also on the scenario analysed. In the event of low deployment, the benefit of coordination is less pronounced when compared to high-growth scenarios, where the integrated policy choices can present a significant impact on network and operation costs.

A first observation pertains to the coordination of offshore connections. When examining the 'Hub' policy choice, significant savings occur in terms of the required network investment. Especially in the case of large-scale offshore deployment, the large offshore-onshore connections required benefit from economies of scale and deliver significant economic benefits when compared to incremental point-to-point connections which entail increased fixed cost expenditure. More precisely, under scenario 1, savings in network investment from coordinating connection of offshore wind clusters are about €40bn, while for small-scale deployment, benefits are about €8bn. To put these numbers into perspective, we mention that under the 'Radial' case, the total transmission investment cost through the study period is estimated between 38.2 and 102.6 billion euros. As such, coordination can lead to capital savings in the order of 20% to 40%, with most pronounced reduction occurring in the case of high offshore wind deployment.

Regarding the benefits of enabling offshore-offshore links, we observe that they are relatively modest in the 'Energy Neutral' case; only a small increase in investment and operation cost savings is achieved by relaxing the constraint of connecting wind farms solely to their country of origin; the potential for optimally utilizing offshore resources across the system is considerably hindered by the energy neutrality constraint. However, in the absence of this limitation (i.e., 'Fully Integrated' policy choice), offshore–offshore links result in significant benefits. As shown in Fig. 9, allowing unconstrained cross-border trade results in substantial operational savings across all scenarios. For example, in the case of scenario 1, operational savings are about €40bn. Note that investment savings are slightly lower when compared to 'Energy Neutral' since additional network capacity is built to take full advantage of the expanded arbitrage opportunities. This pattern persists across all scenarios, although the reduced deployment of zero-marginal offshore wind naturally reduces the scope for savings. Another effect to be considered in the future, when examining EU market integration, is the potential for security of supply savings, as individual member states can share resources and ancillary services provision (in presented results local generation capacity is sufficient to supply internal demand in every country).

A final observation relates to the benefit of enabling coordination between network planning and offshore wind deployment, as demonstrated in the 'Proactive' case study. This policy choice represents the highest level of coordination and as expected results in the most significant savings, in the order of €80bn for S1. The majority of these savings are associated with a reduction in network investment, achieved through the integrated optimization of offshore generation and network resources.

In addition to the policy choices presented in Section 2.4, two further sensitivity studies were carried out to assess the potential benefits of Demand-Side Management (DSM). Deployment of DSM can reduce network congestion and thus enhance utilization of assets by rescheduling energy consumption of flexible loads from peak to off-peak hours. Although DSM capabilities in European systems are currently limited, electrification of heat and transport and the advent of 'smartgrid' technologies are expected to increase the penetration of controllable flexible loads. In this paper, DSM has been modelled through modifications to the peak and off-peak demand levels of each country. Note that the present analysis quantified gross benefits of DSM, not considering the rollout cost of DSM capabilities. In Fig. 9, we show savings for two case studies, 'HUB + DSM' and 'FI + DSM', which correspond to the 'Hub' and 'Fully Integrated' policy choices with DSM capability respectively. As can be seen, DSM deployment results in substantial savings across all scenarios; operation costs are reduced through the diminished need to engage expensive peaking plants, while lower peak flows mitigate the need for network investment. In the case of 'FI + DSM', savings

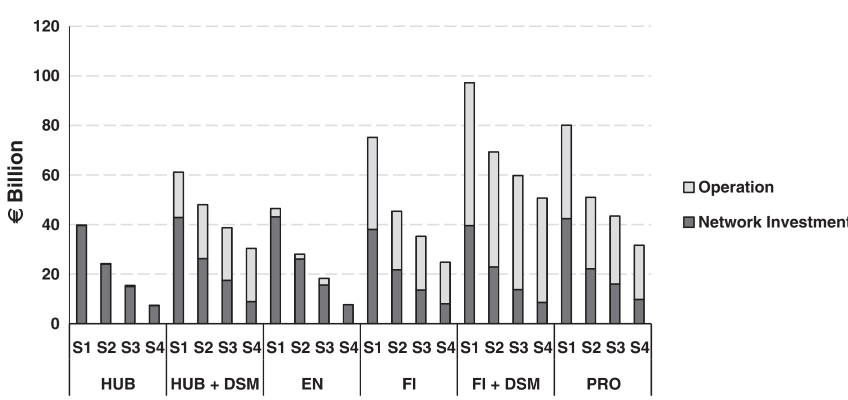


Fig. 9. Savings in operation and network investment costs of different policy approaches when compared to the 'Radial' solution.

are even more pronounced due to the broadened scope for resource sharing between member-countries. It is important to point out that in all cases, savings are largely independent of the offshore wind scenario. This highlights the potential of demand-side measures for widespread system benefits in the future.

3.1.2. Specific case study no 1 under perfect information — Radial design

The optimal network designs for scenarios 1 and 4 for the 'Radial' policy choice, when no uncertainty is considered, are shown in Fig. 10. Table 2 shows the additional network transfer built under the two extreme scenarios.

As can be seen in Fig. 10 and Table 2, in all scenarios significant investment is undertaken in offshore-onshore links to enable offshore wind export to the load centres. Note that link sizes are in all cases smaller than the nameplate capacity, e.g., 43.7 GW are built for 53.3 GW of installed capacity in Denmark. In addition, since no offshore–offshore corridors are allowed under the 'Radial' approach, network investment is focused on direct onshore-onshore links to resolve internal congestion and facilitate cross-border trade. For example, over 30 GW of capacity is constructed in Germany and UK under scenario 1 to relieve internal congestion, thus enabling offshore wind

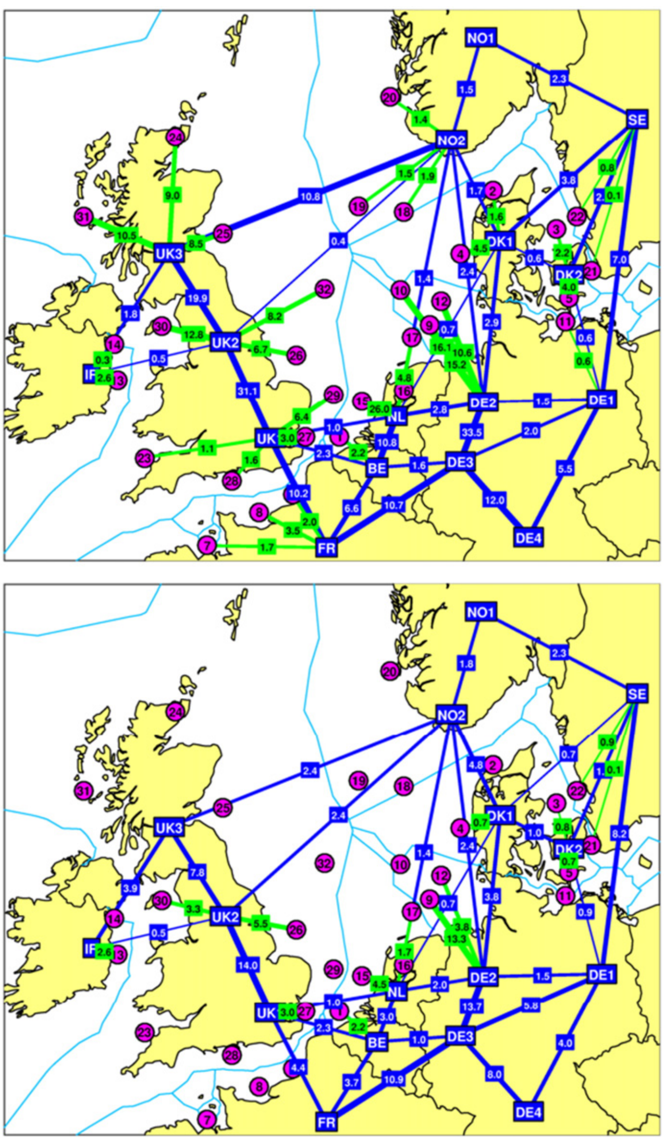


Fig. 10. Optimal network designs obtained under the 'Radial' policy choices for scenario 1 (top) and scenario 4 (bottom) by the end of study horizon.

resources to reach the load centres; this need is less pronounced in lower deployment scenarios. Construction of direct cross-border links is also driven by offshore wind deployment; 63 GW of interconnection is built under scenario 1 while 40 GW is required under scenario 4. Under scenario 1, the most heavily-invested cross-border corridors are UK–Norway, UK–France, France–Germany, Germany–Sweden and Belgium–Netherlands. However, it is important to highlight that the potential of cross-border trade is not fully utilized is this study due to the energy-neutrality constraint. Investment and operational costs for the 'Radial' case covering the entire study period 2020–2044 are shown in Table 3. As expected, both network investment and operational costs depend significantly on the scenario realization. More precisely, the capital cost range over the 25-year study period is from €102.55bn to €38.20bn highlighting the increased infrastructure necessary for the accommodation of offshore resources. In an opposite vein, operational costs range from €1272.15bn to €1723.68bn; high deployment of offshore wind results in a 26% cost reduction in operation. In terms of total system cost, occurrence of the high deployment scenario results in 22% savings when compared to scenario 4. Note that for completeness we also show investment and operational costs per stage for each scenario in Appendix B.

3.1.3. Specific case study no 2 under perfect information—fully integrated design

We present results for the 'Fully Integrated' policy choice to further examine the benefits of increased market integration and offshore coordination. The final optimal network designs for scenarios 1 and 4 are shown in Fig. 11. Table 4 shows transfer capacity tables for the two extreme scenarios.

The possibility for unconstrained cross-border trade and the creation of an offshore grid integrating wind resources and interconnectors have a profound effect on the optimal network design. By comparing between Table 2 and Table 4, some significant differences become apparent. When offshore-to-offshore integration is enabled many direct interconnectors are replaced by offshore corridors that also integrate offshore clusters. For example, in scenario 1 of the 'Radial' case, UK is connected to Norway via a new 10.8 GW direct link. Under the 'Fully Integrated' policy choice, this connection is replaced by three offshore–offshore links totalling 9.3 GW of capacity, while also incorporating large offshore clusters. The design philosophy is applied to the UK–Belgium case and UK–Ireland cases. Another important insight is that the total volume of onshore-to-offshore connections in the UK is reduced from a sum of 68.1 GW to 58.7 GW. This does not mean that wind exports are not fully accommodated, but rather that it is more beneficial to export UK offshore wind directly to continental Europe. This is driven by the large amount of offshore wind capacity in the UK; there are times when very substantial arbitrage opportunities with other European countries arise. Instead of importing wind to the main UK grid and then distributing energy via cross-border links to France, Belgium and The Netherlands (which is the case under 'Radial'), three large offshore–offshore links are built that connect Hornsea, East Anglia and Dogger Bank (clusters 26, 29 and 32 respectively) to a Netherlands offshore cluster and subsequently to the mainland. We also observe that the large decrease in UK onshore-offshore connections is compensated by an increase of almost equal size (from 31.3 GW to 41.8 GW) for The Netherlands. The construction of this large capacity offshore corridor is also partly the reason behind the large onshore reinforcements between The Netherlands–Belgium and The Netherlands–France which are not seen under the 'Radial' approach; to enable efficient distribution of zero marginal cost renewable resources across mainland Europe during times of high wind.

It is also imperative to highlight that the basic synergies enabled via offshore links persist even under the low-deployment scenario 4. For example, the 8.2 GW Sweden–Germany direct interconnector seen under 'Radial' is replaced by an offshore corridor that incorporates offshore wind resources. However, an interesting difference to scenario 1 is that offshore-onshore connections in the UK are now considerably

Table 2
Additional network transfer capacities under the 'Radial' (left) policy choice for scenario 1 (left) and scenario 4 (right) by the end of study horizon.

	BE 2.5	DK 15.0	FR 8.3	DE 53.3	IR 3.4	NL 35.2	NO 8.0	SE 1.1	UK 76.7
BE 2.5	2.2								
DK 15.0		0 / 12.5							
FR 8.3	2.8 / 0		7.3						
DE 53.3	0.6 / 0	1.0 / 0	9.7 / 0	33.1 / 43.7					
IR 3.4			0 / 0		3.0				
NL 35.2	8.1 / 0	0 / 0		0.9 / 0		31.3			
NO 8.0		0 / 0		0 / 0		0 / 0	0 / 5.1		
SE 1.1		3.9 / 0		7.1 / 0			0 / 0	1.0	
UK 76.7	1.4 / 0	0 / 0	7.3 / 0	0 / 0	1.3 / 0	0 / 0	11.2 / 0	0 / 0	38.9 / 68.1

	BE 2.5	DK 2.4	FR 0	DE 20.5	IR 3.0	NL 7.2	NO 0	SE 1.1	UK 13.2
BE 2.5	2.2								
DK 2.4		0.4 / 2.2							
FR 0	0 / 0		0						
DE 20.5	0 / 0	2.1 / 0	9.8 / 0	11.5 / 17.1					
IR 3.0			0 / 0		2.7				
NL 7.2	0.2 / 0	0 / 0		0 / 0		6.4			
NO 0		0 / 0		0 / 0		0 / 0	0.3 / 0		
SE 1.1		0 / 0		8.2 / 0			0 / 0	1.0	
UK 13.2	1.3 / 0	0 / 0	1.4 / 0	0 / 0	3.5 / 0	0 / 0	4.8 / 0	0 / 0	9.6 / 11.8

higher under 'Integrated', increasing from 11.8 GW to 17.5 GW. This is because in the eventuality of a severely restricted deployment of offshore wind in the North Seas, UK becomes a net importer of energy since it has very limited access to cheap energy sources compared to other European countries. As a result, multi-purpose links combining connection of wind farms cross-border trade are built between Belgium, The Netherlands, Ireland and the UK. Note that this is also apparent from the fact that onshore–offshore capacity of Ireland and Belgium is reduced under the 'Integrated' policy choice; resources are directly re-routed to the South England node. Conversely, The Netherlands exhibits an increased need for onshore–offshore capacity, but for largely the same reasons; a multi-purpose corridor between UK–Netherlands is created that also enables energy transfers from the mainland Dutch grid. A final comment is the fact that the resulting offshore grid topology displaces the need to build large direct interconnectors between UK–Norway and UK–Netherlands which are needed under 'Radial' to enable access to cheaper resources. The above demonstrates how even under low-growth scenario realizations, the possibility for offshore–offshore links can profoundly change the system design and operation philosophy.

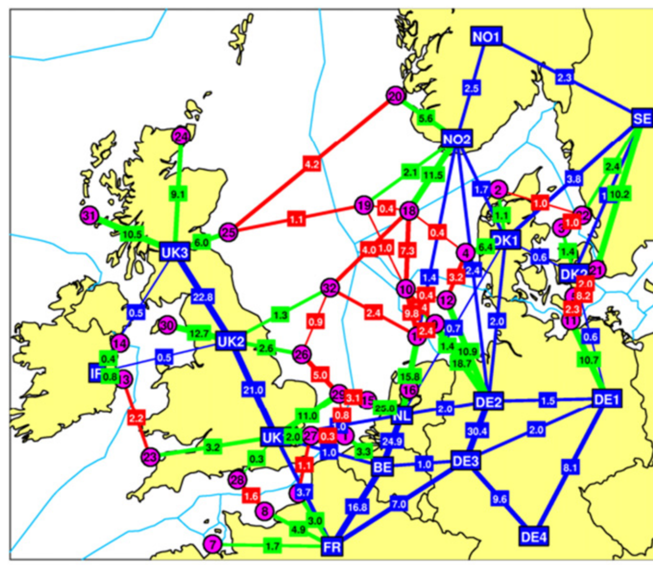
Note that the 'Fully Integrated' policy choice leads to higher investment volume than 'Radial' under all scenarios. However, the overall investment costs are considerably lower under 'Fully Integrated' due to economies of scale and increased coordination. Detailed investment and operational costs for the 'Fully Integrated' case covering the entire study period 2020–2044 are shown in Table 5. Investment and operational costs per stage for each scenario are shown in the Appendix B.

3.1.4. Specific case study no 3 under perfect information—proactive design

In this section we investigate the possibility for a planner that undertakes a holistic optimization approach towards planning both network and generation assets in an integrated fashion. Note that in this comparison we are not concerned with differences in generation investment costs since the overall levels of connected wind are the same; it is the location of these generators that actually changes. The optimal deployment pattern for offshore wind farms under the 'Proactive' policy choice across the four scenarios are shown in Fig. 12.

Table 3
Investment and operational costs (€bn) for the 'Radial' policy choice for the entire study period.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Onshore-onshore links (internal)	8.6	6.7	5.2	4.1
Onshore-onshore links (cross-border)	23.6	24.8	20.6	19.0
Offshore-onshore links	70.4	45.7	30.1	15.1
Network investment cost	102.6	77.2	55.9	38.2
Operational cost	1272.2	1431.1	1570.8	1723.7
Total system cost	1374.7	1508.3	1626.7	1761.9



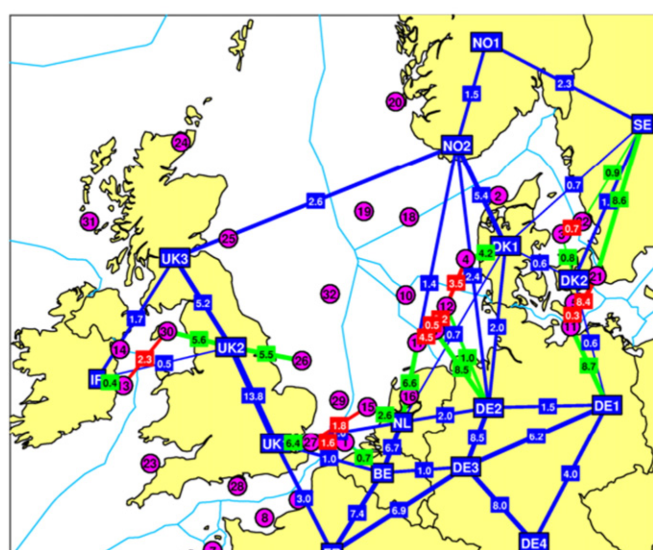


Fig. 11. Optimal network designs obtained under 'Fully Integrated' policy choice for scenario 1 (top) and scenario 4 (bottom) by the end of study horizon.

Table 4
Additional network transfer capacities under the 'Fully Integrated' policy choice for scenario 1 (left) and scenario 4 (right) by the end of study horizon.

Scenario 1 (left):

	BE 2.5	DK 15.0	FR 8.3	DE 53.3	IR 3.4	NL 35.2	NO 8.0	SE 1.1	UK 76.7
BE 2.5	3.3								
DK 15.0		0 / 8.9							
FR 8.3	13.1 / 0		9.6						
DE 53.3	0 / 0	0 / 5.4	5.9 / 0	30.1 / 41.7					
IR 3.4			0 / 0		1.1				
NL 35.2	22.1 / 0	0 / 0		0 / 12.1		41.8			
NO 8.0		0 / 0.7		0 / 8.3		0 / 0	1.0 / 19.2		
SE 1.1		3.1 / 4.0		0 / 8.4			0 / 0	12.6	
UK 76.7	0 / 1.2	0 / 0	0.7 / 2.7	0 / 0	0 / 2.3	0 / 5.6	0 / 9.5	0 / 0	31.6 / 58.7

Scenario 4 (right):

	BE 2.5	DK 2.4	FR 0	DE 20.5	IR 3.0	NL 7.2	NO 0	SE 1.1	UK 13.2
BE 2.5	0.7								
DK 2.4		0 / 5.0							
FR 0	3.7 / 0		0						
DE 20.5	0 / 0	0 / 3.8	5.8 / 0	6.7 / 18.2					
IR 3.0			0 / 0		0.4				
NL 7.2	3.9 / 0	0 / 0		0 / 5.0		9.5			
NO 0		0 / 0		0 / 0		0 / 0	0 / 0		
SE 1.1		0 / 1.0		0 / 8.4			0 / 0	9.5	
UK 13.2	0 / 1.6	0 / 0	0 / 0	0 / 0	1.3 / 2.3	0 / 2.1	2.9 / 0	0 / 0	6.7 / 17.5

Differences between the exogenous and 'Proactive' deployment patterns are most prominent in the low deployment scenarios. Under scenario 1, the planner has to eventually construct all available projects and thus the differences are limited to the stage-wise evolution instead of final deployment levels which are identical. However, when examining the lower-deployment scenarios, we observe that under the generation-transmission coordination paradigm the planner prefers to build more wind in the UK and The Netherlands, while Germany is not an attractive option. This difference can be further investigated by examining the optimal network design for the two extreme scenarios, shown in Fig. 13. Table 6 shows the corresponding transfer capacities.

For scenario 1, although the planner eventually needs to accommodate wind coming from clusters of the same size as in the previous case studies, the investment pattern is different due to the optimized deployment in epochs 1 to 4, where construction of French and German wind farms is delayed in favour of UK and Dutch clusters. Co-optimization of transmission and offshore generation assets results in an aggregate build of 347.5 GW of transmission as contrasted to the 373.4 GW required under the 'Fully Integrated' policy choice.

In the case of scenario 4, the differences in optimal network design are even more prominent. As can be seen in Fig. 13 and Table 6, the planner chooses to deploy offshore wind in such a manner so as to create a synergy between the 'de facto' beneficial trade routes described before (i.e., UK to Norway and UK to The Netherlands) with large offshore wind clusters. Dogger Bank and its associated export link to mainland UK act as part of a large offshore corridor between UK and Norway that also incorporate smaller links to The Netherlands via other offshore clusters. On the other hand, Germany can easily be connected to other countries via considerably cheaper onshore links. In addition, Germany is much closer to the Scandinavian countries, meaning that direct subsea interconnectors are also considerably cheaper to build compared to the UK; the synergistic effect of German wind towards system-wide network integration is considerably less pronounced and for this reason the planner chooses alternative deployment locations.

Detailed investment and operational costs for the 'Fully Integrated' case covering the entire study period 2020–2044 are shown in Table 7. The full investment and operational costs are presented scenario in Appendix B.

3.2. Value of flexibility — min–max regret study

The studies presented in the preceding section assumed full knowledge regarding future offshore wind deployment patterns. In this section, uncertainty is introduced via a scenario tree that couples first-stage decisions; the planner has to undertake first-stage investment commitments without knowing which of the scenarios may materialize. To this end, appropriate constraints have been introduced to equate first-stage decisions across all scenarios. These constraints are relaxed for later epochs, enabling the planner to re-adjust his strategy in view of subsequent offshore wind developments. In view of this uncertainty a minimax regret decision criterion is adopted; the planner's objective is to invest in network assets so as to minimize the maximum regret experienced across all scenarios.

Regret is associated with how first-stage decisions inadvertently ill-condition the system and hinder its ability to adjust to eventual scenario realizations at least cost. On the one hand, increased investments in the first stage may be beneficial for high-growth scenarios, but will lead to unnecessarily high capital costs in the event of low offshore rollout. Similarly, undertaking low investment ill-conditions the system in case of high-growth developments by foregoing economies of scale and forcing the planner to pay increased fixed costs to re-adjust his strategy. In view of the above, the planner's task is to strike an optimal compromise between being able to operate the system efficiently in the short-term (minimize wind curtailment) and being adequately pre-positioned to adjust to the eventual realization at minimum cost (minimize asset stranding). To this end, the minimax regret model can identify the optimal investment *strategy*, as opposed to the set of investment *schedules* produced using deterministic models that assume perfect information of future wind deployment. This strategy appreciates the trade-offs that arise due to lack of information and optimally balances between keeping a risk-averse and an optimistic outlook to ensure that the suggested commitments result in the minimum regret possible. The most notable advantage of optimizing against uncertain future is the fact that we can identify solutions that are not encountered when scenarios are examined in isolation; this is aligned with recent findings published in Munoz et al. (2014) and Konstantelos and Strbac (2015) that use stochastic optimisation models. Such investment decisions can be considered suboptimal from a perfect information, single scenario point of view, but are beneficial in the way they deal with uncertainty; they

Table 5
Investment and operational costs (€bn) for the 'Fully Integrated' policy choice for the entire study period.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Onshore-onshore links (internal)	7.2	4.7	2.5	3.0
Onshore-onshore links (cross-border)	7.5	6.7	5.7	11.5
Offshore-onshore links	31.2	24.8	18.9	9.9
Offshore-offshore links	18.6	19.2	15.2	5.7
Network investment cost	64.5	55.4	42.3	30.2
Operational cost	1235.0	1.407.5	1549.1	1706.9
Total system cost	1299.6	1462.9	1591.4	1737.1

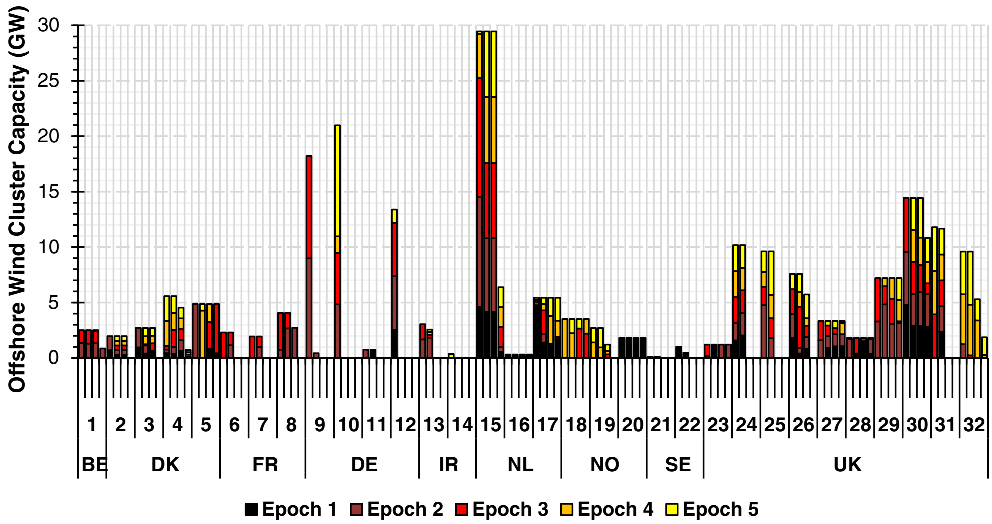


Fig. 12. Optimal capacity of the 32 offshore wind clusters under the 'Proactive' policy choice. Four stacked bars are shown for each of the 32 clusters, the leftmost bar corresponding to scenario 1, followed by scenario 2 etc.

increase the options available in the planning process and enable adjustments to be made to each possible realization in an efficient manner. Conversely, plans obtained from individual scenario analysis are optimal for a particular future but may leave little room for hedging when an adverse scenario occurs. Identification of such cost-efficient openings for strategic investment is an important aspect of uncertainty analysis.

To illustrate this concept, in Fig. 14 we contrast the optimal first-stage network designs for the two extreme deterministic scenarios to the investment pattern resulting in minimization of the maximum regret when considering uncertainty.

As can be seen in Fig. 14, first-stage commitments under the 'Minimax Integrated' paradigm contain some links that are also encountered under the high-growth scenario 1. For example, the minimax planner chooses to adopt an optimistic stance towards future wind developments in clusters 13 and 23 and builds an offshore–offshore link between them, similar to what is proposed by the scenario 1 network. Note that the scenario 4 network does not go ahead with such an investment due to the planner's certainty that little wind will come online in those clusters in the future. This means that the benefit of this commitment is higher than the regret experienced if an adverse realization occurs; a risk-averse stance entails a disproportionately high opportunity cost. In a similar manner, some commitments suggested by the 'Minimax Integrated' model are also encountered in the low-deployment scenarios; this is the case when the planner chooses to keep a conservative stance against some of the riskier projects. For example, the line connecting UK–France via offshore clusters 8 and 28 is not built because under the low-deployment eventuality, France has very limited offshore wind and there is little benefit in pre-emptively integrating these wind farms in an offshore multi-purpose corridor; the planner hedges against stranded costs and keeps a conservative stance that can be corrected later on according to the eventual uncertainty realization.

Most interestingly, there are some first-stage commitments that are not encountered in any of the scenario-specific optimal designs. As can be seen in more detail in Fig. 14, the optimal first-stage decisions under the minimum regret approach includes an interconnection between UK–Netherlands via an offshore–offshore cable that links offshore clusters 29 (East Anglia) and 15. This is an example of a commitment that is not seen under any of the scenario-specific optimal plans and is undertaken to provide flexibility under the envisaged uncertainty. More specifically, this flexibility-driven investment is chosen to enable exports from the large Dutch offshore cluster to the UK in the event that a low-wind scenario occurs. This can essentially be seen as a hedge against low-deployment scenarios, where the UK becomes a net importer; an anticipatory commitment now that will prove valuable in subsequent epochs if scenarios 2, 3 or 4 occur.

What follows is a regret analysis to compare how successful are the first-stage commitments proposed by the different approaches towards handling adverse uncertainty realizations; the regret of scenario-specific plans is contrasted to the minimax network. This type of analysis aims to quantify the level of regret the planner would experience if he was to follow a specific set of first-epoch decisions that can be adapted while the future unfolds. With this in mind, what is important to note is that the regret experienced is essentially a quantification of the ill-conditioning that arises from the over or under-investment that takes place in the first epoch and the extent to which this constrains or facilitates future investment decisions. For example, if large investments occur and a low-deployment scenario follows, the regret will principally be due to the constructed links that eventually proved to be unnecessary. On the other hand, if under-investment occurs and a high-deployment scenario follows, the regret will principally be due to offshore wind curtailment as well as foregone cross-border trade opportunities. Results of the undertaken regret analysis are shown in Fig. 15.

As can be seen above, if the scenario 1 network is built in the first epoch and scenario 1 actually occurs, then by definition there is no regret since the optimal investment decisions have been made. However, if scenario 4 materializes instead, then the planner would experience a regret of €2bn, largely due to unnecessary overinvestment in corridors that are not eventually needed. On the opposite end, if the planner chooses to naively plan the system for scenario 4 and scenario 1 materializes, the net regret sums up to €33.1bn, due to the inability to export offshore wind to the mainland grids. Note that the islanded offshore clusters will be integrated in the system later on since their isolation entails very substantial curtailment costs, which can only be resolved after a five-year delay (i.e., 1 epoch). It is worth noting that the regret in terms of network investment is negative, meaning that by following the scenario 4 network plan, the planner stands to benefit in terms of capital expenditure (when compared to having followed the optimal scenario 1 network plan). However, this cannot be viewed in isolation; these small savings in terms of capital expenditure give rise to a very significant increase of operational costs. As expected, the performance of first stage commitments suggested by the scenario 2 and 3 networks lie between the two extremes. Both networks lead to significant levels of wind curtailment with maximum regrets corresponding to occurrence of scenario 1 and being €3.6bn and €13.4bn respectively. The

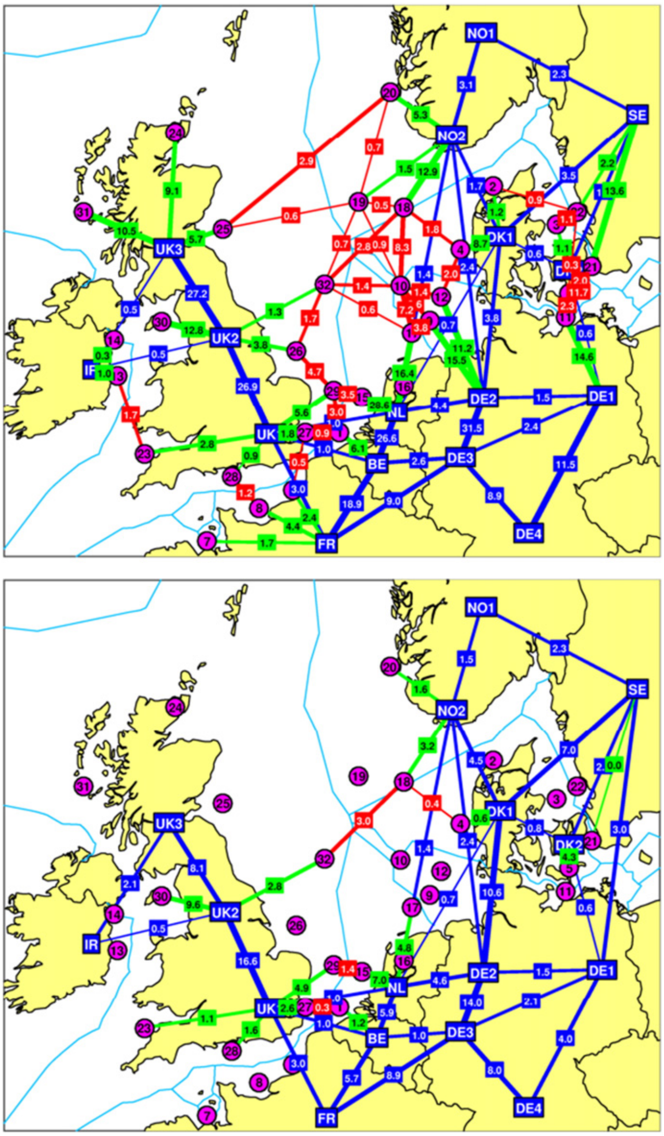


Fig. 13. Optimal network designs obtained under 'Proactive' policy choice for scenario 1 (top) and scenario 4 (bottom) by the end of study horizon.

minimum maximum-regret is achieved by the 'Minimax' network which identifies strategic first-stage commitment that can most flexibly adapt to different levels of offshore wind deployment.

Table 7
Investment and operational costs (€bn) for the 'Proactive' policy choice for the entire study period.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Onshore-onshore links (internal)	6.6	7.1	2.9	3.3
Onshore-onshore links (cross-border)	6.8	6.8	14.8	13.7
Offshore-onshore links	30.0	23.4	14.6	8.2
Offshore-offshore links	16.8	17.8	7.6	3.3
Network investment cost	60.2	55.0	39.9	28.4
Operational cost	1234.5	1402.3	1543.4	1701.8
Total system cost	1294.6	1457.3	1583.3	1730.2

Note that as discussed in (Miranda and Proenca, 1998) stochastic approaches that aim to minimize expected system cost and do not consider risk (or regret) can lead to inadequate planning decisions. This is because although stochastic solution will be best on the average of future scenarios, the regrets corresponding to the most adverse scenarios will generally be higher than those experienced under a minimax regret framework. Allowing the possibility for low-probability futures with highly-adverse consequences to arise is not desirable in large-scale infrastructure planning. Most importantly, stochastic models are shown to exclude attractive investment decisions due to their inherent limitation of identifying solutions that lie on the convex hull of the non-dominated set of solutions. In contrast, minimax regret modelling can uncover attractive compromise solutions that lie within the concave part of the solution hull. This explains the ability of minimax analysis to identify strategic first-stage offshore-offshore decisions that were not uncovered in other analyses. Importantly, the regret-based philosophy is very much in line with existing regulatory frameworks which are based on ex-post performance evaluation against ex-ante-defined targets (National Grid, 2014). A further point that highlights the applicability of minimax regret is the absence of probabilities whose definition can be problematic in a real-world context. When probabilities can be computed with full confidence, however, more coherent risk aversion criteria based on stochastic approaches, such as the Conditional-Value-at-Risk (CVaR), would be preferred as they present important economic properties, i.e. monotonicity, sub-additivity, homogeneity and translation invariance (Artzner et al., 1999). In the literature, there is also a third option that has been recently applied on the power sector which combines robust and stochastic approaches depending on the confidence level associated with the probability values (Esfahani and Kuhn, 2015; Fanzeres et al., 2015; Xiong et al., 2017). These are promising approaches that could be also applied to the problem in this paper and demonstrate that this debate remains open.

Table 6
Additional network transfer capacities under the 'Proactive' policy choice for scenario 1 (left) and scenario 4 (right) by the end of study horizon.

	BE 2.5	DK 15.0	FR 8.3	DE 53.3	IR 3.4	NL 35.2	NO 8.0	SE 1.1	UK 76.7
BE 2.5	3.3								
DK 15.0		0 / 8.9							
FR 8.3	13.1 / 0		9.6						
DE 53.3	0 / 0	0 / 5.4	5.9 / 0	30.1 / 41.7					
IR 3.4			0 / 0		1.1				
NL 35.2	22.1 / 0	0 / 0		0 / 12.1		41.8			
NO 8.0		0 / 0.7		0 / 8.3		0 / 0	1.0 / 19.2		
SE 1.1		3.1 / 4.0		0 / 8.4			0 / 0	12.6	
UK 76.7	0 / 1.2	0 / 0	0.7 / 2.7	0 / 0	0 / 2.3	0 / 5.6	0 / 9.5	0 / 0	31.6 / 58.7

	BE 0	DK 5.6	FR 0	DE 0	IR 0	NL 12.1	NO 5.3	SE 0	UK 26.2
BE 0	0.7								
DK 5.6		0 / 5.0							
FR 0	3.7 / 0		0						
DE 0	0 / 0	0 / 3.8	5.8 / 0	6.7 / 18.2					
IR 0			0 / 0		0.4				
NL 12.1	3.9 / 0	0 / 0		0 / 5.0		9.5			
NO 5.3		0 / 0		0 / 0		0 / 0	0 / 0		
SE 0		0 / 1.0		0 / 8.4			0 / 0	9.5	
UK 26.2	0 / 1.6	0 / 0	0 / 0	0 / 0	1.3 / 2.3	0 / 2.1	2.9 / 0	0 / 0	6.7 / 17.5

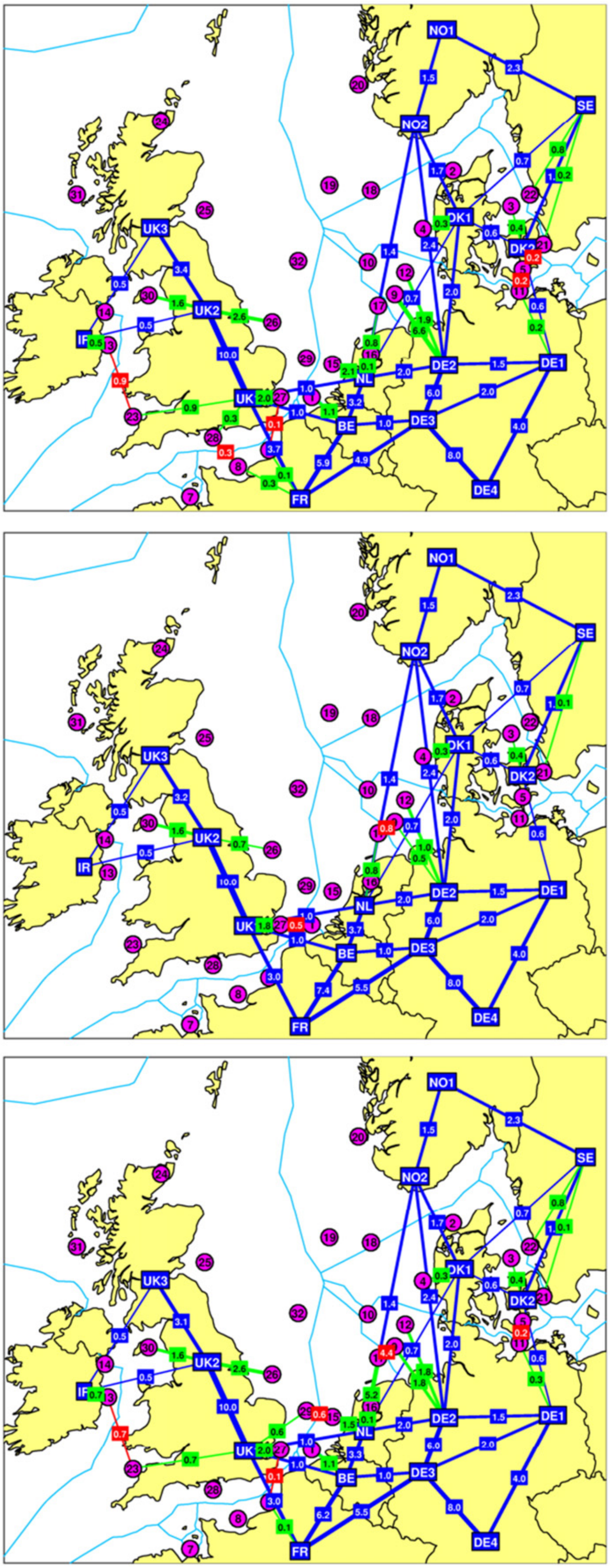


Fig. 14. Optimal first-epoch network design under the deterministic 'Fully Integrated' policy choice for scenario 1 (top), scenario 4 (middle) and 'Min–max Fully Integrated' (bottom).

The present regret analysis demonstrates that when facing uncertainty, it is preferable to over-design the grid in the first stages and anticipate a potentially-large rollout of offshore wind when compared to keeping a conservative stance and limiting investment as suggested by a plan tailored for a low-rollout eventuality. This is because the potential curtailment costs that will arise in the event that more-than-projected wind is built are substantially higher than the potential cost of stranded assets. In this vein, an important message that emerges is that offshore-offshore links can naturally hedge against network stranding of offshore–onshore links. The ability to interconnect offshore clusters so as to form cross-border links as well as alternative transmission corridors for internal congestion alleviation expands the potential uses of offshore cluster connections to onshore grids, substantially reducing the scope for asset stranding that characterizes offshore-onshore links used solely for offshore wind export purposes. Given that offshore–offshore links entail significant strategic value, their benefit valuation should be undertaken on an 'investment-under-uncertainty' basis (i.e., non-perfect information valuation) so as to uncover their full contribution to system welfare.

3.2.1. The role of financial markets

As explain in (Deng and Oren, 2006; Munoz et al., 2016), investors in electricity infrastructure can trade in financial markets many of the risks they are exposed to through financial transmission rights, electricity futures, forwards, swaps, and options. However, risks resulting from changes in policy and regulation, such as network tariffs, subsidies, and renewables incentives (which may have an important impact on the deployment of future electricity infrastructure), cannot be traded. In the context of this paper, financial transmission rights could have an important role to protect electricity producers and consumers if network investment is inadequate for the generation expansion and, for example, does not suffice in the future as explained in (Lyons et al., 2000). There are other (regulatory) risks, however, that cannot be traded and lie primarily with the parties that invest in transmission lines (TSOs as well as private investors in jurisdictions that allow private Offshore Transmission Owners, OFTOs, such as the UK). TSOs and OFTOs face the risk of regulatory backlash, where an investment is deemed unjustified by the regulator and unable to recover its capital cost through tariffs.

3.3. Winners and losers of network integration

Moving towards a more coordinated approach for transmission planning across the North Seas region will create winners and losers. Athough the 'Fully Integrated' policy choice has a positive effect on aggregated total cost (as shown in Section 3.1) and therefore on social welfare at both EU and country level (Hogan, 2011), this does not necessarily hold true for individual market participants since increasing integration will change trading positions, affecting market prices along with overall exports and imports in a country.

The issue of cross-country benefit distribution has been identified as a substantial issue in the past. As explained in (Gately, 1974), the distribution of the benefits arising from various degrees of regional cooperation in planning electricity infrastructure investment has to meet certain minimal criteria of mutual acceptability, including a low *propensity to disrupt* from any member state (where the propensity to disrupt from a member state k is measured as the ratio between other members' losses and those of member k when he refuses to cooperate i.e. ratio between other members' benefits and those of member k when he does cooperate). In the particular case of the North Sea grid, the NorthSeaGrid project (2015) investigated the impact that wind farm integration to cross-border interconnectors can have to producer and consumer surplus in the participating and neighbouring countries. The analysis showed that such interconnection projects can result in highly asymmetric allocation of benefits, requiring compensation rules to offset the losses of some stakeholders. Researchers in (Torbaghan et al.,

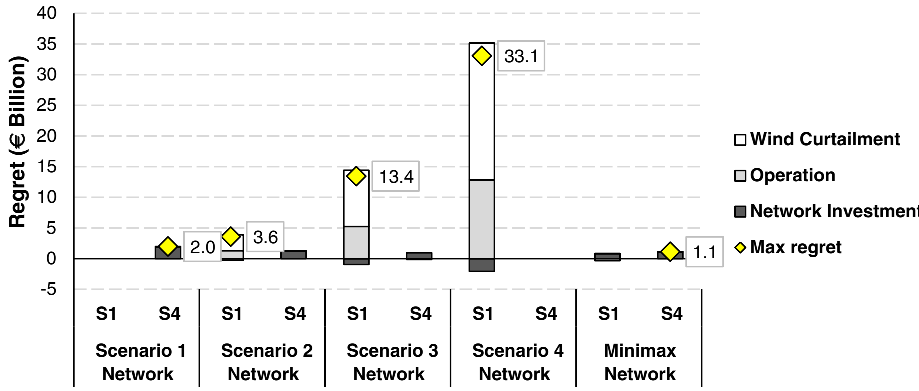


Fig. 15. Regret analysis for different first-stage network designs. Regret is broken down to its different sources; due to wind curtailment, increased operation costs (reduced cross-border trade) and increased network investment costs. The maximum regret of each network design is indicated.

2015) investigated the optimal North Sea grid design using a zonal market model with a focus on the impact of potential delays caused by technical and legal obstacles. They show that the social welfare change of each country is a quadratic function of the change in power imports. As such different countries are affected differently by the offshore wind deployment resulting in substantially unequal incentives for solving them. Clearly, failing to properly allocate the benefits and costs associated with regional integration will affect the materiality and likelihood of such integration (ACER, 2013).

In this context, Fig. 16 shows country-specific distribution of savings under the different deployment scenarios for the 'Fully Integrated' policy choice (as compared to 'Radial'). In Fig. 16, we have employed the "equal share" rule for capital expenditure allocation, where the investment cost pertaining to cross-border interconnectors and offshore–offshore links is shared equally between the two owner countries. Note that a country's operation cost savings are due to the ability to access cheaper supply-side resources than under the 'Radial' policy choice, where cross-border trade is substantially constrained. The presence of network investment savings means that less capital expenditure under 'Fully Integrated' when compared to the 'Radial' policy choice, is undertaken within a country.

A negative saving in operating cost, as that observed in The Netherlands under high-deployment scenarios in Fig. 16 due to higher energy exports in the 'Fully Integrated' case, could be both detrimental for local consumers and beneficial for local producers. Indeed, The Netherlands has a large amount of offshore wind energy resource which, under the 'Fully Integrated' case, is partially transferred to other European countries where prices are more attractive instead of being used locally to displace use of more costly sources of energy. A positive saving in operating cost on the other hand, as that observed in the UK under low-deployment scenarios in Fig. 16 due to higher energy imports in the 'Fully Integrated' case, can significantly benefit local consumers since increased imports can displace more costly energy production in the country, albeit this will naturally harm revenue of UK generators that may, in turn, jeopardize national security of supply. Hence impacts of a 'Fully Integrated' North Seas network are very diverse across different market participants in the North Seas countries, which might affect national governments' will (who may weigh differently consumer and producer surplus) and thus make the realization of such network a more challenging task.

Another major complexity is the remuneration of network investment across beneficiaries in a multi-country context. For instance, Fig. 16 shows that under low-deployment scenario S3, UK consumers significantly benefit from deployment of a 'Fully Integrated' North Seas grid, while investment cost of such integrated network increases abroad, e.g., Norway (where consumers are worst off with a 'Fully Integrated' approach). This imposes significant challenges at the regulatory level since clearly network investment cost has to be properly allocated to beneficiaries across the North Seas (regardless of countries' boundaries) instead of being charged only to the country where the investment belongs.

Moreover, it is unclear how current subsidies to wind generation in every country may affect realization of an integrated network. For example, as explained in Section 3.1, net capacity in offshore-onshore

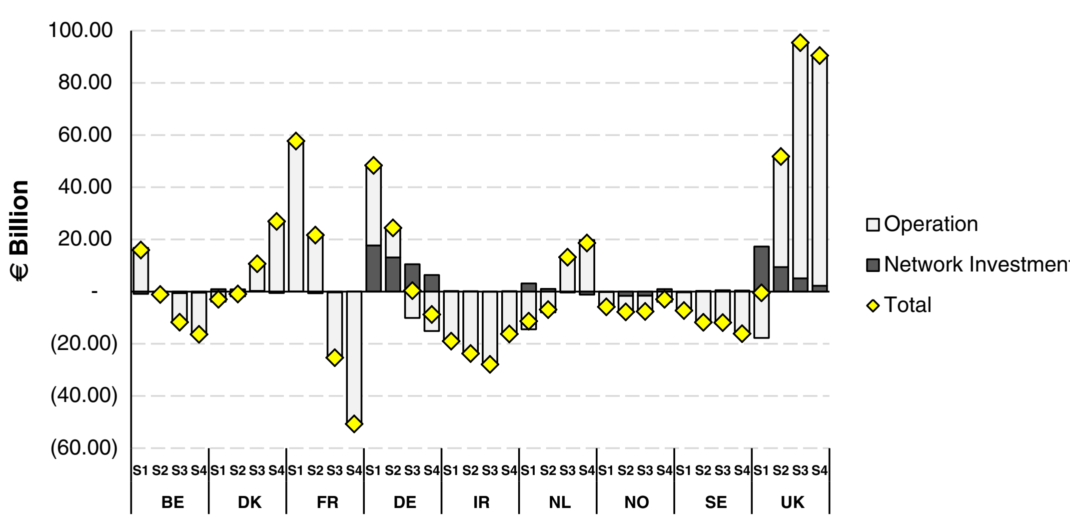


Fig. 16. Savings of the 'Fully Integrated' policy choice in operation and network investment costs for each country when compared to the 'Radial' basecase.

connections associated with UK offshore wind generation in scenario S1 is less than the offshore wind generation capacity itself in the UK, which implies that part of the wind that is subsidized by UK consumers is directly exported and used elsewhere. This can clearly create conflicts between national governments and EU and resolving them, which may require harmonization of mechanisms to incentivise offshore wind generation across North Seas countries, will be essential to realize a fully integrated network policy. Furthermore, it may be necessary to establish a compensation mechanism (in the form of a tax and/or subsidies) which can ensure that transition from current network planning paradigm to a more integrated and coordinated approach represents an improvement from a national government's perspective, who may weigh differently consumer and producer surplus. This involves ensuring that, on the one hand, consumers in a country are not significantly harmed by price increases and, on the other hand, producers present sufficient incentives to maintain adequate levels of security of supply at a country level. Design of such mechanism can facilitate agreement among national governments and unlock regional development of integrated networks.

Finally, realization of a 'Fully Integrated' North Seas network will require that national TSOs work closer together. This can be achieved in different ways, one of which could be the establishment of a new institution, namely a regional ISO, which could neutralize various types of conflicts of interest by taking a country-agnostic view of welfare and being independent from network ownership. A regional ISO would ensure that offshore wind power across the North Seas is efficiently transferred among countries and would be in a better position to evaluate the efficiency of transmission investment and thus to undertake strategic planning functions associated with the transnational power system.

4. Conclusions and policy implications

The analysis presented in this paper aims at informing the development of policy regarding the offshore network investments with a particular focus on the North Seas area. More specifically, the benefit of coordination within offshore clusters and the scope for economies of scale when building connections to shore was shown to be significant across various deployment scenarios. Interest in offshore wind is also opening opportunities for transmission projects that cut across individual transmission regimes, i.e., onshore, offshore and cross-border interconnection. In a similar vein, the studies showed that the ability to establish links between offshore clusters can displace direct cross-border interconnectors as well as some onshore network reinforcement needs in a cost-efficient manner. Our analysis indicates that fully integrated solutions become particularly attractive under the scenario of substantial offshore wind rollout. However, it is important to note that as the cost of grid connection represents a significant proportion of the cost of a typical offshore wind project, savings that developers could make through strategic integration of interconnectors could in turn further enhance the development of offshore wind. Moreover, in order for the benefits of an integrated offshore grid to be fully visible, unconstrained cross-border trade between North Seas member-states is of paramount importance in order to take advantage of the significant arbitrage opportunities that exist between UK, Norway and mainland Europe. The present paper provides a clear case for enhancing coordination across member-states for achieving European decarbonization targets in a cost-efficient manner.

In addition, by considering the impact of uncertainty related to long-term offshore plant developments, we showed that flexibility-driven investments have a critical role to play in balancing the risks of stranded assets due to over-investment against the associated savings in capital expenditure derived from economies of scale. Given that the new reality of increasing penetration of intermittent energy sources is significantly expanding cross-border arbitrage opportunities, offshore–offshore links provide highly-beneficial alternate use cases for offshore connections. Our analysis highlights offshore–offshore links as particularly attractive strategic commitments which can be undertaken on the basis of enhancing future system adaptability. This finding further strengthens the argument for increasing coordination in the North Seas. In addition, the proposed 'min–max regret' framework constitutes a novel and well-founded basis for identifying strategic multi-purpose projects of common interest and enhancing current valuation methodologies (ENTSO-E, 2015).

Given the significant benefits of an integrated offshore grid from a system-wide perspective, we investigate impacts at a market participant level (i.e., consumers and producers in a country), demonstrating significant imbalances. In this context, this study highlights the need for four major developments in regional and European regulatory and market frameworks to enable the unhindered development of multi-purpose transmission projects: (i) a regional ISO who can ensure efficient operation and planning of the North Seas grid, (ii) transmission charging regime based on 'beneficiary pays' principle, regardless of countries' boundaries, (iii) harmonization of incentive mechanisms (i.e., subsidies) for offshore wind generation among North Seas countries, and (iv) a potential compensation mechanism that can facilitate transition to a more integrated and coordinated approach for network planning. In this paper, we have used cost differentials/savings to examine countries' benefits rather than revenues and expenditures from market participants and the latter is recommended for future research.

In conclusion, the strategic and integrated planning and operation of the North Seas grid region presents the opportunity to deliver policy objectives at a vastly reduced cost compared to the current incremental and member-state-centric approach. These potential advantages should not be ignored and it must be made a high priority for energy ministries around the North Seas to consider how these benefits can be realized.

Acknowledgement

Dr. Moreno gratefully acknowledges the financial support of Conicyt-Chile (through grants Fondecyt/Iniciacion/11130612, Newton-Picarte/MR/N026721/1, Fondap/15110019 and the Complex Engineering Systems Institute [ICM: P-05-004-F, Conicyt:FBO1]).

Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2017.03.022.

Appendix B. Additional data

The additional data have been made available in the spreadsheet at the URL: https://goo.gl/1ZBJqC

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