Transmission Expansion Simulation for the European Northern Seas Offshore Grid

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Abstract

HVDC innovations and the integration of power markets and renewables drive the development of a European Northern Seas offshore grid. This power transmission system performs two functions: interconnecting Northern European onshore power systems, and connecting offshore wind farms. Despite its benefits, the development of an integrated offshore grid combining the two functions is slow. The main reasons are the lack of cooperation and governance frameworks to overcome regional differences and distribute costs and benefits. These barriers were studied so far only qualitatively or through perfect foresight optimization models. We complement this by studying transmission expansion pathways of the grid, which are non-optimal and path dependent, using a novel and open-source simulation model for offshore transmission investments. Different expansion typologies are considered, which we find perform the grid functions with different levels of integration and transmission capacities. Besides these typology factors, modelling and simulation factors also affect the expansion selection. Typology, modelling and simulation factors interact to result in radically different offshore grid pathways, which exhibit strong path dependence. Thus, to avoid locking-out beneficial expansions for the Northern Seas offshore grid, planning should be done regional and consider HVDC innovations. Then individual projects can be implemented based on their own merits.

Keywords: Northern Seas; offshore grid; offshore wind; path dependence; simulation; transmission expansion planning

Highlights

- An open-source simulation model for offshore grids expansion is developed.
- Transmission typologies differ in grid function integration and in terminal capacities.
- Modelling, simulation and typology factors interact to determine pathways.
- Expansion pathways exhibit strong path dependence.
- Energy Union transmission should be planned regionally but implemented individually.

Abbreviations: AC/DC, alternating-current/direct-current; BI, British Isles; CE, Continental Europe; IC, interconnector; HVAC, high-voltage alternating-current; HVDC, high-voltage direct-current; NPV_a, absolute net present value; NPV_r, net present value ratio; PV, photovoltaic; SC, Scandinavia; TEP, transmission expansion planning;

1. Introduction

Our aim is to study the Northern Seas offshore grid, in order to understand which factors affect its expansion and make recommendations for the expansion planning. We develop a transmission investment simulation model using myopic optimization, while previously quantitative studies on the offshore grid have applied mainly perfect foresight optimization. Our simulation approach demonstrates the strong influence of path dependence on the grid expansion, a factor which previous studies did not address. In the introduction we present offshore grid, its relation to the European power system and policies, and the current state of research, governance initiatives and development projects on the grid. We then argue for our simulation approach.

An offshore grid has two functions: the interconnection of onshore power systems through interconnectors, and the connection of offshore power generation technologies, usually wind power [1]. An integrated grid has transmission links that combine these functions to some degree, instead of each link performing only one. In early 2016 members of the European Parliament made an appeal to "realise the full potential of the Northern Seas energy system" through increased cooperation of countries in the region. Their manifesto emphasized the benefits of an integrated offshore power grid to the European energy system [2].

The Energy Union is the main strategy of the European Commission to address European energy challenges. The integration of the internal energy market is one of the five priority dimensions of the Union, and offshore electricity interconnectors and the (possibly integrated) Northern Seas grid are important elements to this dimension [2,3]. Other drivers for the grid comprise innovation in high-voltage direct current (HVDC) transmission, offshore wind power development in the Northern Seas, and guaranteeing the reliability of European power systems [1,4,5]. However, despite these drivers and several studies and projects, the development of the offshore grid and especially its integration is slow [6–8]. Not surprisingly then, the manifesto of the members of the European Parliament [2] highlighted the need for regional cooperation and anticipatory investments ("leaving opportunities to upgrade cables at a later stage") for an integrated grid development.

Transmission expansion planning (TEP) is the field that studies how to best develop transmission grids according to preferred criteria [9]. Traditional TEP approaches use optimization or heuristics and face many difficulties. These include the increasing participation of renewables, decentralized and uncertain markets with multiple decision-making actors, conflicting objectives, large-scale generation projects, long permitting times, and regional integration [10]. Nonetheless, studies on European transmission such as the e-Highway 2050 project [11] remain confined to using optimization.

Optimization models provide normative guidance on the grid (that is, how it should develop), and several studies applied optimization to the offshore grid [1]. However, due to the slow development of an integrated grid, approaches to explore non-optimal scenarios and understand this slowness are also needed. Simulation is such an exploratory method, but has been rarely applied to TEP and never to the offshore grid. Scarce examples of TEP simulation include the use of game theory by Yen et

al. [12] and Contreras et al. [13], of agent-based modelling by van Blijswijk and de Vries [14], and of system dynamics by Ojeda et al. [15] and Ochoa et al. [16].

Thus we employ simulation to study the transmission expansion pathways of the grid, i.e. its possible development in time. Our novel open-source model conducts myopic optimization in transmission investments [17]. The model is myopic because it has a restricted investment horizon of one period, as opposed to a perfect foresight optimization model which considers the whole time horizon. A myopic horizon leads to a non-optimal simulation of the grid expansion, which allows us to explore alternative pathways. This simulation approach allows us to represent the grid path dependence, where the previous state of the grid locks-in or restricts the expansion into certain pathways, unless external influences change the pathway. Therefore our approach addresses both the non-optimality and the path dependence of grid expansion pathways.

Many governance initiatives, research and generation and transmission projects in the Northern Seas grid are ongoing. The most recent and important governance initiative is the aforementioned Energy Union, which includes several proposals for the European grid. These comprise minimum interconnection targets for Member States, the establishment of further projects of common interest (PCI), regional cooperation on infrastructure guidelines, and a revised market integration framework. Hence, the proposal from the European Commission and contributions from other energy analysts address financing, governance, top-down and bottom-up policies, and regulation [18–20].

As for projects, the main ones related to the offshore grid are national wind farm clusters and international wind farms (notably Kriegers Flak), and interconnectors between European countries. At least 15 interconnectors in the Northern Seas were in various development stages in 2015 [4,21]. Of those, three combine the onshore systems interconnection and the offshore farm connection functions indicated above.

Finally, on-going and concluded research projects on the offshore grid cover legal, economic, technical and regulatory aspects of the grid. Results indicate an integrated grid approach can provide investment and operational savings and lower environmental impacts, contribute to security of supply, and advance European marine governance [1,8].

Despite these advances, the Northern Seas offshore grid still faces barriers as mentioned, especially for typologies which integrate the two grid functions of connection and interconnection. The fundamental reasons are the lack of cooperation and governance frameworks to overcome regional differences and the distribution of costs and benefits at the national and actor levels. To Jay and Toonen [8] collaboration has progressed but is still slow and limited, both among member states and of these with industry. It is hampered by regulatory complexity and misalignment, project difficulties, soft legal approaches at the European level, and the lack of involvement of civil society. Fitch-Roy [6] on its turn sees an increased convergence among countries in models for developing offshore wind farms, with a mixed contribution of the European Union to this convergence process. Nonetheless, this convergence is not necessarily reflected in an effective cooperation for grid development. Flynn [7] highlights the weight of the national level and national differences in the development of renewables,

as opposed to the European level. The author sees a stark contrast between ambitious visions for an integrated grid and the reality of interconnection and offshore wind being a national or bilateral matter. Hence, the development of interconnection in Europe is challenged by factors that go beyond interconnection economics, and involve governance, preferences and cost and benefit perceptions of actors, and politics. This agrees with Puka and Szulecki [22], who highlight the current primacy of governance and political issues over finance and economics in the development of European interconnectors.

In summary, although an integrated grid provides significant benefits to countries and actors, its development is delayed by various barriers. Given its importance, it has received the attention of numerous research projects using mostly qualitative or perfect foresight optimization approaches, which contributed to understanding the benefits of an optimal grid design [1]. But despite the consensus that the actual grid development will combine both separate and integrated characteristics gradually, there is little research on how such a grid development could be [1].

By conducting TEP with simulation we provide researchers with an alternative methodology to the ones frequently applied to study grid pathways. Also, by studying transmission expansion pathways for the offshore grid this article demonstrates factors that affect the pathways and their path dependence, and elaborates on the consequences to planning of the grid.

This article is organized as follows. Section 2 presents the simulation approach to energy systems modelling, with a theory on the change of transmission infrastructures through investment, and then section 3 presents the offshore grid model. The case studies, results and discussion are presented in section 4, and finally section 5 concludes with the consequences to the expansion planning of the Northern Seas offshore grid within the Energy Union.

2. Transmission expansion planning and pathways

Here we introduce simulation within the context of energy systems modelling and present the framework to model transmission investments, arguing that investments determine the expansions pathways of the offshore grid.

2.1. Energy systems simulation

Energy system models can be classified as top-down or bottom-up [23]. The macroeconomic, sector-aggregated top-down approach opposes the technological, sector-specific bottom-up models. Thus, bottom-up models capture technological and other details of specific sectors, but may not represent feedbacks among sectors [24].

Bottom-up models can be further sub-divided in optimization and simulation. Simulation models do not strive for optimality, focusing on modelling the decisions of actors or groups of actors [23]. A particular approach is myopic optimization, where the optimization horizon considers only part of the whole problem (e.g. a limited area or time period). In this way myopic models do not guarantee global optima as perfect foresight optimization does, and can be classified as simulation models.

Both optimization and simulation are relevant to the study of energy systems. On the one hand, optimization provides an ideal, normative system state. On the other hand simulation represents complex system features (including policy) whose formulation may be unpractical with optimization [24]. The representation of individual actors and their preferences, perceptions and decisions is more tractable with simulation than with optimization. These capabilities allow simulation to explore non-optimal system pathways and the effect of policies in a fast, exploratory manner [25]. However, verification and validation of simulation can be challenging, for these complex features may not be comparable to those of the real world. Also, being a bottom-up approach, simulation does not model feedbacks with other sectors and policies [24,25]. However, these disadvantages also apply to optimization approaches.

2.2. Strategic management and expansion pathways

In the framework for our simulation model presented in Figure 1, the grid is managed by changing its assets and operational control rules. Given a certain initial system state, a sequence of changes in time lead to a final, different state. A pathway is this sequence of system states, from the initial to the final one. The change of grid assets occurs through investments, and this change determines the expansion pathways. Given this, the simulation of investments is central for simulating expansion pathways, an argumentation that is developed in more detail here.

We are interested in how grids composed of social (actors and institutions) and technical (asset) subsystems change, and how simulation can help us explore this. Actors interact within the social and with the technical subsystem through the strategic and the operational management [26]. While the strategic management comprises the investment in transmission assets, the operational one changes the institutions governing the relations among actors and the control of the assets. Hence,

the operational management includes but is not limited to the system operation, also comprising the change of the operational rules and contracting between actors. The performance of the system comes not from the individual performance of the subsystems, but from their interaction (a determinant feature for infrastructures) [27].

However, the characteristics of assets are an important limit to system-level changes, and thus the physical subsystem constrains the possible pathways more than the social subsystem. Namely, since transmission assets are large, capital intensive, durable and specific, changes though strategic management are slow [27,28]. This also leads to path dependence, where given an initial state reinforcing characteristics lock the system into a certain pathway, in the absence of external influences [29].

In contrast, the operational management for power systems is much less capital intensive than the strategic management [20]. For example, in the NorthSeaGrid project, the considered operation & management costs of offshore HVDC interconnectors do not exceed 2% of investment costs [30]. Even with a low social discount rate of 4% and an asset lifetime of 30 years these costs amount to only 26% of total costs. Confirming this, in its analysis of the characteristics of infrastructures Markard [27] indicates that the capital intensity of the power sector is very high, even when compared to other infrastructures.

Because of the lower capital requirements of operational management and the physical transmission asset characteristics, the strategic management represented by investments is thus the main determinant constraining infrastructure pathways. Therefore, the importance of the strategic management to pathways varies but is nonetheless always significant.

3. Methodology

Section 1 demonstrates that transmission expansion planning commonly uses perfect foresight optimization approaches. Moreover, section 2 indicates simulation is an adequate alternative to model transmission expansion pathways of offshore grids which change through investment. For this, our model simulates sequential investment periods forming an expansion pathway, with three steps per period: creation of an expansions portfolio, operation of the system, and strategic management through investment in expansions, as indicated in Figure 2. It is thus a sequential static model following Lumbreras et al. [10].

The first step develops the expansions portfolio (section 3.2), defining the expansions of the system to be considered in the current period. Each expansion belongs to one of the six possible transmission typologies illustrated in Figure 3. For a single typology there can be multiple expansions, each with different combinations of links and their transmission capacities.

In the following step of system operation (section 3.4), the system state for the base case and for each expansion is calculated individually, by finding the optimal power flow which minimizes those generation operational costs of the system. Each considered expansion may reduce these costs in relation to the period base case.

Finally, the strategic management step (section 3.3) calculates a comparative cost and benefit indicator for each expansion, using the present-value net benefits from the base system to the expanded system. The net benefit is composed of the increase in welfare minus transmission investment costs. Then, the expansion of the portfolio with the highest cost and benefit indicator is selected and invested in, and the three simulation steps are iterated until the final period is reached.

3.1. System representation

The model nodes represent offshore wind farms, offshore hubs, and onshore power systems (Figure 3). In each period onshore nodes are categorized as exporter, importers or common nodes, according to their base system nodal price (respectively low, high or intermediate). Offshore hubs are nodes which do not generate or consume any power, just serve as connection points.

The expansion pathways are split into periods, and each period is composed of multiple non-sequential planning cases (Figure 4). While periods represent the sequential expansions of the offshore grid, planning cases represent a year of operation of the power system by aggregating the hours of the year. Each case represents a certain number of hours, with different availabilities of renewable resources such as solar radiation and wind. Thus the generation capacities vary between periods, while the resource availability for each renewable energy technology varies by planning case, as in in [31]. Hence, the total system performance in each period is given by the average of the planning cases. In this study demand is inelastic and constant in all periods.

Two HVDC transmission technologies are considered. HVDC links can be point-to-point (i.e. with HVDC converters at each terminal of the link) or multiterminal (with HVDC converters only at locations where power is injected or withdrawn from the DC grid), as show in Figure 5 [5,32]. Multiterminal links are a recent technology which allows possible savings in

components such as AC/DC converters and has many of the same advantages of point-to-point HVDC links over high-voltage alternating-current (HVAC). However, they currently require innovations in components (e.g. higher-rating HVDC circuit breakers) and control strategies [5]. Moreover, if these HVDC multiterminal grids are meshed, power may flow through parallel paths, as in AC systems, which may lead to reduced transmission capacities. Hence, multiterminal links have both advantages and disadvantages.

3.2. Expansion portfolio

Multiple expansions are created by typology, and have multiple combinations of transmission capacities (Table 1). For each typology, the terminal capacities along the transmission path are sequentially summed from exporter to importer nodes to determine the cable transmission capacities. For onshore exporter nodes the default terminal capacities considered are 2 and 4 GW. The offshore wind farm terminal capacity is equal to the farm capacity adjusted by a multiplier, to account for the average availability of wind in the planning cases:

(1) $wind\ link\ multipler = \sum wind\ availability\ factor \Big/ number\ of\ planning\ cases$

The transmission capacities are then adjusted in two ways. First, capacities of links connected to wind farms vary by ±10% and 20% to represent the over- or underplanting of wind farms [33]. Then, for all links a further variation of ±10% of the capacity values increases the portfolio variety.

Table 1: Transmission typologies

Typology	Color	Description
Hub		All onshore nodes and wind farms connected to an offshore hub
Radial		Interconnectors between all onshore nodes. Radial wind farm connectors to one onshore node
Farm-to-farm		Interconnectors from low- to high-price nodes, passing through two wind farms
Split		Interconnectors from low- to high-price nodes, each pair passing through a single wind farm
IC split		Combination of split and direct interconnectors
Radial split		Combination of split and radial connections of wind farms with direct interconnectors between onshore nodes

3.3. Costs and benefits

Our model considers two cost types: generation operational costs (Figure 6), and transmission investment costs for cable and terminals (Appendix C). The optimal power flow calculation of the operation step of Figure 2 minimizes generation operational costs. Then, the transmission investment costs are used in the calculation of cost and benefit indicators in the investment step.

Two cost and benefit indicators are possible, the absolute net present value (NPV_a), and the net present value ratio (NPV_r). In each period the expansion with the highest positive NPV is selected using one of the indicators:

(2) $NPV_a = (B_e - CI_e)$ (absolute net present value)

(3) $NPV_r = (B_e - CI_e)/CI_e$ (net present value ratio)

Where B_e and CI_e are the benefits and costs of investment of expansion e, respectively. The absolute and ratio NPV types reflect a preference in decision making for maximizing net welfare (the NPV_a) or for investing in an efficient plan which provides the most net welfare per investment (the NPV_r). The latter is relevant in a context of limited budgets of transmission system operators and discussions over their financeability [20].

NPV scopes define which benefits and costs to consider. Three scopes are possible in a system with n nodes and an expansion involving a subset of n_{ep} nodes: the social, the Kaldor-Hicks and the Pareto scopes. The social scope accounts for net benefits (benefits minus costs) for all n system nodes. On its turn, the Kaldor-Hicks scope considers only the subset of nodes n_{ep} involved in the expansion. In the Kaldor-Hicks scope, the n_{ep} nodes must have positive net bet benefits *as a group*. Here, nodes with positive net benefits could *theoretically* compensate participating nodes with benefit losses, though they are not obliged to do so [34]. Lastly, in the Pareto scope the net benefits are null if any of the n_{ep} nodes is a net loser (i.e. its net benefits are negative), because a net loser node could veto an expansion. Hence, the Pareto scope is the strictest, and considers no compensation between nodes would be possible.

(4) $B_e - CI_e = \sum_i^{\mathrm{n}} (\Delta CS_i + \Delta PS_i + \Delta CR_i - CI_i)$ (social scope)

(5) $B_e - CI_e = \sum_i^{n_{ep}} (\Delta CS_i + \Delta PS_i + \Delta CR_i - CI_i)$ (Kaldor-Hicks scope)

(6) $B_e - CI_e = \begin{cases} \sum_i^{ep} (\Delta CS_i + \Delta PS_i + \Delta CR_i - CI_i) \; if \; \Delta CS_i + \Delta PS_i + \Delta CR_i - CI_i \geq 0 \mid \nabla \, i \\ 0, otherwise \end{cases}$ (Pareto scope)

Where ΔCS_i is the consumer surplus, ΔPS_i is the producer surplus and ΔCR_i is the congestion rent, all measured as changes from the base to the expanded system (presented in equations 7-9). CI_i is the allocated nodal investment cost for node i. The model evaluates the present value of these costs and benefits using 25 years and a 4% discount rate.

The NPV scopes represent the actor multiplicity and the international character of the offshore grid. In Europe the most common transmission expansion regulatory design is the regulated investment and remuneration of transmission system operators [9]. For the Northern Seas grid, planning is predominantly national, and thus demands the cooperation of these operators [8]. Thus, while a European decision maker would use the social scope, actual planners could consider regional costs and benefits, ignoring positive or negative externalities to other countries (i.e. use the Kaldor-Hicks scope). Moreover, a regulator could block an expansion resulting in a net welfare loss to its country (i.e. the Pareto scope).

Consumer and producer surplus and congestion rents are the usual economic benefit components [35]. For an inelastic demand, consumer surplus change is the difference in what consumers pay between two different system states. Producer surplus change is the change in the producer revenues that exceed generation costs (i.e. change in producer profits). Finally, congestion rent is value of the flow through a link: the link flow, valued by the nodal price difference at the terminals. Hence, for each node *i* the change in these benefit components from the state *s-1* to *s* can be formulated as:

(7) $\Delta CS_i = \lambda_{i,s} * D_{i,s} - \lambda_{i,s-1} * D_{i,s-1}$ (consumer surplus)

(8) $\Delta PS_i = \sum_{g \in i} P_{g,s} * (\lambda_{i,s} - MC_g) - \sum_{g \in i} P_{g,s-1} * (\lambda_{i,s-1} - MC_g)$ (producer surplus)

(9) $\Delta CR_i = \sum_{l \in i} F_{l,s} * (\lambda_{i,s} - \lambda_{j,s}) - \sum_{l \in i} F_{l,s} * (\lambda_{i,s-1} - \lambda_{j,s-1})$ (congestion rent)

Where D_i is the nodal demand, λ_i is the nodal price, P_g and MC_g are the production and marginal production cost of producer g, and F_l is the flow of link *l* connecting nodes *i* and *j*.

Finally, the cost of investment CI_e of a plan e with L links and T terminals is the sum of its total cable CC and CT terminal investment costs:

(10) $CI_e = \sum_i^L CC_i + \sum_j^T CT_j$ (total investment costs)

(11) $CC_i = c_c * l_i * K_{l,i}$ (cable investment costs)

(12) $CT_j = c_t * K_{t,j}$ (terminal investment costs)

c_c is the cable unit cost (M€/MW.km), while c_t is the terminal unit cost (M€/MW) which varies by node type (Appendix C). K_l and K_t are the capacities of cables and terminals, and l is the cable length. Since a multiterminal HVDC grid needs converters only for points injecting or withdrawing power it reduces the requirements for converter (i.e. terminal) capacity. To model these investment savings, different rules for the terminal capacity K_t for point-to-point and multiterminal links are considered, as in the Appendix D.

3.4. System state modelling

The system state for each period and planning case is determined through the optimal power flow calculated with the Python for Power System Analysis (PyPSA) toolbox, version 0.4.2 [36]. The optimal power flow calculation determines the optimal dispatch of generators which minimizes generation operational costs. The dispatch cost of each generator is determined by the marginal generation costs (Figure 6). The linearized load flow model used (DC load flow) approximates power flows but is usual in transmission expansion studies and adequate for exploring long-term offshore grid transmission pathways [10,37]. Welfare changes are determined as differences between the base and expanded system states using the nodal prices provided by the optimal power flow solution. The model assumes generation technologies bid their marginal cost in a competitive central market, as in Hogan [35].

3.5. Model verification

The model has been verified through replication and extreme input testing. The replication was conducted for the optimal power flow and welfare components (consumer payments, producer surplus and congestion rents). Optimal power flows were compared with the MATPOWER package version 6.01b [38] and welfare components with MATLAB for all systems of the three case studies.

For input testing we varied wind farm and onshore terminal unit costs, cable unit costs, the discount rate, the hydropower capacity and the carbon price, with the extreme values leading to expected model behaviors. For example, no expansion is selected for high wind farm terminal unit costs, high discount rates or excessive hydropower capacity, due to excessively high costs or low benefits. Also, null cable costs lead to the selection of longer expansions instead of shorter split ones, since cable lengths do not affect investment costs in this case. Finally, high carbon prices incentivize connecting the low-carbon hydropower capacity of Scandinavia. The optimal power flow and welfare comparison files and results for the extreme input testing are available in Dedecca et al. [39].

3.6. Case studies data and model

The long-run marginal generation costs of Figure 6 and Appendix B are equal to the levelized operation, maintenance and fuel costs of the Energy Information Administration [40], converted using exchange rates and average carbon emission factors of the International Energy Agency [41,42]. Cable and terminal unit costs are obtained from E3G et al. [30]. The availability factors of the planning cases for each renewable generation technology are in Appendix A, and all planning cases are given the same probability of occurrence. For comparison, according to the Department of Energy & Climate Change [43] the capacity factor for offshore wind farms in the UK in 2014 was 37.3%. The 2014 capacity factor of Danish offshore wind farms commissioned since 2009 amounted to 48% [44]. Demand and onshore generation capacities are based on the 2020 forecasts of the ten-year network development plan scenarios of the European Network of Transmission System Operators for Electricity [45]. The starting interconnector transmission capacities are based on existing interconnectors [21]. The model source code and the simulation setup and results datasets are available in persistent repositories [17,39].

4. Results

We first introduce the case studies, and then present reference expansion pathways for each case study. This allows us to categorize and illustrate factors we observed as affecting the expansion selection, explaining why certain expansions are selected while others are not, and why the expansion pathways deviate from the reference cases. Finally, we discuss the factors and their interaction. Although the reference pathways facilitate the comprehension of the results, it does not mean they are more probable - this depends on the actual realization of parameters in the future and on the cost and benefit indicator and scope.

4.1. Case studies

We explore a system of three onshore nodes (Figure 7). This abstract system is scaled to values comparable to the power systems of Northern Europe, with one offshore hub and two offshore wind farms. The onshore nodes represent Scandinavia (SC), the British Isles (BI) and continental Europe (CE) with the nodal generation capacities and demand of Appendix E.

To study this system, we conduct three case studies: single period, simultaneous and sequential, with the last two being composed of two expansion periods. While in the single period case the capacities of both farms' are introduced at the same time in the unique period, this introduction is split in the multi-period cases (symmetrically in the simultaneous, and asymmetrically in the sequential, Table 2). The multi-period simultaneous and sequential cases allow to study the expansion pathways from a path dependence perspective.

Table 2: Case studies presentation

Case	Single period	Simultaneous multi-period	Sequential multi-period
Expansion periods	One	Two	
Wind farm capacity addition	Total capacity of farms 1 and 2 on the single period	Half of total capacity of farms 1 and 2 in each period	Total capacity of farm 1 in period 1, and of farm 2 in period 2

4.2. Reference expansion pathways

The reference expansions of Table 3 are those which are selected in the case studies using central cost parameters (Appendix C), an NPV ratio indicator and a social NPV scope. Figure 8 shows the reference expansion pathways for point-to-point HVDC links, presenting the NPV_r of alternative expansions together with the selected expansion, for both periods. In the multiterminal simulations (analyzed in section 4.3) all links not directly interconnecting onshore nodes are multiterminal, which may lead to a multiterminal meshed grid after multiple expansion periods. Appendix F and Appendix G provide the selected expansions for all case studies, with the full results dataset available in [39].

Table 3: Reference expansions

	Single-period	Sequential multi-period	Simultaneous multi-period
Point-to-point	West split	Farm 2 radial	West split
	-	West IC split	Farm 1 hub
Multiterminal	Continent split	West IC split 2	Hub
	-	West IC split	Nordic split

4.2.1. First period reference expansions

In the single period case the *west split* expansion is selected, with an NPV_r of 3.3 – hence the expansion net benefits amount to 330% of the investment cost of 7.5 B€ (top left of Figure 8). Although the *west split* expansion through farm 2 is not as direct as a radial typology, it combines the onshore systems interconnection and offshore wind farm connection grid functions efficiently. Through the same links it connects all wind farms and provides two export routes from Continental Europe to the most expensive onshore node, the British Isles.

The same *west split* expansion is selected in the 1st period in the simultaneous case – indeed, since in this case both wind farms are introduced at the same time, the difference between the single period and the simultaneous cases is the total capacity that is introduced in the first period (half, in the simultaneous case). However, costs do not decrease linearly with the offshore wind capacity, so that investment costs decrease by only 25%. Thus, the simultaneous case NPV_r is 2.4, lower than the single period value of 3.3.

The sequential case with its deferred introduction of wind farm capacity selects a different expansion, the *farm 2 radial*, with an NPV_r of 3.2. Here, since only wind farm 2 is beneficial to connect, this expansion separating the grid functions is the preferred one. It connects the wind farm to the closest onshore node, and interconnects the importing British Isles to the other systems who have less expensive generation technologies (the Scandinavian hydropower and Continental Europe's new wind farm 2).

4.2.2. Second period reference expansions

Only the simultaneous and the sequential cases simulate a second period expansion. In the former the *farm 1 hub* expansion is selected, creating a meshed grid complementary to the previous *west split* (center of Figure 8). It is a particular case which connects only the wind farm closest to shore, due to the balance between central values of onshore and wind farm terminal investment costs. Generally, the simultaneous case leads to a highly meshed grid with two expansions combining the interconnection and farm connection functions (Appendix F), due to the symmetric addition of offshore wind capacity.

For the sequential case the w*est IC split* expansion is selected, following the *farm 2 radial* of the 1st period. It joins the new wind farm 1 through the two closest nodes (which also have the highest power prices), and adds a direct interconnection between these nodes. The expansion pathway for the sequential case leads thus to an offshore transmission system that is less meshed than in the simultaneous case, because the asymmetric offshore wind addition favors more radial typologies.

Interestingly, while in the 2nd period the sequential expansion has an NPV_r of 3.11, for the simultaneous expansion this falls to 0.2. The simultaneous expansions generally present a lower NPV_r because investment costs do not decrease linearly with the reduced wind farm capacities.

4.3. Strategic management factors

After presenting the reference expansions, we now analyze which factors lead to alternative pathways and which are the mechanisms they act through (Table 4). Certain factors arise from the model, while others emerge from the actual simulation or from the characteristics of different typologies.

Table 4: Strategic management factors and their mechanisms

	Factor	Mechanisms
Modelling	Cost structure	Higher cable costs favor shorter lengths Higher terminal investment costs favor expansions with lower terminal capacities
	Link technology	Multiterminal links have reduced investment costs, but parallel multiterminal links may restrict flows
	NPV types	The NPV_a favors the maximum net benefit, independently of the investment cost The NPV_r favors investment efficiency by maximizing net benefits over investment costs
	NPV scopes	Kaldor-Hicks and Pareto scopes rule out expansions which may have higher social net benefits
Simulation	Path dependence	Previous investments in expansions change the system and affect the following periods
	Wind farm installation timing	New wind farms are beneficial to connect, so the timing affects expansions
	Candidate exhaustion	Previous expansions or higher investment costs may lead to no beneficial expansions
	Expansion characteristics	Even for the same typology expansions partly differ in capacities and lengths
Typology	Grid functions integration	Function integration may lead to lower investment costs but also higher link congestion
	Terminal capacities levels	Higher terminal capacities increase transfer capacities but require higher investments

4.3.1. Modelling factors

Modelling factors arise from the input data and model formulation. The first modelling factor is the cost structure: the cost parameters and the rules for determining terminal and cable capacities. It directly affects the expansion investment costs and therefore its net benefits (Appendix C and Appendix D). The second modelling factor is the link technology: point-to-point or multiterminal (as described in section 3.1). Multiterminal links reduce the investment cost of some typologies but simultaneously may restrict flows, affecting thus both benefits and costs. The last modelling factors are the NPV scopes and NPV types of section 3.3, which respectively rule out some expansions and affect how net benefits are evaluated.

Cost structure

The cost structure mechanisms are straightforward: higher terminal investment costs favor expansions with lower terminal capacities, and higher cable costs favor shorter typologies (such as radial ones). Nonetheless, since expansions compete for selection, the comparative values for terminal (onshore, wind farm and offshore hub) and cable costs is also relevant for the expansion pathway.

Thus, in the first period of the simultaneous case, increasing wind farm terminal investment costs favor increasingly radial typologies: from *split* to *radial split* to *radial* (first row of Figure 9). However, this is countered by onshore terminal costs increases, as shown in the second row of Figure 9, where even with high wind farm terminal costs only an expansion belonging to the *radial split* typology occurs.

Link technology

Expansions with multiterminal links benefit from reduced investment costs due to a reduced number of converters or converter capacity, but may restrict flows. Point-to-point expansions on the other hand can be more expensive but do not restrict flows (section 3.1). Ultimately the investment savings of multiterminal links outweigh the possible flow restrictions, favoring the *hub* and *split* typologies. Hence, in the simultaneous case, multiterminal links lead to the selection of the *hub* expansion instead of the *Scandinavian radial* expansion (first row of Figure 10). For the same case, in the second period the *Nordic split* expansion is chosen, because it benefits from investment savings while limiting the flow restrictions to which a more logical, shorter expansion (without crossing links) would be exposed. Therefore, seemingly paradoxical expansions may actually be the most beneficial, something that can be accounted for only with load flow modelling.

***NPV* types**

The NPV_a favors expansions with higher terminal and cable capacities, which provide higher net benefits, while the NPV_r weighs net benefits against investment costs. Thus the NPV_r selects the *west split* expansion in the single period and simultaneous reference cases due to their efficient function integration. In other simulations the NPV_r can also select expansions which are less congested in high wind availability, or that have lower terminal and/or cable capacities. Figure 11 contrasts the first period selection of the sequential reference case with that of an NPV_a criteria.

***NPV* scopes**

As seen, the Kaldor-Hicks and Pareto scopes restrict the acceptable expansions, with the Pareto scope being the most restrictive (forbidding welfare losses for all participating nodes). Hence, in the second period of the simultaneous case, the selected reference expansion is the *farm 1 hub*, while the Kaldor-Hicks scope selects the *east split*, and the Pareto scope selects no expansion (Figure 12).

However, the Kaldor-Hicks scope may select a different expansion by excluding (not connecting) a welfare-losing onshore node, and provide a higher NPV overall. Increasing constraints lead thus to complex changes in expansion selection – no dominance of expansions exists between scopes. Thus, for low wind farm and onshore terminal investment costs, the *west radial split* is selected with the social NPV scope, while the Kaldor-Hicks scope selects the *north farm-to-farm* which excludes Continental Europe, and the Pareto scope selects the *east split* which excludes the British Isles (Figure 13).

4.3.2. Simulation factors

Simulation factors are dynamic factors that can be observed from the pathways of the offshore grid. Path dependence is one of the four simulation factors, and as described in section 2.2 the system can be locked into a certain expansion pathway in the absence of external influences. This interacts with the second simulation factor of wind farm installation timing, so that systems where the final offshore wind capacity is the same may end up with different grids depending on how this capacity

is introduced. Also, no expansion may fulfil a given NPV criterion due to previous investments or to a change in cable or terminal investment costs, causing candidate exhaustion (the third factor). Finally, the characteristics of different expansions such as link lengths and terminal capacities affect the investment, even for expansions belonging to the same typology.

Path dependence

Path dependence leads to a higher variation of selected expansions in the 2nd period. Also, path dependence leads to non-monotonic $NPVs$: higher cost parameters do not necessarily reduce $NPVs$ as in single period expansions, because expansions in previous period affect the NPV of following periods.

A strong path dependence can be observed in the exploratory model – while for all runs the single period case study selects only two expansions, the sequential case selects six, and the simultaneous case fifteen different ones (Appendix G). However, path dependence is strong but not absolute, so that complementarity between expansions can be observed in the simulations. Hence, for the simultaneous case with multiterminal links, the *hub* and *Nordic split* expansions are chosen in the first and second period respectively, while low wind farm terminal investment costs lead to the selection of the *west split* and *hub* expansions, respectively (Figure 14). In this way, *hub* and *split* typologies exhibit complementary benefits and their selection is only partly affected by path dependence.

Wind farm installation timing

The wind farm installation timing directly affects the expansion selection, for generally it is most beneficial to only connect all wind farm locations whose installed capacity increases. Hence, in almost all simulations any new wind farm is immediately connected, while no expansion connects wind farms of unchanged capacity (Appendix F and Appendix G). This illustrates the importance that the timing of actual offshore wind development in the Northern Seas can have on the offshore grid expansion pathways.

Candidate exhaustion

As indicated, due to previous investments or a change in investment costs it is possible for no expansion to have a positive NPV (Figure 12). Candidate exhaustion occurs more easily with the more restrictive Kaldor-Hicks and Pareto scopes, and is more rare with multiterminal links because investment savings usually improve the NPV of some expansions. This is illustrated in Figure 12, where the Pareto scope leads to expansion exhaustion – though the NPV_r of expansions considered under the Kaldor-Hicks scope are not necessarily lower than under the social scope.

Expansion characteristics

Expansions of the same typology have different NPVs, due to characteristics of their own or of the system (such as node location or generator capacities and marginal costs). For a same typology, expansions may exclude certain nodes, and terminal

capacities may change as well as link lengths and capacities. Thus, for example with low terminal onshore costs in the 2nd period of the simultaneous case, only radial split expansions are selected – but three different ones (Figure 15).

4.3.3. Typology factors

Although expansions have individual characteristics, each typology also has distinct features. Therefore, the typology characteristics of Table 5 are the last category of factors. The first typology factor is the level of integration of the grid functions (offshore wind power connection and power systems interconnection). The grid functions integration affects both the total investment cost (function integration may require less cabling) and transfer capacities (due to greater congestion of integrated typologies). The second factor is the level of terminal capacities, in other words, if a certain typology requires higher or lower terminal capacities. Terminal capacities influence how different terminal unit costs lead to the selection among possible typologies, especially when multiterminal links are considered.

Table 5: Function integration and terminal capacities for typologies

Typology	Grid functions integration	Onshore terminal capacity	Wind farm terminal capacity
Radial	Low	Medium	Low
Hub	High	Low	
Split	High	High	
Radial split	Medium	Medium	
IC split	Medium	Medium	
Farm-to-farm	High	High	

An example is the *split* typology, which highly integrates the grid functions and has high onshore and wind farm terminal capacities. It shortens cable lengths and thus may allow for lower investment costs for long distances, at the expense of possible congestion of transmission and susceptibility to high terminal investment costs. As such, it could be adequate for long interconnections with high complementarity between offshore wind power generation and power exchanges, being chosen much more often in the simultaneous than the sequential case (Appendix F and Appendix G). Also, it benefits from multiterminal investment savings, possibly avoiding the occurrence of candidate exhaustion.

4.4. Pathways of the Offshore Grid

We presented multiple factors that affect the expansion pathways, but path dependence is especially important for the grid development over time. We demonstrate how expansion pathways exhibit strong but not absolute path dependence, that is, expansion selection is strongly influenced by previous expansions but other factors also play a role. Hence, on the one hand, Figure 8 illustrates how the grid pathways vary significantly, even for the reference case studies. On the other hand, hub and split expansions may complement each other for multiterminal links, so that after two periods both typologies are built, but in different order (Figure 14). This is in accordance with the path dependence characteristic of infrastructures indicated in section 2.2.

Also, factors do not affect pathways equally for all expansions, not even those belonging to the same typology. Some factors affect homogeneously expansions of the same typology (the NPV types, terminal investment costs, and the link technology). Other factors interact more with specific expansions, regardless of their typology (e.g. the NPV scopes, cable investment costs).

As seen, studies indicate the Northern Seas grid will develop gradually [1]. Since the grid exhibits strong path dependence, advocates call for anticipatory investments to avoid lock-in and keep more expansion options open [2,46,47]. However, innovations in HVDC technology will affect the factors and therefore the typologies and expansions differently - we show that high investment costs lead to less integrated typologies (such as the *radial*) or point-to-point links being preferred. Additionally, it is not only the absolute value of investment costs that matters, but also their relation. The need for DC breakers, DC/DC converters and multiterminal control strategies will not be the same for all typologies, for they have different levels of grid functions integration and terminal capacities. Thus different innovation rates for the components of multiterminal HVDC transmission will affect the comparative performance of expansions.

The combination of path dependence with the unequal effect of HVDC innovations highlights the importance of anticipatory investments, cost reductions and the interoperability for HVDC technology. These are required for developing an integrated grid sooner than later and not locking out beneficial expansion pathways.

5. Conclusions

Our aim was to explore transmission expansion pathways for the offshore grid and the factors which affect them under path dependence, to which we used a simulation model with myopic optimization. *Our model does not recommend a particular expansion or even typology*, but analyzes the factors and pathways, and how we can influence those pathways.

Typologies perform the grid functions of connection and interconnection with *different levels of integration and terminal capacities*, with also modelling and simulation factors affecting the transmission expansion pathways. Results indicate that planning of the offshore grid will need to consider these factors when choosing the preferred expansion. Previous models of the Northern Seas offshore grid applying perfect foresight optimization did consider the link technology, costs and benefits types and scopes, and factors such as the expansion characteristics and the timing of offshore development. However, they did not simultaneously address all the factors we identify. *Our simulation model considers the typologies and factors to create expansion pathways and understand the grid path dependence*, which we show to be strong but not absolute.

Cooperation is a central component both of Energy Union proposals and of calls for the development of an integrated offshore grid in the Northern Seas. However, the literature indicates that despite ambitious visions, cooperation and governance are major barriers to a more integrated development, and as a consequence grid development has been conducted nationally or bilaterally. A long time has passed since the first calls for an offshore grid in the end of the last decade, and since then many interconnectors and wind farms were developed, already taking the grid to certain pathways. *The lack of adequate governance frameworks and not evaluating the impact of HVDC innovations will continue to lock-out possibly beneficial pathways using integrated expansions.*

This is unwelcome, given that *innovation and the integration of energy markets are two of the dimensions of the Energy Union*. Given the potential of the offshore grid to be a major contributor to this Energy Union, *HVDC technology innovation must be a part of the Union's strategy*. Also, our model indicates the importance of considering multiple expansions plans with different typologies, but also that these plans have individual advantages and drawbacks. Hence, *planning of the Northern Seas offshore grid in the framework of the Energy Union should be done regionally*, considering multiple typologies and the factors of our study. Planning should choose between benefit maximization or efficiency (i.e. different NPV types), and consider transmission technologies and their innovation rates, expansion and system, and the interests of countries and actors. After this regional planning, *individual projects can then be evaluated and implemented*.

The limitations of the simulation model and the need to support to governance frameworks guide further research needs. Regarding the model, further refinement of the expansion portfolio heuristics can be considered. Concerning governance frameworks for the offshore grid, analyzing different allocation mechanisms for costs and benefits would uphold recommendations concerning their adequacy to develop an integrated grid. Finally, simulation could implement co-investment

in offshore generation and transmission more easily than perfect foresight optimization approaches, and hence support the joint planning of offshore transmission and generation expansion.

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Appendices

Planning Case	1	2	3
Solar PV	0.40	0.25	0.10
Onshore Wind	0.62	0.36	0.10
Offshore Wind	0.70	0.40	0.10
British and continental hydropower	0.24	0.24	0.24
Scandinavian hydropower	0.42	0.42	0.42

Appendix A: Availability factors for renewable energy technologies (% of installed capacity)

	Gas	Coal	Lignite	Nuclear	Offshore Wind	Onshore Wind	PV	Hydropower
Total marginal cost (€/MWh)	52.63	43.70	42.70	18.00	16.88	9.60	8.55	8.18
Equivalent O&M and fuel cost (€/MWh)	44.63	25.20	25.20	18.00	16.88	9.60	8.55	8.18
CO_2 cost @ 20 €/tCO_2 (€/MWh)	8.00	18.50	17.50	0.00	0.00	0.00	0.00	0.00
Emission Factor (tCO_2/MWh)	0.400	0.925	0.875	0.00	0.00	0.00	0.00	0.00

Appendix B: Long-run marginal cost of generation technologies

	Cable Cost c_c	Terminal Investment Cost c_t		
Parameter	c_c	Onshore c_{on}	Wind Farm c_{owf}	Offshore Hub c_{hub}
	M€/MW.km	M€/MW		
Low		0.05	0.10	
Central	0.0004	0.10	0.30	0.20
High		0.15	0.50	

Appendix C: Cable and terminal investment costs

Point-to-point links

	Radial	Farm-to-farm	Hub	Split	IC split	Radial split
Onshore	Sum					
Offshore hub						
Offshore wind farm						

Multiterminal links

	Radial	Farm-to-farm	Hub	Split	IC split	Radial split
Onshore	Sum					
Offshore hub	Null					
Offshore wind farm	Sum	Max	Sum	Max		

Sum: $\boldsymbol{K_t}$ is equal to the total transmission capacity sum of all links connected to the node; **Max:** $\boldsymbol{K_t}$ equals the maximum transmission capacity among links connected to the node; **Null:** $\boldsymbol{K_t}$ is equal to zero

Appendix D: K_t rules according to terminal and link technology

(with figures)

Appendix E: Total nodal generation capacities adjusted for availability and demand

(with figures)

Appendix F: First period expansion maximum NPV_a and selected typology

(with figures)

Appendix G: Second period expansion maximum NPV_a and selected typology

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