Towards a fully integrated North Sea Offshore Grid: An engineering-economic assessment of a Power Link Island

Martin Kristiansen, Magnus Korpås and Hossein Farahmand *

27.01.2018

Article Type:

Focus Article

Abstract

An increasing share of variable power feed-in is expected the next decades in the European power system, with a particularly high offshore wind potential in the North Sea region. This demands more temporal- and spatial flexibility in the system, and an adequate grid infrastructure can provide both. This article presents an engineering-economic approach evaluating the impact of novel infrastructure designs towards a fully integrated North Sea Offshore Grid (NSOG), including TenneT's vision of a Power Link Island (PLI). A PLI is an artificial island for transnational power exchange and distribution of offshore wind resources. We introduce the concept and evaluate the economic benefits and system implications under three different case studies incorporating 2030 scenarios from ENTSO-E. The results demonstrate system cost savings up to 15.8% when comparing a fully integrated PLI solution with traditional, radial typologies. The PLI did in general result in more efficient system dispatch of wind resources, where the involvement from Norway, Great Britain, and Germany occurred most frequently in terms of grid reinforcements and expansions.

*Department of Electric Power Engineering, Norwegian Uni. of Science and Technology (NTNU), Norway.

A NORTH SEA OFFSHORE GRID

The North Sea Offshore Grid (NSOG) has been identified as one of the strategic infrastructure projects in EU Regulation No 347/2013 with the twofold purpose of integrating offshore wind resources and integrating markets for increased cross-border trade (EU Commission, 2011; European Commission, 2016). Multiple studies have addressed the added value of a NSOG in terms of cost-efficient utilization of variables renewable energy sources (VRES), reduced greenhouse gas (GHG) emissions, and increased security of supply (Van Hulle et al., 2009; Egerer, Kunz, & Hirschhausen, 2013; Gorenstein Dedecca & Hakvoort, 2016). In order to speed up investments and attract private investors, financial support netting €5.35bn is provided by Connecting Europe Facility (CEF), but this is only a small portion of the estimated €140bn worth of necessary electricity infrastructure upgrades the coming decade (ENTSO-E, 2016).

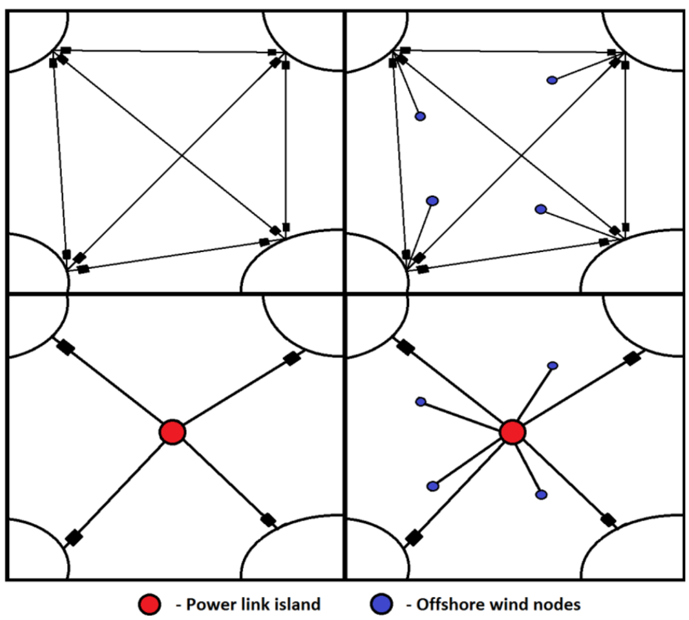

Figure 1: Illustration of different levels of grid integration ranging from radial solutions (in the two upper brackets) to integrated, or meshed, solutions (in the two lower brackets). The solution depicted in the lower-right corner represents a full Power Link Island (PLI) integration. Source: (Solli, 2017).

Typologies, being a combination of grid topology and technology, are traditionally divided into two groups; radial and integrated (Trötscher & Korpås, 2011; Gorenstein Dedecca & Hakvoort, 2016) as shown in Figure 1. A radial typology comprise point-to-point high voltage direct current (HVDC) connections, while an integrated typology[1] enables multiple HVDC connections at one joint – yielding a modular and flexible option with potential benefits in capital- and operational costs. For instance, in order to connect four countries one would need six transmission corridors in order to interlink them all with radial typology, in addition to individual offshore wind power (OWP) connections, while with an integrated typology the number of corridors is reduced from six to four (with approximately half the length, each). This is clearly illustrated with Figure 1. Additionally, an integrated typology will also achieve a higher level of utilization at each transmission corridor. The concept of a Power Link Island (PLI) is a large-scale augmentation of the latter integrated typology with significant potential in economies of scale (van der Meijden, 2016). According to its promoter, TenneT, a PLI can span an area of 6 km^2 and cost approximately €1.5bn for the artificial construction of the island itself; i.e. a pile of stones and sand in the shallow water of the Dogger Bank area (TenneT, 2017b).

A PLI has the capacity to connect 30 GW OWP capacity and by combining multiple PLIs into a so called offshore wind power hub the capacity can be expanded to 100 GW, which translates into enough energy supply for 70-100 million consumers in Europe (TenneT, 2017a). This can potentially serve a major contribution in reaching the European 2050 climate targets (EU Commission, 2011) where approximately 230 GW OWP capacity is needed, whereas 180 GW in the NSOG area (TenneT, 2017a). It is claimed that such an island can be scheduled for operation by approximately 2035 (TenneT, 2017b), connecting Norway (NO), Denmark (DK), Germany (DE), The Netherlands (NL), Belgium (BE), and Great Britain (GB).

Nevertheless, in addition to being an important milestone for OWP integration and cross-border power exchange, a PLI does also possess an advantage of large surface areas in close connection with existing European gas infrastructures. That is, in cases of energy surplus or electricity grid congestion there is a considerable potential in Power-to-Gas (PtG) production at the island (TenneT, 2017a). For instance, hydrogen production for energy storage,

[1] Integrated typologies are often referred to as meshed grids.

heating- or mobility sector. This would impose a stronger coupling of the aforementioned sectors, consequently leading to more flexibility options (Kondziella & Bruckner, 2016) and complex system interdependencies that could affect the benefits of grid expansion (Jesse Jenkins & Nestor Sepulveda, 2017). The gas could also be used as storage and converted back into electricity, but with a round-trip efficiency spanning 35-50% it is currently not profitable with today's electricity price variations and electrolysis technology (Lund, Lindgren, Mikkola, & Salpakari, 2015).

As a response to recent discussions about such an island, this article presents an engineering-economic analysis of a PLI in the NSOG using data for year 2030 (ENTSO-E, 2016). Our scope is to assess its performance under varying degrees of offshore wind development, in addition to national re-allocations from onshore variable renewable energy source (VRES) to offshore wind capacity. The contribution is twofold; i) help establishing a foundation for future research on this relatively new topic, and ii), approximate the added value of a fully integrated PLI solution using an optimization program for power system expansion planning.

METHODOLOGY

Results are obtained by designing a set of case studies that are analyzed using an expansion planning model. The model is well documented in, e.g., (Kristiansen, Munoz, Oren, & Korpås, 2017) and (Kristiansen, Korpås, & Svendsen, 2018), so readers that are interested in the model formulation is referred to those. The following subsections discuss our approach for this paper in greater detail.

An expansion planning model

We use an optimization program for transmission expansion planning, called PowerGIM (Kristiansen et al., 2018), in order to co-optimize investment decisions and market operation for the considered case studies over an economic lifetime of 30 years starting in year 2030. The model is formulated as a mixed-integer linear program (MILP) and incorporates variability in wind, solar, hydro and load by sampling multiple, hourly time steps from full-year profiles (Härtel, Kristiansen, & Korpås, 2017; Kristiansen, Härtel, & Korpås, 2017). Consequently,

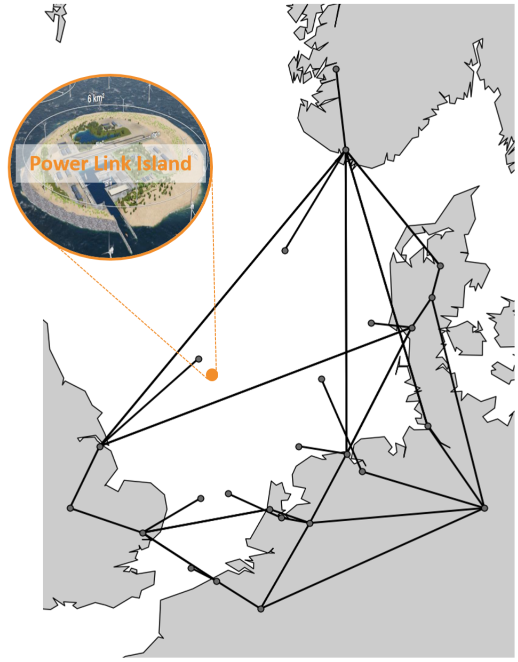

Figure 2: Illustration of the base case grid infrastructure used in the model. The orange dot represent the expected location for a power link island.

this sampling approach ensures that different power flow patterns are accounted for since time series are generated for unique geographical coordinates from numerical weather data (COSMO-EU) (Graabak, Svendsen, & Korpås, 2016).

In turn, this means that the model implicitly incorporates the value any geographical smoothing effects and flexibility needs that arise from the spatial- and temporal mix of variable supply (wind and solar) and demand (Hasche, 2010). This is also one of the objectives with a NSOG, and in particular a PLI, which is within the scope of the following case study spanning six countries; Norway (NO), Denmark (DK), Germany (DE), The Netherlands (NL), Belgium (BE), and Great Britain (GB) as illustrated with the base case model setup in Figure 2. The orange coloured dot in the figure depicts the potential location for a PLI.

Grid expansion is known to yield considerable, material price impact in adjacent price areas (Hogan, 2011), consequently affecting the market landscape in which generators operates their units and plans long-term capacity expansion (Alayo, Rider, & Contreras, 2017) [2]. Repercussions might also arise in surrounding, third-party areas which are not directly

[2] Market landscape as in electricity prices and optimal portfolio of generation technologies. For instance,

connected (Kristiansen, Munoz, et al., 2017) with the transmission projects. Hence, the geographical span of the case study depicted in Figure 2 represents some limitations as the interdependencies with surrounding countries might impact the resulting benefits of a PLI. For instance, France might provide or demand flexibility enabled by a fully integrated PLI through, e.g., Belgium's domestic grid.

Cost assumptions

The construction costs for the PLI itself is estimated to be around €1.5bn. This is for stones and sand, only, so any additional costs for equipment will add on top of this. In comparison with traditional platform costs one would benefit from a PLI in terms of economies of scale, i.e. by utilizing a larger area for modular constructions, storage of personnel and spare parts, in addition to subsequent benefits in term of operation and maintenance. In this study, traditional platform costs amounts to €50m for AC and €406m for DC[3], which is assumed to be large enough for a 2000 MW VSC[4]. This means that a PLI could serve approximately 15 times the capacity of a traditional platform. For an excellent review on costs for offshore high voltage transmission lines and power electronics, please consult (Härtel, Vrana, et al., 2017).

Hence, the expansion planning model can choose to invest in a traditional platform or a PLI, with its associated costs. If a PLI is chosen, all transmission lines connected to it needs one converter, each. The same is the case for an offshore platform, but its size is limited to siting a maximum capacity of 2 GW (compared to 30 GW for the PLI). Operation- and maintenance costs are not included in the study. As a result, total investment costs associated with a PLI are likely to be over-estimated as its economies of scales are not fully captured (compared with traditional platforms).

---

if wind capacity is imported through new transmission capacity this would lead to lower prices and the need for flexibility in order to balance supply-demand (Cochran et al., 2014).

[3] AC and DC stands for alternating current and direct current, respectively. The latter is a preferred option for transmitting power over long distances, and particularly when using submarine cables.

[4] Voltage Source Converter (VSC) is a rather immature technology, but also the most prominent one for integrated/meshed HVDC grid typologies (Trötscher & Korpås, 2011).

	Supply [GW]	VRES [%]	OWP [GW]	Peak demand [GW]
Vision 1	420	48.8	89	209
Vision 4	523	56.5	154	204

Table 1: Summary of aggregate supply- and demand mix, including the share of Variable Renewable Energy Sources (VRES) and Offshore Wind Power (OWP). VRES comprise wind, offshore wind, solar PV and "other RES" according to definitions by (ENTSO-E, 2016).

Case study setup

There are nine scenarios in total (Scenario A - I), branching from three groups of case studies. The first one is a study of varying degrees of PLI integration into the NSOG. The second group studies the impact of re-allocating onshore VRES capacity into OWP capacity at offshore coordinates, utilizing the offshore wind resources and grid infrastructure. Finally, in the third group of scenarios we try to see how the system handles additional OWP capacity on top of the input data given by ENTSO-E, by placing this capacity at different locations in the system. All three clusters of case studies are ran with two sets of input data from the TYNDP 2016[5] (ENTSO-E, 2016), comprising Vision 1 ("slow progress") and Vision 4 ("green revolution"). A summary of aggregate supply- and demand is given in Table 1, while a more detailed illustration for Vision 4 is found in the Appendix including fuel costs and CO_2 price (Table 2).

Varying degree of Power Link Island integration

Different degrees of PLI integration are assessed ranging from radial grid typology to a fully integrated PLI with candidate branches to offshore wind nodes and national onshore nodes. The scenarios are described as follows:

(A) Radial grid expansion.

(B) PLI expansion with 30 GW OWP from GB and candidate branches to be expanded in connection with surrounding countries.

[5] Ten-year network development plan (TYNDP).

(C) Scenario B + candidate branches to surrounding offshore wind nodes.

Offshore versus onshore VRES generation capacity

The possibility for a fully integrated typology in Scenario C is used for the following case studies. Here, a certain share of onshore VRES capacity is re-allocated from being onshore to offshore. This share is calculated with respect to the sum of national solar PV and onshore wind. First, 10% is moved from onshore to offshore, followed by an increase to 25% and 50%. Note that all the re-allocated capacities are converted into OWP utilizing its strong feed-in profiles at respective offshore coordinates. Hence, the amount of energy feed-in to the system is likely to increase although aggregate supply capacity maintains the same.

(D) Scenario C + 10% onshore VRES allocated to national offshore nodes.

(E) Scenario C + 25% onshore VRES allocated to national offshore nodes.

(F) Scenario C + 50% onshore VRES allocated to national offshore nodes.

Additional offshore wind power capacity on top of initial input data

This case study comprise three scenarios studying the impact of different geographical allocations of additional 30 GW OWP capacity. In this case, both aggregate supply capacity and energy feed-in will increase.

(G) Scenario C + 30 GW OWP distributed to all countries' offshore nodes relative to their initial share with respect to total OWP system capacity.

(H) Scenario C + 30 GW OWP directly to the largest OWP node in the system, which belongs to GB (Dogger bank) close to the PLI.

(I) Scenario C + 30 GW OWP directly to the island.

It should be noted that the scenarios are not meant for consistent comparisons due to variations in available capacity and energy. The focus is rather to assess the implications and robustness of offshore grid designs, and particularly to see whether the expansion planning model finds a PLI beneficial for a majority of the scenarios.

Limitations

Although this article presents a real case study, there are some limitations that should be noted. For instance, there are no boundaries for new transmission capacity and some transmission corridor expansions might therefore be very unrealistic. For instance, public opposition will most certainly make it difficult to build, say, 15 transmission lines/cables in parallel. Moreover, the market operation in which grid investments recover their costs does not account for unit commitment constraints such as start-stop, ramping, and minimum up- and downtime. This would somewhat over-estimate the flexibility of, e.g., nuclear and coal units and possibly lead to under-investments in grid expansion.

RESULTS

Recall that the investment costs for an offshore island is €1.5bn. That is, the cost for a PLI as an alternative to traditional platforms. Costs for power electronics at the island are indirectly accounted for with new cables being built, meaning that the total costs for transformers and power electronics most likely will be over-estimated as the model will invest in more equipment than necessary. This means that we only account for economies of scale for the island itself, and not for equipment nor any benefits related to operation maintenance of the OWP capacity near the island. For more information regarding cost calculations of transmission projects, please consult (Svendsen, 2013) for the approach and (Härtel, Vrana, et al., 2017) for an updated review on data.

Power Link Island yields significant cost savings

Figure 3 shows the resulting investment- and operational costs for all scenarios, both in a future system with low shares of VRES (Vision 1) and high shares of VRES (Vision 4). First point to notice is that operational costs are higher for Vision 1 than for Vision 4 due to significantly less low-cost supply capacity in Vision 1, such as wind and solar, compared with relatively similar peak demand levels (see 1). The yearly energy consumption is also relatively identical for both cases, amounting to 1300 TWh.

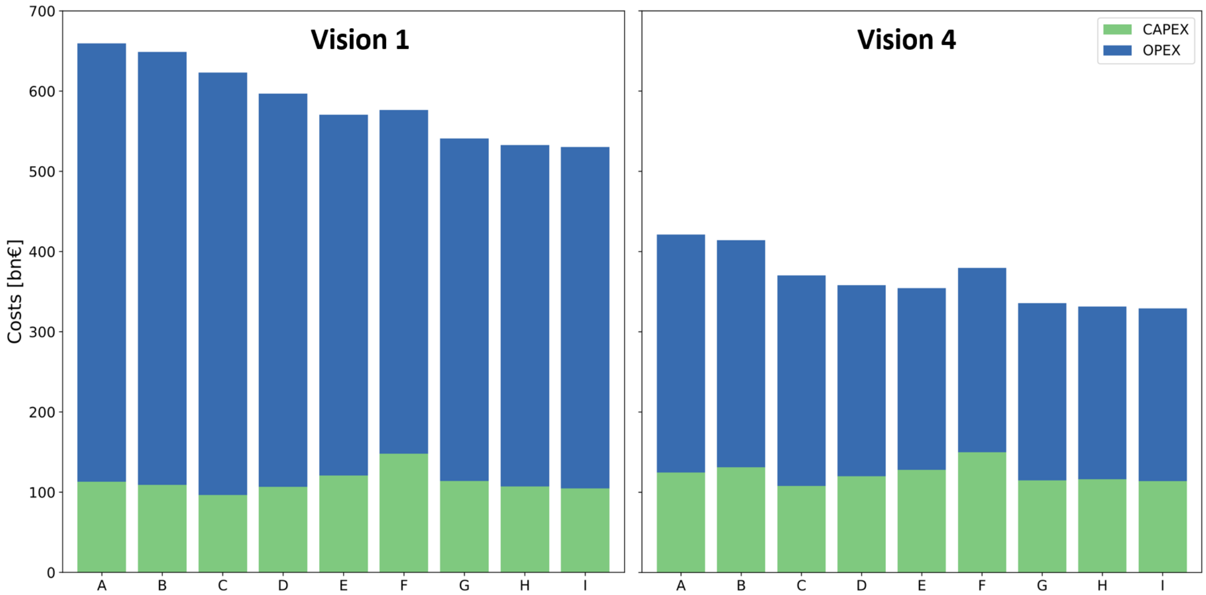

Figure 3: Investment- (green) and operational costs (blue) from the nine different case studies using data from ENTSO-E's least ambitious scenario Vision 1 (left part) and Vision 4 (right part) with high shares of VRES.

The investment costs are generally higher with Vision 4 due to a stronger need for flexibility, where a NSOG has proven to be a prominent solution (North Sea Grid, 2015). The latter is particularly evident for high VRES cases, such as Vision 4, in combination with Norwegian hydropower (Huertas-Hernando et al., 2017). Second, and most importantly, recall that the three first scenarios (A - C) represents different degrees of PLI integration, from no island to an fully integrated PLI serving as a hub for transnational power flow and for OWP distribution. Figure 3 demonstrates that the largest costs savings are found progressively for those three scenarios, whereas the consecutive scenarios builds further on Scenario C (fully integrated).

The total cost savings for a fully integrated PLI amounts to €36.8bn and €50.7bn in Vision 1 and 4, respectively. Parts of these savings are due to the transnational power exchange role of a PLI (Scenario B), but the largest portions of savings arise from the combination of being a transnational power hub and an OWP hub (from Scenario B to C). That is, a fully integrated PLI will require less investments, enable increased utilization of new transmission corridors, and be able to distribute OWP more efficiently to surrounding countries instead of re-routing through multiple countries (with consequently higher transmission losses due to longer distances). This is in line with previous NSOG studies claiming that the level of grid integration tends to relieve grid congestion (NSCOGI, 2012; Farahmand, Huertas-Hernando, Warland, Korpas, & Svendsen, 2011).

Key players for a Power Link Island

The aforementioned cost savings are a result of different system compositions, i.e. a combination of temporal- and spatial characteristics in supply and demand. We can therefore try to identify the most crucial contributors to system cost reductions.

Figure 4 illustrates, with a colour-scale plot of capacity expansion levels, that GB and NO were the two countries representing the largest share of total investments, both in terms of national grid reinforcements and HVDC connections with other countries and the PLI. There is a strong pattern of capacity investments between the two countries as well, due to high gas prices in GB relative to flexible hydropower in NO. Hence, the model found it cost-efficient to use Norwegian hydropower elsewhere in the system, and particularly in GB for Vision 1. The same expansion patterns were found for Vision 4, except that significantly higher levels of OWP (see Table 1) lead to slightly less investments between the two countries (NO and GB).

Stress testing for future VRES development

Since the future deployment of wind power capacity is uncertain, we demonstrate with Scenario D to F how a re-allocation from onshore to offshore VRES capacity affects investment decisions in grid expansion, as well as its subsequent impact on costs. In the latter three scenarios we basically move a share of VRES capacity from onshore to offshore facilities within domestic coordinates, ranging from 10-50% of onshore VRES (solar and wind).

Figure 3 shows an overall decrease in total costs for Scenario D to F, compared with Scenario C, which serves as a base case for this development. One exception is the 50% re-allocation of VRES in Vision 4 (Scenario F) where total costs are higher than for Scenario C. Hence, there is a certain threshold between 0-50% re-allocation for what is cost-efficient in

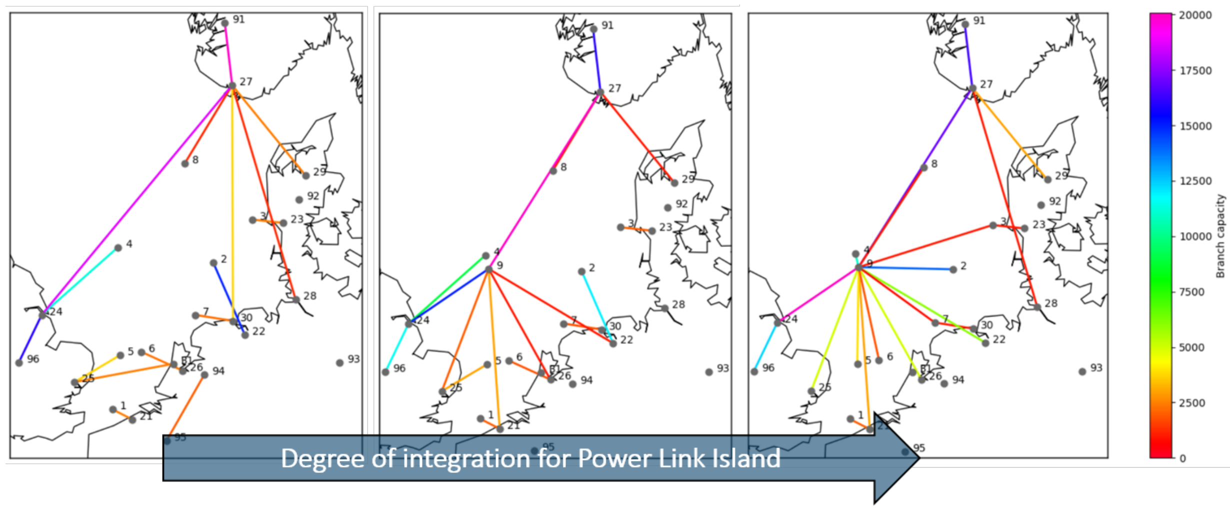

Figure 4: Grid expansions moving from Scenario A (left plot) to Scenario C (right plot), i.e. towards full integration of a PLI as a multinational hub for both cross-border exchange and offshore wind power distribution. Illustrations are based on Vision 1.

Vision 4. The underlying driver for this observation is that VRES represents a larger share of the total supply in Vision 4, where a 50% re-allocation away from the load centers requires considerable investments in cross-border and domestic grid infrastructure in order to avoid load shedding, which exceeds the potential margins to be gained in terms of operational flexibility, better wind resources and subsequent cost savings (which is not infinite as the lowest possible marginal cost (price) is close to 0 €/MWh). Moving VRES away from load centers throughout the system led to NO and DE being the two largest contributors in terms of grid expansion, compared with NO and GB in Scenario C.

As a step further in the stress test, additional 30 GW OWP capacity were added on top of the initial data input. This had minor, and close to uniform, impact on costs, geographical contribution to system benefits, and average area prices. The optimal grid typology remained about the same, independent on the geographical allocation of the additional 30 GW OWP capacity. This implies that the resulting typology in Scenario C, i.e. the fully integrated PLI, is flexible enough to handle this extra supply. However, an evident finding is that the most cost-efficient equilibrium arises when the 30 GWs are allocated directly in connection with the PLI - due to its distributional flexibility as stated earlier in this section.

DISCUSSION

One observed result is the considerable cost-savings of introducing a PLI. In fact, the model found it cost-efficient to invest in a PLI for all nine considered scenarios, and for both a low VRES (Vision 1) and high VRES (Vision 4) future. However, the benefits were in general higher for the most ambitious scenario (Vision 4) due to its temporal- and spatial mix of demand and supply benefiting from the hub functionality of a PLI; cross-border trade and offshore wind distribution. The same results were found in (NSCOGI, 2012) when comparing meshed typologies with radial ones, where the authors identified increasing benefits of an integrated NSOG with increasing shares of VRES. Similar findings have also been supported by, e.g., (Strbac, Moreno, Konstantelos, Pudjianto, & Aunedi, 2014) and more recently (Konstantelos et al., 2017).

Total cost savings for a fully integrated PLI were in the range of 12.6% (Vision 1) to 15.8% (Vision 4), compared with a radial typology (Scenario A). A re-allocation from onshore to offshore wind capacity had a positive impact on system costs, with diminishing returns up to the PLI's maximum capacity near 30 GW. It stands to reason that the latter is due to flexible hub functionality at the PLI, meaning that it has multiple options to distribute this OWP capacity without the need for grid expansion. Finally, by including additional offshore wind capacity on top of the two ENTSO-E visions, allocations in near connection to the PLI gave considerably higher cost-savings than allocating the same amount to national, offshore hubs (not connected to the island). Again, the flexible hub functionality might be a possible explanation in combination with over-supply of generation capacity (not enough demand to distribute it).

In light of previous studies (NSCOGI, 2012; Strbac et al., 2014; Konstantelos et al., 2017), it is clear that increasing levels of grid integration yields multiple benefits. The PLI can be viewed as the ultimate level of integration due to its relative high capacity. However, integrated grid solutions are challenging in terms of cooperation among bordering countries as discussed in, e.g., (Gorenstein Dedecca, Hakvoort, & Herder, 2017). One example being the distribution of costs and benefits, due to asymmetric implications of multinational projects. That is, some countries might gain more benefits than others, as illustrated in for the NSOG in (Egerer et al., 2013) and (Kristiansen, Munoz, et al., 2017).

CONCLUSION

This article performs case studies of TenneT's vision about a Power Link Island (PLI) in the North Sea Offshore Grid (NSOG) serving a twofold purpose as an hub for cross-border trade and offshore wind power (OWP) distribution. We use an optimization program for power system expansion planning to assess the added value of a PLI in the NSOG under the assumption of two distinct futures with low- and high shares of renewable power generation (year 2030), respectively. Three groups of case studies are evaluated, one on the level of PLI integration, the second on re-allocations of renewable capacities from onshore- to offshore coordinates, and third a stress test of the PLI's performance when additional offshore wind capacity is introduced at different geographical locations.

The results establish a starting point for future research on the PLI topic. Based on the scenarios being analyzed, insights can be gained about system cost savings of a PLI, geographical needs for grid reinforcements and expansions, and where it is most cost-efficient to introduce more renewable supply capacity (onshore versus offshore). For the case presented here, a PLI gave cost saving in the magnitude of €36.8bn to €50.7bn compared with traditional, radial grid typologies. Moreover, the key players for realizing such benefits were identified to be Norway, Great Britain, and Germany. However, with support from recent literature we also stress that strongly integrated transmission projects require incentives for cooperation.

Interesting extensions of this work would include studies that incorporate more realistic boundary conditions in order to better approximate costs and benefits. For instance, building 10 to 15 transmission lines/cables are unlikely to be accepted by the public, especially for domestic grid reinforcements onshore. Moreover, accounting for uncertainty would provide a better understanding of what concerns a robust grid typology. Finally, since the PLI is expected to be close to existing gas infrastructure, a sector-coupled analysis would be a valuable contribution.

Acknowledgements

A majority of this work is based on a Master's Thesis (Solli, 2017) supervised by the authors. The authors would like to thank the developers behind PYOMO (Hart et al., 2017) and Gurobi Optimization.

Appendix

Table 2: Supply, demand and fuel price data from ENTSO-E Vision 4 (ENTSO-E, 2016). Onshore and offshore wind capacities are divided according to data from WindEurope (Nghiem & Pineda, 2017). CO_2 price is 76€/tonCO_2.

Supply/	Fuel price	Installed capacity $[MW]$					
Demand	[€/MWh_e]	BE	DE	DK	GB	NL	NO
Bio	50	2500	9340	1720	8420	5080	0
Gas	65	10040	45059	3746	40726	14438	855
Hard coal	21	0	14940	410	0	0	0
Hydro	10-30	2226	14505	9	5470	38	48700
Lignite	10	0	9026	0	0	0	0
Nuclear	5	0	0	0	9022	486	0
Oil	140	0	871	735	75	0	0
Solar PV	0	4925	58990	1405	11915	9700	0
Onshore wind	0	3518	76967	6695	27901	5495	1771
Offshore wind	0	4000	20000	6130	30000	4500	724
Total supply	-	27209	249698	20850	133529	39739	52050
Peak demand	-	13486	81369	6623	59578	18751	24468

References

Alayo, H., Rider, M. J., & Contreras, J. (2017, October). Economic Externalities in Transmission Network Expansion Planning. *Energy Economics*. Retrieved from http://www.sciencedirect.com/science/article/pii/S0140988317303213 doi: 10.1016/j.eneco.2017.09.018

Cochran, J., Miller, M., Zinaman, O., Milligan, M., Arent, D., Palmintier, B., ... Soonee, S. K. (2014, May). *Flexibility in 21st Century Power Systems* (Tech. Rep. No. NREL/TP-6A20-61721). National Renewable Energy Laboratory (NREL), Golden, CO. Retrieved 2016-11-08, from http://www.osti.gov/scitech/biblio/1130630

Egerer, J., Kunz, F., & Hirschhausen, C. v. (2013, December). Development scenarios for the North and Baltic Seas Grid – A welfare economic analysis. *Utilities Policy*, *27*, 123–134. Retrieved 2016-01-29, from http://linkinghub.elsevier.com/retrieve/pii/S095717871300060X doi: 10.1016/j.jup.2013.10.002

ENTSO-E. (2016). *Ten-Year Network Development Plan 2016* (Tech. Rep.). Retrieved from http://tyndp.entsoe.eu/

EU Commission. (2011). A Roadmap for moving to a competitive low carbon economy in 2050. *European Commission*. Retrieved 2015-02-09, from http://www.vliz.be/imisdocs/publications/234029.pdf

European Commission. (2016). *North Seas countries agree on closer energy cooperation.* Retrieved 2017-10-20, from /energy/en/news/north-seas-countries-agree-closer-energy-cooperation

Farahmand, H., Huertas-Hernando, D., Warland, L., Korpas, M., & Svendsen, H. G. (2011). Impact of system power losses on the value of an offshore grid for North Sea offshore wind. In *PowerTech, 2011 IEEE Trondheim* (pp. 1–7). IEEE. Retrieved 2016-01-29, from http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6019345

Gorenstein Dedecca, J., & Hakvoort, R. A. (2016, July). A review of the North Seas offshore grid modeling: Current and future research. *Renewable and Sustainable Energy Reviews*, *60*, 129–143. Retrieved 2016-02-15, from http://linkinghub.elsevier.com/retrieve/pii/S1364032116001428 doi: 10.1016/j.rser.2016.01.112

Gorenstein Dedecca, J., Hakvoort, R. A., & Herder, P. M. (2017, April). Transmission expansion simulation for the European Northern Seas offshore grid. *Energy*, *125*, 805–824. Retrieved 2017-05-25, from http://www.sciencedirect.com/science/article/pii/S0360544217302931 doi: 10.1016/j.energy.2017.02.111

Graabak, I., Svendsen, H., & Korpås, M. (2016, September). Developing a wind and solar power data model for Europe with high spatial-temporal resolution. In *2016 51st International Universities Power Engineering Conference (UPEC)* (pp. 1–6). doi: 10.1109/UPEC.2016.8114132

Hart, W. E., Laird, C. D., Watson, J.-P., Woodruff, D. L., Hackebeil, G. A., Nicholson, B. L., & Siirola, J. D. (2017). *Pyomo - Optimization Modeling in Python* (Vol. 67). Cham: Springer International Publishing. Retrieved 2017-07-05, from http://link.springer.com/10.1007/978-3-319-58821-6 (DOI: 10.1007/978-3-319-58821-6)

Hasche, B. (2010, November). General statistics of geographically dispersed wind power. *Wind Energy*, *13*(8), 773–784. Retrieved 2017-05-13, from http://onlinelibrary.wiley.com/doi/10.1002/we.397/abstract doi: 10.1002/we.397

Hogan, W. (2011). *Transmission benefits and cost allocation*. May. Retrieved 2016-12-12, from http://www.hks.harvard.edu/hepg/Papers/2011/Hogan_Trans_Cost_053111.pdf

Huertas-Hernando, D., Farahmand, H., Holttinen, H., Kiviluoma, J., Rinne, E., Söder, L., … Menemenlis, N. (2017, January). Hydro power flexibility for power systems with variable renewable energy sources: an IEA Task 25 collaboration. *Wiley Interdisciplinary Reviews: Energy and Environment*, *6*(1), n/a–n/a. Retrieved 2017-01-20, from http://onlinelibrary.wiley.com/doi/10.1002/wene.220/abstract doi: 10.1002/wene.220

Härtel, P., Kristiansen, M., & Korpås, M. (2017, October). Assessing the impact of sampling and clustering techniques on offshore grid expansion planning. *Energy Procedia*, *137*, 152–161. Retrieved 2018-01-08, from https://www.sciencedirect.com/science/article/pii/S1876610217353043 doi: 10.1016/j.egypro.2017.10.342

Härtel, P., Vrana, T. K., Hennig, T., von Bonin, M., Wiggelinkhuizen, E. J., & Nieuwenhout, F. D. J. (2017, October). Review of investment model cost parameters for

VSC HVDC transmission infrastructure. *Electric Power Systems Research*, *151*, 419–431. Retrieved from http://www.sciencedirect.com/science/article/pii/S0378779617302572 doi: 10.1016/j.epsr.2017.06.008

Jesse Jenkins, & Nestor Sepulveda. (2017). Enhanced Decision Support for a Changing Electricity Landscape. *MIT Energy Initiative - Working Paper*. Retrieved 2017-12-13, from http://energy.mit.edu/publication/enhanced-decision-support-changing-electricity-landscape/

Kondziella, H., & Bruckner, T. (2016, January). Flexibility requirements of renewable energy based electricity systems – a review of research results and methodologies. *Renewable and Sustainable Energy Reviews*, *53*, 10–22. Retrieved 2017-03-14, from http://www.sciencedirect.com/science/article/pii/S1364032115008643 doi: 10.1016/j.rser.2015.07.199

Konstantelos, I., Pudjianto, D., Strbac, G., De Decker, J., Joseph, P., Flament, A., . . . Veum, K. (2017, February). Integrated North Sea grids: The costs, the benefits and their distribution between countries. *Energy Policy*, *101*, 28–41. Retrieved 2016-11-30, from http://www.sciencedirect.com/science/article/pii/S0301421516306206 doi: 10.1016/j.enpol.2016.11.024

Kristiansen, M., Härtel, P., & Korpås, M. (2017). Sensitivity analysis of sampling and clustering techniques in expansion planning models. *IEEE Xplore, to appear*. Retrieved 2017-06-19, from https://www.researchgate.net/publication/317179028_Sensitivity_analysis_of_sampling_and_clustering_techniques_in_expansion_planning_models

Kristiansen, M., Korpås, M., & Svendsen, H. G. (2018, February). A generic framework for power system flexibility analysis using cooperative game theory. *Applied Energy*, *212*, 223–232. Retrieved 2018-01-08, from https://www.sciencedirect.com/science/article/pii/S0306261917317774 doi: 10.1016/j.apenergy.2017.12.062

Kristiansen, M., Munoz, F. D., Oren, S., & Korpås, M. (2017). Efficient Allocation of Monetary and Environmental Benefits in Multinational Transmission Projects: North Sea Offshore Grid Case Study. *Working paper*. Retrieved 2017-06-19, from https://www.researchgate.net/publication/

317012886_Efficient_Allocation_of_Monetary_and_Environmental_Benefits_in_Multinational_Transmission_Projects_North_Sea_Offshore_Grid_Case_Study doi: 10.13140/RG.2.2.26883.50725

Lund, P. D., Lindgren, J., Mikkola, J., & Salpakari, J. (2015, May). Review of energy system flexibility measures to enable high levels of variable renewable electricity. *Renewable and Sustainable Energy Reviews*, *45*, 785–807. Retrieved 2017-03-14, from http://www.sciencedirect.com/science/article/pii/S1364032115000672 doi: 10.1016/j.rser.2015.01.057

Nghiem, A., & Pineda, I. (2017, 9). *Wind energy in europe: Scenarios for 2030* (Tech. Rep.). WindEurope.

North Sea Grid. (2015). *Offshore Electricity Grid Implementation in the North Sea.* Retrieved from https://ec.europa.eu/energy/intelligent/projects/en/projects/northseagrid

NSCOGI. (2012). *The North Seas Countries' Offshore Grid Initiative - Initial Findings.* Retrieved from http://www.benelux.int/files/1414/0923/4478/North_Seas_Grid_Study.pdf

Solli, E. (2017). Assessing the economic benefits and power grid impacts of the power link island project. Retrieved 2017-10-18, from https://brage.bibsys.no/xmlui/handle/11250/2454955

Strbac, G., Moreno, R., Konstantelos, I., Pudjianto, D., & Aunedi, M. (2014). Strategic development of North Sea grid infrastructure to facilitate least-cost decarbonisation. *Imperial College London*. Retrieved 2016-10-10, from https://www.e3g.org/docs/NorthSeaGrid_Imperial_E3G_Technical_Report_July_2014.pdf

Svendsen, H. G. (2013). Planning Tool for Clustering and Optimised Grid Connection of Offshore Wind Farms. *Energy Procedia*, *35*, 297–306. Retrieved 2015-02-10, from http://linkinghub.elsevier.com/retrieve/pii/S187661021301268X doi: 10.1016/j.egypro.2013.07.182

TenneT. (2017a). *Gasunie to join North Sea Wind Power Hub consortium.* Retrieved 2017-10-20, from https://www.tennet.eu/news/detail/gasunie-to-join-north-sea-wind-power-hub-consortium/

TenneT. (2017b). *Three TSOs sign agreement on North Sea Wind Power Hub.* Retrieved 2017-10-20, from https://www.tennet.eu/news/detail/three-tsos-sign-agreement-on-north-sea-wind-power-hub/

Trötscher, T., & Korpås, M. (2011, November). A framework to determine optimal offshore grid structures for wind power integration and power exchange: A framework to determine optimal offshore grid structures. *Wind Energy*, *14*(8), 977–992. Retrieved 2015-02-12, from http://doi.wiley.com/10.1002/we.461 doi: 10.1002/we.461

van der Meijden, M. (2016). Future North Sea Infrastructure based on Dogger Bank modular island. *Wind Integration Workshop (WIW) 2016*. Retrieved from https://goo.gl/Q9oeTx

Van Hulle, F., Tande, J. O., Uhlen, K., Warland, L., Korpås, M., Meibom, P., ... others (2009). *Integrating wind: Developing Europe's power market for the large-scale integration of wind power* (Tech. Rep.). European Wind Energy Association (EWEA). Retrieved 2015-02-09, from http://orbit.dtu.dk/fedora/objects/orbit:81254/datastreams/file_3628703/content