Final report

1.1 Project details

Project title	North Sea Energy Hub Forundersøgelse
Project identification (program abbrev. and file)	64018-0584
Name of the programme which has funded the project	Systemintegration
Project managing company/institution (name and address)	Danmarks Tekniske Universitet Anker Engelunds Vej 1, Bygning 101, 2800 Kgs. Lyngby
Project partners	Energinet, Dansk Industri
CVR (central business register)	30 06 09 46
Date for submission	9. September 2020

1.2 Short description of project objective and results

This project brings together experts from academia and industry to investigate the feasibility and business potential of an approximately 12 GW North Sea Wind Power Hub. This will lay the foundation for establishing a national consortium including the key industrial stakeholders and initiating a large Danish technology development activity.

Dette projekt bringer eksperter fra universitetsverdenen og industrien sammen, for at udforske det økonomiske og forretningsmæssige potentiale i en North Sea Wind Power Hub på omkring 12GW. Det vil danne grundlag for etableringen af et nationalt konsortium der inkluderer de vigtigste interessenter fra industrien og vil tage hul på en stor dansk teknologiudviklingsopgave.

1.3 Executive summary

This project had two main goals. First, to carry out a detailed prefeasibility analysis of the North Sea Energy Hub, looking (i) at the available technology options and their costs, (ii) its safe operation, (iv) its impact to the electricity prices in Europe, and (iv) the optimal integration of electric power and hydrogen. Second, the determine the technology gaps and initiate a larger research and development activity that will include key industry stakeholders in order to address them.

Below we fist outline the main outcomes of our analyses, and we conclude with the technology gaps we decided to address in a larger R&D effort.

Market analysis

- Using historical market prices for DK, UK, DE, NL and NO, and transmission capacities, we created market models that were able to capture the impact of the North Sea Energy hub on the electricity prices for 2030. We found that:
  - Overall, the electricity prices decrease
  - Transmission capacity higher than the installed offshore wind capacity facilitates increased cross-border trade among the countries surrounding the NSEH, and by that, we achieve further price drops and eliminate wind curtailment (15 GW of transmission capacity for a 10 GW Hub)

  - NSEH also leads to increased exports (and, thus, increased cross-border flows) towards the rest of the European counties
  - Connection of Norway has a positive impact

North Sea Wind Integration Limits for the Europe System

- Based on ENTSOe data, we used a 7'500-node power system model that included all 400kV and 220kV lines for the whole Europe (including the planned reinforcements until 2030). Our goal was to assess if the onshore electricity systems had the ability to integrate the massive offshore wind potential that the North Sea Energy Hubs shall harvest (this exceeds 180 GW). We found:
  - Offshore wind capacity over 13 GW requires either Power-to-X or reinforcing the national grids.
  - A 20 GW-NSEH with 8GW-PtX used for peak shaving can replace 50% of natural gas consumption in Denmark.

Available technology options and costs for the future North Sea Wind Power Hub

- Having compiled a list of all available technology options and their costs from the public domain, we found the following:
  - Organizing Wind Power Plants (WPPs) in Hubs is cheaper than connecting each offshore WPPs directly to the shore for Hub sizes starting from 3 GW and going beyond 15 GW.
  - Using 66 kV as the standard voltage for connecting WPPs to the Hub, a technology that has just been introduced in the market, cost-effective Hub sizes are between 3 GW and 13 GW, with the optimal Hub size being 9 GW
  - If industry moves to 132 kV, then Hub sizes beyond 15 GW can become cost-effective.
  - Low-Frequency AC vs 50 Hz vs Higher Frequency for the Offshore AC Grid: Moving away from the standard frequency of 50 Hz has limited benefits to justify a change of standards.

Safe operation of the North Sea Wind Power Hub

- AC vs DC topology for the Hub (and the Offshore Grid)
  - As DC circuit-breakers are not yet commercially available for 320/525 kV DC, this project focused at the only viable alternative accepted by Energinet and other operators at the moment: AC topology for the offshore grid with direct HVDC connections to the onshore grids for distances longer than 80km and option for AC cables for distances shorter than 80 km.
  - Note: ABB just recently announced a working prototype for such high voltages, which needs to be considered in the upcoming R&D activities)
- AC topology: Zero-inertia vs low-inertia AC offshore grid
  - Zero-inertia = 100% power electronic converters (HVDC and Wind turbines), no conventional generation: Large disturbances propagate instantaneously to the interconnected onshore grids and can lead to high frequency deviations in those grids; but, voltage and frequency oscillations are better damped.
  - Low-inertia = Zero-inertia+Synchronous Condensers installed offshore on the Hub: fast propagations of large disturbances are avoided, due to kinetic energy stored in the synchronous condenser. This reduces the impact of offshore incidents on the interconnected onshore grids.
- Need for new simulation tools: phasor approximation modelling can be used as long as eigen-frequencies in power network are well damped. Otherwise, tools based on Electromagnetic Transients simulations might be necessary. Our findings suggest that system operators could keep on using the phasor-approximation model in the presence of the NSWPH system for performing dynamic security assessment.

Power-to-X: From the North Sea Wind Power Hub to a North Sea Energy Hub

- Comparison of electrolyzer technologies for Power-to-X
  - Alkaline vs Proton-Exchange-Membrane vs Solid-Oxide

    - Despite poorer dynamics, Alkaline electrolysers are the best solution, because of their cost

- In-turbine vs offshore vs onshore electrolysis.
    - Offshore hydrogen hub is the most cost-efficient solution when more than 50% of the produced electricity is converted into hydrogen, i.e. baseload operation (due to economies of scale for storage and pipelines)
    - Onshore electrolysis is the most cost-efficient solution when less than 50% of the wind power is converted into hydrogen, i.e. electrolyzer used for peak load operation
    - In-turbine electrolysis has distinct advantages, such as eliminating the need for additional footprint to install large-scale electrolyzers and offer of electricity grid services by the integrated electrolyzer such as black-start capabilities, and others. However, technological barriers need to be addressed, e.g. the cost of combined transmission of electricity and hydrogen to make this option competitive

- Electrolyzer used for Base-load Operation vs Peak-Shaving Operation
    - Using the electrolyser with baseload power is more cost-effective than use it for peak shaving.

- Hydrogen Storage: Tank vs Geological Storage
    - Geological storage is the most cost-effective storage for gaseous hydrogen, but it can contaminate the stored hydrogen to a quality level that could not be used in fuel cells

Based on the outcomes of our analyses above, we have identified two main technology gaps that we intend to address in an upcoming larger R&D activity. Along the duration of this project, we have submitted two research proposals for a total effort of ~34 million DKK each, together with leading industry partners. Our first goal is to develop technology prototypes that will make in-turbine electrolysis cost-competitive with the large-scale onshore and offshore electrolysis. Second, to reduce the capital costs of offshore wind turbines connected to an offshore Hub, by moving specific grid code requirements from the WT level to the Hub. This can generate savings of up to 20 Billion DKK for a 10 GW Hub.

1.4 Project objectives

This project had two main objectives.

First, to carry out a (i) pre-feasibility analysis of the potential development of the North Sea Energy Hub, (ii) determine its impact on electricity prices, needs for technology and investments, and (iii) the development of power-2-X, and identify technology gaps.

Second, to address some of the gaps that have been identified in this project in a much larger research and technology development activity, in order to develop technological solutions that will remove some of the identified barriers for the cost-effective development of the North Sea Energy Hub. Our expectation is that, if successful, the upcoming R&D activity will lead to the commercialization of the developed solutions.

There were two major risks related to this project. First, that the Danish policy changes, and the interest is no longer on building an artificial island and investing on offshore wind in the North Sea. Second, that the Danish industry members lose interest or are not willing to collaborate and disclose enough information that can help this project identify the true technological gaps. As far as Danish policy is concerned, it moved exactly along the same direction as this project, with the Danish government announcing in May 2020 the mandate for the investigation of the construction of two Energy Hubs, one in the North Sea and one in the Baltic Sea. As far as the collaboration with Danish industry members, we mitigated this risk by forming an Advisory Board and holding Advisory Board meetings in frequent intervals (3-4 months), arranging dedicated 1-1 discussions with specific industry members related to the project topics, and ensuring that our analyses and results were relevant for our industry members, which will ensure that we would receive more valuable feedback.

Despite the initial delay, due to the change of the project leader in 2019 (the person expected to lead this project left DTU right before the start of this project) and due to Covid-19 in 2020, the project was able to successfully achieve both its objectives.

1.5 Project results and dissemination of results

1.5.1 Impact of the Hub size on electricity prices and maximum offshore wind penetration to the European grid by 2030

The study in this section comprises two analyses: a **market analysis** and a **technical analysis**. The market analysis aims at investigating what would be the impact of the NSEH on the existing power exchanges between countries. The technical analysis, instead, looks at what would be the impact of such a system on the existing grid, taking into consideration the technical limitations.

The **market analysis** uses a simplified market model of the four countries (Denmark, Germany, the Netherlands and the UK) directly connected to the island. An extension of the model comprises also Norway. All the other countries, that are not directly connected to the island, are included as positive or negative loads, depending on whether they are importing or exporting energy. The simulations are run for a time period corresponding to one year, using real wind, solar and load profiles from 2019. The location of the NSEH is Dogger Bank, the wind profiles are calculated based on wind speed data from Copernicus ERA5 and 15-MW IEA reference wind turbines.

Three cases are investigated:

1. Connection to **Germany**, **Denmark**, the **Netherlands** and the **UK**. The transmission capacity is equal to the maximum installed wind capacity.
2. Connection to Germany, Denmark, the Netherlands and the UK. **Extra transmission capacity** for energy exchanges between countries.
3. Connection to Germany, Denmark, the Netherlands, the UK and **Norway**.

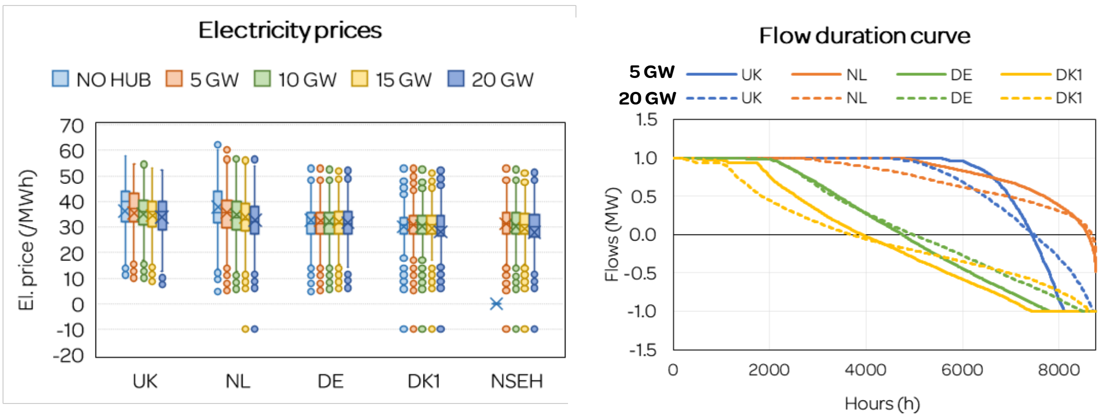


Figure 1.5.1.1: Electricity prices and flow duration curve (case 1).

For the case 1, five simulations are run: the first without NSEH, then with 5, 10, 15 and 20 GW of installed wind capacity. For case 2, two simulations are run with 10 and 15 GW of total transmission capacity, while the installed wind power capacity is kept equal to 10 GW. Finally, for case 3, three simulations are run: the first without the NSEH, the second with connection to DE, NL, DK and UK only, and the third adding a connection to Norway. Similar to case 2, in case 3 the installed wind power capacity is kept equal to 10 GW.

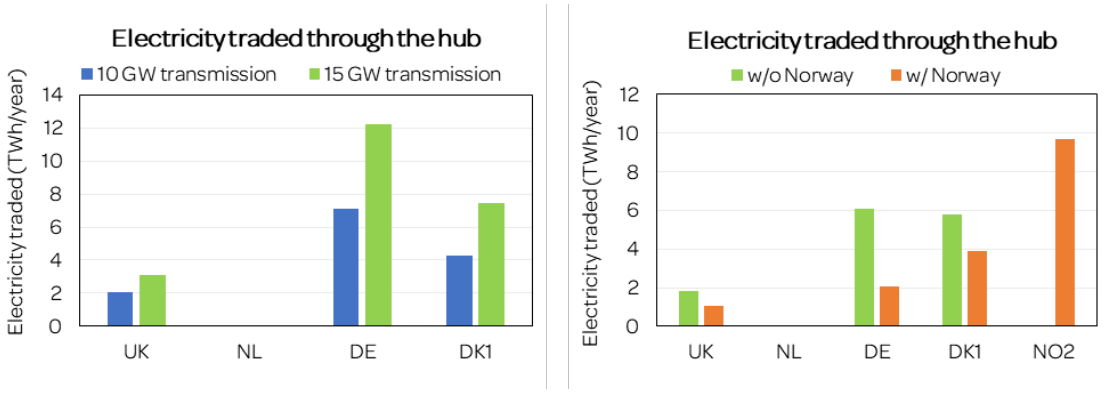


Figure 1.5.1.2: Electricity traded through the hub in case 2 (left) and 3 (right).

In general, the construction of the NSEH means: i) additional wind power capacity with almost zero marginal cost of production, and ii) additional transmission capacity between the countries connected to the island. This, in turn, means increased export for those countries with relatively low electricity prices, and lower electricity prices for those countries with relatively high prices. For case 1, Denmark and Germany are the main exporters through the hub, and the electricity prices tend to increase or remain constant (see Figure 1.5.1.1). The Netherlands, instead, see the highest price drop: lower prices result in increased exports to non-NSEH countries.

When the total transmission capacity is greater than the installed wind power capacity, case 2, the exchanges between countries increase (see Figure 1.5.1.2). This stresses that one of the main benefits of the NSEH is the interconnection of different markets. As a result, prices further decrease in the importing countries.

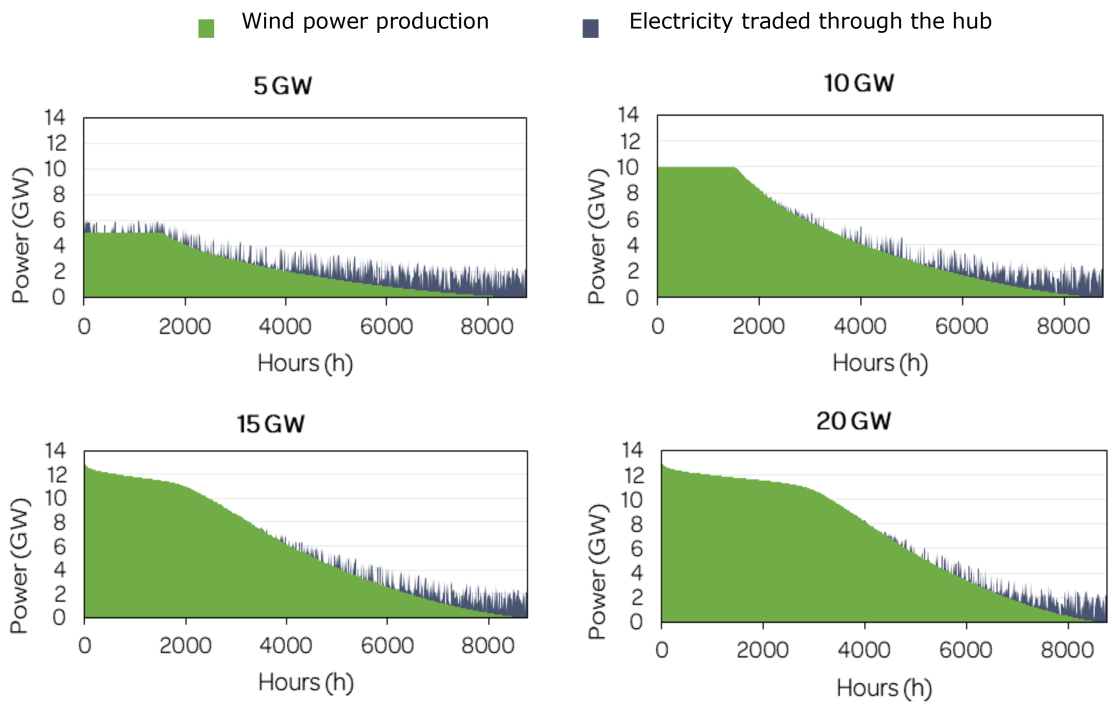


Figure 1.5.1.3: Wind power production and exchanges between the countries.

In Norway, more than 90% of electricity is produced by hydro power plants, resulting in low electricity prices. Therefore, when connected to the island, Norway takes over the role of main exporter through the hub. Overall, prices further decrease in the importing countries and, in addition, in Germany as well.

The **technical analysis** is carried out using a grid model from ENTSO-E. The original grid model comprised more than 17000 nodes; for our analysis the system has been reduced to

7500 nodes to comprise only the 400 and 220 kV networks. Furthermore, the NSEH has been modeled as one aggregated wind farm located in the North Sea with four HVDC interconnectors connecting the generator to DK, DE, NL and UK.

Four simulations are run with increasing size of the hub: the installed capacity varies from 5 to 20 GW with 5GW steps. Each simulation consists on a linearized "dc" optimal power flow problem which considers generation and transmission limits. Up to 10 GW of installed wind capacity, the produced wind energy is fully transmitted to the four connected countries. On top of this, exchanges between countries take place (see *Figure 1.5.1.3*). However, **internal congestions do not allow for more than 13 GW of power flows in the HVDC links**. So, when 15 GW of wind capacity are installed, some of the wind power must be curtailed. Moreover, the bigger the size of the island is (in terms of installed wind power), the less energy is exchanged between countries as more wind energy is available.

Thus, beyond 13 GW, a reinforcement of the existing grid is necessary. As an alternative, **PtX can be used to avoid wind curtailment**. PtX makes economic sense only for hubs greater than 13GW and can replace up to 50% of natural gas consumption in DK with an 8GW PtX (20GW NSEH).

	5 GW	**10 GW**	**15 GW**	**20 GW**
Annual wind energy curtailed	93.9 MWh	26,507 GWh	6,179,808 GWh	17,985,467 GWh
Peak of wind power curtailed	24.15 kW	1.70 GW	6.40 GW	11.10 GW
Maximum natural gas substitution*	0.00 %	0.06 %	17.50 %	51.00 %

Table 1.5.1.1: Wind power curtailment and natural gas substitution.

1.5.2 Offshore transmission grid and collection grid topology

Alternative technologies for transmission and collection grids for wind power plants (WPPs) and offshore hubs were evaluated with respect to economic viability and strategic relevance. The study includes evaluation of some of the most prospective technologies while special attention has been given to Low Frequency AC (LFAC) technology as a means of reducing cost in realization of the electrical infrastructure of offshore energy hubs.

Electrical design parameters under investigation in this study include:

- LFAC as a viable alternative to standard AC technology in the offshore grid
- LFAC as a viable alternative to HVDC technology for transmission hub-to-shore
- Offshore grid topology acc. to the 'small AC' scheme (see Figure 1.5.2.2)
- Offshore grid topology acc. to the 'Large AC' scheme (see Figure 1.5.2.3)
- Collector grid voltages of 66kV or 132kV
- Economy of scale of electrical infrastructure with respect to hub rating

The study was structured as a scenario analysis, for which the above-mentioned design parameters are evaluated for two distinct cases of an offshore energy hub:

- Case 1 – The Danish hub, for which all power generated at the hub is evacuated to the Danish onshore transmission system
- Case 2 – The International hub, where a number of countries surrounding the North Sea are connected to the hub.

The interconnections and location of hubs for the two cases are depicted on Figure 1.5.2.1.

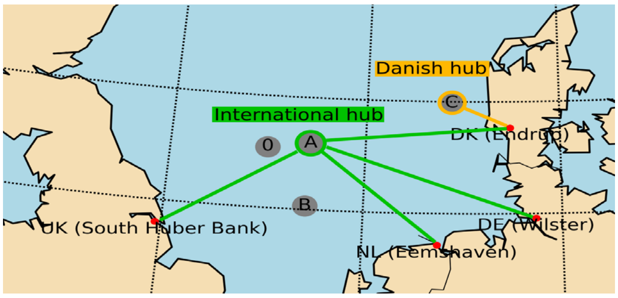


Figure 1.5.2.1 Representative cases of energy Hubs used in study

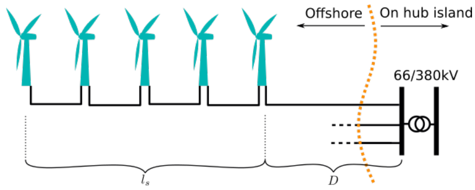


Figure 1.5.2.2 Offshore grid acc. to Small AC scheme

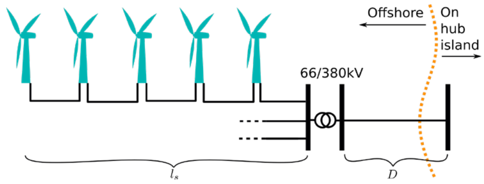


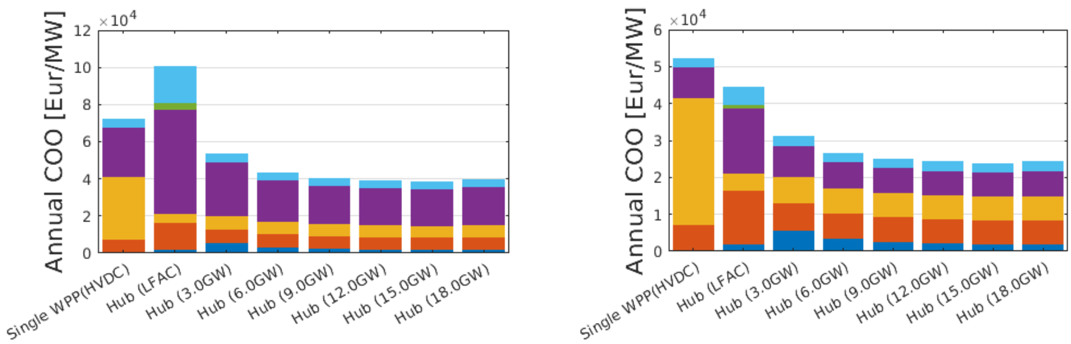
Figure 1.5.2.3 Offshore grid acc. to Large AC scheme

A model suite was developed for expressing cost of components for the electrical infrastructure and other components which are in some way related to the electric system design. The cost models were supplemented by a routine for assessing likely wind power yield at the two hub locations considered in the study. This setup has allowed inference on capital cost and power losses of the individual electric topology designs. Findings on the performance of the different electric topology designs are presented in the following.

1.5.3 Findings related to Transmission Hub-to-shore

In neither of the cases (Danish or International Hub) would a realization with individual WPPs and individual transmission systems be competitive with the Hub configuration. That is, organizing the WPPs around Hubs has lower costs than having each WPP directly connected to the shore.

For the Danish hub, LFAC technology would result in slightly reduced investments compared to a realization with individual WPPs whereas LFAC technology would be the least attractive technology for transmission in the case of the international hub. In fact, some of the transmission distances in case of the international hub were found to be too large for even low frequency power transmission to be technically viable, due to voltage drop considerations.



a) International Hub *b) Danish Hub*

Figure 1.5.2.4 Cost of Ownership of alternative transmission technologies. Annualized and normalized to installed transmission capacity.

For both the Danish and the International Hub the least cost solutions are associated with a transmission system that is comprised of HVDC connections with converter stations situated on the artificial island where the Hub is located. It is furthermore found that economy of scale of the artificial island means that further cost reductions are achieved as hub ratings are increased to ~9GW of transmission capacity. Beyond 9GW the reduction in transmission system cost wears off. Thus, it is concluded that the optimal transmission system topology, among the investigated alternatives, can be realized for a large central hub between 3 and 15 GWs, and is comprised of HVDC connections.

Findings related to Offshore Grid Topology

Cost of alternative offshore grid topologies were investigated for hubs of different power ratings. This study excluded transmission system effects, and results are thus, independent of hub location.

It was found that configuration according to the Large AC scheme leads to lower losses and reduced cost of cabling. In that scheme, offshore substations are used in order to raise the voltage from 66kV to 380kV, before transmitting the electricity to the Hub. However, for smaller Hubs, less than 13GW, these cost reductions are more than offset by the added cost of offshore transformer platforms needed to obtain the desired transmission voltage.

The 66kV technology, which has been recently introduced on the market for wind power extraction, performs better than the Large AC alternative for hubs of rating 13GW or less. However, the relative increase in cost by hub rating is high for this technology. This is because the cost associated with 66kV technology are strongly related to the area of the wind power extraction zone. This dependence introduces a mechanism of diminishing cost reductions as hub rating is increased. The optimal hub rating, considering both cost of offshore grid and transmission hub-to-shore, is approximately 9GW when offshore grid is realized as 66kV small AC.

The 132kV technology for WPP collector grids is not commercially available and cost models of this technology should be considered uncertain. However, the best estimates presented below reveal that the rate of diminishing cost reductions is much lower than for the 66kV technology, and that the 132kV technology in general is less costly. This suggests that energy hubs of more than 15GW could become feasible with this technology.

Findings related to LFAC for the Offshore grid

A sweep of design frequency was made for the different offshore grid topologies for a 9GW hub. Cost reductions by means of lowering design frequency is under no circumstance a possibility with this study.

It is true, as reported in literature, that some cost components are reduced by lowering design frequency. These cost components include losses and high voltage cables. Yet, these minor reductions are completely offset by increased cost of power transformers and substructures.

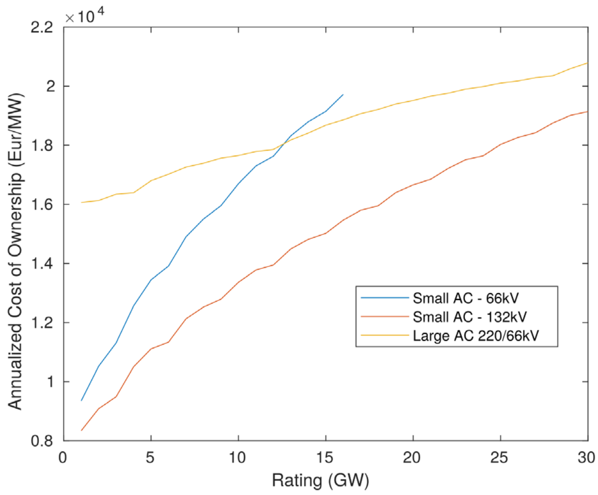
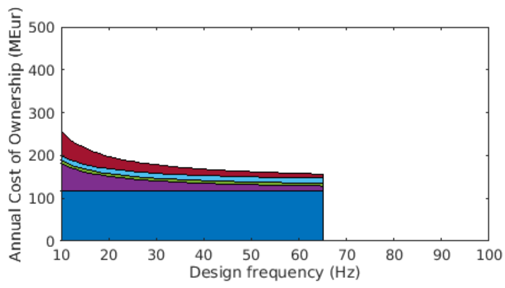
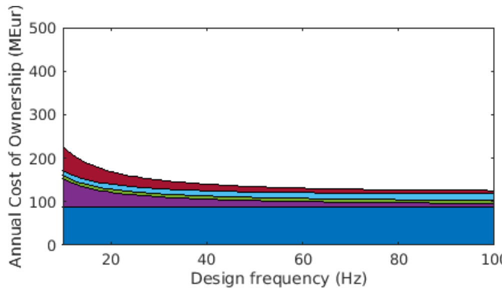


Figure 1.5.2.5 Cost of ownership of Collector grid by technology and Hub power rating

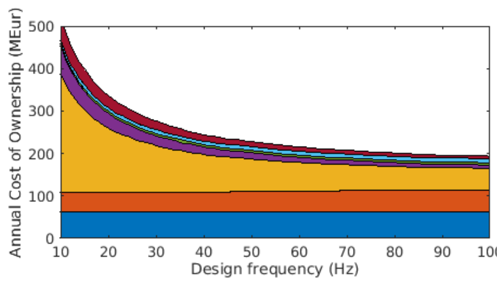
In fact, it is found that cost reductions by altering design frequency can only be achieved for higher design frequencies. However, a 9GW hub cannot be realized with 66kV technology for frequencies larger than 65Hz due to voltage drop considerations. Furthermore, the cost reductions to be achieved by increasing design frequency for hubs of Small AC topology are barely noticed. Hence, recommendations from this study are made to maintain the standard 50 Hz frequency for the Hub and focus development efforts elsewhere - e.g. on maturing 132kV technology.



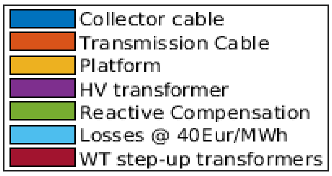
a) 66kV small AC technology



b) 132kV small AC technology



c) Large AC technology



Legend

Figure 1.5.2.6 Cost of ownership of collector grid of 9GW hub by varying design frequency

1.5.4 ***Stability Analysis of Offshore AC Grid Configuration***

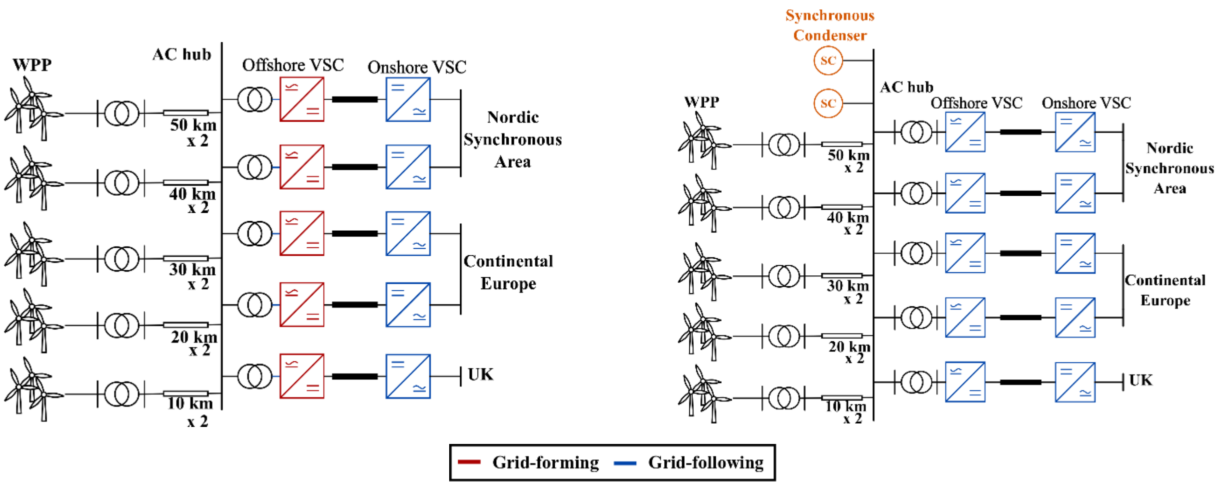


Figure 1.5.3.7: Zero-inertia (left) and low-inertia (right) topologies for NSWPH

In case of an AC grid on the island and between the wind farms, there are two possible configurations, namely a zero- and a low-inertia solution. The zero-inertia solution corresponds to a 100% converter-based system (see Figure 1.5.3.1 - left) while the low-inertia solution corresponds to a system dominated by PE devices, but with at least one synchronous condenser connected (see Figure 1.5.3.1 - right). A comparison between the two configurations is performed, in order to show their stability properties and illustrate their ability to restore the voltage and the frequency of the offshore system for different type of disturbances. For comparison purposes, we define the following two criteria for secure operation of the offshore system: (i) regulate the frequency of the offshore system and (ii) avoid fast disturbance propagation to the onshore grids.

In the zero-inertia configuration, due to the absence of energy storage, a disturbance propagates almost instantaneously to the interconnected onshore grids. Considering scenario 2 and the system response depicted in Figure 1.5.3.2 (middle plot), where an offshore converter outage occurs, the active powers absorbed by the remaining offshore converters change to a new steady state (post-fault equilibrium) within a few milliseconds. In the low inertia case, due to the kinetic energy stored in the rotating mass of the synchronous condenser, the disturbance in scenario 2 and 3 propagate slower to the interconnected onshore grids. As can be seen in Figure 1.5.3.2, the rate of change of active power delivered to the interconnected onshore grids is much lower compared to the zero-inertia case. Thus, we can infer that large disturbances taking place in the offshore grid have less severe impact on the frequencies of the interconnected onshore grids. Lastly, considering scenario 1 and the results depicted in Figure 1.5.3.2 (left plot), we can infer that both configurations can rapidly provide active power to a connected onshore grid. In the zero-inertia system a fast response with short settling time can be observed, while in the low-inertia configuration the power request resulted in an overshoot.

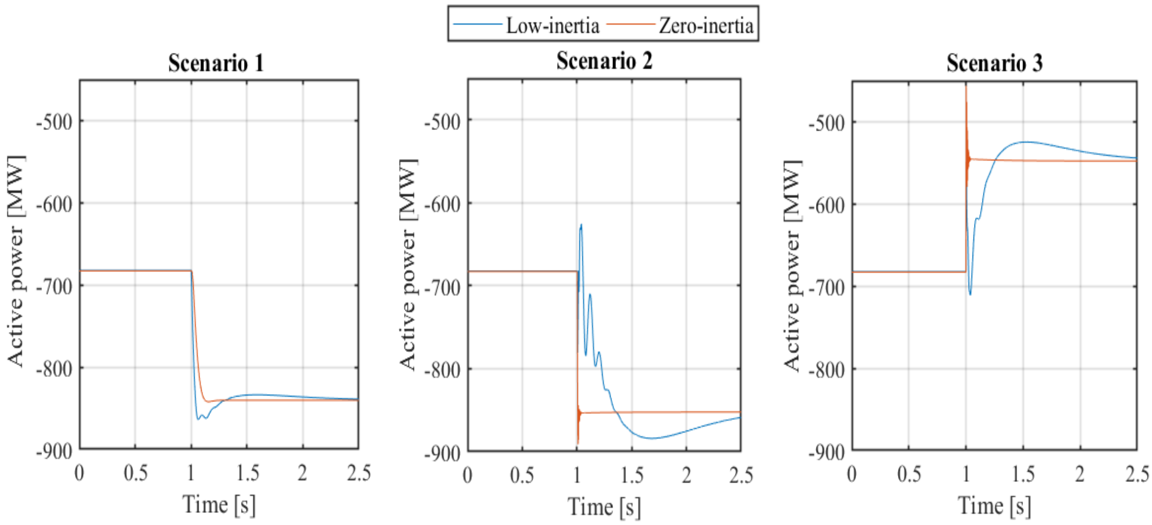


Figure 1.5.3.8: Active power absorbed by the offshore converters. Scenario 1: 200 MW power request from a partner TSO. Scenario 2: DC-link outage. Scenario 3: Wind power loss with AC cable disconnection.

Regarding the frequency of the offshore system (see Figure 1.5.3.3), in the zero-inertia case the system frequency varies almost instantaneously. However, due to the small values of frequency droops, the maximum frequency deviation is small (less than 0.07 Hz). In the low-inertia case, the maximum frequency deviation is higher compared to the zero-inertia case. This is due to the larger values of the frequency droops of the grid-following converters in order to maintain the stability of the system. In the investigated large disturbances, this results in significant frequency deviations (up to 1.6 Hz). Such variations, unacceptable in conventional AC grids, can be tolerated on the isolated offshore island with no load (except for auxiliaries of course). The wind park controllers should be tuned to accept such frequency deviations. Furthermore, the frequency deviation is corrected by the centralized controller, which is updating the power reference set points of the offshore converters.

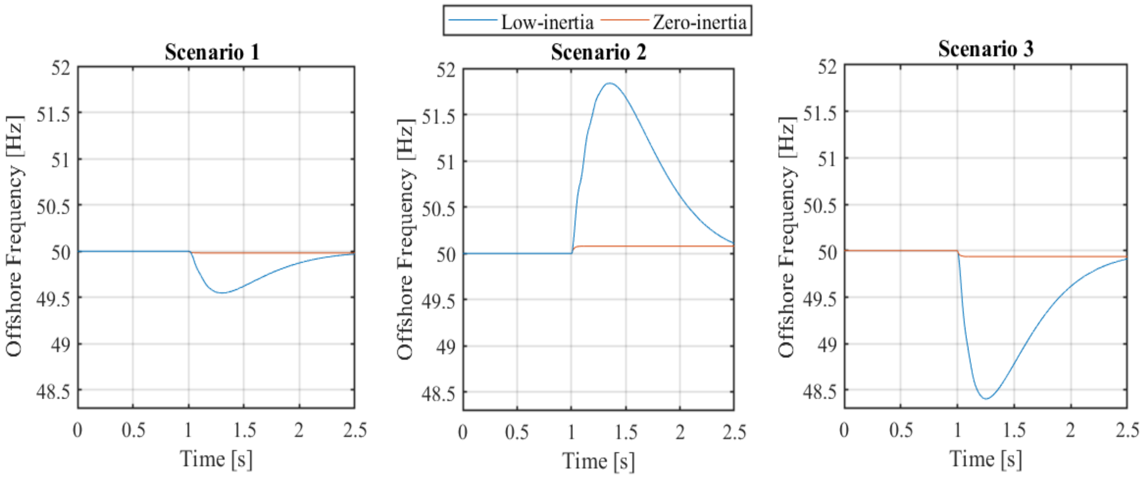


Figure 1.5.3.9: Offshore frequency deviation. Scenario 1: 200 MW power request from a partner TSO. Scenario 2: DC-link outage. Scenario 3: Wind power loss with AC cable disconnection.

In this section, we explored two configurations for the NSWPH and provided a comparison regarding the dynamic behaviour of such a system. For comparison purposes, performance criteria regarding the voltage and the frequency of the offshore system have been considered, as well as the impact of large disturbances on the active power delivered to the interconnected onshore systems. The following observations were made:

- In the zero-inertia configuration the voltage and the frequency oscillations are better damped for the considered scenarios. Moreover, the active power is transmitted faster between partner TSOs.
- In the zero-inertia configuration, large disturbances, which result in active power imbalance of the offshore system, propagate instantaneously to the interconnected onshore grids and can lead to high frequency deviations in those grids.
- In the low-inertia configuration, such fast propagations of large disturbances are avoided, due to kinetic energy stored in the synchronous condenser. This reduces the impact of offshore incidents on the interconnected onshore grids.

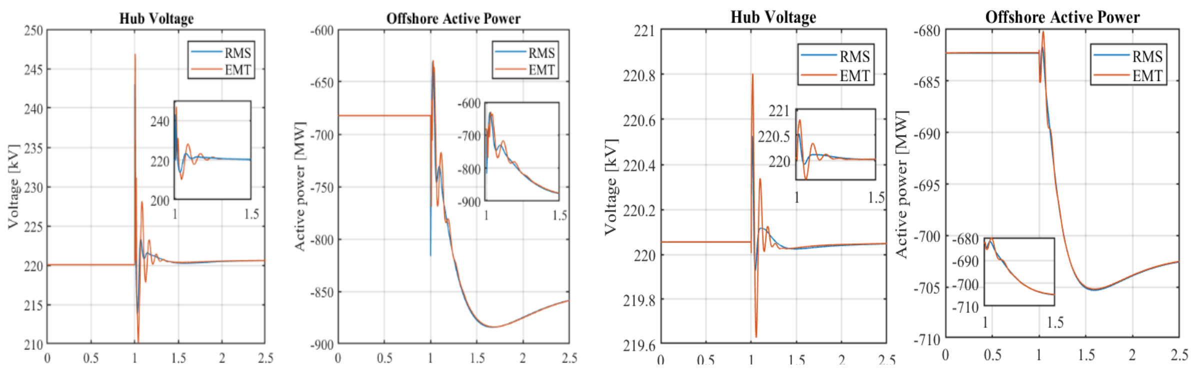


Figure 1.5.3.10: Accuracy of phasor-approximation model for the low-inertia configuration (a) response to an offshore converter outage; (b) response to a power exchange between partner TSOs. Left figures: voltage at the hub. Right figures: active power in offshore converter

Finally, we also found that the phasor approximation modelling can be used as long as eigen-frequencies in power network are well damped. In the zero-inertia case, due to the ability of the grid-forming converter to damp high frequency oscillations, the difference between the phasor approximation and EMT models is negligible. In regard to the low inertia configuration, there is a mismatch between the two models for a slightly higher duration (namely, within 200 ms after the disturbance inception), due to some less-damped eigen-frequencies (depending on the tuning of the inner-current controllers). Our findings suggest that system operators could keep on using the phasor-approximation model in the presence of the NSWPH system for performing dynamic security assessment.

1.5.5 Power-to-X analysis

This study investigated the economics of hydrogen (H2) production, prospected in 2030, from offshore wind power, considering a 12 GW wind power park located in Dogger Bank, referenced from the Wind Power Hub Consortium.

As main result, for alkaline electrolysis located on the offshore hub the cost of the H2 produced has resulted to 2.4-2.7 €/kg, if the production of H2 is set as a priority, thus absorbing the electricity generated until the electrolyser maximum capacity (base load mode), and to 2.7-5.4 €/kg, if H2 is produced only in function of leveling out peaks in electricity, thus prioritising electricity dispatch (peak shaving mode)**.** If the electrolyser is used for shaving power peaks. Thus, the lowest LCOH competes with upper limit of the cost of production of grey and blue H2, 0.8-2.9 €/kg and 1.35-2.6 €/kg respectively, and outperforms current green H2 in Europe, 2.8-3.6 €/kg.

The three main electrolyser technologies for H2 production have been compared: alkaline (ALK), proton-exchange membrane (PEM), and solid-oxide (SOEC) electrolysers. Due to lower investment costs, ALK electrolysers produce H2 at a lower cost than PEM electrolyser (our results showed that the PEM electrolyser was at a maximum 10% more expensive), despite the better operational capacity range, faster cold start-up and lower footprint of PEM. H2 produced by SOEC can be up to double the cost of the hydrogen produced by ALK, due to a larger degradation of the efficiency, and a more frequent stack replacement.

Three main possibilities for the placement of the electrolysers have been conceptualised and compared: (i) H2 production by in-turbine electrolysis then transmitted via pipelines that connect groups of 5 WTs to the offshore hub where it is collected in one pipeline directed onshore; (ii) bulk H2 production on a centralised electrolyser on the offshore hub and then transmitted onshore via pipeline; (iii) bulk H2 production onshore. The H2 infrastructure, running in parallel with the electrical infrastructure, is analysed considering installed capacity of the electrolyser from 0 GW (no H2 production and only electric power is delivered) to 12 GW (only H2 production and no electricity delivered as end-product). Electrolysis on the offshore hub has resulted to be the most cost efficient compared to the other two alternatives if the electrolyser acts as a base load. If the electrolyser acts in a peak shaving mode, the onshore solution is better than the offshore solutions for capacities between 1.5 GW and 2.5 GW for the ALK, between 1 GW and 3 GW for the PEM,and between 1.5 and 4 GW for the SOEC. The LCOE savings emerging for the electricity produced by locating the electrolyser offshore, as we require less electric transmission capacity installed between the hub and the shore, is not sufficient to compensate for the higher CapEx of the offshore installations in the above-mentioned ranges.

As already mentioned, the operation of the electrolyser is compared in the case of base load and peak shaving operations. The use of base load power guarantees a higher capacity factor of the electrolyser during its annual operation thus resulting in lower LCOH of the H2 produced when compared to the peak shaving use of an electrolyser of the same size. The lowest levelised cost of the H2 (LCOH), 2.36 €/MW, has been registered for a 2.5 GW electrolyser installed on the offshore hub using base load power. LCOH of H2 produced with an ALK electrolyser on the offshore hub by peak shaving has resulted in ranges from 5.41 €/kg (500 MW electrolyser) to 2.7 €/kg (12 GW electrolyser). Even if the most cost-effective H2 is obtained in base load mode, the advantage of the peak shaving mode is reflected in the levelised cost of the electricity (LCOE), delivered in parallel with H2. The electricity system benefits of higher CF when we increase the electrolyser installed capacity. The lowest LCOE, 41.9 €/MWh, is registered for 10 GW of installed capacity of the electrolyser for the offshore case (with a respective LCOH of 2.8 €/kg). This LCOE is 14.1% lower than it would be if no electrolyser would be installed to shave the electricity peaks, 48.7 €/MWh. In the case of in-turbine electrolysis, the lowest LCOE is 44.6 €/MWh (with a respective LCOH of 3.9 €/kg), registered for an electrolyser installed capacity of 6 GW.

A breakdown of the capital expenditures has been also investigated. The electrolyser cost is the most relevant cost when compared to the other components. In the in-turbine case, the sum of the cost of the pipelines that carry H_2 from each array of WTs to the hub is the second-most relevant cost throughout the sizes of the electrolyser installed, and it is the most relevant for the smallest size installed for ALK and PEM, covering up to 62% of the CapEx. For the smallest scales, e.g. 500 MW (800 x 625 kW electrolyser), the small amount of H_2 produced is transported through a pipeline that is oversized to 100 mm of diameter to be manufactured. The economies of scale reduce the unitary costs if larger sizes are installed. In the offshore case, the cost of the transmission pipeline accounts from 44%, for a 500 MW installed capacity, to 19% of the total CapEx, for a 12 GW capacity for the ALK electrolyser. The CapEx of the compressor is larger in the case of the in-turbine electrolysis due to a pressure at the inlet of the compressor, located on the offshore hub, which is lower than in the cases of offshore and onshore electrolysis. The reason for that is the pressure drop in the distribution pipeline from the WTs to the Hub. The differences between the CapEx of compressor by types of the electrolyser are due to the different pressure of the H_2 produced: the lower is the pressure of the H_2 produced, the higher is the power consumed by the compressor. In the onshore case, the compressor covers 9%, 2% and 35% of the CapEx in the case of ALK, PEM and SOEC respectively. In the onshore case, the pressure to which the H2 is compressed, 70 bar, is lower than the offshore case, 100 bar, thus reducing the absolute CapEx of the compressor in the offshore case. The artificial sand island built to create the offshore hub accounts for less than 4% of the total CapEx in all the cases. The desalination unit used for supply water to the electrolyser in the in-turbine and offshore configurations accounts for less than 2% of the total CapEx.

Figure 1.5.4.1 and Figure 1.5.4.2 show the results discussed above in the case of base load and peak shaving operations respectively, while Figure 1.5.4.3 shows the breakdown of the CapEx.

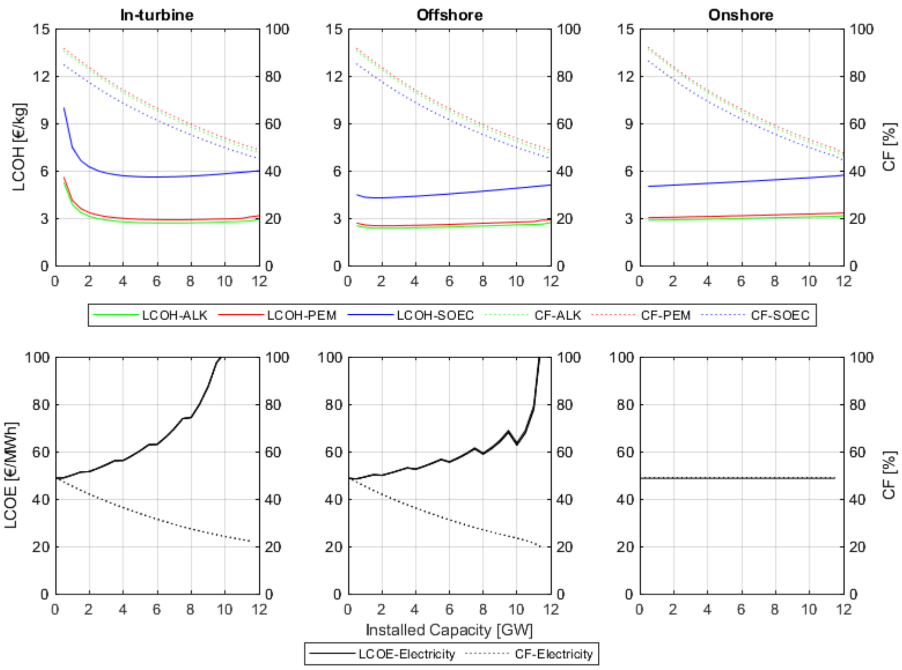


Figure 1.5.4.1 Resulting LCOH, LCOE and CF for the base load operation. Note: the installed capacity is referring to the total electrolyser capacity installed; the CF showed for the electricity infrastructure is the one of the HVDC transmission line.

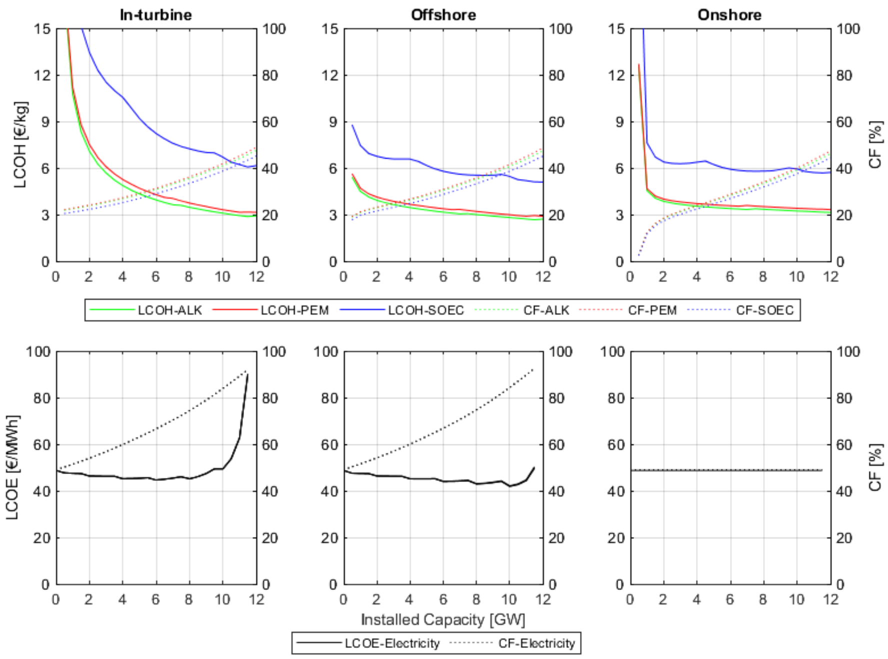


Figure 1.5.4.2 Resulting LCOH, LCOE and CF for the peak shaving operation. Note: the installed capacity is referring to the total electrolyser capacity installed; the CF showed for the electricity infrastructure is the one of the HVDC transmission line.

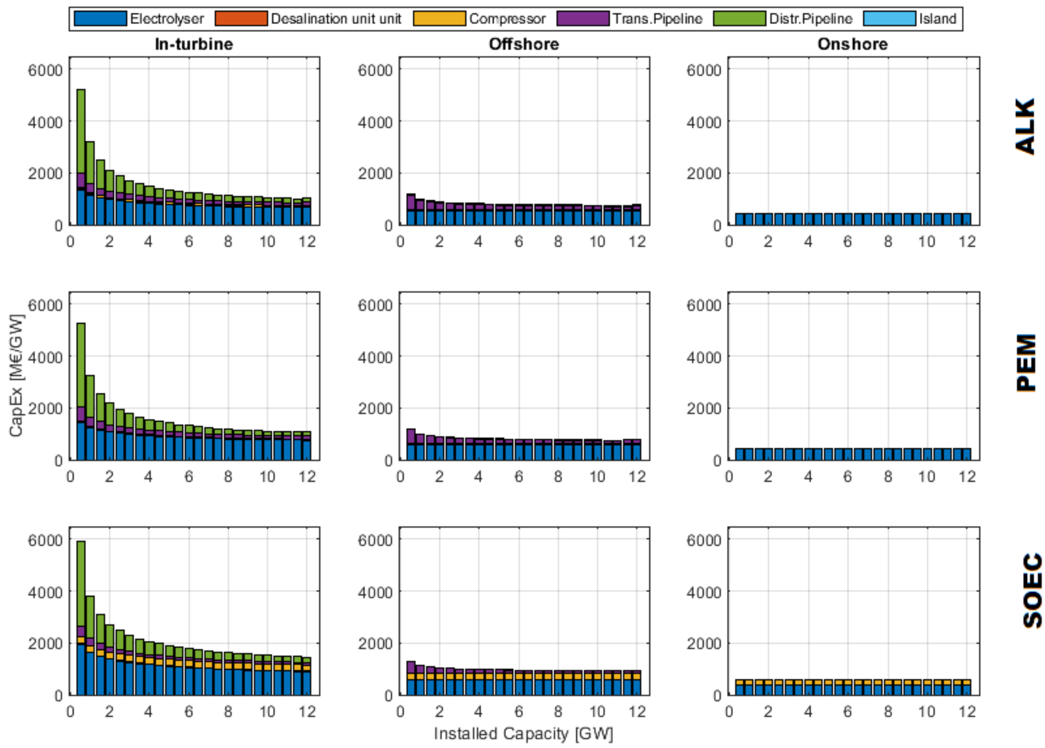


Figure 1.5.4.3 Resulting CapEx per unit of installed capacity. Note: these results are valid for both base load and peak shaving use of the electrolyser.

1.6 Utilization of project results

This project has been a pre-feasibility analysis of the North Sea Energy Hub, so the development of technology prototypes that can be subsequently commercialized was not among the objectives of this work. Still, the knowledge we have generated over the past 1.5 years is expected to assist towards the strategic decisions that leading Danish industries participating in our Advisory Board shall probably take in the near future. Besides that, our analyses has led to the identification of concrete technological gaps that we expect to address in a larger R&D effort with some of the leading Danish industry stakeholders.

1.7 Project conclusion and perspective

Here are the main recommendations to industry stakeholders and policy makers for the Offshore Energy Hubs developments, which were extracted from the results of this project:

- Organizing Wind Power Plants (WPPs) in Hubs is cheaper than connecting each offshore WPPs directly to the shore for Hub sizes starting from 3 GW and going beyond 15 GW.
  - Using 66 kV as the standard voltage for connecting WPPs to the Hub, a technology that has just been introduced in the market, cost-effective Hub sizes are between 3 GW and 13 GW, with the optimal Hub size being 9 GW
  - If industry moves to 132 kV, then Hub sizes beyond 15 GW can become cost-effective.
- The benefit from a system frequency ≠ 50Hz is too small to justify a change of standards.
- Overall, with the NSEH the electricity prices decrease.
- 15 GW transmission for 10GW-Hub: Higher transmission capacity leads to further price drops and eliminates wind curtailment.
- Countries with higher prices, such as the Netherlands, experience price drops and increase their export to non-NSEH countries.
- Connection of Norway has a positive impact.

- More than 13GW of installed wind capacity need either PtX or reinforcing the national grids. (we used a detailed ENTSOe power system model for Europe with >7500 nodes)
- A 20 GW-NSEH with 8GW-PtX used for peak shaving can replace 50% of natural gas consumption in DK.
- Comparison of electrolyzer technologies for Power-to-X
  - Alkaline vs Proton-Exchange-Membrane vs Solid-Oxide
  - Despite poorer dynamics, Alkaline electrolysers are the best solution, because of their cost

- In-turbine vs offshore vs onshore electrolysis.
  - Offshore hydrogen hub is the most cost-efficient solution when more than 50% of the produced power is converted into hydrogen, i.e. baseload operation (due to economies of scale for storage and pipelines)
  - Onshore electrolysis is the most cost-efficient solution when less that 50% of the wind power is converted into hydrogen, i.e. electrolyzer used for peak load operation
  - In-turbine electrolysis has distinct advantages, such as eliminating the need for additional footprint to install large-scale electrolyzers and offer of electricity grid services by the integrated electrolyzer such as black-start capabilities, and others. However, technological barriers need to be addressed, e.g. the cost of combined transmission of electricity and hydrogen to make this option competitive
  -
- Electrolyzer used for Base load Operation vs Peak Shaving Operation
  - Using the electrolyser with baseload power is more cost effective than use it for peak shaving.
  -
- Hydrogen Storage: Tank vs Geological Storage
  - Geological storage is the most cost effective storage for gaseous hydrogen, but it can contaminate the stored hydrogen to a quality level that could not be used in fuel cells

The results of our analyses have been included in two research publications, four presentations to our Advisory Board members, and have led to the identification of concrete technological gaps that led to two R&D proposals submitted to Innovation Fund Denmark.

Annex

1. G. Misyris, T. Van Cutsem, J. Møller, M. Dijokas, O. Renom-Estragués, B. Bastin, S. Chatzivasileiadis, A. Nielsen, T. Weckesser, J. Østergaard, F. Kryezi, North Sea Wind Power Hub: System Configurations, Grid Implementation and Techno-economic Assessment. Accepted for publication to the Cigre Paris Session 2020.

2. A. Singlitico, S. Chatzivasileiadis, In-turbine, offshore or onshore electrolysis? Cost comparison for hydrogen production from offshore power. Working Paper (to be submitted)

3. Spyros Chatzivasileiadis, Introduction and Topics of the 1st Advisory Board Meeting, NSEH Advisory Board Meeting, January 2020, Presentation

4. Jakob Glarbo Møller, Challenges in designing the electric infrastructure for large scale integration of remote offshore wind power, NSEH Advisory Board Meeting, January 2020, Presentation

5. Alessandro Singlitico, NSEH: The Case of Hydrogen, NSEH Advisory Board Meeting, January 2020, Presentation

6. Spyros Chatzivasileiadis, Introduction and Topics of the 1st Advisory Board Meeting, NSEH Advisory Board Meeting, January 2020, Presentation

7. Andrea Tosatto, North Sea Energy Hub:Impact on Electricity Prices, and Inputs about Transmission Investments and Technology, NSEH Advisory Board Meeting, May 2020, Presentation

8. Alessandro Singlitico, In-turbine, offshore or onshore electrolysis? Cost comparison for H2 production from offshore wind power, NSEH Advisory Board Meeting, May 2020, Presentation