Offshore Grid Investment Decisions in the North Seas for a Long-Term Scenario with High Levels of Decarbonisation

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Overview

In order to comply with ambitious climate goals, e.g. resulting from the Paris Agreement, a considerable decarbonisation of today's energy system is inevitable. As the heat and transport sectors are at present still strongly relying on fossil fuels, this long-term transition cannot be limited to the traditional power sector (Mancarella et al., 2016). Based on current deployments and projections, the future multi-energy system will be primarily based on wind and solar generation to supply and decarbonise the energy demand of all relevant energy sectors through electricity-based technologies and fuels. While the additional cross-sectoral electricity demand will entail notably higher renewable generation capacities for future power systems, it might also bring, through coupled operation of bi- and multi-valent or storage-connected consumers, substantial flexibility contributions in its wake.

Given the vast potential of offshore wind, it can play a crucial role in scenarios with considerable sector interaction, helping to meet the high electricity demand and offering an alternative for onshore wind which is being increasingly subjected to social acceptance issues. With that in mind, it is important to acknowledge the fact that offshore wind farms require transmission systems with high investment costs to connect their generation to the onshore market areas. Of similar importance is the growing challenge of balancing fluctuations between market areas with higher renewable penetration, both on- and offshore. Making sound investment decisions for offshore grids with their twofold connection function of integrating offshore wind generation and facilitating power trade between onshore market areas is therefore of great relevance. At the same time, competing onshore flexibility options (e.g. flexible CHP, heat pumps, electric vehicles) have to be put in the balance when assessing offshore grid infrastructure options in long-term scenarios.

Methods

To investigate offshore grid investment decisions for the Northern Seas region in the proposed case study, a two-stage approach is applied.

In a first step, a European energy scenario for 2050 is determined by running the SCOPE model which has been developed at Fraunhofer IWES (Trost, 2017). Minimising system operation and investment costs, while at the same time complying with a given carbon emission target covering all relevant sectors, this deterministic cross-sectoral generation expansion planning model is formulated as a linear program (LP) for a full year discretised into 8760 consecutive hours. Capturing the flexibility introduced by the coupled operation of power, heat, and transport sectors in a multi-energy system with its various technology combinations is one of the main purposes of this model (Härtel and Sandau, 2017). All time series data related to meteorological information, e.g. wind and solar production, thermal and cooling loads, heat pump's coefficient of performance, is based on COSMO-EU weather model data (Deutscher Wetterdienst, 2016). To ensure consistency along both grid planning stages, the same data base for offshore wind generation data is used. This means that structural and spatial information of single offshore wind farms, based on (4C Offshore, 2017), is combined with site-specific wind generation profiles.

In a second step, the resulting energy system scenario is used in a deterministic large-scale offshore grid expansion planning model with a particular focus on capturing future onshore flexibility to compute the offshore grid investments. For computational reasons, this market-based grid planning model needs to reduce the spatial resolution by clustering the single offshore wind farms to so-called offshore wind hubs. Moreover, it covers all major European market areas while keeping the same optimisation horizon in hourly resolution as is used by the SCOPE model. Hence, the model requires aggregated modelling approaches for hydropower systems (Härtel and Korpås, 2017) and thermal power plants (integer clustering), as well as bi- or multi-valent sector coupling technologies, see (Härtel and Sandau, 2017). Based on the linear cost model presented in (Härtel et al., 2017), the model also accounts for the important fixed cost components of offshore grid infrastructure, i.e. fixed converter and platform costs. It is therefore formulated as a mixed-integer linear program (MILP). What is more, a new investment cost parameter set for VSC HVDC technology will be used which has been validated against realised back-to-back, interconnector, and offshore wind connection projects. Despite the aggregation efforts, a novel decentralised solution approach based on a proximal bundle method had to be developed to efficiently handle the hourly interactions of the key flexibility providers and the renewable generation when making investment decisions in offshore grid infrastructure.

Results

Following the two-stage methodology, the obtained results will be twofold. First, a possible decarbonisation scenario for the European region in 2050 will be presented as a result of the SCOPE model. To be able to meet the additional electricity demand for heat and transport sectors, this scenario will show a generation mix with considerable renewable capacities, i.e. on- and offshore wind as well as rooftop and utility-scale solar power. Least-cost compliance with cross-sectoral carbon emission reductions will favour highly efficient and flexible technology combinations such as electric vehicles, decentralised heat pumps, and multi-valent CHP systems. It is important to mention that these key flexibilities and interactions are taken into account by the second modelling stage. Moreover, the model will also give a carbon price as the emission budget is modelled as a hard constraint.
Second, the large-scale offshore grid expansion planning model will be used to assess three offshore grid topology paradigms facilitating the connection of offshore energy to the onshore market areas and the exchange between them:

- **Status quo**, allowing radial offshore hub connections and no expansion on existing interconnector corridors,
- **Business as usual**, allowing radial offshore hub connections and expansion on existing interconnector corridors, and
- **Meshed grid**, allowing meshed offshore hub connections and expansion on existing interconnector corridors.

For the highly decarbonised 2050 scenario, these paradigms will show different offshore grid investments and their corresponding system operation cost. Because the geographical scope of the market-based offshore grid expansion planning model covers all major European countries, the model results will indicate cost impacts for directly and indirectly connected market areas to an offshore grid in the Northern Seas. To exhibit the competing role of onshore flexibility for integrated offshore transmission infrastructure, a sensitivity analysis with increased flexibility of electric vehicles is going to be presented.

Conclusions

The contribution will provide insights into a long-term energy scenario complying with cross-sectoral decarbonisation goals and its consequences for offshore wind energy as well as (integrated) offshore grid infrastructure. As the main implication, the results will show that achieving ambitious carbon emission reductions across all energy sectors can enable offshore wind and offshore grid infrastructure to significantly contribute to a future energy system. However, the role of and necessity for increased power trade facilitated by integrated offshore grids in the Northern Seas exhibit a large dependency on onshore flexibility developments introduced by increased energy sector interaction.

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