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Optimal investment for energy transmission options for offshore wind considering multiple energy vectors

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ABSTRACT

The United Kingdom has ambitious net zero targets of 50 GW of offshore wind and 10 GW of low carbon hydrogen by 2030. The increased uptake in renewable energy technologies requires significant infrastructure reform to enable connection to the existing energy system. This paper aims to outline a novel methodology capable of optimising large-scale projects with multiple energy vectors to maximise the highest return on investment and plan for the future. A novel framework is established that takes three key design parameters into account: cable landfall, offshore substations, and green hydrogen production.

Keywords: green electricity, renewable energy, green hydrogen, transmission, optimisation, offshore renewable energy

NOMENCLATURE

Abbreviations	
C	Cost
CAPEX	Capital expenditure
GR	Grid reference
H_2	Hydrogen
HVAC	High voltage alternating current
HVDC	High voltage direct current
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
O&G	Oil and gas
OPEX	Operational expenditure
OSS	Offshore substation
OWF	Offshore wind farm
R	Revenue
ROI	Return on investment
Symbols	
GW	Gigawatt
TW	Terawatt

1. INTRODUCTION

1.1. Offshore wind landscape

Offshore wind is growing rapidly in the United Kingdom with an ambitious target of 50 GW by 2030 driving change (DESNZ, 2022). Offshore wind is predicted to have a 13% average annual growth rate from 2020 to 2050 (NGESO, 2022). National Grid's Future Energy Scenarios (FES) predict that offshore and onshore wind will increase by 23-33 GW by 2030, to a total of 54 GW by 2040 (NGESO, 2022a).

However, with the allocation of new generation projects at each Contracts for Difference round, the onshore electrical grid requires an expeditious transformation. At present, grid capacity in Scotland is 6.6 GW, approximately a quarter of its future demand (NGESO, 2022b) and due to Scotland's abundant wind resource it is expected that there will be 11 GW of offshore wind capacity by 2030 in Scottish waters (2022c) and 1.8 TW of grid connected offshore wind capacity by 2050 in the UK (NGESO, 2022a). As a result, offshore and onshore wind developers are constrained by insufficient grid capacity and the GB consumer pays a curtailment cost, equating to £446 million in 2021-22 for Scotland (NGESO, 2022b). The electrical network operators are working hard to reinforce and upgrade the network with 94 reinforcements prescribed, totaling an investment of £21.7 billion (NGESO, 2022c).

Increased connections and consumer demand reduces the availability of connection sites both spatially and environmentally. In this case, other solutions must be considered such as offshore substations or chemical bulk transmission. These solutions have the potential to complement the fast and ambitious development timeline for new onshore electrical transmission infrastructure, enabling the delivery of export capability and providing energy security to the United Kingdom.

1.2. Objectives

This is a paper for 15th International Conference on Applied Energy (ICAE2023), Dec. 3-7, 2023, Doha, Qatar.

The focus of this paper is to detail a methodology for tackling an optimisation problem wherein both electrical and chemical transmission solutions will be considered. The profitability of each option will be compared by assigning an economic value to the key system components including technical and environmental considerations.

1.3. Research contribution

The optimisation of electrical and chemical transmission options for renewable generation is a novel area of research wherein existing research has considered hydrogen and electrical infrastructure separately. This includes, hydrogen and wind infrastructure integration (Ibrahim, Singlitico, Proskovics, McDonagh, Desmond, Murphy, 2022), optimisation of offshore network layouts (McKinstry, 2018) and hydrogen pipeline infrastructure (Jeleňová, Race, Thies, Mignard, Mortimer, 2022). This research is unique in three distinct aspects:

1) Develop an optimisation model to maximise the return on investment of multi-vector transmission solutions for offshore wind.
2) Determine the optimal transmission option for industrial projects influencing the pre-development stage.
3) Consider the real spatial and environmental restrictions on infrastructure siting and propose valid solutions that can be implemented.

The model will indicate which transmission option is most viable for individual projects on a return on investment (ROI) basis enabling industry to capitalise on the deployment of technology and industry. This will provide a net gain to the consumer with lower electricity bills and will enable the integration of additional renewable energy generation technologies such as wave, tidal and solar, in the future.

2. ENERGY SYSTEM

2.1. Design parameters

Three key design parameters have been identified in the system which are cable landfall, offshore substations and green hydrogen production. These will impact the overall transmission option performance and cost. The energy vectors can be broadly considered as electrical and chemical, however electricity enables the production of green hydrogen and associated derivatives such as ammonia and methanol. Figure 1 represents the transmission options comprised of three main energy routes from an offshore wind farm which generates electricity in alternating current (AC).

1) At nearshore locations (<15 km) AC can be used to transmit the electricity via subsea cables which connect to an onshore substation, the electricity can be stepped down for distribution.
2) Two cases have been depicted wherein either, an offshore wind farm has multiple cables connected to an offshore substation or, multiple wind farms or generation sources connect to an offshore substation, if the location of the wind farm is nearshore, HVAC technology can be used and the cables are connected to an onshore substation. If the wind farm is far shore (>15km) it could be more economical to use HVDC technology to minimise losses, which would require a converter station and substation at the offshore and onshore side to enable compatibility with the onshore grid.
3) An alternative option to electrical transmission is chemical transmission, in this case, hydrogen. The HVAC electricity and desalinated or freshwater source are fed into an electrolyser which can be located offshore or onshore, this produces green hydrogen. The hydrogen can be transported by pipelines, via ship or converted into liquid ammonia. The conversion of ammonia to hydrogen requires cracking and the conversion of hydrogen into electricity requires a fuel cell or combustion.

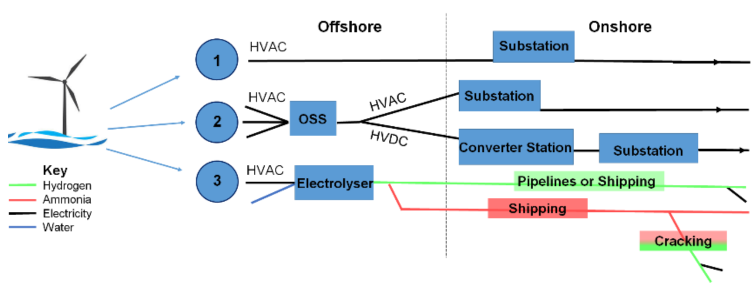

Figure 1: Transmission options for offshore wind including HVAC, HVDC and chemical transmission.

2.2. Marine cable landfall

Marine cable landfall describes the interface between an offshore cable and the shoreline. This point can be described as a geographical location, with a grid reference. A landfall point could be on a beach, underground via a cliff-face or subsea into a port, all of which have unique challenges. There are various parameters to consider when selecting a landfall site, which include: the typology of the shore and seabed, the protection of the land around the coast, the technical feasibility, the length of cable required and the overall installation cost. The purpose of the landing site is to allow offshore electrical infrastructure to connect to the onshore grid and the process requires consenting.

With the advent of increased offshore wind, in addition to tidal, wave, solar and hydrogen devices requiring grid connection, there will be spatial constraints on landing sites for both cables, pipelines and other connective infrastructure. This unique methodology aims to identify suitable landfall sites whilst considering difficult and challenging options as a "next best" solution based on the cost of the installation techniques and mitigation methods required, this methodology will be a new contribution to research as landfall siting has not been considered in academic literature.

2.3. Offshore substations

Multiple cables are used in two main cases, design for redundancy to enable power transfer to shore during faults and for connecting multiple assets. Each cable will require a landing point so a proposed solution to mitigate this is the development of offshore substations which act as a collector point for the inter-array cables (typically 66 kV) and feed into the transformers which can step up the voltage up to 600 kV on a HVDC submarine export cable (Gulski, Anders, Jongen, Parciak, Siemiński, Piesowicz … Irska, 2021).

Offshore substations (OSS) have been commissioned and their design is constantly evolving where new fixed platforms have been installed, such as Iberdrola's Saint Brieuc OSS for their 496 MW offshore wind farm, with a footprint of 1.7 km^2 and a mass of 3400 tonnes. The OSS has 90 km of HVAC inter-array cables feeding in and exports on two 225 kV cables, landing at Caroual Beach (Iberdrola, 2023). Current research highlights that existing oil rig platforms could house new converter stations. ABB have developed both floating and submerged offshore substation concepts. The model will consider four different platforms for offshore substations which will be fixed (new and old), floating and submerged.

Offshore substations could also provide electrical hubs for other users and activities as announced in the Innovation and Targeting Oil and Gas (INTOG) leasing round this year which promotes a green power supply to oil and gas (O&G) assets offshore which are directly connected to offshore wind farms (Crown Estate Scotland, 2022). In addition, Ofgem have proposed multi-purpose interconnectors which centralise offshore industrial activities into clusters or hubs offshore. Patel et al. investigated "hydrogen interconnector systems" (Patel, Roy, Roskilly, Smallbone, 2022). They focused on offshore conversion of electricity to hydrogen for transport via a pipeline to shore which is reconverted back into electricity for use onshore. Patel et al. investigated the economics of HVDC interconnection versus hydrogen production and showed the levelised cost of electricity (LCOE) for this system is competitive with HVDC if constructed in 2050 at distances greater than 350 km from shore based on a 1 GW plant. This implies that the hydrogen infrastructure will not be market ready or competitive until 2050 whereas the maturity of HVDC interconnection technology can lead the market. MacIver et al. considered the market mechanisms for electrical interconnection to achieve a reliable and secure energy supply, concluding that HVDC is the best technology for interconnection (MacIver, Bell, Adam, 2021).

Offshore substations provide the vital connection point for these assets enabling power transfer, export opportunities and reduced onshore infrastructure.

2.4. Hydrogen

Hydrogen has captured industry's attention due to its applicability in energy storage, transport (heavy goods vehicles (HGV's) and shipping) and as a replacement for natural gas, supported by the UK target of 10 GW low carbon hydrogen production by 2030 (Spyroudi, Wallace, Smart, Stefaniak, Mann, Kurban, 2022). Hydrogen is a low density gas at atmospheric pressure and requires a cryogenic temperature of -253 ^{0}C to liquefy (Spyroudi et al.). The main two processes to produce hydrogen currently are firstly, by steam methane reforming in which natural gas is reacted with steam and the carbon dioxide is captured, producing "blue" hydrogen. A less carbon intensive approach is by using water electrolysis in which water is split into hydrogen and oxygen using an electrolyser. If the electricity is from a renewable source then the hydrogen is "green" (Spyroudi et al.).

Hydrogen production has received investment from the U.K. government with projects such as Hynet, Aberdeen Hydrogen Hub, Gigatest by ITM Power and Project Union UK (Spyroudi et al.) however there is a lack of hydrogen transport technologies which could inhibit the transmission of energy both locally and globally. Hydrogen export could contribute £5-25 bn/year to Scotland's economy by 2045 (Scottish Government, 2020) with key markets including China, USA, Japan, India, South Korea and Europe.

Green hydrogen production coupled with offshore wind has also been considered by many researchers recently. Gea-Bermudez et al. examined the case of producing green hydrogen onshore or offshore based on a case study in the North Sea with the Balmorel model (Gea-Bermudez, Bramstoft, Koivisto, Kitzing, Ramos, 2023). It was found that offshore wind generation has higher monetary value when transmitted to shore electrically versus hydrogen. A dedicated offshore hydrogen production facility would increase the cost of the wider energy system but hydrogen as a storage medium could be beneficial. Komorowska et al. investigated the competitiveness of offshore wind to hydrogen production using Monte Carlo simulation for Poland as a case study, where there are twenty-three offshore wind farms planned for deployment in the Baltic Sea (Komorowska, Benalcazar, Kaminski, 2023). They calculated that the levelised cost of hydrogen (LCOH) is 3.6-3.71 EUR/kg H_2 by 2030 with expected decrease to 2.05-2.14 EUR/kg H_2 by 2050. Dinh et al. investigated LCOH from offshore wind based on a 510 MW wind farm with expected 50,000 tons of hydrogen production (Dinh, Dinh, Mosadeghi, Todesco Pereira, Leahy, 2023). At this scale, LCOH is expected to be less than 4 EUR/kg when electricity is 100% dedicated.

Kumar et al. investigated the syngergy of green hydrogen with other industries offshore such as oil and gas, shipping and aquaculture (Kumar, Baaslisampang, Arzaghi, Garaniya, Abbassi, Salehi, 2023). The inclusion of green hydrogen could benefit these industries and contribute to their green transition. Singlitico et al. considers the different green hydrogen production locations and potential integration in offshore wind power hubs (Singlitico, Østergaard, Chatzivasileiadis, 2021). The scenarios considered are onshore, offshore and in-turbine. It is shown that green hydrogen production offshore can achieve a LCOE 2.4 EUR/kg green hydrogen. Ibrahim et al. investigate the feasibility of dedicated offshore wind to hydrogen sites at large scale and particularly look at the potential typologies for a system of this type (Ibrahim et al., 2022). A decentralised offshore hydrogen production facility on a semi-submersible platform could provide continuous green hydrogen production.

Some researchers consider hydrogen as a stand-alone production platform and the operational requirements of such a system. Bonacina et al. are focused on offshore hydrogen production with a use case of ship refueling (Bonacina, Gaskare, Valenti, 2022). It is believed that hydrogen could be a decarbonisation fuel for the shipping industry. It was determined that a plant operating for twenty five years could have an LCOH of less than 4 EUR/kg with overall efficiency of 55.2 % and electrolysers are the main cost of a hydrogen plant. Klyapovskiy et al. aim to understand the operational performance of a hydrogen Power to X plant focusing on the GreenLab Skive industrial cluster. It was found that a reduction in the operational cost of 51.5-61.6 % was possible and an increased share of green hydrogen by 10.4 - 37.6 % was possible due to the improved management system proposed (Klyapovskiy, Zheng, You, Bindner, 2021).

As renewable generation fluctuates, storage is required to meet times of demand. For hydrogen, there are several ways it can be stored: pressurised in tanks, pumped into underground salt caverns, stored in depleted subsea reservoirs or via a carrier such as ammonia which is liquid at 33 ^{o}C and can be converted into hydrogen, however there are concerns around toxicity and some ports have banned ammonia shipments (Tawalbeh, Murtaza, Al-Othman, Alami, Singh, Olabi, 2022).

Kiran et al. investigated the potential of underground hydrogen storage in an existing offshore Tapti gas field which would have efficient operation if producing gas for eighty days per annum (Kiran, Upadhyay, Rajak, Gupta, Pama, 2023). The withdrawal rate of hydrogen is higher compared to other gases due to lower viscosity and quartz-sandstones are optimum storage rocks, however this gas field has an expected leak rate of 4 % during the initial injection year. Abreu et al. examined large scale hydrogen storage in a salt cavern offshore (Abreu, Costa, Costa, Miranda, Zheng, Wang … Nishimoto, 2023). They found that hydrogen at large scale is only possible for a select number of sites as hydrogen is reactive with different materials. Halcite was found to be the best salt rock suitable and is the most abundant. In addition, salt caverns onshore are a cheaper storage site however the deposits may be found offshore. For a 400 m high by 80 m diameter cavern, the hydrogen would be pressurised between 133 and 283 bar which would allow 40 ton/day hydrogen production for 340 days.

Baldi et al. developed a linear programming optimisation design for deep offshore wind farms and consider the possibility of hydrogen production offshore, it is concluding that hydrogen and ammonia storage could be beneficial to the wider system balance (Baldi, Coraddu, Kalikatzarakis, Jeleňová, Collu, Race, Maréchal, 2022). Hydrogen is preferred for 12 hours of storage or less whereas ammonia can be cheaper for longer periods of storage. Ma et al. considered a hybrid hydrogen battery storage system for offshore wind, this would allow storage during peak generation and low demand (Ma, Tian, Cui, Shu, Zhao, Wang, 2023). The focus of the paper was on the Chinese market which is the leading offshore wind market globally. It was found that the electrolyser for the hydrogen production system contributed 67.9 % of the total storage capital expenditure, highlighting that at present, electrolysis is less mature and developing a hydrogen production site will require investment.

In terms of transport, industry is looking at the feasibility of using existing offshore oil and gas pipelines however, the steel grade has to be considered as some steels are susceptible to hydrogen embrittlement which will compromise the integrity of the pipe and cause leakages. The pressure and purity of the hydrogen at outlet is also dependent on the use case and can be adapted.

Overall, hydrogen has the ability to target heat and transport sectors and is a viable contender for supplying an energy resource mix in a whole system approach. This research will aim to identify if hydrogen or ammonia production offshore has any cost benefit versus equivalent electrical transmission solutions.

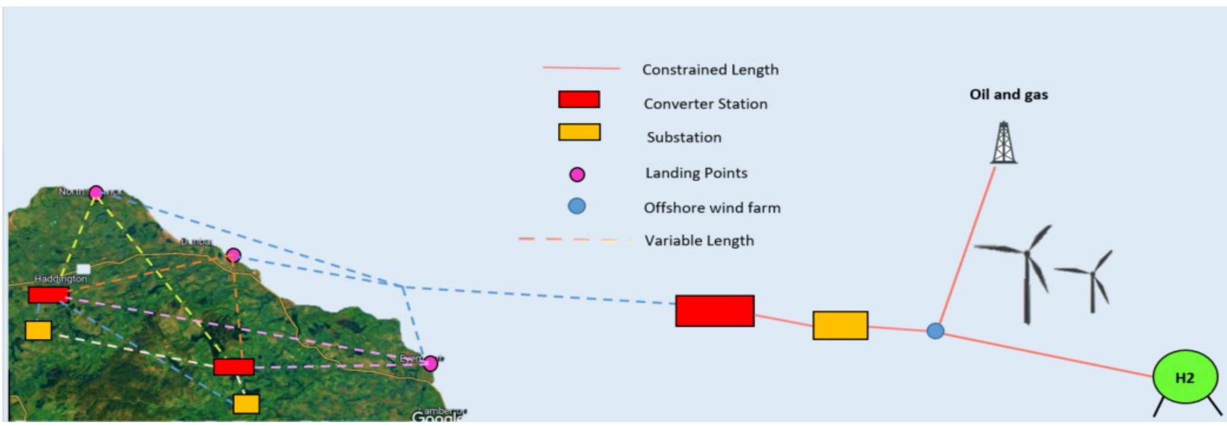

Figure 2: Constrained and variable distances between onshore and offshore assets.

3. METHODOLOGY

3.1. Scope

The model will consider economic, environmental and technical data for each of the transmission options shown in Figure 1. The model will be optimised on the basis of cost to understand the return on investment for each option for long-term infrastructure planning across the renewable energy, gas and utility industries.

3.2. Transmission option selection

Ten transmission options have been formulated to describe the key energy flows in the system and are expected to yield different results due to different variables highlighted in bold, a sample of these options is shown in Table 1.

Table 1: Extract of defined transmission options

Transmission Options	Description
Nearshore-Electricity (NEAR)	**Offshore wind farm** is connected to shore with **HVAC cables** for nearshore distances **less than 15 km** and connected into an **onshore substation**.
Multi-Farshore-Electricity (FAR)	**Multiple offshore wind farms** connected to **multiple offshore substations** connected to shore with **HVDC** cables where **two converter stations** will be required to connect to an **onshore substation**.
Offshore-H_2-Pipe (H_2OP)	**Multiple offshore wind farms** with an **offshore electrolyser** and **platform**, **HVAC** cables connect the generation source to the electrolyser platform. There will also be a **water source** and **desalination plant** for seawater. In this case there will be an **offshore pipeline** that connects to an **onshore pipeline**.
Offshore-H_2-Ship (H_2OS)	**Multiple offshore wind farms** with an **offshore electrolyser** and **platform**, **HVAC** cables connect the generation source to the production platform. There will also be a **water source** and **desalination plant** for seawater. In this case there will be a shipping vessel which will transport the

	hydrogen from the **generation source** to a **demand location**.

Each option has multiple variables that can operate within a range of values and can be considered or not, depending on the design case analysed, allowing it to be adapted to any project or input data.

3.3. Data Acquisition

The model input will use publically available data and assumptions to allow the wider research community to benefit from the results. However, a bespoke industry model will be supplied with confidential data in partnership with SP Energy Networks to aid infrastructure planning specific to the utility industry.

3.4. Data Utilisation

An example approach in collecting data and curating reasonable assumptions for the model is detailed for cable installation. The offshore and onshore cables connect electrical infrastructure together and can be deployed by a cable laying vessel offshore. These vessels have different sizes, loads, availabilities and hire costs. The Offshore Technology Yearbook (reNEWS, 2023) details all of the current state of the art technology for the offshore wind industry including cable laying vessels, an extract of which is shown in Table 2.

Table 2: Cable laying vessel carrying capacity

Vessel	Cable Laying Capabilities	Deadweight Tonnage
Asso Subsea Ariadne	export, array, HVDC interconnectors	9000
Asso Subsea Atalanti	export, array, HVDC interconnectors, beaching	7000
Asso Subsea Athena	array, trenching, inspection, maintenance	1500

The deadweight tonnage is the load carrying capacity of the ship, in this case the load is assumed to be cables. Three cable types manufactured by Prysmian were analysed, as shown in Table 3. The mass per cable length was used to derive the quantity of cable that could fit on the vessel in a single trip to aid with vessel scheduling and understand the overall vessel hire cost for a specific cable lay (Prysmian, 2023).

Table 3: Vessel cable carrying capacity

Vessel	XLPE Submarine (65 kg/m) (km)	P-Laser Submarine (50 kg/m) (km)	MIND Submarine (30 kg/m) (km)
Asso Subsea Ariadne	138.4	180	257.1
Asso Subsea Atalanti	107.7	140	233.3
Asso Subsea Athena	23	30	50

The MIND submarine cable is the lightest cable alternative to XLPE however, it is also the most expensive. The vessel that can carry the most cable of all types is the Asso Subsea Ariadne and it has the capability to install export, array and interconnectors. This analysis has been done for over twenty vessels and there is additional port data that can be used to identify which ports are used for the deployment of offshore renewables. This may give an indication of the hire price on a distance basis, duration required to install as well as the number of trips to port and back to collect new materials. In addition, it is hoped that with assumptions like these, the XLPE cable which is an industry standard could act as a ”worst case” basis in the model - so that if technology advances in the future the cost of the cable may increase but the vessels could carry more cable length per journey due to reduced weight.

4. SYSTEM MODEL

4.1. Variable Selection and System Boundaries

The system has been modelled based on ten transmission options which represent a simplified version of the energy system. The simplification allows the model to optimise and compute whilst considering key variables for analysis (Figure 3).

There are several parameters that have been assumed or constrained in the model which are discussed in greater detail. The offshore generation type will be offshore wind as it is the most mature technology and is currently being deployed and developed, the grid point will be the centre of the offshore wind farm. The wind data will be derived from an annual probabilistic curve based on a Weibull distribution as temporal offshore wind data is difficult to obtain versus onshore wind data. The electricity price of generation will be assumed to be constant as will the price of green hydrogen production, however this may be altered in a sensitivity analysis. The generation capacity of the offshore wind farm will be based on a commissioned OWF in the North Sea however factors such as the inter-array network layout and platform design will not be considered.

The cable connection between the offshore wind farm, associated interconnection, transmission infrastructure and landing points will be considered on a length basis however some grid points will be fixed as a case study and the cable type will be chosen, most likely XLPE, as it is the industry standard.

A selection of landing points will be chosen and land features will be considered to formulate a land value per m^2 which will inform the installation cost. The landing points will be constrained to the area SP Energy Networks operates in which is Central and Southern Scotland. The Firth of Forth and Firth of Clyde are two coastal regions where landing points will be analysed. The technology used to install the cables will not be considered unless the site requires horizontal directional drilling and the bathymetry and cable protection required will not be considered too. The land value will be a range of values based on characteristics defined in the valuation process. The legal and consenting challenges associated with acquiring the land will not be considered as this work considers pre-development screening.

The onshore substations will be fixed as they exist on the network and converter stations will be constrained to a suitable distance from the onshore substation (Figure 2). The capacity of the substations will be considered in terms of satisfying the generation from the OWF however the intrinsic design, expansion or creation of a substation will not be considered. However, as converter stations are typically new assets on the network a cost per m^2 of installation will be assumed.

The use cases for both hydrogen and electricity will be considered in a qualitative sense which may be reflected in some demand cases in a sensitivity analysis to show the fluctuation of price or demand dependent on services such as electric vehicles, hydrogen for heating or system restoration services.

In terms of installing infrastructure, a broad view will be taken on the suitability of reusing infrastructure, informed by existing literature, and costs will be determined on a high-level installation basis.

Hydrogen infrastructure will be considered in terms of pipeline length as with cable length, vessel availability and plant size and location. In terms of hydrogen inputs, the water source considered will evaluate three water costs: desalinated, abundant freshwater and scarce freshwater which will relate to three cases or locations. The associated desalination plant will have a cost per area and this will differ based on the platform and location chosen.

The option of interconnection or multi-purpose interconnectors will be considered from a demand and supply point of view, or a positive and negative cash flow. This will determine if connection of assets offshore could provide a wider economic benefit to the energy system.

An important factor to consider is the lifetime of an asset throughout the commissioned phase of the project. This will enable the return on investment to be calculated and will provide a business case for selecting a potentially higher capex option versus a lower capex, providing that the ROI is higher.

The model will aim to generate multiple solutions and variations within the ten transmission option frameworks as inputs can be adjusted based on the project or case study, it is therefore important to focus on the main cost factors associated with the transmission element of the problem and neglect some factors on the generation and distribution side.

5. OPTIMISATION MODEL

5.1. Optimisation tool

The coding software used to build the model is Python v.3.10 which has built in optimisation solvers such as Pyomo. At present the model structure is being developed and an optimisation solver and sensitivity analysis approach are still to be decided for the test cases.

5.2. Optimisation techniques

Numerical optimisation techniques are used to solve complex problems which can be linear or non-linear. Several optimisation techniques have been identified which could apply to the model, such as the weighted sum method in which a scalar value is applied, the epsilon-constraint method which systematically targets and constrains variables and genetic algorithms which iterate solutions until an optimum has been found.

5.3. Proposed approach

The optimisation technique is yet to be determined however both weighted sum and epsilon constraint are linear methods whereas genetic algorithms apply best to non-linear problems. The approach chosen will aim to simplify the energy system and will include constraints to limit the bounds of the optimisation problem, in addition to decision variables and dependent variables whilst maintaining reasonable assumptions supported by data, the model will be validated by implementing test cases based on key design variables.

5.4. Objective function

An objective function instructs the optimisation model to yield the desired outputs. In the case of this project, the model aims to consider different transmission options that have a maximum return on investment with consideration of environmental gain. In practical terms this ensures that the transmission option chosen is technically feasible and uses readily available parts from an established supply chain with adequate infrastructure available for deployment thus reducing the overall cost. A priority for industry is a strong business case with a projected return on investment for infrastructure options selected. Finally, when installing the option the environment will be impacted and therefore it is important to consider the overall detriment to the environment and the mitigation strategies implemented. This is a difficult parameter to quantify however there are industrial practices that exist to mitigate the impact.

The objective function can be described as:

$$maxROI(x,y) = R(x,y) - C_{CAPEX}(x,y) - C_{OPEX}(x,y) \qquad (1)$$

operational costs of each transmission option over the lifetime of the offshore wind farm. The variables can be considered as fixed, non-design variables (y) or decision variables (x) subject to defined constraints (Ω).

5.5. Design variables

The system boundaries have been discussed to show the limitations of the model and highlight the focus of the work. As some variables are constrained there are also key design variables that will be optimised based on the objective function. These key design variables are described below.

The landing point location will vary depending on the location of the generation source and connecting onshore substation, this can be described by a grid reference $GR_{LP_{1,2..n+1}}$. An example of this could be the derived distance $(D_{LP_{1,2...n+1}-on-ss})$ between the landing point and the onshore substation where the location of the onshore substation (GR_{on-ss}) is dependent on the required capacity and proximity to the landing point.

$$D_{LP_{1,2...n+1}-on-ss} = GR_{LP_{1,2..n+1}} - GR_{on-ss} \qquad (2)$$

In the case of HVDC technology, the location of the onshore converter station $(GR_{CS_{on-s}})$ is dependent on the landing point and connecting substation.

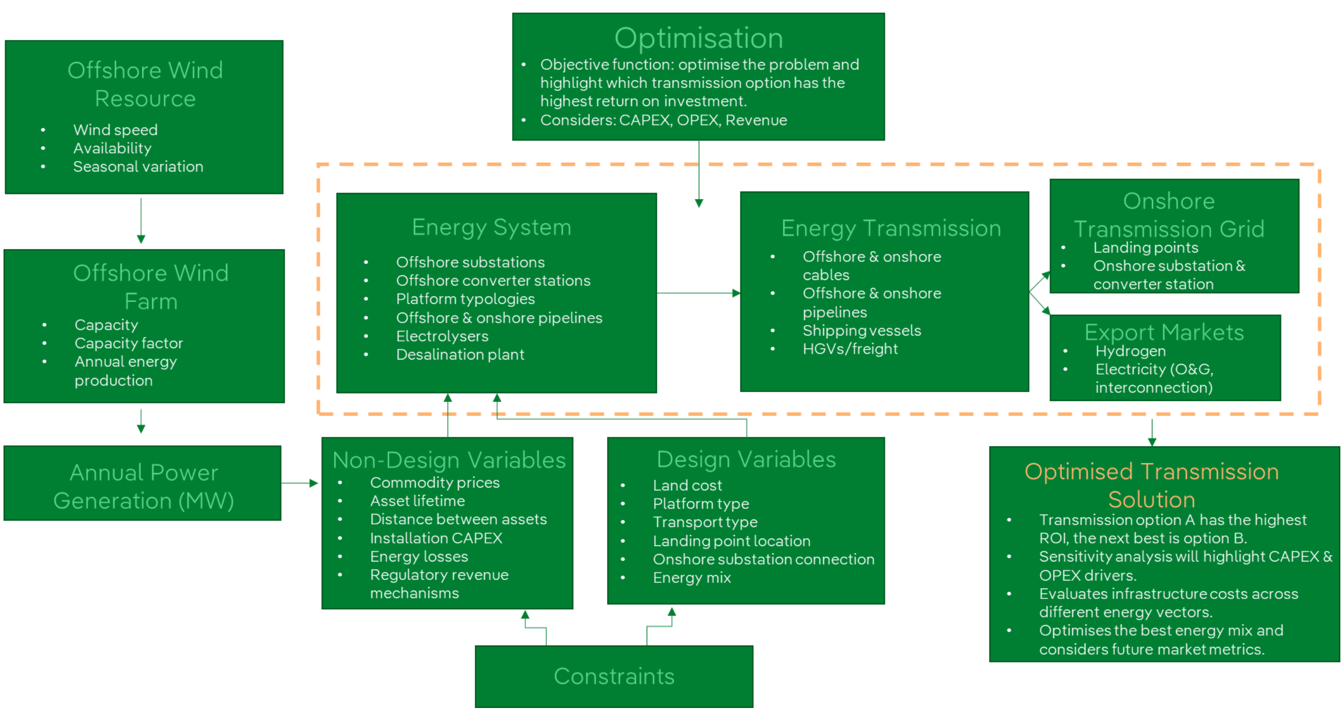

Figure 3: Optimisation boundaries for the energy transmission system

Where the return on investment (ROI) is to be maximised by considering the revenue, capital costs and

$$D_{LP_{1,2...n+1}-CS_{on-s}} = GR_{LP_{1,2..n+1}} - GR_{CS_{on-s}} \qquad (3)$$

The value of land (C_l) is an important parameter to optimise as it will vary according to land use, land quality and the impact a development may have on services in the area. Land value is complex to measure however can be described by a range of costs for a sample of characterised landing points, this will inform which installation techniques may be required at the landing point and transmission route.

The offshore system will require offshore platforms (pm) to house the electrical and chemical equipment. The four typologies considered are fixed-new, fixed-old, floating and submerged. It is expected that each will have a different construction or retrofit cost and will apply to different transmission options. For example, submerged platforms will not be considered for the hydrogen production platform but will be considered for the offshore substation. The platform cost will be a function of the area required for infrastructure which will be dictated by the capacity required for transmission. The model will employ a binary selection rule to consider each platform type.

Transport or transmission (T) is an important parameter to consider which will be different for each energy vector. For example, electrical transmission requires cables ($C_{HVDC,c}$, $C_{HVAC,c}$) whereas chemical transmission could be via a pipeline ($C_{T,\,pl}$), vessel ($C_{T,\,sp}$) or road ($C_{T,\,r}$).

For green hydrogen production, water (W) and electricity are required. The former could be abundant ($W_{pr,fw,at}$) or scarce freshwater ($W_{pr,fw,se}$), assumed for onshore locations or desalinated seawater ($W_{pr,sw}$). In certain locations, onshore freshwater may be scarce so onshore desalination and hydrogen production could be an option. There will be a cost to acquire the supply of water and a treatment cost.

The final design variable chosen is the production mix of energy ($\%pn_{H_2,NH_3,E}$) which can be three main vectors: electricity, hydrogen and ammonia. The model will generate which mix is preferred and will highlight if multiple plants are required. However, case studies will analyse 100% electricity production vs 100% hydrogen production.

These variables have been selected as they are expected to significantly impact the results and are new aspects to consider in a multi-vector offshore and onshore energy system. These variables will also provide insightful results which will give a new perspective as to the optimum transmission option for renewable generation.

6. CONCLUSION

The potential transmission options for electrical and chemical energy vectors reflect realities in the future energy network. By optimising the return on investment for each, a new tool will be available to enable expedited infrastructure planning in the renewable energy industry. Optimisation of electrical and chemical transmission for offshore renewables has not been studied and is a clear gap in literature which this work aims to address with a new and rigorous methodology for transmission planning.

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