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Published in:
Floating Wind; Systems Design and Multi-Fidelity/Multi-Disciplinary Modelling; Future Wind; Smaller Wind Turbines

Link to article, DOI:
10.1088/1742-6596/2265/4/042035

Publication date:
2022

Document Version
Publisher's PDF, also known as Version of record

PAPER • **OPEN ACCESS**

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To cite this article: Wei He *et al* 2022 *J. Phys.: Conf. Ser.* **2265** 042035

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Abstract Advances in large-scale green hydrogen production (LGHP) create commercial opportunities for enhancing rapid offshore wind farm (OWF) development. This study investigates whether LGHP co-location at OWF sites improves those OWF's economic outlooks under potential electrical grid capacity bottlenecks towards 2050. Eight cases have been studied using measured annual OWF power production series and cost estimation integrated with offshore engineering experience: i) two base cases: 2 GW OWFs with HVAC and HVDC transmission infrastructure showing that the levelized cost of electricity (LCOE) increases, and ii) six LGHP co-location cases demonstrating that the calculated levelized cost of hydrogen (LCOH) reduces when the LGHP capacity increases from 20% to 50%, and 100% of 2 GW. Furthermore, three economic improvement factors studied are: i) utilizing existing gas pipelines reducing LCOH by 7.5%, ii) hydrogen for offshore customers changing "no-go" projects to "go", and iii) scaling-up from 2 to 4 GW reduced the LCOH by 17%. This study shows that LGHP co-location is effective at maintaining OWF full production, but has higher risks including i) LGHP co-location safety at OWFs, ii) high costs to cover more operational conditions and iii) running LGHP operations using high, fluctuating OWF power. Further R&D of LGHP co-location are recommended.

1. Introduction

The use of hydrogen as a fuel source is crucial for overcoming anthropogenic CO_2 emissions, and enabling a transition to a renewable-based energy system. Green hydrogen can either be produced onshore or offshore where it can utilize the electricity generated from OWFs. The offshore green hydrogen production via the electrolysis of seawater can be either used locally by offshore customers and/or transported to onshore customers either via new hydrogen pipelines (HPLs) or through re-purposing existing gas network infrastructure. Accordingly, green hydrogen transportation has the potential of supplementing the currently planned building of new electricity network infrastructure required for Europe to reach its goal of 450 GW generated from OWFs by 2050 [1]. This study kicks off the green hydrogen for offshore applications under GreenHyScale (100 MW of green hydrogen production in a replicable and scalable industrial hosting environment), which is an on-going five-year project with EU approved funding (project nr.101036935) [2] running from October 2021 to September 2026 paving the way towards the large-scale deployment of electrolysis both onshore and offshore in line with the EU's hydrogen and offshore renewable energy strategies.

As demonstrated in studies carried out [3], using new HPLs or re-purposing existing gas network infrastructure in the North Sea, to transport green hydrogen from offshore to onshore to meet hydrogen

demand, will significantly reduce the requirement for investment in new electricity network infrastructure. The additional costs of the electricity network are significant, reaching £37.5bn [3] (€44.2bn), that is assuming the costs of repurposing existing gas pipes to transport hydrogen onshore is low, demonstrating that the preferred approach for green hydrogen production would involve co-location at OWF sites.

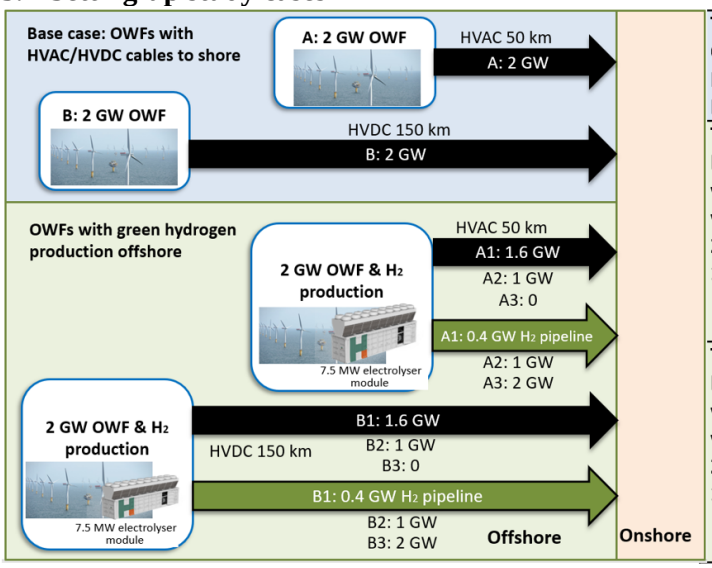
There has been a limited number of studies investigating the concept of LGHP co-location at OWF sites including the position paper [4] evaluating emerging hydrogen value chains in 2030 and in 2050, the techno-economic assessment of alternative integration designs for green hydrogen production into Offshore Wind Power hubs [5] and 84 Cases for Power-to-Hydrogen IJmuiden Ver [6]. There are no engineering designs and operational experiences of LGHP co-location at OWF sites. These techno-economic studies need further investigation, specifically of the crucial costs associated with the safe co-location of LGHP at OWF sites. This study will address both the benefits and the potential risks of LGHP co-location. Furthermore, this study has been inspired by the economic feasibility or profitability [7], business model [8], barrier identification [9] and optimal investment and sizing [10] of OWFs.

2. Objectives

This study aims at contributing to the LGHP co-location at OWF sites through collaborative initiatives from partners (including both developers and operators of the LGHP systems and OWFs) in GreenHyScale. The four objectives are as follows:

- Identifying the potential risks of OWF LCOE increases due to potential electric grid capacity bottlenecks that could appear towards 2050.
- The economic analysis of the increased capacity of offshore LGHP co-location at OWF sites. The case studies will cover the capacity of LGHP from 20% to 50%, and 100% of OWF capacity.
- Quantitatively evaluating the economic improvement factors of LGHP including i) application of existing gas pipelines for hydrogen transportation, ii) hydrogen use by offshore customers at premium prices, and iii) scaling-up effects (e.g. hydrogen production capacity from 2 to 4 GW).
- Indicating the potential major risks for LGHP co-location at OWF sites, including the requirements for safe LGHP co-location, high costs to cover more operational conditions and the operations coping with the rapid rate change of the fluctuating power generated from OWF.

3. Setting-up study cases



Two base cases: OWFs (HVAC, HVDC) without LGHP co-location	A	2 GW HVAC 50 km cable
	B	2 GW HVDC 150 km cable
Three cases of LGHP co-location with OWF (HVAC) with capacity of 20%, 50% and 100% of 2 GW	A1	1.6 GW HVAC 50 km cable; 0.4GW LGHP; H2 pipeline 50 km
	A2	1 GW HVAC 50 km cable; 1 GW LGHP; H2 pipeline 50 km
	A3	2 GW LGHP; H2 pipeline 50 km
Three cases of LGHP co-location with OWF (HVAC) with capacity of 20%, 50% and 100% of 2 GW	B1	1.6 GW HVAC 150 km cable; 0.4 GW LGHP; H2 pipeline 150 km
	B2	1 GW HVAC 150 km cable; 1 GW LGHP; H2 pipeline 150 km
	B3	2 GW LGHP; H2 pipeline 150 km

Figure 1. Eight study cases of green hydrogen production offshore and HPL transport to onshore

Eight OWF cases with LGPH are set up, as shown in Figure 1. Firstly, two base cases: A and B are 2 GW future OWFs with either HVAC (50 km) or HVDC (150 km) offshore electric transmission infrastructure to an onshore grid. Secondly, the three cases of LGPH co-location at OWFs with HVAC: A1, A2 and A3 will cover the hydrogen production capacity from 20%, 50% to 100% of 2 GW: 0.4 GW, 1 GW to 2 GW respectively. The 2 GW cases will involve 100% of the OWF power used for hydrogen production and there will be no electricity export to an onshore grid. Thirdly, three similar cases: B1, B2 and B3 have been produced for the co-location of LGPH at the OWF with HVDC present. The offshore hydrogen production at these two OWFs is assumed to be centralized on the OWF transformer platforms and transported via new HPLs to onshore users.

Eight cases have been studied using the annual OWF power production series shown in Figure 2, which is based on the measured wind power production series from one OWF in the North Sea and is scaled up for 2 GW OWFs. The annual OWF power production shows high fluctuations, and the daily wind production series in Figure 3 illustrates its higher fluctuating characteristics than the wind speed since it depends on the third power of the wind speed.

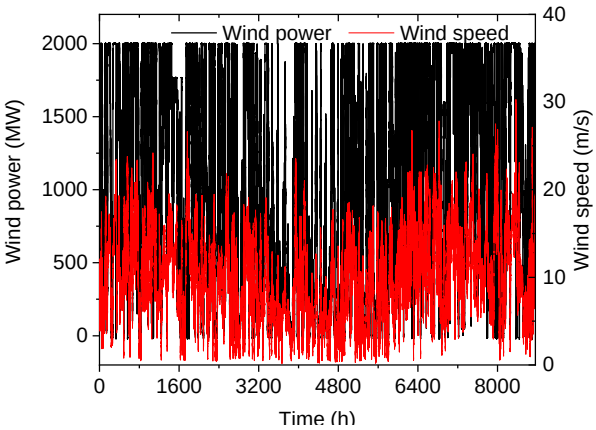


Figure 2. The annual wind power production

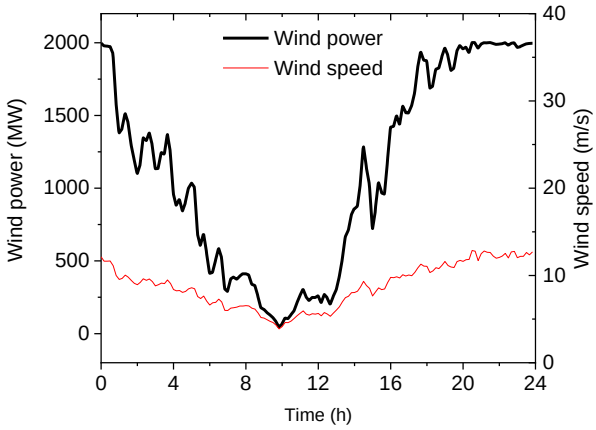


Figure 3. One daily wind production series

4. Implementation

4.1 The development of DTU LCOH calculator

DTU LCOH calculator is a DTU in-house program dedicated to green hydrogen LCOH assessment and is implemented using Python 3.7. The DTU LCOH calculator has been further developed to quantitatively evaluate the eight setting-up cases in Figure 1. The major improvements and developments include the following four aspects:

- The annual electricity production series in 10 minutes in Figure 2 is used for the economic analysis while the production series in one second is used to identify the fluctuating characteristic of the power production from OWF.
- The new LCOE and LCOH definitions have been implatemented to deal with the LGHP co-location with the OWF to deliver both the electricity and hydrogen onshore.
- The LGHP system calculation is based on the use of multiple 7.5 MW offshore alkaline electrolysis modules developed by Green Hydrogen Systems.
- The cost estimation considers unit prices, installation costs and scale-up effects when integrated with offshore engineering experiences.

When the LGHP is co-located with the OWF, the final products are electricity and hydrogen delivered to onshore by sharing the investment, maintenance and operational costs. The LCOE definition for this study is based on the electrical energy produced by the OWF, delivered to both the onshore grid and the offshore LGHP (intermediate product). Accordingly, the proposed definitaoitn of LCOE includes both the OWF energy power for onshore grid (utilizing the offshore electric transmission infrastructure) and the OWF enery power for the offshore LGHP (no utilizing the transmission

infrastructure). $LCOE_H$ is defined as modified LCOE since the OWF electricity is used for LGHP instead of being exported to the onshore grid. The LCOE and $LCOE_H$ are defined by Equations (1) and (2) as follows:

$$LCOE = \frac{\sum_{t=1}^{T} \frac{I_{wt,t} + M_{wt,t}}{(1+r)^t} + \sum_{t=1}^{T} \frac{I_{tran,t}((1-\alpha_H)E_t) + M_{tran,t}((1-\alpha_H)E_t)}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}} \quad (1)$$

$$LCOE_H = \frac{\sum_{t=1}^{T} \frac{I_{wt,t} + M_{wt,t}}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}} \quad (2)$$

Where the $I_{wt,t}$ and $I_{tran,t}$ denote the investment expenditure related to the OWF and the transmission infrastructure in the year t, respectively. $M_{wt,t}$ and $M_{tran,t}$ are the corresponding operation and maintenance costs. $I_{tran,t}$ and $M_{tran,t}$ depend on the ratio of capacity planned for hydrogen production, denoted as α_H. α_H=0, 20%, 50% and 100% for base case A/B, case A1/B1, A2/B2 and A3/B3 respectively. E_t represents the total electricial energy generated by OWF in the year t. r is the discount rate. $(1-\alpha_H)E_t$ is the electricity exported to the onshore grid, which determines the $I_{tran,t}$ and $M_{tran,t}$.

For LCOH calculation, the $LCOE_H$ is an internal parameter and is used for the electricity price for the LGHP. The LCOH is defined by the following Equation (3):

$$LCOH = \frac{\sum_{t=1}^{T} \frac{I_{LGHP,t} + M_{LGHP,t} + E_{H,t} \times LCOE_{H,t}}{(1+r)^t}}{\sum_{t=1}^{T} \frac{H_t}{(1+r)^t}} \quad (3)$$

Here, $I_{LGHP,t}$ and $M_{LGHP,t}$ are the investment and maintenance cost of the LGHP in the year t. $E_{H,t}$is the electricity used for production of hydrogen in the year t. H_t represents the total amount of the hydrogen produced.

The above LCOE and LCOH approach has been used for this case study. For a given OWF, the LCOE by the Equation (1) decreases when the capacity of LGHP increases due to the reduced capacity of the offshore transmission infrastructure.

The DTU LCOH calculator has integrated the new cost estimation module with engineering experiences from both the developers/operators of hydrogen systems and OWFs. The cost estimation includes the linearly scale-up the unit price, the engineering approach for offshore installation costs and the scaling-up effects (e.g. the installation of the second electrical transmission cable has half price of the first cable). The offshore installation costs are often several times higher than the unit cost and depend on many factors. Accordingly, the improved DTU LCOH calculator gives more realistic LCOE and LCOH calculations and is able to study the scaling-up effects of LGHP systems.

4.2 Assumptions and input parameters for two base cases

Many simplifications and assumptions have been introduced in the previous section and this section will list the input parameters and further assumptions required to provide the preliminary results of the two base cases, A and B: 2 GW future OWFs with HVAC (50 km) and HVDC (150 km) cables to the onshore grid. The input parameters for the LCOE, Net Present Value (NPV) and Internal Rate of Return (IRR) calculations of Base cases A and B are listed in Table 1. The assumptions for LCOE calculations include i) the same wind production time series in Figure 2 is used for every year, ii) both

the capital expenditure (Capex) and operation and maintenance (O&M) of OWF with HVDC is 20% higher than the OWF with HVAC since the OWF with HVDC is 100 km further offshore than the OWF with HVAC and the HVDC cables might be more expensive than HVAC cables, iii) annual O&M is a fixed percentage of Capex [6], iv) both HVAC and HVDC cables have the largest capacity of 500 MW, four cables are required for 2 GW capacity. The offshore transmission infrastructure costs consist of cables and the conversion equipment and the calculation uses the unit price plus the installation costs considering the scale-up effects according to the offshore engineering experience.

For the NPV and IRR calculation, i) the assumption of the electricity price including both the generation and transmission cables is 80/40 €/MWh which is 12 hours with 80 €/MWh and 12 hours with 40 €/MWh, this simplification aims at easy checking the electricity price impact on both NPV and IRR, and comparing the electricity price of 120/60 €/MWh, and ii) the discount rate of 5% is used.

Table 1. The input parameters for LCOE, NPV and IRR calculations for Base case A and B

		Input parameters	Base Case A	Base Case B
LCOE	OWF total without transmission cables	Capacity MW	2000	2000
		Annual wind production series	Figure 2	Figure 2
		Distance to shore km	50	150
		Capex €/kW	3500	3500*1.2
		Annual O&M per % of capex	0.03	0.03*1.2
		Lifetime year	20	20
	Electricity transmission HVAC/HVDC cables	Capacity MW	2000	2000
		Length km	50	150
		Unit price M€/km per 500 MW	2.4	2.4*1.2
		Number of cables	4	4
		Lifetime year	20	20
		Annual O&M % of capex	0.0015	0.0015*1.2
NPV, IRR		Electricity price €/MWh	80/40	80/40
		Discount rate %	5	5

4.3 Assumptions and input parameters for six cases with hydrogen production

The input parameters for the LCOE, LCOH, NPV and IRR calculations of six cases with hydrogen production at OWFs with HVAC and HVDC are listed in Table 2. The assumptions for the LCOH calculations include i) the costs of the sea water treatment systems are lumped in the Capex of the electrolyser unit, ii) the Capex of the offshore electrolyser unit uses twice the price of the on-shore Capex target of 400 €/kW in GreenHyScale to cover the marinization costs, considerable safety risks when co-locating LGHP alongside OWFs (see risks in section 7) and other unknown aspects. The DNV recommendation of adding an additional 20% [6] applies for general and known equipment marinization costs. The electrolyser unit in LGHP has high safety risks and many unknown aspects, accordingly twice the price of the on-shore Capex has been used to account for this. iii) the lifetime of electrolyser stack is assumed to be 10 years and the replacement is scheduled during the 10th year. The replacement cost is assumed to be half of its Capex including the safety tests etc, iv) the electrolyser efficiency, i.e. hydrogen conversion rate, is assumed to be constant under all loads throughout its lifetime, 48.65 kWh/kg is used [11], v) the working range of the electrolyser is from 0 to 100% of its capacity, vi) the costs of start/stop of hydrogen production is not considered, vii) one new HPL with 28 inch (71.12 cm) operating at 200 bar is assumed to have sufficient capacity to transport the pressurized hydrogen for all cases. For NPV and IRR calculations, the electricity prices and discount rate use the same input as for the Base cases A and B, and the hydrogen price uses 2 to 10 €/kg for the different scenarios.

Table 2. Input parameters for the LCOH calculations for hydrogen production co-location at OWFs

Model	Input parameters	Case A1, A2, A3: OWF with HVAC	Case B1, B2, B3: OWF with HVDC
Electrolyser systems including seawater treatment	Capacity MW	400, 1000, 2000	400, 1000, 2000
	Unit Capex €/kW	800	800*1.2
	Hydrogen conversion (kWh/kg)	48.65	48.65
	Annual O&M % Capex	0.03	0.03*1.2
	Lifetime year	10	10
Hydrogen pipelines	Capacity MW	400, 1000, 2000	400, 1000, 2000
	Length km	50	150
	Unit capex M€ /km	2	2
	Lifetime year	40	40
	Annual O&M % Capex	0.0015	0.0015*1.2
	Number of HPL	1	1

5. Calculation results

5.1 A comparison of four scenarios for Base cases A and B

The current tendency of the LCOE of OWFs is to assume a continued decreasing due to technology development (e.g. the cost reduction from large turbine, support structure and installation) and supply chain (e.g. production scale up and competition) etc. To indicate the potential risks OWFs' LCOE will increase with regards to the potential grid capacity bottlenecks towards 2050, a comparison of four scenarios for Base cases A and B with full and reduced power production every year is presented in this section. The four scenarios are Scenario S (Base cases) were the OWF with full production during its lifetime and Scenarios: S1, S2 and S3 present the setup that the OWF production will be reduced by 1%, 2% and 3% every year during its lifetime due to either the potential grid capacity being exceeded or by the presence of demanding load limitations. The LCOE, NPV and IRR are used for a comparison of the economics of the four different scenarios.

The calculated total wind production, LCOE, NPV and IRR for the four scenarios of Base Cases A and B with the OWF lifetime of 20 years are listed in Tables 3 and shown in Figure 4. The calculations with the same OWFs being built this time with a lifetime of 25 years are shown in Figure 5. As expected, both Base cases A and B will have significantly higher LCOE and lower NPV & IRR when the OWF will have reduced production yearly towards 2050. Figures 4 and 5 show that the economic numbers of OWFs with a lifetime of 25 years are better than those of OWFs with a lifetime of 20 years.

Table 3. A comparison of four scenarios with full and reduced annual energy production

		Scenario S: Full production Base cases	Scenario S1: 1% reduced production	Scenario S2: 2% reduced production	Scenario S3: 3% reduced production
Base case A	Wind power TWh	195	177	162	148
	LCOE €/MWh	80	87 (8.1%)	94(16.5%)	101 (25.3%)
	NPV M€	2389	1479	663	-71
	IRR %	8.3	7.2	6.1	4.8
Base case B	Wind energy TWh	195	177	162	148
	LCOE €/MWh	100	108 (8.1%)	117 (16.6%)	126 (25.4%)
	NPV M€	-82	-992	-1808	-2543
	IRR %	4.9	3.7	2.5	1.2

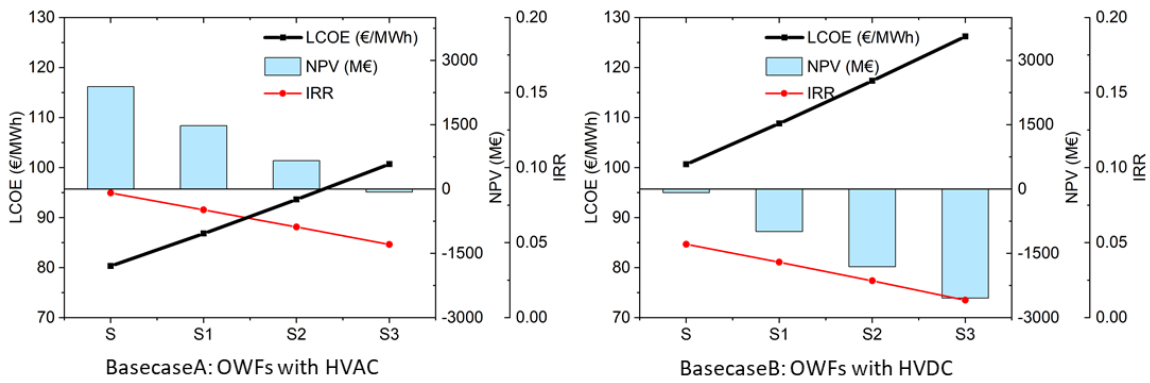


Figure 4. Calculated LCOE, NPV and IRR for Base case A and B with lifetime of 20 years

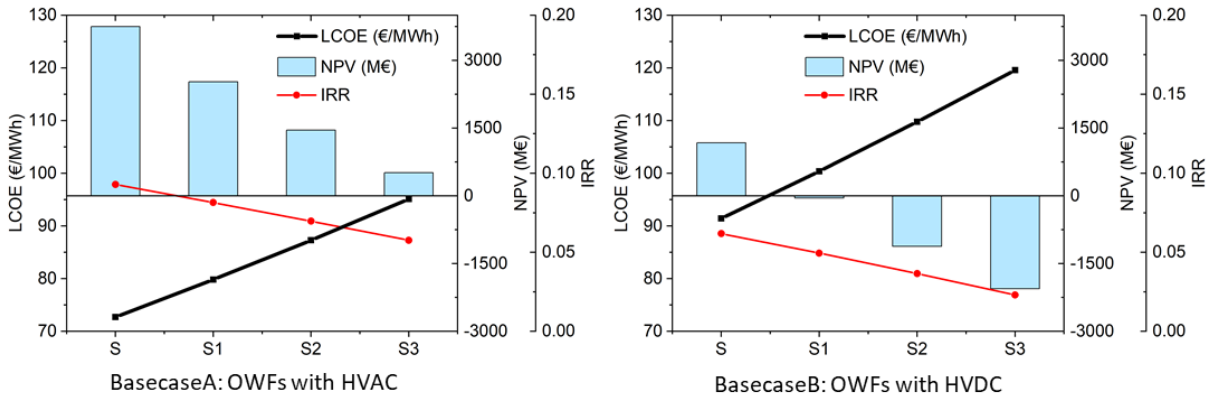


Figure 5. Calculated LCOE, NPV and IRR for Base case A and B with lifetime of 25 years

5.2 Offshore hydrogen production at an OWF with HVAC

The three cases: A1, A2 and A3 have LGHP co-location at 2 GW OWF with HVAC where the capacity of hydrogen production is varied from 20%, 50% to 100% of 2 GW: 0.4 GW, 1 GW to 2 GW respectively. Two assumptions have been introduced to simplify the calculations in this section. Firstly, that the electricity has 12 hours exported at a high price and another 12 hours exported at half that price. Secondly, the OWF power will be exported to the onshore grid up to its transmission capacity limitations and the rest of the OWF power will be used for LGHP during the high electricity price periods. The available OWF power will be used for LGHP up to its capacity during low electricity price periods and the rest of the generated OWF power will be exported to the onshore grid. The LCOH, LCOE, NPV and IRR of Base case A and Cases A1, A2 and A3 are listed in Table 4 and illustrated in Figure 6. The LCOE decreases when the capacity of LGHP increases due to the reduced capacity of the offshore transmission infrastructure. The LCOH decreases due to the LCOE decreasing. The NPV and IRR results show improvement when the LGHP capacity increases due to lower LCOH.

Table 4. A comparison of LGHP capacity of 20%, 50% and 100% at OWF with HVAC

H_2 price €/kg	Electricity price €/MWh	Base case A: No H_2 production		Case A1: H_2 production: 0.4 GW		Case A2: H_2 production: 1 GW		Case A3: H_2 production: 2 GW	
		NPV €M	IRR %	NPV €M	IRR %	NPV €M	IRR %	NPV €M	IRR %
2		-2473	1.0	-3570	-0.6	-4902	-2.8	-6951	-7.7
4	80/40	-2473	1.0	-2562	1.2	-2411	1.6	-1954	2.3
6		-2473	1.0	-1555	2.8	81	5.1	0	8.7
2		1172	6.7	-560	4.2	-2927	0.8	-6953	-7.7
4	120/60	1172	6.7	448	5.6	-435	4.4	-1957	2.3
6		1170	6.7	1455	6.9	2056	7.6	3040	8.7

Electricity TWH	195	195	195	195
Electricity to grid	195	155	98	0
LCOE €/MWh	80.3	79.4	78.1	72.0
H_2 MT	0	808.5	1999.2	4009.5
LCOH €/kg	N/A	5.4	5.0	4.8

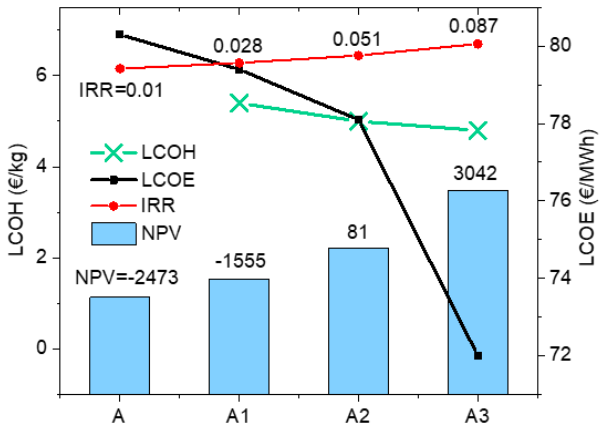


Figure 6. LCOH, LCOE, NPV and IRR for hydrogen production capacity from 0 to 100% at OWFs with HVAC

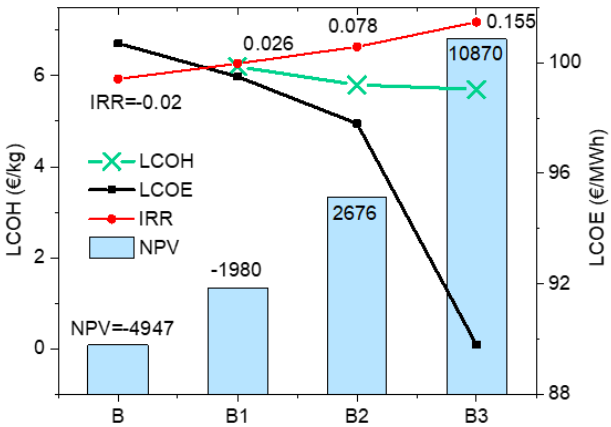


Figure 7. LCOH, LCOE, NPV and IRR for hydrogen production capacity from 0 to 100% at OWFs with HVDC

5.3 Offshore hydrogen production at OWF with HVDC

The similar three cases: B1, B2 and B3 for the offshore LGHP co-location with the 2 GW OWF with HVDC are presented in this section. Cases B1, B2 and B3 cover the capacity of offshore LGHP from 20%, 50% to 100% of 2 GW: 0.4 GW, 1 GW to 2 GW. The same two assumptions as for the HVAC in section 5.3 have been introduced. The LCOH, LCOE, IRR and NPV of Base case B and LGHP co-location cases B1, B2 and B3 are listed in Table 5 and illustrated in Figure 7. As expected, the LCOH, LCOE, IRR and NPV in Figures 6 and 7 have the same tendency for the 2 GW OWF with HVAC or HVDC.

Table 5. A comparison of LGHP capacity of 20%, 50% and 100% at OWF with HVDC

H_2 price €/kg	Electricity price €/MWh	Base case B: No H_2 production		Case B1: H_2 production: 0.4 GW		Case B2: H_2 production: 0.4 GW		Case B3: H_2 production: 2 GW	
		NPV M€	IRR %	NPV M€	IRR %	NPV M€	IRR %	NPV M€	IRR %
4		-4947	-2.2	-5002	-1.8	4802	-1.2	-4122	-0.3
6	80/40	-4947	-2.2	-3994	-0.2	-2311	2.3	875	6.0
10		-4947	-2.2	-1980	2.6	2672	7.8	10870	15.5
4		-1303	3.4	-1992	2.6	-2827	1.6	-4122	0.3
6	120/60	-1303	3.4	-984	3.8	-335	4.6	875	6.0
10		-1303	3.4	1031	6.2	4648	9.7	10870	15.5
Electricity TWH		195		195		195		195	
Electricity to grid		195		155		98		0	
LCOE €/MWh		100.7		99.5		97.8		89.8	
H2 MT		0		808.5		1999.2		4009.5	
LCOH €/kg		N/A		6.2		5.8		5.7	

6. Economic improvement factors for offshore hydrogen production

The economics of a LGHP project at an OWF site depend on many conditions. This section will show the potential impacts of three key cost drivers. The LGHP at Case A: OWF with HVAC will be discussed in this section and the results can be applied to the Case B: OWF with HVDC.

6.1 Utilizing existing gas pipelines

When it is possible to re-purpose existing gas pipelines, the investment in new HPLs can be avoided. The cost of re-purposing an existing gas network infrastructure is assumed to be very low and hence it is not considered in this study. The LCOH will be reduced. For Cases A1, A2 and A3, the calculated LCOH reductions are 0.8 €/kg (15%), 0.4 €/kg (8%) and 0.3 €/kg (6%) respectively, as shown in Table 6. The LCOH reduction in Case A1 is larger than Cases A2 and A3 assumes only one HPL to transport the pressurized hydrogen for all cases in section 4.3.

Table 6. Three cases re-purposing existing pipelines for H_2 transportation from OWF site to onshore

H_2 price €/kg	Electricity price €/MWh	Base case A: No H_2 production		Case A1: H_2 production: 0.4 GW		Case A2: H_2 production: 1 GW		Case A3: H_2 production: 2 GW	
		NPV €M	IRR %	NPV €M	IRR %	NPV €M	IRR %	NPV €M	IRR %
2		-2473	1.0	-3162	-0.1	-4393	-2.3	-6442	-7.3
4	80/40	-2473	1.0	-2475	1.0	-2155	1.7	-1901	2.2
6		-2473	1.0	-1147	3.3	590	5.8	3552	9.5
Electricity TWH		195		195		195		195	
Electricity to grid		195		155		98		0	
LCOE €/MWh		80.3		79.4		78.1		72.0	
H_2 MT		0		808.5		1999.2		4009.5	
LCOH €/kg		N/A		4.6		4.6		4.5	
LCOH with new HPL €/kg		N/A		5.4		5.0		4.8	
LCOH reduction €/kg		N/A		0.8 (15%)		0.4 (8%)		0.3 (6%)	

6.2 Hydrogen for offshore customers

When LGHP has offshore customers, it might get a premier price for the hydrogen and the HPL costs to shore can also be saved. LGHP directly for offshore customers promotes Blue industry growth including the supply of clean fuel for offshore oil/gas installations, aquaculture farms, offshore mining sites and offshore hydrogen fuel refuelling stations for maritime and aviation sectors. The assumptions are that the produced green hydrogen is half for onshore users and half for offshore users at double price. Readers might question whether the doubling of the price for offshore users is too optimistic a scenario. Experiences from the oil and gas sector show that for some offshore customers negotiated electricity prices (or costs for other products) are often several times higher than the normal market prices for electricity. However, this is because there are often considerable additional costs forced onto the seller in order to meet the offshore customer's often unique requirements. When hydrogen is supplied to offshore customers, either bulk hydrogen handling or offshore storage infrastructure will require high investment costs. These costs are assumed to be for the offshore customers to deal with and are not considered in this analysis. Any further study should then consider the costs of hydrogen storage offshore.

Table 7. A comparison of four cases of without offshore customers vs with offshore customers

H_2 €/kg	H_2 Offshore €/kg	Electricity price €/MWh	Case A1: H_2 production: 0.4 GW		Case A2: H_2 production: 1 GW		Case A3: H_2 production: 2 GW	
			NPV M€	IRR%	NPV M€	IRR%	NPV M€	IRR %
4	No	80/40	-2562	1.2	-2411	1.6	-1954	2.3
4	8		-1555	2.8	81	5.1	3042	8.7

Table 7 shows that the hydrogen for offshore customers at premium prices can significantly improve both the NPV and IRR of a project which in turn might be able to turn "No Go" projects with negative NPV and low IRR into attractive "Go" prospects, Case A3 in Table 7 was with NPV: -1954 M€ with IRR: 2.3% under electricity price 80/40 €/MWh. By selling half of the hydrogen to offshore

customers at a hydrogen price of 8 €/kg, its NPV became 3042 M€ with IRR: 8.7% which might then meet go criteria.

6.3 Scaling-up effects

To identify the potential economic benefits of LGHP and OWF scaling-up, results of the base case A and A3 of 2 GW OWF with 2 GW versus 4 GW OWF are listed in Table 8. As shown in Table 8, the electricity generation will be doubled annually from 195 TWH to 390 TWH while the LCOE is reduced from 80.3 to 78.4 €/MWh due to the scaling-up effects of the doubling of installed offshore transmission infrastructure. The LCOH is reduced by 17% (from 4.8 to 4.1 €/kg) following the LCOE reduction.

The decreasing LCOE is driven by the implementation of a new, more realistic cost estimation module in the DTU LCOH calculator which considers the offshore transmission infrastructure costs by the linearly scale-up of the unit price, the engineering approach for offshore installation costs and the scaling-up effects. The Capex and Opex of OWF with 4 GW are assumed to be double that of an OWF with 2 GW capacity. The 2GW and 4 GW OWFs' electricity is delivered to LGHP and the LCOEs are 72 €/MWh in Case A3 which is lower than base case A due to no offshore transmission infrastructure costs for both the 2 GW or the 4 GW OWFs.

Table 8. A comparison of the scale-up effect from 2 GW to 4 GW

H_2 price €/kg	Electricity price €/MWh	2 GW case				4 GW case			
		Base case A: No H_2 production		Case A3: H_2 production: 2 GW		Base case A: No H_2 production		Case A3: H_2 production: 4 GW	
		NPV M€	IRR %	NPV M€	IRR %	NPV M€	IRR %	NPV M€	IRR %
2		-2473	1.0	-6951	-7.7	-4469	1.3	-10704	-5.3
4	80/40	-2473	1.0	-1954	2.3	-4469	1.3	-710	4.5
6		-2473	1.0	3042	8.7	-4469	1.3	9283	11.2
Electricity (TWH)		195		195		390		390	
Electricity to grid		195		155		98		0	
LCOE €/MWh		80.3		72.0		78.4		72.0	
H2 MT		0		4009.5		0		8019.0	
LCOH €/kg		N/A		4.8		N/A		4.1	

7. Identifying the risks of LGHP co-location at OWF

There are no previous accounts of engineering implementation and operational experiences of LGHP co-location at OWF sites. This section identifies three potential risk aspects towards promoting further investigation in this area.

Firstly, the six cases of LGHP co-location at OWF sites have assumed that the LGHP will be centralized on the OWF transformer stations. With LGHP capacity of 20%, 50% and 100% of 2 GW OWF, the hydrogen production rate can reach about 8000 kg/h, 20,000 kg/h, and 40,000 kg/h respectively. The hydrogen refuelling station explosion in Norway in 2019 was related to a capacity of 1 kg/h of hydrogen [12]. The safety of such high-volume hydrogen production infrastructure should be carefully investigated. Moreover, the installation of the LGHP also results in significate weight and footprint gain: i) 280 ton & 2000 m^2 for 400 MW, ii) 7000 ton & 5000 m^2 for 1 GW, and iii) 1400 ton & 10000 m^2 for 2 GW by scaling-up the weight and footprint in [11]. The high Capex of offshore electrolyser units of 800 €/kW has been used to cover the additional costs of safety, weight and footprint required in the co-location of LGHP at an OWF transformer station. However, if a new platform must be built to host LGHP, the additional costs might be very high, which result in a show-stop decision. According to the LGHP scale-up advantages, LGHP might have more potential commercial opportunities as an energy hub e.g. with 20 GW generated from ten OWFs instead of monopolising a single OWF.

Secondly, many simplifications and assumptions have been introduced into this LGHP co-location with 2 GW OWF case study. Additional high costs might be required for extra processes and infrastructure installations when LGHP considers the effects of more operational conditions. For example, the hydrogen processes required to deliver customers requirements (e.g. water separations and pressurization/liquified) and LGHP operations under abnormal conditions including start/shut down and no wind for short and long period.

Thirdly, LGHP operations utilizing high, fluctuating OWF power might result in higher costs of operation and maintenance (O&M) and a shorter lifetime of the electrolyser models and systems. An OWF must smooth its power output to match the LGHP operational characteristics which might then reduce significantly the OWF's power production and increases both LCOE and LCOH.

This study has initiated quantitative estimation of the differences between the annual production from a 2 GW OWF with and without LGHP co-location. In order to predict the change rate of the fluctuating power from a 2 GW OWF, this study has reviewed the measured wind power production series from a single 6 MW wind turbine in time steps of one second of and the power production is seen to change rapidly. The probability of change rate in power production is classified at three different production levels (15%, 60% and at 100%). The differences between the maximum and the minimum in 60 seconds are shown in Figures 8. For the analysed series, the largest difference between maximum and minimum power reaches 3000 kW (50% of the capacity: 6000 kW) at 60% production in 60 seconds. For a 2 GW OWF which consists of hundreds of wind turbines, the change rate is expected to be smaller compared to a single wind turbine. The real wind power generation losses depend on the OWF wind resources, wind turbine generation characteristics, the wind farm size, and LHPG generation characteristics etc. Further comprehensive studies are required to properly deal with these factors.

Here we assume that this 2 GW OWF smoothing its power output to match LGHP operational characteristics results in the power reductions by 5, 10 and 15%. The calculated increases of both LCOE and LCOH are listed in Table 9. The LCOE increases 3 €/MWh (4%), 8 €/MWh (11%), and 12 €/MWh (18%) and the LCOH increases 0.4 €/kg (8%), 0.7 €/kg (15%), and 1 €/kg (22%) respectively. In order to mitigate such significant increases in LCOE and LCOH risks, one suggestion is not to use 100% power from the OWF for hydrogen production or using the power from an OWF energy hub instead of a single OWF.

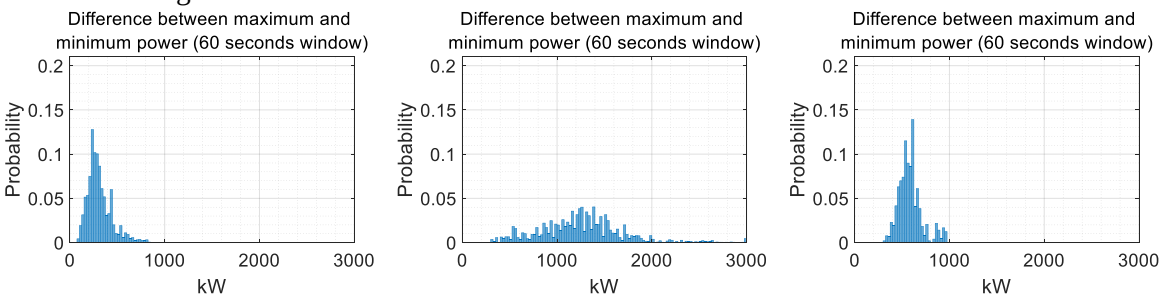


Figure 8. The difference between maximum and minimum power in 60 seconds.

Table 9. The LCOE and LCOH increase due to OWF smoothing its power productions.

	OWF full production & 100% for H_2 production	OWF annual power production reduction 5%	OWF annual power production reduction 10%	OWF annual power production reduction 15%
LCOE €/MWh	72	75 (3, 4%)	80 (8, 11%)	85 (12, 18%)
LCOH €/kg	4.6	5.0 (0.4, 8%)	5.3 (0.7, 15%)	5.6 (1, 22%)

8. Conclusions

This study has investigated whether LGHP co-location at OWF sites improves those OWF's economic outlooks towards 2050. Two OWF base cases with HVAC and HVDC and six LGHP co-location with OWFs have been studied and the case study results can be summarised as follows: (1) firstly, both base cases: 2 GW OWFs with HVAC and HVDC transmission infrastructure show the LCOE increases when the OWF production would be reduced by 1%, 2% and 3% every year during its lifetime of 20 years; (2) secondly, the three cases with LGHP capacity from 20%, 50% to 100% (0.4 GW, 1 GW and 2 GW) at the OWF with HVAC shows the LCOH dropping from 5.7 to 5.3 and 4.8 €/kg. The three cases with hydrogen production at the OWF with HVDC also show the LCOH dropping; (3) thirdly, the three economic improvement factors of LGHP are effective: i) using existing gas pipelines has the potential to reduce LCOH by 7.5%, ii) hydrogen use by offshore costumers at premium prices has significantly improved both NPV and IRR which might be able to turn "No Go" projects into attractive "Go" prospects, and iii) scaling-up from 2 to 4 GW hydrogen production capacity at OWF sites reduces the LCOH by 17% (4.8 to 4.1 €/kg). The potential high safety risks of LGHP co-locating at OWFs, additional high costs due to considering additional LGHP operational modes, and LGHP operations using high, fluctuating OWF power have been discussed. We hope that this study will motivate further R&D activities towards accelerating LGHP co-location at OWFs.

Acknowledgement: This study has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 101036935 (GreenHyScale). All authors thank Olve Mo at SINTEF for his power deviation analysis and Torque 2022 reviewers' improvement suggestions for this article.

Disclaimer: This paper presents LGHP at OWF cases study for GreenHyScale project and does not represent in any way author's company strategies or views of green hydrogen development.

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