Impact of integration of wind and tidal power on hydrogen production costs (March 2021)

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Abstract—**Wind power is making an increasingly important contribution to the UK's energy system and the governments legal commitment to reach Net Zero carbon emissions by 2050. However, wind generation is intermittent, so energy storage technologies are necessary to ensure a secure supply of energy. One option is hydrogen, which has applicability for seasonal energy storage and as fuel for heavy duty transport. Combining wind power with renewables with different generation profiles, such as tidal power, can reduce energy storage requirements. This research envisions that Orkney's ferry service has converted to hydrogen, and finds the optimal plant capacity and fuel cost in several scenarios. Here we show that tidal power can increase hydrogen cost due to its expensive electricity. However, it can reduce costs when grid electricity is not used, by reducing minimum plant capacities. This shows the importance of choosing favourable business models and plant operation strategies when developing proposals.**

Index Terms—**Hydrogen, Tidal power, Wind power**

I. Introduction

RENEWABLE energy is making an increasingly important contribution to decarbonising our energy systems and meeting Net Zero targets. In the UK, the share of electricity generation from renewables exceeded 40% for the first time in 2020, specifically with 47.2% in quarter 1, 44.4% in quarter 2 and 40.2% in quarter 3 [2]. This share will increase further through the UK's Ten Point Plan, which aims to quadruple offshore wind capacity to 40 GW by 2030 [3].

Despite their advantages, renewable power generators such as wind and solar farms operate intermittently and independently of demand. Thus, other technologies are required to support renewables, such as energy storage. There are a number of options here, including batteries and hydrogen. Batteries are an efficient option, achieving an electrical round trip efficiency of 85 to 95% in the case of lithium ion devices [4]. In contrast, hydrogen systems have an estimated efficiency range of 35 to 55%. However, hydrogen has applicability for seasonal energy storage (i.e. energy storage over several months) [4]. Additionally, the International Energy Agency found hydrogen to be an economic option for energy storage with discharge times between 20 to 45 hours [5]. Furthermore, there are some applications which cannot be easily electrified, or powered by batteries, such as heavy duty transport. Hydrogen propulsion systems may be relevant here, due to their energy density [6].

The minimum energy storage capacity will vary depending on the generation profiles of the technologies supplying it; relying on a single renewable power source, e.g. wind power, may necessitate a large and expensive energy store. Introducing a second type of generator, such as tidal energy devices, may reduce the storage requirement and the overall system cost, even if it provides relatively expensive electricity. Projects like ITEG are demonstrating the use of tidal devices to power electrolysis [7].

This work examines a case study in which a computer model was used to show the impact of integrating wind and tidal power on optimal (lowest unit cost) plant capacities to meet an essential hydrogen demand. The case study envisages that Orkney's internal ferry fleet has switched to hydrogen. I used an iterative process to find the optimal plant capacities, with 10 minute time series for wind and tidal data as well as demand. Demand is based on an annual ferry fuel consumption value. Four scenarios are considered, each identifying the lowest cost combination of plant capacities.

The case study shows that expensive tidal power has the potential to increase the unit cost of hydrogen if it displaces lower cost power. However, with electrolysers that are not connected to the grid, it can reduce minimum plant capacity and so reduce the overall unit cost.

II. Methodology

The main aspects of the model are outlined in this section.

A. Background

The scenarios described in this work envisage that the Orkney's grid has been upgraded and that third

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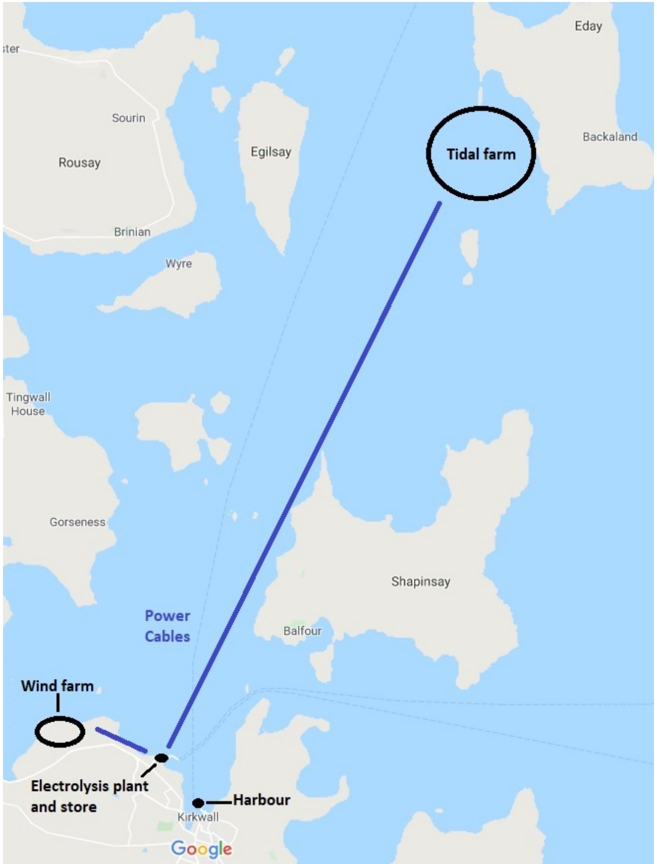

Fig. 1. The envisioned hydrogen supply system [9].

parties have built wind farms and tidal farms. The electrolyser owner purchases electricity from these third parties, making electricity an operating cost.

The modelled scenario is shown in Fig. 1. The electrolysis plant location is a pier near Orkney's largest town (Hatston Pier, near Kirkwall). Ferries based in Kirkwall can travel to the plant for refuelling. Ferries based in other harbours can have the hydrogen delivered using tube trailers (although these logistics costs are not included in the analysis).

The wind farm location is near the electrolyser (Quanterness) and is based on a planned wind farm [8]. The tidal farm location is EMEC's tidal test site (the Fall of Warness, near the island of Eday). Delivering the power from the tidal/wind farm to the electrolyser could be done with a private wire or via the grid (which I assume has been upgraded).

B. Wind and tidal data and power curves

Times series of wind and tidal current speeds were used in this analysis (with a time step of ten minutes). Wind speed data was collected by a 10 m mast at Kirkwall airport [10]. It used a 10 minute averaging time [11]. Two years of data was used, between 15 May 2009 and 15 May 2011. There were some gaps in the data (less than 10) that were filled in with the wind speed recorded on the previous time step. The original data had a recording timestep of one hour. I used linear interpolation to change this to a ten minute timestep.

This work used a 5 MW wind turbine capacity, based on an Orkney wind farm in planning [8]. The power

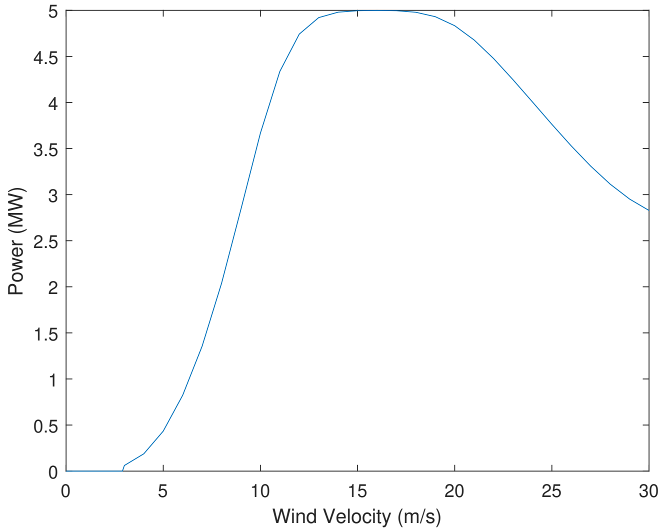

Fig. 2. Power curve of the SG 5.0-132 wind turbine [13].

curve (Fig. 2) and tower height (84 m) were based on the SG 5.0 - 132 device [12].

The wind speed was corrected from the measurement height to the tower height using (1).

$$U(z) = U(H)\left(1 + \frac{\ln\left(\frac{z}{H}\right)}{\ln\left(\frac{H}{z_0}\right)}\right) \tag{1}$$

Where $U(z)$ is the wind velocity, m/s, at elevation z m. H is the reference height, m, and z_0 is the roughness parameter, m. This changes depending on the surrounding landscape [14]. As a conservative estimate, I used the arithmetic average of values corresponding to coastal areas with onshore wind (0.0055 m). This resulted in a modelled wind turbine capacity factor of 41.6%. This work assumes that wake effects and maintenance periods would have a negligible impact on electricity generation. These could be included in more detailed studies.

EMEC kindly provided tidal current speed data. They used harmonic analysis of modelled data to estimate depth averaged current speeds between 15 May 2009 and 15 May 2011, with a 10 minute time step. I assumed the device would yaw to face the predominant direction of current flow. Again, wake effects and maintenance periods were neglected. The turbine power curve (Fig. 3) was based on guidelines values kindly provided by Orbital Marine Power.

C. Ferry fuel demand profile

Orkney's internal ferry fleet uses about 30 GWh/year in the form of 2.8 million litres of marine gas oil (MGO) [17], [18]. This equates to an average hydrogen demand of 2,500 kg/day. However, the annual energy demand may change due to efficiency improvements and services changes. In this work, a value of 1,000 kg/day is used, which would be sufficient for a proportion of Orkney's ferries. I assume that each day has a four hour refuelling period (from 13:00 to 17:00), with an average refuelling rate of 250 kg/hour. This could potentially be achieved using

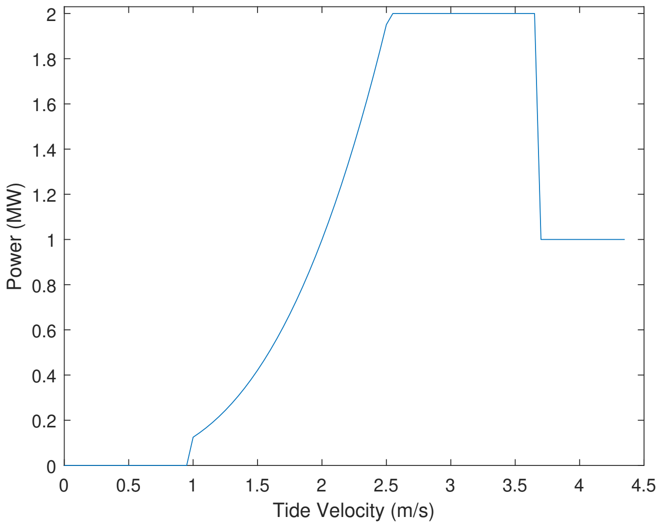

Fig. 3. Power curve of the modelled tidal turbine [15], [16].

balance fills, driven by the difference in pressure between the dispensing and receiving stores, or by a compressor. For example, the PDC-8-4500 compressor can reach a flow rate of about 210 kg/hour (with inlet and discharge pressures of 40 bar and 268 bar respectively) [19].

D. Electrolysis plant performance

I assume an electrolyser specific energy requirement of 51 kWh of electricity per kg of hydrogen. (The Fuel Cell and Hydrogen Joint Undertaking (FCH JU) has a 2023 target of 50 kWh/kg [20].) The compression requirement is modelled as 4 kWh/kg, which covers both compression into site storage and any additional compression requirements of ferry fuelling [21]. Stack degradation is not considered (although this may become important when considering periods of longer than two years).

The turn down ratio is modelled as 1% of nominal power. (The FCH JU has a 2023 target of operating from 0% upwards [20].)

The standby energy requirement is the power drawn while the plant is not generating hydrogen. EMEC's ITM Power HGas electrolyser had a power consumption of around 600 kW and a standby power draw of around 6 kW. ITM Power have estimated their 2 MW electrolyser will have a 7 kW standby power draw [22]. Conservatively, this relationship is assumed to be linear, giving (2), which I used in this work.

$$p_{sb} = 0.71RC + 5.57 \tag{2}$$

Where p_{sb} is the standby power requirement, kW, and RC is electrolyser capacity, with units of MW in this case.

The water consumption is modelled as 20 litres per kilogram of hydrogen [22], [23].

I neglected maintenance periods and assumed a plant lifetime of 20 years.

TABLE I
VARIABLES WHICH GIVE FOUR SCENARIOS

Parameter	Option 1	Option 2
Renewable power supply	Wind	Wind and Tide
Grid power for H_2 generation	Used	Not used

E. Storage

The model only considers the mass in the store - volume and pressure are not considered. This should be considered in more detail in future, as these properties affect the ability to perform balance fills. The model only allows generation if the mass in the store is below the store limit (e.g. 2,000 kg). I assume that any mass of hydrogen in the store can be extracted. In each scenario, the store starts full. The cost of filling the store with hydrogen produced from grid power is included in the model. The electrolysis plant can continue to generate hydrogen while dispensing into a ferry. Leaks are neglected. I assumed a lifetime of 20 years.

F. Scenarios

This work considers four scenarios, as outlined in Table I. Tidal is not considered as a sole power source because it is relatively expensive (Section II-H).

In the two scenarios where wind and tidal power are both used, wind power is used preferentially. Any available tidal power is also used.

In the two scenarios which allow the use of grid power to generate hydrogen, it is used only as a last resort, i.e. it is only used when there would otherwise be a shortfall in hydrogen supply. All four scenarios use renewable power (preferentially) and grid electricity to meet standby losses.

G. Finding optimal plant size

To find the optimal plant size, the model is run with a range of capacities of electrolysis (1 MW test resolution), storage (1,000 kg test resolution), wind farm (1 turbine test resolution) and tidal farm (1 turbine test resolution). Based on a demand of 1,000 kg/day and an energy requirement of 55 kWh/kg, the minimum electrolyser capacity required is 2.3 MW. As this would require a capacity factor of 100%, the model uses a minimum capacity of 2.5 MW. The minimum store capacity considered is 1,000 kg. The largest capacity of wind and tidal farm considered is 50 MW (each).

H. costs

The costs of this proposal are uncertain and should be updated as more detailed studies are performed.

1) Electricity costs: The electricity prices used in the model are shown in Table II. The wind and tidal power costs were taken from targets and forecasts in literature [24], [25]. This analysis uses constant prices for electricity, which could be secured with a power purchase agreement.

TABLE II
ELECTRICITY RATES

Source	Cost, £/MWh	Notes
Wind power	28	Based on 35 USD/MWh by 2030 [24]
Wind power delivery	1	Based on EMEC information [26]
Wind power total	29	
Tidal power	88	Based on 2030 target of 100 EUR/MWh [25]
Tidal power delivery	30	Based on EMEC information [26]
Tidal power total	118	
Grid power	120	Adapted from EMEC information [28]

The delivery cost rates were based on cable cost estimations from EMEC: the installed cost of connecting the tidal site to the electrolyser with a 22 km long cable with a 5 MW capacity with a 20 year life span was estimated as £1,000/m [26]. The cable capex cost contribution of delivering energy from a 5 MW tidal farm with a 33% capacity factor would add £76/MWh. However, it may be possible to increase the cable utilisation by allowing other generators, e.g. wind turbines, to use the cable. An alternative delivery strategy could be to agree a price with the grid owner to use their infrastructure. This work is agnostic to which route is used and has a tidal power delivery cost of £30/MWh.

The wind power delivery cost was also estimated. The proposed wind farm is about 2.4 km from the proposed electrolysis site. EMEC estimated materials costs of £70/m and burial costs of £65/m [26], giving capex of about £326k for a 5 MW connection. The cable capex contribution for a 5 MW wind farm with a 41.6% capacity factor and 20 year lifetime [27] would be about £1/MWh.

The grid power cost was adapted from EMEC information [28]: neglecting the standing charges, the cost of grid power on EMEC's Eday site, consuming relatively small quantities of electricity in 2018/19, was about £130/MWh. As a consumer of larger quantities of electricity on the Orkney Mainland, EMEC could reasonably expect to pay less than this, as shown by reports on energy prices from the UK Department for Business, Energy and Industrial Strategy [29], [30]. Thus, a price of £120/MWh is used here.

2) Other opex costs: Yearly operations and maintenance costs are estimated as 3% of total capital costs. This was based on literature values for the electrolyser [31], and is an estimate for the store and compressors.

The cost of water is set £1.30/m^3 [32], giving an cost contribution of £0.03/kg-H_2.

3) Capex costs: Previous EMEC work was the basis for the capex costs in this work, which are shown in Table III.

Electrolyser and commissioning costs are calculated as a function of capacity using an equation, (3), proposed by Mignard et al. [33], [34]. The two terms of the equation correspond to 1) cost components of the plant that scale linearly, such as cells, and 2) cost components which scale with a power law, such as process plant equipment.

TABLE III
CAPEX RATES

Plant component	Item	Rate	Units
Electrolyser equipment	Electrolyser (at 2.5 MW)	440	£/kW-electrolysis
	Compressor	360	
	Shipping	40	
	Commissioning (at 2.5 MW)	36	
	Site - civil works	125	
	Site - electrical infrastructure	350	
	Total	1351	
Storage equipment	Store	600	£/kg
	Shipping	30	
	Commissioning	13	
	Site - civil works	268	
	Total	911	

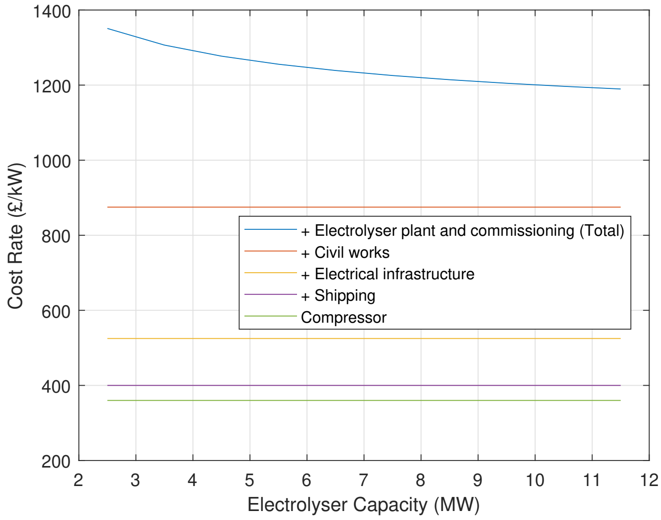

Fig. 4. Capital cost rate as a function of electrolyser capacity.

$$Capex = \alpha(RC) + \beta(RC)^{\gamma} \tag{3}$$

The value of γ was set as 0.606. The values of α and β need to be found for a "base cost". This work envisages that electrolysis plant costs are successfully reduced [35] and so uses a base cost of £440/kW at 2.5 MW. Including the commissioning costs, this comes to £476/kW. Research from Mayyas et al. [35] suggested that once production rates reach 100 x 1 MW electrolysers per year, the stack will account for 25% of costs, with 75% from the balance of plant. This gives α and β values of 119 and 7788 respectively, where RC has units of kW. The result is the cost profile shown in Fig. 4.

The compressor and storage costs are appropriate for 700 bar diaphragm compressors and 450 bar storage vessels [26]. If a 450 bar compressor is sufficient for refuelling operations, this cost could be reduced using an index factor of 0.18 [36], i.e. by about 8%. This could reduce the 2.5 MW system total cost by 2%.

The electrical infrastructure cost was based on that paid by EMEC when it deployed an electrolyser on its Eday site in 2017 (£435/kW-electrolysis). A discount (about 20%) was applied due to this development taking place on the Orkney mainland and the larger plant capacity. The change in cost with electrical equipment capacity can be seen in literature: Phung [37] gave a relative cost per rating of 0.39 for a 230 kV 150 MVA transformer and a relative cost of 0.3 for a 230 kV 250 MVA machine.

Shipping costs were estimated as 5% of the 2.5 MW system cost.

4) Cost calculation: To reduce code complexity, a simplified cost calculation was used, (4). This neglects the discount rate, stack degradation and stack replacement. This could be considered in more detailed studies.

$$c_{H_2} = \frac{\frac{I \cdot t}{l} + E_t + W_t + M_t}{H_t} \tag{4}$$

c_{H_2} is the hydrogen cost, £/kg. I is initial capital investment, which is all spent at the start of the project. t is the time period from which data was used (2 years). l is plant lifetime in years. E_t, W_t and M_t are the electricity, water and maintenance costs incurred over time period t. H_t is the mass of hydrogen produced over time period t.

III. Results

The main results are shown in Table IV. The first scenario, wind power with grid backup, achieves the lowest unit cost. The second scenario, wind and tidal power with grid backup, achieves a higher cost, but with a lower electrolyser capacity. The third scenario, wind power without grid backup, requires a larger store (5,000 kg) to meet demand, which increases the cost. The optimum wind capacity here is 35 MW (although very similar results were achieved for wind farm capacities up to 50 MW). The fourth scenario, wind and tidal power without grid backup, achieves a lower cost than the third scenario.

Fig. 5 shows a contour plot which indicates how the cost of hydrogen changes depending on wind and tidal capacity in the second scenario. (All combinations satisfy demand through the use of grid power.)

Fig. 6 shows a filled contour plot which indicates how the cost of hydrogen changes depending on wind and tidal capacity in the fourth scenario. The blank space corresponds to tests in which hydrogen demand was not satisfied without the use of grid power, which this scenario excludes. The 8 wind turbine and 16 tidal turbine case meets demand, whereas the 8 wind turbine and 17 tidal turbine case does not. This is due to the method of controlling mass in the store, which allows generation if the mass in the store is less than the limit. This sometimes allows the 16 tidal turbine case to generate more hydrogen than the 17 tidal turbine case, specifically when the store is at capacity (2,000 kg) in the 17 turbine case, but at slightly less than capacity in the 16 turbine case (e.g. 1,996 kg). The 16 turbine case can then generate for ten minutes and slightly overshoot the limit (e.g. 2,003 kg). This extra mass allows the 16 turbine case to avoid the use of grid power which is seen in the 17 turbine case. If a hard store mass limit of 2,000 kg is imposed, the 16 turbine case also fails to meet demand without the use of grid power.

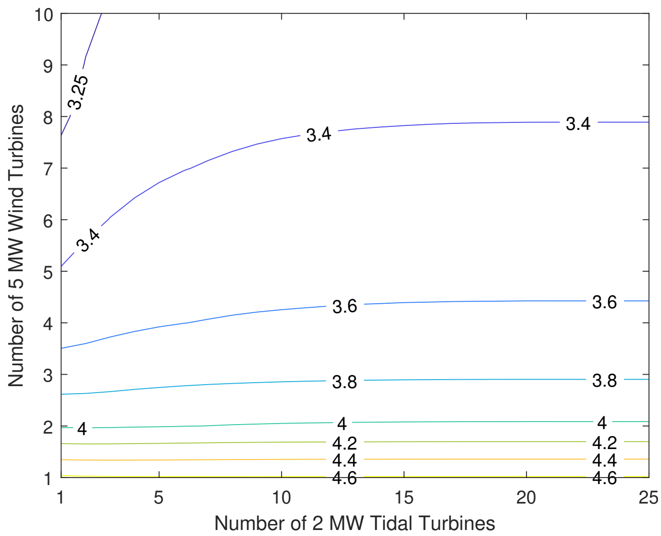

Fig. 5. Change in hydrogen cost, £/kg, as a function of wind farm and tidal farm capacity with the optimal electrolyser and store capacity in the second scenario.

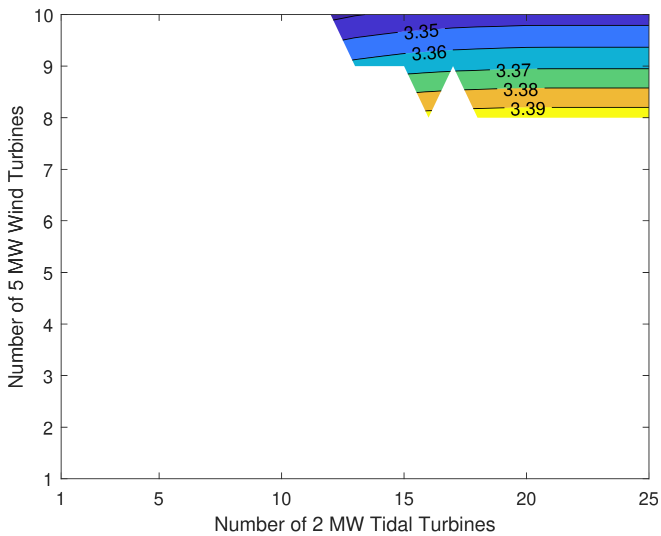

Fig. 6. Change in hydrogen cost, £/kg, as a function of wind farm and tidal farm capacity with optimal electrolyser and store capacity in the fourth scenario.

IV. Discussion

These results suggest that the use of tidal power can increase the unit cost of hydrogen from a renewable supply chain. This could be due to relatively high cost tidal power displacing lower cost wind power. However, if the electrolyser cannot use grid electricity as a backup to meet demand, the use of tidal power can reduce the unit cost. This is because it enables lower plant capacities.

This second finding does have a caveat: the wind and tidal powered electrolyser scenarios have a larger total

TABLE IV
OPTIMAL COST AND PLANT CAPACITIES IN THE FOUR SCENARIOS

Scenario	Cost, £/kg	Electrolyser capacity, MW	Store capacity, kg	Wind farm capacity, MW	Tidal farm capacity, MW
1. Wind power with grid backup	3.12	3.5	2,000	50	NA
2. Wind and tidal power with grid backup	3.28	2.5	2,000	50	2
3. Wind power without grid backup	3.67	3.5	5,000	35	NA
4. Wind and tidal power without grid backup	3.34	2.5	2,000	50	24

power supply that the wind only scenarios, meaning this may not be a comparable test. However, using only one type of generator will eventually reach a cost plateau that can only broken with a second type of generator.

There are several other notes to draw from Section III. For example, the first scenario unit cost is optimized with a 50 MW wind farm (the maximum considered here) because this minimizes the use of grid power for hydrogen production.

Fig. 5 shows that increasing tidal capacity increases the hydrogen unit cost. This could be due to an increasing proportion of the electrolyser's electricity coming from relatively expensive tidal power. The optimal tidal capacity is therefore 2 MW. Fig. 5 also shows that increasing wind capacity reduces the unit cost. However, as shown in Table IV, the contribution from tidal power does allow for lower electrolyser and store capacities.

Table IV shows that, in the third scenario, the best cost can be achieved with a wind farm capacity of only 35 MW. This is because there is effectively only one electricity source and cost; provided there is enough wind energy to meet demand, a larger capacity does not affect the hydrogen cost.

Fig. 6 shows the fourth scenario's compromise between relying on tidal power to meet demand while minimising its relatively expensive contribution. The greater the wind farm capacity, the less tidal capacity is required.

One weakness of this analysis is the use of a simplified cost calculation instead of a levelized cost calculation, with discount rate and stack degradation and replacement. This may affect the unit costs of the four scenarios.

These findings may have relevance to a national scale energy system. Relying on grid power, as in the first and second scenarios, is realistic for a multi-MW hydrogen facility. However, it becomes less feasible as the facility scales to the national level (which may be useful for large scale energy storage). If the main contributor to the grid is wind power, for example, then an electrolyser will not be able to rely on grid power when there is a low wind speed. Thus, the third and fourth scenarios are more realistic at large scale. Table IV therefore provides some evidence that predictable renewable energy generators, such as tidal devices, can reduce overall renewable energy storage costs.

Future work could re-examine this case study using more detailed models, which could include: maintenance periods; electrolyser efficiency as a function of power consumption; models for gas transfer as a function of the pressure difference between the dispensing and receiving stores; and an equation to find additional capex costs as a function of capacity. Additional, higher-level work could explore the validity of applying these findings to national energy systems. For example, instead of a hydrogen system supplying a inter-island ferry service, a future study could investigate the optimal plant capacities to enable seasonable energy storage.

V. Related work

For further investigation into this case study, please see my thesis [1]. This explored many avenues, including: a second method of combining wind and tidal power, where tidal power is only used to displace grid power; the effect of changing annual and seasonal hydrogen demand; and the effect of using a finer test resolution.

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