Comparison of floating offshore wind and tidal range for green hydrogen production and storage for industrial decarbonization

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Abstract – **UK Government targets 5 GW of electrolysers by 2030, however the role of green hydrogen for decarbonisation is not explicit. The government identifies the need to research the "archetypes" of production, transport, storage, and use. This paper presents a techno-economic model, comparing Floating Offshore Wind (FLOW) to tidal range, supplying uninterrupted power and hydrogen for industrial decarbonisation. The model employs Levelised Cost of Electricity (LCoE) and Hydrogen (LCoH), with sensitivities for Discount Rate (DR) and electrolyser efficiency. Storage is essential; FLOW must overcome seasonal patterns and changeability between years, and tidal must bridge both the springs-neaps, and equinox cycles. The Royal Society identifies salt caverns as optimal for GWh storage, and the British Geological Society (BGS) report halite beneath the Celtic Sea. The model includes an onshore electrolyser, desalination, compression, subsea pipeline, storage platform, Underground Hydrogen Storage (UHS), and Hydrogen Gas Turbine Generator (HGTG). Components are scaled to meet demands over 25 years. When renewable generation falls below demand, hydrogen is withdrawn from storage to top-up electrolyser production to meet the continuous gas demand, and as fuel for the HGTG. The study shows how marine renewables can provide continual power and hydrogen for decarbonisation, and hydrogen's ability as an energy store and flexible fuel. FLOW was found to require a smaller generating and electrolyser capacity, with lower LCoE and LCoH. Tidal's predictability results in a smaller storage. Costs are most sensitive to DR. Tidal merits further investigation due to its long asset life and compatibility with alternative storage technologies.**

Keywords— **Floating Offshore Wind, Tidal Lagoon, green hydrogen, storage, compression, decarbonisation.**

I. INTRODUCTION

HYDROGEN will play a significant role in industrial decarbonisation, however its role and integration is not explicit [1]. The International Energy Agency (IEA) reports a mismatch between Government policy for production and demand stimulation. The private sector has started to adopt low emission hydrogen, but remains at small scale [2]. The UK Government has identified that low carbon hydrogen should be used to replace high carbon hydrogen (grey) within existing industrial activity, such as petroleum refining, fertiliser manufacture, and steel [3]. This paper presents a new energy system model that considers a large-scale industrial green hydrogen adoption decarbonisation scenario. Marine renewable resources of wind and tidal are compared to produce green hydrogen with storage. Model components are proven with high Technology Readiness Levels (TRL). The unique aspect of this work is the combination of variable renewable resource, the provision of both power and hydrogen gas, applied to a real-world case study.

Within the UK, the Committee for Climate Change (CCC) forecast hydrogen to provide 240 TWh/yr of final energy by 2050, including 95 TWh/yr green hydrogen. The UK power grid is predicted to double annual power delivery by 2050 with the majority of the generation forecasted from offshore wind [4]. The coupling of green hydrogen and offshore wind appears probable [5], and is being actively investigated by industry, with notable examples being RWE's Dutch study H2opZee [6] and Pembroke Net Zero Centre set in South West Wales and the Celtic Sea [7].

The UK Gov. has set an ambitious goal of 5 GW of FLOW and 5 GW of electrolysers by 2030 [8] [9]. The Crown Estate (TCE) is undertaking a seabed leasing round

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for the Celtic Sea, with the target of leasing 4.5 GW of real-estate by 2025 with water depths 68-88m [10]. This leasing round can contribute significantly to the 2030 FLOW target. The UK's tidal lagoon generation potential has been assessed, with a theoretical opportunity of 37 GW, in 18 locations around the UK, generating 55 TWh/yr, with a combined capacity factor of 17%. The Bristol Channel and Seven Estuary is the single largest resource area in the UK [11].

The UK's power sources include nuclear, wind, solar, coal, natural gas, and interconnectors. With variable renewable generation, and changeable demand (hourly and seasonally), supply and demand must be continually managed. System balancing is achieved using several technologies; however, natural gas provides the majority of the GW scale hour by hour matching [12]. Hydrogen's role in the UK's future energy mix is evolving, reflected in the wide range of scenarios estimated [4]. One potential pathway for hydrogen is as an energy store and flexible generator, potentially supplanting natural gas's role [13] [14], especially during periods of instability caused by high renewable generation [15].

Another potential benefit of future hydrogen adoption is to help address curtailment challenges. In 2022, 3.4 TWh of wind energy was curtailed due to transmission bottlenecks [16], equivalent to 1% of the UK's annual electricity demand. The future expansion of wind energy in the UK will present challenges relating to curtailment. Green hydrogen production has the potential to reduce curtailment, and the need for transmission upgrades [17].

Hydrogen storage is a key enabler of hydrogen adoption by industry, ensuring availability. The Royal Society and UK government have identified salt (halite) caverns as the most suitable storage medium, with the UK requiring a hydrogen storage capacity of 60-100 TWh by 2050 [18] [1] [3].

Industrial clusters within the UK consume unabated grey hydrogen used for its chemical properties (not burned for heat). Grey hydrogen is produced from natural gas, with the UK importing half of the gas consumed [19]. Replacing the grey hydrogen with green hydrogen, produced from renewables, could facilitate their transition to decarbonisation, and potentially reduce gas imports. Much of the remaining industrial sectors can, to a large extent (70-90%), be decarbonised via electrification [20] [21], with the benefit of improving national energy security [4]. Remaining sectors are the hard to abate industries, including plastics, specialty metals, glass, and transport (aviation and shipping). Green hydrogen's decarbonization credentials can be leveraged both for its role in chemical processes, such as producing plastics, and for generating high temperatures.

The UK government has identified South Wales and the UK's South West (SW) regions, which border the Celtic Sea and the Severn Estuary, as having potential to adopt green hydrogen [22] [23]. The SW of the UK is sparsely populated; should power make landfall in this region significant transmission upgrades would be required to reach consumers to the South and East [24]. South Wales has significant industry and an industrial cluster and oil refinery in Milford Haven, with annual emissions of 8.9 Mte.CO_2e/yr [25]. There is a significant tidal range resource in the Severn Estuary, which, if developed, also has the potential to contribute to green hydrogen production [11]. The wind resource is equally good, with TCE planning to lease over 16 GW [26].

II. Method

To explore the generation and storage of green hydrogen in the UK SW regions, a new energy system model has been developed. Components are represented in Fig. 1, set within the Celtic Sea and the Seven Estuary. Renewable generation is either FLOW or tidal. Wind resource is exploited through the development of 9 off modular 510 MW FLOW farm, comprising 34 x 15 MW Wind Turbine Generators (WTG) each with an Offshore Sub Station (OSS). Tidal resource is exploited via a lagoon, adopting the Swansea Bay Tidal Lagoon (SBTL) project, with a 320 MW capacity and surface area of 11.5 km^2, scaled to meet the demands.

HVAC power is cabled to shore, where it is received by switchgear & transformers. Power is preferentially directed to the industrial cluster with a continuous demand. Excess power is then routed to the electrolyser system. Produced hydrogen is then prioritised to meet the continuous hydrogen gas demand. Excess hydrogen is compressed in two stages and routed to storage. Both power and hydrogen demand have been assessed to be typical of a refinery, with green hydrogen replacing grey and all other fuel sources replaced with power. Continuous demand is met through withdrawal of hydrogen from storage, with the hydrogen used as fuel within the HGTG. Bukhari et al in 2023 observed that existing natural gas power stations have the potential to be retooled to burn hydrogen, hinting at the possibility of future cost savings [27]. Pure water and cooling water is produced using desalination, so as not to put pressure on local water sources [28]. The model includes a grid connection, but is reserved solely for power export, whereby the excess power is 'sold' at the LCoE.

The modelled cases include FLOW and tidal range, with hydrogen storage and power peaking using a hydrogen fuelled gas turbine. The models assume a constant demand for both electricity and hydrogen. As energy generation from the renewable generator falls, hydrogen is withdrawn from storage and used to ensure a constant hydrogen supply, and as fuel for the gas turbine (HGTG), ensuring the continuity of both hydrogen gas and electricity. Power is preferentially routed to the industrial cluster rather than the electrolyser system, which is an expensive Capex component, and minimises the efficiency losses from conversion of power to hydrogen and back to power. Consumption of generation locally as either power or hydrogen, lessens the need for transmission upgrades and minimises curtailment due to transmission bottlenecks.

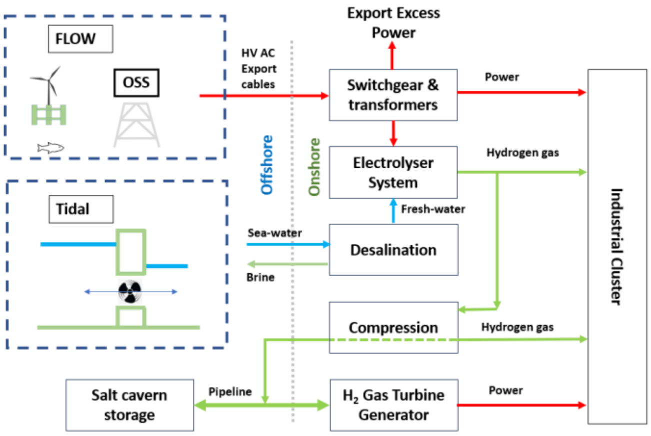

Figure. 1 Model schematic, FLOW / Tidal, HVAC cables, electrolyser system, compression, offshore storage (pipeline and storage platform), and HGTG.

From here-on this section firstly describes the source of the power datasets, definition, and derivation of the loads (power and hydrogen gas), and component sizing. Secondly, the equations for deriving LCoE / H are described.

A. *Techno-economic model inputs*

This section breaks out the high-level model inputs, including wind-speed and tidal range datasets, the reference WTG, electrolyser technology and sizing, hydrogen compression for direct consumption and storage, hydrogen storage sizing, desalination technology, offshore pipeline sizing, and HGTG.

1) *Windspeed datasets and WTGs*

Windspeed data has been drawn from the website RenewableNinja [29], at a rotor hub height of 150m above sea-level. Data granularity is hourly average windspeeds (m/s). The model uses 25 years of data drawn from a single location in the centre of the TCE leasing area at position N 51.1° E -005.6°. The WTG used is a National Renewable Energy Laboratories NREL-IEA 15 MW reference machine, with hub height 150m and rotor diameter of 240m [30].

2) *Tidal range power generation dataset*

The Hendry Report defines the SBTL installed capacity (320MW) [11]. Mackie et al [31] describe the methodology for developing an annual power timeseries, derived from hydrodynamic modelling using the Thetis unstructured grid coastal model [32]. Applying the SBTL installed capacity gives a dataset of energy production, with units of megawatt hour (MWh), at 2-minute intervals. A tidal lagoon generates power on both the high and low tides, resulting in four distinct generating periods per day. The energy system model presented in this paper sums these 2-minute intervals to create an annual hourly dataset, repeated for a 25-year production period.

3) *Electrolyser technology and sizing*

The two main commercially available and high TRL electrolyser technologies are Alkaline Electrolysis (AEL) and Proton Exchange Membrane (PEM), with AEL having the longest track record. Electrolyser stacks and Balance of Plant (BoP) are expensive Capex items, with system costs ranging €1,400 /kW for AEL to €1,800 /kW for PEM in 2020 [33]. For contrast installed costs for FLOW is £3.52 M/MW and Tidal £3.89 M/MW.

PEM is better suited to load following. The world's current largest AEL-renewables system in China has experienced load following problems [34]. However, AEL systems are predicted to increase their hot-idle speed of response from 60 s (2020) to 10 s (2030) [35]. Both are capable of operating using pressurized water, allowing hydrogen to be piped directly to the industrial cluster, reducing storage compression horse-power [36]. PEM operates in an acidic environment which demands expensive and scarce Platinum Group Metals (PGM) within the catalysts. Iridium is used on the anode side and is particularly limited, with an annual production of <10 te/yr. Scarcity of PGM cast a shadow over the viability of GW scale PEM systems [37] [38]. For this reason, the model adopts AEL technology, operating at 3 MPa, assuming future system control development will permit load following of intermittent renewables.

AEL technology requires membrane replacement every 9 years, at a cost of 50% of the stack Capex [17]. Due to the significant Capex, stack sizing will likely be scrutinized for optimal capacity, redundancy, and maintainability, as a function of Capex, hydrogen generation, and LCoH. Stack capacity and storage size has been sized such that continuous uninterrupted power and hydrogen can be delivered for the life of the facility, 25 years. The FLOW case required 9 x 510 MW modules coupled to a 2.18 GW electrolyser system. The tidal case required scaling the 320 MW SBTL by 50 times coupled to a 7.16 GW electrolyser. Scaling the surface area of the SBTL gives a lagoon size of 575 km². A lagoon of this dimension is not feasible within the confines of the Seven Estuary; however, it serves to demonstrate the modelling principle to allow direct comparison. The disparity in electrolyser size between the two archetypes of FLOW and tidal is explained by FLOW having a much higher Capacity Factor compared to tidal, and the cyclical nature of tidal

4) *Water and desalination*

Electrolysis requires pure water; contamination causes degradation of the membrane and the catalysts, reducing the operating life. AEL operating temperature is 70 – 90 °C [36], requiring additional cooling water. A GW scale AEL electrolyser system requires 15 M.L/day, assuming a water consumption of 32.2 L/kg.H2 [28]. The average UK daily water consumption per person is 145 L/day [39], hence a GW scale electrolyser operating at capacity consumes water equivalent to 100,000 people.

An alternative to supplanting grey hydrogen with green is to add a Carbon Capture and Storage (CCS) system to the grey hydrogen plant. However, a blue hydrogen system consumes water at a rate of 36.7 L/kg.H2, 14% more than green hydrogen [28].

This model adopts the position that pure water and cooling water will be provided by desalination, avoiding pressure on the local water sources. The Industrial Cluster of Milford Haven is situated close to the sea, facilitating desalination intake and effluent discharge.

There are several desalination technologies, however they fall into two categories, thermal which is a distillation and evaporation process, or membrane technology that exploits osmotic pressure. The leading desalination technology is Reverse Osmosis (RO), and is the technology applied herein. RO has a purified water to brine ratio (recovery rate) of 35-50% operating at 5.4 – 8 MPa [40]; resulting in a pressurized water stream and a concentrated brine. RO technology is suitable for coupling with renewable power generation because it requires only an electrical power input, is low Capex, and is reactive to variable power. The desalination system requires both a seawater suction and effluent disposal pipelines. Brine is toxic to the marine environment, and requires dilution and distributed dispersal [41].

5) Industrial cluster hydrogen and power demand

The case-study assumes a continual hydrogen gas and power demand from an industrial cluster, based upon the needs of the Milford Haven oil refinery, with a throughput of 270,000 barrels/day [42]. Hydrogen demand is assessed on a requirement of 17.4 $Nm^3.H_2$/barrel (1.46 $kg.H_2$/barrel), equivalent to 16,434 $kg.H_2$/h [43]. For context, this would require a continual power consumption by an electrolyser system of 0.9 GW, equivalent to 3% of UK electricity consumption in 2020 [44].

Continual electrical power consumption is estimated at 1.12 GW, equivalent to 99.1 kWhe/barrel. This figure was derived from an assessment of the range of fuels used by a refinery including power, natural gas, steam and petroleum coke; reported by the US Energy Information Administration (US-EIA) [45], and converted to power by applying US-EIA quoted conversion factors [46]. Modelling is predicated on preferential use of power before electrolysis, due to conversion losses associated with a 30% round-trip efficiency of power to hydrogen to power [14].

These two demands; power and hydrogen gas, emphasize the energy consumption of large industrial activity. The modelling presented in this paper investigates the use of marine resources coupled with green hydrogen to meet an uninterrupted demand. For context the UK has six oil refineries, and several fertilizer plants, offering a significant market for green hydrogen to supplant grey.

6) Hydrogen storage

Storage of a large quantity of energy as compressed hydrogen is challenged by hydrogen's low volumetric energy density. Storage of 0.1-1 $GWh.H_2$ as compressed gas requires additional high-pressure compression and large storage pressure vessels, with dimensions of 3m diameter and 25-250m length operating at 35.0 MPa. Such a system would be expensive, require rigorous inspection and maintenance, and present a significant safety risk, and only provide back up for a short period of hours to days. The alternative is geological storage permitting 10-100's $GWh.H_2$.

Salt caverns have been successfully used to store hydrogen in both the UK and USA, with volumes ranging from 70,000 to 580,000 m^3 and operating pressures up to 15.2 MPa [47]. The UK salt caverns are formed in older Permian epoch halite deposits. The UK has extensive salt deposit resource, including younger Triassic deposits beneath the Celtic Sea. The UK halite resource has a theoretical capacity to store 2,150 $TWh.H_2$ [47], far exceeding the CCC prediction of UK annual hydrogen consumption [4].

This model presumes the Celtic Sea's younger Triassic halite is suitable for hydrogen storage and for operation in both injection and withdrawal on short time frames. The UK North Sea and Southern North Sea have been extensively mapped from oil and gas exploration, as a result the geology of the Permian salt deposits is better understood. In contrast the Celtic Sea has been sparsely drilled, without identifying commercial petroleum reserves, hence there are no detailed maps of the Triassic halite [48].

The BGS report borehole 93/6-1 indicates a halite thickness of 1,735′, with an overburden of 3,682′ from the water surface [49]. Salt caverns characteristically operate at a pressure range of 24–80% of the lithostatic pressure, typically 22.5 MPa/km, giving an operating range of 6.1-20.2 MPa, the lower pressure is referred to as cushion gas. Operation below this pressure risks the structural integrity of the store. Allsop [50] reviewed salt cavern potential for hydrogen in the Southern North Sea and applied a cavern dimension of 300m height and volume 750,000 m^3, similar dimensions have been applied here. Each salt cavern has the potential useable capacity of 0.27 $TWh.H_2$ based upon Higher Heating Value (HHV) and cavern temperature of 55 ˚C.

The case-study draws on oil and gas experience and technology, assuming a storage platform from which wells can be drilled and the salt caverns leached [51], with well-heads retained within the platform. Storage volume was determined via an iterative approach, with both volume and starting inventory increased incrementally until an optimum solution was determined that prevented inventory falling below cushion gas, which would cause an interruption to both continuous hydrogen gas and power.

7) Compression

The UK is actively developing a national hydrogen transmission pipeline system, called "Project Union", comprising re-purposed gas transmission pipelines and new pipelines. The current natural gas system operates at up to 9 MPa. [52]. The model assumes a two-step compression process, with step 1 raising the pressure from 3 MPa to 10 MPa, allowing for friction losses. This would allow a future connection with Project Union, for hydrogen export / import. Step 2 lifts the pressure to a maximum storage pressure of 20.2 MPa.

Hydrogen's low molecular weight results in increased energy for compression compared to natural gas, requiring a compressor energy consumption of 10 times for an equivalent mass flow-rate and 3.9 times for energy content [53]. This additional compression, and most current hydrogen production derived from natural gas, explains the status quo whereby natural gas is compressed and transported via pipeline and processed to hydrogen (and CO_2) in-situ close to the demand. Hydrogen's low molecular weight makes centrifugal compressors a poor choice due to the excessive number of stages required. Reciprocating compressors are typically used for hydrogen service [54].

Storage compressors are sized based upon the peak mass flow rate. The FLOW case was determined to be 7.1 kg.H_2/s and for tidal is 33.6 kg.H_2/s.

Compressor power (MW) per stage can be calculated from Eq (1) [55].

$$P_{Comp} = Q.\frac{RTZ}{\eta_{com} M_H}\frac{N\gamma}{\gamma - 1}\left[\left(\frac{P_O}{P_i}\right)^{\frac{\gamma-1}{N\gamma}} - 1\right] \quad (1)$$

The number of stages (N) can be derived from Eq(2) [56]

$$N = \left(\frac{Log_{10} P_O - Log_{10} P_i}{Log_{10} . PR_{stage}}\right) \quad (2)$$

Table I lists the input conditions for both step 1 and step 2 compression, the inputs for Eq 1 & 2.

TABLE I
Input values for equations 1 and 2

Symbol	Description	Value	Units	Reference / Note
Q_{FLOW}	Mass flowrate	7.1	kg.H_2/s	Model result
Q_{Tidal}	Mass flowrate	33.6	kg.H_2/s	Model result
R	Ideal gas constant	8.314	J/mol.K	
T	Temperature	310	˚K	
Z	Compressibility factor	1.1		[57]
η_{comp}	Compressor efficiency	75	%	
M_H	Molecular mass	2.02	g/mol	
γ	Isentropic coefficient	1.41		
PR_{stage}	Stage Pressure Ratio	2.1		[58]
Step 1 - From electrolyser outlet pressure to pipeline export pressure (Project Union)				
Po	Outlet pressure	10	MPa	
Pi	Inlet pressure	3.0	MPa	
Step 2 – From export pressure to maximum storage pressure				
Po	Outlet pressure	20.2	MPa	Max. salt cavern pressure
Pi	Inlet pressure	10.0	MPa	Pipeline pressure

8) Hydrogen gas turbine generator

When the renewable resource is insufficient to meet the continuous power demand, hydrogen is withdrawn from storage and consumed as fuel within a HGTG. Hydrogen turbines are under development by several manufacturers, including GE and Siemens. Fuel efficiency has been modelled as 49% [59]. Capex and Opex costs have been taken from UK Government estimates for combined cycle gas turbine (CCGT) power stations [60].

9) Hydrogen pipeline

Several studies have been undertaken for proposed hydrogen pipelines. Table II summarises several projects. The model uses an average unit rate of 3.40 £M/km.

TABLE II
Summary of existing and proposed hydrogen pipeline projects.

Project Name	**Pipeline km**	**£M.2023/km**	**Ref.**
Statista Av. for subsea H_2 pipelines in 2021		5.26	[61]
NZTTP H_2 Backbone Scotland to Europe	~1,400	1.99	[62]
Barcelona-Marseille	455	4.84	[63]
Gulf of Mexico – (oil and gas)		2.13	[64]
DNV Power to Hydrogen Ijmuiden Ver	110	2.81	[65]

B. System performance

This section sets out how energy production, losses, hydrogen generation and aggregate annual production are estimated in the energy system model. Included is hydrogen directed to storage and withdrawn to ensure continuous demand for both hydrogen gas and power is met. There are two discrete steps, first the LCoE is calculated, then the LCoH, with LCoE acting as an input to the LCoH.

1) Energy production

This section reviews energy generation and losses.

The FLOW power produced by the WTG's follows the classic wind energy equation Eq (3) with units of Watts [66].

$$Pe = 0.5\rho A C_v u^3 \quad (3)$$

Energy produced per hour (MWh) from each WTG is given by Eq (4).

$$Pe(t) = \begin{cases} 0, & u < u_c \\ Pe & u_c \leq u \leq u_r \\ Per, & u_r \leq u \leq u_f \\ 0, & u \geq uf \end{cases} \tag{4}$$

u	Av. windspeed per hour	m/s
uc	Cut-in wind-speed	m/s
ur	Rated wind-speed	m/s
uf	Cut-out wind-speed	m/s
t	Time period – one hour	h
Pe	WTG energy at u & time t	MWh
Per	WTG rated energy	15.0 MWh

Power at windspeed u was linearly interpolated from the NREL-IEA provided windspeed – power curve and supporting data table [30].

2) Power losses

Energy available for the industrial cluster and the electrolyser system is the generated power from the renewable generator, less system energy losses. For the FLOW case, power generated by the WTGs is subject to losses throughout the system. These losses include, wake effects, downtime for maintenance, and energy losses in the HV array cables, OSS switchgear and transformers, HV export cables, and switchgear and transformers onshore. Table III lists the system losses. The percentages apply sequentially. The tidal case applies only the Operations and Maintenance and HV export cable losses.

TABLE III
Power losses throughout the system
(*) Losses applied to the Tidal case

Component	Symbol	Losses %	Comment / Reference
Wake-effects	PL_{wake}	5	[67]
Operations & Maintenance*	PL_{ops_main}	10	[68]
Array-cables	PL_{array}	5	
OSS	PL_{OSS}	0.01	
HV export cable*	$PL_{exportHV}$	0.02	[69]

Models exclude baseloads, for example lights, heating, communications, and operational loads, including compressors. These loads are small relative to the capacity of the facility and are omitted for expediency.

3) Hydrogen production

Generated power, after system losses (Tab. 3), is preferentially directed to the industrial cluster. The balance is routed to the electrolyser system, which includes desalination. Variable nature of renewables leads to changeable hydrogen volumes, given by Eq (5) (kg.H_2/h).

$$H(t) = \frac{Pe(t) - CP}{Eff_{desal} + Eff_{electrolyser}} \tag{5}$$

CP	Continuous Power	1.12 GWe
Eff_{desal}	Efficiency – desalination	kW/kg.H_2
$Eff_{electrolysers}$	Efficiency – electrolyser	kW/kg.H_2

2.2.3 LCoE and LCoH cost inputs

The LCoE (£/MWe) is presented in Eq (6) [70].

$$LCoE = \sum_{T=-4}^{N} (I_T + M_T) + (1+r)^T \ / \ \sum_{T=-4}^{N} Pe_T \ / \ (1+r)^T \tag{6}$$

N	Project Lifetime, of 30 years, includes Devex (1 yr), Capex (3 yrs) and Decex (1 yr).
T	Years of Operation, of 25 years
I_T	Annual Investment (includes Devex and Capex), £/T(yr)
M_T	Annual Expenditure (includes Opex & Decex), £/T(yr)
r	Discount Rate, %

The LCoE is ring-fenced around the production facility, HVAC power transmission, and onshore switchgear, costs for which are inputs to the LCoE. Similarly, the LCoH is boxed around all the other facilities. Power consumed by the electrolyser is taken as an Opex input in the LCoH calculation.

The LCoH calculation (£/kg.H_2) substitutes annual energy production for annual mass of hydrogen produced, and is given by Eq(7).

$$LCoH = \sum_{T=-4}^{N} (I_T + M_T) + (1+r)^T \ / \ \sum_{T=-4}^{N} H_T \ / \ (1+r)^T \tag{7}$$

H_T Annual H_2 production in year T kg.H_2/T(yr)

4) Inflation

Both LCoE and LCoH (Eq 6 & 7) incorporate inflation throughout the project lifetime (T). An inflation rate of 2.3%, a median value for UK inflation from 1998 to 2028, was applied to Opex [71]. Capex spend occurs at the front end of the project and is less influenced by inflation.

5) Development expenditure – Devex (Dev)

The development of a project includes all activities required to reach Financial Investment Decision (FID). This includes sea-bed leasing, Environmental Impact Assessment, and sufficient design works to be granted approval to construct [72]. FID is a project milestone, after which the Capex expenditure commences, typically funded through project finance or similar instruments.

For the FLOW case, Devex was drawn from BVG Associates (BVGA) cost estimate for a 500 MW FLOW [73], a 50% reduction factor was applied because TCE has released the Habit Regulation Assessment [74] and the 9 x FLOWs are similar to one another.

For the tidal case, data for both the Devex and Decex is scarce. The model applied the methodology followed by BVG Associates method of using 2.5% of the Capex and Opex[74]. The lagoon Capex was excluded as it would have skewed the value due to being significantly higher than the other components.

6) Capital expenditure – Capex

Capex covers engineering, procurement, fabrication, installation, and commissioning (EPIC), and typically comprises the majority of project financing. The model assumes Capex is spent over three years [75], following an S-curve pattern of 15%, 50% and 35% per sequential year, with procurement and construction taking the greater part [76]. FLOW Capex estimates were based on the BVGA report, closely aligned with Celtic Sea conditions. Cost components include the WTG (tower, nacelle, blades), semi-substructure, mooring (chains and anchors), array cables, OSS (topside, jacket, piles), installation, and HVAC export cable. Onshore Capex covers the electrolyser system (switchgear, transformers, alkaline stacks, BoP, desalination), two-stage compression, offshore pipeline, storage platform, and HGTG. Electrolyser costs came from the ISPT GW-scale hydrogen report [33], compression from Ariel Corp. (USA), and storage platform from BVGA [73] and DNV [65].

Tidal Capex was based on the Hendry report [11], using figures from the proposed “Bridgewater” project. Costs were normalised to £/MW and adjusted to 2023 values. Devex and Decex were included, and Opex assumed at 1% of Capex annually.

7) Decommissioning expenditure (Decex)

At the end of the operational life all the installed facilities are required to be decommissioned, removed, and recycled. Full decommissioning is assumed to be completed within one project year. FLOW Decex was derived from BVG Associates [73]. Decex for the electrolyser system applied a 2.5% factor to the project Capex and 25 years Opex [74].

8) Project lifetime / operational lifetime

LCoE & LCoH are time weighted and are based upon the project phases and durations. The total project lifetime (N) is 30 years, 1 year to develop (Devex), 3 years EPIC, 25 years in operational service (Opex) (T) and 1 year to decommission (Decex). The operating lifetime of a tidal lagoon could be as long as 120 years [11].-The classic LCoE evaluation technique disadvantages long lived assets. Refer to section IV.E Further research, which the tidal case deserves.

9) Discount rate

DR has a significant impact upon LCoE and LCoH. Increasing DR reduces the cost fraction of the energy consumed in the LCoH. Very high DR favours low Capex, at the expense of high fuel costs [77]. An increase in DR partially explains the absence of offshore wind awards in UK Contract for Difference (CfD) Auction Round 5 (AR5) [78]. Subsequently the UK has increased the Administrative Strike Prices (ASP) values for CfD AR6 [79]. For a new technology, lending banks and investors typically view as high risk, with projects subject to high interest rates to offset that risk. This was the case for OSW. With capacity build-out and UK government CfD, risk softened, resulting in a lower DR, a drop in CfD award (strike price) and reduced LCoE [80]. A similar trajectory is forecasted for LCoH arising from CfDs [81]. ORE Catapult estimate reduction in DR to be responsible for ~50% of the decrease in OSW LCoE between 2016 and 2021 [82]. The model adopts a standard DR of 6%, a lending rate predicted once the technology matures. IRENA anticipate a reduction from 10% to 6% [36] and ORE Catapult applied a DR of 8% to their offshore hydrogen model, with a prediction of 5.5% by 2029 and 4.2% by 2033, for 500 MW projects [83] [84].

10) Sensitivity analysis

Sensitivity analysis was conducted for Discount Rate and electrolyser system energy consumption. ORE Catapult highlight the importance of a falling Discount Rate to the reductions in LCoE seen in the UK offshore wind sector. Analysis by Glenk et al conclude the cost of power is 70 -90% of the LCoH. [85]. Improvements in electrolyser stack efficiency will have a direct reduction in LCoH. Sensitivity analysis was conducted to test the model and determine the importance of these two factors, Table IV lists the predicted ranges applied.

Learning Rates are important to future cost reductions. Section IV.E Further Research identifies this would be a merit-worthy subject to explore.

TABLE IV

Variables assessed for sensitivity runs with analysis range

Variable	Symbol	Unit	Range	Ref.
DR	r	%	4-10	[36]
Electrolyser efficiency	$Eff_{electrolyser}$	kWh/kg.H2	47-52	[86]

11) Model inputs

Tables V and VI list the model component cost inputs, which have been drawn from many sources, and quote costs for differing years and currencies. These have been adjusted for inflation and currency conversion and are quoted in 2023 UK £ sterling. Real values are identified, and were not subjected to inflation [87]. Table V lists FLOW costs and common inputs for both models, Table VI lists tidal lagoon inputs only.

Table V FLOW Model inputs

Description	Value	Units	Ref.
WTG rated power	15	MW	[30]
WTG cut-in wind speed	3	m/s	
WTG rated wind speed	10.6	m/s	
WTG cut out wind speed (aka furling)	25	m/s	
Discount Rate	6	%	

Operating years of the plant	25	yrs	
Project lifetime	30	yrs	
Inflation rate	2.3	%/yr	
WTGs per 510MW	34	Qty	
510MW FLOW-OSS	9	Qty	(*)
FLOW Electrolyser capacity	2,181	MW	(*)
Desalination efficiency	0.046	kWhe/kg. H_2	[88]
Electrolyser water consumption	32.2	l/kg.H2	[28]
Electrolyser efficiency	0.052	MWhe/kg. H_{22}	[86]
H_2 fired gas turbine	49	%	[60]
Storage cushion gas pressure.	6.1	MPa	[47]
Storage max. operating pressure	20.2	MPa	
Devex:			
FLOW Devex	371.79	£M	[73] Real
H_2 system Devex	166.83	£M	[73] Real
Capex:			
WTGs	6,444.36	£M	[73]
Balance of Plant	8,427.24	£M	
Installation and commissioning	1,834.16	£M	
Electrolyser system	2,768.47	£M	[33]
Export comp.	5.22	£M	
Storage comp.	28.01	£M	
Desalination system	41.17	£M	[89]
Storage platform Topside	38.556	£M	[73]
Jacket	14.872	£M	
Installation	13.219	£M	
Drilling, casing and wellheads	218.19	£M	[90, 91]
Auxiliary systems	4.131	£M	
Pipeline	238.323	£M	
H_2 gas turbine generator	795.83	£M	[60]
Opex:			
FLOW	351.961	£M	[73] Real
Stack replacement	22.84	£M	[17]
Electrolyser system	32.25	£M	[92]
Export and storage comp.	0.66	£M	[93]
Desalination	5.65	£M	[89]
H_2 gas turbine generator	26.02	£M	[60]
Pipeline	6.2	£M	[94]
Decex:			
FLOW Decex	843.58	£M	[73] Real
H_2 system Decex	158.79	£M	[73] Real

(*) value determined by the Matlab modelling.

Table VI Tidal Lagoon Model inputs

Description	**Value**	**Units**	**Ref.**
Lagoon installed Capacity	16,000	MW	(*)
Electrolyser Capacity	7,160	MW	(*)
Devex:			
Devex Lagoon	413.9	£M	[73] Real
Capex:			
Capex_Lagoon	62,181.1	£M	[11]
Electrolyser system	9,088.62	£M	[33]
Export comp.	15.96	£M	
Storage comp.	129.6	£M	
Desalination	135.16	£M	[89]
Opex:			
Tidal Lagoon	621.8	£M	
Stack replacement	74.97	£M	[17]
Electrolyser system	105.88	£M	[92]
Export and storage comp.	2.911	£M	[93]
Desalination	2.592	£M	[89]
Decex:			
Decex_Lagoon	413.9	£M	[73] Real

(*) value determined by the Matlab modelling

III. RESULTS

Table VI summarizes model outputs from both FLOW and tidal cases with DR of 6% and an electrolyser efficiency of 0.052 MWh/kg.H_2. The FLOW base case model returned an LCoE of 83.94 £/MWh, and LCoH of 6.60 £/kg.H_2. This LCoH falls within the ranges of previous estimates including the UK Government estimate of £4.73 /kg.H_2 [17], Pagani et at £4.40 /kg.H_2 [95], Lazards £4.45 /kg.H_2 [96], and the UK government's first Hydrogen Allocation Round (HAR1) at £9.49 /kg.H_2 [97]. The model uses FLOW, which is higher Capex driving up the LCoH, compared to the UK government, Pagani, and Lazards. This model also incorporates Long Duration Energy Storage in salt caverns and power peaking using a HGTG adding a sizeable extra Capex, pushing up LCoH. The HAR1 awards are small scale circa 10MW projects for specific industrial application, and are fully profited, and likely applying a higher Discount Rate. The model's LCoH is contextualised due to higher Capex of FLOW and the additional infrastructure included.

Table VI Comparison between FLOW and Tidal

Description	**Unit**	**FLOW**	**Tidal**	**Delta**
Generation capacity	GW	4.59	16.0	349%
Energy generation CF	%	65.7(*)	22.2	296%
Electrolyser capacity	MW	2181	7160	328%
Electrolyser CF	%	64.7 – 51.6	30.9	209 – 169%
Total energy production – 25 years	TWh	525,190	777,280	48%
Total energy exported over 25 yrs	TWh	33.3	68.6	205%
Salt cavern storage	Qty	17	2	-12%
Storage volume range	TWh	4.25	0.44	-10.3%
LCoE	£/MWh	83.94	209.6	250%
LCoH	£/MWh	6.64	14.07	219%

(*) average over 25 yrs

By contrast, the tidal lagoon model returned an LCoE = £/209.60 MWh, and LCoH = £14.07 /kg.H_2, greater than the FLOW case.

The installed capacity of the tidal lagoon and electrolyser system are 349% and 328% greater than the FLOW system respectively. This can partly be explained by the annual power generation Capacity Factors (CF) of 65.7% for FLOW and 22.2% for tidal, before power losses. The installed unit rate for both generating technologies is similar, however, due to the low CF the tidal lagoon requires a greater installed capacity for the same annual electricity production. A larger electrolyser system and compression train is necessary to generate and store hydrogen to meet the continuous demands. The tidal case also results in additional power being exported. These factors drive up the Capex, and subsequent LCoE and LCoH, alongside the assumptions regarding project life.

Model sensitivity runs that consider the influence of DR and electrolyser efficiency are discussed and presented in Section III (Fig. 10 and 11).

Applying an average carbon footprint for grey hydrogen of 11.5 te.CO_2/te.H_2 [98], switching grey hydrogen for green for this case study would save 1.66 Mte.CO_2/yr in both cases, since they both provide a continuous hydrogen supply.

A. Power generation and distribution

Fig. 2 and 3 shows the energy generated by FLOW and tidal, and its distribution, either direct to the Industrial Cluster, the electrolyser system, or exported. Note Fig. 2 FLOW has data-points aggregated bi-weekly and Fig. 3 for tidal is aggregated daily. Both are snap shots from the 25-year datasets. The rationale being that the variability and seasonality for FLOW is only revealed over a long time frame, three years shown, whereas the cyclical pattern of tidal can be represented clearly over 3 months.

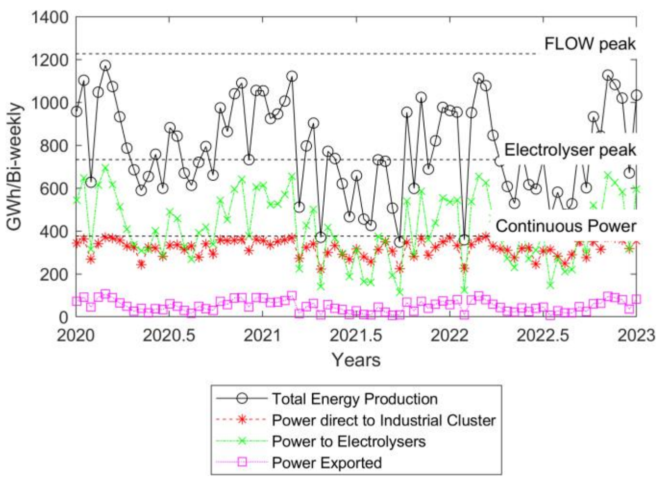

Figure. 2 FLOW - Energy production aggregated bi-weekly. Total energy production, energy routed preferentially to the industrial cluster, directed to the electrolyser system, and exported. Data presented over a period of three years.

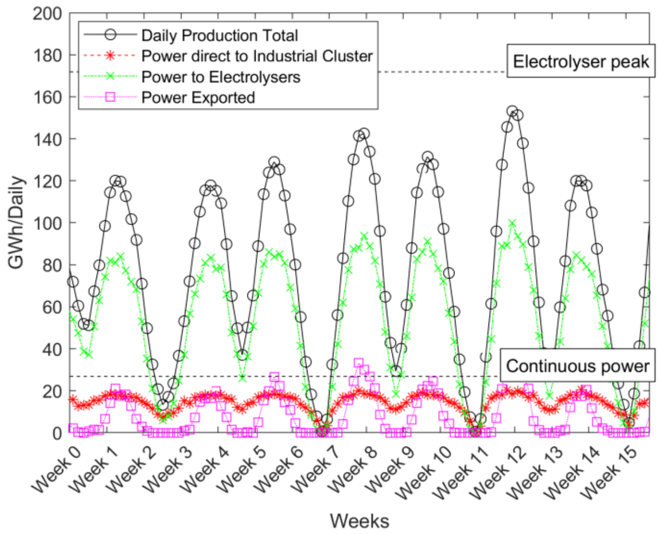

Figure. 3 Tidal - Energy production aggregated daily periods. Data presented over a period of three months.

Fig. 2 reflects the variable nature of windspeeds from season to season and year to year, whereas Fig. 3 highlights a positive attribute of tidal, its cyclicity and predictability. The lower capacity factor of the tidal system is reflected in "Daily Production Total", being significantly below the name-plate generating capacity of 16GW (384GWh/day). Whereas, for the FLOW case there are several bi-weekly periods of strong winds, with energy production approaching maximum (Fig. 2 "FLOW peak").

B. Hydrogen production and distribution

Fig. 4 and 5 demonstrate how the models ensure a continuous supply of 16.4 t.H_2/hr hydrogen gas, either directly from the electrolyser system, or withdrawn from storage, or a combination. Both are snapshots of hourly production and storage withdrawal. Note, hydrogen routed to storage infers the industrial cluster hydrogen gas demand has been met.

For FLOW, Fig. 4 shows that falling windspeed reduces power available to the electrolyser system, causing hydrogen production to drop, and hydrogen directed to storage reduces, until insufficient hydrogen is generated to meet the base hydrogen demand. At this point hydrogen is withdrawn from storage to top-up the continuous hydrogen supply. If the windspeed falls further the FLOW power generation is less than the industrial cluster continuous demand, and additional hydrogen is withdrawn to provide fuel to the HGTG. When windspeed $u_c > u > u_f$ power generation ceases, and both hydrogen and power demand are met fully via hydrogen withdrawn from storage. At FLOW rated capacity the electrolyser system operates at peak capacity, generating 41,900 kg.H_2/h, of which 16,434 kg.H2/h is directed to the industrial cluster. When windspeed $u_c > u > u_f$ the industrial cluster power demand is entirely met with HGTG generation. Peak fuel withdrawal is 58,013 kg.H_2/h, at HHV and gas turbine efficiency of 49%. Combined peak withdrawal is 74,447 kg.H_2/h.

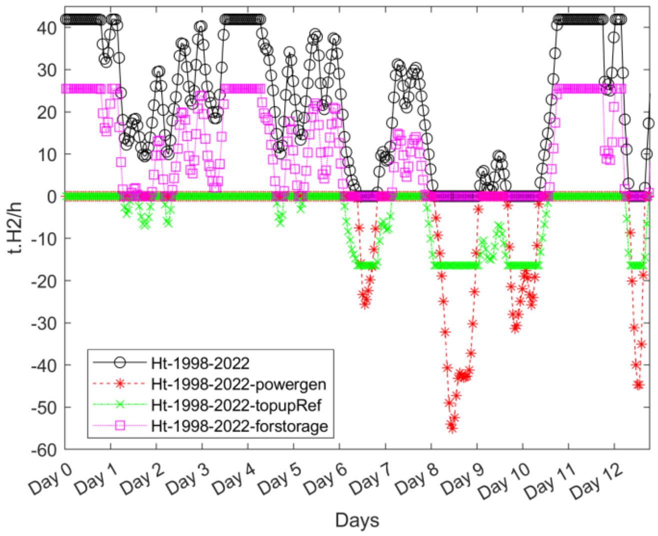

Fig. 4 FLOW – Total hydrogen production, directed to storage, and withdrawn from storage for both hydrogen gas demand top-up and fuel for power generation, hourly basis (snapshot). Hourly data presented over 12 days.

The tidal case Fig. 5 shows the four daily power generation periods exhibited in the tidal case. This results in hydrogen withdrawal for hydrogen gas top up and HGTG fuel on every generation-idle cycle. The idle periods reflect gas withdrawal rates to support 100% of the continuous hydrogen gas demand and HGTG fuel to meet the power demand, with peak withdrawal of 74,447 kg.H2/h. This would require the HGTG to start and reach full capacity every six hours.

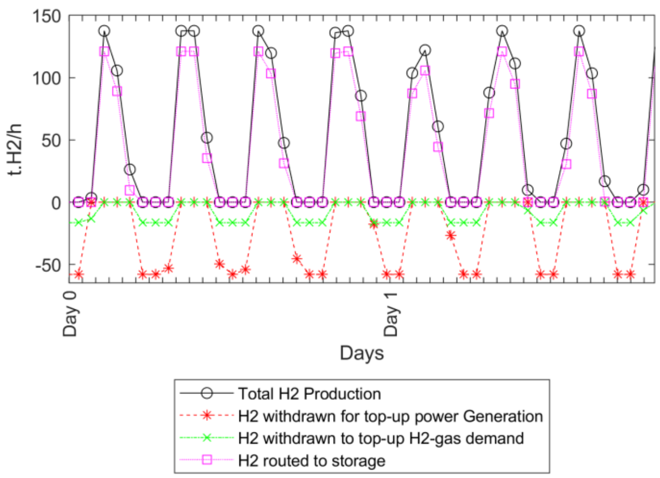

Figure 5 Tidal Lagoon (snapshot). Hourly data presented over two days.

C. Power demand

Fig. 6 and 7 show how the continuous power supply of 1.12 GWe is achieved. This consists of generated power routed preferentially from FLOW directly, with top-up power generated using hydrogen fuel for the HGTG.

For the FLOW case Fig. 6, as the windspeed falls below the level at which FLOW generation meets the full demand, hydrogen is withdrawn from storage and used as fuel. The hour-by-hour variability of the windspeeds is revealed. For the tidal case Fig. 7 the periodic six hourly cycle of generation and idle is clearly shown, with the idle period requiring the storage system to provide the full hydrogen gas demand and HGTG fuel.

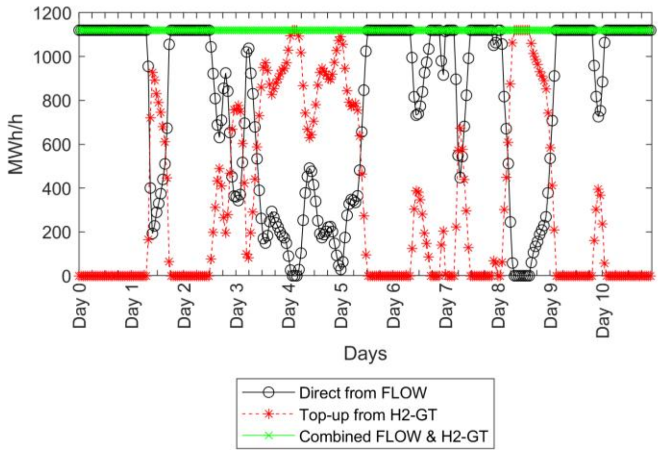

Figure 6 FLOW - Power directed to the Industrial Cluster, consisting of FLOW generation and HGTG generation when top-up is required. Hourly data, over a period of 11 days.

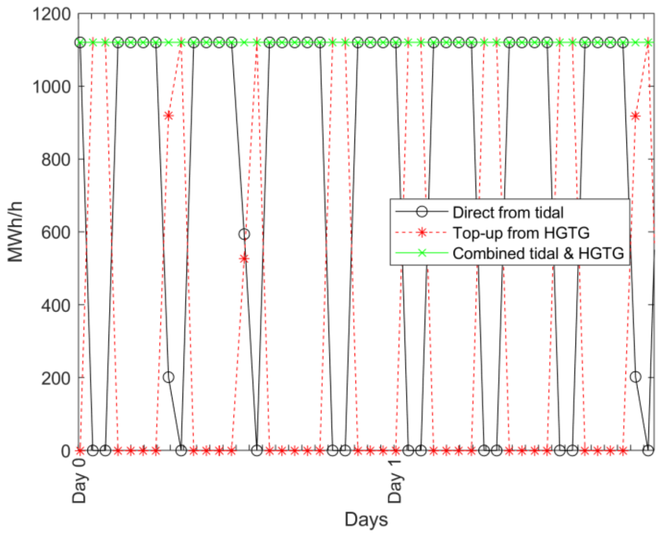

Figure 7 Tidal - Hourly data, two days.

Fig. 7 highlights that top-up power is required on every six-hour generation cycle. The current model adopts the position that hydrogen storage and a HGTG provide this power. Provision of GW power for one or two hours is at the outer boundary of chemical batteries [99], however their potential application for this scenario merits additional research.

D. Storage

Fig. 8 and 9 show the temporal variation in stored hydrogen inventory within the salt cavern stores. The FLOW case Fig. 8 is shown over the 25 years' operating lifetime, and assumes operations commence with the stores at cushion gas pressure. The Y-axis units are 1,000's of tonnes of hydrogen kt.H_2. Fig. 8 indicates a seasonal windspeed pattern between winter and summer. Of note are two pronounced poor wind year periods, between 2009-11 and 2020-22. The 2009-11 is highlighted in the Royal Society hydrogen storage requirements analysis [18], and poor wind years between 2020-22 (inclusive) are noted in TCE annual wind report [100].

The tidal case Fig. 9 is a four-year snapshot. The rhythmic six-monthly equinox cycles (peak to peak) are clearly seen, and the hydrogen inventory year on year remains constant. For this case the store was assumed to be 50% full, between cushion gas and maximum operating pressure, at the commencement of operations. Initial inventory depends upon the commencement of operations within the equinox cycle. Assuming a 50% initial inventory minimised the number of salt caverns.

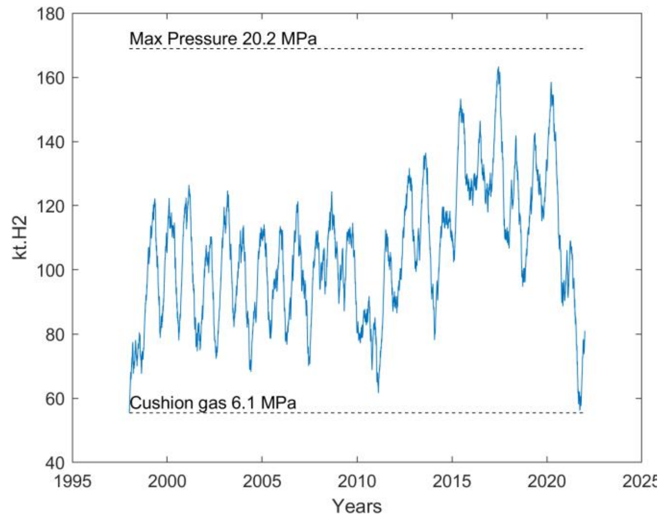

Figure 8 FLOW - Hydrogen inventory over 25 years.

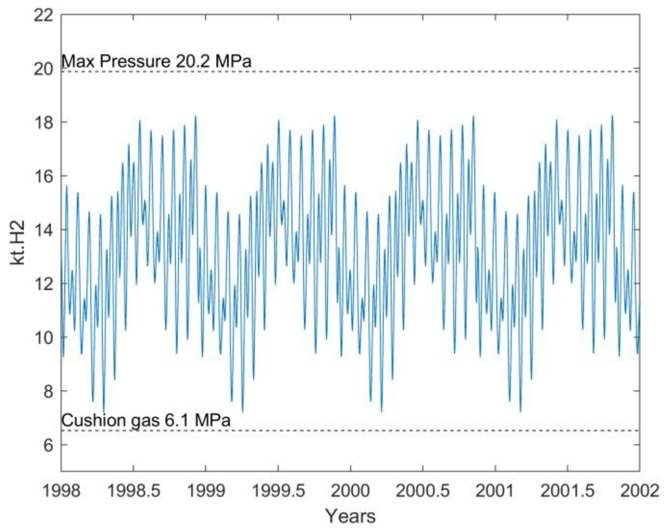

Figure 9 Tidal - Hydrogen inventory over 4 years.

3.5 LCoH sensitivities

Fig. 10 and 11 are the results of the two LCoH sensitivities for the FLOW and tidal cases, with ranges per the Table IV, with variable Discount Rate on the upper image and the electrolyser system efficiency on the lower.

The DR range holds the electrolyser efficiency constant at 52 kWh/kg.H_2 and gives an LCoH ranging between £5.20 - 9.48 /kg.H_2, with a variance from the base DR at 6% -21 to +44%. The electrolyser efficiency range holds the DR constant at 6% and varying the electrolyser efficiency from 52-47 kWh/kg.H_2 results in an LCoH ranging between £6.60 - 6.01 /kg.H_2, a change of up to - 9%.

The tidal case (Fig. 11) shows a DR LCoH range of £10.67 - 21.04 /kg.H_2, a range of -24 to +50% around the DR at 6% base-case. The electrolyser efficiency sensitivity results in a range of £12.72 - 14.07 /kg.H_2.

The implications of the LCoH sensitivities are discussed further in Section IV.

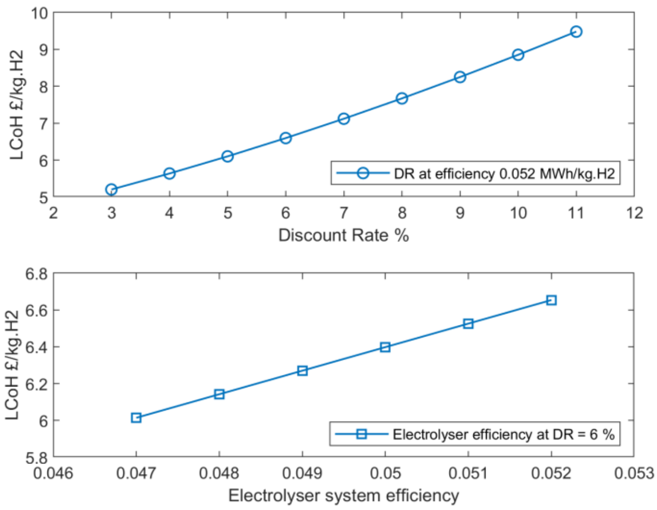

Figure 10 FLOW - Sensitivity analysis of LCoH to DR (3-11%) and electrolyser efficiency (0.052-0.047 MWh/kg.H_2)

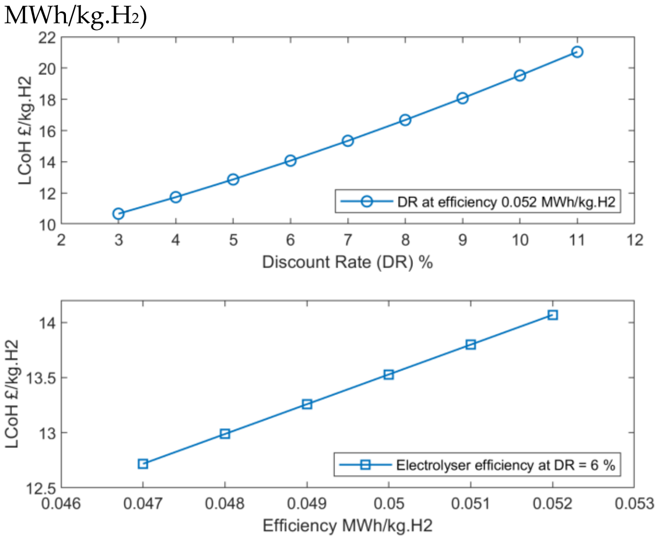

Figure 11 Tidal - Sensitivity analysis

IV. DISCUSSION

A. *Power generation and distribution*

The FLOW case in Fig. 2 emphasises the variable nature of the wind resource. FLOW generation occasionally approaches a Capacity Factor of 100% over the two-week data resolution. Power generation is routed preferentially to the Industrial Cluster, which is reflected in the close match between the continuous demand and the preferentially directed power tracking closely to the demand line (red data points). The balance is routed to the electrolyser system (green data points), these show much more variability, which is to be expected. This results in an electrolyser annual CF ranging between 52 - 65%. In contrast, in the tidal case, the CF of the accompanying electrolyser system is just 30.9% annually, because of tidal's lower capacity factor.

B. Hydrogen and power demand balancing

Both models ensure the continuous electrical and hydrogen demands are met. The FLOW case Fig. 4 and 6 highlight the variability of wind, whereas the tidal case Fig. 5 and 7 emphasises the predictable cyclical ebb and flow of the daily tides. The FLOW case requires the HGTG to load follow the variable generation. The tidal case must also follow the generation, with the difference being the HGTG must reach full capacity on every six hour cycle. The models assume the CCGT can meet these demands, further investigation is warranted to confirm.

C. Storage

The FLOW case Fig. 8 requires a hydrogen storage volume equivalent to 17 salt caverns. Peak energy inventory is circa 4 TWh.H_2, in line with the Royal Society estimate of national hydrogen storage needs (60-100 TWh.H_2) [18]. The CCC Sixth Carbon budget suggests that large-scale hydrogen storage is not required, however, this assumes a nationally connected system, whereas this model stands alone and must weather the seasonality of windspeeds [4]. The two poor wind speed periods highlight the need for modelling over decades to determine storage capacity for both resilience and security.

The tidal case Fig. 9 needs only 2 salt caverns. Each six hour cycle requires a withdrawal of hydrogen, of circa 250 te.H_2 (10 GWh), which varies with the equinox-springs-neaps cycle. The total storage volume is dictated by the equinox-springs-neaps cycle. The predictability and regularity of tidal range power greatly reduces the need for storage.

D. LCoH sensitivities

The base-case LCoH, of £6.64 /kg.H_2 for FLOW and £14.07 /kg.H_2 for tidal is expensive relative to grey and blue hydrogen, with costs of £1.66 and 2.42 /kg.H_2 respectively [101]. Both the IEA and Capgemini attribute the high cost of green hydrogen as hampering its deployment, with only 4% of global green hydrogen projects having reached FID [2] [102].

Considering the impact to the domestic consumer of liquid petroleum (petrol and diesel), the cost of green hydrogen of 1.46 kg.H_2/barrel [43] translates to an additional cost of 0.06 – 0.13 £/L, FLOW to tidal. Assuming green hydrogen replaces the existing grey hydrogen, allowing a cost saving, the additional cost of switching green hydrogen translates to an additional cost of 0.04 - 0.12 £/L at the gasoline pump, a modest increase of 3 - 8%. This is a simplification of the refining process, but it serves to demonstrate that "expensive" green hydrogen in certain circumstances has only a modest impact.

E. Further research

Further study is justified to examine the effect upon LCoH by supplementing marine renewable generation with lower cost solar and onshore wind. In 2024 the UK government awarded contracts for £70.47 and £70.75 /MWh respectively [103]. Research suggests this could potentially improve electrolyser system capacity factors, and / or smaller capacity electrolyser systems, lowering LCoH. However, this could be at the expense of increasing curtailment and bottlenecking existing transmission lines.

Learning Rates (LR) are not explored herein, however capacity build-out for both FLOW and tidal would be expected to result in cost savings. Several studies conclude FLOW LCoE will fall with LRs [84]. Tidal lagoons are less well studied, with only two tidal barrier projects from which to compare. Hendry acknowledges Learning Rates could be expected to reduce costs with Capacity Build-out [11]. New research suggests that design and operation optimisation can reduce LCoE [104]. Tidal range LR merits further investigation.

Both models assumed hydrogen storage within salt caverns. Alternative hydrogen storage technologies exist, and investigation into their suitability might yield further cost optimisation. For the FLOW case, energy could be stored as Synthetic Natural Gas (CH_4) (SNG) [105], which requires a source of carbon. Direct Air Capture (DAC) is an option, however it is both energy intensive and costly [106]. SNG adds complexity and Capex but has the advantage of compatibility with current installed natural gas infrastructure. For comparison, the UK "Rough Field" natural gas storage has a capacity of 16.5 TWh (54 bcf) [107]. For the tidal case, which needs only 2 salt caverns, Liquid Organic Hydrogen Carriers (LOHC) offer as an alternative option if halite deposits are not available, albeit LOHC storage is less efficient [18]. Tidal storage range peak to trough is 0.44 TWh.H_2. LOHCs have a storage capacity of 47.4 - 57 kg.H_2/m^3 [108]. Assuming a 100,000 m^3 storage tank with dimensions 80m diameter and 19.5m working height [109], two tanks would suffice. Commercial scale LOHCs are yet to be constructed, however, the first demonstration project is under development [110].

Both models ensure uninterrupted electricity to the industrial cluster with a combination of power direct from the renewable generator and HGTG, which has a poor round-trip efficiency. The research would benefit from examining alternative technologies storage technologies, with better round trip efficiencies including Compressed Air Energy Storage, liquid air, and chemical batteries.

The models presented here take the stance that both hydrogen gas and power must be uninterrupted over 25 years, without importing grid power. Optimisation of the system design is needed to determine the extent of hydrogen and power shortfalls with smaller capacity generation and/or electrolyser systems.

Importing grid power to increase electrolyser system Capacity Factor should be investigated as it has the potential to balance the grid, reducing curtailment. The carbon intensity of the grid power must be considered on the final hydrogen product if it is to meet the UK low carbon hydrogen standard of 2.4 $kg.CO_2/kg.H_2$ [111], since using grid-power runs the risk of increasing fossil fuel generation to run the electrolyser system at a higher CF [98].

Both FLOW and tidal are compared over 25 years. It is acknowledged that in the tidal case, this is a simplification. Tidal has a potential to operate over longer time-spans of around 100 years, so comparison over 25 years puts tidal at a disadvantage. Estimation of LCoE/LCoH over representative operating period is necessary to provide a fairer economic comparison between the FLOW and tidal cases. Alternative LCoE techniques exist, notably the UK government enhanced LCoE which considers the value of flexibility and dispatchability[17].

V. Conclusions

The model presented here investigates how green hydrogen could depose grey and act as a TWh scale energy store whilst responding flexibly to a changing demand. Decarbonisation via electrification as opposed to adoption of green hydrogen is more energy efficient, due to conversion losses. Hence, the model prioritises preferential power consumption before electrolysis. This has the advantage of reducing the electrolyser capacity, which is a high Capex item.

The FLOW model returned an LCoH that sits within the ranges of other cost estimates, lending credibility. The tidal LCoH is more expensive, due to the higher installed capacity of the tidal generation and electrolyser system. The tidal case is sized at 16 GW installed capacity requiring a 575 km^2 surface area. This would appear to challenge practicality within the Bristol Channel / Seven Estuary. Conversely, the FLOW case meets the scale of the current The Crown Estate seabed leasing round.

DR singularly has the greatest effect upon LCoH. Bank lending rates are predicted to fall with capacity build-out and Governmental support, leading to DR and LCoH reduction. Cost of energy forms the greater part of the LCoH. Electrolyser efficiency improvements carry directly to reduction in LCoH but are more modest.

This model postulates operation almost exclusively in isolation from the grid, i.e. an island. This has the advantage of side-stepping the need for expensive transmission upgrades, maximises local consumption of renewable resource, and minimises curtailment.

The use case presented, with local power generation being consumed locally, has the advantage of minimising transmission upgrades, whilst reducing curtailment, as all the power is consumed directly by the industrial cluster, or turned into hydrogen. The UK has several oil refineries and fertiliser plants, offering the opportunity for several such GW scale offshore renewables to hydrogen projects to replace the current grey hydrogen.

Green hydrogen is comparatively expensive compared to grey or blue hydrogen, with cost identified as a major barrier to projects achieving FID. However, when viewed from the retail cost of gasoline the additional premium for green hydrogen is modest at 0.04 - 0.12 £/L, 2.7 – 8.0% assuming a retail price of £1.50 L, whilst reducing dependence on imported gas and improving energy security.

Tidal generating infrastructure is long-lived compared to FLOW. For this reason, further research is needed to investigate the effect upon LCoE/H when viewed from a longer perspective. The six hourly cyclical generation for tidal suggests a chemical battery system could be employed to provide the continuous power, rather than rely solely upon hydrogen storage and HGTG.

Acknowledgement

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