

An integrated spatio-temporal framework for offshore wind-powered green hydrogen supply, HGV freight demand, and dynamic pricing: A Portsmouth, UK case study

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ABSTRACT

This study presents an integrated spatio-temporal framework jointly characterising seasonal offshore wind-powered green hydrogen supply, HGV freight demand, and hydrogen refuelling station (HRS) system modelling for Portsmouth, UK, projected to 2050. Monthly Weibull wind speed distributions, validated against UK Met Mast observations ($r = 0.95$, $RMSE = 0.52$ m/s), are integrated with a full HRS system model. Results reveal a pronounced seasonal supply–demand mismatch: Winter and Autumn generate hydrogen surpluses of 27 and 4 tonnes respectively, while Spring and Summer produce deficits of 10 and 27 tonnes, driven by the inherent seasonal asymmetry of the offshore wind resource. The framework incorporates a three-state dynamic pricing mechanism yielding seasonal hydrogen prices ranging from £2.70/kg to £4.71/kg across three scenarios, with sensitivity analysis confirming electrolyser utilisation as the dominant pricing factor. The framework provides quantitative guidance for HRS developers, fleet operators, and policymakers advancing UK net-zero and Clean Power 2030 targets.

1. Introduction

The United Kingdom (UK) has established a legally binding commitment to achieve net-zero greenhouse gas emissions by 2050 under the amended Climate Change Act (2008) [1], with the UK Government's Hydrogen Strategy setting an ambitious goal of deploying 10 GW of low-carbon hydrogen production capacity by 2030 [2]. Hydrogen has been positioned at the core of the nation's decarbonisation strategy as a critical low-carbon energy vector for sectors otherwise difficult to electrify, including heavy goods transport, long-haul freight, and residential heating. Substantial public investment is being directed towards demonstration projects such as the Tees Valley Hydrogen Transport Hub and the H100 Fife project [3,4].

Road freight transportation forms a critical sector in this decarbonisation plan. In the UK, Heavy Goods Vehicles (HGVs) account for less than 2% of the total vehicle population [5] but contribute more than 20% of transport energy consumption and 16% of transport sector

emissions [6]. With diesel powering approximately 98.6% of the UK HGV fleet and the fleet size projected to increase by nearly 50% by 2050 [7], the imperative for clean fuel alternatives is clear. The UK Climate Change Committee (CCC) 6th Carbon Budget identifies hydrogen as a key energy carrier for decarbonising HGV freight [4,8]. Green hydrogen — produced through the electrolysis of desalinated water using electricity from renewable energy sources — offers a zero-emission alternative, characterised by high gravimetric energy density and shorter refuelling times relative to battery alternatives, making it particularly suitable for long-distance and high-load HGV applications [9].



Fig. 1 shows a schematic of the integrated offshore wind-powered green hydrogen production and refuelling system for HGV freight applications.

In the UK, offshore wind energy provides a promising renewable energy source for green hydrogen production [10]. However, the

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inherent seasonal variability of wind resources results in fluctuations in hydrogen supply [11], while freight logistics demand varies across regions and seasons, causing a spatial and temporal misalignment between green hydrogen supply and demand — creating challenges for hydrogen infrastructure design and pricing strategies [12]. Using Portsmouth City's A288 freight corridor as a case study, this study presents an integrated spatio-temporal modelling framework combining GIS-based geospatial analysis, real-world HGV traffic count data, and a hydrogen production model powered by an offshore wind farm (OWF). The framework incorporates a scenario-based dynamic pricing (DP) mechanism capturing seasonal variability and the supply–demand mismatch for HGV freight. This study contributes one of the first data-driven approaches to spatially and temporally resolve hydrogen pricing within the UK transport context, providing a scalable framework to support local government planning, national infrastructure rollout, and net-zero decarbonisation policy by 2050.

2. Literature review

Hydrogen production economics are governed by distinct production pathways, commonly classified by colour-based nomenclature. The Levelised Cost of Hydrogen (LCOH) — representing the minimum hydrogen selling price required to recover total capital and operational expenditure over the asset lifespan — has emerged as the principal techno-economic metric [13]. Grey hydrogen remains the most cost-competitive pathway at approximately \$1.5–\$2.5/kg, though its long-term viability is increasingly constrained by carbon pricing mechanisms and tightening emissions regulations [13]. Blue hydrogen, priced at approximately \$2.0–\$3.5/kg, offers a transitional low-carbon alternative, though its economic performance is sensitive to natural gas price volatility and CCS efficiency [13]. Green hydrogen, despite its zero-carbon footprint, currently represents the most expensive pathway at \$3.5–\$6.0/kg [13], though declining renewable energy costs and electrolyser learning rates are projected to narrow this gap significantly. To address cost competitiveness, the UK Government has adopted the Hydrogen Production Business Model (HPBM) through the Low Carbon Hydrogen Agreement (LCHA), providing revenue certainty for new low-carbon hydrogen projects over approximately 15 years [14]. Under the HPBM, producers receive payment based on a pre-agreed strike price — if the market price falls below it, the Low Carbon Contracts Company (LCCC) compensates the producer; if it exceeds it, the producer returns

the difference to the LCCC [14–16]. For HRS supplying hydrogen to HGVs in the UK, the Renewable Transport Fuel Obligation (RTFO) provides an additional revenue stream through Renewable Transport Fuel Certificates (RTFCs), operating alongside the HPBM as a complementary policy instrument [17].

As the hydrogen market matures, effective price formation will increasingly depend on mechanisms reflecting real-time operational dynamics. Consequently, the adoption of DP mechanisms becomes essential to reflect real-time market conditions where prices are influenced by the elasticity of supply and demand [16,18], facilitating the strategic coordination of hydrogen production and consumption with fluctuating renewable energy generation [19,20] and improving overall system efficiency [20,21]. DP mechanisms incentivise consumers to shift hydrogen demand from deficit to surplus production periods through demand-side management (DSM), maintaining system stability and improving renewable resource utilisation [22,23]. Several studies have examined the technical and economic benefits of DSM for green hydrogen [24–26].

The decarbonisation of freight transportation, reinforced by the UK's CCC 7th Carbon Budget [27], is expected to drive substantial expansion of HRS infrastructure across national freight networks due to the anticipated large-scale adoption of fuel-cell electric HGVs [28]. However, renewable energy availability varies considerably across regions — Northern Europe is characterised by stochastic and strongly seasonal wind patterns — introducing operational uncertainty for HRS reliant on variable renewable energy sources [18,29]. Recent industry developments indicate a growing shift toward market-responsive pricing: Plug Power has introduced spot pricing for liquid green hydrogen [30], while H2 Mobility Deutschland has implemented a DP approach adjusting retail prices to reflect procurement and operational costs [31]. While these developments demonstrate movement toward flexible pricing, their implementation remains limited to short-term signals with limited consideration of seasonal variability, spatial demand distribution, and system-level supply–demand imbalances.

Existing studies on DP for hydrogen refuelling infrastructure have predominantly focused on passenger and light-duty fuel-cell vehicles [12] or stationary energy-storage applications [19], with limited attention to HGV freight transport, characterised by higher hydrogen-throughput requirements, greater dependence on supply continuity, and seasonally varying transport activity. Within the UK context, hydrogen-infrastructure studies have generally examined

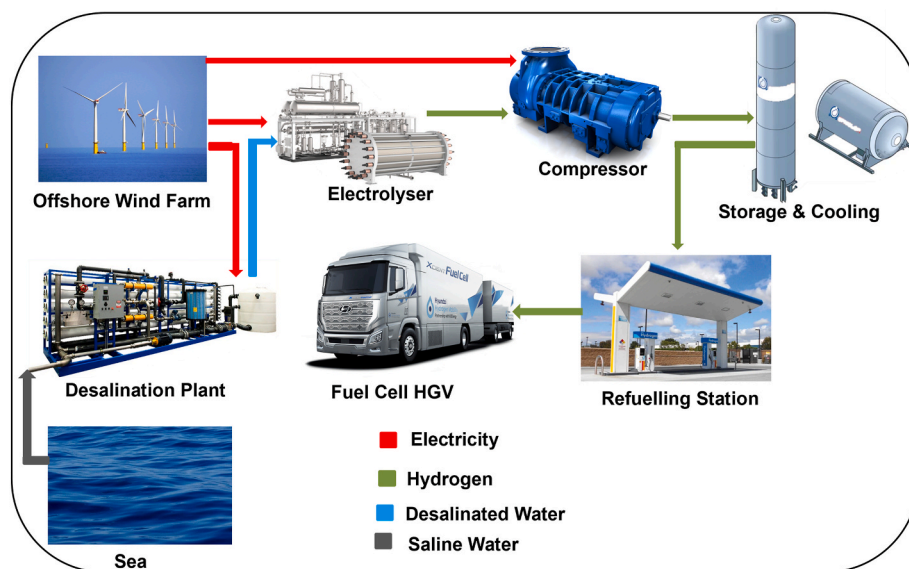


Fig. 1. Schematic of the integrated offshore wind-powered green hydrogen production and refuelling system for HGV freight applications. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

renewable-energy integration [10,32], and HRS planning [33,34] as separate research areas, rather than within an integrated spatio-temporal framework jointly representing offshore-wind variability, seasonal freight demand, and hydrogen-price formation. International studies have separately examined hydrogen production from offshore wind [35] and onshore renewable resources [36]; however, limited evidence was found of a location-specific, data-driven framework for the UK HGV freight sector in which dynamic hydrogen prices are explicitly linked to seasonal supply–demand imbalances, electrolyser utilisation, and renewable-hydrogen availability. More broadly, existing assessments predominantly employ static or annually averaged profiles, obscuring seasonal mismatches inherent in renewable-powered hydrogen systems, while existing pricing approaches provide limited integration of operational variables into price formation. These limitations restrict stakeholders from evaluating how renewable-resource variability, infrastructure operation, and freight demand interact across locations and seasons. The present study addresses these gaps through an integrated spatio-temporal modelling framework for Portsmouth, UK, that jointly characterises offshore-wind generation variability, seasonal HGV hydrogen demand, complete HRS system operation, and a DP mechanism informed by supply–demand imbalance, electrolyser utilisation, and hydrogen-supply variability — establishing a direct connection between HRS technical performance and the economic signals required to support DSM in the HGV freight sector.

3. Portsmouth City and route A288

Portsmouth City is located on the South Coast of England at approximately 50.8°N and 1.1°W. Its coastal exposure to prevailing south-westerly winds and proximity to the English Channel make it particularly suitable for offshore wind-powered renewable energy applications, supporting electrolysis-based green hydrogen production. Accordingly, an OWF with onshore hydrogen production configuration, consistent with the offshore wind-to-hydrogen framework proposed by ORE Catapult [32], was adopted in this study to serve HGV freight demand along Route A288. Fig. 2 shows the A288 road in Portsmouth — identified using Google Maps and ArcGIS — a critical urban freight corridor on Portsea Island with a high concentration of HGV movements, making it a representative case study for local hydrogen infrastructure planning.

4. System model

Fig. 3 presents the integrated spatio-temporal modelling framework adopted in this study. The framework combines GIS-based OWF site selection and hydrogen demand centre identification, offshore wind energy characterisation, hydrogen production via proton-exchange-membrane (PEM) electrolysis of desalinated seawater, HRS system load modelling, HGV demand estimation, seasonal supply–demand balancing, and DP within a unified analytical structure. Renewable electricity generated by the OWF drives on-site hydrogen production, with the resulting seasonal supply evaluated against HGV freight demand. The supply–demand imbalance, together with electrolyser utilisation and seasonal generation variability, forms the input basis of the proposed DP mechanism. Scenario and sensitivity analyses are incorporated to evaluate the influence of key pricing parameters on seasonal hydrogen price formation.

4.1. HGV fleet analysis in Portsmouth

Manual traffic count data for HGVs along the A288 route in Portsmouth, retrieved from the UK's Department for Transport (DfT), was used to establish a baseline for estimating projected hydrogen demand in 2050. According to the DfT, an average of 98 HGVs travelled the A288 route daily in 2023 [37]. The seasonal average daily Vehicle Kilometre (VKM) travelled by HGVs was derived using quarterly national HGV distance data for Great Britain in 2023 [38]. The quarterly distances are aligned with the seasonal structure to capture temporal variations in operational patterns. A day-weighted average was applied to account for the varying number of days in each month, ensuring accurate seasonal representation of HGV travel distance. Let $\mathcal{S} = \{S_i\}_{i=1}^s$, where $s = |\mathcal{S}|$, denote the set of all seasons and let $S_i = \{M_j^i\}_{j=1}^{n_i}$, where $n_i = |S_i|$, represent the number of months comprising each season in the UK. The average daily VKM travelled by HGVs in season S_i can be expressed as:

$$\Psi_i = \frac{\sum_{j=1}^{n_i} d(M_j^i) \psi(M_j^i)}{\sum_{j=1}^{n_i} d(M_j^i)}, i = 1, \dots, s \quad (2)$$

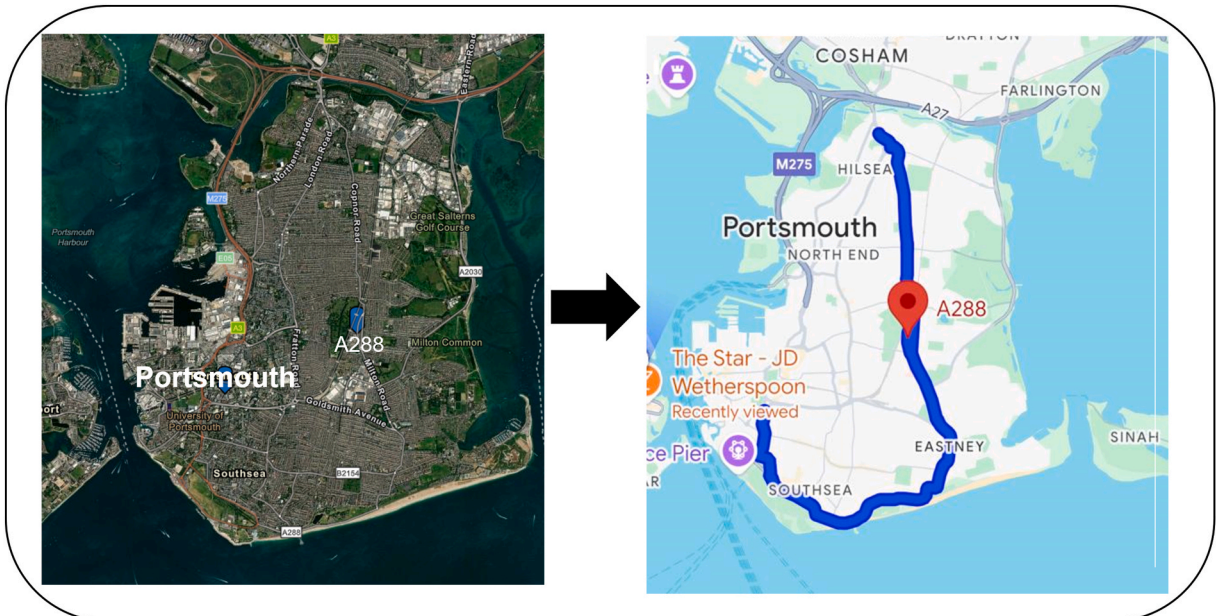


Fig. 2. A288 road in Portsmouth, United Kingdom.

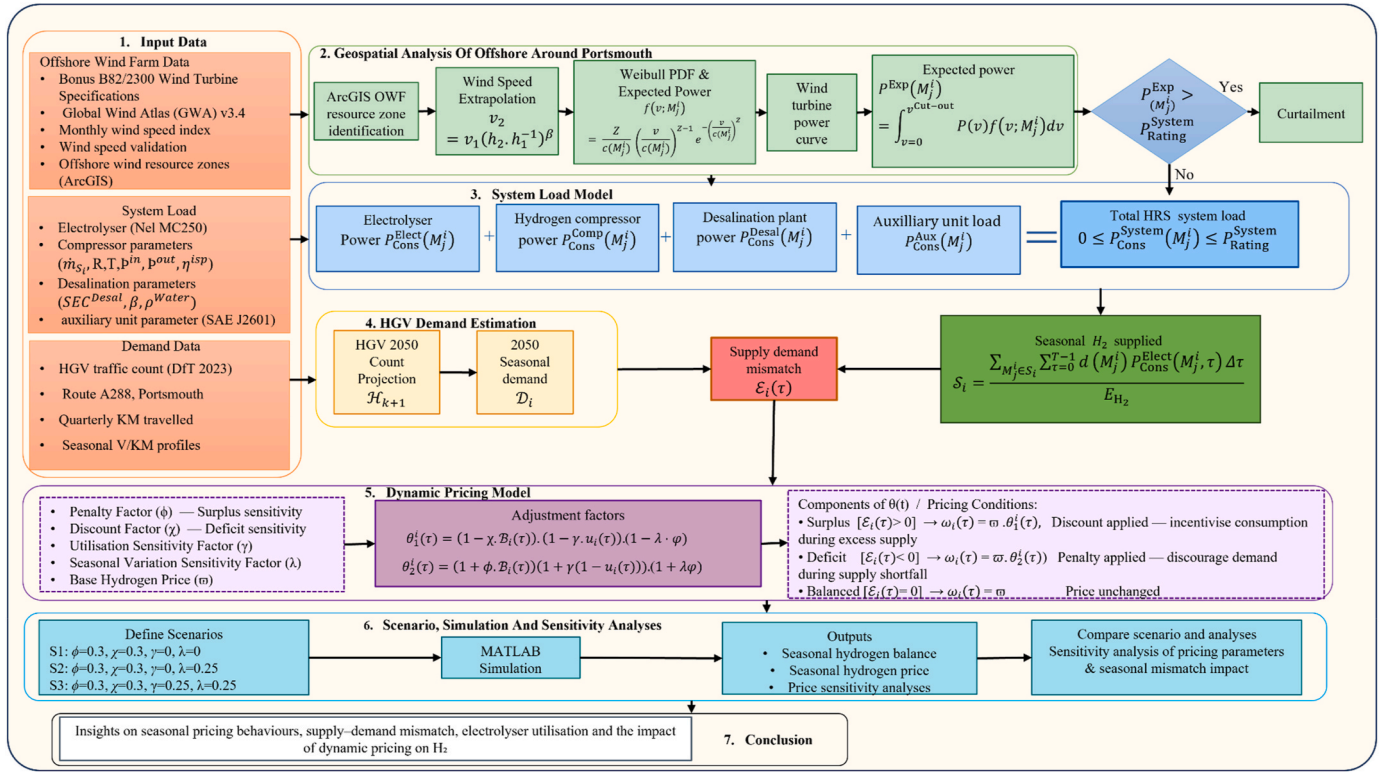


Fig. 3. Integrated spatio-temporal modelling framework for offshore wind-powered green hydrogen supply, HGV demand estimation, and dynamic pricing. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

where $d(M_j^i)$ is the number of days in month j and $\psi(M_j^i)$ is the average daily VKM travelled by the HGVs in month j .

Let $\mathcal{N}_i$ be the total number of days in each season i so that,

$$\mathcal{N}_i = \sum_{j=1}^{\mathcal{N}_i} d(M_j^i), M_j^i \in S_i \quad (3)$$

where $M_j^i \in S_i$ denote the months in season S_i . In the UK, there are four seasons (Winter, Spring, Summer and Autumn), each of these seasons is made up of three months. It follows that

$$S = \{\text{Winter, Spring, Summer, Autumn}\} \quad (4)$$

where Winter = {Dec, Jan, Feb}, Spring = {Mar, Apr, May}, Summer = {Jun, Jul, Aug} and Autumn = {Sept, Oct, Nov}.

The number of days in month M_j^i was used as follows:

$$d(M_j^i) = \begin{cases} 31, & \text{if } M_j^i \in \{\text{Jan, Mar, May, Jul, Aug, Oct, Dec}\} \\ 30, & \text{if } M_j^i \in \{\text{Apr, Jun, Sep, Nov}\} \\ 28, & \text{if } M_j^i = \text{Feb.} \end{cases} \quad (5)$$

Thus, the total number of days in season S_i , e.g., Winter $\mathcal{N}_1 = 90$, Spring $\mathcal{N}_2 = 92$, Summer $\mathcal{N}_3 = 92$, and Autumn $\mathcal{N}_4 = 91$.

4.2. HGV demand estimation

To estimate the 2050 daily HGV traffic volume on Route A288, a compound annual growth model is employed. The baseline traffic volume of 98 HGVs per day, based on current observational data for year 2023 [37] is used. The future traffic projection is estimated using:

$$\mathcal{H}_{k+1} = \mathcal{H}_k(1+r)^{\Delta t}, k = 0, 1, 2, \dots, \Delta t - 1 \quad (6)$$

where $\mathcal{H}_{k+1}$ is the projected HGV traffic volume, $\mathcal{H}_k$ is the baseline traffic volume, $r = 1.60\%$ is the annual growth rate, and $\Delta t = 27$ years is the projection period (2023–2050). The annual HGV traffic growth rate of $r = 1.60\%$ was adopted consistent with the observed annual road traffic growth rate reported by the DfT and the long-term HGV traffic projections of the National Road Traffic Projections in Ref. [39]. Applying Equation (6) to the 2023 baseline traffic volume of 98 HGVs per day yields a projected daily traffic volume of 150 HGVs on Route A288 by 2050. Using this projection, the hydrogen demand of the HGVs in kg in season S_i denoted as $\mathcal{D}_i$ is calculated as:

$$\mathcal{D}_i = \eta \cdot \mathcal{H}_{k+1} \cdot \mathcal{N}_i \cdot \Psi_i \quad (7)$$

where η is the H_2 fuel economy of HGVs, that is 0.085 kg/km.

4.3. Geospatial analysis of offshore around Portsmouth

In the UK, Everoze Partners Ltd was commissioned by the Crown Estate to map geographically suitable offshore wind resource zones within UK territorial waters [40]. Using ArcGIS, this study identifies OWF resource zones around Portsmouth suitable for fixed-bottom foundation deployment, consistent with Everoze recommendations and established spatial energy system integration practices [9], [40]. As shown in Fig. 4, the identified zone spans 479.83 km², centred at latitude 50.57° and longitude -0.99°, approximately 33.72 km from the A288 road corridor. This zone represents the geographically eligible area from which the proposed OWF site is selected. The OWF site area required to accommodate the selected wind turbines is calculated as:

$$A = \frac{\mathcal{N} \cdot (W^{cw} \cdot L) \cdot (W^{dw} \cdot L)}{10^6} \quad (8)$$

where A is the area of the OWF site in km², $\mathcal{N}$ is the number of wind turbine considered, L is the rotor diameter of the wind turbine (in m), $W^{cw} = 5$ and $W^{dw} = 10$ are the dimensionless crosswind and downwind

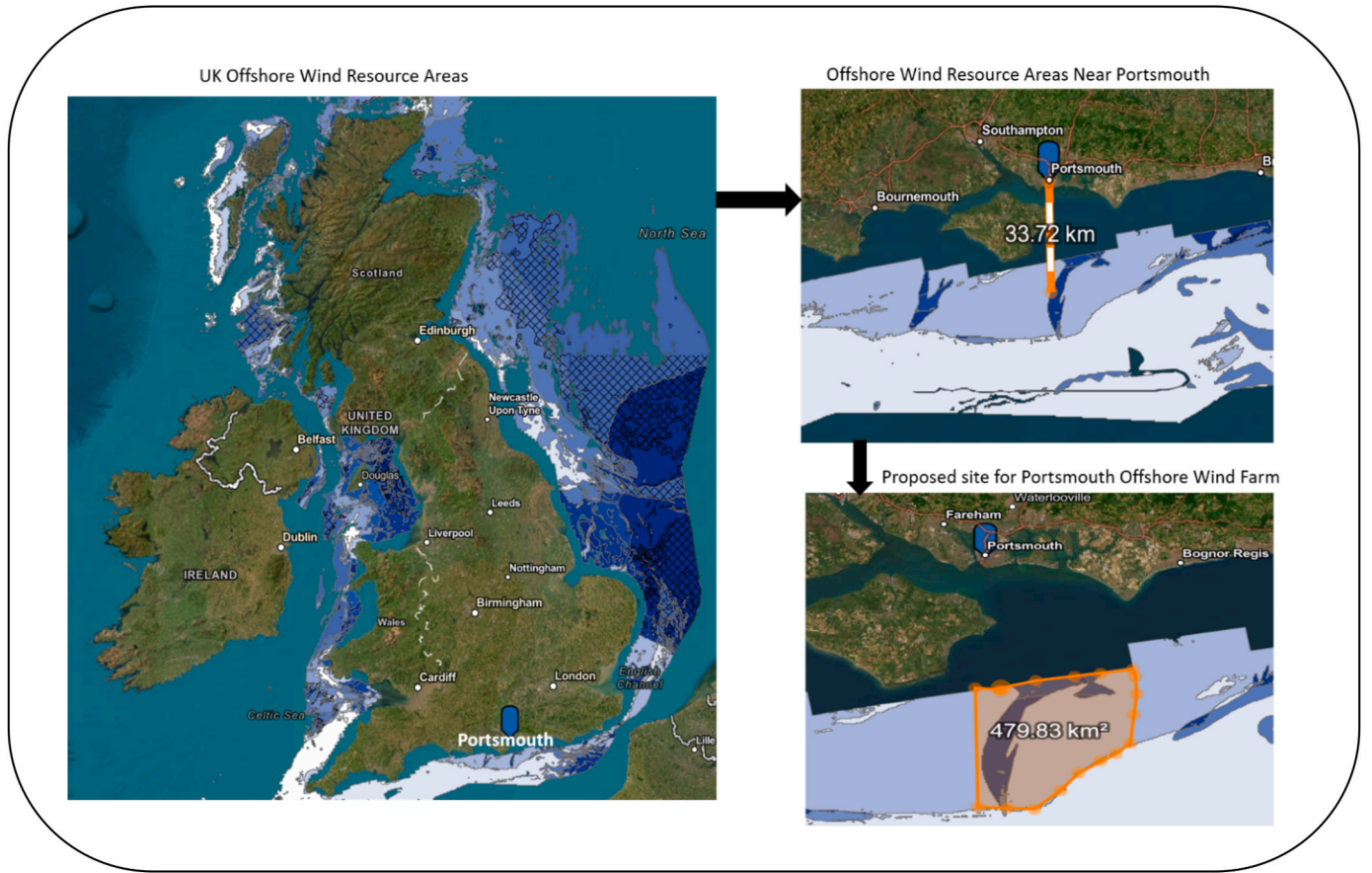


Fig. 4. Proposed Offshore wind farm site using ArcGIS software.

spacing factors respectively, adopted to minimise wake losses and ensure efficient spatial utilisation of the OWF site, consistent with established offshore wind farm layout practice [41].

4.4. Wind data

The Global Wind Atlas (GWA) version 3.4 was used to analyse wind resources around the identified OWF site, providing a decade-long record of average wind speeds and monthly wind speed indices [42]. GWA wind data were validated against long-term historical meteorological records from a UK Met Mast located at the Round 3 offshore wind energy development zone at Navitus Bay, using Root Mean Square Error (RMSE) and mean bias error (MBE) as validation metrics. GWA wind data were provided at a hub height of 50 m, used as the reference height h_1 for wind resource assessment. The average monthly wind speed was obtained by adjusting the annual average wind speed to the monthly wind speed index. The Bonus B82/2300 offshore wind turbine, typically installed at hub heights of 80–100 m, was selected for this location. Accordingly, monthly wind speeds were extrapolated to a hub height of 100 m to obtain v_2 using the power law model:

$$v_2 = v_1 (h_2/h_1)^{\beta} \quad (9)$$

where v_1 is wind speed at h_1 , $\beta = 0.11$ is wind shear exponent, which is often used for offshore areas [43].

4.5. Wind turbine power curve

The Bonus B82/2300 2.3 MW wind turbine selected for the proposed OWF has a power curve that provides the basis for converting a given wind speed, v , into electrical power output $P(v)$. The power-curve data

were interpolated over a refined wind-speed resolution of 0–25 m/s to facilitate accurate power-output estimation. The resulting power curve is represented by the following piecewise function:

$$P(v) = \begin{cases} 0, & v < v^{\text{Cut-in}} \\ p^{\text{Rated}}, & v^{\text{Rated}} \leq v \leq v^{\text{Cut-out}} \\ p^{\text{Rated}} \cdot (\alpha)^3, & v^{\text{Cut-in}} \leq v < v^{\text{Rated}} \\ 0, & v > v^{\text{Cut-out}} \end{cases} \quad (10)$$

where α is a dimensionless normalised wind speed bounded by the cut-in and rated wind speeds. It is calculated as:

$$\alpha = \frac{v - v^{\text{Cut-in}}}{v^{\text{Rated}} - v^{\text{Cut-in}}} \quad (11)$$

where $v^{\text{Cut-in}}$, $v^{\text{Cut-out}}$, and v^{Rated} , are the Cut-in, Cut-out and the rated speed of the wind turbine, respectively and p^{Rated} is the rated power output of the wind turbine.

4.6. Weibull distribution and expected power output

To estimate wind-turbine power output from the monthly average wind-speed data obtained from GWA, a separate Weibull probability density function (PDF) was constructed for each month M_j^i to account for monthly wind-speed variability at the proposed OWF site [44]. The monthly Weibull PDF is expressed as:

$$f(v; M_j^i) = \frac{Z}{c(M_j^i)} \left(\frac{v}{c(M_j^i)} \right)^{Z-1} e^{-\left(\frac{v}{c(M_j^i)} \right)^Z} \quad (12)$$

where Z is the Weibull shape parameter and $c(M_j^i)$ is the scale parameter corresponding to month M_j^i . A single shape factor was retained for all months, while the scale parameter was calculated separately from the corresponding monthly average wind speed, $\bar{v}(M_j^i)$, as:

$$c(M_j^i) = \frac{\bar{v}(M_j^i)}{\Gamma\left(1 + \frac{1}{Z}\right)}, j = 1, 2, 3, \dots, n_i \quad (13)$$

Accordingly, the annual dataset produces twelve monthly scale parameters, $c(M_1^i), c(M_2^i), \dots, c(M_{12}^i)$, but these are not independently assumed values; each is derived directly from the corresponding monthly average wind speed. For the adopted shape factor $Z = 2$, $\Gamma(1 + 1/Z) = \Gamma(1.5) \approx 0.8862$.

The expected power output of one wind turbine in month M_j^i , denoted by $P^{\text{Exp}}(M_j^i)$, was calculated using trapezoidal numerical integration of the turbine power curve weighted by the Weibull PDF:

$$P^{\text{Exp}}(M_j^i) = \int_{v=0}^{v^{\text{Cut-out}}} P(v)f(v; M_j^i) dv \quad (14a)$$

For the complete OWF, the average power available to the HRS in month M_j^i is:

$$P_{\text{OWF}}^{\text{av}}(M_j^i) = N_{\text{WT}}^{\text{Eq}} \cdot A_{\text{WT}} \cdot P^{\text{Exp}}(M_j^i) \quad (14b)$$

where $N_{\text{WT}}^{\text{Eq}}$ is the equivalent turbine-number sizing parameter and A_{WT} is the turbine operational-availability factor. In this study, $A_{\text{WT}} = 0.95$ was applied to account for scheduled maintenance and unplanned outages, consistent with values reported in the literature for modern offshore wind turbines [45,46]. Thus, $P_{\text{OWF}}^{\text{av}}(M_j^i)$ represents the availability-adjusted monthly wind power, which may be lower than, equal to or greater than the rated HRS system load. The equivalent turbine-number sizing approach builds upon the OWF configuration adopted in the earlier study [11]. In the expanded HRS model, $N_{\text{WT}}^{\text{Eq}} = 3.4$ corresponds to an equivalent OWF capacity of 7.82 MW for the Bonus B82/2300 turbine, i.e., $3.4 \cdot 2.3 \text{ MW} = 7.82 \text{ MW}$.

$N_{\text{WT}}^{\text{Eq}} = 3.4$ is therefore interpreted as a continuous capacity-sizing variable used for system-level modelling rather than as a physically installed fractional turbine. This representation enables the OWF capacity required to support the integrated electrolyser, compressor, desalination plant, and auxiliary loads to be evaluated without imposing discrete turbine-selection constraints. Any conversion of the equivalent capacity into an integer turbine configuration would form part of a subsequent detailed engineering-design stage.

The gross annual capacity factor obtained from the Weibull model is calculated as:

$$CF^{\text{annual}} = \frac{\sum_{i=1}^s \sum_{j=1}^{n_i} P^{\text{Exp}}(M_j^i) \cdot T \cdot d(M_j^i)}{P^{\text{Rated}} \cdot T \cdot 365} \cdot 100 \quad (15)$$

where $T = 24$ denotes the number of hourly time steps per day.

4.7. HRS system load

The HRS was designed to produce, compress, store, and dispense hydrogen to HGVs, minimising transportation costs while improving supply reliability and availability [34]. Key components include electrolysers, hydrogen compressors, water desalination units, high-pressure storage tanks, pre-cooling systems, and dispensing units [33]. In this study, the HRS is powered directly by the OWF, with primary electricity-consuming subsystems comprising the electrolyser,

compressor, desalination plant, and auxiliary units including the chiller, dispenser, pumping, monitoring and control systems. The aggregate monthly HRS power consumption is therefore expressed as:

$$P_{\text{Cons}}^{\text{System}}(M_j^i) = P_{\text{Cons}}^{\text{Elect}}(M_j^i) + P_{\text{Cons}}^{\text{Comp}}(M_j^i) + P_{\text{Cons}}^{\text{Desal}}(M_j^i) + P_{\text{Cons}}^{\text{Aux}}(M_j^i) \quad (16)$$

where $P_{\text{Cons}}^{\text{Elect}}, P_{\text{Cons}}^{\text{Comp}}, P_{\text{Cons}}^{\text{Desal}}$ and $P_{\text{Cons}}^{\text{Aux}}$ denote the actual power consumption of the electrolyser, compressor, desalination plant and auxiliary subsystems, respectively.

The auxiliary power consumption comprises a fixed standby requirement and a variable component proportional to the actual electrolyser power consumption. Since the HRS is supplied exclusively by the OWF and neither grid electricity nor electrical energy storage is considered, the actual auxiliary consumption is constrained by the available wind power:

$$P_{\text{Cons}}^{\text{Aux}}(M_j^i) = \min[P_{\text{Fix}}^{\text{Aux}}, P_{\text{OWF}}^{\text{av}}(M_j^i)] + L^{\text{Aux}} \cdot P_{\text{Cons}}^{\text{Elect}}(M_j^i) \quad (17)$$

In this study, $L^{\text{Aux}} = 0.03$, representing a variable auxiliary load equivalent to 3% of the actual electrolyser power consumption. The fixed auxiliary demand, $P_{\text{Fix}}^{\text{Aux}}$, was assumed to be 1% of the rated electrolyser power to account for standby and balance-of-plant requirements associated with monitoring, ventilation, control and support systems. This formulation allows the auxiliary demand to vary with hydrogen production while retaining a baseline electricity requirement [47].

The rated HRS system load is the combined electrical demand at rated hydrogen-production operation and is expressed as:

$$P_{\text{Rating}}^{\text{System}} = P_{\text{Rating}}^{\text{Elect}} + P_{\text{Rating}}^{\text{Comp}} + P_{\text{Rating}}^{\text{Desal}} + P_{\text{Fix}}^{\text{Aux}} + L^{\text{Aux}} \cdot P_{\text{Rating}}^{\text{Elect}} \quad (18)$$

The rated compressor, desalination and variable auxiliary loads correspond to rated electrolyser operation. The monthly available OWF power, $P_{\text{OWF}}^{\text{av}}(M_j^i)$, determines the actual operating load of the HRS. Accordingly:

$$P_{\text{Cons}}^{\text{System}}(M_j^i) = \min[P_{\text{OWF}}^{\text{av}}(M_j^i), P_{\text{Rating}}^{\text{System}}] \quad (19)$$

Equation (19) indicates that when the available OWF power is lower than the rated HRS system load, the HRS operates under a partial-load condition and consumes the available renewable power. When the available OWF power exceeds the rated HRS capacity, the system is capped at rated operation, and the excess renewable power is curtailed.

The fixed auxiliary standby requirement is considered before allocating power to the throughput-dependent subsystems. The monthly proportional load-scaling factor is therefore defined as:

$$\eta_{\text{PL}}(M_j^i) = \min\left[1, \max\left(0, \frac{P_{\text{OWF}}^{\text{av}}(M_j^i) - P_{\text{Fix}}^{\text{Aux}}}{P_{\text{Rating}}^{\text{System}} - P_{\text{Fix}}^{\text{Aux}}}\right)\right] \quad (20)$$

where $0 \leq \eta_{\text{PL}}(M_j^i) \leq 1$. A value of unity indicates rated operation of the throughput-dependent subsystems, whereas a value below unity indicates partial-load operation. When the available wind power falls below the fixed auxiliary standby demand, the load-scaling factor becomes zero, and hydrogen production ceases. Under this condition, the available wind power is allocated only to the auxiliary demand because neither grid electricity nor electrical energy storage is included in the model.

The actual power allocated to the electrolyser, compressor and desalination plant is then:

$$P_{\text{Cons}}^q(M_j^i) = \eta_{\text{PL}}(M_j^i) \cdot P_{\text{Rating}}^q, \quad q \in \{\text{Elect}, \text{Comp}, \text{Desal}\} \quad (21)$$

For seasonal reporting, the monthly load-scaling factors are aggregated using an operating-hour-weighted average:

$$\eta_{PL,S_i}^{season} = \frac{\sum_{M_j^i \in S_i} \eta_{PL} (M_j^i) \cdot T \cdot d(M_j^i)}{\sum_{M_j^i \in S_i} T \cdot d(M_j^i)} \quad (22a)$$

The total HRS system utilisation factor in season S_i is defined as the ratio of the actual HRS energy consumption to the energy that would be consumed under continuous rated operation:

$$U_{S_i}^{HRS} = \frac{\sum_{M_j^i \in S_i} P_{Cons}^{System} (M_j^i) \cdot T \cdot d(M_j^i)}{P_{Rating}^{System} \sum_{M_j^i \in S_i} T \cdot d(M_j^i)} \quad (22b)$$

Since the fixed auxiliary load is not proportionally scaled, $U_{S_i}^{HRS}$ may be slightly different from η_{PL,S_i}^{season} , although both indicators follow the same seasonal operating pattern.

When the available OWF power exceeds the rated HRS system load, the excess wind energy is curtailed. The curtailed energy in season S_i , denoted by C_i , is obtained by summing the monthly curtailment:

$$C_i = \sum_{M_j^i \in S_i} \xi(M_j^i) \left[P_{OWF}^{av} (M_j^i) - P_{Rating}^{System} \right] \cdot T \cdot d(M_j^i) \quad (23)$$

where the monthly curtailment-state variable is defined as:

$$\xi(M_j^i) = \begin{cases} 1, & P_{OWF}^{av} (M_j^i) > P_{Rating}^{System} \\ 0, & P_{OWF}^{av} (M_j^i) \leq P_{Rating}^{System} \end{cases} \quad (24)$$

Thus, $\xi(M_j^i) = 1$ indicates wind-energy curtailment, whereas $\xi(M_j^i) = 0$ indicates no curtailment. Positive seasonal curtailment does not necessarily imply 100% HRS utilisation throughout the season. Curtailment may occur in one month while the remaining months within the same season operate below the rated HRS load.

4.8. Electrolyser and seasonal hydrogen supply

Three commercially available Nel MC250 PEM electrolyzers were considered, each with a nominal power rating of 1.25 MW and a specific electricity consumption of 59 kWh/kg H_2 , providing a combined rated capacity of 3.75 MW. The hydrogen-production capability depends on the actual electrolyser power consumption determined by monthly OWF availability and the operating condition of the integrated HRS.

The hydrogen supply in kg in season S_i denoted as $\mathcal{S}_i$ can be calculated as:

$$\mathcal{S}_i = \frac{\sum_{M_j^i \in S_i} \sum_{\tau=0}^{T-1} d(M_j^i) P_{Cons}^{Elect} (M_j^i, \tau) \Delta \tau}{E_{H_2}} \quad (25)$$

where τ denotes the discrete operating time step, $\Delta \tau$ is the duration of each time step, and E_{H_2} is the specific electricity consumption of each electrolyser in kWh/kg H_2 , $\Delta \tau = 1$ hour.

In the present study, the available OWF power and electrolyser power consumption are evaluated using monthly average values. Therefore, $P_{Cons}^{Elect} (M_j^i, \tau)$ is assumed to remain constant throughout the representative day for each month. Under this assumption, Equation (25) is equivalent to:

$$\mathcal{S}_i = \frac{\sum_{M_j^i \in S_i} P_{Cons}^{Elect} (M_j^i) \cdot T \cdot d(M_j^i)}{E_{H_2}} \quad (26)$$

When $P_{Cons}^{Elect} (M_j^i)$ is expressed in kW, the equation gives the seasonal

hydrogen supply in kilograms. The general time-step formulation is retained to provide consistency with the seasonal hydrogen-balance and dynamic-pricing formulations discussed in later sections.

4.9. Compressor and water desalination plant

Hydrogen produced by the electrolyser must be compressed prior to storage and dispensing. A variable-speed centralised compressor was specified to serve the three PEM electrolyzers, scaling dynamically with the hydrogen mass flow rate $\dot{m}$ (kg/s). Due to the inherent intermittency and seasonal variability of offshore wind generation, $\dot{m}$ varies temporally, resulting in seasonal fluctuations in compressor power demand. An isentropic compression process was adopted for system-level energy estimation, consistent with established approaches in hydrogen system modelling [9,48]; it is acknowledged that in practice, the high-pressure ratio adopted in this study would require multi-stage compression with intercooling to manage thermal loading and mechanical constraints [49].

The specific gas constant of hydrogen R_{H_2} (J/kg/K) is derived from the universal gas constant R and the molar mass of molecular hydrogen M_{H_2} as:

$$R_{H_2} = \frac{R}{M_{H_2}} \quad (27)$$

where $R = 8.314$ J/(mol·K) and $M_{H_2} = 2.016 \times 10^{-3}$ kg/mol, yielding $R_{H_2} = 4124$ J/kg/K.

The compressor power consumption in season S_i , denoted $P_{S_i}^{Comp}$ (kW), is expressed as:

$$P_{S_i}^{comp} = \frac{\dot{\Gamma}}{\dot{\Gamma} - 1} \cdot \frac{R_{H_2} \cdot T \cdot \dot{m}_{S_i}}{\eta^{isp}} \cdot \left[\left(\frac{p^{out}}{p^{in}} \right)^{\frac{\dot{\Gamma}-1}{\dot{\Gamma}}} - 1 \right] \quad (28)$$

where $\dot{\Gamma}$ is the specific heat ratio of hydrogen ($\dot{\Gamma} = 1.4$), T is the hydrogen inlet temperature (K), p^{in} and p^{out} are the compressor inlet and outlet pressures (bar) respectively, η^{isp} is the isentropic efficiency, and $\dot{m}_{S_i}$ is the seasonal hydrogen mass flow rate (kg/s). The hydrogen inlet temperature was assumed to be $T = 298$ K, representing standard ambient conditions; seasonal variation in inlet temperature was neglected as a simplifying assumption consistent with system-level modelling practice [9]. The isentropic efficiency was adopted as $\eta^{isp} = 0.80$, consistent with values reported by Pellegrini et al. [48] for hydrogen reciprocating compressors operating at comparable pressure ratios.

The seasonal hydrogen mass flow rate $\dot{m}_{S_i}$ (kg/s) is derived from the total hydrogen produced—and equivalently supplied—in season S_i , denoted $\mathcal{S}_i$ (kg), distributed uniformly across all operating hours of the season:

$$\dot{m}_{S_i} = \frac{\mathcal{S}_i}{T \cdot \mathcal{N}_{i,3600}} \quad (29)$$

The denominator converts the total seasonal duration to seconds, under the assumption of continuous compressor operation across all hours of the season.

The compressor inlet pressure was set at $p^{in} = 30$ bar, consistent with the nominal outlet pressure of the PEM electrolyser stack [50]. The compressor outlet pressure, hydrogen storage pressure, and dispensing pressure were assumed equal and maintained at $p^{out} = 700$ bar throughout, such that:

$$p^{out} = p^{storage} = p^{dispenser} = 700 \text{ bar} \quad (30)$$

A dispensing pressure of 700 bar is consistent with the high-pressure fuelling protocol specified for heavy-duty hydrogen vehicles under SAE J2601-2 and is adopted as the dispensing standard for long-haul fuel cell HGVs requiring extended range and higher cargo loads [51], making it appropriate for the 2050 study horizon.

Green hydrogen production requires significant quantities of desalinated water. Based on Equation (1), approximately 9 kg of water is theoretically required per kilogram of hydrogen; however, practical electrolyser systems typically require 10–15 kg/kg due to purification losses, cooling requirements, and system inefficiencies [52]. Given the proximity of the A288 HRS location to seawater resources, a modular reverse osmosis desalination plant was considered, capable of dynamically adjusting its power consumption according to seasonal hydrogen production requirements [53,54].

Accordingly, the desalination power consumption in season S_i , denoted as $P_{S_i}^{\text{Desal}}$ (kW), is calculated as follows:

$$P_{S_i}^{\text{Desal}} = \frac{\mathcal{S}_i \cdot SEC^{\text{Desal}} \cdot \beta}{T \cdot \rho_{\text{Water}}} \quad (31)$$

where SEC^{Desal} is the specific energy consumption of the desalination plant in kWh/ m^3 that is 4 kWh/ m^3 , β is the water demand coefficient for electrolysis in kg. H_2O /kg. H_2 that is 13 kg H_2O /kg. H_2 based on the selected electrolyser model used in this study. ρ_{Water} is the density of water that is 1000 kg/ m^3 .

4.10. Seasonal hydrogen balance

For any season S_i , the hydrogen market must satisfy an equilibrium condition in which the total quantity of green hydrogen supplied at the refuelling station equals the total quantity demanded by HGV freight operations across all months M_j^i within that season. Let $\mathcal{D}_i(\tau)$ denote the hydrogen demand (kg) in season S_i at discrete time step τ , and $\mathcal{S}_i(\tau)$ denote the corresponding hydrogen supply (kg), where $\tau = 0, 1, \dots, T-1$. The seasonal market equilibrium condition is expressed as:

$$\sum_{\tau=0}^{T-1} \sum_{M_j^i \in S_i} \mathcal{S}_i(M_j^i, \tau) = \sum_{\tau=0}^{T-1} \sum_{M_j^i \in S_i} \mathcal{D}_i(M_j^i, \tau), \quad i = 1, \dots, s.. \quad (32)$$

In practice, however, the inherent variability of offshore wind generation means that Equation (32) will rarely hold with equality across all seasons. Deviations from equilibrium whether positive or negative constitute the primary input signal to the DP mechanism proposed in this study. The seasonal net hydrogen supply, $\mathcal{E}_i(\tau)$, is therefore defined as:

$$\mathcal{E}_i(\tau) = \mathcal{S}_i(\tau) - \mathcal{D}_i(\tau), \tau = 0, 1, \dots, T-1.. \quad (33a)$$

where $\mathcal{E}_i(\tau) > 0$ denotes a surplus condition (supply exceeds demand), $\mathcal{E}_i(\tau) < 0$ denotes a deficit condition (demand exceeds supply), and $\mathcal{E}_i(\tau) = 0$ denotes a balanced market. To incentivise demand-side response and maintain economic viability of the HRS across all seasons, a price adjustment is applied according to the state of $\mathcal{E}_i(\tau)$ as follows:

$$\begin{cases} \mathcal{E}_i(\tau) > 0, & \text{discount is applied} \\ \mathcal{E}_i(\tau) < 0 & \text{penalty is applied} \\ \mathcal{E}_i(\tau) = 0, & \text{price is unchanged} \end{cases} \quad (33b)$$

This pricing logic reflects a DSM strategy: during surplus periods, a discounted hydrogen price incentivises HGV operators to increase refuelling activity, thereby absorbing excess production and improving electrolyser utilisation; during deficit periods, a price premium moderates demand relative to the constrained supply, mitigating the risk of station outage. The assumption of price-responsive HGV refuelling behaviour is supported by evidence that fuel cost represents a primary determinant of hydrogen adoption decisions in long-haul freight operations [16,18]. To quantify the magnitude of the supply–demand mismatch as a proportion of seasonal demand, the imbalance ratio $\mathcal{B}_i(\tau)$ is defined as:

$$\mathcal{B}_i(\tau) = \frac{|\mathcal{E}_i(\tau)|}{\mathcal{D}_i(\tau)} \times 100 \quad (34)$$

where $|\cdot|$ denotes the absolute value. $\mathcal{B}_i(\tau)$ provides a normalised, dimensionless measure of market imbalance that is agnostic to the direction of deviation and serves as the primary input to the DP formulation introduced in the following sub-section.

4.11. Hydrogen market and proposed dynamic pricing

Traditionally, hydrogen markets at the wholesale level have been governed through long-term contracts, futures agreements, Power Purchase Agreements (PPAs), and spot market transactions, all of which are characterised by fixed pricing structures. However, fixed pricing mechanisms fail to reflect seasonal variations in renewable generation, fluctuations in logistics demand, or prevailing market conditions. To address these limitations, this study proposes a DP mechanism for the green hydrogen market that adjusts the retail price of hydrogen in response to real-time supply–demand imbalances, electrolyser utilisation, and seasonal generation variability.

Let ϖ denote the base hydrogen price (£/kg), representing the reference price under balanced market conditions. The base price is set at $\varpi = £4.00/\text{kg}$, consistent with projected 2050 delivered hydrogen cost estimates for offshore wind-powered PEM electrolysis at the scale modelled in this study. Commercial-scale UK offshore wind-to-hydrogen projects employing onshore electrolysis, as adopted in this study, are projected to achieve an LCOH of £2.91/kg at the production site [35], while delivered hydrogen costs are estimated at \$3.00–\$7.00/kg by 2050 [55]. Accordingly, the assumed base price of £4.00/kg implies a modest £1.09/kg uplift above production cost to account for compression, storage, and dispensing infrastructure. This selection is further supported by Arthur D. Little's projection of a 56% reduction in hydrogen production costs by 2050 [36]. The seasonal hydrogen prices derived from the proposed DP framework scale proportionally with the base hydrogen price ϖ . Using the base hydrogen price ϖ , the proposed seasonal hydrogen price in season S_i at time step τ , denoted $\omega_i(\tau)$, is determined by the state of the seasonal hydrogen balance $\mathcal{E}_i(\tau)$ as follows:

$$\omega_i(\tau) = \begin{cases} \varpi \cdot \theta_1^i(\tau), & \text{if } \mathcal{E}_i(\tau) > 0 \\ \varpi \cdot \theta_2^i(\tau), & \text{if } \mathcal{E}_i(\tau) < 0 \\ \varpi, & \text{if } \mathcal{E}_i(\tau) = 0 \end{cases} \quad (35)$$

where $\theta_1^i(\tau)$ and $\theta_2^i(\tau)$ are the adjustment factors applied to the base hydrogen price, ϖ , under surplus and deficit conditions, respectively. These factors depend on the penalty factor, ϕ , discount factor, χ , utilisation sensitivity factor, γ , and seasonal variation sensitivity factor, λ . The adjustment factors are defined as:

$$\theta_1^i(\tau) = (1 - \chi \cdot \mathcal{B}_i(\tau)) \cdot (1 - \gamma \cdot u_i(\tau)) \cdot (1 - \lambda \cdot \varphi) \quad (36a)$$

$$\theta_2^i(\tau) = (1 + \phi \cdot \mathcal{B}_i(\tau)) \cdot (1 + \gamma(1 - u_i(\tau))) \cdot (1 + \lambda \varphi) \quad (36b)$$

The electrolyser utilisation factor was used in the dynamic-pricing formulation because it directly represents the utilisation of the installed hydrogen-production capacity. Although the compressor, desalination plant and auxiliary loads are included in the integrated HRS power balance, their operating levels are primarily governed by electrolyser throughput and are therefore indirectly reflected in the resulting hydrogen supply.

For the present monthly implementation, the seasonal electrolyser utilisation factor is calculated as:

$$u_i = \frac{\sum_{M_j^i \in S_i} P_{\text{Cons}}^{\text{Elect}}(M_j^i) \cdot T \cdot d(M_j^i)}{P_{\text{Rating}}^{\text{Elect}} \sum_{M_j^i \in S_i} T \cdot d(M_j^i)} \quad (37)$$

where $u_i(\tau) = u_i$ within season S_i under the present monthly-resolution implementation. In a subsequent higher-resolution formulation, $u_i(\tau)$ may be calculated directly at each operating time step.

The seasonal variation factor, φ , is represented by the coefficient of variation of hydrogen supply across all seasons:

$$\varphi = \frac{\sigma_S}{\mu_S} \quad (38)$$

where:

$$\mu_S = \frac{1}{S} \sum_{i=1}^S \mathcal{S}_i, \quad (39)$$

and:

$$\sigma_S = \sqrt{\frac{1}{S} \sum_{i=1}^S (\mathcal{S}_i - \mu_S)^2} \quad (40)$$

Here, σ_S and μ_S are the standard deviation and mean of hydrogen supply across all seasons, respectively. A high value of φ indicates greater seasonal variation in hydrogen supply and may signify an increased need for storage and demand-response strategies to mitigate supply inconsistencies.

Fig. 5 illustrates the state-transition framework underlying the proposed dynamic hydrogen pricing model. The system is defined by three discrete operating states, which are: Balanced, Surplus, and Deficit — determined by the relationship between hydrogen supply $\mathcal{S}_i(\tau)$ and demand $\mathcal{D}_i(\tau)$. Under the Balanced state ($\mathcal{S}_i(\tau) = \mathcal{D}_i(\tau)$), the hydrogen price remains at the base level ω , representing equilibrium market conditions in which supply precisely meets demand. When supply exceeds demand ($\mathcal{S}_i(\tau) > \mathcal{D}_i(\tau)$), the system transitions to the Surplus state, in which the hydrogen price is reduced via the time-dependent discount factor $\theta_1^i(\tau) < 1$. This downward adjustment reflects excess hydrogen availability and provides an economic incentive for HGV operators to increase refuelling activity, thereby absorbing surplus production and improving electrolyser utilisation. Conversely, when supply is less than demand ($\mathcal{S}_i(\tau) < \mathcal{D}_i(\tau)$), the system enters the Deficit state, where the price is elevated through the penalty factor $\theta_2^i(\tau) > 1$ to reflect scarcity conditions and moderate consumption relative to the constrained supply. State transitions are governed by temporal variations in supply and demand, while self-transition loops represent the persistence of system conditions under prolonged surplus or deficit — a characteristic feature of seasonally-driven offshore wind generation.

This framework inherently captures both short-term fluctuations and

longer-term seasonal variability associated with renewable-based hydrogen production and consequently establishes a dynamic and adaptive pricing mechanism that responds to real-time system imbalances, facilitates demand-side flexibility, and enhances overall system utilisation within hydrogen-based HGV freight transport networks.

4.12. Dynamic pricing scenarios

To evaluate the influence of the dynamic-pricing parameters under different operating conditions, a scenario-based simulation framework was adopted. Four scaling factors were considered: the penalty factor, ϕ ; discount factor, χ ; utilisation-sensitivity factor, γ ; and seasonal-variation-sensitivity factor, λ . These parameters govern the response of hydrogen price to the normalised supply–demand imbalance, electrolyser utilisation and seasonal hydrogen-production variability. The three scenarios considered are summarised in Table 1.

The penalty and discount factors were set to $\phi = \chi = 0.30$ to represent moderate responsiveness to supply–demand imbalance. These values produce a 30% adjustment of the base price when the normalised imbalance ratio $\mathcal{B}_i(\tau)$ is equal to unity. This range is broadly consistent with demand-response studies for analogous energy carriers, where adjustment factors of approximately 0.20–0.40 have been used to provide effective demand-shifting signals without causing excessive price volatility [19,20]. The utilisation-sensitivity factor was set to $\gamma = 0.25$ in Scenario 3. Under surplus conditions, the term $[1 - \gamma u_i(\tau)]$ applies a stronger discount as electrolyser utilisation increases, giving a maximum utilisation-related reduction of 25% at full load. This reflects the lower unit-cost implications of distributing fixed system costs across greater hydrogen output while maintaining a moderate pricing response, consistent with adjustment magnitudes reported for analogous energy-carrier demand-response mechanisms [19,20].

The seasonal-variation-sensitivity factor was set to $\lambda = 0.25$ in Scenarios 2 and 3 to account for variability in hydrogen production across the four seasons. This value allows seasonal fluctuations to influence price formation without outweighing the direct supply–demand imbalance. The sensitivity analysis subsequently varies all four parameters from 0.05 to 0.40 to assess the consistency of the model response under alternative assumptions.

Scenario 1 represents the baseline formulation, in which price responds only to supply–demand imbalance through ϕ and χ , with

Table 1
Pricing scenarios.

Scenarios	ϕ	χ	γ	λ
Scenario 1	0.3	0.3	0	0
Scenario 2	0.3	0.3	0	0.25
Scenario 3	0.3	0.3	0.25	0.25

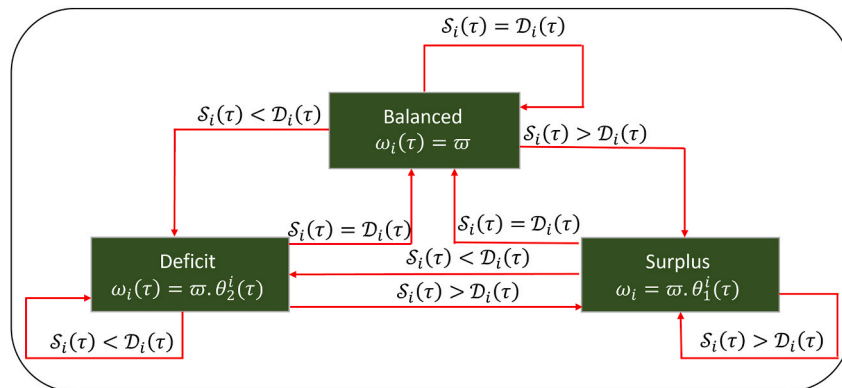


Fig. 5. State-transition framework for dynamic hydrogen pricing.

$\gamma = \lambda = 0$. Scenario 2 additionally includes λ , allowing seasonal production variability to influence price formation. Scenario 3 further introduces γ , representing the complete formulation by accounting for both seasonal variability and electrolyser utilisation. This progressive structure enables the effects of seasonal variability and utilisation on hydrogen-price formation to be isolated and compared.

5. Results and discussion

Fig. 6 presents the validation of GWA wind speed data against UK Met Mast observations at Navitus Bay for the period 2001–2011. The validation yielded a Pearson correlation coefficient ($r = 0.95$), an RMSE of 0.52 m/s, and a mean MBE of -0.01 m/s, confirming excellent agreement between the datasets and supporting the reliability of the GWA wind resource data use in the study.

Fig. 7 presents the monthly Weibull wind speed probability density functions for the proposed OWF site, fitted with shape parameter $Z = 2$. The distributions capture the probabilistic variability of wind speed at the site and form the basis for expected power output estimation through integration with the turbine power curve.

Fig. 8 presents the estimated gross annual capacity factor as a function of numerical integration sample size. The results demonstrate convergence behaviour consistent with trapezoidal numerical integration: the gross capacity factor decreases marginally with increasing sample size, indicating that coarser discretisations slightly overestimate the expected power output due to the non-linear shape of the turbine power curve in the cut-in to rated speed transition region. The difference between the gross capacity factor estimates obtained using 100 and 500

integration points was approximately 0.01 percentage points, confirming that further refinement of the discretisation beyond 500 samples has a negligible impact on the numerical result. The rate of change diminishes progressively as sample size increases, demonstrating convergence of the trapezoidal integration to a stable solution. Consequently, a sample size of 500 was adopted for all subsequent analyses to ensure adequate representation of the Weibull wind-speed distribution while minimising numerical integration error.

The converged gross annual capacity factor is approximately 46.61%. Applying the turbine operational-availability factor of $A_{WT} = 0.95$ to account for scheduled maintenance and unplanned outages yields a net capacity factor of approximately 44.28%, which falls within the 40–45% range reported in the manufacturer specification for the Bonus B82/2300 2.3 MW wind turbine [56].

Fig. 9 presents the seasonal hydrogen supply–demand balance, expressed as net surplus or deficit (tonnes) for each season. A pronounced seasonal mismatch is evident: hydrogen supply exceeds demand during Winter and Autumn, yielding surpluses of approximately 27 tonnes and 4 tonnes respectively, while demand exceeds supply during Spring and Summer, producing deficits of approximately 10 tonnes and 27 tonnes respectively. The near-symmetry between the Winter surplus (27 tonnes) and the Summer deficit (27 tonnes) indicates that these seasons represent near-mirror-image extremes of the supply–demand envelope, while Autumn and Spring constitute transitional shoulder seasons with smaller imbalances.

This seasonal mismatch cannot be resolved through simple capacity scaling. Increasing the electrolyser capacity could reduce the Spring and Summer deficit; however, depending on the available OWF capacity,

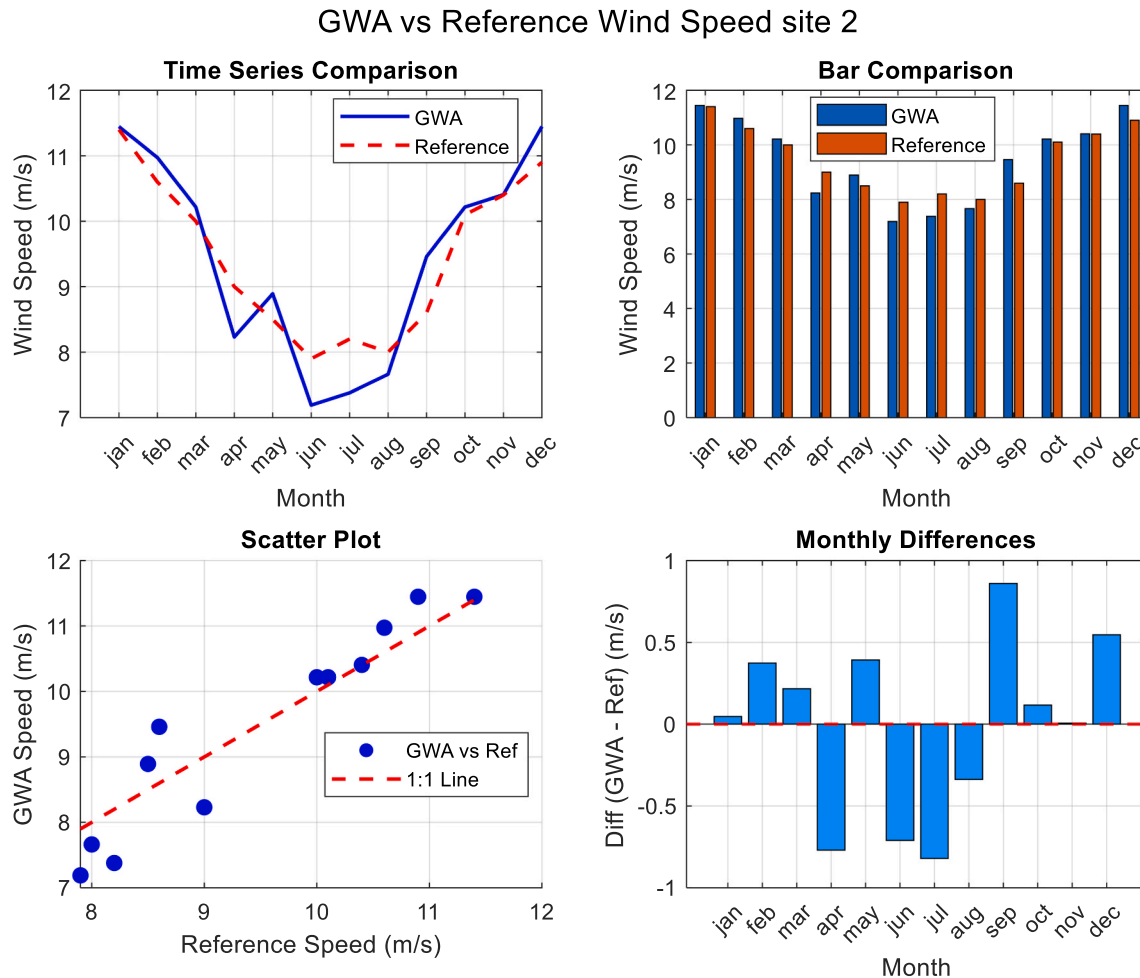


Fig. 6. Validation of global wind Atlas monthly wind speed data against UK Met Mast observations at Navitus Bay (2001–2011).

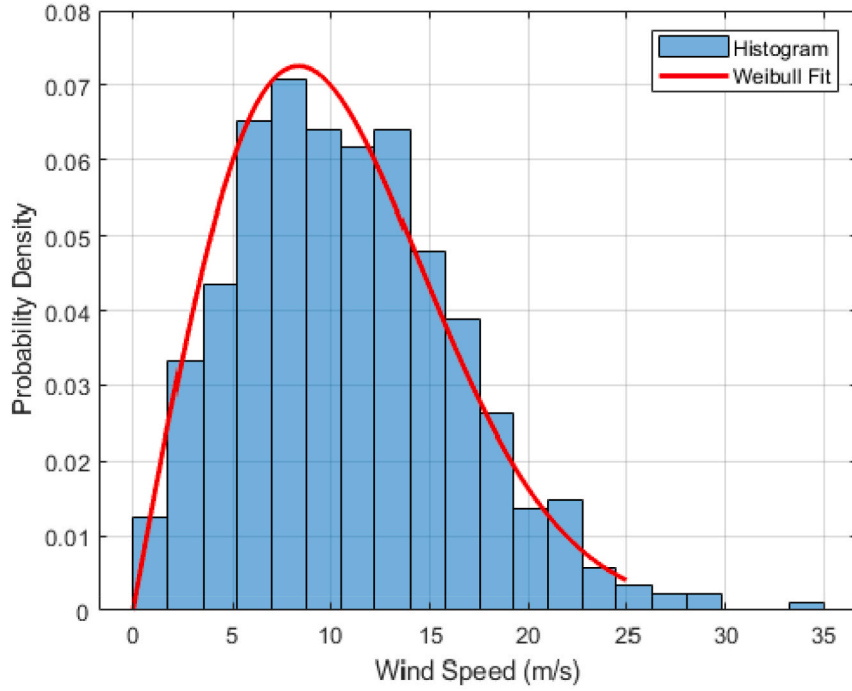


Fig. 7. Weibull wind speed probability density functions at the proposed Portsmouth OWF site.

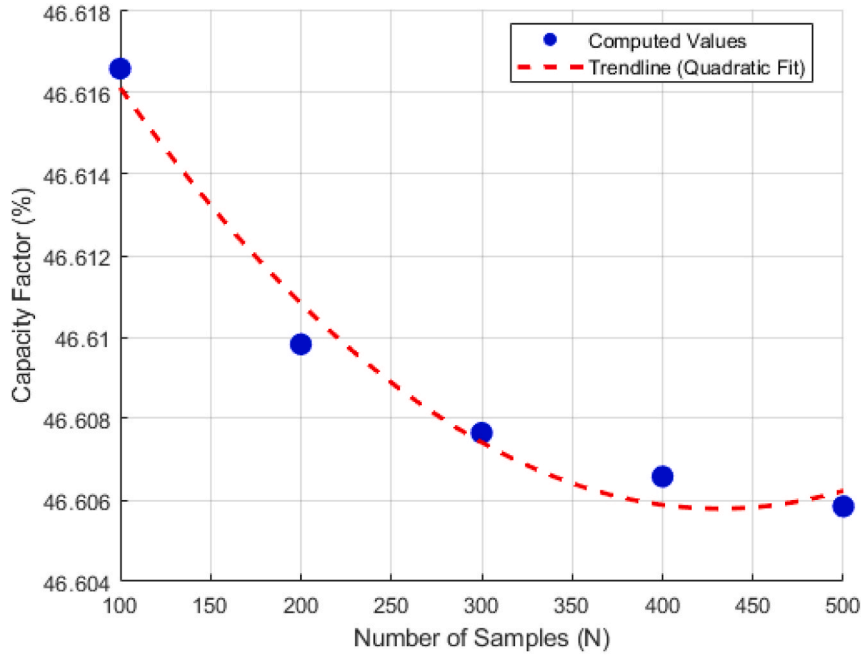


Fig. 8. Convergence of gross annual capacity factor with increasing numerical integration sample size.

this risks generating excess production and additional curtailment during high-wind seasons. Conversely, increasing the OWF installed capacity would intensify curtailment during high-wind seasons without proportionally addressing the Summer deficit, due to the non-linear relationship between wind speed and turbine power output captured in the piecewise power curve of Equation (10). These constraints confirm that two complementary interventions are required: seasonal hydrogen storage — to carry surplus production forward to meet Spring and Summer deficits — and DSM through DP to activate HGV operator response during surplus periods, reducing the storage burden and improving overall system economics. The surplus-period discount

signals also support additional RTFC generation under the UK RTFO, maximising certificate yield during periods of peak renewable hydrogen production.

Fig. 10 presents the seasonal wind-energy curtailment, C_i (MWh), and HRS utilisation factor, $U_{S_i}^{\text{HRS}}$, across the four operating seasons. Winter achieves full HRS utilisation ($U_{S_i}^{\text{HRS}} = 1$), with 111 MWh of wind energy curtailed as the HRS reaches its maximum operating capacity — coinciding with a seasonal hydrogen surplus ($\mathcal{E}_i(\tau) > 0$) and activating the discount-pricing regime of Equation (35). In Autumn, an HRS utilisation factor of 86% occurs alongside 66 MWh of curtailment. This reflects intra-seasonal wind variability — OWF power exceeds rated

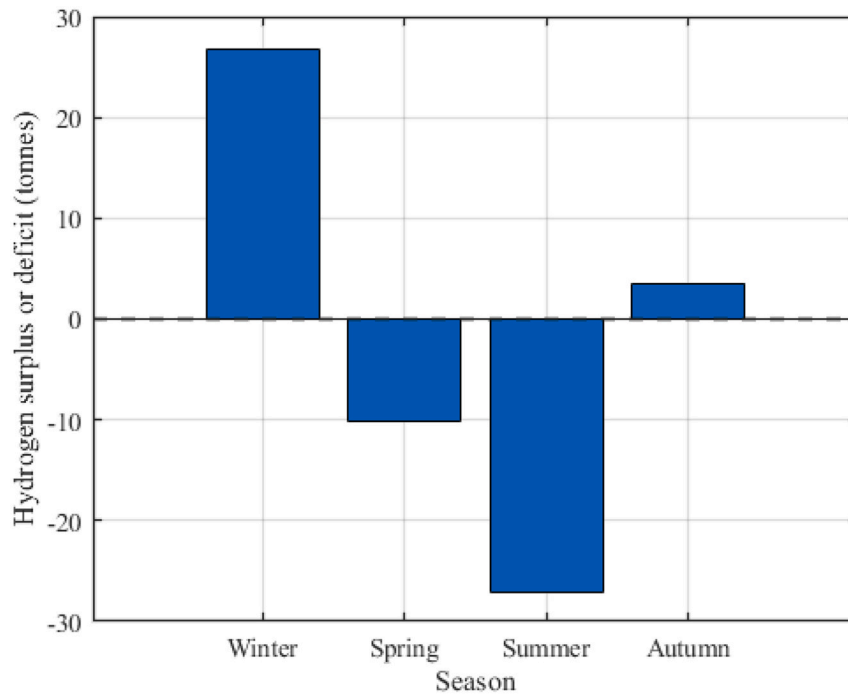


Fig. 9. Seasonal hydrogen supply-demand balance at the Portsmouth HRS projected to 2050.

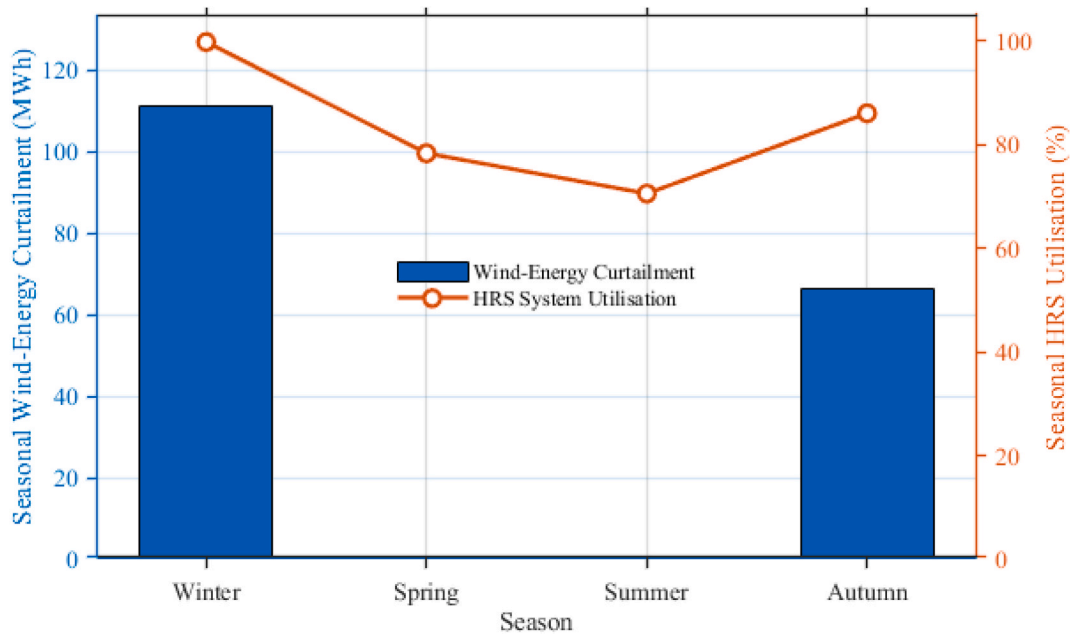


Fig. 10. Seasonal wind energy curtailment and HRS utilisation.

HRS capacity in November while September and October reduce the seasonal average — demonstrating the advantage of the monthly Weibull formulation over seasonal-average models.

No curtailment occurs during Spring or Summer, while HRS utilisation decreases to 78% and 70%, respectively, due to lower offshore-wind availability and reduced hydrogen production. The resulting hydrogen-deficit conditions ($\mathcal{E}_i(\tau) < 0$) activate the penalty-pricing regime. Summer represents the most constrained season, combining the lowest utilisation, the largest supply-demand deficit and the highest hydrogen-price premium across the three pricing scenarios.

The combined curtailment-utilisation results provide three important insights. First, the coexistence of full HRS utilisation and wind-

energy curtailment during Winter demonstrates that DP alone cannot recover all surplus renewable energy. Although discounted prices may encourage greater or rescheduled hydrogen offtake, additional electrolyser capacity or electrical storage would be required to absorb the curtailed electricity, while hydrogen storage would support subsequent dispensing. Second, the 70–100% seasonal utilisation range provides direct quantitative justification for incorporating electrolyser utilisation into the adjustment factors $\theta_1^i(\tau)$ and $\theta_2^i(\tau)$, which reflect variations in renewable-energy availability by applying discounts during surplus periods and premiums during constrained conditions. Third, the annual curtailment of 177 MWh, concentrated entirely in Winter and Autumn, confirms that surplus renewable-energy availability is both seasonal and

capacity constrained. Discount pricing may increase HGV hydrogen demand; however, converting curtailed wind energy into additional hydrogen requires further electrolyser or storage investment which is beyond the scope of this study. Subject to the applicable sustainability, traceability and reporting requirements, increased renewable-hydrogen dispensing may also contribute to RTFC generation under the UK RTFO.

The seasonal hydrogen prices obtained under the three DP scenarios are presented in Fig. 11, using a base hydrogen price of $\varpi = £4.00/\text{kg}$. A consistent pattern is observed across all scenarios: Winter and Autumn — characterised by surplus hydrogen production ($\mathcal{E}_i(\tau) > 0$) — exhibit prices below the base value, while Spring and Summer — characterised by supply deficits ($\mathcal{E}_i(\tau) < 0$) — exhibit price premiums, confirming that the proposed mechanism responds correctly to the direction of the seasonal supply–demand imbalance.

Under Scenario 1 ($\phi = \chi = 0.30$, $\gamma = \lambda = 0$), prices are determined solely by the normalised imbalance ratio $\mathcal{B}_i(\tau)$, yielding a seasonal range of £0.55/kg (£3.71/kg in Winter to £4.26/kg in Summer). Winter receives a discount of approximately 7.3% relative to ϖ , while Spring and Summer carry premiums of 2.5% and 6.5% respectively. The Autumn price of £3.96/kg — marginally below the base price — reflects the comparatively small magnitude of the Autumn surplus imbalance under Scenario 1.

Scenario 2 ($\lambda = 0.25$ added) incorporates the seasonal variation sensitivity factor, widening the price range to £0.79/kg. Winter and Autumn prices decrease to £3.60/kg and £3.84/kg respectively, while Spring and Summer prices increase to £4.23/kg and £4.39/kg. The moderate widening relative to Scenario 1 indicates that seasonal supply variability acts as a secondary amplifier of the underlying imbalance signal rather than a primary pricing driver.

The most pronounced differentiation is produced under Scenario 3 ($\gamma = 0.25$ additionally included), where the complete DP formulation yields a seasonal price range of £2.01/kg — more than three and a half times that of Scenario 1. Winter and Autumn prices decrease substantially to £2.70/kg and £3.01/kg, while Spring and Summer prices increase to £4.50/kg and £4.71/kg. The comparison between Scenarios 2 and 3 — in which ϕ , χ and λ remain unchanged — isolates the contribution of the utilisation sensitivity factor γ . Under surplus conditions,

the adjustment term $[1 - \gamma u_i]$ amplifies the discount in proportion to electrolyser utilisation: the high utilisation during Winter ($u_i = 1.00$) and Autumn ($u_i = 0.86$) produces stronger price reductions than would be generated by the imbalance ratio alone, reducing the Winter price from £3.60/kg to £2.70/kg and the Autumn price from £3.84/kg to £3.01/kg. Under deficit conditions, the complementary term $[1 + \gamma(1 - u_i)]$ amplifies the price premium in proportion to unused electrolyser capacity: the lower utilisation during Summer ($u_i = 0.70$) relative to Spring ($u_i = 0.78$) produces a larger premium increase in Summer, consistent with its more severely constrained hydrogen supply.

Relative to ϖ , Scenario 3 produces discounts of 32.5% in Winter and 24.8% in Autumn, with premiums of 12.5% in Spring and 17.8% in Summer. The stronger surplus discounts reflect the combined influence of the imbalance ratio, electrolyser utilisation, and seasonal supply variability, providing the strongest demand-shifting incentive during periods of peak renewable generation. The scenario progression collectively demonstrates the layered contribution of the pricing components: Scenario 1 establishes the direct imbalance response, Scenario 2 incorporates supply variability, and Scenario 3 represents the complete formulation in which electrolyser utilisation emerges as the principal operational factor governing the magnitude of seasonal price differentiation.

To contextualise the seasonal hydrogen prices within the UK transport fuel market, a comparison with retail diesel costs for HGVs was performed. Based on the 2024 UK annual average retail diesel price of approximately £1.487/litre [57] and the calorific values of diesel (35.8 MJ/L) and hydrogen (120 MJ/kg), the energy-equivalent hydrogen price threshold for cost parity with diesel is estimated at approximately £4.98/kg.

Accounting for the thermodynamic efficiency advantage of hydrogen fuel cell powertrains over diesel internal combustion engines [58], all seasonal hydrogen prices across the three scenarios (£2.70/kg–£4.71/kg) fall below this threshold, confirming year-round cost competitiveness. The surplus-period prices under Scenario 3 — £2.70/kg in Winter and £3.01/kg in Autumn — represent periods of clear economic advantage, providing strong market-based incentives for flexible HGV refuelling during peak renewable generation.

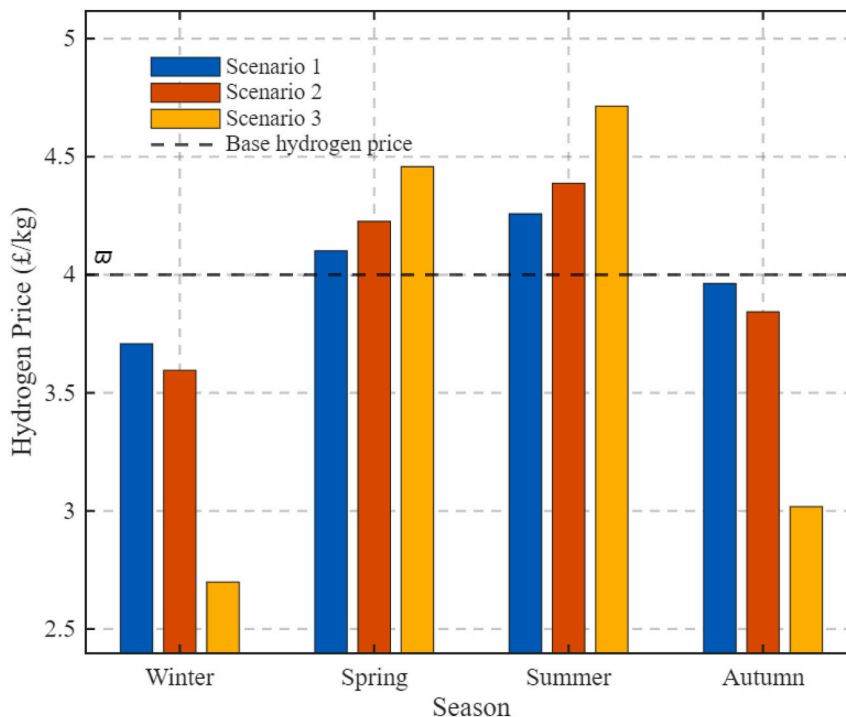


Fig. 11. Seasonal variation in hydrogen price under the three dynamic pricing scenarios, benchmarked against a base price of £4.00/kg.

Fig. 12 presents the sensitivity of the seasonal hydrogen price to each of the four scaling parameters (ϕ , χ , γ , λ) across the range 0.05–0.40, evaluated separately under surplus and deficit conditions. The surplus conditions correspond to Winter ($\mathcal{E}_i > 0$, $u_i = 1.00$) and Autumn ($\mathcal{E}_i > 0$, $u_i = 0.86$), while the deficit conditions correspond to Spring ($\mathcal{E}_i < 0$, $u_i = 0.78$) and Summer ($\mathcal{E}_i < 0$, $u_i = 0.70$), yielding eight parameter-condition combinations in total. The results reveal a pronounced asymmetry between the surplus and deficit price responses, confirming the dominant influence of the utilisation sensitivity factor γ . The γ Surplus line exhibits the steepest gradient of all eight parameter-condition combinations, decreasing from approximately £3.40/kg at a scaling factor of 0.05 to approximately £2.10/kg at 0.40 — a range of approximately £1.30/kg attributable to γ alone. This is physically consistent with the surplus adjustment term $[1 - \gamma u_i]$: at Winter utilisation of $u_i = 1.00$, every unit increase in γ produces the maximum achievable surplus discount. At $u_i = 1.00$ this term reaches its maximum sensitivity to γ , activating the full discount potential of the γ parameter — more so than in any other season where utilisation is below unity. In contrast, the γ Deficit line increases only moderately, confirming that the deficit adjustment term $[1 + \gamma(1 - u_i)]$ is attenuated by the relatively high utilisation values observed during Spring and Summer.

The penalty factor ϕ exerts the second greatest influence on the deficit price, rising from approximately £4.50/kg to £4.75/kg across the scaling factor range. The discount factor χ produces a moderate downward trend on the surplus side while its deficit influence is negligible — confirming that χ governs surplus discounting only. The seasonal variation sensitivity factor λ produces the smallest response under both conditions, with the λ Surplus and λ Deficit lines remaining nearly flat and closely tracking the corresponding χ lines, indicating that seasonal variability acts as a secondary modulating influence rather than a primary pricing driver.

At a scaling factor of approximately 0.25, the surplus and deficit lines within their respective groups converge most closely, reflecting balanced parametric sensitivity at the mid-range. Beyond this point the γ Surplus line diverges most markedly, confirming the dominant influence

of electrolyser utilisation at higher scaling factor values. All deficit lines remain above, and all surplus lines remain below $\varpi = £4.00/\text{kg}$ across the full scaling factor range. The adopted value of $\gamma = 0.25$ corresponds to this inflexion point — representing a balanced parameterisation that captures meaningful utilisation sensitivity without excessive price reduction. While higher values of γ produce stronger demand incentives, scaling factors above 0.30 risk generating surplus prices below the lower bound of projected 2050 LCOH estimates, which would compromise operator cost recovery.

The adopted value of $\gamma = 0.25$ therefore represents the balanced parameterisation at which the γ parameter produces a meaningful Winter surplus discount of 32.5% below ϖ — sufficient to incentivise flexible HGV refuelling during periods of peak renewable generation — without generating prices below the LCOH cost-recovery threshold of £2.91/kg. This confirms that the scenario-based selection of $\gamma = 0.25$ — informed by sensitivity analysis rather than formal optimisation — produces seasonal prices that are economically viable for HRS operators, cost-competitive for HGV operators relative to diesel, and aligned with the RTFO surplus-period dispensing incentive structure.

6. Conclusion

This study developed an integrated spatio-temporal modelling framework for assessing seasonal green-hydrogen production, HGV freight demand, HRS operation and DP for an offshore-wind-powered HRS in Portsmouth, UK, projected to 2050. The framework combined GIS-based analysis, validated wind-resource data, DfT traffic information and MATLAB simulation to represent offshore-wind generation, PEM electrolysis, auxiliary HRS processes and seasonal hydrogen-price formation. The strong agreement between the Global Wind Atlas and UK Met Mast data ($r = 0.95$, RMSE = 0.52 m/s, MBE = −0.01 m/s) supports the reliability of the wind-resource inputs.

The results revealed pronounced seasonal supply–demand mismatches. Winter and Autumn produced hydrogen surpluses of approximately 27 and 4 tonnes respectively, whereas Spring and Summer

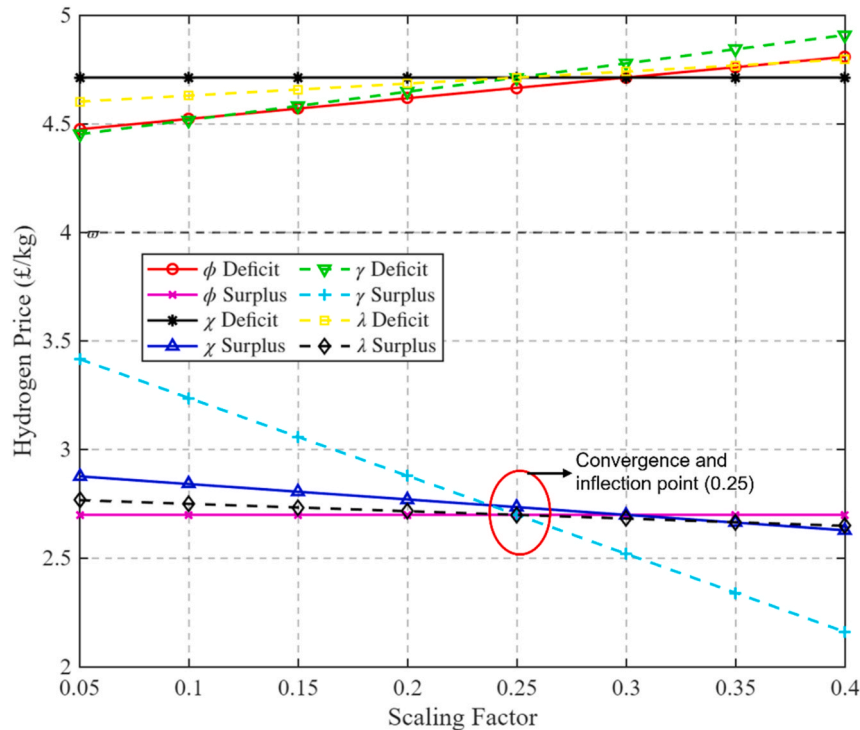


Fig. 12. Sensitivity of seasonal hydrogen price to scaling parameters (ϕ , χ , γ , λ) across 0.05–0.40 under surplus and deficit conditions. The oval highlights the convergence region around a scaling factor of 0.25, beyond which the γ -Surplus response diverges most markedly, confirming electrolyser utilisation as the dominant pricing factor. The dashed horizontal line denotes the base price, $\varpi = £4.00/\text{kg}$.

experienced deficits of approximately 10 and 27 tonnes. HRS utilisation varied from 100% in Winter to 70% in Summer, while 177 MWh of annual wind energy was curtailed entirely during Winter and Autumn. The coexistence of full HRS utilisation and wind-energy curtailment during Winter demonstrates that DP alone cannot absorb all surplus renewable energy, indicating the potential value of additional electrolyser capacity, electrical storage and hydrogen storage.

The proposed three-state pricing mechanism translated seasonal supply–demand imbalance, electrolyser utilisation and hydrogen-production variability into differentiated price signals. Using a base price of £4.00/kg, seasonal hydrogen prices ranged from £2.70/kg to £4.71/kg across the three scenarios. The sensitivity analysis identified the penalty and utilisation-sensitivity factors as the most influential parameters, while the comparison of Scenarios 2 and 3 demonstrated that electrolyser utilisation was the principal driver of the wider price separation between surplus and deficit seasons. All seasonal prices generated across the three scenarios remain below the diesel energy-equivalent threshold for HGV operations, confirming year-round cost competitiveness and providing economic signals for increased or rescheduled hydrogen offtake.

Overall, the framework establishes a direct connection between offshore-wind variability, HRS technical operation, freight hydrogen demand and seasonal price formation, providing a decision-support basis for renewable-hydrogen infrastructure planning and DSM in the UK HGV sector. The surplus-period discount signals are directly aligned with the UK RTFO framework, wherein increased hydrogen dispensing during periods of high renewable availability supports additional RTFC generation — complementing the HPBM revenue support structure and contributing to the Government's Clean Power 2030 and net-zero 2050 commitments.

CRedit authorship contribution statement

Oghenovo Okpako: Writing – review & editing, Writing – original draft, Validation, Supervision, Software, Methodology, Formal analysis, Conceptualization. **Imran Usman Sumda:** Writing – review & editing, Validation, Software, Methodology, Formal analysis, Conceptualization. **Kelvin Anoh:** Writing – review & editing, Validation, Methodology, Formal analysis, Conceptualization. **Ademola Odunsi:** Writing – review & editing, Validation, Formal analysis. **Jebraeel Gholinezhad:** Writing – review & editing, Validation, Formal analysis. **Haile-Selassie Rajamani:** Writing – review & editing, Validation, Formal analysis, Conceptualization.

Data availability statement

The data supporting the findings of this study are available from the corresponding author upon reasonable request. Wind resource data are publicly available from the Global Wind Atlas (<https://globalwindatlas.info>). HGV traffic data are available from the UK Department for Transport (<https://roadtraffic.dft.gov.uk>).

AI use declaration

During the preparation of this work, the authors used AI-assisted writing tools to support proofreading and structuring of content. After using these tools, the authors reviewed and edited the content as necessary and take full responsibility for the content of the publication.

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The authors declare that they have no known competing financial

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