Mapping hydrogen storage capacities of UK offshore hydrocarbon fields and exploring potential synergies with offshore wind

Anna Peecock[1,2]*, Katriona Edlmann[1], Julien Mouli-Castillo[3], Alfonso Martinez-Felipe[2] and Russell McKenna[2,4,5]

[1]School of Geosciences, University of Edinburgh, W Mains Rd, Edinburgh EH9 3LW, UK

[2]School of Engineering, University of Aberdeen, Centre for Energy Transition, Kings College, Aberdeen AB24 3UE, UK

[3]Department of Earth Sciences, Durham University, South Road, Durham DH1 3LE, UK

[4]Department of Mechanical and Process Engineering, Institute for Energy and Process Engineering, ETH Zurich, Zurich, Switzerland

[5]Laboratory for Energy Systems Analysis, Paul Scherrer Institute, Villigen, Switzerland

AP, 0000-0002-1705-4692; KE, 0000-0001-5787-2502; JM-C, 0000-0003-0811-6780; AM-F, 0000-0002-1446-8398; RM, 0000-0001-6758-482X

*Correspondence: a.peecock.21@abdn.ac.uk

Abstract: Energy storage is an essential component of the transitioning UK energy system, a crucial mechanism for stabilizing intermittent renewable electricity supply and meeting seasonal variation in demand. Low-carbon hydrogen provides a balancing mechanism for variable renewable energy supply and demand, and a method for decarbonizing domestic heating, essential for meeting the UK's 2050 net-zero targets. Geological hydrogen storage in porous rocks offers large-scale energy storage over a variety of timescales and has promising prospects due to the widespread availability of UK offshore hydrocarbon fields, with established reservoirs and existing infrastructure. This contribution explores the potential for storage within fields in the UK Continental Shelf. Through comparison of available energy storage capacity and current domestic gas demands, we quantify the hydrogen required to decarbonize the UK gas network. We estimate a total hydrogen storage capacity of 3454 TWh, significantly exceeding the 120 TWh seasonal domestic demand. Multi-criteria decision analysis, in consultation with an expert focus group, identified optimal fields for coupling with offshore wind, which could facilitate large-scale renewable hydrogen production and storage. These results will be used as inputs for future energy system modelling, optimizing potential synergies between offshore oil and gas and renewables sectors, in the context of the energy transition.

Supplementary material: Field data, developed suitability analyses tools and briefing document for expert focus group are available at https://doi.org/10.6084/m9.figshare.c.6150395

The deployment of renewable energy technologies at grid-scale will accelerate the reduction of carbon emissions needed to achieve national and global agreements and commitments (IRENA 2021; IEA 2021*a*). Within the international context, the UK is making good progress in the development of renewable energy supply, especially in electricity generation, which has increased from below 10% renewable a decade ago to 43.1% in 2020 (BEIS 2021*b*). The high proportion of non-dispatchable capacity, *c.* 17% of total capacity from solar and (increasingly offshore) wind in 2020 (BEIS 2021*c*), places significant strain on the energy system. Fluctuating generation needs to be accommodated through a combination of measures, including network expansion and densification, flexible supply and demand and storage at multiple spatial and temporal scales – collectively referred to as energy system integration.

Whilst energy system integration will include a number of measures, as a mechanism to flexibly transfer energy across sectors, time and space, the keystone lies in long-term energy storage at scale. Electrochemical batteries are suitable for short-term balancing, flexibility and ancillary services provision in seconds, minutes and hours, but they are not suitable for longer storage durations at the GW scale (DoE 2021). Pumped storage, on the other hand, is currently the most economical solution for long-term energy storage (Ma *et al.* 2014), and an established and proven technology. However, a lack of long-term remuneration schemes and uncertainty over

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electricity prices means pumped storage plants, which often have high associated capital expenses (CAPEX), can be viewed as less attractive (IEA 2021*a*). Historically, natural gas (NG) storage has provided economic stability during colder winter months in the UK, preventing drastic inflation for consumers. However, closure of the Rough Storage Facility in 2017 (CMA 2017), which comprised 70% of the UK's total seasonal storage capacity, has increased dependence on imported NG and liquified NG (LNG) to meet peak winter demand. Novel energy storage strategies, such as low-carbon hydrogen, are urgently required to ensure flexibility of supply and crucially alleviate reliance on NG imports, which satisfied 46% of UK NG consumption in 2020 (BEIS 2020*b*), increasing energy security in domestic, industrial and transport sectors (REA 2019).

Hydrogen (H_2) is an attractive energy carrier, due to its high molecular energy density (higher heating value of *c.* 285 kJ·mol^{-1}). H_2 obtained from renewable sources (so-called green hydrogen) can become a net-zero energy vector, due to its low environmental impact during its combustion or electrochemical transformation. Compared to pumped storage, both H_2 and air energy storage (liquid, LAES and compressed, CAES) technologies are currently less economic. However, large future cost reductions are expected once these are implemented at grid-scale, with estimations of halving their levelized costs of storage (LCOS) by 2050 and H_2 becoming the most cost-efficient form of seasonal storage (Schmidt *et al.* 2019). Even though large-scale H_2 storage and LAES/CAES may become economical solutions, questions remain about their contribution to and integration into the energy system (CCC 2020).

Different decarbonization strategies have already identified hydrogen as a key pillar in the global green energy transition, with potential to becoming a long-term energy storage vector, particularly in 'hard-to-abate sectors' of the economy (Masson-Delmotte *et al.* 2018; UNFCCC 2020). The UK is among more than 30 nations to publish a H_2 roadmap, highlighting essential regulatory frameworks, investment incentives and government support needed to facilitate the development of an economically sustainable H_2 economy (BEIS 2021*e*). Converting surplus renewable electricity to H_2 by electrolysis (green H_2) and storing it in the subsurface may represent an attractive opportunity for long-term H_2 storage (IRENA 2020). Excess on- and offshore renewable electricity generation can power electrolysers in times of peak supply; the generated green H_2 can then be applied in times of short supply and higher demand in different sectors. The coupling of green H_2 production and geological storage may therefore be an efficient balancing mechanism to support seasonal variation in demand in net-zero economies (Bruce *et al.* 2018).

In this paper, we evaluate the potential of H_2 geological storage as a large-scale, long-term and economic energy storage strategy. More specifically, we assess the storage requirements for balancing UK heating demands and explore opportunities to achieve this using subsurface H_2 storage. Furthermore, we will explore the potential sector coupling of gas storage in depleted hydrocarbon reservoirs and offshore wind, as part of a complete green H_2 generation, distribution and storage system. We believe that our study will prompt new research to support a wider uptake of H_2 technologies to achieve the ambitious net-zero targets.

Subsurface hydrogen storage

Seasonal H_2 storage requires capacities significantly greater than above-ground tanks can economically satisfy (Andersson and Grönkvist 2019). Subsurface H_2 storage (SHS) provides a large-scale and potentially economic energy storage solution, over seasonal and/or short-term timescales. Candidates for SHS include salt caverns, saline aquifers and depleted hydrocarbon reservoirs.

The UK currently has a seasonal NG storage capacity of 16.6 TWh, with a maximum delivery of 1.41 TWh per day, in stores across eight geological sites; the majority within salt cavern formations but over a fifth within porous rocks at Humbly Grove and Hatfield Moor facilities (BEIS 2021*d*). Commercial experience of pure H_2 storage, however, is limited to salt cavern technologies, such as the SABIC H_2 storage facility located at Teesside, UK, comprising three elliptical caverns that store 25 GWh (0.63 t) (Williams *et al.* 2020). Salt caverns offer a high degree of flexibility, both through the ability to rapidly switch between injection and withdrawal and complete up to ten injection/withdrawal cycles annually (Tarkowski *et al.* 2021), but low energy storage capacity compared to depleted natural gas reservoirs (Aftab *et al.* 2022). As a result, they are better suited to short- to medium-term energy storage, providing the essential balancing mechanism to support an electricity grid dominated by renewable energy sources (Caglayan *et al.* 2020). Therefore, salt caverns are not particularly well-suited to providing interseasonal gas storage.

Depleted hydrocarbon reservoirs hold 75% of the NG stored worldwide within the subsurface (Tarkowski 2019), and can provide similarly effective large-scale storage for H_2. The reservoir formation comprises high porosity permeable rocks, overlain by a relatively impermeable caprock that prevents fluid migration. Injected H_2 will displace formation waters or residual hydrocarbons occupying the pore space, and will accumulate beneath the caprock seal, from where it can be recovered as required (Heinemann *et al.* 2021*b*; Mouli-Castillo *et al.* 2021). Caprock integrity and storage behaviour of potentially available fields are well understood, based on a combination of historical extraction and demonstrated gas-sealing efficacy (Juez-Larré *et al.* 2019). Despite its greater diffusivity, compressibility factor and lower viscosity, Amid *et al.* (2016) show that hydrogen losses through dissolution and diffusion through the caprock are negligible. While pure-H_2 has not been commercially stored in porous rocks, town gas containing 25–60% H_2 has been stored within porous reservoirs in the Czech Republic, Germany and France (Zivar *et al.* 2021). While these porous reservoirs were commercially operated for decades as H_2-rich town gas stores, the experience demonstrated several key challenges, including losses due to microbial activity and geochemical reactions, that need to be better understood before commercial deployment (Heinemann *et al.* 2021*b*). In Lobodice, a 17% decrease in H_2 was observed over a seven-month cycle, consumed by methanogenic bacteria (Šmigáň *et al.* 1990), which demonstrates the importance of ensuring the environmental conditions of selected storage reservoirs do not promote microbial growth (Thaysen *et al.* 2021). Hence, until an actual commercial site is developed, it remains to be seen whether these technical challenges can be overcome, and their associated risks managed.

Using depleted hydrocarbon fields also offers the opportunity to benefit from repurposing existing infrastructure, widespread geographical availability and reduced cushion gas requirements, decreasing installation costs. These factors are particularly advantageous for repurposing and revalorizing old fields, such as those of the UK Continental Shelf (UKCS). Scafidi *et al.* (2021) estimated a total H_2 storage capacity for gas fields within the UKCS of 6900 TWh, based on reservoir formation pore volumes. Alternatively, Mouli-Castillo *et al.* (2021) calculated a potential 2661.9 TWh of available H_2 storage in 41 offshore UKCS gas reservoirs, based on NG production data. Developing the model of Mouli-Castillo *et al.* (2021) using NG production data, we account for geological and economic factors, as well as human error. Storage volumes are thus anticipated to be less than those calculated by Scafidi *et al.* (2021), which used minimal geological information. Although better than purely volumetric calculations, we recognize the limitations of the updated methodology. Until we have operational data it is debatable whether the economics and technical/geological risks of oil and gas production are transferable to H_2 storage and, therefore, whether this is the most optimal model by which to assess storage capacity.

Methods

Hydrogen storage demand estimate

Evaluating H_2 storage capacity estimates within the context of UK domestic heating demand is crucial for establishing a benchmark against which the suitability of calculated capacities can be assessed. We have quantified two scenarios for storage. In the first, we have considered storage of pure H_2 (net-zero scenario) and in the second, we assess the utilization of a 20% blend (vol% of hydrogen) with natural gas (transitioning scenario) (BEIS 2020*a*).

Subsurface Hydrogen Storage (SHS) requirements were based on non-daily metered gas demand data, accessed from the National Grid Data Item Explorer (National Grid 2021). Data have daily granularity, kWh precision and are spatially distributed across the UK's 13 Local Distribution Zones (LDZ) (Fig. 1a). The geospatial component, and its correlation to existing gas network infrastructure, ensures that storage capacity estimates are geographically relevant and economically feasible. The non-daily metered component of UK gas demand accounts for domestic and small business use, which is the target of our study, and excludes heavy industry and power generation (Wilson *et al.* 2013). Consumption data were collected for the 57-month period, June 2016 to February 2021.

Monthly UK NG demand was determined by adding the monthly demand across each LDZ, then compared to the mean monthly demand for each 12-month period, which is indicative of baseload requirements. Assuming a constant H_2 production rate equal to the annual baseload, in the absence of H_2 imports, we calculated the seasonal storage needs as the energy needed to satisfy the maximum cumulative demand in excess of the annual baseload (Fig. 1b). By calculating average monthly demand over each 12-month period (9 months for 2020/21), we reflect the full extent of change in seasonal demand, in opposition to previous reports that assume that spring and autumn storage requirements are not sufficient in magnitude to compete against alternative storage technologies (Mouli-Castillo *et al.* 2021).

Hydrogen storage capacity estimates

Geological site selection. In this work, we focus primarily on H_2 storage capacities of offshore gas fields within the UKCS. We note, however, that further studies should consider the complex multiphase fluid interactions possible within hydrocarbon reservoirs and consequent reduction of pore space availability, as well as potential contamination of stored H_2 (Scafidi *et al.* 2021; Thaysen *et al.* 2021). The majority of UK gas fields are situated in the Southern

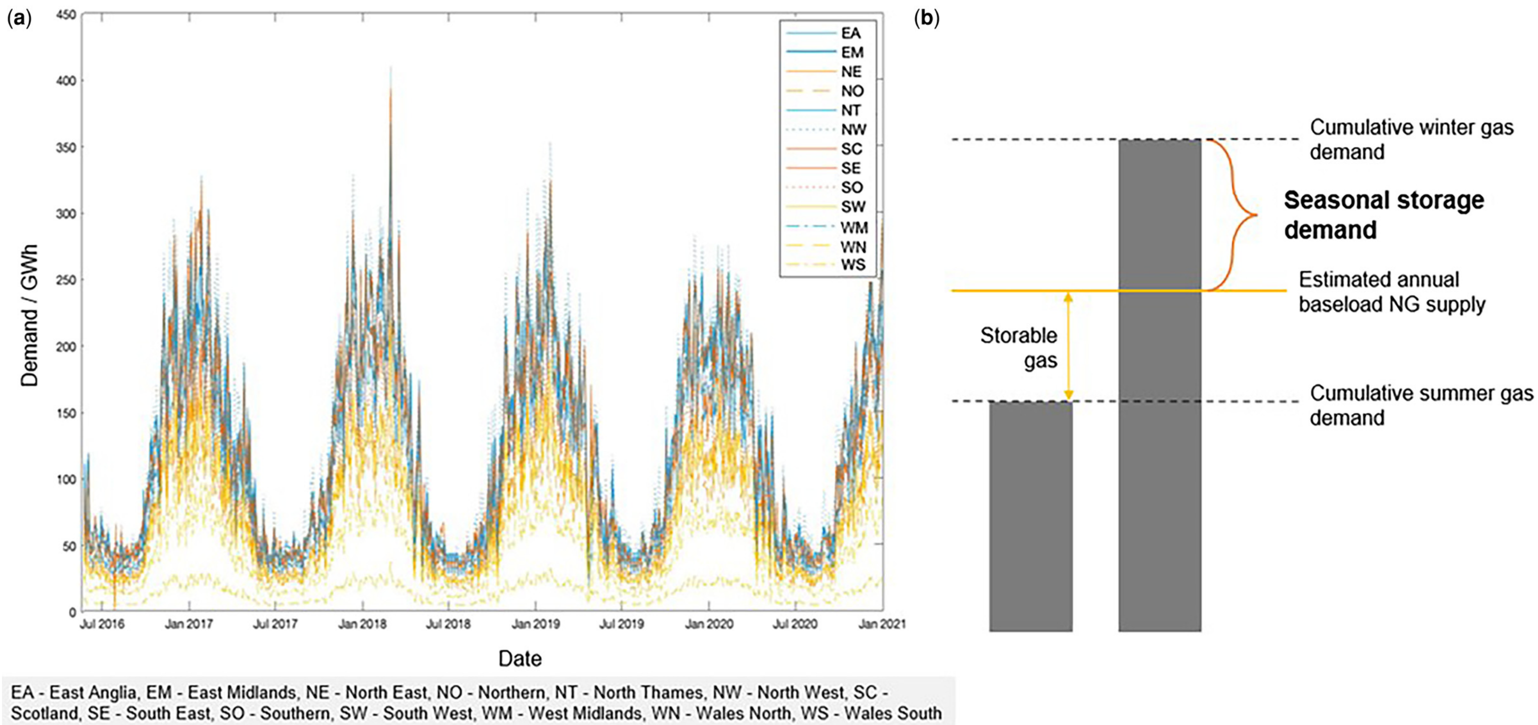

Fig. 1. (**a**) Non-daily metered NG demand by LDZ, representing domestic and small business supply (National Grid 2021). Colours correspond to respective district network operators: Scottish Gas Networks (red), Northern Gas Networks (orange), Wales and West Utilities (yellow), Cadent (blue). (**b**) Method used to determine seasonal storage demand calculation, based on data presented in (a). Source: modified from Mouli-Castillo *et al.* (2021).

North Sea basin, comprising predominantly Triassic, Permian and Carboniferous reservoir formations (Goffey *et al.* 2020), and in the East Irish Sea, which hosts primarily Triassic reservoirs (Gluyas and Hichens 2003). However, there are few gas fields in the Central and Northern North Sea, and West of Shetland regions, despite the fact Scotland has the best wind resource in Europe (O'Keeffe and Haggett 2012). Thus, in the interest of exploring the combination of offshore green H_2 production and SHS, some oil-bearing fields that have commercially produced gas within their lifetime have also been considered within this study. These comprise Middle Jurassic to Lower Cretaceous reservoirs that have significant gas caps with proven seal integrity, at scales that would enable H_2 storage within the gas cap zone (Gluyas and Hichens 2003).

Even though depleted fields are normally considered for gas storage (Stuart 1991; Ward *et al.* 2003), H_2 storage in partially depleted fields could prove economically advantageous, by reducing the volume of cushion gas that needs to be injected (Juez-Larré *et al.* 2019; Heinemann *et al.* 2021*a*; Heinemann *et al.* 2021*b*). Additionally, net-zero targets and growing pressure to reduce North Sea oil and gas exploration (IEA 2021*b*), as well as potential impacts of government incentives such as the North Sea Transition Deal (BEIS 2021*a*), promoting CO_2 and low-carbon energy storage, could result in operational fields facing decommissioning sooner than anticipated. These have thus been included within this study.

A total of 55 fields have been included in this study: 49 gas fields and 6 oil-bearing fields with significant gas caps. Fields with multiple reservoirs, such as the Hewett Field, have been included as distinct sites, representing individual H_2 storage prospects. Unfortunately, field data from some more recent explorations remain protected under the 'thirty-year rule' (Public Records Act 1967).

Storage capacity estimates. The volume of gas storable in each field was calculated using densities of H_2 and methane, obtained at reservoir temperature and pressure values available in the 'CoolProp' database, accessed in Python (Bell *et al.* 2014). Assuming NG properties to those of methane (Bains *et al.* 2016), the amount of energy storable within a reservoir as H_2 working gas can be determined using equation (1).

$$E_{\mathrm{H}} = HHV_{\mathrm{H}} \times \rho_{\mathrm{H,s}} \times OGIP \times \frac{\rho_{\mathrm{CH_4,stp}}}{\rho_{\mathrm{CH_4,s}}} \times UG \qquad (1)$$

where E_{H} is the energy stored as H_2 working gas (TWh); HHV_{H} is the higher heating value of H_2 (MWh kg^{-1}); $\rho_{\mathrm{H,\ s}}$ is H_2 density at reservoir temperature and pressure (kg m^{-3}); *OGIP* is original gas in place (m^3); $\rho_{\mathrm{CH4,\ stp}}$ is NG density at standard temperature and pressure (kg m^{-3}); $\rho_{\mathrm{CH4,\ s}}$ is NG density at reservoir temperature and pressure (kg m^{-3}); and *UG* is the fraction of storage volume usable for working gas. Hassanpouryouzband *et al.* (2021) demonstrated that a given caprock can retain a greater column height of H_2 compared to NG, thus by using a volumetric approach to calculate H_2 storage capacities, we implicitly assume that the gas/water contact will not be deeper than for NG, thereby accounting for maximum storage pressures. This is deemed suitable for early feasibility, but we would recommend more robust mechanical modelling of the storage to be undertaken. The effects of compressibility factor of the gases are accounted for in the computation of the gas densities, in the 'CoolProp' library which implements Helmholtz energy formulations. OGIP and recoverable volume of gas (RG) serve as useful proxies for available pore space and working gas recovery capacity, providing a realistic indication of working gas volume storable in a particular field (Mouli-Castillo *et al.* 2021). Field data presented in Table S1 also indicate the volume of residual NG within each formation, which reduces the additional cushion gas needed to ensure optimal reservoir pressures are maintained (Tarkowski *et al.* 2021).

The exact fraction of storage volume occupied by cushion gas will vary for each field, normally ranging from 0.3 to 0.6 (Flanigan 1995). Based on a precedent study on seasonal H_2 storage within the Rough Gas Field, we will use a value of 0.5 to maintain suitable reservoir pressures (Tarkowski *et al.* 2021). Since working and cushion gases are different, the cycled gas, H_2, must account for >20% of the cushion gas volume (Misra *et al.* 1988). We will hence use the following assumptions: (1) fields with RG greater than 62.5% of OGIP will have working gas fractions of 0.5; (2) fields where less than 62.5% of OGIP is recoverable have a working gas fraction equal to 0.8 of the recoverable fraction, thus ensuring >20% of the cushion is also H_2 (equation 2) (Mouli-Castillo *et al.* 2021).

$$UG = \frac{WGV}{WGV + CGV} = \min\left[0.5, 0.8\left(\frac{RG}{OGIP}\right)\right] \qquad (2)$$

where *WGV* indicates working gas volume (m^3) and *CGV*, the cushion gas volume (m^3). The *HHV* is the parameter used to calculate UK NG demand statistics (BEIS 2019). *HHV* indicates the upper limit for thermal energy released in the complete combustion of H_2, once the products have reached the original temperature and vapours condensed, taking into account latent heat of vaporization (PNNL 2021). A H_2 HHV_H of 39.4 kWh kg^{-1} is used in this study (Engineering ToolBox 2003).

Coupling hydrogen storage and offshore wind

A database of 96 fields, comprising the 55 newly calculated H_2 storage capacity estimates, combined with the 41 previously determined by Mouli-Castillo *et al.* (2021), was loaded into ArcGIS for geospatial analysis. Offshore wind (OW) installation data for February 2022 were obtained from UK Crown Estate (UKCE) and Scottish Crown Estate, then compared to 4C Offshore's 'Global Offshore Renewables Map', which included some projects absent from the UKCE dataset, that likely have not yet submitted a formal lease application (Crown Estate Scotland 2022; 4C Offshore 2021; UKCE 2021). Although option leases for Scotwind sites are yet to be signed, they have been included in proximity analyses. 33 OW developments were considered in this study, selected based on their operational status. Projects in the 'Development Zone' or 'Concept/Early Planning' phase, yet to obtain consent, have greater potential to incorporate H_2 generation and storage within their development models. A nearest neighbour analysis was performed to ascertain proximity of potential storage reservoirs to planned OW developments.

Expert elicitation and criteria development. This study employs a methodology based on the Analytic Hierarchy Process, a multi-criteria decision analysis that deconstructs a complex problem into several sub-problems (Saaty 1988; Ren *et al.* 2014). Five criteria were initially developed for determining the most suitable UK hydrocarbon fields for coupling with pre-development offshore wind farms, in the context of storage and generation of green H_2. These included H_2 storage capacity, length of existing gas pipeline, proximity to OW site, operational status of the field and field type. During our expert elicitation, detailed below, the following five additional criteria were identified: proximity to terminal, water depth, age of operation, reservoir depletion mechanism and number of wells.

Our expert focus group consisted of 16 individuals, approached by the authors, representing a variety of relevant sectors and organizations (Fig. 2). In advance, each participant was sent a briefing document containing a summary of the study (S2 focus group brief). In online 30 minute, one-to-one interviews, participants were shown a PowerPoint presentation containing Figures 5 and 7, then asked to critically review the original five criteria, ranking them based on relative importance to their industry and motivation. Experts were also challenged to justify the inclusion of additional criteria they considered important. As the proposed criteria span multiple areas of expertise, although all participants were able to rank them, the majority felt unable to suggest specific weightings. However, the discussions that ensued provided a wealth of qualitative feedback, based on industry experience, enabling the authors to ensure as many key criteria were captured as possible. It was important to consider interview data as guidance rather than fact, as each participant had their own vision of the 'best' decarbonization strategy for the UK depending on their sector, increasing likelihood of bias. Similarly, basing responses on personal experience among a focus group of varying levels and types of expertise could lead to biases, creating the illusion of validity in observational results (Tversky and Kahneman 1982). Despite this, the validity is strengthened by the diversity of expertise, cumulative results representing each major participant in the proposed H_2 generation, distribution and storage scenario.

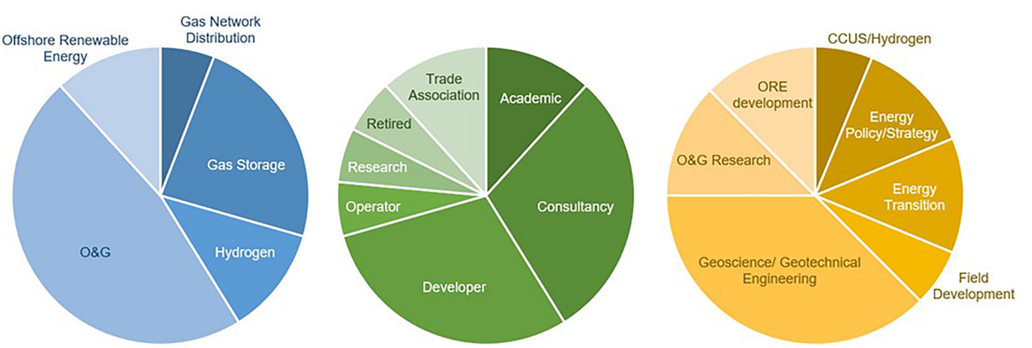

Fig. 2. Sector (blue), company type (green) and area of expertise (yellow) of expert focus group participants. O&G, oil and gas; ORE, offshore renewable energy; CCUS, carbon capture, utilization and storage.

Table 1. *Preferential scale for PCA*

Score	Interpretation
5	One an important consideration in initial screening; the other not
4	Both important considerations in initial screening; one more critical
3	Neither critical for initial screening; one poses greater technical challenges
2	Both pose technical challenges; one incurs greater cost
1	Both economic considerations; one incurs greater cost

This heuristic approach yielded sufficient information, both in terms of quantitative rankings and qualitative data, to facilitate the following paired comparison analysis (PCA), to rigorously assess our criteria and determine relative weightings. This provided a more robust output than a weighted decision matrix, which could have been subject to the unconscious bias of the authors. Assessing comparative importance, based on the scale presented in Table 1, each pair of criteria was evaluated (Table 2). For example, both H_2 storage capacity and length of existing pipeline are important considerations for converting a field to storage, but while a new H_2 pipeline could be built, the H_2 storage capacity of a field cannot be adjusted if insufficient, making this the more important criterion. The overall score assigned to each criterion was calculated to determine respective weightings (Table 3).

H_2 storage capacity and operational status are considered by the experts the most important selection criteria, as these parameters would most significantly affect the economic viability of a project, and thus the likelihood of commercial development. While H_2 storage within the gas cap of a gas- and oil-bearing field is deemed technically feasible (Mouli-Castillo *et al.* 2021), the additional complexity of multiphase flow fluid interactions between hydrocarbons and H_2, and higher cushion gas requirements, make 'field type' an important criterion. Length of existing pipeline and proximity of fields to both demand centres and OW developments can be considered largely economic factors, secondary to an initial site screening process. As the costs of retrofitting NG pipelines and building new H_2-pipelines are \$US3.1m and 7.1m km^{-1} respectively (McKinsey and Company 2021), repurposing existing pipelines has a substantial impact on CAPEX. However, technical challenges surrounding retrofitting for H_2 delivery, including embrittlement, H_2-enhanced fatigue and effects of sulfur residues (ACER 2021), would necessitate detailed analyses of each pipeline to assess feasibility.

While the operational status of a field, whether it is producing or decommissioned, may not in itself influence development potential, as point of depletion is determined economically, there are several parameters within this criterion to consider. On optimistic timescales, the need for commercial H_2 storage is not anticipated until 2035 (National Grid ESO 2021). Therefore, fields with a further decade of production could be considered optimal candidates, due to the shorter period of suspended use, where they could be vulnerable to post-production aquifer intrusion (Bentham *et al.* 2017). As a criterion, operational status reflects the business case for converting a hydrocarbon field for storage, which will drive commercial development. Considering fields not yet decommissioned, where useable sub/surface infrastructure exists, could create significant cost savings, improving the economic feasibility of development.

Water depth, age, drive mechanism and number of wells are all technical considerations that, while surmountable, could greatly affect project costs. Water depth, for example, determines whether both above-sea infrastructure and nearby OW farms would involve floating technology (depths

Table 2. *PCA matrix*

	A	B	C	D	E	F	G	H	I	J
A: H_2 storage capacity		A, 4	A, 4	A, 4	E, 4	A, 4	A, 5	A, 5	A, 5	A, 5
B: Length of existing pipeline			B, 1	D, 1	E, 4	B, 4	B, 5	B, 5	B, 5	B, 5
C: Proximity to OW				C, 1	E, 4	F, 4	C, 5	H, 2	I, 2	J, 2
D: Proximity to terminal					E, 4	D, 4	D, 5	H, 2	D, 2	D, 2
E: Operational status						F, 4	E, 5	E, 5	E, 5	E, 5
F: Field type							F, 5	F, 5	F, 5	J, 5
G: Age of operation								G, 3	I, 3	G, 3
H: Water depth									I, 3	J, 3
I: Drive mechanism										I, 3
J: Number of wells										

Letters indicate the more important criteria in each pair and numbers indicate comparative score, as per Table 1.

Table 3. *Criteria weightings, as determined by PCA results*

	PCA Score	Weighting
H_2 storage capacity	41	0.21
Operational status	37	0.19
Length of existing pipeline	30	0.15
Field type	28	0.14
Proximity to terminal	18	0.09
Drive mechanism	14	0.07
Number of wells	10	0.05
Water depth	7	0.04
Proximity to OW	6	0.03
Age of operation	6	0.03

>200 m), increasing development risk (ORE Catapult 2021). The number of wells associated with a field provides a useful indication of reservoir quality; a high number of wells/sidetracks could suggest poor permeability or high structural complexity, which may impede seasonal H_2 injection. Furthermore, it indicates the number of caprock perforations, that may not have been plugged effectively, depending on the age of operation, potentially compromising sealing integrity for H_2. Lastly, fields with a depletion drive recovery mechanism are less vulnerable than those driven by aquifer support, to both invasion of water during gas production and reduced storage capacity as a result of water influx (Wang *et al.* 2020).

Suitability analysis. Based on the criteria and weightings outlined above, fields were ranked to ascertain optimum fields for coupling with offshore wind, as part of a green H_2 system. Criteria were applied in a manner reflecting the type of field data; water depth, for example, was divided into two discrete categories, either greater or less than 200 m, whereas age of operation was applied linearly, the newer the field, the higher the score. Details and justification of how each criterion was applied can be found in Table S1.

Results

Hydrogen storage demand estimate

Figure 3 indicates the significant seasonal variation in domestic gas demand, relative to the annual mean (National Grid 2021), and suggests a maximum annual H_2 storage requirement of 119.80 TWh. A maximum value is taken, rather than the mean, to ensure that storage is sufficient to balance uncharacteristically high demand in particularly cold winters, thereby increasing energy security. Geographically interpreting these results by LDZ, Figure 4 highlights the uneven regional distribution of storage demand, largely influenced by high population densities, so-called regional demand centres, such as London and Liverpool.

Through comparison of estimated maximum H_2 storage needs with the calculated mean annual NG

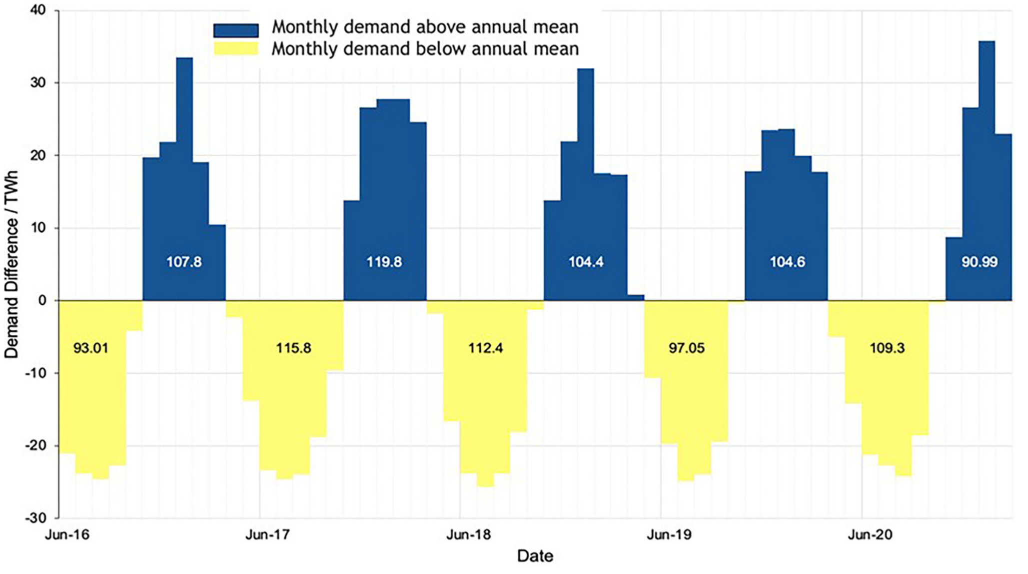

Fig. 3. UK domestic gas demand difference from annual mean, indicating seasonal variation in gas demand. Labelled numbers denote cumulated demand above/below annual mean. Source: based on raw data from National Grid (2021).

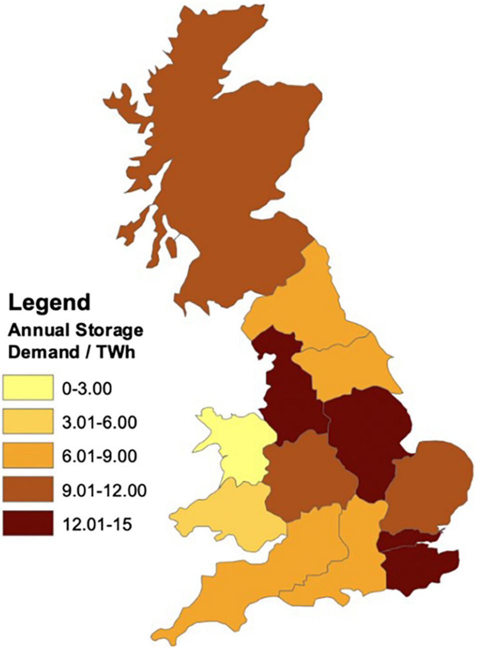

Fig. 4. Map showing annual H_2 storage demand by LDZ.

demand for domestic and small business users over the study period, 421 TWh, annual baseload demand can also be determined. 120 TWh of storage requirement suggests a baseload demand of 301 TWh. Assuming each kg of H_2 provides 39.4 kWh of usable energy (HHV_H), 7.64 and 3.04 Mt of H_2 would be needed to meet domestic baseload and storage energy needs respectively, in the event of a complete conversion of the UK grid to H_2. In the alternative scenario, in which 20% H_2 is blended into the NG feedstock, 8.92 TWh of H_2 storage (0.223 Mt) would still be needed to offset seasonal variation in demand (Table 4).

Table 4. *Annual UK domestic H_2 demand, based on actual NG demand over the five-year period studied*

	Storage demand		Baseload demand	
	Energy (TWh)	Mass (Mt)	Energy (TWh)	Mass (Mt)
100% H_2	120	3.04	301	7.64
20% H_2	8.92	0.223	22.4	0.568

Figures for 20% blend scenario are calculated using HHV in J mol^{-1}, based on a determined energy ratio of $0.0744 = 0.2HHV_{H2}$ / $(0.2HHV_{H2} + 0.8HHV_{NG})$ (Jin *et al.* 2022). Values reported to 3 significant figures.

Hydrogen storage capacity estimates

Storage capacities reported refer only to working gas, as cushion gas does not participate in injection/withdrawal cycles. The total estimated H_2 storage capacity across the 55 fields included within this study is 793 TWh. Combining this result with that of Mouli-Castillo *et al.* (2021), which calculated capacities for 41 different fields via a similar method, a cumulative 3454.9 TWh of H_2 storage is available within 96 fields in the UKCS, exceeding domestic demand by more than 25 times.

Individual field capacities are presented in Figure 5, spanning orders of magnitude of storage, from 0.8 TWh for the Topaz Field to 86.2 TWh for Hewett's 'Upper Bunter' Reservoir. Results suggest greatest capacities can be accessed through the Bacton Gas Terminal (300.0 TWh). Fields without existing pipelines connecting them to the UK grid, either due to decommissioning or alternative export strategy, account for 20% of the total assessed storage capacity.

Relative locations and capacities of all 96 fields are illustrated in Figure 6, together with pipelines, terminals and regional demand distribution. The Southern North Sea accounts for 54.6% of identified H_2 storage capacity, the Central and Northern for 36.4% and the East Irish Sea for 8.96%.

The ratio of storable energy within a field of H_2, relative to methane (E_{H2}/E_{CH4}), lies almost uniformly between 0.25 and 0.30 (Table S1). The exceptions, Dunbar and Curlew D, which have E_{H2}/E_{CH4} ratios of 0.32 and 0.31 respectively, have the highest recorded reservoir pressures. At high pressures intermolecular forces are stronger, reducing the volume of reservoir occupied by the same injected mass of H_2, increasing the relative energy storage capacity ratio. Higher pressures and temperatures typically increase with reservoir depth, with which E_{H2}/E_{CH4} also increases (Hassanpouryouzband *et al.* 2021).

Coupling hydrogen storage and offshore wind developments

Figure 7 presents a comparison of locations for the 33 OW sites and 96 hydrocarbon fields included within this analysis. Although the Southern Gas Basin contains the greatest number of potential H_2 storage sites, available wind resources can be up to 50% less powerful than those off the coast of Scotland (DTI 2004).

Applying the developed weighted criteria to the 96 fields considered in this analysis produced a suitability matrix comparing and ranking fields (Table S1). The 10 highest ranked fields, identified as optimal for coupling with OW as part of a green H_2 generation and storage system, are presented in

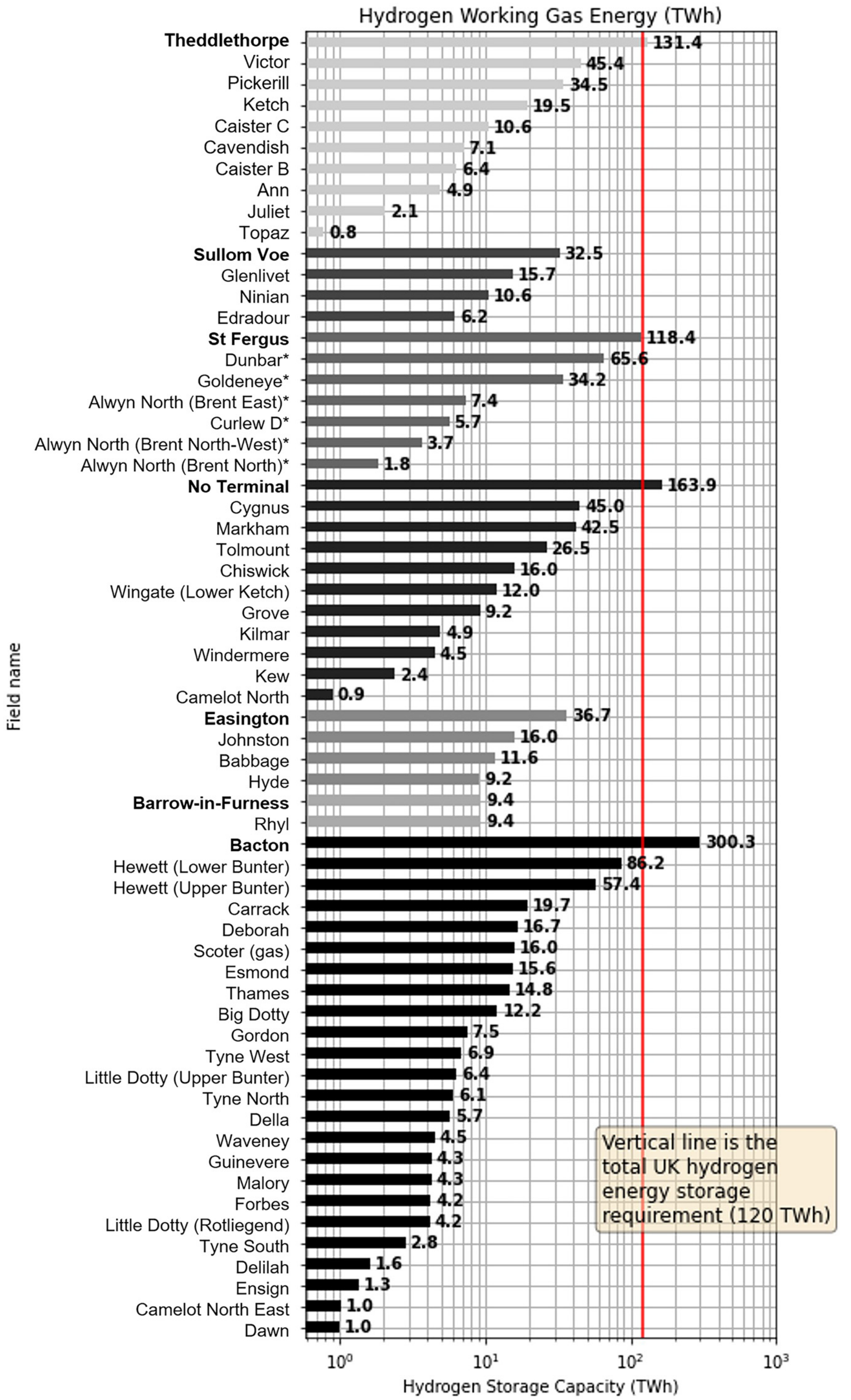

Fig. 5. H_2 storage capacities of analysed hydrocarbon fields, in terms of working gas energy content. Fields are sorted according to the gas terminal to which they are connected, the cumulative working gas capacity of which is shown. Fields marked with an asterisk are oil-bearing.

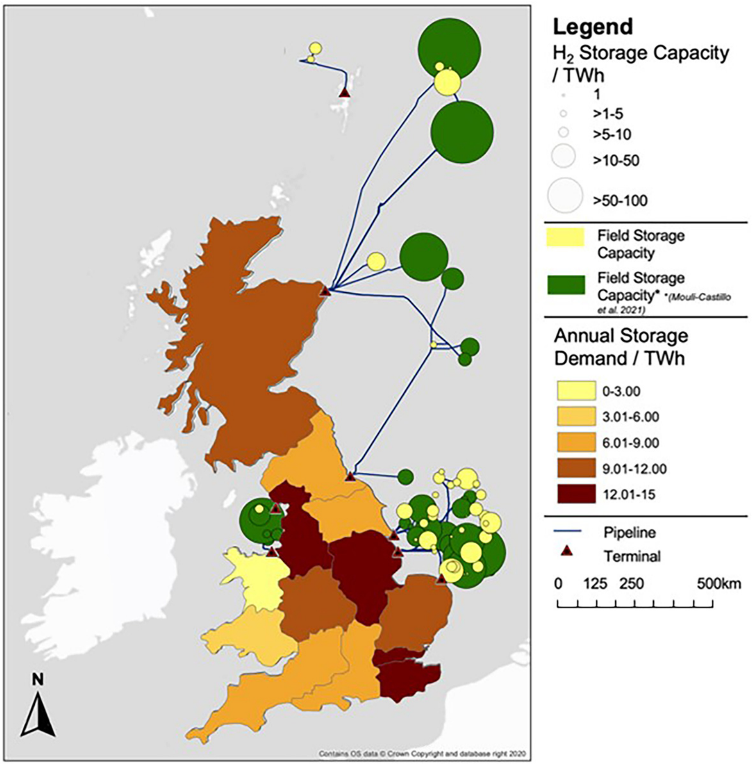

Fig. 6. Map showing relative H_2 storage capacities of analysed fields, annual storage demand of each LDZ and location of existing pipelines and terminals.

Figure 8. All ten identified are gas fields located in the Southern North Sea and East Irish Sea. Although both Hewett reservoirs ranked in the top ten, only one has been included due to the anticipated geomechanical complexities of simultaneously injecting and withdrawing H_2 from adjacent reservoirs in a single field.

Discussion

A notable result of our study is the vast quantity of H_2 required to decarbonize UK heating, based on current NG demand (421 TWh, 10.68 Mt_{H2}). Even to facilitate 20% blending of H_2 into the NG grid, outlined as a target in the UK Government's '10 Point Plan' (BEIS 2020*c*), 0.791 Mt_{H2} would be needed, including storage of 8.92 TWh. Whilst this is likely an overestimate, as a large proportion of domestic heating should be decarbonized through electrification and some properties will benefit from heat pump installations or new district heating schemes (Coal Authority 2020), many will require a clean molecule such as green H_2. However, results of the H21 North of England project, which investigated a 100% H_2 rollout and concluded 8 TWh of storage would be required to meet domestic demand (Sadler and Anderson 2018), validate our results, which estimate a storage demand of just under 9 TWh for the same area.

In a blended gas system, it is debatable whether deblending the gas stream for storage would make sense as it would ease financial, energetic and logistical challenges to the integration of the storage onto the main system (GIE 2021). However, from an industry standpoint, 100% H_2 storage is more likely to be used at production sites before it gets blended into the gas transmission system (GIE 2021). If we therefore consider that a pure-H_2 salt cavern can store approximately 300 GWh per cavern (Michalski *et al.* 2017; Caglayan *et al.* 2020), at 20% the H_2 energy stored per cavern is reduced to 22.3 GWh (7.4%). Per TWh of storage, 44.8 caverns are thus required, hence meeting the calculated 8.92 TWh storage demand for a blended system would necessitate 400 caverns. Presently, there are around 60 gas storage caverns in the UK (BEIS 2021*f*), both active and inoperative, falling significantly short of the vast

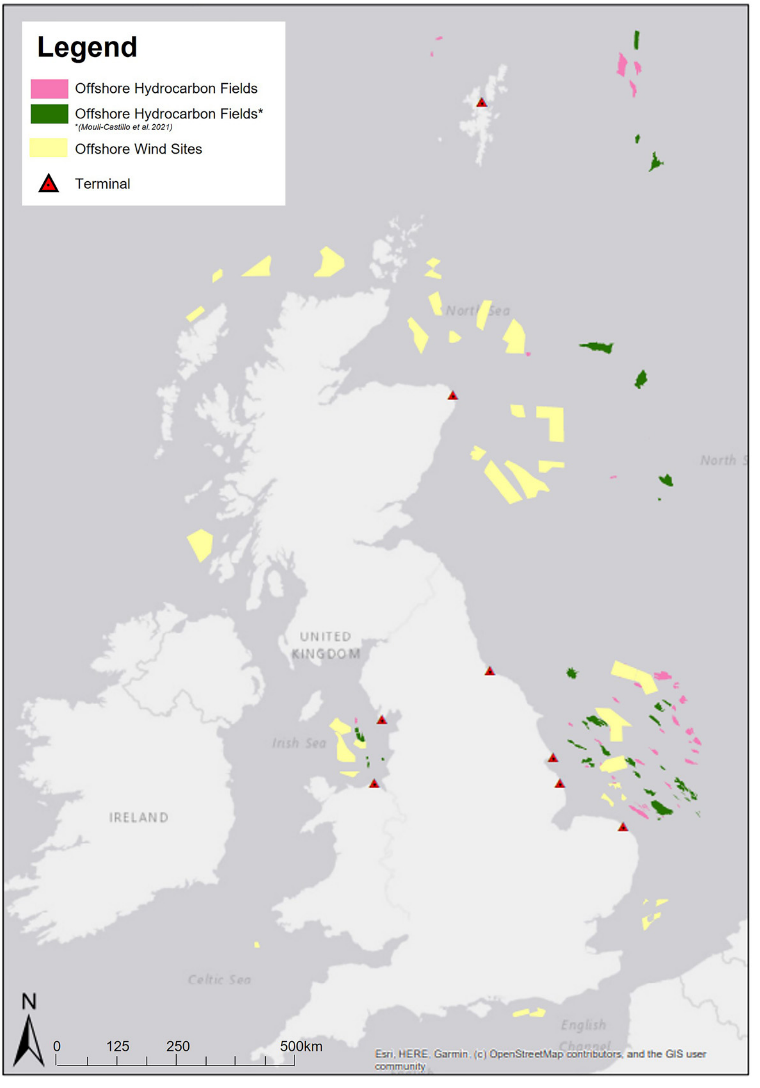

Fig. 7. Map showing pre-development offshore wind projects and potential storage fields.

number required. Conversely, if pure-H_2 was stored and blended on demand, only 30 caverns would be needed. Therefore, if a mixed model were implemented, in which some onshore caverns store blended gas and others, offshore and near the H_2 source, store 100% H_2, a middle ground could be achieved necessitating between 30 and 400 caverns. Exploiting storage of blended gas in onshore salt caverns, and the high flexibility attainable, could prove logical for peak load storage, offering high deliverability to satisfy short-term demand increases. However, use of just a few offshore porous reservoirs could reduce the need to invest in new salt cavern sites, while benefitting from existing infrastructure and comprehensive historical operation data. We thus present a nuanced picture that highlights the benefits of combining high-deliverability blended salt cavern storage and high-capacity offshore storage in depleted hydrocarbon reservoirs, to meet anticipated UK gas demands.

Our results indicate that there is potential of almost 3500 TWh of H_2 storage capacity in depleted or disused hydrocarbon fields in the UKCS, 790 TWh of which was determined in this analysis. This exceeds total estimated domestic H_2 storage demand by a factor of more than 25. Individual fields offer a range of capacities, from <1 to >85 TWh; utilizing smaller multiple fields could prove an

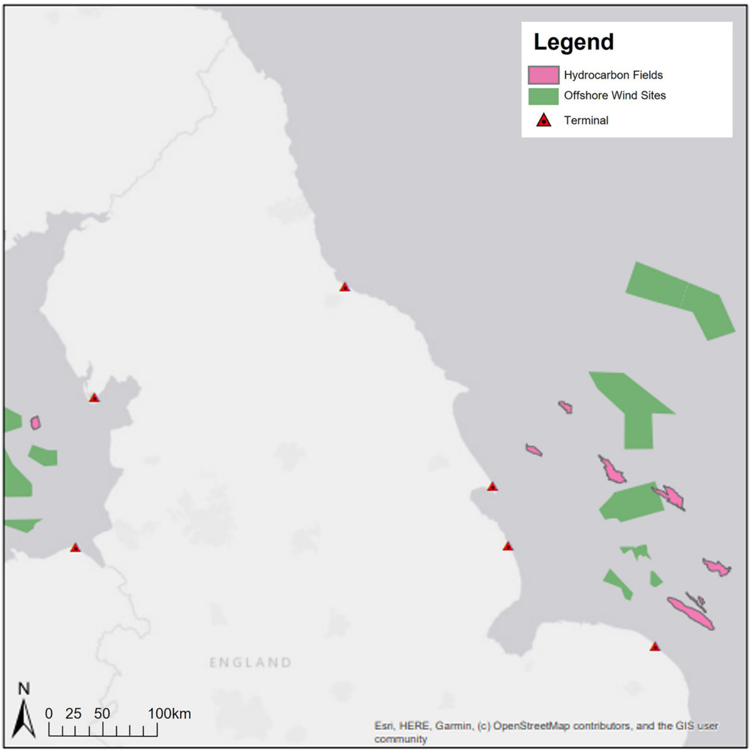

Fig. 8. Map showing optimal fields for coupling, according to developed criteria and weightings.

effective optimization strategy, ensuring sufficient H_2 can be extracted on demand despite its lower energy density (Arup 2016). Analysis undertaken also captures regional variation in domestic energy demand, highlighting the benefit of multiple storage sites, to individually satisfy the needs of a particular gas terminal. Figure 6 indicates that energy storage needs of each LDZ can be accommodated by a single field, connected through the associated gas terminal. Not only would this reduce transportation distances, increasing system stability, but also facilitate a more flexible system.

While the conversion of the National Transmission System for H_2 could result in significant changes to existing infrastructure, elements of the system with anticipated longevity, including geological reservoirs, geographical distribution of housing stock and locations of large gas terminals, constitute the focus of this study (Benson and Cook 2005; Mouli-Castillo *et al.* 2021). A more detailed model (such as that of Samsatli and Samsatli (2019)), comprising possible transmission network upgrades or modifications, could thus explore the relevance of potential H_2 storage sites within the wider context of techno-economic optimization using our geologically informed findings.

To validate the robustness of our methodology, capacity results were compared to findings of a study modelling the conversion of the Rough Field NG storage facility to H_2 (Amid *et al.* 2016), which estimated a H_2 energy deliverability of 42%, compared to NG. This study estimated a working gas capacity of 19.4 TWh, delivering 47.2% of the energy available whilst operating as a NG facility (Cave *et al.* 2016); aligned results thus providing confidence in this methodology. However, this figure is higher than the 27.7% reported in Table S1 as H_2 has a higher working to total gas ratio, 0.5 compared to 0.3 (Amid *et al.* 2016), indicating that the relative deliverability of H_2 for each field may be underestimated.

Results of our weighted analysis suggest the best prospects for coupling green H_2 generation and storage in depleted reservoirs are found in the Southern North Sea and East Irish Sea. It consolidates the assumption, echoed by our expert focus group, that proximity to demand centre (terminal), which in itself will drive the development of a H_2 economy and thus investment in distribution and storage, is critical when evaluating the commercial viability of converting a field for storage. The relatively low weighting assigned to ‘proximity to OW’ means criteria are relevant whether considering on- or offshore H_2 production, as each would require an export cable and H_2 pipeline. While repurposing existing facilities presents an attractive opportunity for reducing CAPEX, the increased complexity associated with offshore operations and maintenance, challenges of converting aged platforms to H_2 production facilities and increased ongoing costs makes onshore generation more commercially viable. However, demonstration projects including Dolphyn and Oyster, in which developers are integrating floating turbines and electrolyser technology (ERM 2021; ITM Power 2021), also indicate significant industry momentum behind offshore H_2 development.

It is important to consider that in the event of 20% H_2 blending for heat, smaller fields capable of satisfying reduced storage demand would score more optimally. This could promote the use of several smaller sites, serving more localized UK regions, increasing stability of supply. Blending offers benefits including the opportunity to utilize existing infrastructure due to reduced risk of H_2 embrittlement, affording time for the scaling up of green generation facilities, thus serving as a pivotal stepping-stone in the transition to a sustainable gas network (Deasley *et al.* 2020).

While useful for conducting a high-level evaluation, the suggested criteria could be further strengthened by considering deliverability of H_2 storage in each field, developing a timeline for how long it would realistically take to pressurize and fill a storage field, such that it could support seasonal demand variations, with H_2 generated by electrolysis and how this would affect the business development model. There are several scenarios in which the criteria weightings would differ, particularly in the context of alternative export scenarios. While proximity to a demand centre is crucial when considering H_2 for UK heating, it is insignificant if H_2 were to be exported by ship, in an alternative form (e.g. ammonia) or by international interconnector. The latter would likely favour fields in the Southern North Sea and could promote the UK becoming a net-exporter of H_2, in an established global H_2 economy.

Future research in this area, essential for enabling commercial development of seasonal H_2 storage in UK fields, should include analysis of how the planned, staged abandonment of offshore hydrocarbon assets could optimally be aligned with new offshore wind developments, and thus offshore green H_2 production.

Conclusions

In this study, we present a quantitative assessment of H_2 storage potential within hydrocarbon fields in the UKCE, in the context of decarbonizing UK heating. A total storage capacity of 3454 TWh was determined across 96 fields, significantly exceeding the 120 TWh required to meet forecast seasonal domestic heating demands, 8.92 TWh if considering a 20% H_2-blending scenario. Capturing maximum demand ensures storage will always offer sufficient H_2 capacities to meet UK needs, crucial for increasing energy security, a key priority of the UK's net-zero strategy. The most suitable sites for coupling subsurface H_2 storage in porous reservoirs with offshore wind, as part of a green H_2 generation, transportation and storage system, are gas fields located in the Southern North Sea and East Irish Sea. However, criteria weightings must be adjusted if exploring alternative export strategies to the domestic gas grid, such as shipping or international interconnector. This methodology can be applied to any region where field and offshore wind data are available, to provide a high-level assessment of H_2 storage potential and indicate sites that may prove optimal for coupling with green H_2 generation.

This study represents a comprehensive estimate of H_2 storage capacities in UK depleted and disused offshore hydrocarbon fields, assuming technical challenges can be overcome, and their associated risks managed. Whilst the results suggest a very large storage potential, further research is required to assess the technological feasibility of repurposing existing infrastructure for H_2 transport, as well as consideration of the deliverability of H_2 storage in potential fields and challenges regarding storage loss due to geochemical and microbial activity in porous reservoirs.

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Competing interest The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Author contributions **AP**: conceptualization (lead), data curation (lead), formal analysis (lead), investigation (lead), methodology (equal), software (equal), validation (equal), visualization (equal), writing – original draft (lead), writing – review & editing (equal); **KE**: conceptualization (equal), investigation (equal), methodology (equal), supervision (lead), writing – review & editing (equal);

JM-C: data curation (supporting), investigation (supporting), methodology (equal), software (supporting), writing – review & editing (equal); **AM-F**: supervision (equal), writing – review & editing (equal); **RM**: methodology (equal), supervision (equal), writing – review & editing (equal).

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Data availability All data generated or analysed during this study are included in this published article (and its supplementary information files).

Correction notice Table 2 has been revised. The publishers apologize for the error in the previous version.

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