ETP Hydrogen Innovation Programme

Industry Engagement Report

ARM Hub hydrogen energy park to decarbonise heavy-duty vehicles

Prepared for:

Dalhousie Estates

Contributing Authors:

Dr Jan Vorstius

Dr Christopher Dixon

Dr Wattala Fernando

Dept. of Mechanical and Industrial Engineering, University of Dundee

Mr Mark Richardson

Ristol Consulting Ltd

October 2023

This report summarises the work completed under ETP HIP project PH004-H2 on the investigation and development of an H_2 generation microgrid for the Angus Rural Mobility (ARM) Hub, Dalhousie Estate, Brechin, from July to October 2023.

Table of Contents

1. Introduction and overview

1.1 General introduction

This project has supported the Angus Rural Mobility (ARM) Hub, introduced in previous ETP-funded work (PR062-ECS), with the development of an energy park with renewable energy generation, green hydrogen production and a refuelling facility, intended to support local heavy-duty vehicle (HDVs). The ARM Hub site is situated on land owned by Dalhousie Estates, located west of Brechin, Angus. The estate areas of interest for this work are west/south-west of Brechin (highlighted in Figure 1.1):

1. the land assigned to the ARM Hub (approx 16 ha) at the north of the estate land;
2. the disused quarry site adjacent to Stannochy farmhouse, 1 km south of the ARM Hub site (primary consideration for solar PV siting);
3. regions of high ground (90-120 m), situated 2 km south of the ARM Hub (wind turbine siting).

The ARM Hub site is also for consideration for small/medium-scale renewable energy generation (e.g. roof- or ground-mounted PV), where possible and practical, acknowledging wider plans for the site, proximity to the A90 and the developed industrial/residential regions immediately to the east. The estate land considered here is currently managed by the estate, mainly for agriculture and with some regions of forestry and a small number of residential properties.

The site is served by 11 kV overground cabling from the Bridge of Dun 33/11 kV substation (1 km to the east), but which is constrained to 50 kW [SSEN]. The castle visitor centre and ARM Hub site both have electricity demand that is intended to form part of the load for the renewable generation from the microgrid, to offset grid electricity dependence.

Figure 1.1. OS map data covering sites of interest: ARM Hub (north); Stannochy Energy Hub and PV site (centre); optimal wind generation sites (south) [1] (UoD licence 100025252).

1.2 Summary of key aims for the ARM Hub

The ARM Hub project aims to build a green energy and mobility hub to progress the work towards a clean growth business park with supporting infrastructure. Angus Council's ambition, with private sector support, is to deliver a regional business park to provide the infrastructure, services and skills programme needed to enable the Tay region's transition to a low carbon, inclusive economy through a range of smart mobility and energy services. ARM Hub has the potential to support a step change in mobility infrastructure and heavy-duty vehicle refuelling near the site and A90 trunk road network, with the creation of a supply centre for H_2 and other low carbon fuels. In doing so, this is intended to create skills and new career opportunities within Angus and the Tay Region to support the further role out low carbon energy and technology [2].

The energy side of the business is one part of a scheme of developments including a facility providing clean heavy-duty vehicle fuelling (green hydrogen, bio-CNG, and rapid EV charging), alongside last mile logistics, car share and a range of micro mobility services. A digital twin will enable market access to project performance for wide application. Onsite renewable energy generation may support the further development (architecture, technology and operational platform) for smart local energy neighbourhoods.

The ARM Hub has already received £5.9 million of public funding (Tay Cities Deal £2.9m, Angus Fund £3m) to progress site construction. The ARM Hub has reached the stage of public consultation and plans are ready to be submitted for the development, with Dalhousie Estates and Angus council directly supporting the project. Green H_2 generated on-site is intended for sale to immediate demand in the local area, including supporting the plans by Angus Council to decarbonise local authority refuse HDVs in Forfar and Brechin with H_2 fuel cell powertrains. The ARM Hub project is progressing with multiple commercial themes, moving to construction phase at the end of 2023 subject to final planning approval. No groundworks or final plans for the construction phase have been actioned at the date of this report. With local authority support, public funding in place, a diverse business plan, and demand for green energy, the ARM Hub has an accelerated route towards commercial operation. The energy infrastructure is one part of the business model, working alongside the other themes to complement each other, but where each theme can be allowed to progress on its own merits. The challenges of commercial green H_2 production at the scale intended are, of course, clearly recognised from the outset.

Plans for the green energy/H_2 generation aspect of the ARM Hub have been considered for the Stannochy site as a central base for the dedicated electrical infrastructure, electrolysers and storage equipment. This can be collectively known as **Stannochy Energy Hub** for the purpose of onward planning and this report, although equipment may be physically located on either Stannochy or the main ARM site as required.

1.3 Summary of recent progress

Previous work under ETP KEN III (PR062-ECS), September 2022, had the following key outputs:

1. Discussion was presented for steps towards resource assessment and the installing of renewable energy generation equipment on the estate land, with the intention for this to repeated on similar sites (a.k.a. the 'toolkit').
2. The toolkit was applied to the estate land near Brechin, where the key wind and PV generation sites were identified. For wind power generation – the high ground at the south of the Estate was optimal due to its exposure to the southwest (approx 4 MW). There was also potential identified for medium-scale wind generation on the ARM Hub site, and one large unit on the north edge of the quarry at Stannochy.

For PV power generation – opportunity for ground-mounted PV on the quarry (approx 1 MW) was identified with some minor groundworks requirements. Floating PV of MW scale was considered but not identified as the primary opportunity, due to additional complications. Opportunities for small-medium scale building-integrated PV at the ARM Hub was discussed and some modular ground-mounted PV to increase generation as required, working within the site plan and building development. Working with a ratio of 1.45 MW PV to 1 MW wind identified as an optimal balance to maintain near-equal monthly average generation.

Some opportunity for run-of-river micro hydro generation was identified on the South Esk, although subject to further investigation on practically available head and not recommend for initial stages of development due to extensive planning requirements and long return-of-investment in comparison to the wind and PV opportunities. The survey of the Estate land did not present any natural opportunities for pumped storage or thermal/underground energy storage. Battery energy storage was identified as the primary storage choice for the scale of the development.

3. The 11 kV network supplying the Estate land was identified as constrained from the Bridge of Dun substation, until October 2028. This restricts power export from the site from renewable generation to the local grid, with a system export limit of 50 kW.

4. Power transmission across Estate land via mainly above-ground cabling was suggested to connect the generation sites directly to the ARM Hub, so that generated power can be used directly for H_2 generation and remaining capacity prioritised to offset Estate electrical demand. Any further excess exported where possible. Direct use/offset is clearly more beneficial than export and import via the grid with the present tariff structure (and also more profitable than producing H_2).

5. Working with a constrained grid was reported as a significant challenge to optimise and balance intermittent generation and demand at any scale significantly above 50 kW. Routes forward were identified/discussed directly with the ARM Hub team as:

   (a) restricting the system generation rating to approx 200 kW so that dumping of power would be infrequent/minimal;

   (b) oversizing the electrolyser rating (beyond optimal commercial rating) to manage more of the complete power range from the generation equipment;

   (c) commissioning a MW-scale system for 2028 to align with the removal of the grid constraint (with some attention to early reservation of power capacity).

6. Similar energy hubs producing green H_2 were noted to be at the development stage or not operational (e.g. awaiting further investment). Several factors affecting the routes towards commercial green H_2 production in the UK were considered (a refreshed survey of these points will be provided in the next section). In general, it is widely discussed that progress requires the development and growth of the following all simultaneously or at least aligned, to allow each stage to have commercial purpose, supporting each other:

   (a) supply of green H_2 (with generation of renewable power via wind and PV, conversion via electrolysis, as the primary route);

   (b) building the required infrastructure network and storage to make this available;

   (c) demand (within e.g. existing industrial processes, and for powering future HDVs and other hard-to-electrify sectors, in place of oil, gas etc).

Currently, H_2 demand remains satisfied almost entirely by fossil-fuel reforming processes traded via established fuel companies. Offsetting H_2 purchasing from non-renewable sources remains as an opportunity for sites such as the ARM Hub. It is well understood that the development of the key technologies involved in such generation sites (particularly any bespoke power conversion or control requirements, and electrolysis) are not in sufficient widespread use to bring down costs, and the availability of skilled engineers/technicians to build and commission the systems remain as challenges regionally. This presents a challenging initial landscape for the immediate consideration of investment in green H_2 generation.

Following the outcomes of the previous work and ongoing discussion with the Dalhousie Estate and lead project consultant, the following plan was formed based on point 5(b) for this current work as reported:

- Progress the investigation and simulation of a MW-scale microgrid based at Stannochy, with a 50-kW constrained grid connection, equipped with an oversized electrolyser stack rating to mitigate overgeneration issues. The simulation work intended to investigate high and low generation cases and scale optimal system configurations.

1.4 Project objectives

The project was set out with the following main objectives listed in the ETP fund application form:

(a) Develop theoretical computational model to simulate a balanced microgrid with H_2 production from electrolysis as the primary outputs.

1. Collect wind and solar datasets for site (supported by on-site measurements)
2. Write algorithm to simulate balanced systems from computation of supply/demand data and storage capacity
3. Optimise system scale for site profile

(b) Develop technical solution for the microgrid for power generation, storage and H_2 production

1. Design microgrid
2. Identify bespoke power control, conversion, and balancing requirements

(c) Complete commercial model / business plan for the H_2generation/microgrid

1. Integrate the project objectives, modelling and technical solutions into the design of the ARM Hub
2. Undertake market engagement with end users to inform the site requirements, scale, phasing and commercial modelling
3. Carry this work though into the wider project Full Business Case, to deploy the infrastructure in 2024.

2. Brief review of status, challenges and opportunities for green H_2

2.1 Review of current status

This review is written nearly eight years beyond the signing of the Paris Agreement during the UN Climate Change Conference (COP21), aiming to hold the increase in the global average temperature to well below 2°C, and to try to limit the temperature increase to 1.5°C, above pre-industrial levels [3]. One can illustrate the apparentness of the challenge from the constant records being reached (e.g. September 2023 was the most anomalously warm month ever recorded in the US [4]). There is no doubt that green hydrogen will be one part of the pathway forward to a zero-carbon energy mix, but the immediate steps and how this will progress via the multiple routes is not clear for all stakeholders.

Figure 2.1 is a snapshot of total UK energy consumption by source for 2022. Further analysis of this and a range of other datasets are presented by the source. 'Other renewables' is mainly biomass. Wind, biomass and solar energy resources are key and progressing technologies for the UK. Green H_2, as an energy vector, can be linked directly to wind and solar energy production through electrolysis, and to biomass via gasification processes.

Oil	36.47%
Gas	35.43%
Wind	10.29%
Nuclear	5.88%
Other renewables	5.57%
Coal	2.89%
Solar	1.79%
Hydropower	0.68%

Figure 2.1: Share of energy consumption by source, United Kingdom [5]

The UK Hydrogen Strategy launched in August 2021 is one formal pathway for government support for such processes for green H_2, which aims for 20 to 35% of UK final energy consumption shall be supplied from H_2 in 2050 [6]. Data for recent greenhouse gas (GHG) emissions from various sectors and traditional H_2 production is shown in Appendices A1 and A2. The figures show that the transport sector (road, air, rail and shipping) has been responsible for 30% of GHG emissions in 2019. These proportions are more or less same in 2021. Green H_2 has potential to reduce the GHG emission from all of these sectors i.e. in the transport sector through vehicles fuelled with green H_2 (fuel cell or internal combustion engines), residential heating networks, heat (and power) for various industrial and business sectors, and the agriculture sector (power, fertiliser production).

Global hydrogen demand increased 5% in 2021, reflecting recovery of economic activity in traditional applications from the pandemic-related curtailments. Figure 2.2 shows a useful global comparison of European data and recent demand (read as demand and supply), and policies and pledges for 2030. The Global Hydrogen Review 2022 [7] reports ammonia production at 34 Mt of hydrogen demand, methanol at 15 Mt the steel industry at 5 Mt. Almost all of this was met by industrial reforming of natural gas.

Electrolysis has traditionally formed around 4% of global H_2 production, little of which is coupled directly with renewable sources, but indirectly within grid networks now having increased renewable energy penetration. Much more progress must be made, and the route forward must involve practical, proof-of-concept, informative and visible projects such as the ARM Hub proposed in this work. Several very large H_2 projects are discussed in section 2.3 (and appendices). The present demands for conventional H_2 are all potential markets for green H_2, which can begin by offsetting the reformed H_2 and supplying directly to these current and emerging/developing H_2 markets.

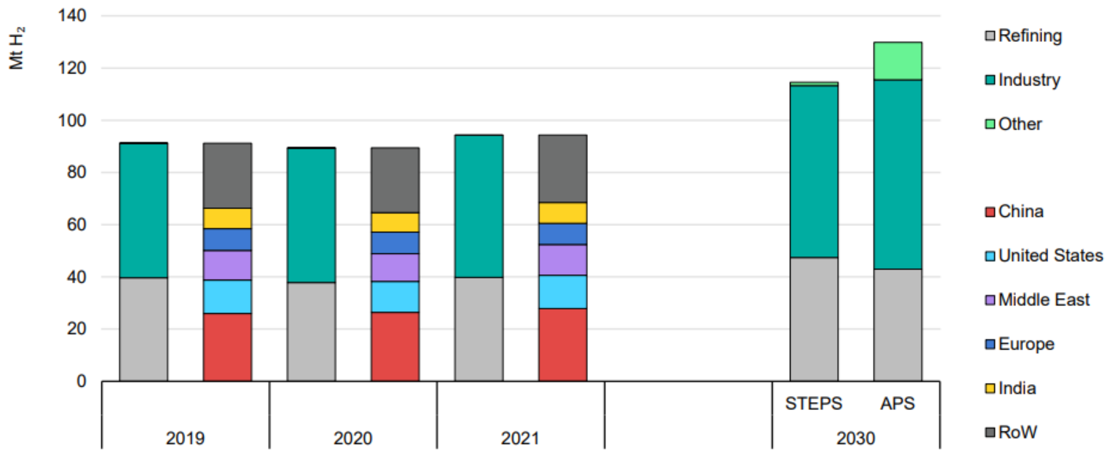


Figure 2.2: Recent hydrogen demand by sector and by region (million tonnes), with stated policies (STEPS) and announced pledges (APS). 'Other' includes transport, buildings, power generation, H_2-derived fuels and blending [7].

A summary of general H_2 demands is as follows [7]:

1. Ammonia/fertiliser synthesis, methanol synthesis
2. Industrial fuel refineries (crude oil processing)
3. Other industrial processes such as steelworks (including new steel production projects), electronics, glassmaking, chemical, materials processing, and pharmaceutical/biotechnology industries
4. Transportation via hydrogen-fuelled vehicles (fuel cells/internal combustion engines)
5. Emerging demands are other synthetic fuel process and power-to-x projects, domestic heating schemes (such as H100 in Fife), direct feed into the gas network, CHP plants.

Appendix A3 contains a further summary table of local demands. Key local demands for the ARM Hub include the local RCVs, bus fleets, local plant and agriculture, other local haulage/HDV fleets, whisky distilleries, biotech sector, bespoke projects involving H_2/energy storage/heating schemes and synthetic fuels throughout the Angus region and along the east coastline. These would be typically supplied by the large industrial chemical suppliers (such as BOC).

Generation sites (such as the ARM Hub) should focus on interventions in the local sector that are targeted and aligned with local demands, supply chain strengths, and skillsets [8]. Establishing local (but significantly upscaled) generation sites could open export markets to Europe. This sector could lead to a £25 billion contribution to Gross Value Added with over 300,000 jobs by 2045. This would require significant offshore wind potential, dependent on Scotland producing green H_2 that is competitive in a European market. A domestic H_2 market is likely to support anywhere between 70,000 to 175,000 jobs (£5-16 billion GVA) and is very dependent on the extent of the development of and penetration of H_2 in the energy system [8].

Figure 2.3 shows global H_2 demand in road transport has increased 60% since 2020, although from a low baseline. Figure 2.4 shows the stock of fuel cell electric vehicles exceeded 50,000 in 2021. Notably, based on

26 million kg total consumption for 10,000 buses/commercial vehicles, the 2021 data indicates an approximate per-vehicle H_2 demand of 2600 kg per year (for bus/commercial vehicles), up to 13,000 L diesel equivalent.

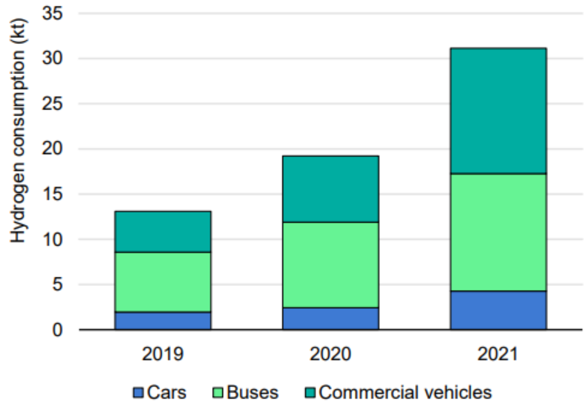


Figure 2.3: H_2 consumption by road transport sector [7]

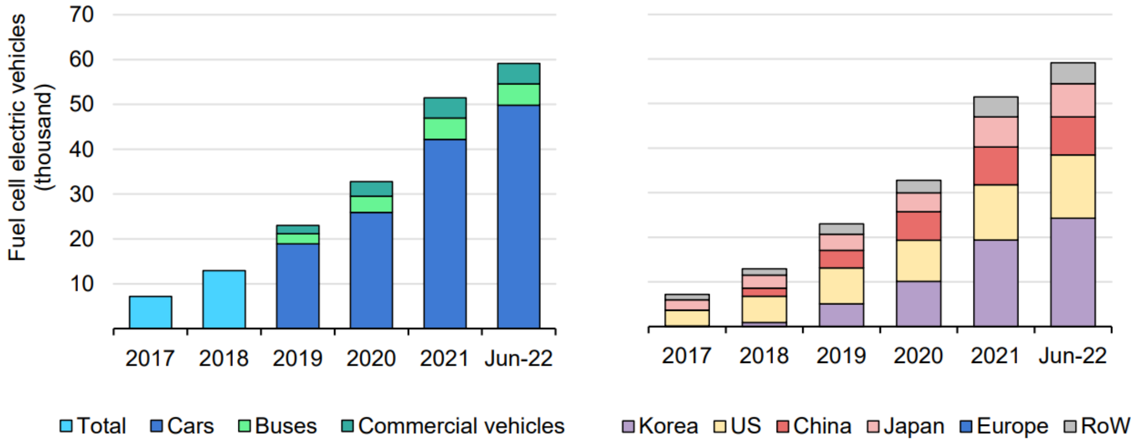


Figure 2.4: Global emergence of fuel cell vehicles [7].

Appendix A4 provides a graphical summary of the expanding infrastructure for H_2 in transport, with more than 700 hydrogen refuelling stations in operation at end of 2021.

2.2 Summary of cost and predicted cost for green H_2

The levelised cost of electricity (LCOE) is a good indicator to compare the cost efficiency of different technologies [9]. In 2022 the global weighted average LCOE of new onshore wind energy projects was approximately £0.033 kWh^{-1}, 52% lower than the cheapest fossil fuel option. For solar PV energy, the cost figure has fell to 28% lower than the cheapest fossil fuel option [10]. Both figures are broadly relevant to the UK, where onshore wind is the cheapest source of renewable electricity.

Wind and PV renewables are now leading the evolution of the UK electricity market and essential for the development of green H_2, and the new opportunities for H_2.

Figure 2.5 shows the most recent levelised cost of global H_2 production published by IEA as a useful reference to the wider setting. Cost data here broadly aligns with the future expectations for the ARM Hub green H_2 production. Figure 2.6 estimates the cost evolution of electrolysis to 2030. This includes the complete system (cells, control, gas handling etc), and implies costs at around £1,000 per kW in the UK in 2023.

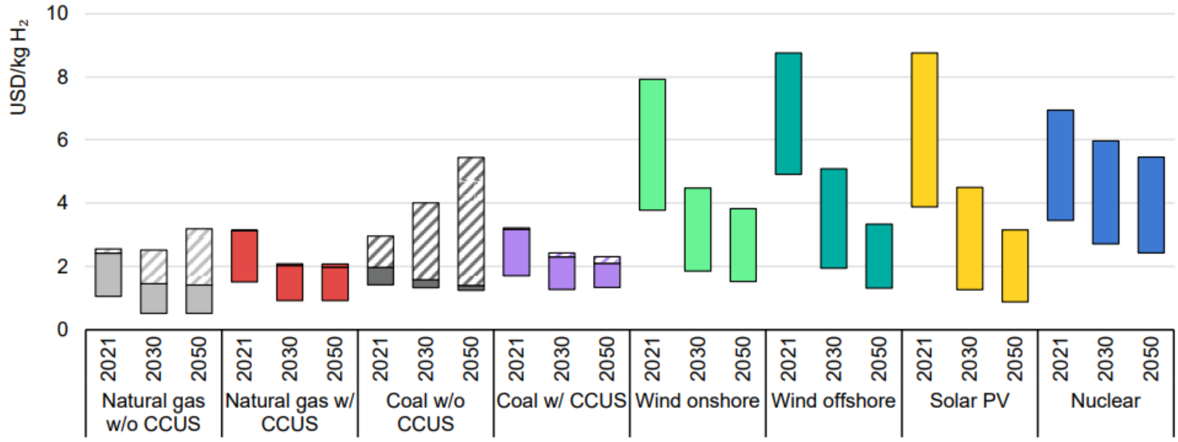


Figure 2.5. Levelised cost of Hydrogen in \$ kg^{-1}. The ranges reflect local variations in cost and cost efficiencies [7].

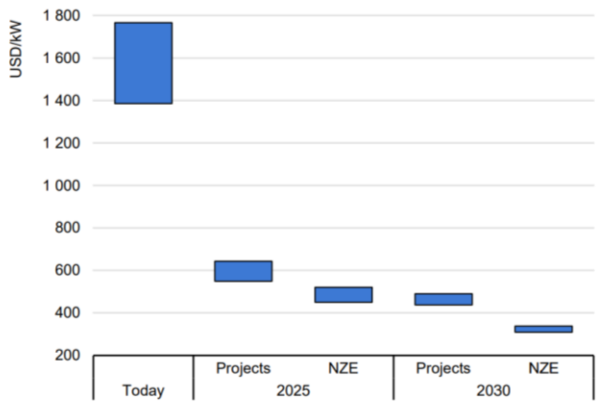


Figure 2.6. Estimated electrolyser cost reduction to 2030 (NZE - Net Zero Emissions by 2050 scenario) [7].

Appendices A5 and A6 contain a summary of recent data for electrolyser capacity and manufacturing capability. In 2021 approx 70% of the installed capacity was alkaline electrolysis, followed by PEM electrolysers accounting for 25%. Other emerging technologies are solid oxide and anion exchange membrane electrolysis. In many cases developers have not announced the electrolyser type, especially for projects coming online after 2025. The share of alkaline electrolysis in the total installed capacity (for which technology information is available) remains at around 60% for the next five years, but decreases afterwards, so that by 2030 the total capacity could be equally split between alkaline and PEM electrolysers. But the final split of technologies will depend on the choice of projects. For a combined capacity of 115 GW of projects the electrolyser type has yet to be announced.

According to IEA, global electrolyser capacity could exceed 35 GW by the mid-2020s and reach 134 GW by 2030 based on the current project pipeline. Electrolyser manufacturing capacity could exceed 60 GW per year by 2030, with Europe and China leading the way.

2.5 Review of recent green H_2 initiatives

As part of the UK Hydrogen Strategy 2021, the UK government formally recognised green H_2 as a viable solution to the climate challenge, ranking it second behind wind energy but ahead of nuclear, zero-emission vehicles and greener buildings. The UK government has agreed to support multiple low-carbon H_2 production technologies i.e. the ‘Net Zero Hydrogen Fund’ has announced 15 successful applicants (£37.9 million) to support the development of low-carbon H_2 production projects in March 2023. In addition, the government has announced a number of H_2 funding supports (i.e. hydrogen allocation rounds and the hydrogen production business model, cluster sequencing, hydrogen production innovation). Currently, there are 16 H_2 generation facilities (green or other) identified in the UK, listed in Figure 2.7. Further lists of planned projects are contained in Appendices A6, A7 and A8. In the case of the large projects in Appendix A8, if fully built out, these new facilities alone would provide more than 100 million tonnes a year, about one third of the total global requirement by 2050. A net-zero world would require approx 306 million tonnes of green hydrogen to be produced annually by 2050, according to the International Energy Agency (IEA). That would require approx 3 TW rated electrolyser capacity and 6 TW of renewable energy rated capacity, based on current technology.

Also, recently announced are US government and large industrial partner projects, very notable for the development of the global H_2 sector [11]. To reinforce a hydrogen economy (10 GW Hydrogen production by 2030), the UK is in the process of establishing H_2 transport and storage (T&S) infrastructure. Similar to the rest of the world, the UK has also identified the use of H_2 in the industrial sector, power generation sector, buildings to decarbonise heat, and transport sector (road, maritime, rail and aviation). Figure 2.8 shows the proposed electrolyser and CCUS-enabled hydrogen facilities in the UK.

Project name	Date online	Technology	Type of electricity	End use	Size	m^3 H_2 h^{-1}
HARI project, West Beacon Farm	2004	ALK	Other/unknown	Power, CHP	0.034 MW	7
PURE Project, Unst	2005	ALK	Other/unknown	Transport, Power, CHP	0.015 MW	3
Baglan Energy Park Wales	2008	ALK	Other/unknown	Transport, Power		10
Hydrogen mini grid system Yorkshire (Rotherham)	2012	ALK	Other/unknown	Transport, Power, Grid	0.03 MW	7
Fife, Levenmouth Community Energy Project	2016	Other Electrolysis	Dedicated renewable, onshore wind	Transport, Power	0.37 MW	82
Aberdeen Conference Centre	2018	ALK	Other/unknown	Domestic heating, biofuels	1 MW	200
Hydrogen plant - Orkney Islands - BIG HIT 1st phase	2018	PEM	Dedicated renewable, onshore wind	Transport, Power, Grid	0.5 MW	96
HRS Swindon	2018	PEM	Grid	Transport		
HRS Beaconsfield	2018	PEM	Grid	Transport		
HyDeploy	2019	PEM	Grid	Grid	0.5 MW	96
HRS Gatwick airport	2019	PEM	Grid	Transport		
Hydrogen plant - Orkney Islands - BIG HIT 2nd phase	2020	PEM	Dedicated renewable, onshore wind	Transport, Power, Grid	1 MW	192
Tyseley Energy Park refuelling hub	2021	PEM	Dedicated renewable, onshore wind	Transport	3 MW	577
Northern Irish hydrogen project	2022	Other Electrolysis	Other/ unknown	Transport	1 MW	222
Dorset Green H_2 Project	2022	Other Electrolysis	Dedicated renewable, solar PV	Transport	0.87 MW	193
Green Hydrogen for Scotland	2023	PEM	Dedicated renewable, solar PV	Transport	20 MW	3,846

Figure 2.7: Operational and under construction Hydrogen generation facilities in the UK

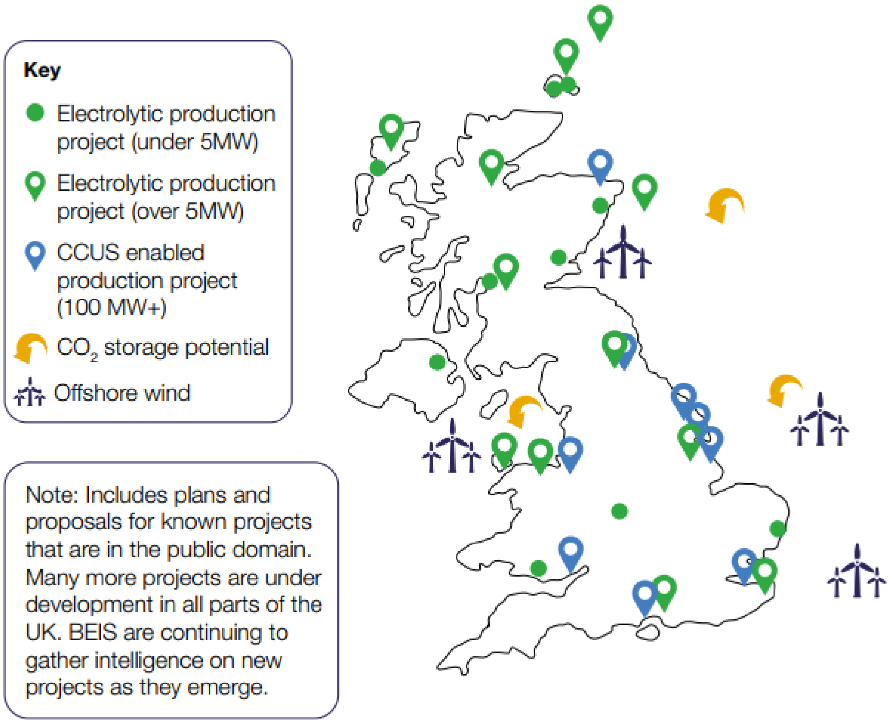


Figure 2.84. Proposed electrolyser and CCUS-enabled hydrogen production projects in the UK as of 2021 [6].

2.6 Responding to the demand of electricity and green H_2

A study led in 2021 aimed to determine if the actual produced H_2 can be decarbonised and become green, while the renewable energies system should also respond to the demand of electricity. For that purpose, the potentials of wind, PV and hydropower resources were studied, as they are considered as more mature technologies in comparison with other renewables. For the latter, European countries have already developed around 60% of the total potential of hydropower.

The potential of UK electricity is established as higher than the demand. The surplus is estimated at 900 TWh [12]. Appendix A9 shows a summary of the data.

2.7 Summary of key challenges for green H_2

There are a number of well-known general challenges across the H_2 value chain (production, storage, transport and distribution, demand) that need to be overcome in synchronisation to properly develop a hydrogen economy.

The key general challenges are considered in this report as follows:

- Policy and regulatory uncertainty. Most projects will need significant public funding.
- Current production is based on reforming. Green H_2 production is progressing too slowly. Continued conventional production to meet any immediate and short/medium-term upscaling of demand is a necessity in the route to a green H_2 economy, but is heavily scrutinised.
- Production costs for green H_2 (estimated/actual) must be significantly reduced, to align with conventional processes. This is in part due to the slow progress of electrolyser system upscaling, lack of trade experience and efficiency when delivering projects, lack of effective knowledge sharing by

industry and stakeholders/ unnecessary duplication of work, lack of complete systems, policy barriers to the role-out of renewables.

- Securing demands for new production sites from the offset.
- Lack of green H_2 near demand (e.g. Liverpool LCRCA H_2 bus fleet)
- Rural sites may have constrained grids. Off-grid systems and the bespoke power management requirements deter progression of systems.
- Availability of electrolysis plant, and complications from cell stability, thermal management, cost of MEA materials.
- The cost, availability and suitable refinement of power control/conversion requirements.
- Access to local skilled installers.
- Energy efficiency of fuel cells hinders full (round-trip) systems converting H_2 back to electricity.
- The technical and political/policy uncertainties and risks for large-scale hydrogen production investment.
- Cost-effective practical solutions need to be found for mobile transportation and storage, e.g. further R&D on possible solid-state storage.
- Distribution network infrastructure needs to develop along with supply and demand in a timely manner (i.e. to suit generation projects, supply and demand coordination).
- Effective CCS solutions are required to trade carbon rather than store it, to support conventional reforming methods.
- Use of FCs and H_2 limited to hard-to-electrify applications, such as HGVs, rural trains, shipping. There is uncertainty about the role and development of synthetic fuels and the extent of future battery electric vehicle penetration in these applications.
- Practical challenges with the integration into gas grids, e.g. upgrades of some old infrastructure to minimise leakage, updates for domestic boilers in phase with the transition to H_2 etc.

3. Computational modelling of Stannochy Energy Hub

This section of the report addresses objective (a).

3.1 General simulation setup and parameters

Simulation of Stannochy Energy Hub was completed using a custom computational model with a one-hour time base considering the inputs, outputs, energy conversion and storage parameters of a virtual microgrid. Incoming average power values were created for wind and PV with selectable rating, and adjustment for efficiency. Outputs profiles for the demand and export were entered and the remainder was considered for electrolysis and converted into H_2 outputs. These outputs were added to a running total for a storage value with upper and lower limits. Demand profiles for H_2 were created to reduce the storage total. Instances where storage limits were reached were set to require dumping of power or cutting H_2 demand as necessary. In some cases the limiting of export power was triggered following very low input levels. The parameters for establishing wind and PV data, system/subsystem profiles and efficiencies incorporated into the modelling are detailed in the next subsections. Three system configurations were run to simulate a set of theoretical microgrid specifications matching what has been discussed with the Dalhousie project team. Raw data was entered into Excel for convenient use by Dalhousie Estates. Further simulations with adjusted parameters can be carried out on-demand using the spreadsheets as created for this work.

3.2 Wind power generation

Summary of detail

- 1 MW and 2 MW rated wind turbine simulated profiles (based on Enercon E70 model) applied to data from site southwest of Stannochy, 80 m hub height
- Power curve in Appendix A10
- Capacity factor of turbine as specified set between 32% to 36% (10-20% reduction from raw data)
- Power ramping not considered in the hourly data

Wind data was analysed from online databases including Renewables Ninja (RN) [17] and the Global Wind Atlas (GWA) [18] applied to the optimal wind turbine (WT) site south of Stannochy. Also, data from an anemometer installed on the ARM Hub site (since December 2022) was analysed. In each case the wind speed and turbine performance at 80 m hub height was considered for a 2 MW WT. Note that turbines can be rated by factors such as their swept area or maximum electrical power, and also benchmarked at a specific wind speed. Large WTs are typically rated by maximum electrical power, whereas micro/small turbines can be rated more usefully by their performance at 12 m s^{-1}. Since the power output of large WTs must be considered by the local grid, it is more relevant to rate by their generator/electrical power limit. The generator limit is usually based on a working current limit at a fixed voltage and frequency, since the true limit could be much higher at higher voltage/frequency. The generator must stay within its physical current limit to prevent it being pulled out of phase (noting that generator torque and current are approximately proportional). The diameter/area of the rotor usually has more than one option available (e.g. for Enercon 2 MW: 66 m, 70 m and 82 m diameters), so that the power generation from a site can be taken to a reasonable maximum within the generator rating. Increasing the rotor size increases power extraction but adds additional cost, stresses, and further slows the shaft speed (not desirable for electrical power generation considering the existing low-speed conditions). Most modern large turbines are classed as fixed-speed to facilitate 50 Hz grid connection. Their efficiency (not power) is designed to peak around mid-ranges. This is for simplicity, ruggedness and overall practicality for the turbine and grid network. Techniques such as pitch or stall regulation may be employed to limit maximum power at the higher ranges where the aerodynamics become unfavourable due to the fixed-speed condition, but to avoid overloading the generator.

Wind speed and power data from RN is formed from global weather data sets adjusted for the grid reference. Wind speeds are converted into power using a simple algorithm, with the option to select different turbine types from a list of common turbines. The data is based on predicted/theoretical power curves considering swept area and a generator rating. This introduces some uncertainty to the dataset, as real generator specifications and turbine performance do not confirm so closely to these mathematical models, e.g. due to changes in air density, exact generator limits and several other practical factors.

A practical turbine specification should be chosen based on the site wind speed conditions and required rating etc. In the case of the RN models, the data for the Enercon E70 at 80 m hub height and with a limit of 2 MW was considered as most representative of a practical real turbine performance on the WT site. Other models appear to be impractical, close to theoretical limits, or not optimal. This is shown in Appendix A10 where the models are compared to the Lanchester-Betz limit (forms an approximate theoretical power extraction limit). Data for the E70 is likely more representative of the E82 based on comparison to theoretical expectations. Further consideration for exact turbine specification should be carried out more rigorously at a later stage with support from the supplier, when at the relevant planning stage.

It should be noted that the data in this report is simulated. Real turbine performance, whether from an Enercon E70, E82 or similar, will be reasonably similar to as shown here in terms of capacity factor, but the discrete hourly data points should be considered with some care concerning their individual accuracy. Data sets via computations/simulation cannot fully consider the natural variability of air flow and complicated underlying factors including those relating to the terrain type, wind direction, wind shear, turbulence, and also inaccuracies with turbine performance specifications etc. Renewable Ninja data was extracted for 2020-2022, indicating the data in Figure 3.1. The baseline data was adjusted by a factor of −10% for confidence.

Year	Average speed (m s^{-1})	Capacity factor (%)	Adjusted CF (%)
2020	8.6	41	36
2021	7.8	35	32
2022	8.5	41	36

Figure 3.1: Table of wind data values from Renewables Ninja.

Data from the final week of 2022 was mapped with the anemometer and compared to the Renewables Ninja dataset to provide some validation (data is shown in Appendix A11). The Renewable Ninja data is based on a larger time base of one hour and lacks the same detail. It does show a similar trend, but with a higher average speed. The lower values from the anemometer are partly responsible for this difference. To lift the values to 80 m the power law was used. This relies on a numerical classification of the surrounding terrain roughness (as an exponent) and allows simple conversion of speed at the required height (80 m) from the reference height of the anemometer (4.4 m). In the case of this work, one number was used to represent the terrain in all directions. This can lead to some further inaccuracy depending on the wind direction and the terrain variance by direction, so it should be noted that this technique is not exact. More advanced application of fluid dynamics theory and extensive computations would not be practical here. Another weakness is when low speed values register as zero on the anemometer. These may relate to significant non-zero speeds at the turbine hub height but cannot be mapped directly from a zero reference speed. Hence the data from the basic anemometer used for this work is useful to characterise the site, and compare nearby sites, but cannot provide an accurate set of discrete data at significantly raised height for the direct conversion to indicative turbine power values. No simulated wind data for 2023 was available at the time of this work to further validate using the anemometer data.

Data from the GWA builds an approximate rating for a grid reference, based on global weather datasets. The data can provide monthly and yearly averages, at heights of 50m and 100 m. At 80 m the data can be considered close to the mean of the two values given. For comparison, the GWA data indicated an average wind speed of 7.33 m s^{-1} for the WT site, which was used as a further validation. Based on anticipated capacity factors for turbines, e.g. from previous site work, the performance of a 2 MW turbine of 80 m hub height (similar to an Enercon E70 or E82) optimised for the site south of Stannochy could be similar to the data generated for this work, i.e. approximately 35-41%. To minimise the possibility of wind resource overestimation, the deduction of 10% was applied to the wind data, taking these values to 32-36%. For a 1 MW turbine, this could be in theory maintained at similar capacity factors through rotor design, but a more reasonable expectation would be closer to 32%. For the microgrid modelling, the hourly data values were adjusted by a total of −10% for the 2 MW and −20% for the 1 MW WTs, and set as inputs.

3.3 PV power generation

Summary of details

- 1 MW of conventional PV sited at Stannochy
- 10% electrical power conversion loss applied to raw generation data
- CF equates to approx 12%
- Power ramping not identified in the hourly data

Use of RN provides a reasonable data set for PV generation at the Stannochy site. The data does not consider the possible shading from nearby buildings or trees, and the surrounding raised ground. Simulation of PV data is much easier than that of wind due to the near-linear factors of irradiance to power conversion, assuming irradiance is accurately measured at nearby locations to give some understanding of local cloud cover patterns and general trends etc. A tilt angle of 38° was returned from RN as the optimal angle, which is standard for the specific latitude. For clarity, this means the panel is facing is 38 from vertical, and south facing. Between 36-40° will return similar outputs. Note that solar tracking systems are not recommended for Scottish sites due to the added complexity and cost, for minimal increases in generated energy due to regular diffused conditions. For the microgrid modelling, the RN data values were adjusted by −10% to account for electrical power conversion losses. The adjusted hourly data values were set as inputs.

The data does not consider a module specification or type, only the peak power rating of the system. The power rating is a useful measure, as all large module suppliers/wholesalers in the UK will be inclined to sell MCS-approved modules. These are tested for performance. The test conditions are at a specified irradiance level (1000 W m^{-2} at AM 1.5, 25 °C module temperature), and the performance stamped onto the module [19]. This means that 1 MW of one specified type of PV will produce the same as another. Choice of cell is a decision based on availability, cost, preferred efficiency (i.e. area used), perceived reliability, installer preference etc. Present use of PV modules is mainly from monocrystalline Si cells and these are recommended for the Stannochy Energy Hub. These were noted to be trading at approximately £180 kW^{-1} in September 2023 wholesale costs [20], with typical operation at around 20% efficiency (i.e. 1 m^2 of active module area produces approx 200 W during testing). Lower efficiency cells such as polycrystalline are slightly cheaper on a per-Watt basis but require slightly larger area, cell degradation of performance is slightly higher etc. Even cheaper cells are available but not recommended for this type and scale of installation. In Brechin, a ‘1 MW’ array would be likely to peak at around 0.9 MW of electrical power in mid-summer, clear sunny days. The 1 MW array would require a typical land area of approx 2 ha.

A sample of RN data was compared to a University of Dundee data set (Dundee) for validation. The data are shown in Appendix A12. A reasonable correlation was observed. The PV data used in this report can be considered accurate for an open-aspect site, although, like the case of wind data, the discrete hourly data points hide some significant variations and should be considered with some care concerning their individual accuracy. Shading from hills and trees in the southernly aspect from the Stannochy site will affect certain times of day, and for the surrounding high ground on the horizon that will have a small effect on the mid-winter generation. One particular concern for PV is the ramp-rate, e.g. the sudden change in power output due to isolated cloud shading, affecting performance over timescales of seconds and minutes. This was identified as one of the main stresses on the microgrid and partly defines the role, capacity and power rating of the battery energy storage system (BESS), along with the relevant power ramping capabilities of the electrolyser. Power ramping for a 1 MW array could be considered to reach ±400 kW within 10 s. This is one area requiring further investigation/mitigation, before battery requirements can be progressed.

3.4 Electrolyser stacks, H_2 storage and demand

Summary of details

- 1 MW rated electrolyser capacity with 80% average conversion efficiency (electrical energy to H_2)
- Max 1.11 MW incoming electrical power requirement from microgrid with 10% conversion loss
- Further 10% loss for storage and compression applied
- Storage modelled from 1000 to 2000 kg
- Demand set between 146 to 244 kg day^{-1} to optimise system output

Typical modern polymer electrolyte membrane (PEM) electrolyser technology operates between 75%-90% conversion efficiency (possibly higher by design for lower current density). Between 170-200 MJ of electrical power is therefore required to produce 1 kg H_2. PEM has been considered here due to current readiness and the high purity of H_2, compared to cheaper alkaline electrolyte technologies. Electrolyser stacks are considered to be size-limited due to their thermal management. Large plates can have thermal gradients between the centre and edges, which can lead to cracking. For this reason, a stack would likely be a set of smaller stacks, e.g. 1 MW made from 4 × 250 kW stacks. Each of these stacks would typically require a three-phase 415 V or 11 kV input when considering a conventional arrangement. The electrolyser would typically be built into a 6 m shipping container and the required power conversion supplied and set-up inside the container by the electrolyser manufacturer. The power conversion may step-down in ac via a conventional transformer, then rectify, then provide further dc-dc control as required, or it may work without an ac transformer and first rectify and then manage in dc.

The electrolyser is a dc system and the working voltage will be from 1.6 – 2.0 V per cell depending on power density required. This must be managed by the dc-dc power controller and it will build up the voltage to reach the rating of the system (i.e. from 1.6 V to 2.0 V) at an appropriate power ramping rate. This could range from 1°C in 30 s to around 10°C in 60 s for conventional stacks of the scale intended in this work, depending on technology, which means that the possibility of up to 30 mins to get a stack from idle to max power should be considered, or a 100 kW ramp up or down in 3 mins. Note this is dependent on the supplier's recommendations and it may be that the system can be ramped quicker on occasional emergency conditions with damage. The electrolyser can use thermal management to maintain an optimal working cell temperature (e.g. 75°C, this is a compromise between thermodynamic efficiency of the reaction and electrical conduction efficiency of the cell membrane) and this could be maintained at lower than rated power via the thermal management if set-up to do so.

It is important that the electrolyser system for Stannochy Energy Hub is equipped with complete dc-dc conversion and control requirements across each stack so that the system has maximum flexibility and can provide even distribution of power across stacks, minimising the effects of changes to the operating power. Individual stack selection may also be required for low-power conditions to reduce the minimum practical operating power limit (when current crossover may become significant across the complete set of stacks). Typical use of electrolysers would involve longer constant-power cycles, so the variable power set-up considered here is slightly bespoke and would likely require some additional power and thermal management control beyond the norm to ensure maximum suitability across all scenarios.

For the microgrid modelling, the stack configuration was set at as a demand of maximum rating of 1.11 MW. The internal cell arrangement was not specified (as this would be invisible to the microgrid). An efficiency profile was set for a typical stack taking into consideration the electrical power conversion loss and subsystem demand of approx 10%. The applied power was therefore assumed as up to 1.11 MW to give 1 MW electrolyser function. All the modelled datasets were based on this 1 MW electrolyser rating. The applied power was converted to H_2 production considering an average efficiency of 80% and additional storage losses of 10%. Non-ideal aspects such as the lower operating limit, down-time and power ramping where not considered at the one-hour discrete level. It can be assumed that the effects of ramping would be corrected over a one-hour cycle. Export and demand could compensate in the case of low generation and if necessary on a small number of occasions grid power could be imported to cover very low electrolyser operation. These are important features hidden within the data, although have quite negligible overall effect on the H_2 generation.

An alternative arrangement would be to power the electrolyser stacks directly from the BESS with dc conversion. These would be a dc load onto the batteries, requiring the same dc-dc conversion/control but not the rectification or transformers if applicable. Advantages of this are the potential for further simplicity. This may not align with the battery voltage arrangement and would redefine some of the BESS power conversion requirements (greatly increased grid-to-battery power conversion). In a future version without the grid constraints this may not be beneficial, since the role of the BESS would change. Either configuration was considered as invisible for the simulation of the overall microgrid performance.

H_2 storage was built into the model as a floating value subject to the H_2 generation and demand profile set. The base H_2 level was set at 2% of capacity. Maximum storage was set between 1000 to 2000 kg for the three microgrid models simulated. Hourly data provided H_2 input. Demands were set as outputs, forming a total stored value for each hourly data point. In the case that demand could not be achieved, or generation could not be stored, then these conditions were highlighted and considered in the overall demand figure.

3.5 Battery storage

Summary of details

- Requires sufficient power rating and capacity to stabilise the microgrid (including frequency) to match the requirements of the electrolyser, e.g. due to PV or wind power ramping, and sudden changes in demand (including microgrid demand or exports)
- Sudden shutdown due to no generation fault scenario while the electrolyser is operating at full power sets the highest rating (this exceeds any specification for PV/wind ramping or other demand). Rating may be reduced by uprated grid connection.
- Allows off-grid function/balancing during extended grid outages, the system would continue to power the demand including the electrolyser and ARM Hub (shutdown and restart would be required to re-establish grid connection).

The effect of the BESS in terms of both power rating and storage capacity within the one-hour dataset was minimal, since no visibility of sudden ramping was available. It was assumed that for most discrete data points the system would have sufficient power rating and be able to correct/balance the system within the one-hour time base. The effects of ramping were hidden within the dataset used.

The BESS power rating was noted to be defined by the maximum ramping of inputs in comparison to the maximum rate of change and limits of power demand from the outputs. The BESS must be able to respond to sudden changes in either inputs or outputs so that the microgrid can maintain the power supply to the electrolyser and stay synchronised with the external grid.

In cases of oversupply (e.g. when the PV and/or wind ramp up, or the ARM Hub site demand suddenly reduces, or the infrequent case of export to the grid failing), the BESS must hold the microgrid stable by consuming power, so that the microgrid remains synchronised. The power consumption level should reduce gradually as the electrolysers ramp up to align with the generation.

In cases of sudden overdemand (e.g. ramp down of PV/wind, sudden increase of demand at the ARM Hub), the BESS must start to produce power onto the microgrid. Some smart charge control would be required to maintain a part charged state, e.g. 90%, to allow response to both battery supply and demand.

The power rating for the BESS could not be established from hourly data. Some specific scenarios to further inform this can be considered from further analysis of the data shown in this section.

The BESS capacity must be sufficient to ramp up or down according to the ramp rate specifications of the electrolyser stack. This reaches a theoretical maximum in the case that the inputs step from their limit to zero, or zero to their limit, and the BESS fully compensates for this. The former would likely be through a fault scenario and more relevant. It is also possible to shut down or reduce inputs in special cases of ramping, i.e. through dc-dc control of PV and pitch control of WTs.

In normal operating conditions the BESS response would be matched to typical ramp steps in the supply (since inputs are much greater than the variable ARM Hub and export demands). This would require further detailed assessment of local PV/irradiance data and further investigation of wind data, at time intervals ideally no more than 10 s.

Although these types of scenarios are reasonably well understood (e.g. 'Rapid changes in insolation in southern England due to variation in cloud cover: influence on operation and testing of solar modules' by Goldstraw and Reynolds [21], and 'Estimation of the largest expected photovoltaic power ramp rates' by Lappalainen, Wang and Kleissl [22]), there may not be exact data established for the local region and for this scale of PV array.

Effects of ramping must also consider initial battery charge state. Assuming 90% capacity is maintained at the start of a ramp up of battery supply, the rating would have to be at least 130% of the max ramp scenario (considering DoD, loss etc). E.g. for a 400 kW ramp step, the electrolyser may require up to 1/5 hr to stabilise, and the BESS capacity would be required at approx 50 kWh (and 400 kW power rating). This is not a significant storage capacity, although a relatively high power rating.

Since the normal operating conditions of the system are unlikely to be challenging for the BESS, and this could be corrected within timescales of one hour, and ramping was hidden in the data, the battery charge state was only considered in specific scenarios within the dataset.

3.6 Simulation results

Datasets using the following three baseline microgrid systems in Figure 3.2 were simulated for 2020-2022.

Parameter	System 1	System 2	System 3
WT rating	1 MW	1 MW	2 MW
PV rating	1 MW	1.45 MW	1 MW
Electrolyser rating	1 MW	1 MW	1 MW
H_2 storage capacity	1000 kg	1500 kg	2000 kg
BESS capacity	Not specified within hourly data	Not specified within hourly data	Not specified within hourly data
Average H_2 demand request	146 kg day^{-1}	158 kg day^{-1}	244 kg day^{-1}
Average export	50 kW	50 kW	50 kW
Average site elec demand	10 kW	10 kW	10 kW
H_2 demand satisfied	128-143 kg day^{-1}	131-162 kg day^{-1}	213-249 kg day^{-1}

Figure 3.2. Table of simulation parameters

The full datasets are graphed in Appendices A13, A14 and A15. System 1 is intended to be a theoretical baseline/entry point and simple to benchmark. System 2 represents the case of close balancing of monthly energy production from wind and solar energy. System 3 is based on a specific WT, with significantly larger generation.

3.7 Analysis and summary of data

The final H_2 data broadly aligns with expectations. H_2 storage capacity is key to providing a buffer against volatile supply profiles and regular and flexible demand outputs. 2000 kg stored at 10 MPa (100 bar) would require a theoretical tank volume of 250 m^3, for example this could be formed from five cylindrical tanks of diameter 2.4 m and length 10 m. This and larger tank options are not prohibitive in terms of mass and volume on the Stannochy or ARM Hub sites, or higher pressure storage, but would be subject to further investigation of cost factors and practicalities etc.

The maximum power ramping (shutdown) for the electrolyser in the case of system faults has been identified as the power rating factor for the BESS. This would be defined by the electrolyser supplier, depending on the robustness of the stacks, thermal ramping characteristics, internal thermal management resilience, whether this has internal power storage, and the maximum import from the grid.

Power ramping from PV was identified as the largest input ramp during normal operation. This could ramp by 40% of the PV rating over a time duration of 10 s. This is unlikely to exceed the specification for any emergency shutdown power provision.

The content and data provided in this section is subject to consideration of various technical factors discussed in section 4.

4. Microgrid technical solutions

This section of the report addresses objective (b).

4.1 Overview of technical solution

The Stannochy Energy Hub microgrid and data simulated and reported in the previous section used an input/output model and typical characteristics of each sub system to generate expected H_2 outputs, demands, and the running total for storage (H_2 available on demand), as specified. In each case, reasonable performance characteristics of each subsystem were applied within the model. This section discusses some of the practical and technical factors of each subsystem and the overall microgrid considering connection to a constrained local grid network. This is intended to provide some insight to its layout, development and additional requirements. Further review/investigation of various planning aspects, applicable grid codes and electrical power regulations should be considered alongside this.

4.2 Connecting to the constrained grid for export and demand offset

Regular export to an unconstrained grid experiences a practically unmoveable frequency and the generation systems can simply work to their limits. Demands within the system will reduce the export and are easily compensated by the grid when necessary. The control of such a system is easy and robust. For a constrained connection and with oversized generation considered in this work, the situation becomes challenging, as the generation must be controlled carefully. Since this is not easily possible for a large WT within the timescales required, variable demand (and supply) must be present, in the form of the BESS continually balancing the microgrid. The additional challenge is also the lack of control over the electrolyser in terms of fast power ramping. In such cases a sophisticated and bespoke power control system is necessary.

The microgrid will likely be restricted to one connection point to the local grid, ideally at the point of demand. This will be limited to 50 kW export before 2028 (subject to confirmation of works by SSEN). Import rating is subject to request and availability. It may be necessary to form one larger incomer to serve demand at the ARM Hub and Castle Visitor Centre sites to provide one connection point for the microgrid, so that maximum power can be offset. Offsetting demand and exporting is achieved by frequency control, trying to speed-up the local grid frequency to offset demand, and to export. With a constrained grid connection this will require the microgrid control system to continually sense the local grid frequency and allow the inputs, BESS, electrolyser demand and other demands to be managed so that they balance out and result in the export remaining very close to 50 kW (depending on how strictly this limit is enforced by the grid operator).

Sudden changes in demand or supply anywhere in the microgrid will have to be balanced immediately by the BESS. Sudden changes e.g. switching on a 10 kW load in the demand sites will ask this from both the main grid and microgrid. How this is balanced, and how quickly, will depend on the system, but it is likely that the control system will sense this from a change in the frequency and will apply power quickly from the BESS. Sudden increase in generation could be larger and must be limited so that it does not overload the grid connection or demand site (these are essentially two features of the same connection point). Further bespoke power measurement/control at the demand sites may be required to optimise the response of the microgrid to these changes. In some cases the BESS would be continually working to balance the microgrid. Fixed export may be maintained more easily with a dedicated ac-dc-ac load system that creates a constant 50 kW load onto the microgrid for the export and is not frequency-dependent. A similar strategy may be required for the offset of demand to regulate this more easily.

4.3 Wind turbine technical points

WT units are 3-phase ac devices. The voltage is set by the generator spec/manufacturer, it can be assumed as 690 V phase-to-phase (50 Hz when synchronised) for this stage of work. This will be stepped-up (11 kV) at the site to allow the 1 km transmission to Stannochy. The WT site should be managed by a control unit to manage demand or shut down requests, monitor faults and running data. Regulation of power and start-up/synchronisation can be achieved by pitch control, for example slight changes in pitch regulate torque, and speed in the case of start-up. Continual dynamic control of pitch to manage microgrid power is not advised due to excessive wear. Battery load management should maintain the balancing. Sudden changes of frequency will be challenging to manage and correct due to the inertia of the WT that will not respond quickly. Start-ups may also be difficult for the BESS to balance and may require certain low wind conditions (start-ups should not be regular events).

4.4 PV technical points

PV is naturally dc. When coupled to a grid it is set into strings with dedicated dc-dc converters/inverters to track maximum power and form the three phases. At MW scale the output cabling cannot travel far at low voltage so would have to be stepped-up, either in dc or ac, to link to the microgrid and demands. At the Stannochy site this could accommodate either a dc or ac connection between the PV and BESS. The PV can be shut down or controlled by the dc-dc converter. This may be required during excessive ramp-ups, faults, or to support the microgrid/BESS e.g. when at capacity. The PV is otherwise straight-forward to implement.

4.5 BESS technical points

The BESS and associated power converter will naturally respond quickly to sudden changes. The dc-dc converter and inverter to tie the BESS to the microgrid must be bi-directional and set into 3-phase. The response time should be in ms range, dependent on the sensing frequency and the dc-dc converter frequency (the later typically 10 kHz+). Adding capacitance (dc side) may be beneficial to support faster response of the BESS. The BESS units are typically supplied in 6 m shipping containers, which could be sited at Stannochy. The ac transformer requirements would depend on the BESS configuration. The extent of BESS support could be reduced by dynamic control of the grid export and demands at the ARM Hub, and also uprated import from the grid. For example it may be possible to increase beyond 50 kW or stop the export for short durations, switch on or off demands in the castle centre and ARM Hub site, or draw power from a dedicated grid connection (ideally at Stannochy). General control of import/export would typically involve frequency control, which may be challenging for the microgrid over short timescales e.g. seconds, considering the WT inertia. These are routes to minimising investment in BESS capacity, but exchanged with reduced benefits of export and offset, and the cost of an uprated incoming connection. Ramp rate codes for the grid would require consideration in the case of an uprated incomer and any future exports > 50kW.

4.6 Grid transmission technical points

Based on investigation work for the previous ETP project, overground cabling was identified as a cheaper solution compared to underground cabling. 1 km of private overground cabling work could be costed around £100k. This would involve crossing over the South Esk. This work must be overseen by a high-voltage senior authorised person. 11 kV is typical for the long-distance transmission and standard transformers can be used. Further investigation of a dc grid is recommended to refine the requirements for Stannochy Energy Hub. Figure 4.1 provides a general topology for the proposed microgrid.

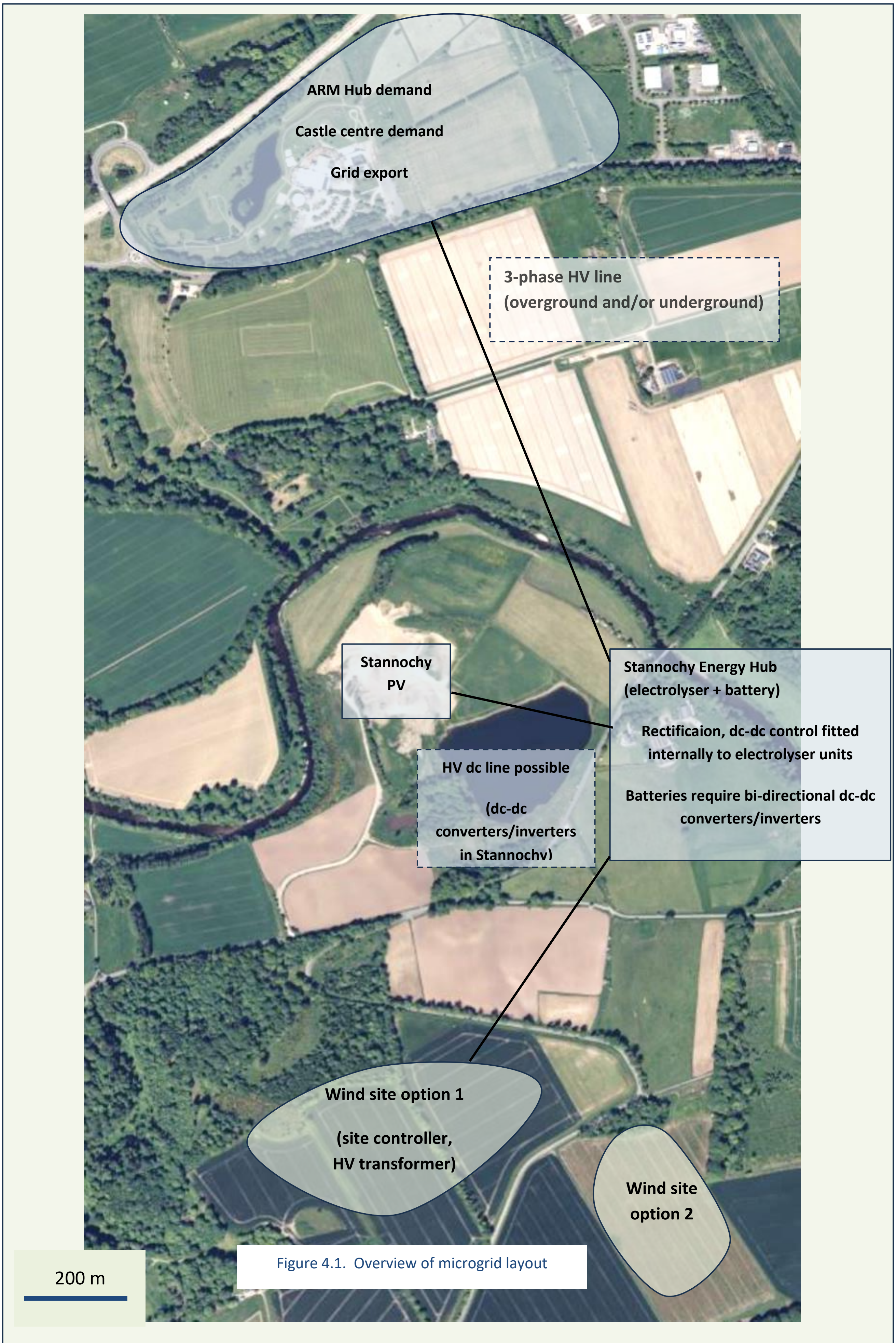


Figure 4.1. Overview of microgrid layout

5. Commercial model and business plan for H_2 generation and microgrid

This section of the report addresses objective (c).

5.1 Overview

A constrained electrical grid presents significant challenges for generating green hydrogen from wind and PV due to the restricted export level (50 kW), necessitating sourcing on site uses for the power and balancing, notably the BESS. With grid constraints forecast to run into the late 2020's/early 2030's, the micro grid model developed through the project presents an invaluable tool for testing proof of concept scenarios to integrate the transport service elements (ARM Hub) with locally produced green hydrogen, electricity and balancing. The model enables the sizing of the micro grid to align with forecast demand for green hydrogen and associated electrical loads at the ARM Hub.

The early-stage adoption of green hydrogen as a transport fuel necessitates a scalable approach to production, which the model helps profile, informed by market engagement.

5.2 Market engagement

The ARM Hub business case has been developed through active engagement with the logistics, OEM and energy (oil majors, gas services and distribution network operators) sectors, around HDV decarbonisation trends, clean fuel options, infrastructure and the role and scalability of hydrogen. The model enables clean fuel scenarios (in the form of green H_2 and EV) to be profiled against generation and green hydrogen production. Through the various scenarios run covering different scales of generation, the model provides confidence in a proof of concept that the forecast demand trajectory can be met through increasing generation and production capacity, whilst also providing an eco-system for regional suppliers, thereby building local supply chain. This approach is aligned with the decarbonisation and regional economic transition objectives of the ARM hub as illustrated in the power to demand concept in Figure 6.1.

Market research has established that years 1-5 are likely to see hydrogen demand as a transport fuel underpinned by the public sector. In the case of the ARM Hub this is through refuse collection vehicles, with Angus Council transitioning their diesel fleet to hydrogen with a depot at the ARM hub, alongside limited but helpful early adoption by regional logistics and agricultural machinery operators.

For years 5-10+, market research forecasts that the HDV sector's transition to green hydrogen will lift in scale and pace, moving from Euro 6 diesel and CNG to hydrogen with possibly an EV component, to reflect an increased availability of vehicles, reduction in the cost of ownership and overall confidence in performance and, critically access to public refuelling facilities.

The commercial model shows how the level of demand for years 1-5 based on refuelling of 5-10 HDV/RCVs (up to 250 kg H_2 per day average from the generation model 2, an equivalent of 800+ L diesel) could be met by the micro grid, with excess electricity distributed to the BESS and site-wide uses covering EV chargers, gas storage compression, Brechin Castle Centre (the garden centre), Brechin Business Park and planned commercial units. Whilst the scale of demand in years 5-10 is unclear, the model enables scenarios to be explored for generation and production increases in addition to importing H_2. With an unconstrained grid connection there is a significant opportunity for additional wind and solar generation on the site to increase the scale of the operations, reduce reliance on importing energy and create further opportunities for green energy supply. With grid constraints anticipated to ease by years 5-10+, the model can assist in informing decisions on exporting electricity set against hydrogen production and import.

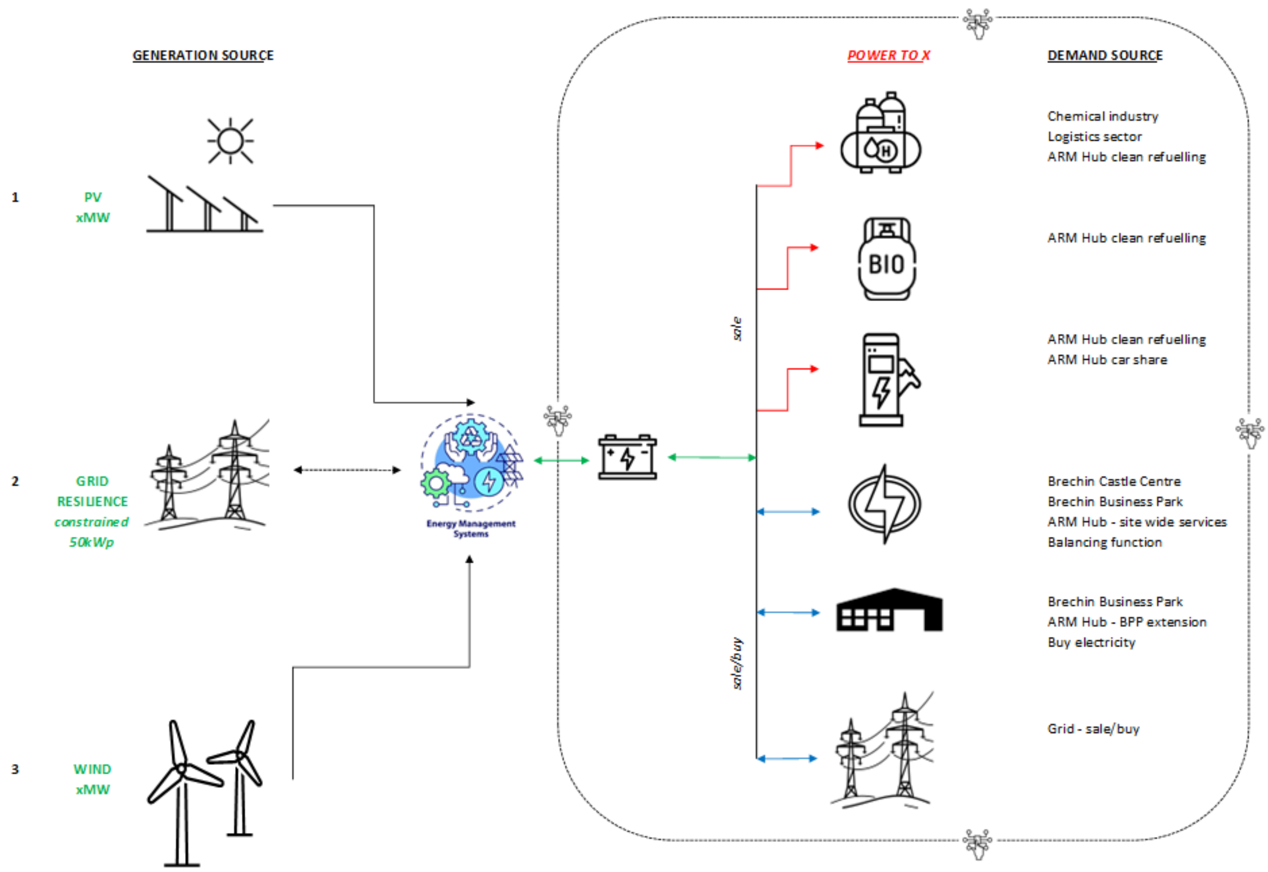


Figure 6.1. Stannochy Energy Hub power-to-demand model

5.3 Development of the business case

The model enables the development of a range of scenarios based on aligning optimum renewable energy generation with green H_2 production and integrating with market demand for public refuelling infrastructure at the ARM Hub. Understanding this dynamic and evolving market is helped enormously through the capabilities of the model. Underpinned by the power management system, the model also assists in exploring resilience (through BESS) and the commercial case for electrical sales to a range of land uses.

Through the commercial model a green hydrogen production route map has been developed that is integrated with demand scenarios and is based on solid understanding of renewable energy generation capacity. This provides a clear dataset to develop commercial models and build a delivery strategy that will send signals to the market to enable a regional HDV fleet transition and supply chain to green hydrogen.

Extracts from the business and generation modelling developed through this work are shown in Figures 6.1 to 6.3 showing the computed economic scenario for the generation model 1, 2 and 3.

Average values	**Total (GJ)**	**Non-H_2 (GJ)**	**Export (MWh)**	**Export (£)**	**Offset (MWh)**	**Offset (£)**	**H_2 (kg adj)**	**H_2 (£)**	**Total (£)**
Yr	13876	1577	350	52560	88	26280	51760	258800	**337,640**
Month	1156	131	29.2	4380	7.3	2190	4313	21567	**28,137**
Week	267	30.3	6.7	1011	1.7	505	995	4977	**6,493**
Day	38	4.32	0.96	144	0.24	72	142	709	**925**
Hr	1.6	0.18	0.04	6.00	0.01	3.00	**5.9**	29.54	**38.54**

Figure 6.2. Revenue forecast aligning with system 1 (1 MW WT, 1 MW PV, 1 MW electrolyser). Sale of H_2 assumed at £5 kg^{-1}, export at £0.15 kWh^{-1} and offset demand at £0.30 kWh^{-1}.

Average values	**Total (GJ)**	**Non-H_2 (GJ)**	**Export (MWh)**	**Export (£)**	**Offset (MWh)**	**Offset (£)**	**H_2 (kg adj)**	**H_2 (£)**	**Total (£)**
Yr	15579	1577	350	52560	88	26280	55377	276884	**355,724**
Month	1298	131	29.2	4380	7.3	2190	4615	23074	**29,644**
Week	300	30.3	6.7	1011	1.7	505	1065	5325	**6,841**
Day	43	4.32	0.96	144	0.24	72	152	759	**975**
Hr	1.8	0.18	0.04	6.00	0.01	3.00	**6.3**	31.61	**40.61**

Figure 6.3. Revenue forecast aligning with system 2 (1 MW WT, 1.45 MW PV, 1 MW electrolyser). Sale of H_2 assumed at £5 kg^{-1}, export at £0.15 kWh^{-1} and offset demand at £0.30 kWh^{-1}.

Average values	**Total (GJ)**	**Non-H_2 (GJ)**	**Export (MWh)**	**Export (£)**	**Offset (MWh)**	**Offset (£)**	**H_2 (kg adj)**	**H_2 (£)**	**Total (£)**
Yr	26490	1577	350	52,560	88	26,280	89,688	448,442	**527,282**
Month	2208	131	29.2	4,380	7.3	2,190	7474	37,370	**43,940**
Week	509	30.3	6.7	1,011	1.7	505	1725	8,624	**10,140**
Day	73	4.32	0.96	144	0.24	72	246	1,229	**1,445**
Hr	3.0	0.18	0.04	6.00	0.01	3.00	**10.2**	51.2	**60.20**

Figure 6.4. Revenue forecast aligning with system 3 (2 MW WT, 1 MW PV, 1 MW electrolyser). Sale of H_2 assumed at £5 kg^{-1}, export at £0.15 kWh^{-1} and offset demand at £0.30 kWh^{-1}.

5. Conclusions and further recommendations

The work here has involved a focussed review of the setting of the ARM Hub within the developing hydrogen markets. It is clear that projects such as the ARM Hub and Stannochy Energy Hub are directly aligned with the requirements and routes towards future energy. Many similar sites are required, including those that are much larger. The constrained grid is a significant additional challenge to work around for the case of MW-scale renewable energy deployment and a H_2 production site near Brechin, requiring a bespoke technical solution for power balancing.

A renewable energy generation dataset for the Stannochy Energy Hub site was established through a customised online database, validated with local data. Modelling a set of three microgrids with 2 to 3 MW of power generation, a 1 MW electrolyser and 1000 to 2000 kg of H_2 storage was completed, forming balanced inputs and outputs, reporting production from 128 to 249 kg H_2 per day depending on sizing. The mix of wind and PV allows reasonable balancing through the year. The microgrid must be based around a battery system to balance the supply/demand, frequency and integration with the local grid. BESS capacity is defined by the largest support/power requirements of the electrolyser in the case of fault/failure and shut-down. For the microgrids models in this work, the BESS is expected to be of relatively high power capacity (e.g. 400 kW to manage PV ramping) but not a significant amount of storage (e.g. 50 kWh). Larger capacities would be likely for fault scenarios requiring shut-down of the electrolyser, e.g. up to 1 MW for several minutes depending on how much power can be imported from the grid or balanced other ways, and the specific electrolyser requirements.

Technical requirements for the microgrid are complicated by the constrained export. Several, mainly power control aspects, of the proposed ac microgrid discussed here are not standard. Use of dc in some parts of the grid is suggested to add further options for control and stability.

The ARM Hub has developed a diverse business model to compliment a green energy hub. A list of routes to market for the green H_2 and other refuelling and EV charging have been identified within the business plan, mainly for local HGV fleets including RCVs. Securing public funding and steady local demand is recognised as an important requirement at this stage. The first phase of development involving the 2 to 3 MW of installed generation capacity has been modelled with offset, export and sale of H_2 valued between £925 to £1445 per day. This equates to 800 L diesel equivalent, with H_2 price of £5 kg^{-1} modelled around parity with diesel at £1.60 L^{-1}.

The ARM Hub and Stannochy Energy Hub offer significant opportunities for future collaborations between UoD and Dalhousie Estates. This may be through future funded projects, KTPs or other partnerships, and student projects. The theme of the work aligns directly with that of UoD and the new Binks Institute for Sustainability. The next stages of work related to the ARM Hub include:

(i) Further develop the electrical design, with a particular focus on the power control system, balancing and resilience infrastructure
(ii) Review the concept design with the DNO (SSEN)
(iii) Build a full capital and operational cost plan to inform fuel & energy pricing
(iv) Explore on-site electricity revenue sources
(v) Develop the model as a digital twin to inform decision making.

Reference list

[1] 'Invest in Angus', Accessed: 10 Oct 2023 [Online]. Available: https://investinangus.com/tay-cities-deal/the-angus-fund/low-carbon/angus-rural-mobility-hub

[2] OS Maps, Accessed: 10 Oct 2023 [Online]. Available: https://digimap.edina.ac.uk (UoD licence 100025252)

[3] 'The Paris Agreement' | UNFCCC. Accessed: 24 Oct 2023. [Online]. Available: https://unfccc.int/process-and-meetings/the-paris-agreement

[4] A. Thompson, 'September Was the Most Anomalously Hot Month Ever', Scientific American. Accessed: 24 Oct 2023. [Online]. Available: https://www.scientificamerican.com/article/september-was-the-most-anomalously-hot-month-ever

[5] 'Our world in Data' - United Kingdom - Energy Country Profile. Accessed: 27 Oct 2023. [Online]. Available: [https://ourworldindata.org/energy/country/united-kingdom]

[6] 'UK Hydrogen Strategy'. [Online]. Available: https://www.gov.uk/government/publications/uk-hydrogen-strategy

[7] 'Global Hydrogen Review 2022' - International Energy Agency (IEA). [Online]. Available: https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf)

[8] 'Scottish Hydrogen Assessment'. [Online]. Available: https://www.gov.scot/publications/scottish-hydrogen-assessment-report/

[9] M. Papapetrou, G. Kosmadakis, 'Chapter 9 - Resource, environmental, and economic aspects of SGHE', in *Salinity Gradient Heat Engines*, A. Tamburini, A. Cipollina, and G. Micale, Eds., in Woodhead Publishing Series in Energy, Woodhead Publishing, 2022, pp. 319–353. doi: 10.1016/B978-0-08-102847-6.00006-1.

[10] 'Renewable power generation costs in 2022'. [Online] Available: https://www.irena.org/Publications/2023/Aug/Renewable-Power-Generation-Costs-in-2022

[11] Renewable Energy World. [Online] Available: https://www.renewableenergyworld.com/news/the-day-has-arrived-here-are-the-recipients-of-7-billion-in-federal-hydrogen-hub-funding/

[12] G. Kakoulaki, I. Kougias, N. Taylor, F. Dolci, J. Moya, A. Jäger-Waldau, 'Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables', *Energy Conversion and Management*, vol. 228, p. 113649, Jan. 2021, doi: 10.1016/j.enconman.2020.113649.

[13] '2021 UK Greenhouse Gas Emissions, Final Figures'. [Online]. Available: https://assets.publishing.service.gov.uk/media/63e131dde90e07626846bdf9/greenhouse-gas-emissions-statistical-release-2021.pdf

[14] 'Hydrogen Demand in Scotland: A Mapping of Industrial Applications'. [Online]. Available: https://www.evaluationsonline.org.uk/evaluations/Documents.do?action=download&id=1089&ui=browse

[15] IEA (2021), 'Hydrogen Projects Database', [Online]. Available: https://www.iea.org/reports/hydrogen-projects-database

[16] Hydrogen Insight. [Online]. Available: https://www.hydrogeninsight.com/production/impossible-dreams-the-11-biggest-green-hydrogen-projects-announced-around-the-world-so-far/2-1-1517618

[17] Renewables Ninja. [Online]. Available: https://www.renewables.ninja/ (grid reference 56.7129, 2.6842)

[18] Global Wind Atlas. [Online]. Available: https://globalwindatlas.info/en

[19] 'MCS Guide to Installation' (2021) [Online]. Available: https://static.solartricity.ie/wp-content/uploads/2014/07/MCS-guide-to-installation.pdf

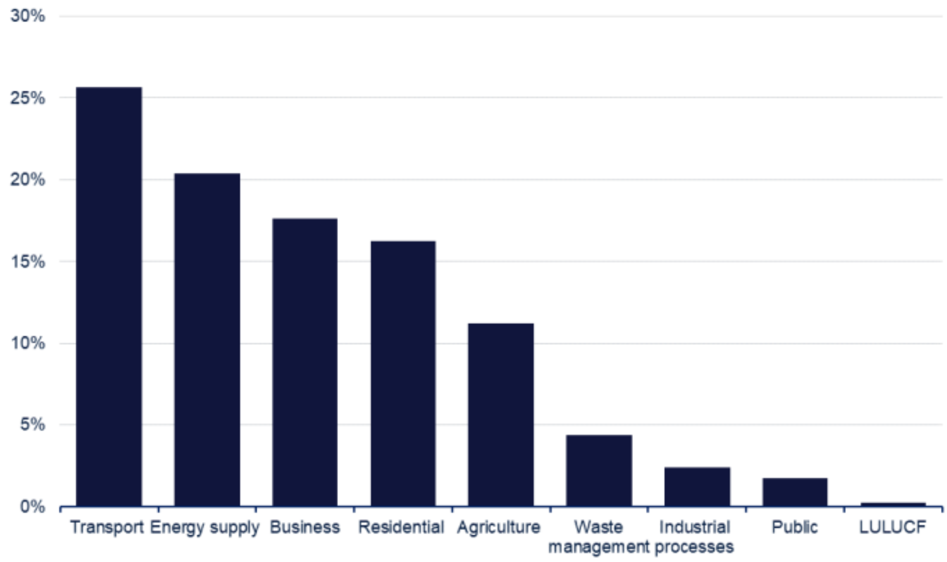
[20] PV Exchange, 'Price index'. Accessed: 10 Oct 2023. [Online]. Available: https://www.pvxchange.com/Price-Index

[21] E Goldstraw, S Reynolds, "Rapid changes in insolation in southern England due to variation in cloud cover: influence on operation and testing of solar modules". *Proceedings of SEEP2013*, Maribor, Slovenia, 2013.

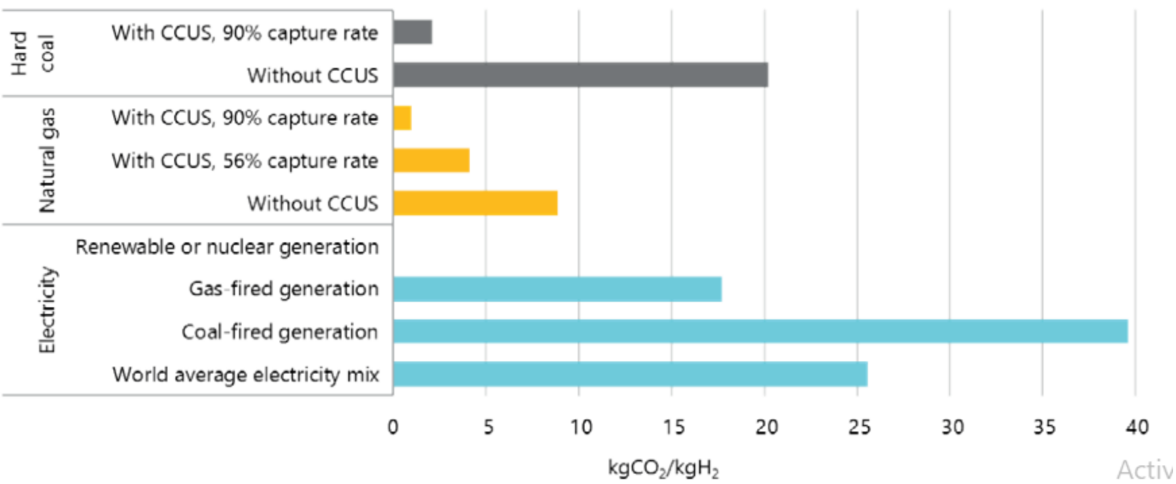
[22] K Lappalainen, G Wang, J Kleissl, "Estimation of the largest expected photovoltaic power ramp rates", *Applied Energy,* vol. 278, Nov 2020

Appendices

Appendix A1: Green House Gas (GHG) Emission by Sector 2021 (UK) [13].



Appendix A2: CO2 emissions from recent industrial H2 reforming [7].

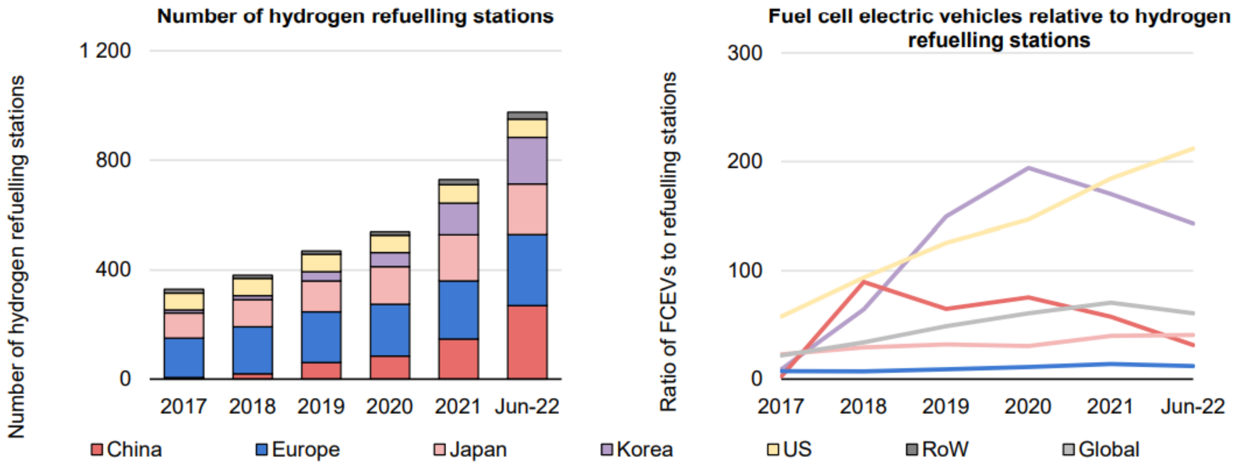


Appendix A3: Summary of H2 demands in Scotland [14].

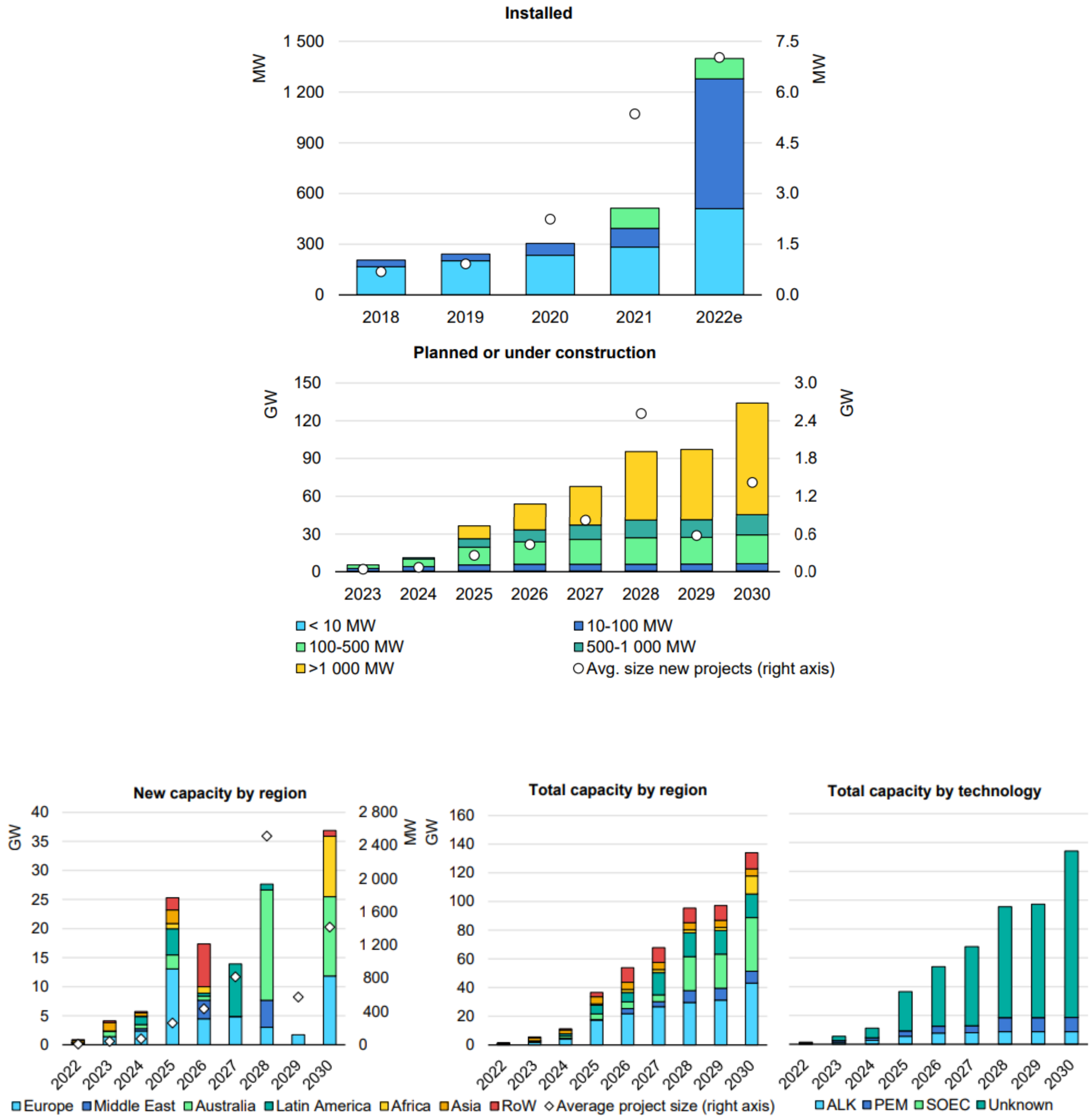
Sector	Type of use case(s)	Alternative technologies	Notes on hydrogen usage potential and likelihood
Chemicals & pharmaceuticals		Electrification, CCUS	Industrial heating requirements could be met both by electrification or hydrogen, though some processes also require hydrogen as a feedstock
Oil and gas refining		CCUS, electrification	Refineries use hydrogen and have many energy uses, showing a strong potential for hydrogen use
Cement		Biomass, CCUS	Due to the process emissions, CCUS is more likely to be used as a decarbonisation pathway
Fertilisers		Electrification, alternative fuels	Hydrogen may be produced on site before conversion into ammonia, so this may not be a source of additional hydrogen usage
Glass		Electric furnaces	High temperatures mean that hydrogen may be better suited than electrification, though issues remain over flame characteristics
Paper and pulp		Biomass, Waste-derived fuels	Many sites have moved to alternative fuels e.g., biomass to partially decarbonise their operations, so there is less 'push' to switch to hydrogen
Distilleries		Electrification, Biomass	The Scottish Whisky Association found that hydrogen will have a significant role to play in all net zero sectoral pathways
Food and drink		Electrification	Unique subsector processes and equipment may impair the potential for hydrogen to replace some existing natural gas fired appliances
Power Generation		CCUS, Renewables	The only CCGT power plant in Scotland (Peterhead) has chosen to pursue CCUS and so is unlikely to be a source of hydrogen usage
Non-residential heating		Electrification	SG policy does not prioritise hydrogen for heating in buildings, but there may be edge-cases
Large Events and Construction		Electrification, Biofuels	Currently met through diesel powered generators, with hydrogen being seen as a viable alternative. Batteries and biofuels are potential alternatives.

Indirect heating processes **Direct heating processes** **Chemical feedstock**

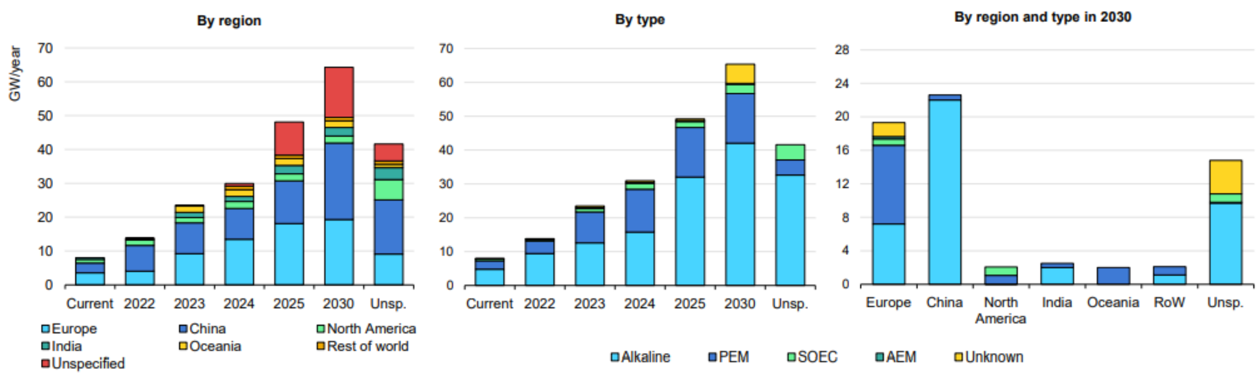
Appendix A4: Overview of the H2 refuelling infrastructure [7].



Appendix A4: Summary of electrolysis capacity. The right axis is the average size of new projects [7].



Appendix A5: Electrolyser manufacturing capacity [7].



Appendix A6: Hydrogen Business Model / Net Zero Hydrogen Fund: shortlisted projects allocation round 2022. The shortlist contains the UK electrolyser H2 projects, totalling 408 MW of capacity. The Dept. of Energy Security and Net Zero expects to award contracts totalling up to 250 MW of capacity from HAR1, subject to affordability and value for money. They aim for contracts to be awarded in Q4 2023, with first projects becoming operational in 2025 [15].

Project Name	Lead Developer	Location
Aldbrough Hydrogen Pathfinder	SSE Thermal	Yorkshire
Barrow Green Hydrogen	Carlton Power	North West
Bradford Low Carbon Hydrogen	Hygen	Yorkshire
Cheshire Green Hydrogen	Progressive Energy Net Zero	North West
Commercial Scale Demonstrator	ERM Dolphyn	Scotland
Cromarty Hydrogen Project	Pale Blue Dot Energy	Scotland
Gigastack	Phillips 66	North East
Gordonbush Hydrogen Project (GBH2)	SSE Renewables	Scotland
Green Hydrogen 1	RES and Octopus Renewables	Scotland
Green Hydrogen 2	RES and Octopus Renewables	Wales
Green Hydrogen 3	RES and Octopus Renewables	South East
H2 Production Plant at High Marnham	JG Pears	East Midlands
HyBont	Marubeni Europower	Wales
HyGreen Teesside	BP Alternative Energy Investments	North East
Langage Green Hydrogen	Carlton Power	South West
Quill 2	INOVYN ChlorVinyls	North West
Tees Green Hydrogen	EDF Renewables Hydrogen	North East
Trafford Green Hydrogen	Carlton Power	North West
West Wales Hydrogen Project – Phase 1	H2 Energy and Trafigura	Wales
Whitelee Green Hydrogen	Scottish Power	Scotland

Appendix A7: Table of proposed H2 generation facilities in the UK [15].

Project name	Date online	Status	Technology	Type of electricity	End use	Size
H100 Fife Project, Levenmouth	2023	FID (final investment decision)	ALK	Dedicated renewable	Domestic heat	5 MW
Trafford Low Carbon Energy Park	2023	Feasibility study	Other Electrolysis	Dedicated renewable	Transport, other industry	200 MW
Herne Bay, Kent	2023	Concept	Other Electrolysis	Offshore wind		8-9t H_2/d
Green Hydrogen for Scotland	2023	Under construction	PEM	Solar PV	Transport	20 MW
Octopus Hydrogen - BayWa MoU	2023	Concept	Other Electrolysis	Dedicated renewable		30 MW
H-Awel	2023		PEM	Onshore wind	Iron and Steel, transport	50 MW
Acorn Aberdeenshire	2024	Feasibility study	NG w CCUS	Dedicated renewable	Refinery, other ind., grid	200 MW - 0.4Mt CO2/y
Aberdeen Hydrogen Hub, phase I	2024	FID	Other Electrolysis	Dedicated renewable	Transport, grid, domestic heating	400 kg H_2/day
Dolphyn 1, phase 1	2024	Feasibility study	Other Electrolysis	Offshore wind		2 MW
Cerulean Winds - North Sea	2024	Concept	Other Electrolysis	Offshore wind		1.5 GW
Cromarty Hydrogen Project, phase 1	2024	Feasibility study	PEM	Dedicated renewable		50 MW
H2 Green - Shoreham port - phase I	2024	Feasibility study	Other Electrolysis	Dedicated renewable	Ammonia, transport	20 MW
Cromarty Hydrogen Project, phase 2	2024	Concept	PEM	Dedicated renewable	Other ind.	300 MW
EMEC tidal-battery-hydrogen demo	2025	DEMO	PEM	Dedicated renewable		0.67 MW
Port of Immingham	2025	Feasibility study	PEM	Offshore wind		20 MW
HyGreen Teesside, phase I	2025	Feasibility study	Other Electrolysis	Dedicated renewable		60 MW
Aberdeen Hydrogen Hub, phase II	2025	FID	Other Electrolysis	Dedicated renewable	Other ind., transport	1000 kg H_2/day
Pembroke power station	2025	Feasibility study	Other Electrolysis	Offshore wind	Transport, grid, domestic heating	100 MW
Mayflower Hydrogen project	2025	Feasibility study	PEM	Dedicated renewable		20 MW
ScottishPower - Felixtowe Port	2025	Concept	Other Electrolysis	Dedicated renewable	Transport and synthesis fuel	100 MW
Carlton Power hydrogen hub	2025	Feasibility study	Other Electrolysis	Dedicated renewable	Ammonia, methanol, other ind. Transport, power, synthesis fuel	35 MW
Hynet Northwest, phase 1 (Essar Stanlow refinery)	2026	Feasibility study	NG w CCUS	Dedicated renewable	Transport, power	3 TWh H_2/y - 1Mt CO_2/y
H2H Saltend	2026	Feasibility study	NG w CCUS	Dedicated renewable	Refining, other ind., transport, power, grid	1.4Mt CO_2/y - 600 MW H_2
Protium - Wilton Universal Group Teeside	2026	Feasibility study	PEM	Dedicated renewable	Other ind, power, grid	40 MW
H2Teeside 1st phase	2027	Feasibility study	NG w CCUS	Dedicated renewable		500 MW - 1 million t CO_2/y

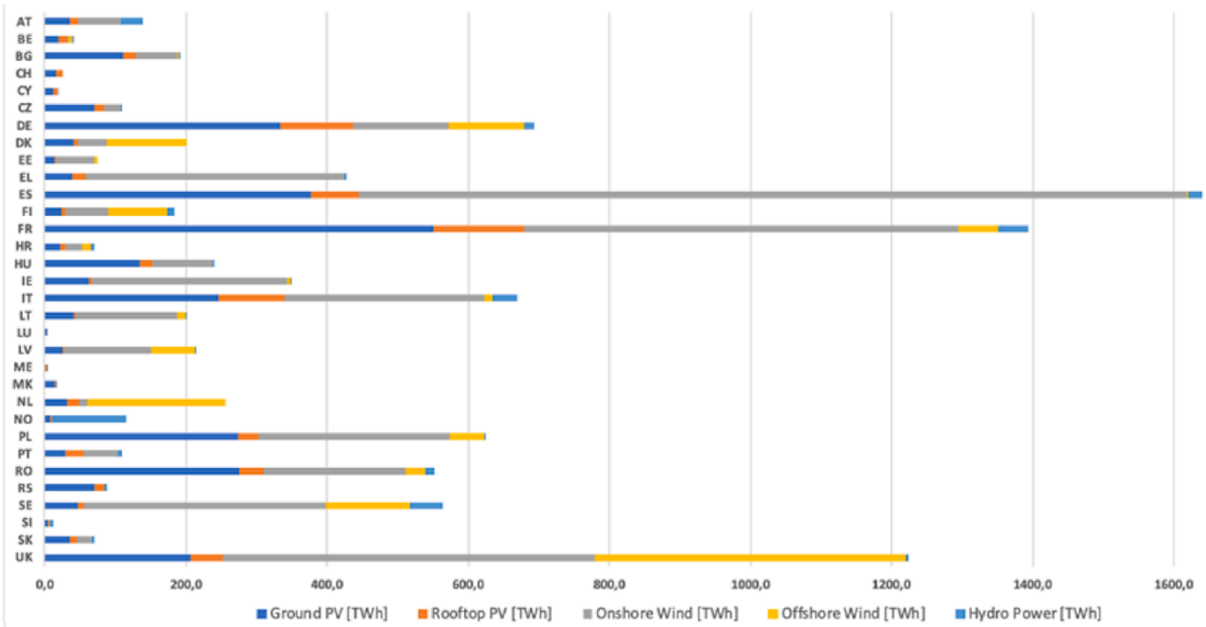
Dolphyn 1, phase 2	2027	Feasibility study	Other Electrolysis	Offshore wind		10 MW
DelpHYnus (cluster)	2027	Feasibility study	NG w CCUS	Dedicated renewable		1.8 GW - 5 to 8 Mt CO_2/y
Budweiser - Protium Wales brewery	2027	Concept	Other Electrolysis	Dedicated renewable		
Project Cavendish	2027	Feasibility study	NG w CCUS	Dedicated renewable	Other ind, transport	700 MW-1.2 Mt CO_2/y
H2NorthEast Kellas Midstream Teesside Blue Hydrogen Phase 1	2027	Feasibility study	NG w CCUS	Dedicated renewable		355 MW
Shell Uniper Humber Hub Blue North Killingholme	2027	Feasibility study	NG w CCUS	Dedicated renewable		720 MW
Dylan, phase 1	2028	Feasibility study	Other Electrolysis	Offshore wind		300 MW
Lindsey refinery	2029	Feasibility study	NG w CCUS	Dedicated renewable		1.1 Mt CO_2/y
H2 Green - Shoreham port - phase II	2029	Feasibility study	Other Electrolysis	Dedicated renewable	Refining	15 t H_2/d
Hynet Northwest, phase 2	2030	Feasibility study	NG w CCUS	Dedicated renewable	Ammonia, transport	30 TWh H_2/y - 10Mt CO_2/y
H2Teeside 2nd phase	2030	Feasibility study	NG w CCUS	Dedicated renewable	Refining, other ind, transport, power, grid	1 GW - 2 million t CO_2/y
Keadby Hydrogen	2030	Feasibility study	NG w CCUS	Dedicated renewable		1.2 GW
Northern Horizons wind project	2030	Concept	Other Electrolysis	Offshore wind	Power	
HyGreen Teesside, phase II	2030	Feasibility study	Other Electrolysis	Dedicated renewable		500 MW
Gigastack-Hornsea 2, phase II	2030	Concept	PEM	Offshore wind		1 GW
INEOS / Petroineos Grangemouth refinery	2030	Feasibility study	NG w CCUS	Dedicated renewable		190 kt H_2/y - 1000000 t CO_2/y
Fawley refinery	2030	Feasibility study	NG w CCUS	Dedicated renewable	Refining	4.3 TWh H_2/y - 2Mt CO_2/y
Freeport East Hydrogen Hub	2030	Feasibility study	Other Electrolysis	Dedicated renewable	Refining, grid	1 GW
H2NorthEast Kellas Midstream Teesside Blue Hydrogen Phase 2	2030	Feasibility study	NG w CCUS	Dedicated renewable	Other ind, transport, grid	1 GW
Dylan, phase 2	2030	Concept	Other Electrolysis	Offshore wind		1 GW
H21 North of England	2035	Feasibility study	NG w CCUS	Dedicated renewable		12.15 GW H_2 - 20Mt CO_2/y
Fawley refinery	2023	FID	ALK	Dedicated renewable	Ammonia, other ind, transport, grid	5MW

Appendix A8: Table of the 11 biggest green hydrogen projects announced around the world so far [16].

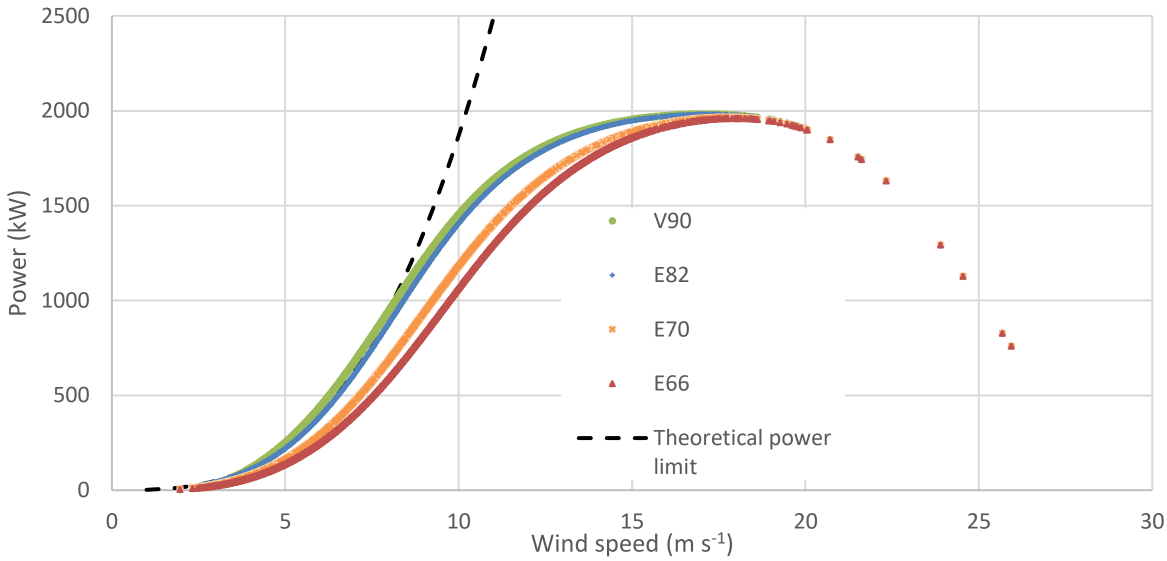
Project/location	Developer	Est annual prod	Elect capacity	Power source	Planned use of H2	Development schedule	Expected cost
Spirit of Scotia Green Hydrogen Production Hub Nova Scotia, Canada	Green Hydrogen International, a Texas-based firm founded in 2019, which as of writing, has four employees listed on LinkedIn	43 million tonnes	Unknown	500 GW offshore wind	Export to European and North American markets	No timeline for final investment decision (FID), construction or operation has been disclosed, but the developer says it has secured 52,000 ha of storage-grade salt cavern rights across the Canadian province.	Not disclosed.
Fleur-de-lys Green Hydrogen Production Hub Quebec, Canada	Green Hydrogen International	43 million tonnes	Unknown	500 GW offshore wind	Green ammonia, but unknown if meant for international or domestic markets	No timeline disclosed, although 16,000 ha of potential salt cavern storage have been secured.	Not disclosed.
Unnamed Nouakchott project Mauritania	Infinity Power Holding (a joint venture between the UAE's Masdar and Egypt's Infinity) and Germany's Conjuncta	8 million tonnes	10 GW in full phase	Not revealed	Export to Germany, although no agreements to this effect have been signed.	The first 400 MW phase is due to start operations by 2028, but timelines for scaling up have not been disclosed.	$34bn
Western Green Energy Hub Western Australia, specifically, the Goldfields-Esperance region in the southeast of the state	InterContinental Energy (based in Singapore), CWP (founded in Serbia), the Mirning Traditional Lands Aboriginal Corporation, and potentially South Korean power company Kepco	3.5 million tonnes	35 GW (BNEF estimate)	50 GW wind and solar	Unknown, although co-developer Kepco, which signed a memorandum of understanding to co-develop the project in July, is already exploring imports of ammonia and hydrogen to South Korea for co-firing in existing fossil-fuel-fired power plants.	Site assessment is ongoing, with FID due in 2027.	Not disclosed.
Hydrogen City Texas, with pipelines to deliver H2 to the port of Corpus Christi	Green Hydrogen International	3 million tonnes	Unknown	60 GW onshore wind and solar	Export to Asia as green ammonia, feedstock for fertilisers, sustainable aviation fuel and rocket fuels, and co-firing in domestic power plants.	A first phase, drawing on 2GW of upstream renewables and using two salt caverns for storage, is due to start operations in 2026, but no timeline has been given on when the full phase will start construction.	Not disclosed.
Unnamed SCZONE Ain Sokhna project Ain Sokhna, in Egypt's Suez Canal Economic Zone	ACME, an Indian renewables developer	2.1 million tonnes	18GW (BNEF estimate)	Not revealed	Unknown, but would probably used for refuelling ships passing through the Suez Canal and/or exports	Construction of an initial 100,000 tonnes-a-year pilot is reportedly due to kick off in early 2024, but no firm date on start of operations of the full project.	$12-13bn (although this may only refer to the cost of the pilot)
Hyrasia One Kuryk, Kazakhstan	Hyrasia One (a subsidiary of German developer Svevind)	2 million tonnes	20GW	40 GW wind and solar built in the country's SW steppes	Export as ammonia, probably to Europe (via pipeline)	FID is due in 2026, with first production expected in 2030 and full capacity onstream from 2032. Preliminary studies were kicked off in June, and an investment agreement has already been signed with the Kazakh government.	$40-50bn

Green Energy Oman Duqm, Oman	Oil major Shell, Intercontinental Energy, Omani state-owned oil firm OQ, and Kuwait-based EnerTech Holdings	1.8 million tonnes	14GW (BNEF estimate)	25 GW wind and solar	Domestic use and export as ammonia to international markets	FID after 2026, although it is unclear whether this refers to the first phase powered by 4GW of renewables (for which the consortium had been awarded land in the Oman's first green H2 auction) or the full production capacity.	Not disclosed.
Aman Northwest Mauritania	CWP	1.8 million tonnes	Unknown	30 GW renewables (18 G W wind and 12 GW solar)	Local use and export, with 50 million cubic metres of additional desalinated ocean water supplied to nearby communities and agriculture.	Unknown, although a framework agreement has been signed with the Mauritanian government.	$40bn
Unnamed Mozambique project Inhambane, southern Mozambique	UK-based Jearrard Energy Resources, founded in 2021	1.6 million tonnes	Not disclosed	12 GW of solar power	Mainly export to Europe, some volumes to be used in Mozambique and neighbouring countries	Construction to kick off in mid-2024, but start of operations unknown.	Not disclosed
Australian Renewable Energy Hub The Pilbara region in the north of Western Australia	Oil major BP, Australian-headquartered bank Macquarie, InterContinental Energy, and CWP	1.6 million tonnes	Estimated to be 14GW	26 GW of wind and solar	Domestic markets and export, as well as supplying renewable power directly to the local customers.	At the end of 2022, BP's then chief financial officer (and now-interim CEO) Murray Auchincloss described bringing the first phase serving the domestic market on line between 2025 and 2027, with the full export hub to start production "by the end of the decade".	Not disclosed

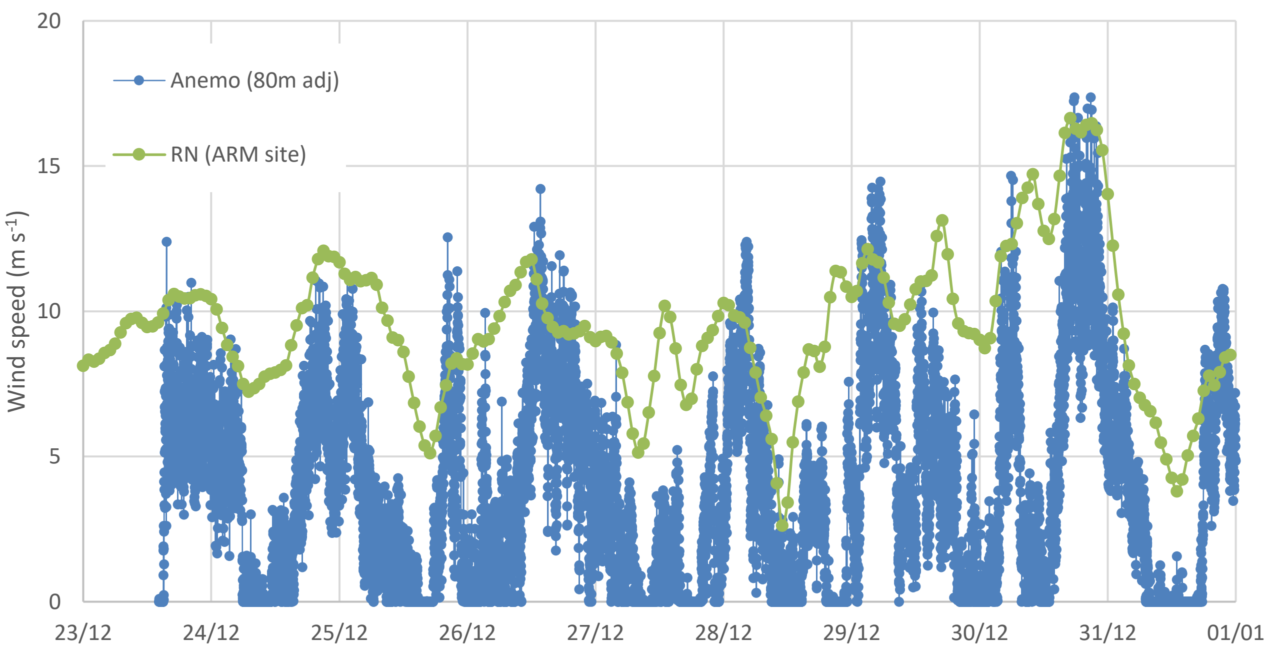
Appendix A9: Potential of renewable energy generation in Europe. The potential of UK electricity is higher than the demand. The surplus is estimated at 900 TWh [12].



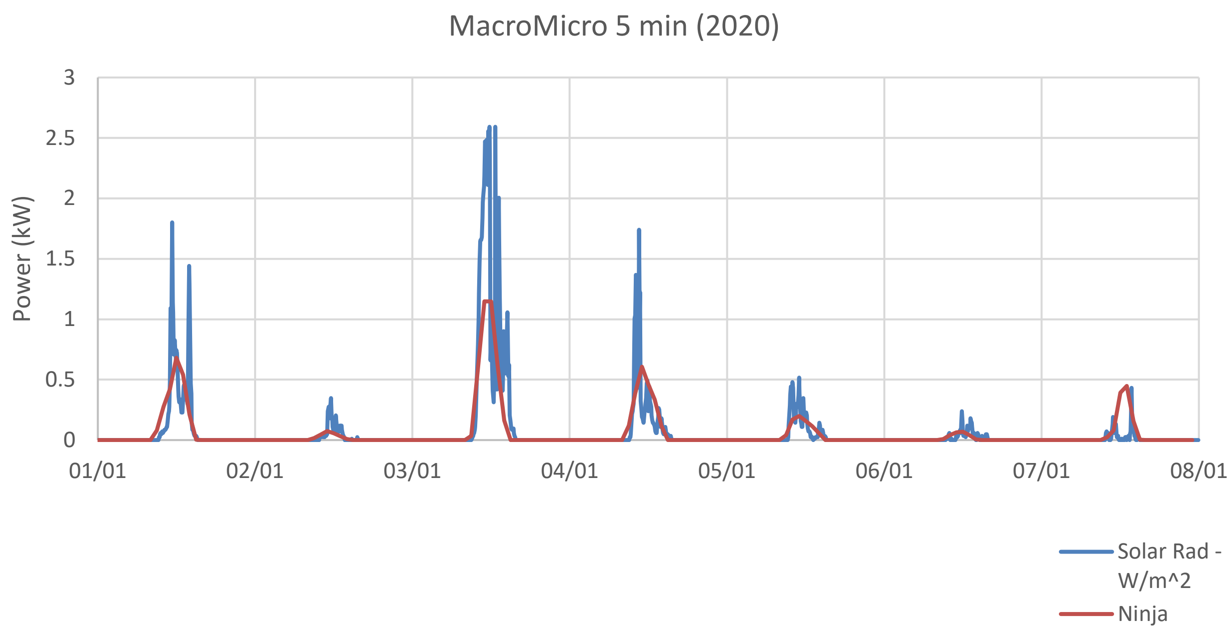
Appendix A10: Renewables Ninja turbine model data compared to the approx theoretical limit for an 82 m diameter rotor (i.e. Enercon E82). The E82 model would be expected to be slightly less than the theoretical limit when at its peak efficiency. The E70 data appears to more accurately model the E82 power through the data set [17].

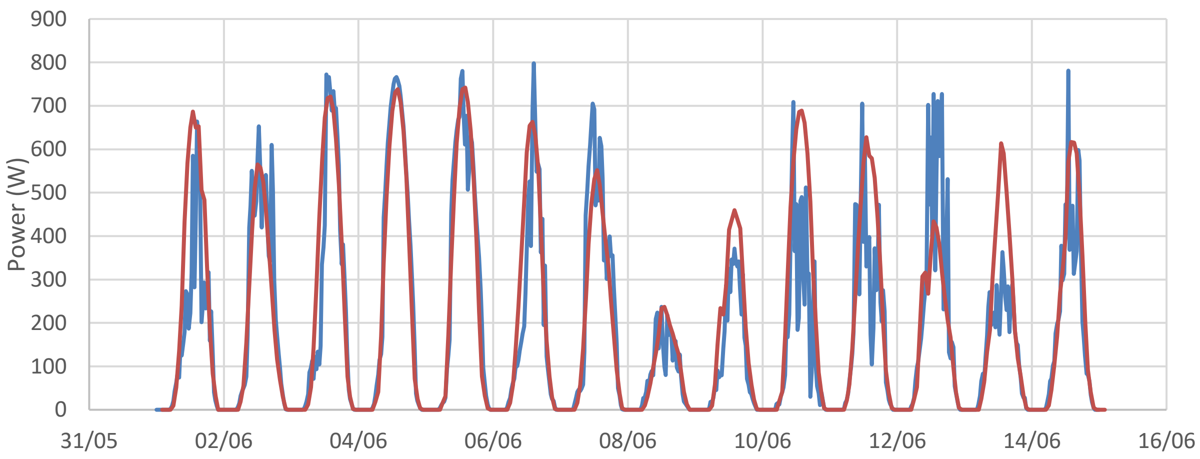


Appendix A11: Graph of anemometer data mapped at 80 m compared to Renewables Ninja sample data for validation. This is based at the ARM Hub site not the wind site (the Renewables Ninja data does not vary significantly at this spatial resolution) [17].

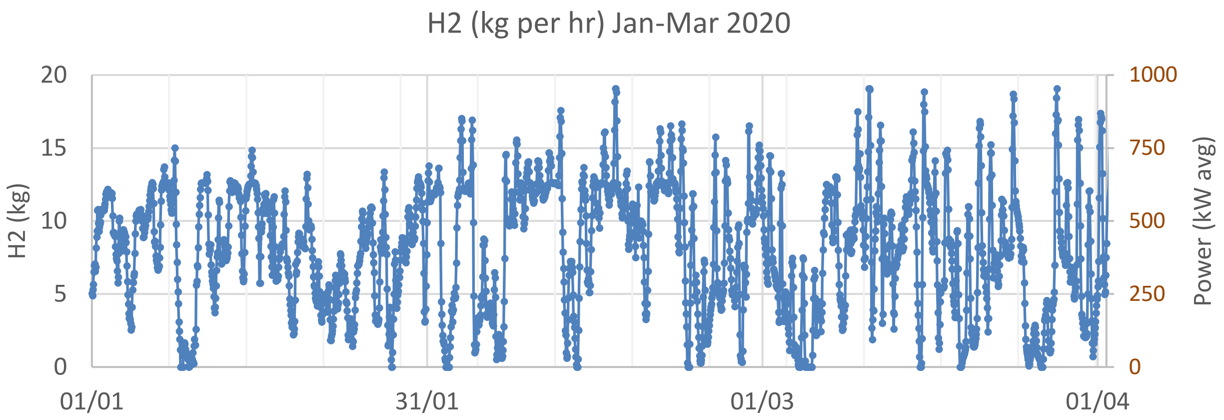


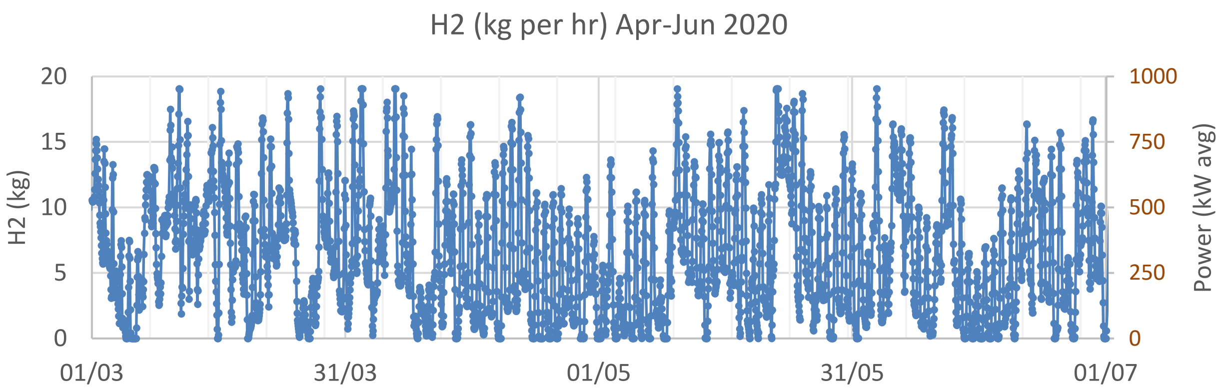
Appendix A12: Graph of UoD data compared to Renewables Ninja sample data for validation [17].

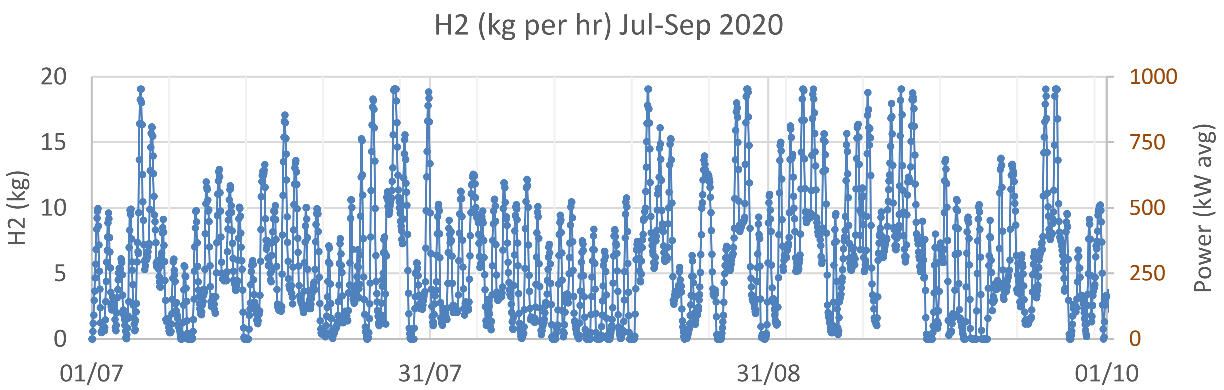


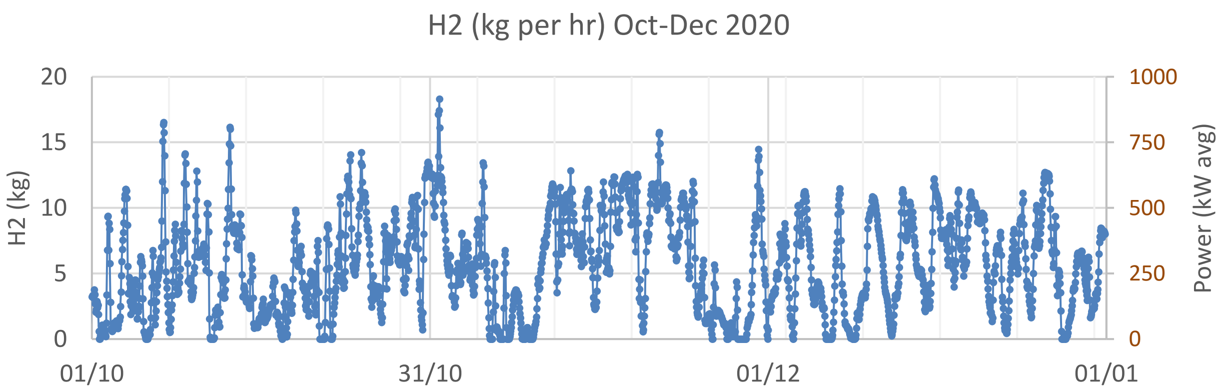


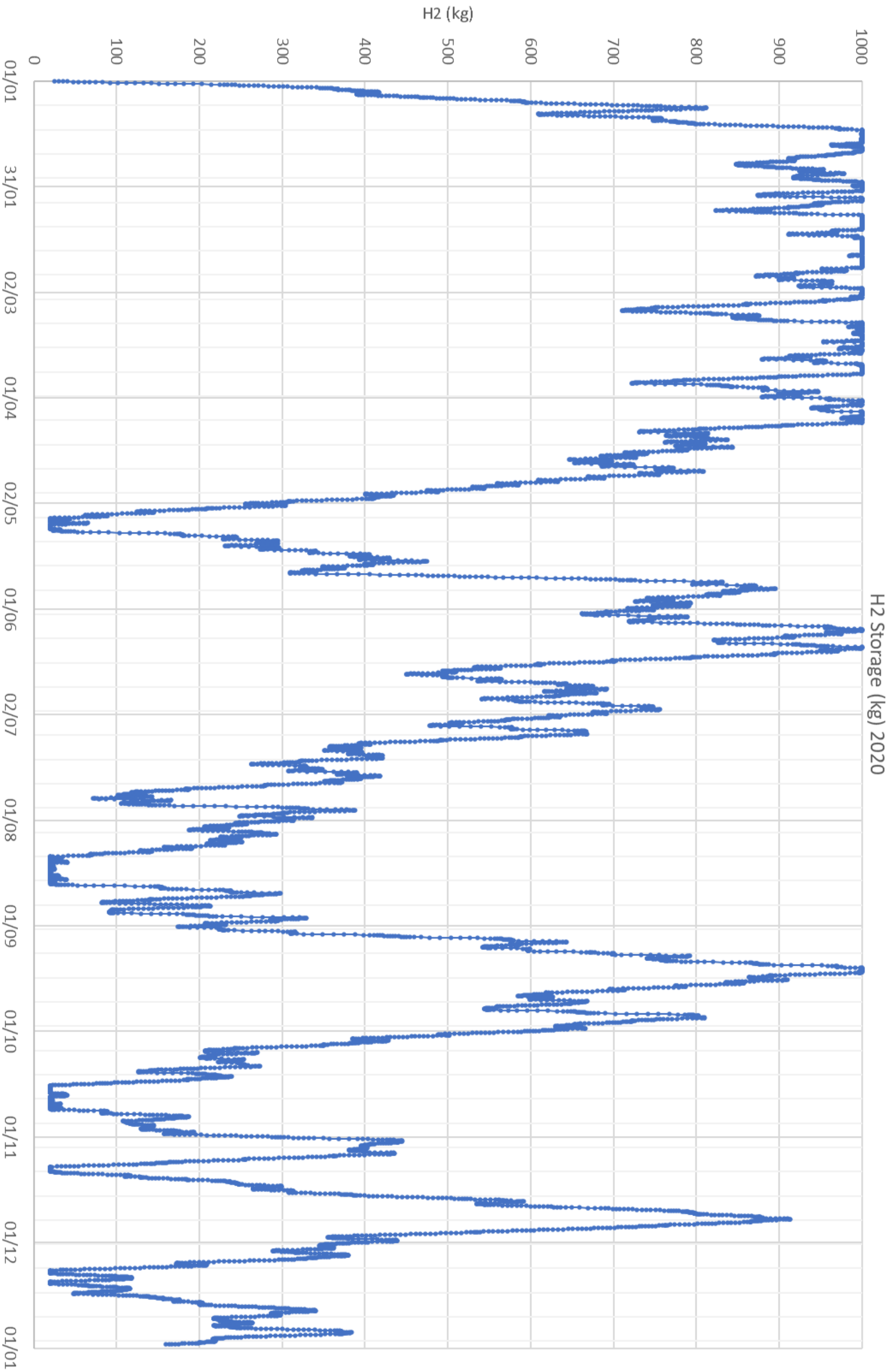
Appendix A13: Modelled data for H_2 production and storage, 2020-2022. System 1 (1 MW WT, 1 MW PV, 1000 kg H2 storage, demand of 146 kg day^{-1}). Power values on right axis are approximate to H2 hr^{-1}.

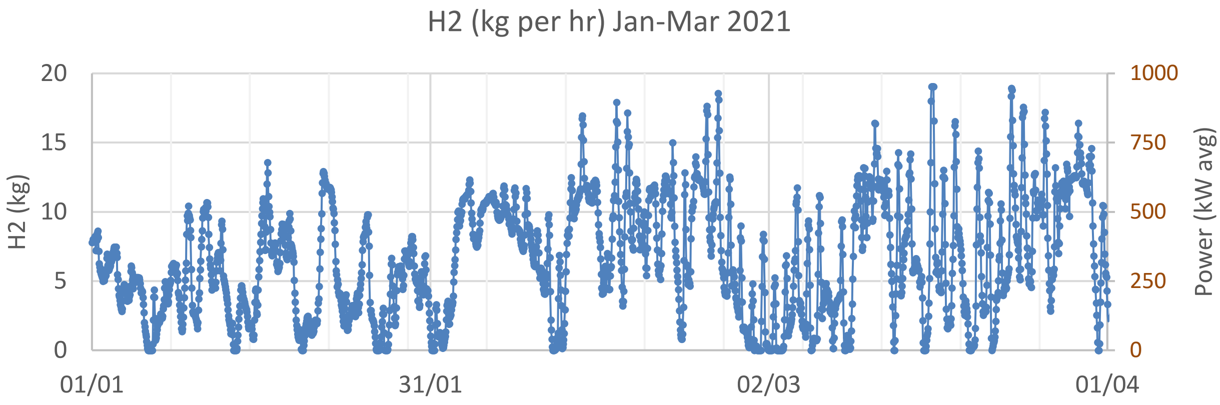


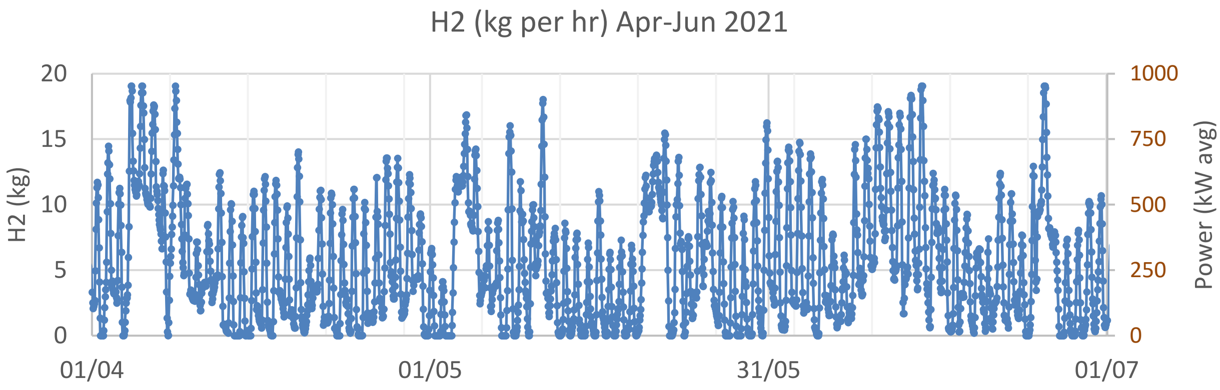


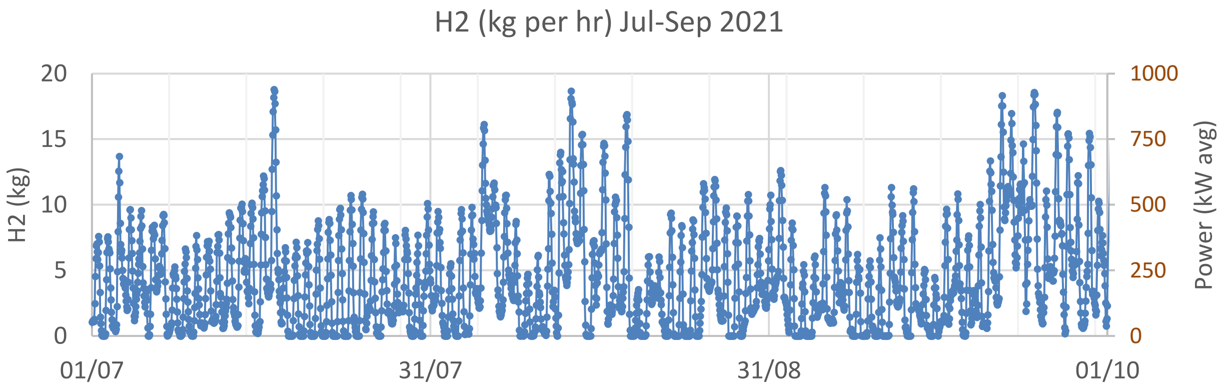


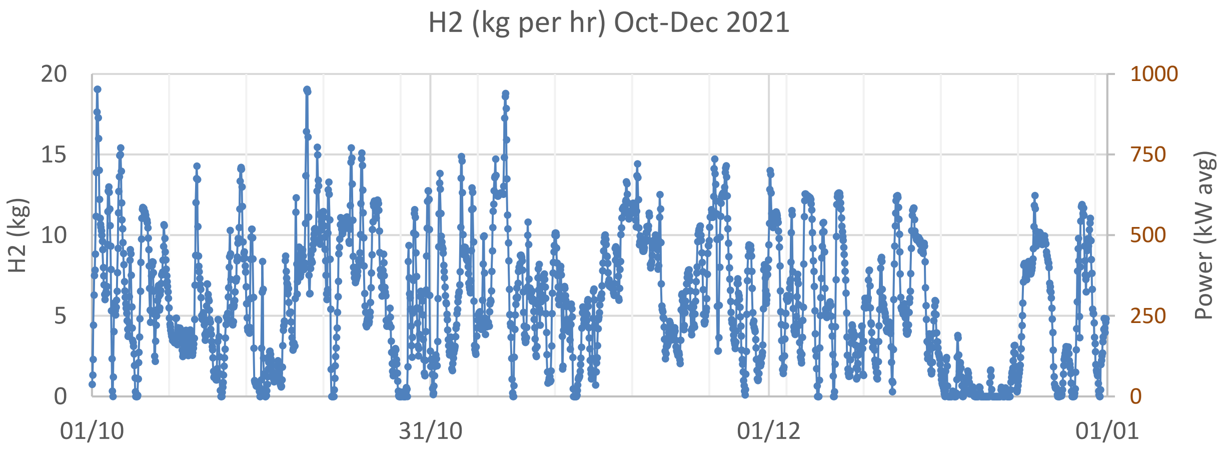


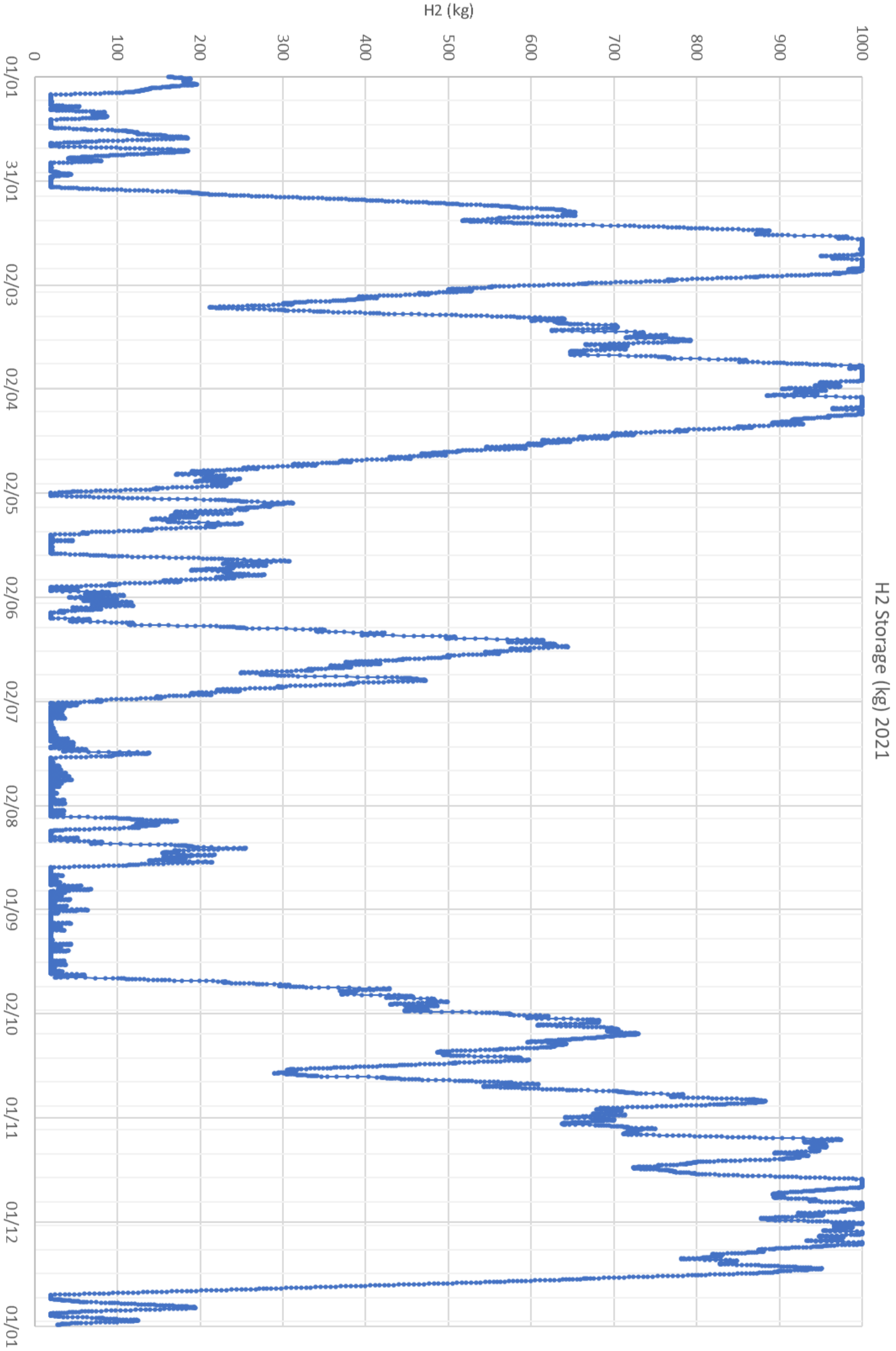

H2 Storage (kg) 2020
H2 (kg)
0
100
200
300
400
500
600
700
800
900
1000
01/01
31/01
02/03
01/04
02/05
01/06
02/07
01/08
01/09
01/10
01/11
01/12
01/01

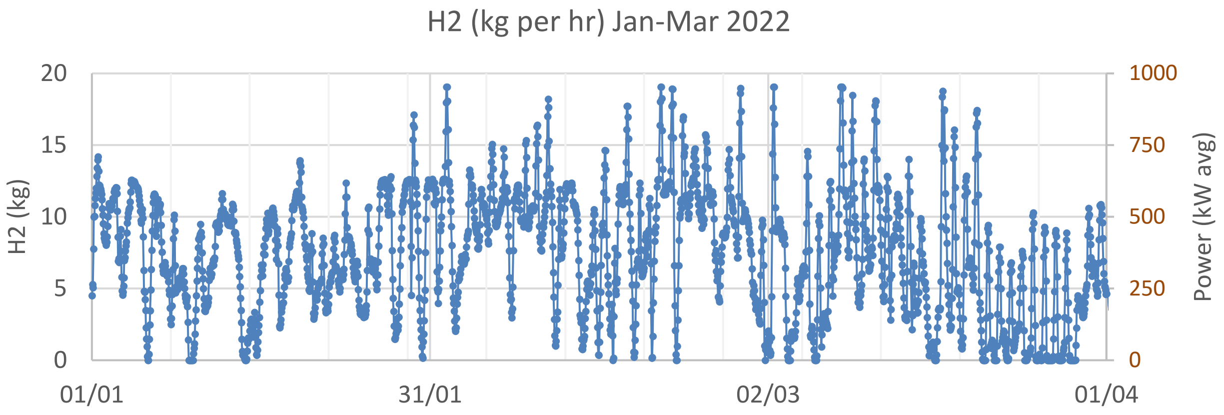

H2 (kg per hr) Jan-Mar 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/01
31/01
02/03
01/04

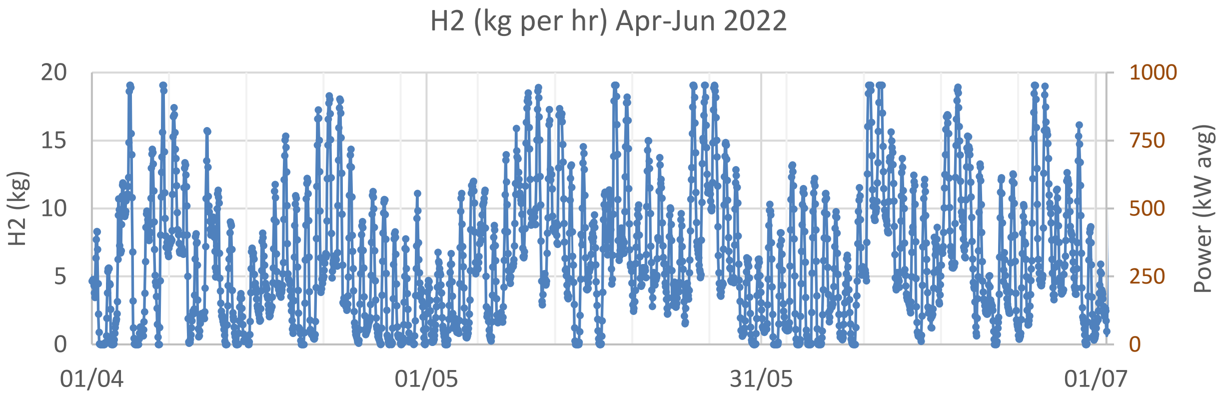

H2 (kg per hr) Apr-Jun 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/04
01/05
31/05
01/07

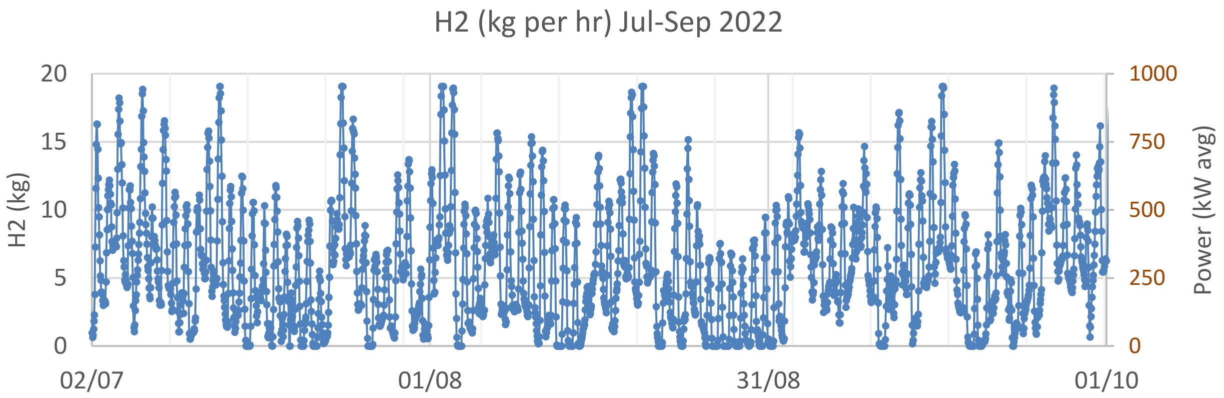

H2 (kg per hr) Jul-Sep 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/07
31/07
31/08
01/10

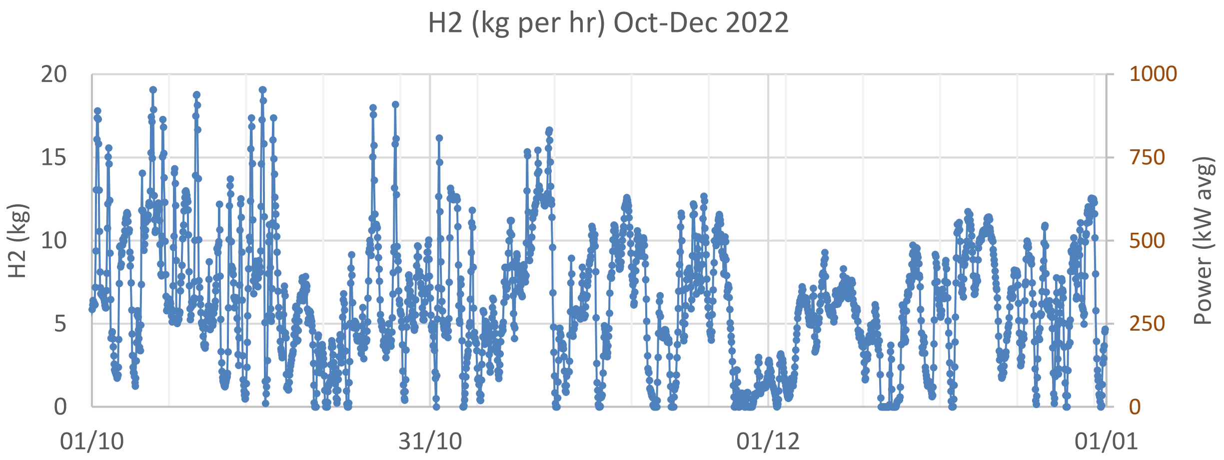

H2 (kg per hr) Oct-Dec 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/10
31/10
01/12
01/01

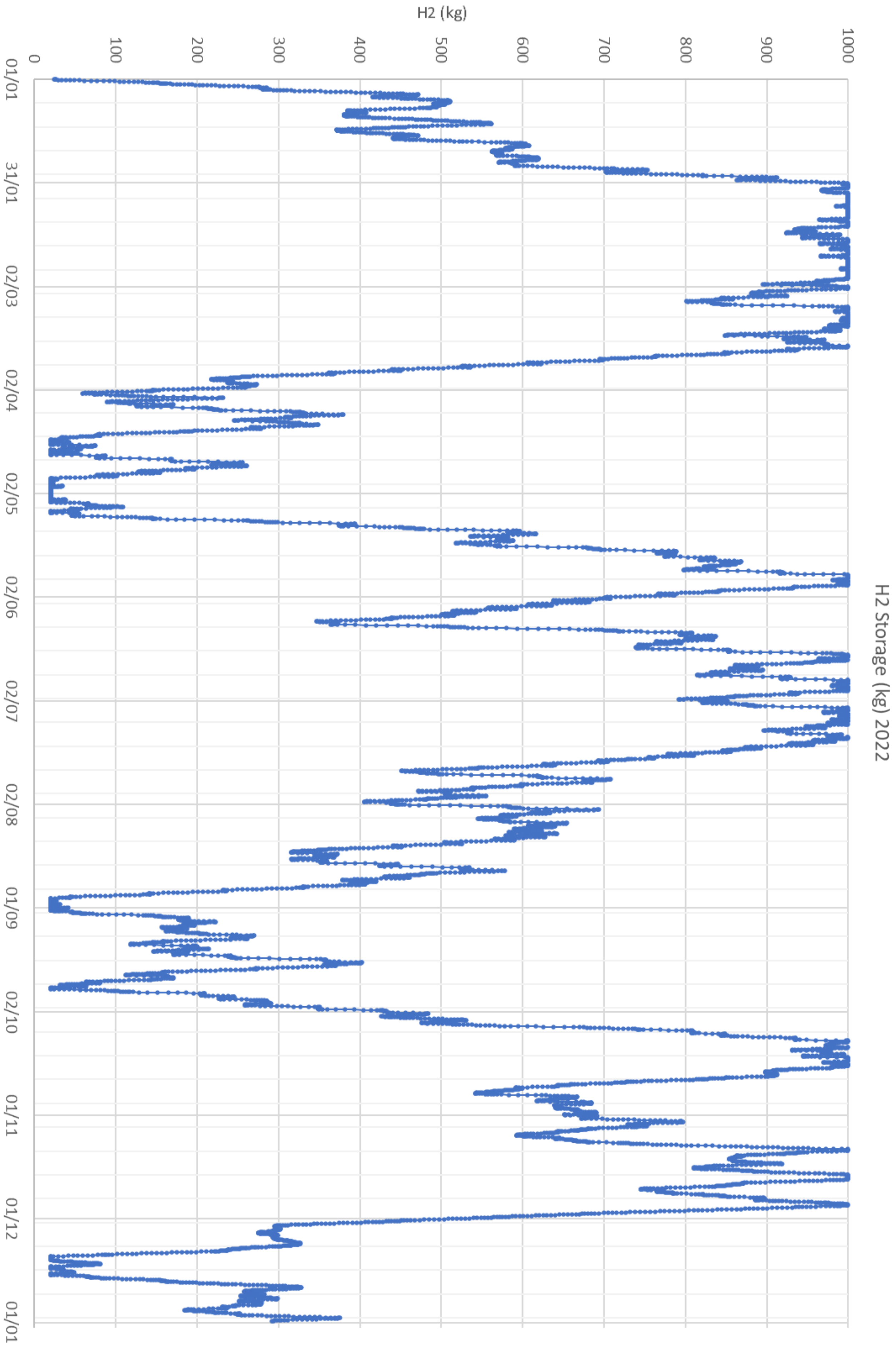

H2 Storage (kg) 2021
H2 (kg)
0
100
200
300
400
500
600
700
800
900
1000
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01


H2 (kg per hr) Jan-Mar 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/01
31/01
02/03
01/04

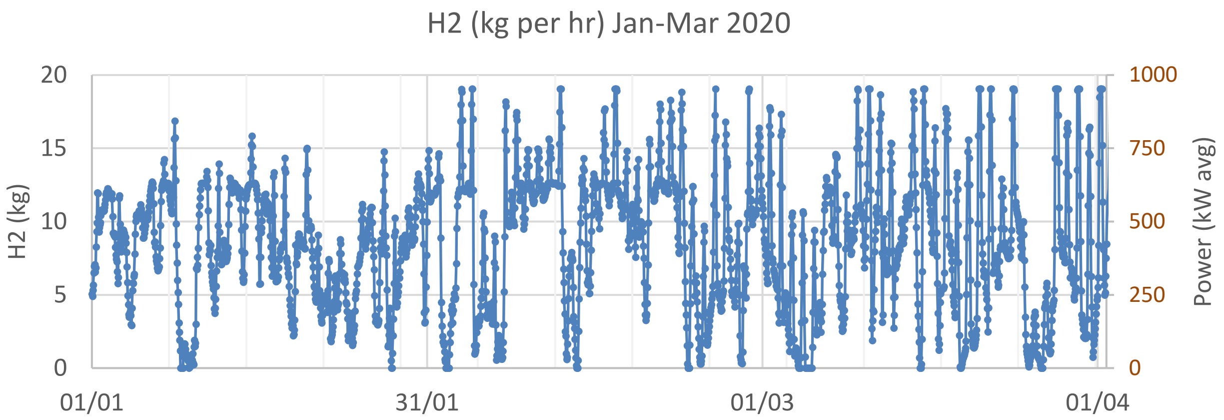

H2 (kg per hr) Apr-Jun 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/04
01/05
31/05
01/07

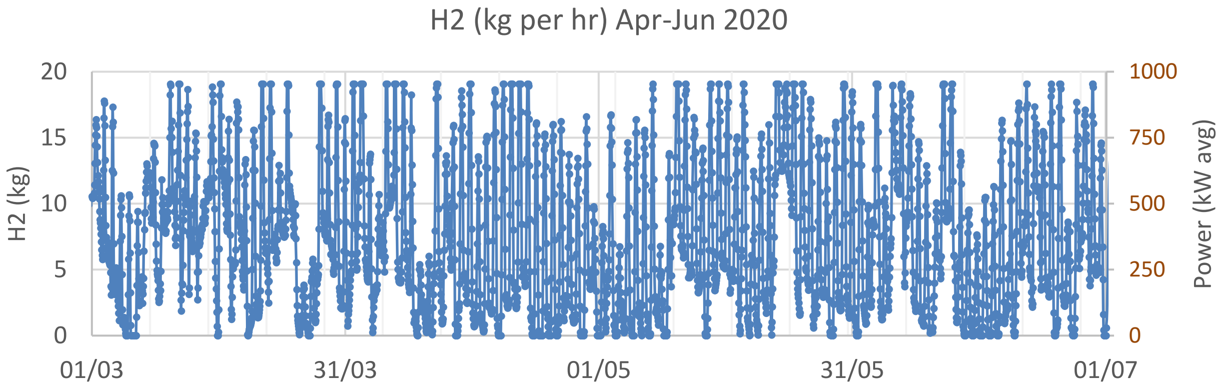

H2 (kg per hr) Jul-Sep 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
02/07
01/08
31/08
01/10

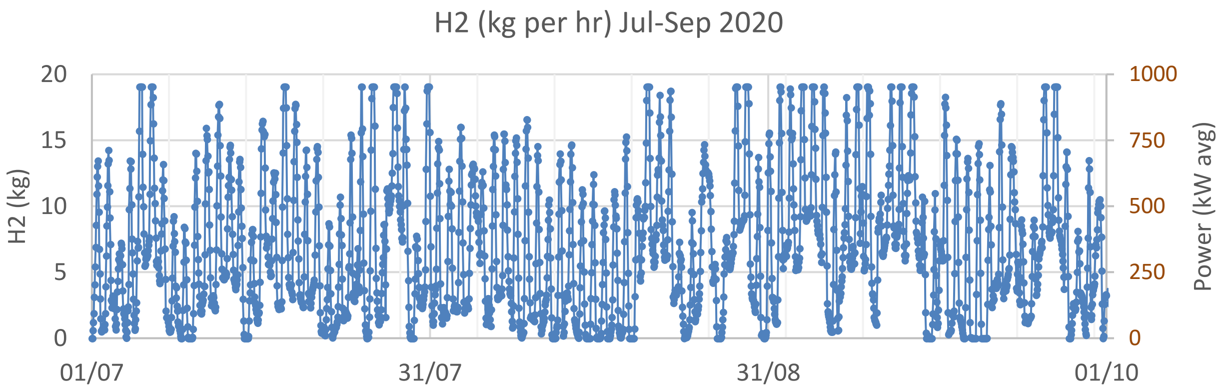

H2 (kg per hr) Oct-Dec 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/10
31/10
01/12
01/01

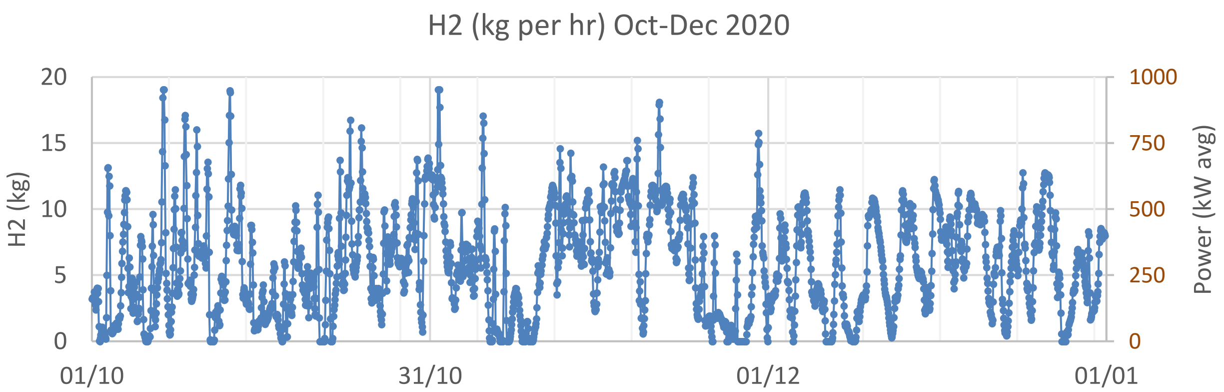

H2 Storage (kg) 2022
H2 (kg)
0
100
200
300
400
500
600
700
800
900
1000
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01

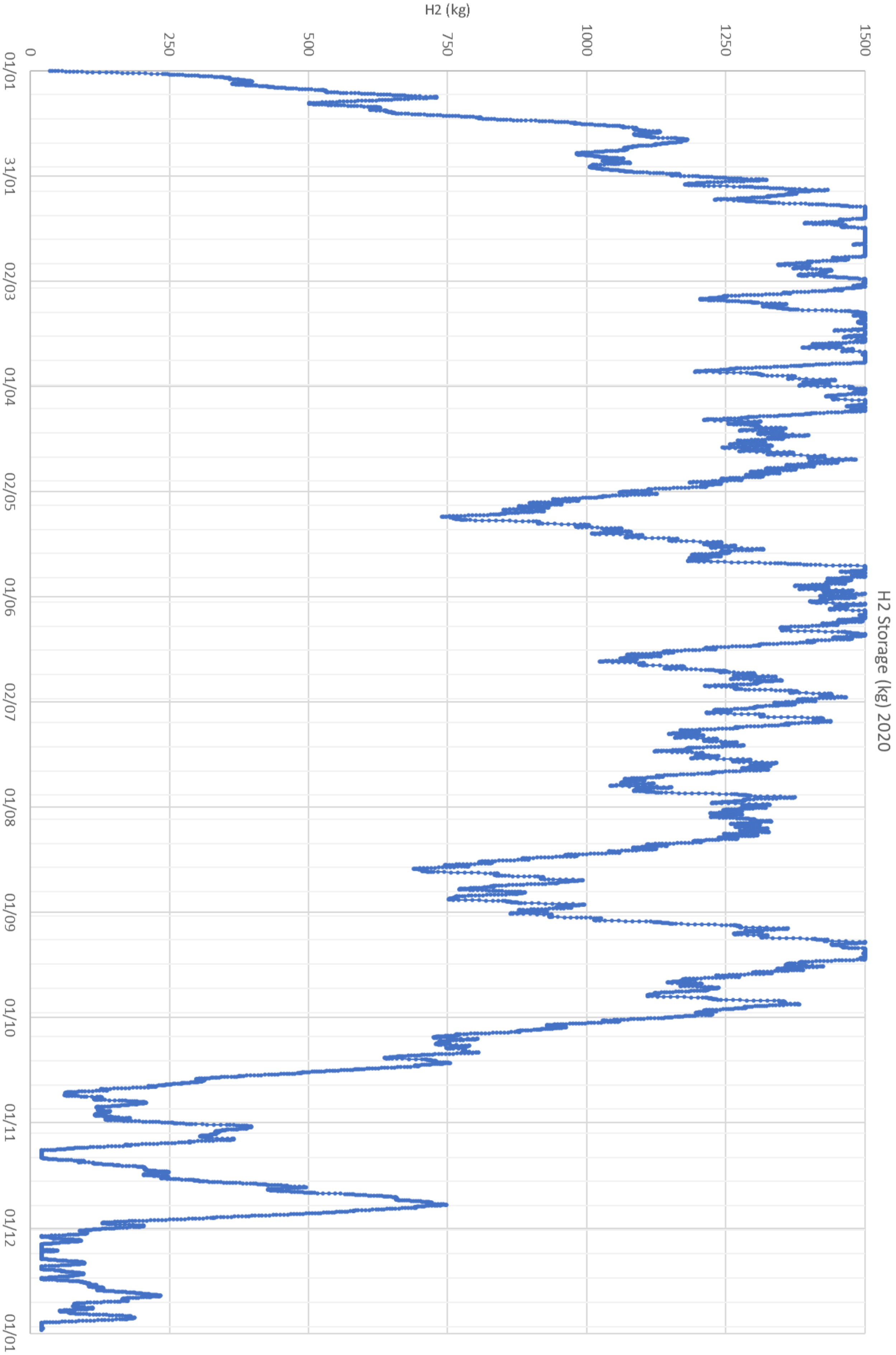
Appendix A14: Modelled data for H_2 production and storage, 2020-2022. System 2 (1 MW WT, 1.45 MW PV, 1500 kg H2 storage, demand of 158 kg day^{-1}). Power values on right axis are approximate to H2 kg hr^{-1}.

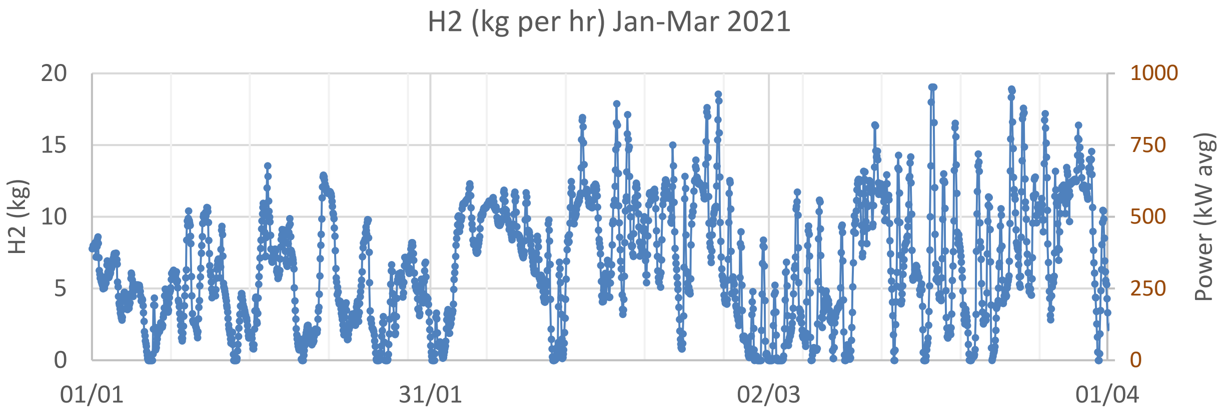


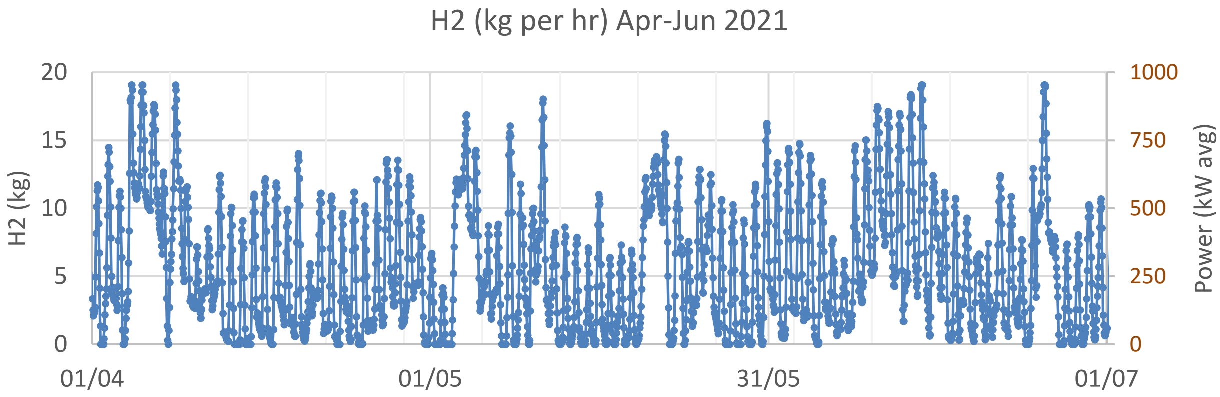


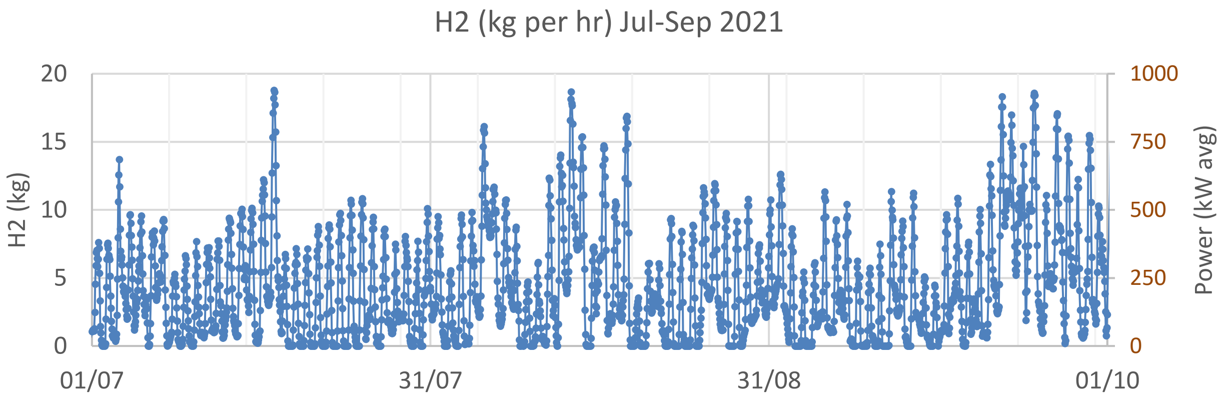


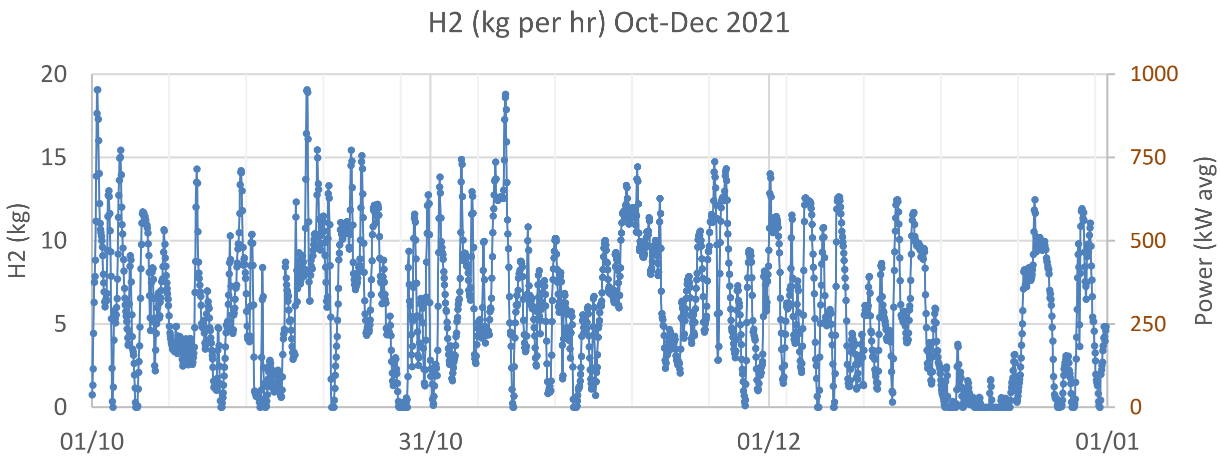


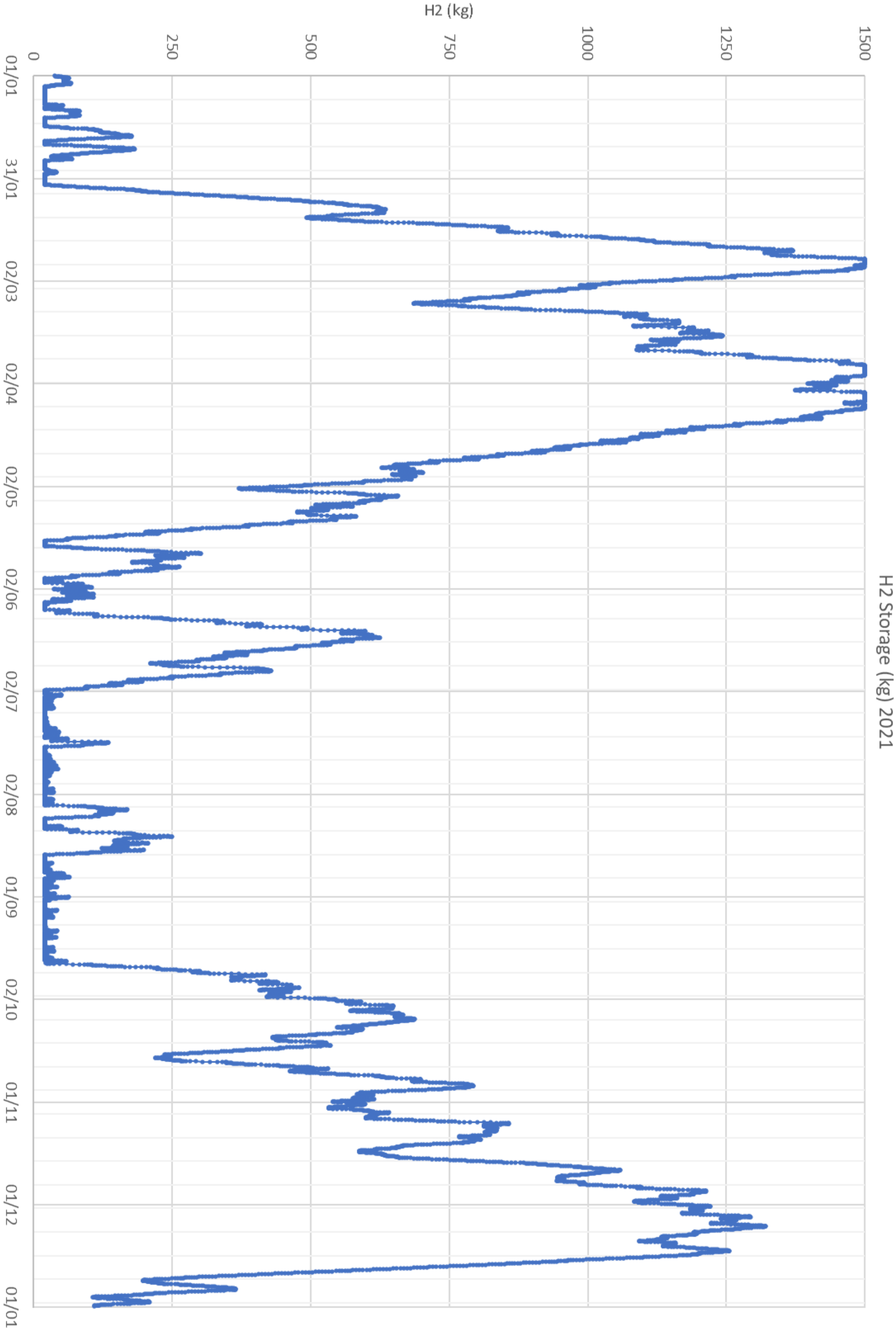

H2 Storage (kg) 2020
H2 (kg)
0
250
500
750
1000
1250
1500
01/01
31/01
02/03
01/04
02/05
01/06
02/07
01/08
01/09
01/10
01/11
01/12
01/01

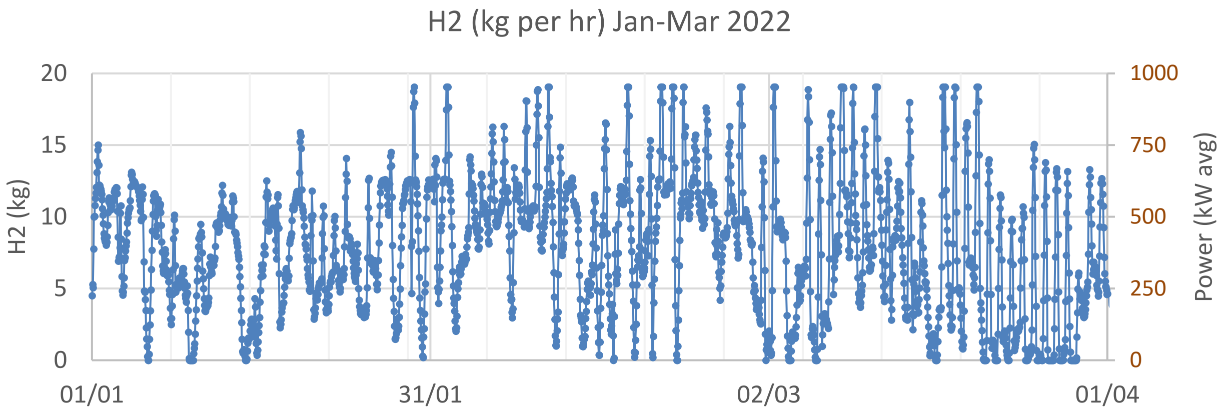

H2 (kg per hr) Jan-Mar 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/01
31/01
02/03
01/04

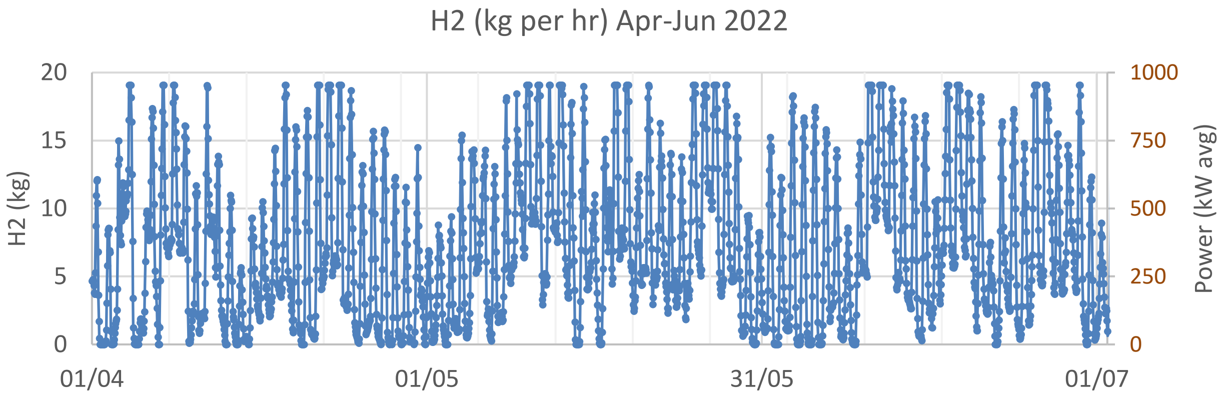

H2 (kg per hr) Apr-Jun 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/04
01/05
31/05
01/07

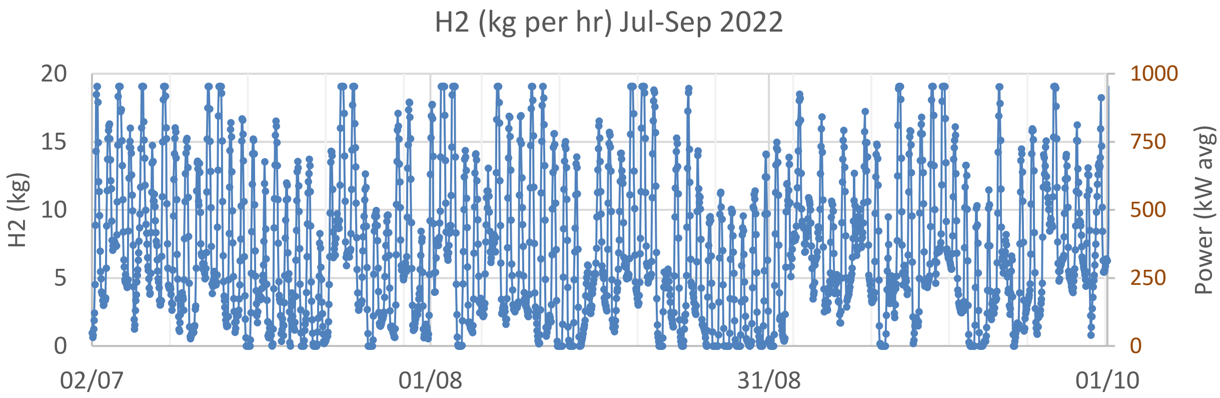

H2 (kg per hr) Jul-Sep 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/07
31/07
31/08
01/10

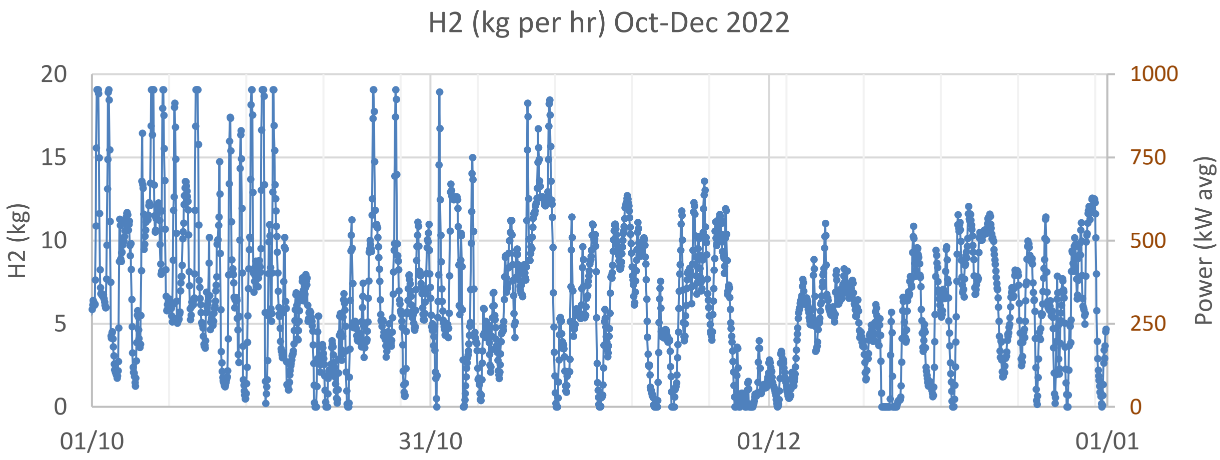

H2 (kg per hr) Oct-Dec 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/10
31/10
01/12
01/01

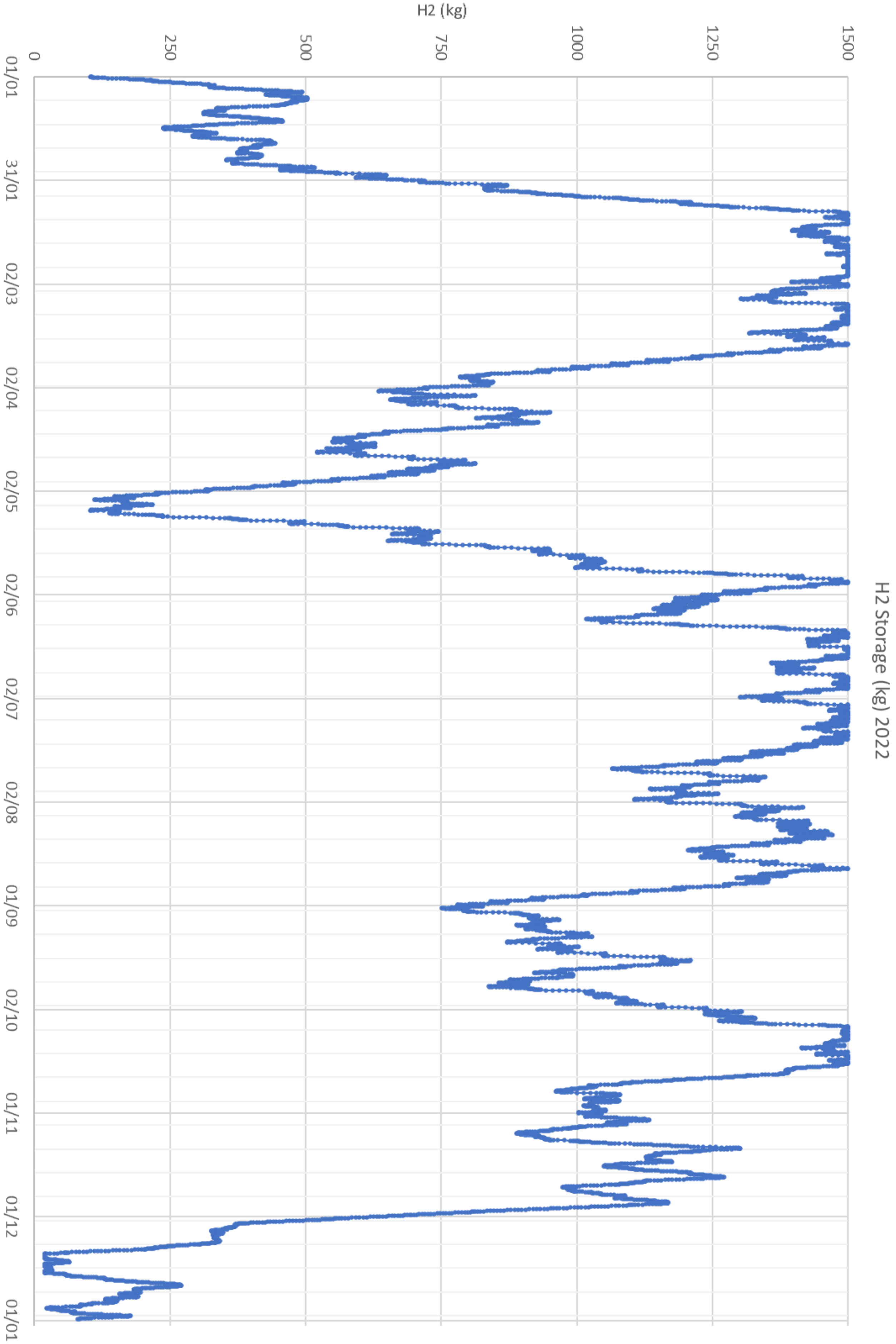

H2 Storage (kg) 2021
H2 (kg)
0
250
500
750
1000
1250
1500
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01


H2 (kg per hr) Jan-Mar 2022
H2 (kg)
Power (kW avg)
0
5
10
15
20
0
250
500
750
1000
01/01
31/01
02/03
01/04

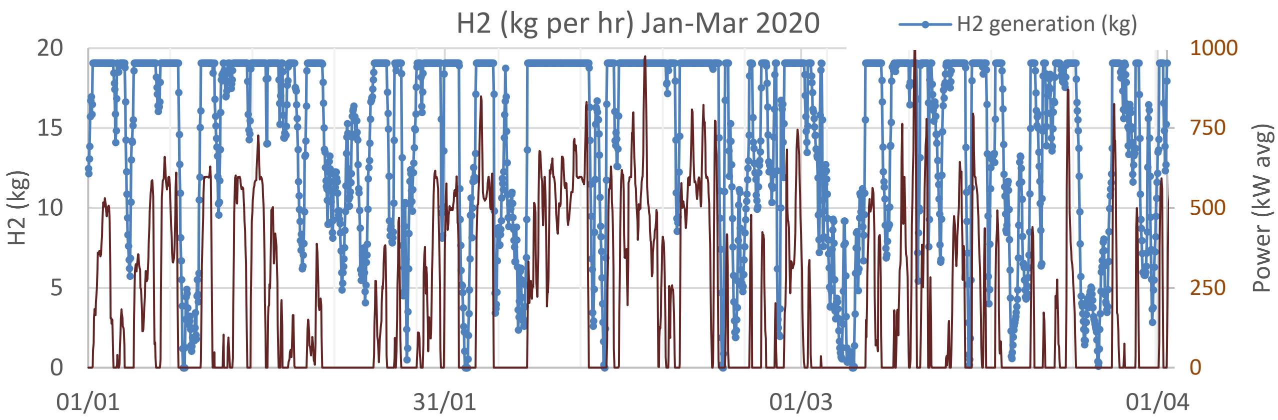

H2 (kg per hr) Apr-Jun 2022
H2 (kg)
Power (kW avg)
0
5
10
15
20
0
250
500
750
1000
01/04
01/05
31/05
01/07

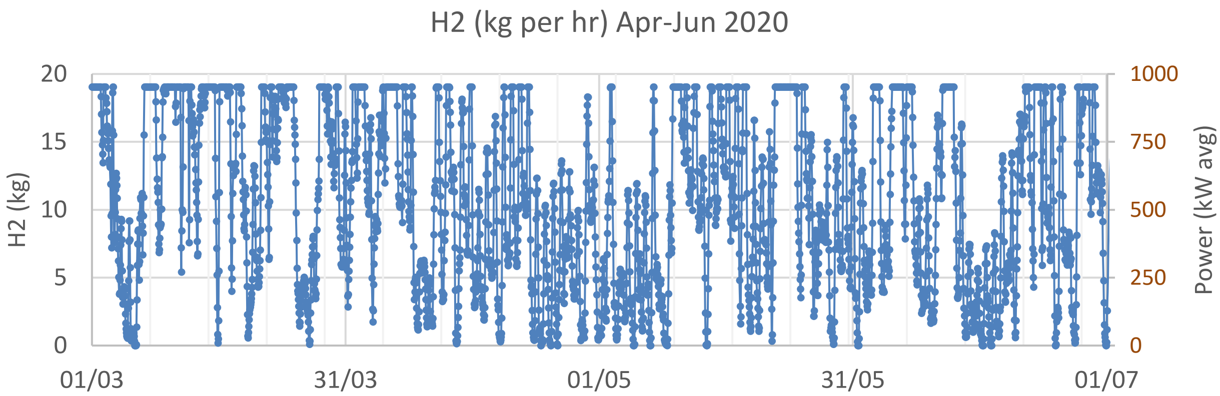

H2 (kg per hr) Jul-Sep 2022
H2 (kg)
Power (kW avg)
0
5
10
15
20
0
250
500
750
1000
02/07
01/08
31/08
01/10

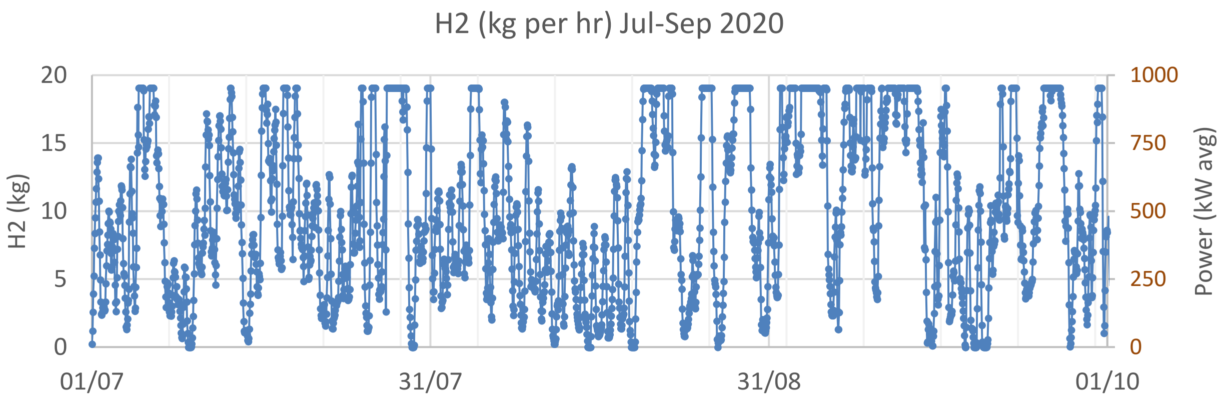

H2 (kg per hr) Oct-Dec 2022
H2 (kg)
Power (kW avg)
0
5
10
15
20
0
250
500
750
1000
01/10
31/10
01/12
01/01

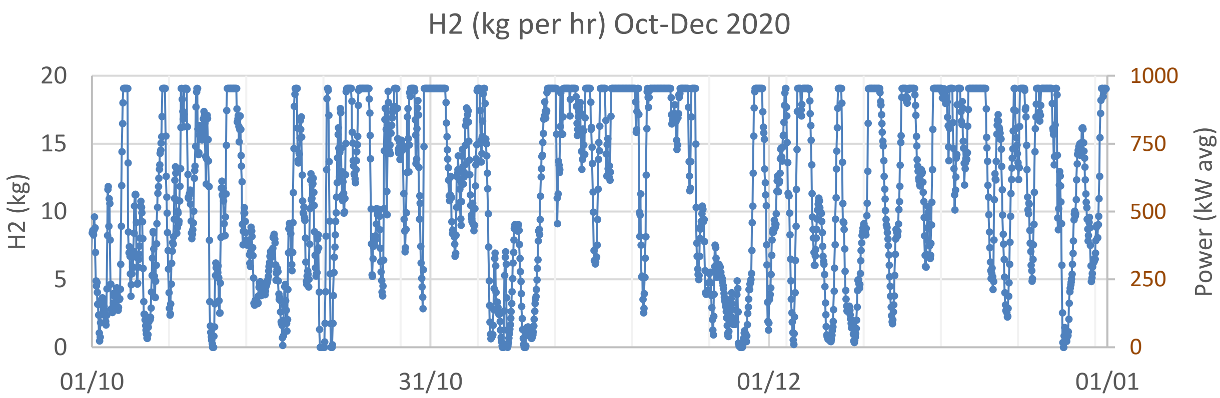

H2 Storage (kg) 2022
H2 (kg)
0
250
500
750
1000
1250
1500
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01

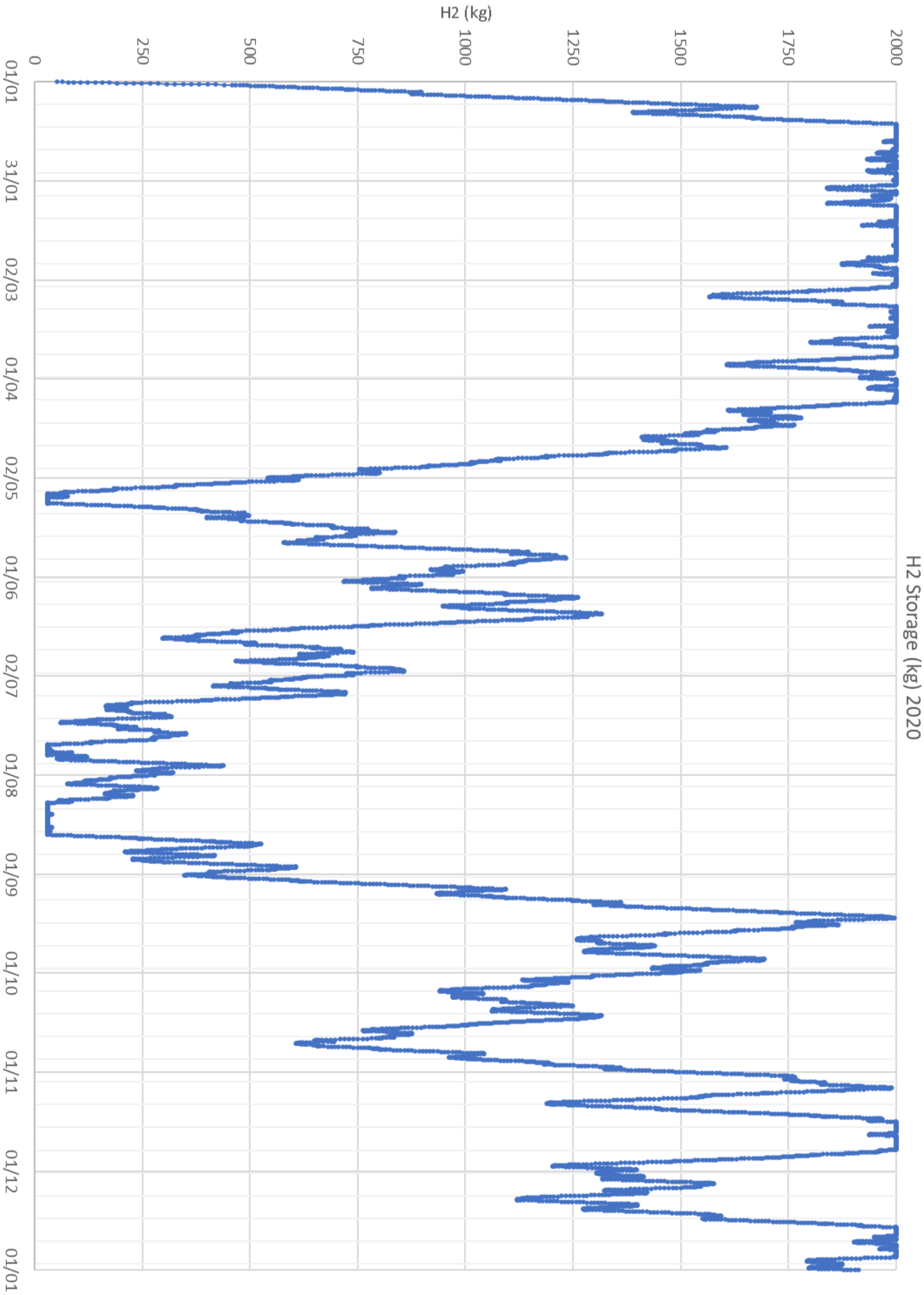
Appendix A15: Modelled data for H_2 production and storage, 2020-2022. System 3 (2 MW WT, 1 MW PV, 2000 kg H2 storage, demand of 244 kg day^{-1}). Power values on right axis are approximate to H2 hr^{-1}.

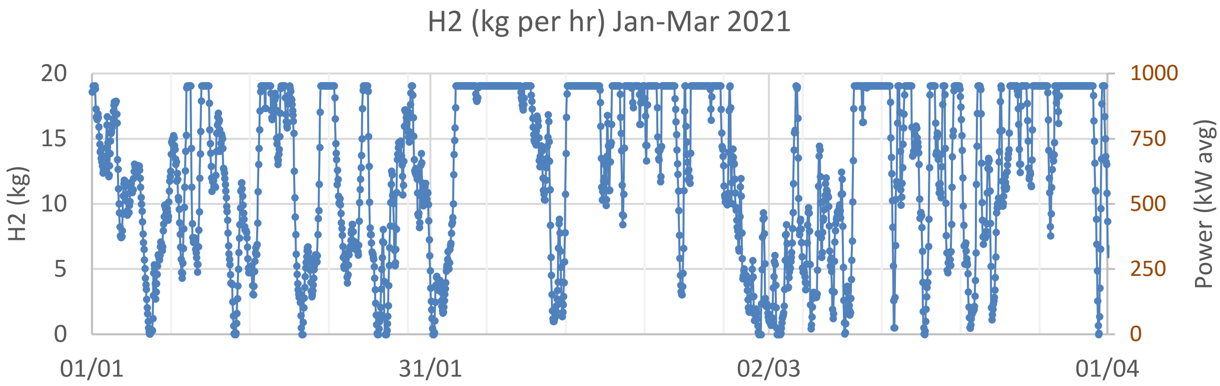


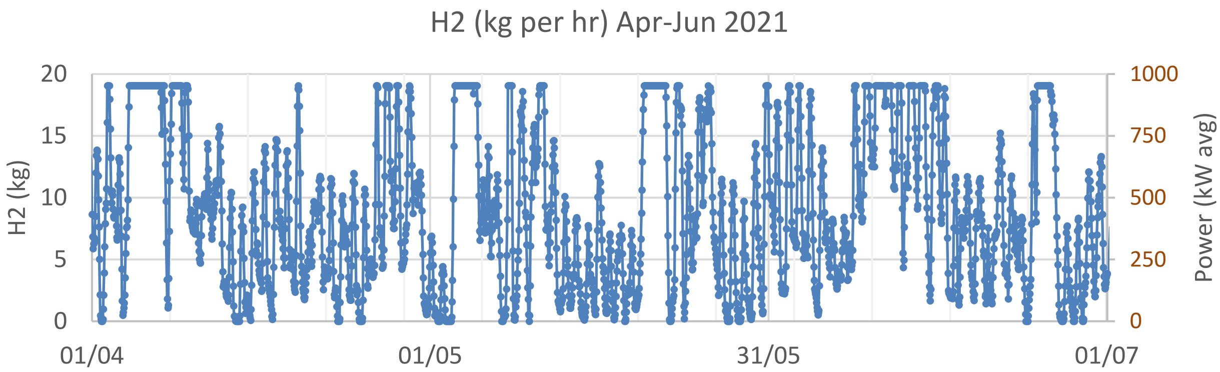


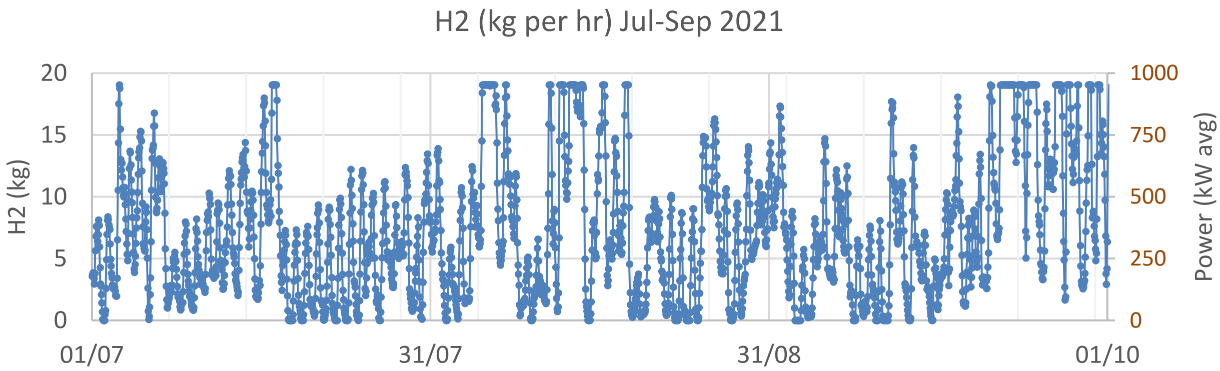


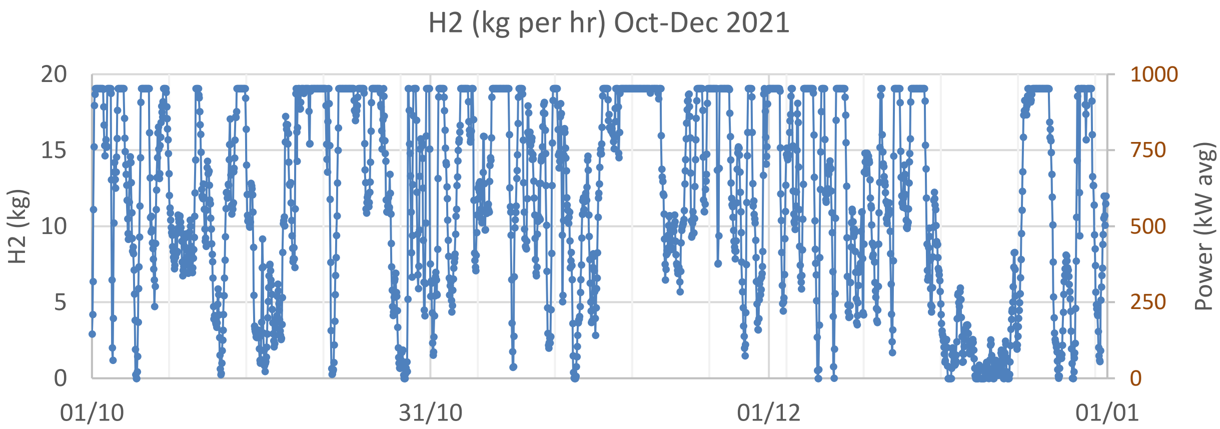


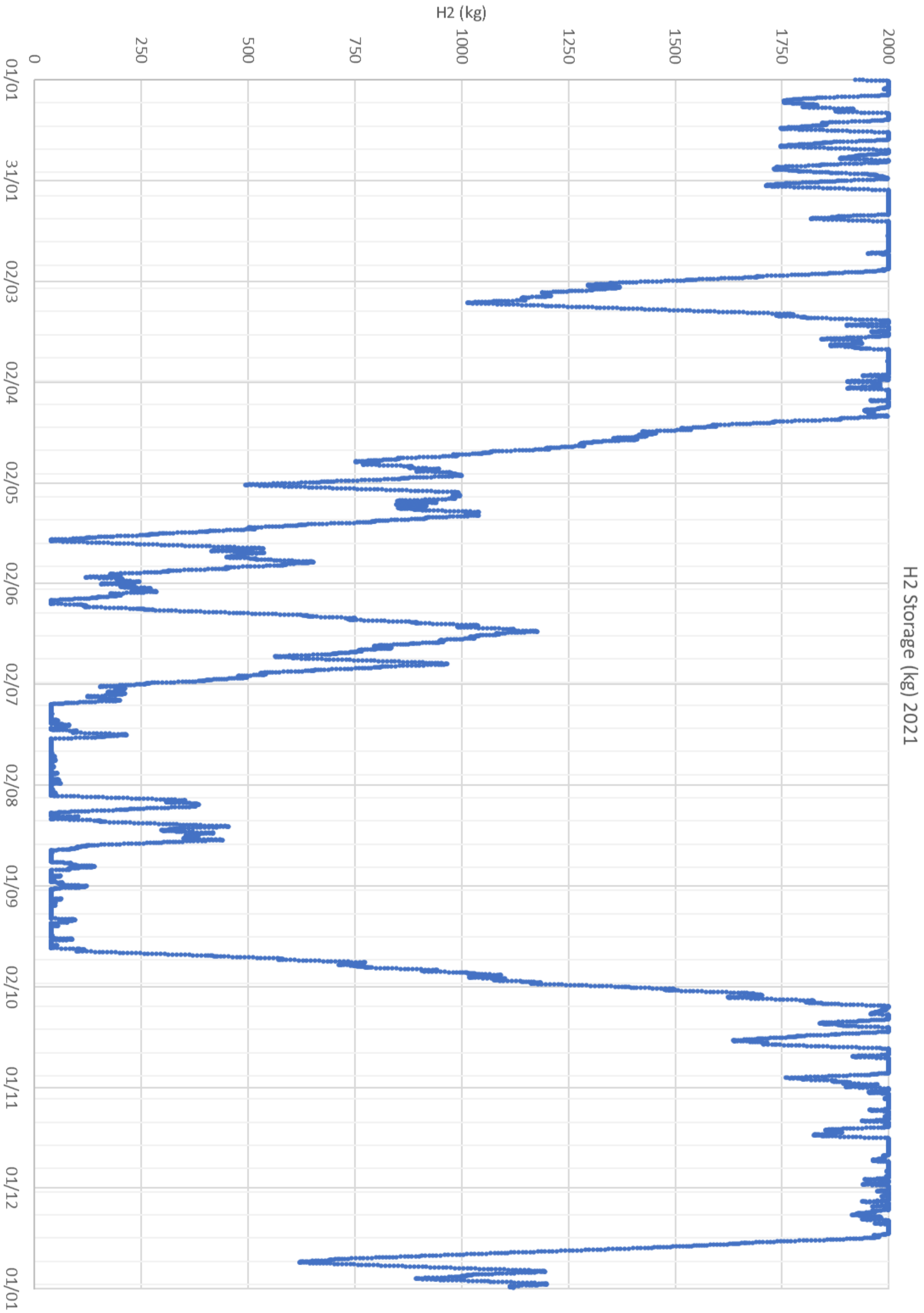

H2 Storage (kg) 2020
H2 (kg)
0
250
500
750
1000
1250
1500
1750
2000
01/01
31/01
02/03
01/04
02/05
01/06
02/07
01/08
01/09
01/10
01/11
01/12
01/01

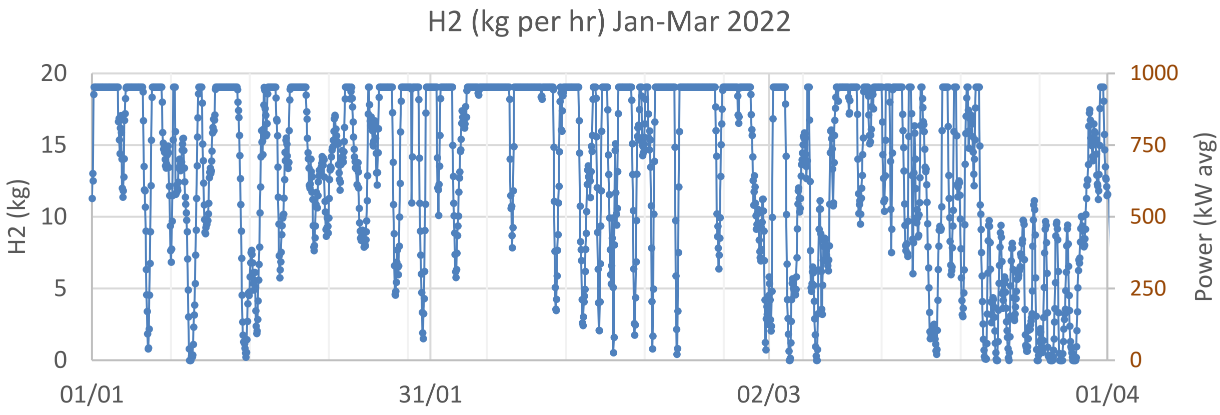

H2 (kg per hr) Jan-Mar 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/01
31/01
02/03
01/04

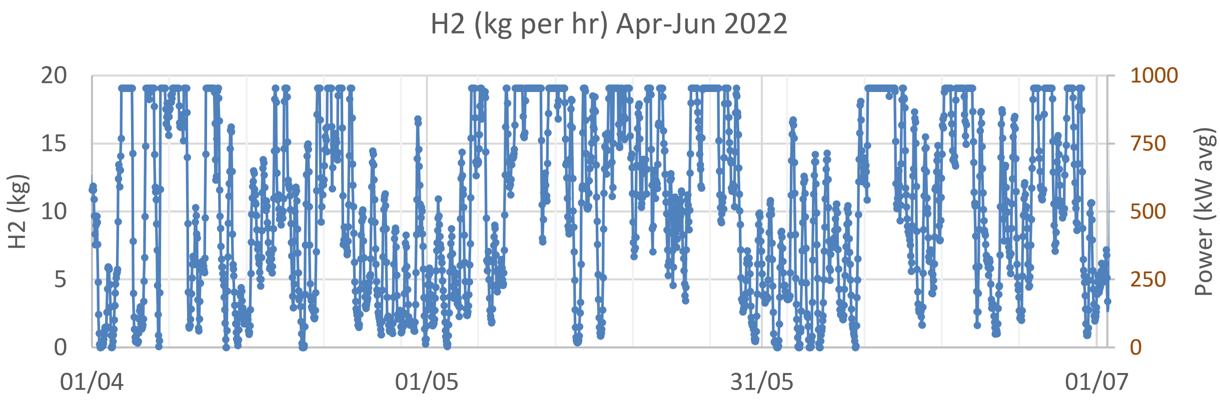

H2 (kg per hr) Apr-Jun 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/04
01/05
31/05
01/07

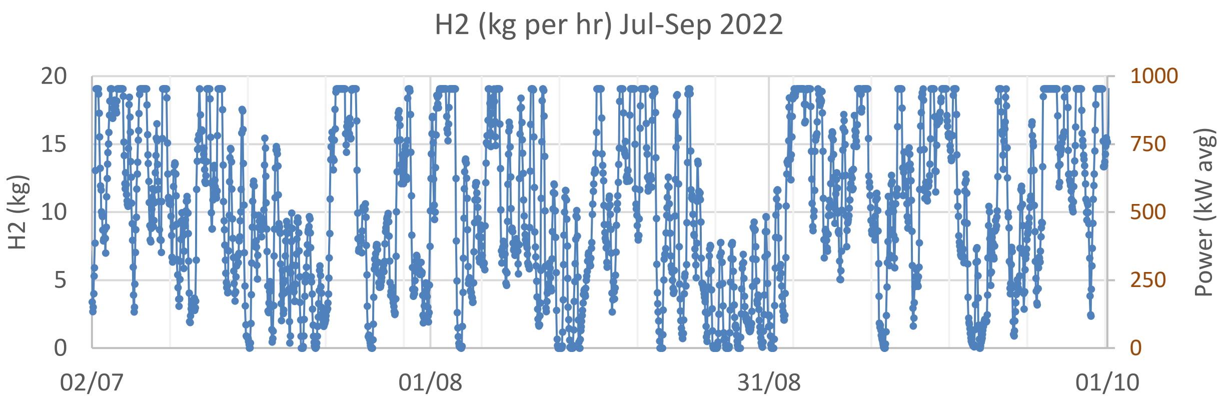

H2 (kg per hr) Jul-Sep 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/07
31/07
31/08
01/10

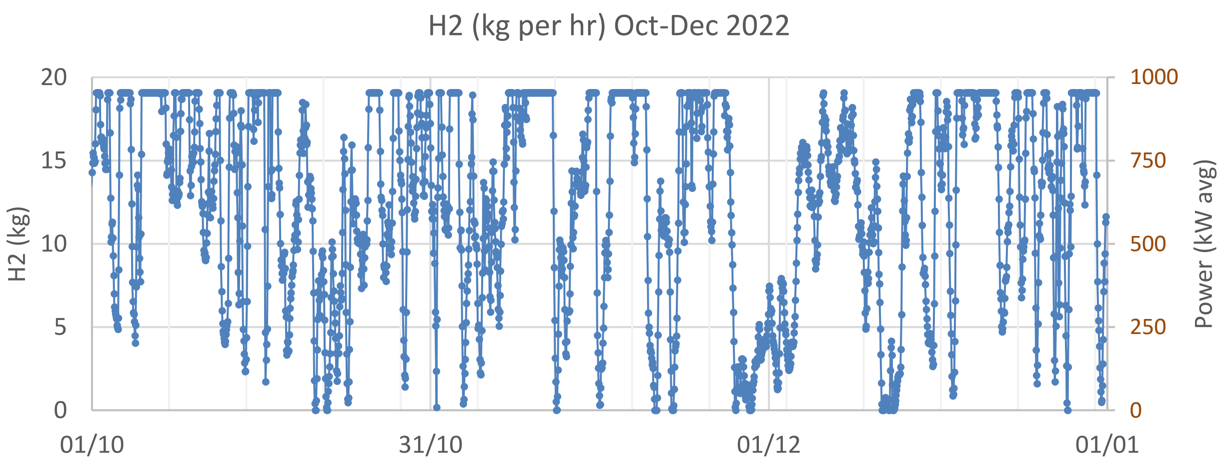

H2 (kg per hr) Oct-Dec 2021
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/10
31/10
01/12
01/01

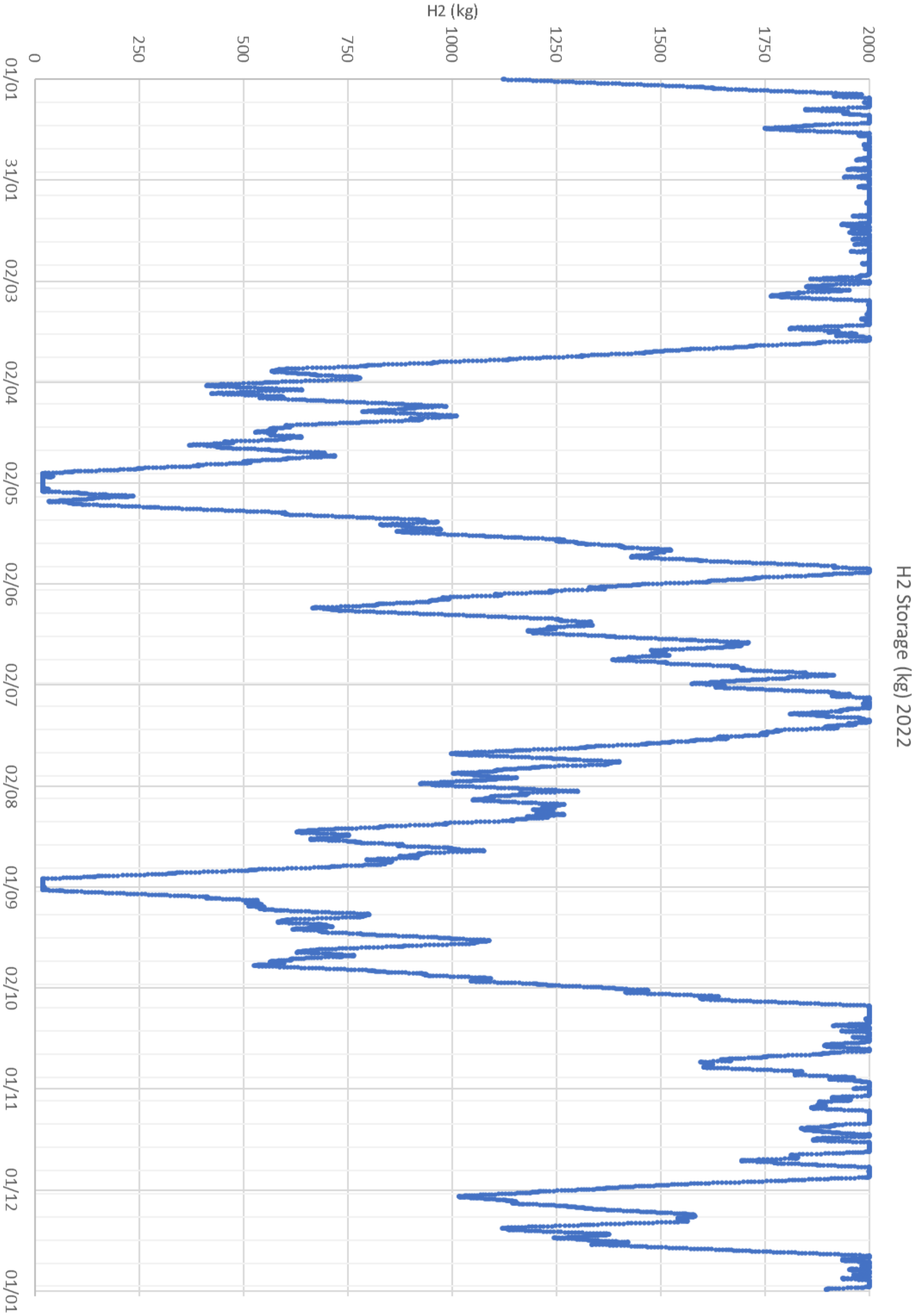

H2 Storage (kg) 2021
H2 (kg)
0
250
500
750
1000
1250
1500
1750
2000
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01


H2 (kg per hr) Jan-Mar 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/01
31/01
02/03
01/04


H2 (kg per hr) Apr-Jun 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/04
01/05
31/05
01/07


H2 (kg per hr) Jul-Sep 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
02/07
01/08
31/08
01/10


H2 (kg per hr) Oct-Dec 2022
H2 (kg)
Power (kW avg)
20
15
10
5
0
1000
750
500
250
0
01/10
31/10
01/12
01/01


H2 Storage (kg) 2022
H2 (kg)
0
250
500
750
1000
1250
1500
1750
2000
01/01
31/01
02/03
02/04
02/05
02/06
02/07
02/08
01/09
02/10
01/11
01/12
01/01