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DOI
10.1016/j.apenergy.2022.118540

Publication date
2022

Document Version
Final published version

Published in
Applied Energy

Applied Energy 310 (2022) 118540

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Optimisation-based system designs for deep offshore wind farms including power to gas technologies

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ARTICLE INFO

Keywords:
Offshore wind farms
Energy storage
Renewable energy
Green ammonia
Batteries
Liquid hydrogen

ABSTRACT

A large deployment of energy storage solutions will be required by the stochastic and non-controllable nature of most renewable energy sources when planning for higher penetration of renewable electricity into the energy mix. Various solutions have been suggested for dealing with medium- and long-term energy storage. Hydrogen and ammonia are two of the most frequently discussed as they are both carbon-free fuels. In this paper, the authors analyse the energy and cost efficiency of hydrogen and ammonia-based pathways for the storage, transportation, and final use of excess electricity from an offshore wind farm. The problem is solved as a linear programming problem, simultaneously optimising the size of each problem unit and the respective time-dependent operational conditions. As a case study, we consider an offshore wind farm of 1.5 GW size located in a reference location North of Scotland. The energy efficiency and cost of the whole chain are evaluated and compared with competitive alternatives, namely, batteries and liquid hydrogen storage. The results show that hydrogen and ammonia storage can be part of the optimal solution. Moreover, their use for long-term energy storage can provide a significant, cost-effective contribution to an extensive penetration of renewable energy sources in national energy systems.

1. Introduction

Climate change is arguably one of the greatest challenges of our time. As of 2016, 196 nations set the goal of keeping the global temperature rise during this century well below 2 °C compared to pre-industrial levels by signing the Paris Agreement. To achieve this long-term goal, nearly every nation is committed to reduce CO_2 and greenhouse gas emissions by transforming its economy from using fossil-based fuels to alternative energy sources and technologies.

Amongst potential solutions being investigated, Renewable Energy Sources (RES) are expected to become the main driver for most, if not all, of the energy demands of human society. Many researchers have shown the existence of several pathways for the decarbonisation of human activities within reasonable time frames based on the power of wind, sun, biomass, geothermal heat, and water [1–4].

1.1. Electricity storage and the challenge of stochasticity of renewable energy sources

Whilst there is little discussion in the literature regarding the existence of sufficient RES to meet energy demand, research results often disagree on what would be the cost of dealing with the inherent stochasticity of RES [2,5–8].

Taking as an example studies that look into the feasibility of a 100% RES-based EU energy grid, it can be shown that most studies agree that such a scenario is feasible. Child et al. [9] even suggests that it would be achievable at a lower levelized cost of energy (LCOE) compared to the current energy system. Zappa et al. [10], on the other hand, reached the opposite conclusion: it would require 90% more generation capacity and 240% more transmission capacity compared to the current European energy system, and therefore it would be more economically

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https://doi.org/10.1016/j.apenergy.2022.118540
Received 7 October 2021; Received in revised form 26 December 2021; Accepted 10 January 2022
Available online 1 February 2022

Table 1
Acronyms and abbreviations.

Acronym	Description
C3S	Copernicus Climate Change Service
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CHS	Compressed H_2 Storage
ECMWF	European Centre for Medium-Range Weather Forecasts
ESS	Energy Storage System
IEC	International Electrotechnical Commission
LCOE	Levelized Cost of Energy
LHS	Liquid H_2 Storage
LOHC	Liquid Organic Hydrogen Carrier
LP	Linear Programming
MAD	Market Activation Delay
MILP	Mixed-integer Linear Programming
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
PEME	Proton-Exchange Membrane Electrolysers
PEMFC	Proton-Exchange Membrane Fuel Cell
PtG	Power-to-Gas
RES	Renewable Energy Sources
SOFC	Solid Oxide Fuel Cell

convenient to rely heavily on nuclear power or Carbon Capture and Storage (CCS).

When analysing large-scale scenarios, such as the energy system of the European Union, energy transmission plays a substantial role in balancing non-programmable renewable power generation. At smaller scale scenarios, the balance shifts towards the use of different types of Energy Storage Systems (ESSs). For instance, Jafari et al. [11] consider the case of the Italian energy system, and show that the decarbonisation of the system can be achieved at a much lower cost when allowing for the use of lithium-ion batteries for grid-level storage. Numerous similar studies have been devoted to detailed comparisons, cost-benefit analyses, and commercial application potential and it is generally accepted that batteries are likely to be the cheapest energy storage option for applications with a relatively small number of cycles. However, their energy density, performance, and cost are expected to be the limiting factors in their expansion into a variety of applications. Flywheel energy storage, used for applications with very short storage periods and frequent use, and magnetic energy storage have received less attention, with key needs being reductions in mechanical, electrical and power conversion losses. Pumped hydroelectric and compressed air energy storage technologies are mature, cost effective and reliable and used for large scale storage with frequent cycling capabilities. However, pumped hydro storage faces challenges in terms of geographical limitations and seasonal influence [12] and compressed air storage experiences barriers of low total energy efficiency, heat loss and large storage tank size [13]. The interested reader should refer to reference literature in the field [14–17] for more information on the current state-of-the-art of energy storage technologies.

1.2. Hydrogen as storage

Hydrogen (H_2) is regarded as one of the most promising clean fuels, with a high potential for replacing fossil fuels, as it is the most abundant and lightest element in nature with the highest known energy content per unit of weight when compared to any fossil fuel [18]. Conventionally, H_2 has served as an intermediate chemical in chemical processing with its most critical usage being in the crude oil refining sector and in ammonia (NH_3) and urea production. The global demand of H_2 is expected to increase by 4–5% annually over the coming years, primarily due to the increased demand for crude oil refining, methanol and NH_3 synthesis. By 2030 it is anticipated that H_2 consumption in the refining sector will more than double compared to the consumption in 2005 [14,18]. Research studies also suggest that successful developments in production and storage technologies for H_2 will result in a further increase in demand for H_2, especially in decarbonising hard-to-electrify applications. However, several social and political barriers need to be overcome before pure hydrogen-based technologies can be used in large scale applications [14,19].

H_2 energy storage systems appear to be the most promising, when compared with available alternatives [19], as H_2 production and utilisation is considered highly versatile and efficient, despite its low volumetric energy density. Generally, H_2 can be stored as compressed H_2, liquid H_2 or be physically or chemically bonded to an appropriate solid-state material, with ongoing research being conducted to develop safe, reliable, compact and cost-effective technologies for H_2 storage [20–22].

Compressed H_2 storage (CHS) refers to the physical storage of H_2 in highly pressurised tanks [23]. Standard pressures for compressed H_2 storage today are 350 to 700 bar. This method is beneficial for storage purposes, because in this form H_2 can be stored in compact spaces while retaining its energy effectiveness. Although the technology is simple, the compressed H_2 storage solution is relatively expensive compared with the alternatives, and it is considered more suitable for small scale applications (such as for private land transportation) rather than for long-term storage [23,24]. Higher compression pressures allow higher storage density, but also require higher energy expenditure and thicker/more expensive storage tanks, thus representing a trade-off that needs to be appropriately designed depending on the specific application. The energy demand for compressing hydrogen ranges between 2 and 4 kWh/kg_{H_2} depending on the storage pressure [25] (generally 350 or 700 bar) and on the level of the technology, thus representing between 6% and 12% of the energy content of the stored H_2.

In liquid H_2 storage (LHS), hydrogen is stored in liquid form, thus dramatically increasing its energy density. However, H_2 cannot exist in liquid form at normal ambient temperatures and cannot be condensed by compression alone: in practice, the liquefaction of H_2 requires cooling it to about 20 K, a process which is associated with a relatively high energy cost. The energy required for hydrogen liquefaction could theoretically be as low as 2–3 kWh/kg_{H_2} [25], while actual values in real industrial facilities are in the range of 7–13 kWh/kg_{H_2} [25], thus representing up to 40% of the energy content of the stored H_2.

Currently, research is focused on the development of composite tank materials that will result in lighter and stronger tanks [20,21,26]. Although the technology appears to be very promising, as it is gravimetrically and volumetrically efficient, ongoing research is being conducted to overcome problems dealing with H_2 losses in the liquefaction process, high H_2 liquefaction energy demand, H_2 boil-off and tank cost [14,23,27].

H_2 can also be stored at ambient conditions through Liquid Organic Hydrogen Carriers (LOHCs), which are organic substances in liquid or semi-solid states that store H_2 by catalytic hydrogenation and dehydrogenation processes over multiple cycles. They allow the storage of H_2 for large amounts of time, while eliminating the phenomenon of boil-off and other operational issues [28]. However, the de-hydrogenation of LOHCs is an endothermic reaction, which makes the process relatively complex as heat needs to be provided to the system that uses H_2. While the exact values depend on the type of LOHC and on the catalyst used in the de-hydrogenation process, general values are in the order of 64–69 kJ/mol_{H_2} for the heat demand, to be supplied at around 300° C [29]. Furthermore, the “exhaust” LOHCs needs to be stored and regenerated before they can be used again, a process which can constitute a challenge from a logistic perspective.

Metal hydrides are another alternative to LOHCs. These are materials known for their unique ability to absorb H_2 at high capacity, and to release it under appropriate temperature conditions. They are usually considered for safety-critical applications that require low reactivity and high storage density [23,30]. However, they too suffer from limitations that have prevented their widespread usage and commercialisation, as they react violently upon exposure to moist air, and can reduce the lifetime of storage tanks as they cause absorption of impurities during H_2 uptake [23,31]. Various studies have also proposed the conversion of H_2 to conventional fuels, such as syngas, methane (CH_4) and methanol (CH_3OH) as a possible solution for long-term storage and transportation. However, none of these solutions would prove to be CO_2 neutral, unless biomass and carbon capture technologies are used as sources for the required carbon.

1.3. The role of ammonia as a hydrogen carrier

Amongst all of these potential solutions, one technology has received significant attention from both government and industry: the use of nitrogen as a binding atom to store H_2 by converting it to ammonia (NH_3). NH_3 is the second most commonly produced chemical in the world and the infrastructure involved in its production, transportation and distribution is already technologically mature and cost-effective. Moreover, NH_3 has the highest H_2 net volumetric density, potentially the highest total energy efficiency and it shows higher utilisation flexibility, as it can be used directly or be decomposed to release the contained H_2 [15].

In the systems engineering community, renewable NH_3 production has been investigated from the perspective of capacity planning [32–34], optimal operation [35–37] and actual implementation via a small-scale production facility [38], to name a few examples. However, there is comparatively little research published on the use of NH_3 for energy storage.

The economic feasibility of utilising NH_3 as energy storage has been discussed and demonstrated in a number of case-specific studies. For example, in [39], the authors investigated the economic feasibility of using H_2-based and NH_3-based energy storage for islanded renewable energy supply systems in 15 US cities. They utilised an optimal combined capacity planning and scheduling model, in order to determine the optimal unit selection and size of the various units, production rates, and storage inventories for the system. They concluded that NH_3 is generally more cost-effective than H_2 as a single method of energy storage, whereas their combined use (H_2 for short-term storage, and NH_3 for long-term storage) outperforms the use of either one individually.

An optimal capacity planning and scheduling problem was also solved in [40], in which the authors studied a wind-powered system that relies on renewable NH_3 for sustainable energy supply and agriculture.

The economic viability of NH_3 for energy storage was also demonstrated in [41]. The authors investigated the viability of islanded NH_3 production, using a Haber–Bosch process fed with H_2 produced by water electrolysis and N_2 from air separation, powered entirely by renewable energy. Based on the results of their work, they concluded that renewable-derived NH_3 is economically viable under favourable power supply conditions.

The authors of [42] researched the use of NH_3 as an energy carrier to transport wind and solar energy from rural areas to more populated areas with several case studies in Texas, USA. Their results favoured the use of NH_3 as a storage system for storage times of greater than 3 months, underlining that NH_3 is the most suitable chemical for longer storage periods.

The high performance of NH_3-based energy storage has also been demonstrated in various case studies. An early system design was reported in [43]. The authors designed and implemented a small-scale system for solar-driven thermochemical energy storage using NH_3, concluding that their experimental work supports the results presented in model-based studies, thus suggesting that this technology could be one of the most cost-effective routes to the provision of continuous 24-hour solar electricity. [44] presented a detailed optimal design study for an electrochemical NH_3 production plant to store solar energy. The authors proposed a pressurised reversible solid-oxide fuel cell for power conversion, coupled with external NH_3 synthesis and decomposition processes, and a steam power cycle coupled with a refrigeration cycle to recycle N_2 completely. The authors studied the performance of a 100 MW system under stationary conditions, concluding that a round-trip efficiency of 72% can be achieved. High efficiencies were also reported in [45]. The authors developed a new renewable-energy based integrated system, utilising both solar and wind energy sources, in which the excess power generated was stored in the form of NH_3. By performing dynamic simulations considering variations in solar radiation intensity and wind speeds over the period of a year, they demonstrated that the energy efficiency of their approach varies between 46.1% and 53.3% over the year. Similar results were also observed in [46], in which the authors showcased a novel NH_3 storage system, in which H_2 was recovered via decomposition with energy and exergy efficiencies of 85.6% and 85.3%, respectively. The conceptual design of NH_3-to-power processes was also performed in [47], in which the authors reviewed storage systems in the size range of 1–10 MW, and evaluated alternatives for H_2 and N_2 production, NH_3 synthesis, separation, storage and combustion. Through design optimisation, the authors concluded that it is possible to operate the islanded energy system at a round-trip efficiency of 61%.

A general conclusion that can be drawn from these studies is that the potential for NH_3-based energy storage is limited by the intensive capital investment that is required for the process units (e.g. N_2 and NH_3 production) and the further energy required to transform the H_2 to NH_3. Nevertheless, NH_3 can be even more attractive as a fuel, as its usage is feasible with relatively few modifications to already existing prime mover technologies (i.e. compression ignition engines) with the appropriate after-treatment systems, as it can be combusted with diesel or any other lower auto-ignition temperature fuel in dual-fuel mode resulting in a significant reduction of carbon-based emissions [48–50].

1.3.1. Gaps and objectives

Whilst the subject of using NH_3 as a means of renewable energy storage has already been explored, we believe that there are some gaps in the existing literature on the subject. More specifically, to the best of our knowledge, there is no study that approaches the question of using NH_3 for energy storage and its comparison to H_2 using an optimisation approach. This approach allows an exploration of the whole variable domain whilst taking multiple objectives and constraints into account simultaneously. Hence, the question that we aim to answer is: does NH_3 constitute a cost-efficient option for individual energy providers? In this work, we aim to answer this question by employing a techno-economic analysis perspective, where the objective is to minimise the total annualised cost of the system, thus taking into account both capital expenditure (CAPEX) and operational expenditure/revenues (OPEX), with the aim of looking at the potential for the wind farm operator to include the production of green hydrogen and ammonia to maximise the profitability of the investment. A 1.5 GW hypothetical Offshore Wind Farm (OWF) located in the North-West of Scotland was chosen, as the site has been previously identified as a potential location for OWF development. Using wind speed and electricity price data with an hourly resolution, a model was developed to calculate the total operational revenues of the wind farm. The use of a simplified model for the effect of increased wind power penetration in the UK energy system on energy prices allows analysis of how the results will change in a more renewable-based economy, such as the one that is predicted for the mid-term future of the UK energy system. The question of whether to include Power-to-Gas (PtG) options, and the related sizes, were treated as an optimisation problem, with component sizes and hourly load factors as optimisation variables. To the best of the authors' knowledge, this is the first paper to approach the analysis configurations by combining wind speed and electricity price data from an OWF with a PtG system that can combine both hydrogen and ammonia storage as options using an optimisation approach.

The rest of the paper is organised as follows. Section 2 will describe the optimisation problem, with the objective of minimising the total annualised cost of the system. Section 3 will present the case study investigated in this study, including wind data, OWF description and its baseline performance and electricity market prices employed. Section 4 will report the results of applying the methodology presented in Section 2 using the data described in Section 3. Section 5 will provide the reader with a detailed discussion about the main results and findings of the paper. Finally, Section 6 will conclude the paper.

2. Method

In order to compare the different alternatives (namely electricity curtailment, electric energy storage, H_2-based PtG and NH_3-based PtG) an optimal system design problem is formulated. The objective of the problem is the minimisation of the total annualised cost of the system ($\boldsymbol{C}^{\mathbf{tot,ann}}$). The main decision variables are the installation sizes ($\boldsymbol{f}_{\mathbf{u}}$) of each of the units that can be installed and their hourly load ($\boldsymbol{f}'_{\mathbf{u,t}}$) over one year of operation. The problem is solved based on the simulation of one reference year of operation, with an hourly definition for the input data and for the time-dependent variables. Given the nature of the problem and the number of variables and constraints, the problem was defined as a Linear Programming (LP) problem.

2.1. Optimisation problem definition

2.1.1. Objective function

The LP's objective is the minimisation of the $\boldsymbol{C}^{\mathbf{tot,ann}}$ of the system (Eq. (1)), defined as the sum of the operational cost ($\boldsymbol{C}^{\mathbf{op}}$) and the annualised investment cost ($\boldsymbol{C}^{\mathbf{inv,ann}}$), defined in Eqs. (2) and (3) respectively.

$$\boldsymbol{C}^{\mathbf{tot,ann}} = \boldsymbol{C}^{\mathbf{op}} + \boldsymbol{C}^{\mathbf{inv,ann}} \tag{1}$$

$$\boldsymbol{C}^{\mathbf{op}} = -\sum_{u\epsilon\mathbb{U}}\sum_{t\epsilon\mathbb{T}}\sum_{ev\epsilon\mathbb{EV}} \boldsymbol{f}'_{\mathbf{u,t}} max(c_{\mathrm{ev,u,t}}, C_{\mathrm{ev,min}}) \dot{E}^{\mathrm{max}}_{\mathrm{ev,t}} \Delta t_{\mathrm{t}} \tag{2}$$

$$\boldsymbol{C}^{\mathbf{inv,ann}} = \sum_{u\epsilon\mathbb{U}} \frac{\boldsymbol{f}_{\mathbf{u}} c^{\mathrm{inv,var}}_{\mathrm{u}} \dot{E}^{\mathrm{max}}_{\mathrm{size,u}}}{F^{\mathrm{ann}}_{\mathrm{u}}} \tag{3}$$

In the equation system above, the problem parameters are: the price of each energy vector per unit of energy ($c_{\mathrm{ev,t}}$ [e/kWh], this value is considered time-dependent only in the case of electricity, while it is assumed as a constant in the case of hydrogen and ammonia), the minimum guaranteed energy price ($C_{\mathrm{ev,min}}$, only defined for electricity), the maximum generation potential of each energy vector ev of each utility u ($\dot{E}^{\mathrm{max}}_{\mathrm{ev,u,t}}$), the duration of each time step (Δt_{t}), the variable (i.e. size-dependent) investment cost of each utility ($c^{\mathrm{inv,var}}_{\mathrm{u}}$), and the maximum energy/material flow used for sizing purposes of each utility u ($\dot{E}^{\mathrm{max}}_{\mathrm{size,u}}$).

It should be noted that in this paper the "energy vectors" that are considered (electricity, hydrogen, and ammonia) are sold to a hypothetical market, and hence they represent a revenue rather than a cost. For this reason, the term $\boldsymbol{C}^{\mathbf{op}}$ is negative. The annualisation factor (F^{ann}_{u}) is defined in Eq. (4) and is a function of the lifetime of each utility ($N^{\mathrm{y}}_{\mathrm{u}}$) and of the interest rate (i). $\mathbb{U}$ and $\mathbb{T}$ represent the set of utilities and of time steps included in the problem, respectively.

$$F^{\mathrm{ann}}_{\mathrm{u}} = \frac{(i+1)^{N^{\mathrm{y}}_{\mathrm{u}}} - 1}{i(1+i)^{N^{\mathrm{y}}_{\mathrm{u}}}} \tag{4}$$

2.1.2. Problem constraints and unit modelling

The optimisation problem is constrained by the fact that energy and material balances must be respected at all times:

$$\sum_{u\epsilon\mathbb{U}} \boldsymbol{f}'_{\mathbf{u,t}} \dot{E}^{\mathrm{max}}_{\mathrm{l,u}} + \sum_{p\epsilon\mathbb{P}} \dot{E}_{\mathrm{l,t}} = 0 \qquad \forall t\ in\ \mathbb{T},\ l\ in\ \mathbb{L} \tag{5}$$

In the equations above, $\dot{E}^{\mathrm{max}}_{\mathrm{l,u}}$ represents the maximum value of the net energy/material flow l for unit u, and $\dot{E}_{\mathrm{l,p,t}}$ represents the energy/material flow l at time step t of the process p, where processes represent units whose load and size are not optimisation variables. In this problem, only the wind farm is considered as a process and the only $\dot{E}_{\mathrm{l,p,t}}$ parameter is the hourly power generation of the offshore wind farm.

As both the overall MILP formulation of the problem and Eq. (5) imply, all units in the optimisation problem are modelled using a linear approach. Hence, each unit is defined by additional constraints relating the different input and output flows. The general form of the different energy flows of a generic unit is given by Eq. (6).

$$\dot{\boldsymbol{E}}_{\mathbf{u,l,t}} = \dot{E}^{\mathrm{max}}_{\mathrm{l,u}} \boldsymbol{f}'_{\mathbf{u,t}} \qquad \forall\ uin\mathbb{U}, t\ in\ \mathbb{T},\ l\ in\ \mathbb{L} \tag{6}$$

While this might not appear explicitly from Eq. (6), this equation includes in its formulation the conversion efficiency of each unit, given that the $\boldsymbol{f}'_{\mathbf{u,t}}$ is the same for all energy and material flows of each unit. As an illustrative example, the efficiency of a Proton-Exchange Membrane Electrolysers (PEME) in converting hydrogen is given as

$$\eta_{\mathrm{PEME,t}} = \frac{\dot{E}_{\mathrm{el,PEME,t}}}{\dot{E}'_{\mathrm{H2,PEME,t}}} = \frac{\dot{E}^{\mathrm{max}}_{\mathrm{el,PEME,t}} \cdot f'_{\mathrm{PEME,t}}}{\dot{E}^{\mathrm{max}}_{\mathrm{H2,PEME,t}} \cdot f'_{\mathrm{PEME,t}}} = \frac{\dot{E}^{\mathrm{max}}_{\mathrm{el,PEME,t}}}{\dot{E}^{\mathrm{max}}_{\mathrm{H2,PEME,t}}}. \tag{7}$$

Which is constant at all time steps of the optimisation problem.

The hourly load factor and the installed capacity of each unit are related by the constraint shown in Eq. (8)

$$\boldsymbol{f}'_{\mathbf{u,t}} \leq \boldsymbol{f}_{\mathbf{u}} \qquad \forall\ uin\mathbb{U}, t\ in\ \mathbb{T} \tag{8}$$

The problem definition also includes batteries, hydrogen and ammonia energy storage. These are modelled with a state variable indicating the current state of charge of the storage, that is calculated for each time step in accordance with the following definition:

$$\Delta E_{\mathrm{u,t}} = \left(\dot{E}^{\mathrm{max}}_{\mathrm{u}} \boldsymbol{f}'_{\mathbf{u(cha),t}} - \dot{E}^{\mathrm{max}}_{\mathrm{u}} \boldsymbol{f}'_{\mathbf{u(dis),t}} \right) \Delta_{t_{\mathrm{t}}} \tag{9}$$

In the equation above, the subscripts (dis) and (cha) refer to the discharge and charge processes. It should be noted that, to preserve the overall energy balance, it is assumed here that the state of charge of the energy storage must be the same at the start (01:00 AM on the 1st of January) and at the end (01:00 AM on the 31st of December). Charging and discharging units are modelled as "standard" units, and hence follow Eq. (6): from a mathematical modelling perspective, as an example, the charging unit of the battery converts electricity to "stored electricity" with an 88% efficiency. This allows accounting for losses in charging and discharging processes, whose numerical values are reported in Table 3.

In the case of ammonia and hydrogen, a connection to a hypothetical pipeline or grid cannot be taken for granted. Hence, the model should also be able to take into account the fact that these fuels cannot be continuously shipped out of the production plant, but need to be stored on site (hence increasing the investment cost of the system). This is modelled by a parameter that we call "market activation delay" (MAD) which represents the frequency at which the "market" unit in the model is activated. This corresponds to:

$$\dot{E}^{\mathrm{max}}_{\mathrm{ev,market,t}} = \begin{cases} \dot{E}^{\mathrm{max}}_{\mathrm{ev,market}}, & \text{if } \frac{t}{MAD} = floor(\frac{t}{MAD}) \\ 0, & \text{otherwise} \end{cases} \tag{10}$$

2.2. Problem units data

This section includes a detailed description of all the assumptions made in the paper for the different numerical values required by the optimization model. A summary of all such assumptions is provided in Tables 1 and 2.

2.2.1. Water electrolysis

The technology selected for the electrolysis is Proton-Exchange Membrane Electrolysers. Although alkaline electrolysers are more mature, PEME technology is more suitable for intermittent renewable power supply due to their 0–100% partial load range [51]. While alkaline electrolysers require the power supply to be uninterrupted, PEME are more flexible and can work with load drops. PEME also produce hydrogen at higher purity and allow hydrogen output at higher pressures. Solid oxide electrolysers are still in a pre-commercial stage and thus, despite their promising performance, they are not considered in this study.

Taking into account the fact that the performance of a PEME tends to increase with decreasing load [52], and considering also other literature sources on the subject (such as [53] who report a 67–82% range for PEME efficiency), we assume here a constant 70% average conversion efficiency for the PEME.

The CAPEX of PEMEs has a wide range of uncertainty. In this paper, we employed the values suggested by [54], which are located on the lower end of the confidence range proposed by [55]: 1200 €/kW installation cost, out of which 420 €/kW relates to the electrolyser stack, which needs to be replaced with a higher frequency. The uncertainty in this value, especially in relation to future developments of a technology that is still developing, is wide and investment costs are reported to range between 250 and 1250 €/kW for a 2030 horizon [55,56]. The lifetime of the PEME system is assumed to be 20 years, whilst, based on an estimation of 40,000 h lifetime [54] and on 8000 h/year of operations, the lifetime of the stack was assumed to 5 years, with future developments expected to increase these values to 80,000 h and 10 years, respectively. It should be noted that this represents a conservative assumption, as in most cases the electrolyser is only used for a few hours per day, which increases the lifetime of the stack dramatically.

2.2.2. Ammonia synthesis

The synthesis of ammonia requires the production of two main raw materials: hydrogen and nitrogen. The hypothesis related to hydrogen generation has already been detailed in Section 2.2.1. For the production of nitrogen, a capital cost of 1450 €/kg/h [56] is assumed for the related plant and a specific energy demand of 0.108 kWh/kgN_2 [56].

For the ammonia synthesis plant, an investment cost of 3000 €/$\frac{kg}{h}$ and a specific energy demand of 0.64 kWh/kg NH_3 were considered for a generic plant based on the Haber–Bosch process [56].

2.2.3. Electricity generation

The main focus of this study is on the production of hydrogen and ammonia for the respective existing markets, such as agriculture or chemical industry feedstocks. However, part of this work also aims to identify the potential of hydrogen and ammonia as means for dealing with the fluctuations in energy production from wind power plants. Hence, the requirement for converting these material flows back to electricity was also considered in this study.

For both ammonia and hydrogen, two alternative scenarios were considered: the co-combustion of the fuel in existing power plants, or their use in fully hydrogen/ammonia-powered units, based on fuel cell technology.

In the case of co-combustion, no investment cost is included, as it is assumed that existing facilities can be fed with hydrogen and ammonia without further adjustments. The co-combustion of ammonia with other fuel was proven to be feasible both in gas turbines and coal power plants [57], whilst efforts in the case of hydrogen have focused on the use in gas turbines [58]. In this paper, only the case of co-combustion in gas turbines was considered, as this was judged the most realistic case for future developments of the UK energy systems, given the role of gas turbines in high efficiency generation (in the case of combined cycles) and of peak power generation (in the case of simple cycles). The efficiency of conversion was assumed to be 40% for single cycle gas turbines and 60% for combined cycles, and different optimisation runs were performed varying the overall value within this range to represent different shares of hydrogen/ammonia being used in single cycle or combined cycle power plants.

In the case of dedicated plants, two different technologies were considered for hydrogen and ammonia. In the case of hydrogen, we

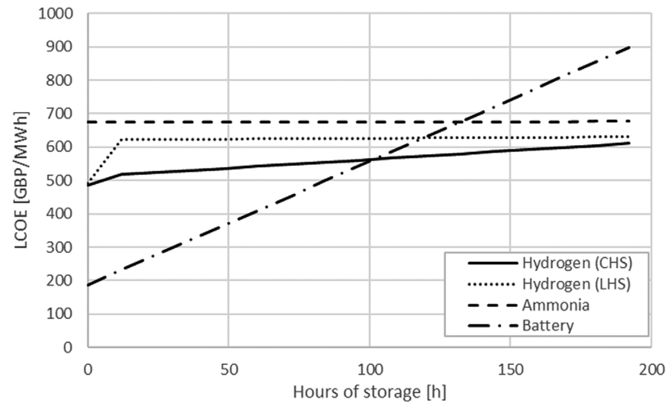


Fig. 1. Estimate of the equivalent LCOE for the power-to-gas-to-power pathway in reference conditions, for different storage requirements.

considered the direct use in a Proton-Exchange Membrane Fuel Cell (PEMFC). PEMFCs are currently a relatively mature technology, available commercially and extensively proven on different types of applications. PEMFCs can convert pure hydrogen with an electrical efficiency ranging between 40% and 60% [59,60], where a value of 55% was assumed for this study, taking into account technological improvements of a technology in constant development. The cost of PEMFCs is assumed to be divided between the system and the stack, which are assumed to be respectively, 730 €/kW and 275 €/kW [61], with lifetimes assumed to 20 and 5 years, respectively.

Whilst direct ammonia-powered Solid Oxide Fuel Cells (SOFCs) are not currently available commercially, their feasibility has been proven at lab scale, and there seems to be no conceptual obstacle to this development [62]. SOFCs are assumed to work at a 55% electric efficiency and can be directly fed with ammonia. The capital cost of the system and stack of the SOFC is assumed to amount to 1280 €/kW and 640 €/kW with a lifetime of between 20 and 4 years, respectively [61].

The power-to-gas-to-power pathway, although certainly a viable option to take into account in the optimisation procedure, is expensive, both in terms of CAPEX (for the required machinery) and of OPEX (because of the losses in the different conversion steps). While the choice of the most valuable solution based on different working assumptions is left to the optimiser, it can be helpful for the reader to get an idea of the numbers at play. The equivalent LCOE calculated in reference conditions (yearly utilisation factor for energy conversion technology is assumed at 0.8, storage is calculated as the size required to store a continuous 1 GW output) is shown in Fig. 1. This example estimate of the LCOE clearly shows that the power-to-gas-to-power pathway is much less dependent on storage size compared to batteries (especially in the case of ammonia), and becomes hence favourable for storage requirements of a few days or more.

2.2.4. Storage

In this paper, we consider four types of energy storage: electricity (in batteries), compressed hydrogen, liquid hydrogen, and liquid ammonia.

In the case of electric storage, while many technologies are currently under development, lithium-ion batteries currently represent the choice of most grid-level storage installations, and are henceforth considered as the reference battery technology in this paper. Lithium-ion batteries are characterised by a relatively high investment cost, in spite of the rapid decreasing trend. Based on the BloombergNEF Battery Price Survey,[1] the average battery pack price in 2018 was 176 $/kWh.

[1] https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices

By assuming an average 15% reduction per year (approximately as observed for the past years in the aforementioned study) and converting to €, we assume for 2020 a price for batteries of approximately 120 €/kWh. We assume here a 70–30% split between the cells and the system, with the latter having a lifetime of 20 years and the former of 5 years.

The cost of compressed hydrogen storage depends on the storage pressure. Different sources estimate the cost of pressurised hydrogen storage between 400 and 2500 €/kg [56]. In this study, assuming a relatively low-pressure storage to avoid excessive compression losses, we assumed a value of 500 €/kg, corresponding to approximately 15 €/kWh. Storage of hydrogen in the form of a high-pressure gas also requires the necessary means to bring the gas from the pressure at the electrolyser outlet to the storage pressure. A base case estimate for the compressor investment cost is 15,600 $\$/(kg_{H_2}/h)$ and optimistic estimate 7800 $\$/(kg_{H_2}/h)$ [63]. In this study we used 11,000 $€/(kg_{H_2}/h)$, which translates to approximately 230 €/kW of electrolysis input power [56].

The cost of liquid hydrogen storage largely depends on the size of the storage. In the results proposed by Amos [64] the estimate ranges between 18 and 450 $/kg depending on the size (300,000 kg and 270 kg, respectively). For sizes in the order of several MWh, it appears that lower cost estimates are more realistic. We hence used an assumption of 50 €/kg, which translates to approximately 1.5 €/kWh. In the case of hydrogen liquefaction, the efficiency of the process was assumed to be equal to 0.64 [25]. The investment cost of the hydrogen liquefaction plant was estimated at 650 €/kW [65].

The cost of ammonia storage is reported to range between 0.65 and 0.9 €/kg [56]. In this paper, we used a reference value of 0.75 €/kg, corresponding to 0.0125 €/kWh. We considered no specific investment cost or operational energy requirement for the liquefaction of ammonia, as it was assumed that these are both included in the values relative to the Haber–Bosch process.

Table 2
Summary of components' capital costs.

Name	CAPEX	Unit	Lifetime
PEME (system)	780	€/kW	20
PEME (stack)	420	€/kW	5
PEMFC (system)	730	€/kW	20
PEMFC (stack)	275	€/kW	5
SOFC (system)	1,280	€/kW	20
SOFC (stack)	640	€/kW	4
H_2 liquefaction plant	650	€/kW	20
H_2 compression plant	230	€/kW	20
Battery (system)	40	€/kWh	20
Battery (cells)	80	€/kWh	5
Air liquefaction plant	1450	$€/kg_{N_2}/h$	20
Haber–Bosch plant	3000	$€/kg_{NH_3}/h$	20
Hydrogen storage (gas)	15	€/kWh	20
Hydrogen storage (liquid)	1.5	€/kWh	20
Ammonia storage	0.0125	€/kWh	20

Table 3
Technologies Efficiencies.

System	Efficiency	Reference
PEM electrolysis	0.7	[53]
Battery charging	0.88	[68]
Battery discharging	0.93	[68]
H_2 liquefaction	0.64	[25]
H_2 compression (350 bar)	0.93	[25]

2.2.5. Hydrogen and ammonia prices

To evaluate and compare the economic performance of the different alternatives, we consider that the energy and material flows produced by the system can be sold to the market. Whilst results will be evaluated for different values of hydrogen and ammonia market prices, it is worth looking at the current range of prices, both for the state-of-the-art of green hydrogen generation and for the expected targets to be reached.

The determination of the market price for hydrogen is more complex, given the lack of reliable sources. It is generally assumed that green hydrogen will be cost competitive once it can reach a price of 2–3 €/kW; the cost of hydrogen delivered to refuelling stations is in the range of 6.5 to 9.5 €/kg, and is expected to fall to 5.5 to 8 €/kg by 2025 [66]. It should be noted, however, that this price also includes the delivery to the refuelling station. Current production prices for fossil-based hydrogen oscillate between 1.5 and 5 €/kg depending on the scale of the supply [55]. As a result, we assume in this study a market price of 2.5 €/kg (0.075 €/kWh) for hydrogen sold on the market, recognising however that this value is subject to a high degree of uncertainty.

Ammonia market prices fluctuate widely in time and depending on the region. Based on the data reported in [67] for the last two years and for the Western European market, we assumed a price of 0.3 €/kg, which corresponds to 0.06 €/kWh. Finally, the lower heating value of ammonia used in this study is 18.6 MJ/kg

3. Application

3.1. Wind data

The ERA5 reanalysis long term data set has been used for the analysis of wind resource due to the lack of good quality measured data in the area of interest. Reanalysis data sets are created by assimilating a large number of historical observations from many sources, such as satellites, ground stations and weather balloons, providing a numerical description of the recent climate by combining models with observations. ERA5 is the European Centre for Medium-Range Weather Forecasts (ECMWF) climate reanalysis data set, covering the period from 1979 to the present, with preliminary data from 1950–1978 also available. ERA5 is being developed through the Copernicus Climate Change Service (C3S) and provides hourly estimates of a large number of atmospheric, land, and oceanic climate variables. The data covers the Earth on a 30 km grid and resolves the atmosphere using 137 levels from the surface up to a height of 80 km [69]. This data set has been chosen over others such as MERRA2 due to better resolution.

3.2. Wind turbine and farm description

The wind turbine adopted for the wind farm considered is the Denmark Technical University (DTU) 10 MW Reference wind turbine [70], mainly based on (and upscaled from) another reference wind turbine, the National Renewable Energy Laboratory (NREL) 5 MW offshore wind turbine [71]. This wind turbine is not an actual commercial wind turbine, but it is a publicly available, open access reference model. The model is based on actual utility scale offshore wind turbines, obtained through an upscaling approach, that allows the definition of an industrially relevant wind turbine that includes technical details not usually disclosed by the wind turbine manufacturer. The DTU 10 MW wind turbine is an offshore (International Electrotechnical Commission (IEC) class 1 A) three-bladed, upwind, variable (collective) pitch, variable speed wind turbine, with a cut in wind speed of 4 m/s, rated wind speed of 11.4 m/s, and a cut out wind speed of 25 m/s. Table 4 provides the main characteristics of this wind turbine and in Fig. 2 the (mechanical) power curve is presented. The electric power curve has been obtained from Fig. 2, considering a generator electrical efficiency of 0.94.

The wind farm considered is based on the work by Jelenova et al. [72], in which a hypothetical offshore wind farm has been defined in the North Sea, north of the Shetland islands, for the production of hydrogen in a location suitable for the re-use of an existing pipeline from the oil and gas industry. Although the selected area, N8, is no longer in the current plan options selected by Marine Scotland for

Table 4
DTU 10 MW reference wind turbine main characteristics [70].

Parameter	Value/description	Unit
Wind regime	IEC Class 1A	
Rotor orientation	Upwind	
Control strategy	Variable speed and pitch	
Cut in, rated, cut our wind speed	4, 11.4, 25	m/s
Rated power	10	MW
Number of blades	3	
Rotor diameter	178.3	m
Hub height	119.0	m
Drivetrain	Multiple-stage gearbox	
Generator electrical efficiency	0.94	
Min, max rotor speed	6.0, 9.6	rpm
Rotor mass	228	t
Nacelle mass	446	t
Tower mass	628.5	t

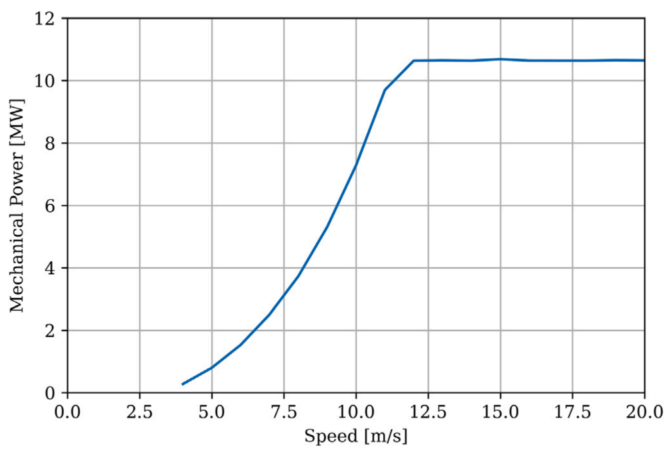


Fig. 2. Mechanical power curve of the DTU 10 MW wind turbine [70].

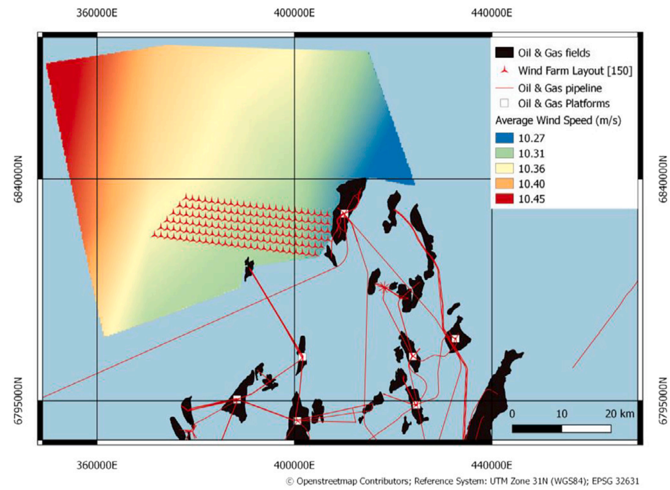


Fig. 3. Wind farm layout [72].

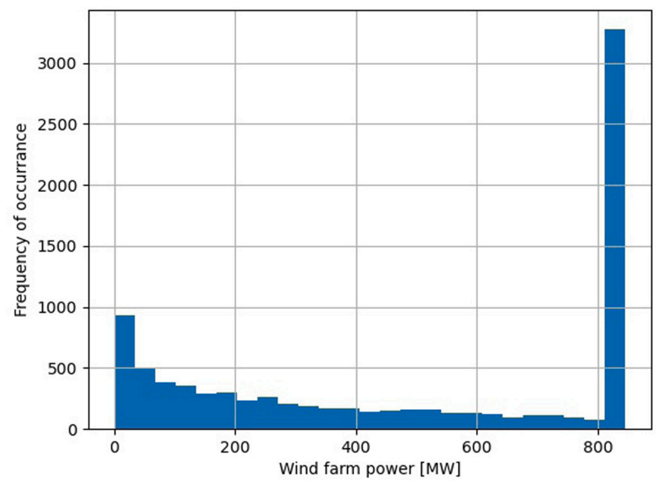


Fig. 4. Simulated power generation for the wind farm.

Scotwind leasing round, it could be revisited in the future. The rated power of the wind farm has been capped at 1.5 GW as per the capping suggested by the Crown Estate for England [73]. Therefore, 150 wind turbines of 10 MW have been considered. To minimise the wake loss and maximise the power production, the spacing between individual wind turbines was set to 12 diameters in the direction parallel to the prevailing wind direction and 8 diameters in the perpendicular direction, adopting a staggered configuration. The resulting wind farm layout and geographical position, with an indication of the magnitude of the average wind speed in the site [72], is shown in Fig. 3. The wind data described in Section 3.1 was used to calculate the available energy produced over the calendar year 2017. Using the power curve for the DTU 10 MW reference wind turbine [70] described in Section 3.2, the power output of the turbine was calculated assuming an availability of 95% and an estimated wake loss of 7.38% [72]. The frequency of the power generated by the wind farm according to the selected modelling approach is shown in Fig. 4, which corresponds to an average capacity factor of 48% for the reference year.

3.3. Electricity prices and wind power penetration in the UK energy system

Electricity market prices are taken from the official statistics of the UK government for the day-ahead baseload contracts [74]. Monthly average values between 2009 and 2019 varied between 40 and 75 €/MWh. Hourly prices for the year 2017 were arbitrarily used as a baseline for the electricity prices calculation.

Hourly electricity prices are the result of a balance between supply and demand. More specifically, the electricity price for a specific hour is given by the intercept of the supply curve $S(P)$ and the demand curve $D(P)$. As pointed out by Johnson and Oliver [75] intermittent renewable energy sources (such as wind power) tend to enter at the base of the total electricity supply curve, given that they cannot be dispatched and that they have near-zero marginal costs.

This effect was accounted for with a simplified model of the UK energy system marginal costs, based on a series of theoretically grounded simplifications. To begin with, the demand curve is assumed to be flat. As such, electricity price depends only on the supply curve, which is given by a hyperbolic function of the form

$$P = \frac{a + bS}{c + dS}. \tag{11}$$

where $a = 65$, $b = 36.4$, $c = 65$, and $d = -1$ are the coefficients of the hyperbolic function obtained as a fit of the available data. It is further assumed that the vertical asymptote of the supply curve is located at $S = 65$ GW. This value was chosen as it corresponds to the total installed capacity of 2019 [76]. In addition, wind power is assumed to be available at zero marginal cost. This implies that the available wind power is always sold to the grid, unless demand is lower than the total generated wind power. Finally, to account for the influence of wind power on the grid, it is assumed that the wind power generation at any given time step t_i is equal to the total wind power capacity in the UK grid $P^{\mathrm{w,es,max}}$, multiplied by the instantaneous load factor of the wind farm under consideration $\lambda_{\mathrm{wf,t}}$, defined as

$$\lambda_{\mathrm{wf,t}} = \frac{P_{\mathrm{wf,t}}}{P^{\mathrm{max}}_{\mathrm{wf,t}}}. \tag{12}$$

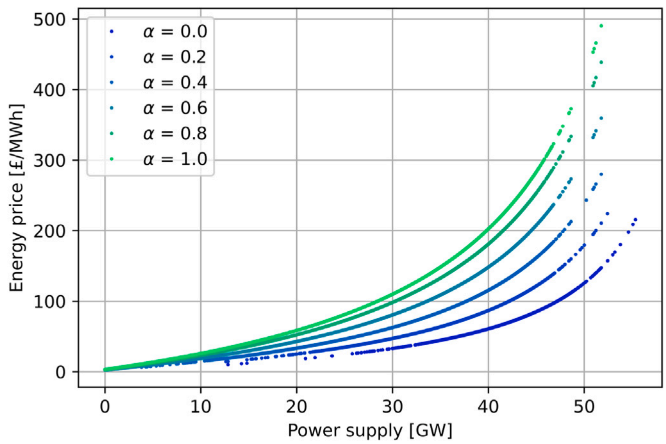


Fig. 5. Influence of the wind power installed capacity in the UK grid on electricity prices.

where $P_{wf,t}$ is the power of the wind farm under study at time step t, and $P_{wf,t}^{max}$ the maximum power that the wind farm can deliver.

This is a reasonable approach to account for the influence of wind power on the grid, even though wind speed variability is implicitly neglected. Under these simplifications, electricity price can be evaluated as

$$c'_{el,t} = \frac{a + b(D_t - \lambda_{wf,t} \cdot P^{w,es,max})}{c + d(D_t - \lambda_{wf,t} \cdot P^{w,es,max})} f_c. \tag{13}$$

In the equation above, D_t represents the electricity demand at time step t. The term f_c is a correction factor that is introduced to keep the overall average electricity price constant. The resulting influence of the wind power installed capacity, expressed as a fraction of the total current installed capacity, is shown in Fig. 5.

The actual price of electricity considered in the calculation of the wind farm revenues is calculated according to Eq. (14), thus including the possibility of ensuring a minimum energy price guarantee ($C^{el,min}$, as this is currently the standard for wind energy generation in the UK).

$$c_{el,t} = max(c'_{el,t}, C^{el,min}) \tag{14}$$

3.4. Wind farm baseline performance

The performances of the wind farm purely connected to the electrical grid are shown in Fig. 6. Firstly, increasing wind power capacity beyond a certain installed power (approximately 36 GW) will generate the need to curtail part of the energy generated by the wind farm, which will in turn slow down the growth of wind power penetration in the system. Secondly, in the absence of a minimum energy price guarantee ($C^{el,min}$), wind farm revenues decrease rapidly with increasing wind power penetration: at 60% wind power penetration (which corresponds to a wind installed power capacity of about 80% of today's total installed power capacity) revenues are reduced to approximately 30% of the reference value (no wind power). Finally, it can be noticed that, whilst the minimum price guarantee strongly mitigates this phenomenon, it has the downside of increasing the total energy cost of the system, calculated as the cumulated sum of the energy price multiplied by the energy demand for each time step, including the aforementioned incentive to wind farms. The reason for the revenue loss can be observed in Fig. 7. Based on the influence that the wind power generation has on the energy prices, the wind farm is increasingly forced to sell most of its energy generation when prices are low, with increasing wind penetration in the UK power generation market. Whilst these conclusions are based on simplified modelling of the UK wind generation and on its influence on prices, they show both the economic and energetic rationale of looking into ways of storing energy generated by wind farms in order to both minimise curtailment and maximise revenues.

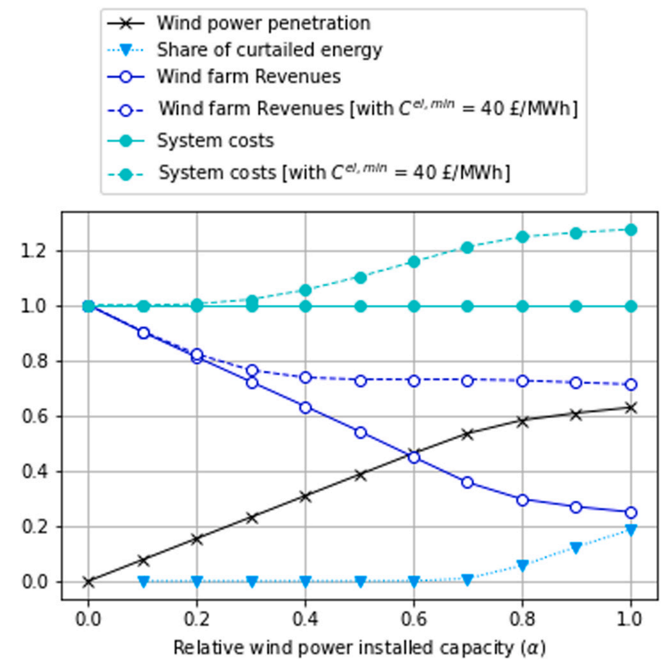


Fig. 6. Energy and economic indicators with varying wind power installed capacity. The x-axis shows the total wind installed capacity relative to the reference non-renewable installed capacity.

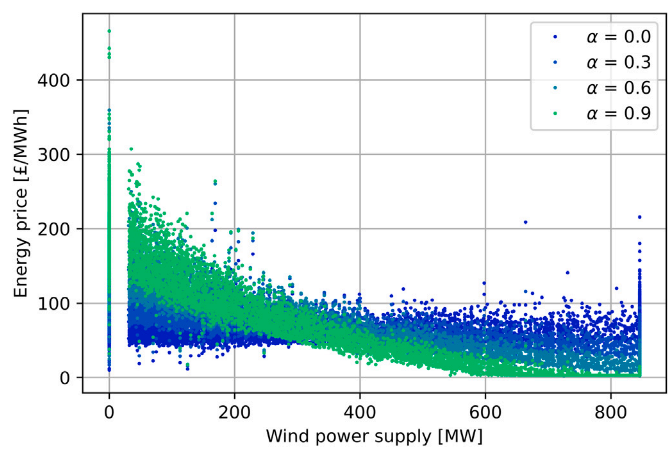


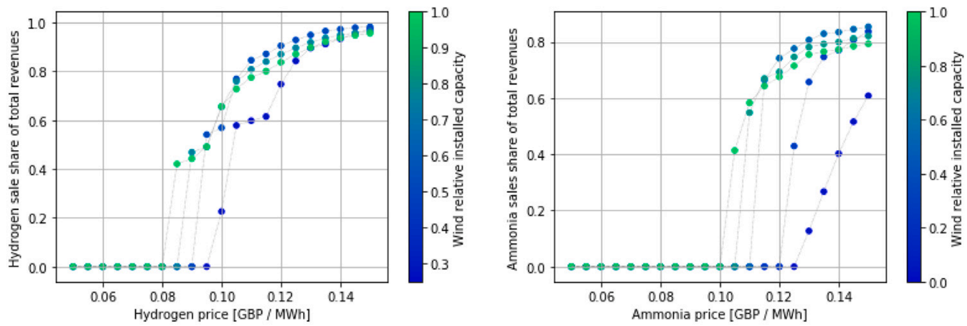
Fig. 7. Variation of price of energy at different power generation levels for the wind farm, as a function of the wind power installed capacity (α) in the UK grid.

4. Results

4.1. Comparison of hydrogen vs ammonia scenarios

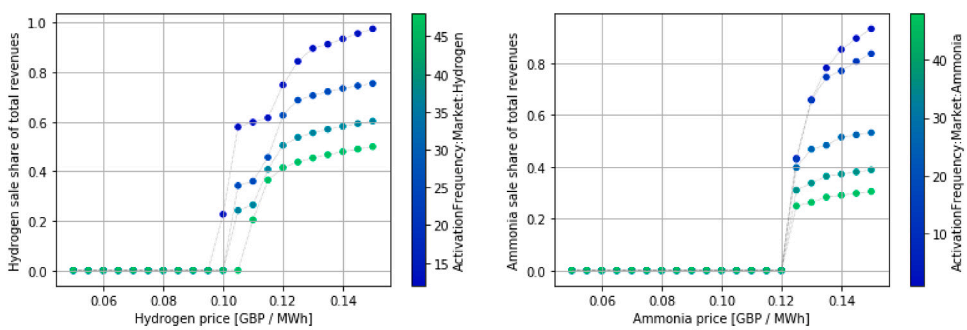
In this study, both the hydrogen and ammonia scenarios were optimised separately and compared. The results for the optimisation with varying fuel prices for both hydrogen and ammonia, considering $C^{el,min}$ equal to 20 £/MWh and MAD equal to 12 h, are reported from Figs. 8 to 10.

The effect of increasing the total installed wind power in the national grid is shown in Fig. 8. As expected, both increasing fuel prices and installed wind capacity are favourable conditions for an increased



(a) Hydrogen (b) Ammonia

Fig. 8. Share of total revenues coming from hydrogen/ammonia sales versus hydrogen (a) and ammonia (b) price for different values of the wind relative installed capacity (α).



(a) Hydrogen (b) Ammonia

Fig. 9. Results of the optimisation versus hydrogen/ammonia price for different values of market activation frequency.

use of hydrogen and ammonia. In the case of hydrogen, increasing the installed wind capacity from $\alpha = 0$ to $\alpha = 1$ shifts the minimum hydrogen price at which the hydrogen pathway becomes part of the optimal choice from 10 to 8.25 £/MWh, and from 12.5 to 10.25 £/MWh in the case of ammonia. Once the power-to-gas pathway is activated, further increasing the fuel price leads to a rapid increase in the share of total revenues. In both cases, for high values of fuel price (approximately 12 £/MWh for hydrogen and 14 £/MWh for ammonia) and of α (0.25 for hydrogen, 0.5 for ammonia) the share of revenues shifts almost entirely to the power-to-gas pathway, as more than 80% of the revenues are expected to come from selling hydrogen or ammonia (see Fig. 8).

The effect of the need to store the fuel on site is shown in Fig. 9. As expected, increasing the need for storage (which is represented in the model by increasing the value of the MAD) makes hydrogen a less preferable choice. The minimum price for hydrogen raises from 10 to 11 £/MWh, while the minimum price for ammonia remains constant at approximately 12.5 £/MWh, as a consequence of the fact that ammonia storage is much cheaper compared to hydrogen storage. However, the main effect of increasing the market activation delay is to reduce the hydrogen production: at 12 h MAD and 15 £/MWh almost all income comes from hydrogen sales, while this figure goes down to about 50% when the MAD is increased up to 48 h.

Finally, the effect of granting a minimum price for electricity to wind farms is shown in Fig. 10. As expected, increasing the minimum electricity price comes at a disadvantage for both hydrogen and ammonia production, as the very low price time steps are avoided without the need to recur to power-to-gas.

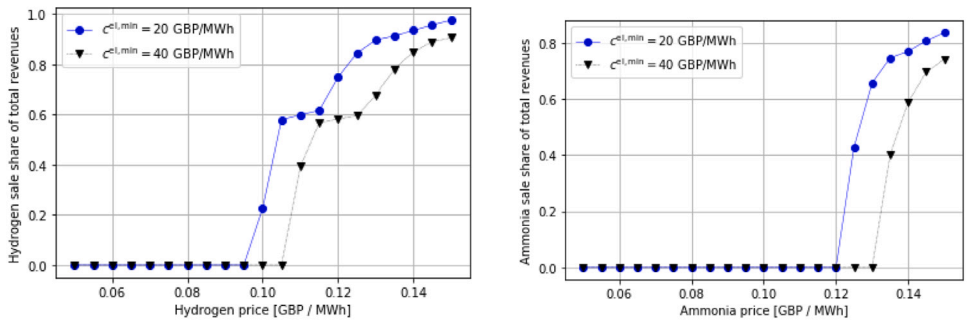
Fig. 11 analyses in detail the choice between the two selected methods for hydrogen storage: liquid and compressed. As it can be seen, compressed hydrogen storage is always selected first, up to approximately 2 GWh storage size. On the other hand, additional capacity beyond this value is installed in the form of liquid hydrogen, because of its lower storage cost, in spite of the additional investment cost for the hydrogen liquefaction facilities and of the higher specific energy demand.

Fig. 12 presents an in-depth analysis of the time-dependent behaviour in one of the scenarios where hydrogen is selected as part of the optimal solution. The electrolyser is basically used as base load, at almost fixed electric power input (see Fig. 12(a)), thus maximising its usage (given its high investment cost). The use of the optimisation approach for the design of the system hence enables selection of the best size for the electrolyser, achieving the optimal balance between increasing the CAPEX and reducing the OPEX.

The behaviour of the hydrogen storage's state of charge, shown in Fig. 12(b) further highlights the importance of the MAD: the hydrogen storage is emptied whenever possible, and increasing the MAD increases the requirement for storage size, at a given hydrogen generation rate.

The same results are shown in Fig. 13 for a scenario where ammonia production and its related units are included in the optimal configuration. The analysis first highlights how the hydrogen production dominates the energy required by the process, even when ammonia is considered: having similar production rates for hydrogen and ammonia (see Fig. 13(b)) the power required by the ammonia-related units (the Haber–Bosch process and the air liquefaction unit) is far lower than required to produce the hydrogen required by the process (see Fig. 13(b)). Hence, the real factor limiting the inclusion of ammonia in the optimal solutions seems to be more the high investment cost rather than the additional energy requirement.

The analysis presented in Fig. 13 also shows how, in general, the generation of hydrogen is prioritised over the generation of ammonia. This can be seen in the 2050–2070 time steps, where in a condition of



(a) Hydrogen (b) Ammonia

Fig. 10. Results of the optimisation versus hydrogen/ammonia price for different values $C^{el,min}$.

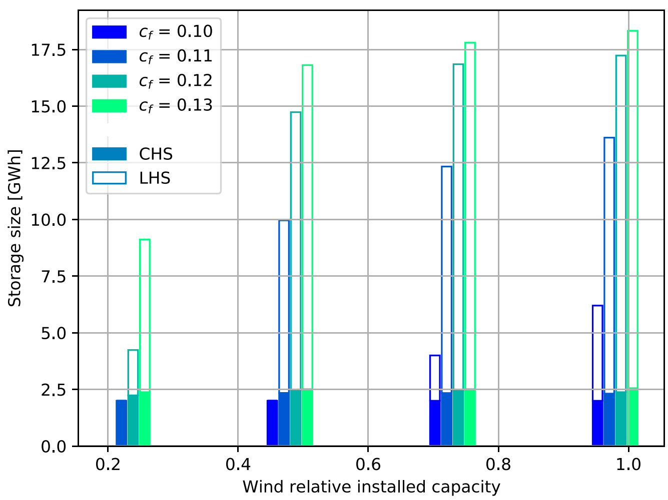


Fig. 11. Analysis of liquid versus compressed energy storage optimal sizes for different penetration of wind power in the UK energy system and for different fuel (ammonia and hydrogen) prices.

scarce availability of wind power, hydrogen production is maintained, whilst ammonia production is not. In this case, the idea is that the optimiser attempts to always fill the hydrogen storage until the next market activation and reverts to ammonia generation to use the extra energy available.

When comparing the hydrogen pathway to the ammonia pathway, it can be observed that optimisation runs performed with no need for fuel storage do not show any improvement with the addition of ammonia as optimisation possibility, unless the cost of ammonia per MWh is much higher than the cost of hydrogen. However, the analysis in the previous section showed that the need for storing the hydrogen produced by the process has a significant influence on the optimal solution. The analysis of the effect of storage requirements is shown in Fig. 14, where the relative share of the total revenues of hydrogen and ammonia is represented against the MAD. These results show that the need for storage loses part of its advantage when compared to ammonia: at MAD = 24 h, between 20% and 30% of the total fuel-related revenues originate from ammonia production and sale. The energy amounts in play involve the requirement of high storage volumes, which come at a high energy and investment cost. This situation suggests that ammonia, which is more expensive to produce but much less expensive to store, could become a viable option in the case where long-term storage is needed.

4.2. Power-to-gas-to-power

The results of the optimisation runs with no hydrogen and ammonia markets are shown in Figs. 15 to 17. Results are only shown for the case with no minimum price guaranteed for wind power plants.

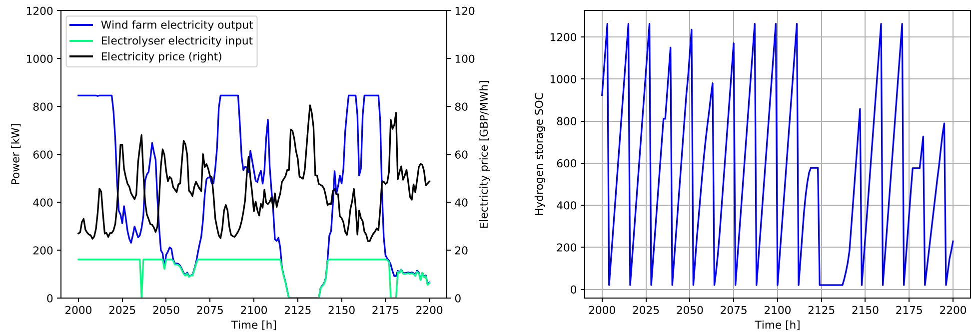
The results of these simulations show that hydrogen co-combustion in existing plants can be a viable (profitable) solution when wind installed power in the grid increases beyond approximately 70% of the non-renewable installed power. In this case, the effect of prices being lower when the power production of the wind farm is higher makes it convenient to produce hydrogen and ammonia for later use. Whilst the results highlight that the installation of dedicated fuel cells is not convenient due to the high investment cost (the solution is never chosen in any scenario, even when co-combustion is not allowed), the use of ammonia and hydrogen in existing power plants is considered profitable. Interestingly, hydrogen and ammonia go hand in hand: whenever hydrogen is selected, ammonia follows. Hydrogen storage size is, however, much lower (between 20% and 50%) than the installed size of ammonia storage, as a consequence of the higher investment cost. This can be seen clearly in Fig. 16, where investment costs are shown instead of installed sizes: the proportions are inverted and hydrogen storage costs dominate.

The conversion efficiency of the co-combustion plant also has a large influence. Sub-critical conventional fossil-fuel power plants run at around 40% conversion efficiency, a number which can increase to about 45% when new designs (supercritical and ultracritical Rankine cycles) are considered. Large, stationary diesel engines can also achieve 40−45% conversion efficiency and allow for part of the waste energy to be recovered for cogeneration. Combined cycle power plant can achieve more than 60% conversion efficiency, and the feasibility of co-firing gas turbines with both hydrogen and ammonia has been shown in previous studies. When a higher conversion efficiency is assumed, the share of electricity used for generating hydrogen and ammonia increases, as shown by the larger size of the related storage units (see Fig. 15). This allows increasing revenues (see Fig. 17).

To better understand how these revenues are generated, it can be interesting to look more in detail at one of the simulations where the power-to-gas-to-power pathway is selected. One such example is shown in Fig. 18, where the energy stored in the installed storage types is shown for the whole year. As expected, gas-type storage (ammonia and liquid hydrogen) is mostly used for multi-day storage; in the case of ammonia, even a certain degree of seasonal storage can be observed. Batteries are also used, but only for compensating infra-day fluctuations.

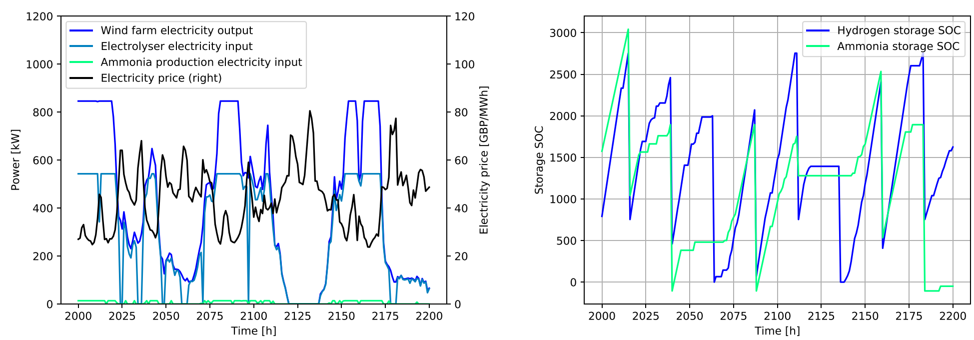
4.3. Full optimisation

In this section, the results for the case when all technologies are available are included. Fig. 19 shows how the operational revenues are



(a) Power and price   (b) Hydrogen state of charge

Fig. 12. Analysis of the time-dependent behaviour of the system in a scenario with hydrogen production and storage.



(a) Power and price   (b) Hydrogen and Ammonia state of charge

Fig. 13. Analysis of the time-dependent behaviour of the system in a scenario with hydrogen and ammonia production and storage.

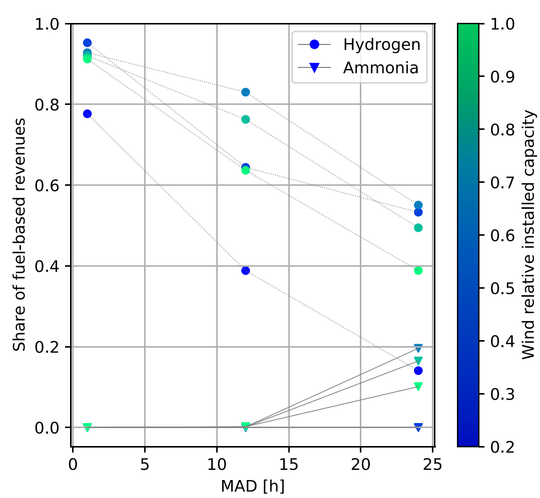


Fig. 14. Results of the optimisation versus hydrogen/ammonia price for different values of MAD.

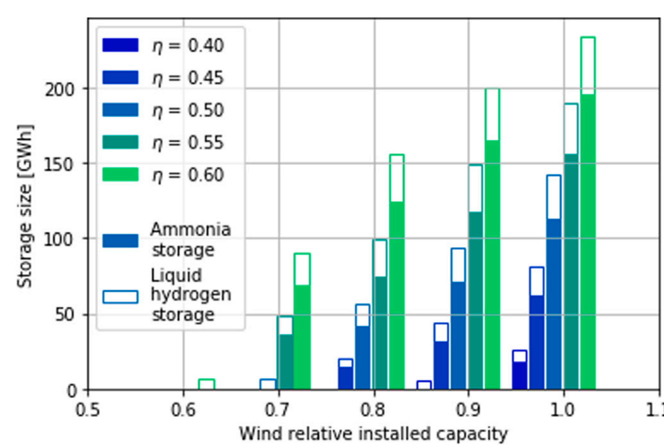


Fig. 15. Results for the use of hydrogen and ammonia for grid storage: Installed storage size.

subdivided among the three energy vectors depending on the share of wind power capacity and on the energy price of hydrogen and ammonia. In the 12h market activation frequency scenario, hydrogen becomes an option for prices as low as 0.08 £/kWh (only slightly higher than today's reference of 0.075 £/kWh) already at $\alpha = 0.6$, where hydrogen sales make up almost 40% of all operational revenues. Assuming a hydrogen price at 0.10 £/kWh and above, hydrogen revenues dominate the total revenues for any $\alpha \geq 0.4$.

Ammonia is only marginally used in the cases where market activation frequency is assumed equal to 12h (hence in the case of pipelines or of local high-frequency use). The situation is however different when looking at the case of $MAD \geq 24$, where low-cost ammonia storage becomes an important part of the solution. When the MAD increases beyond a certain value, the cost of storing hydrogen for a long time (and, hence, installing large hydrogen storage capacity) becomes too high when compared to the alternative choice of installing ammonia generation facilities, and their related storage.

It is interesting to note that the electricity contribution to operational revenues, after declining for increasing α up to 80%, increases again for increasing wind relative installed capacity. As shown in Fig. 20 this is due to the increasing contribution of hydrogen and ammonia co-combustion, which for $\alpha = 1$ accounts for about a third of all electricity sold to the grid. This is hardly surprising, as in this case electricity hourly prices can fluctuate between 6% and 230% of the average value.

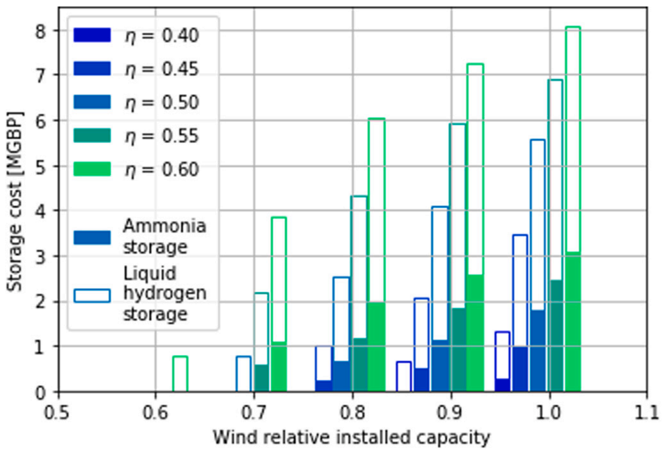


Fig. 16. Results for the use of hydrogen and ammonia for grid storage: Investment cost.

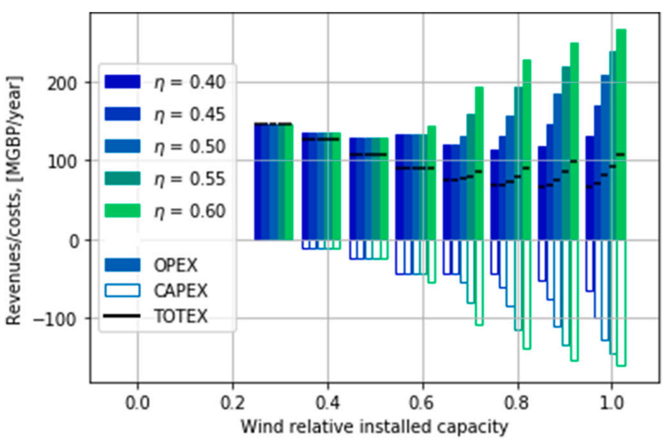


Fig. 17. Results for the use of hydrogen and ammonia for grid storage: Total wind farm revenues.

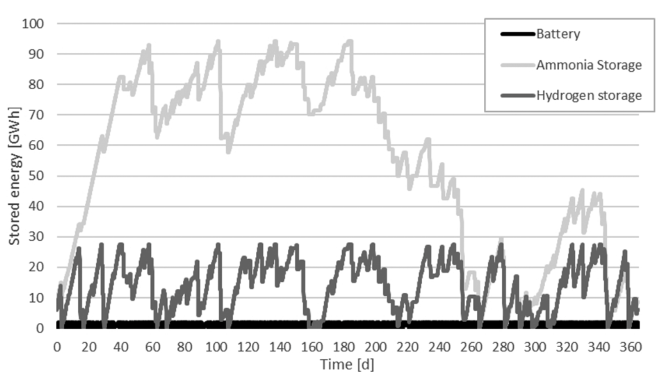


Fig. 18. Caption.

5. Discussion

5.1. Method discussion

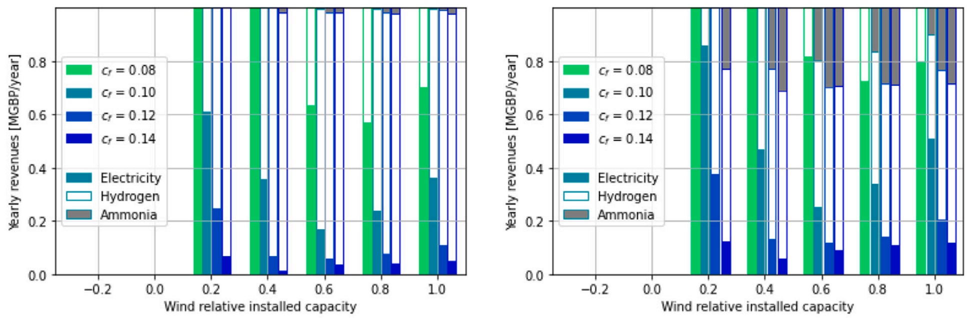
The results and findings in this paper are based on a number of assumptions and modelling choices, that while reasonable can certainly be put into question, with respect to how they influence the insights and conclusions of the paper.

In this paper we assumed that the hourly price of electricity can be influenced by the amount of installed wind power in the grid. The details of how this was modelled in this paper are provided in Section 3.3, while the overall principle is based on assuming that i. the demand is inflexible; ii. the wind power is the least likely to be curtailed/reduced; iii. the price vs supply curve follows the behaviour of a hyperbole; iv. the variability of wind generation at grid level follows the same pattern as the wind farm under study.

Whilst reasonable, all of these assumptions can be debated. In the work of [77], it is also assumed that electricity price variability due to the stochasticity of renewable generation is entirely attributed to wind power generation, thus validating hypothesis iv. Also, the same study reports that *"comparing the wind speed across the whole jurisdiction against the wind speed at the planned OWF site, we find them to be highly correlated, with a coefficient of determination equal to 0.92)"* [77], thus further validating hypothesis iv.

On the other hand, we found no study in the literature that attempts to include not only the hourly-variability of electricity prices in the estimation of the performance of a wind farm, but also the influence that increasing wind power penetration in the grid can have on electricity prices. Based on the results of this work, this has a larger influence compared to curtailment on the economic performance of the wind farm, especially when looking at options for energy storage. It should be noted, however, that most of the influence is seen at relatively high levels of wind power penetration in the energy mix, at which the behaviour of energy prices becomes very unstable. This is likely to be due both to the over-simplification of the model and to the assumption of inflexible demand. In fact, there is already some demand-side flexibility (McDoagh et al. [77], for instance, assume a 1500 MW grid flexibility in the case of Ireland), and this is expected to increase in the future [78,79]. Whilst we believe that the results presented have a sufficient degree of reliability and provide useful insights, future work in this area should hence focus on improving the quality of the energy price and curtailment modelling.

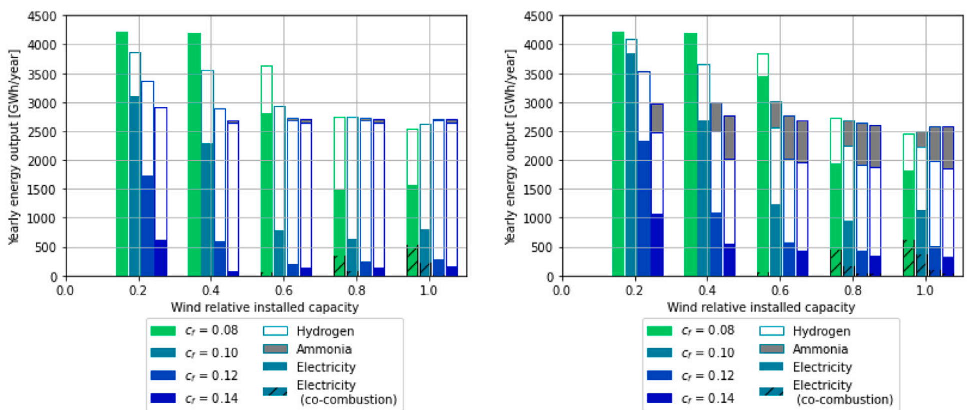
The wind farm generation was based on the assumptions described in detail in Section 3.1, which represent the most typical choice in studies that focus on the system rather than the specific performance of the wind farm, such as [77,80]. The method offers a reliable prediction based on a relatively small set of required information. It should be noted, however, that the optimisation framework reported in this paper heavily depends on the hourly energy generation and not only on the cumulated yearly value: hence, even relatively small variations can play a role in the results. In particular, the effect of the wind direction is not captured by the current model, which in turn can have an influence on the relevance of the "shading" effect amongst different rows of turbines. While this is not expected to have a major impact on the results, especially with respect to the choice between different conversion pathways that was the core of this paper, future studies could benefit from an improved modelling of the wind farm power generation, taking the effect of wind direction and turbine shading into account. As showed by Hassoine et al. [81], several different models exist to take into account the effect of the turbine's wake on the power generation, which can be as large as to generate a 27% on the overall annual energy production of the wind farm. This would allow a more diverse wind power generation profile, and most likely avoid long periods during which the power output of the whole wind farm is constant. Although it is difficult to predict the effect of such expected increased variability in the wind farm power output would, we would expect that it would only make the power-to-gas pathways more convenient, since they are generally acting as a way to balance such variability. The wind farm power prediction could also benefit from taking more than one year into account. More specifically, it would be interesting to analyse the effects of long duration whether extremes, such as what was observed during 2021 in the North Sea, on the overall results of the optimisation. It should be noted, however, that the year taken into account for this study (2017) was not considered as a sticking out of the average for any specific reason, neither for what concerns wind power output, nor for energy prices.



(a) Market activation frequency: 12h

(b) Market activation frequency: 24h

Fig. 19. Operating revenues versus wind relative installed capacity for different values the market activation frequency.



(a) Market activation frequency: 12h

(b) Market activation frequency: 24h

Fig. 20. Yearly energy flows to market versus wind relative installed capacity for different values the market activation frequency.

The results of the optimisation are also affected by the uncertainty in the input data. Previous research in the field of energy systems modelling has shown the large effect of uncertainty in these models [82], mostly concentrated in the uncertainty of investment cost estimates for different technologies (and particularly for relatively new technologies, such as electrolysers) and in energy prices, whose variation is hard to predict [82]. In this study, we only verified the influence of a few uncertain parameters (hydrogen prices, ammonia prices, wind energy penetration in the grid, and the efficiency of conversion of hydrogen and ammonia to electricity), based on the assumption that these parameters have the largest impact on the outcomes. Future work on the topic should include a thorough sensitivity analysis of the optimisation-based model and could benefit from the application of uncertainty-based optimisation strategies, such as the stochastic-optimisation methods employed in [83].

On a related topic, the assumptions related to some of the technologies considered in this paper (primarily batteries and those related to hydrogen generation and usage) can be challenged, and this can affect the results of the paper. This is reflected primarily on the assumption that the lifetime of some crucial components, such as the internal cells of batteries and PEM electrolysers, can be included in the model as a fixed values in years, here considered equal to 5 years for both technologies. While the authors are aware that the actual lifetime of these components depends on operational parameters (such as the number of charging cycles for batteries, or the operating hours for electrolysers), these are common assumptions in papers dealing with system-level optimisation. It should be noted that, based on the output of selected optimisation runs, we attempted to verify our initial assumptions:

- For the case of batteries, in the optimisation runs where they were included we noticed a number of cycles in the range of 500 cycles per year.
- In the case of electrolysers, our analysis of the results shows that, when they are installed, they are basically always running, as close as possible to their design output, in order to maximise the use of the (costly) investment. As the initial lifetime value was based on the assumption of a relative constant use (8000 h/y), it is safe to say that the initial assumption was verified.

Clearly, future technological developments are expected to improve the situation. For instance, enhancing the lifetime of the electrolysers would reduce their annualised investment cost, thus further extending their range of applicability.

Cost estimates could also be improved by improving the model from a LP to a Mixed-integer Linear Programming (MILP) approach, thus allowing the inclusion of fixed and variable investment costs. This would represent an improvement when compared to the current LP modelling approach, as it would allow limit the tendency of the model results to include all potential solutions (for instance mixing both compressed hydrogen, liquid hydrogen and ammonia as storage solutions). It should be noted, however, that modifying the modelling approach to an MILP tends to increase the time required for optimisation convergence dramatically, which is why large scale models tend to be based on the LP approach (such as [84]). It should also be noted that, whilst in other types of energy systems it is possible to reduce the size of the optimisation problem by employing the typical-days approach (see the method proposed by [85]), offshore wind power generation does not show the same periodic behaviour, which forces a high number of time steps in the optimisation problem to be maintained.

The linear programming approach also forces other simplifications, which are well known but should be mentioned for a matter of completeness. First, Eq. (6) implies that the conversion efficiency of each component is constant, regardless of the environmental or operational conditions. This relatively strong assumption, made necessary by the linearisation of the problem, is common in the field of energy systems optimisation [86,87], and has limited influence on the final design. Whilst a piece-wise linearisation could help improve the accuracy of the model, it would also increase the computational requirements because of the additional binary variables.

In addition, the current linear model does not include any constraint related to the dynamic capabilities of the different units in the system. Some unit types, such as electrolysers and fuel cells, do not easily tolerate rapid load shifts and this should be taken into account in studies that focus on the detailed design of the system. It should be noted, however, that the results obtained in the paper points to a relatively constant use of these units, which suggests that constraints on the dynamic behaviour of these units might not play a relevant role. It should be noted, however, that when analysing the way these components are used in the optimal scenarios where they are installed, their operational conditions seem to be relatively steady-state. With the example of the electrolysers, for instance, as shown in Fig. 12(a), these units are ran as often as possible, as to maximise the return of the initial investment; starts and stops are relatively rare, as are periods when they are operated in load-following mode. As a result, it is believed that the model limitation of not including operational constraints on the dynamic capabilities of these units does not represent a too strong assumption in this case.

Finally, in this paper, only conventional lithium-ion batteries where used as an alternative to hydrogen and ammonia for grid-level storage. Today, several other options are being discussed, such as compressed air energy storage, flow batteries, and more [88]. Future work that focuses on a wider comparison of grid-scale energy storage technologies, including the most recent developments in the field, is certainly needed. In this study, however, the focus was on hydrogen and ammonia storage technologies, when compared to what today is the standard for new grid-scale storage projects.

5.2. Results discussion

Whilst the results vary based on the scenario and assumptions, it appears rather clearly that, as of today, neither hydrogen nor ammonia can be produced using wind power and be economically competitive. At today's ammonia and hydrogen market prices, the related infrastructure is never selected by the optimiser, meaning that it is always more convenient to sell electricity to the grid. At current levels of wind power penetration in the UK national grid, it appears that green hydrogen can be produced with profit only if hydrogen prices are at the upper end of the range, while in the case of ammonia the distance between current prices and "profitable" prices seems even larger.

Increasing the wind penetration in the grid makes both ammonia and hydrogen more convenient, especially when it is assumed that a connection to a pipeline is available (and, hence, that there is no need for on-site storage). However, green hydrogen only becomes attractive at today's grey hydrogen prices when a total of approximately 60 GW of installed wind power is connected to the grid, something which, according to the recently announced goals (40 GW by 2030 [89]) will probably not happen in the near future. Nonetheless, some factors such as the introduction of a carbon tax (making grey hydrogen more expensive), or the decrease in PEME prices coming with automated mass production of electrolysers, or even more ambitious decarbonisation targets with governments offering hydrogen subsidies, could make this happen earlier.

In addition to the above, it should be noted that these results are obtained assuming no minimum price for electricity guaranteed to offshore wind farms as this is the situation for most new OFW installations. In 2019, strike prices for offshore wind farm auctions were reduced to 40 £/MWh, down from approximately 120 £/MWh in 2015. Whilst these are expected to decrease further in the future, the results shown in this paper suggest that even a 20 £/MWh strike price would increase the barrier for the development of any type of storage infrastructure. This leads to the reflection that, whilst guaranteed minimum prices for wind farms definitely help the development of wind power, they hinder the uptake of storage technologies.

The situation is similar once the focus shifts from the production of hydrogen and ammonia for the commodity market to the idea of using them as means for storage. The minimum wind relative installed capacity at which any relevant power-to-gas-to-power storage is used is 0.7 (more than 40 GW of wind power), which again is not expected to be installed within the next 10 years.

Clearly, expected reductions in the cost of the related infrastructure (zinc-based batteries, flow batteries, electrolysers, etc.) will contribute to an earlier uptake of green storage technologies. Based on the results of this study, however, there are a few policy instruments that could be used/further developed to speed up the process:

- The institution of a "green capacity market": most revenues for peak demands are currently fulfilled by fossil-based power plants. Creating a parallel market only based on carbon-free peak power plants, or forcing electricity operators to offer a share of the peak coverage based on renewable energy, could provide an incentive to grid storage based on batteries, hydrogen or ammonia. This would basically have a similar effect to artificially increasing the wind power penetration effect, hence increasing the energy price when wind power production is low.
- Ensure correct certifications for green hydrogen and ammonia, and expect users of these commodities to prove that a share of their hydrogen/ammonia supply is "certified green". This would create a parallel market for green hydrogen and ammonia, at higher price, thus creating favourable conditions for the generation from renewable power.

The results also show that the optimum configurations including hydrogen and ammonia are never based entirely on hydrogen and ammonia production, unless hydrogen and ammonia prices are unrealistically high. This result stands in opposition to the few existing projects that involve the use of wind power to generate green hydrogen or ammonia, where all electricity is used for PtG processes. Whilst this undeniably simplifies the required infrastructure, the results of this work suggest that this is never energetically/economically optimal, as it is always more convenient to allow a minimum level of direct electricity supply to the grid, when prices are sufficiently high.

6. Conclusion

This work demonstrates that although currently it is more convenient to sell the electricity to the grid, there will be a case for hydrogen or ammonia storage, once there is a further penetration of renewables to the grid and wind farm financing moves from current minimum electricity pricing to subsidy-free. In the 12 h market activation frequency scenario, hydrogen becomes an option for prices as low as 0.08 £/kWh already at 60% renewables penetration. Assuming a hydrogen price at 0.10 £/kWh and higher, which is possible if carbon tax for grey hydrogen or subsidies for green hydrogen are introduced, hydrogen revenues dominate the total revenues for any wind relative installed capacity over 40%. This work shows that, whilst hydrogen is the preferred method of storage for market activation frequency 12 hours and under, ammonia becomes more favourable when longer term storage is required as it is cheaper to store.

At a higher level, from a policy point of view, if incentives are offered (or legislation forcing electricity operators enforced) towards carbon-free generated power to cover the energy peaks, grid storage based on batteries, hydrogen, or ammonia, already technically feasible, can become an economically viable and preferred solution. Furthermore, implementing a transparent and recognised certification framework for hydrogen and ammonia produced from green sources would allow these products to be sold at higher prices, therefore creating favourable conditions earlier and enhancing the need for renewable energy sources.

CRediT authorship contribution statement

Francesco Baldi: Conceptualisation, Methodology, Data curation, Writing – original draft, Writing – review & editing. **Andrea Coraddu:** Conceptualisation, Methodology, Data curation, Writing – original draft, Writing – review & editing. **Miltiadis Kalikatzarakis:** Writing – original draft, Writing – review & editing. **Diana Jeleňová:** Conceptualisation, Data curation, Methodology, Writing – original draft. **Maurizio Collu:** Conceptualisation, Writing – original draft. **Julia Race:** Supervision, Conceptualisation, Reviewing, Writing – original draft. **François Maréchal:** Conceptualisation, Methodology, Reviewing.

Declaration of competing interest

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

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