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Quantifying the additionality of grid-connected hydrogen in a decarbonising energy system

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Keywords Additionality; Green Hydrogen; Power System Model; Curtailment; Variable Renewable Energy

JEL Classification D24 ;H23; L94; Q42; Q47

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Introduction

Hydrogen, a flexible energy vector with high energy density [1], has been considered for decarbonising sectors with high carbon intensity that are challenging to fully decarbonise using Variable Renewable Energy (VRE) [2]. Amongst the different colours of hydrogen, Green hydrogen, i.e., hydrogen produced from renewable electricity via electrolysis, has the advantage of the lowest life cycle emissions [3] and promotes energy security [4]. Green hydrogen generated by cheap electricity from VRE can have a lower production cost (with proper carbon pricing and high gas price) than blue hydrogen, which may suffer from less than 100% carbon capture and methane leakage [5]. Thanks to the current sharp decline in the cost of renewable energy, green hydrogen has been proven to be cost-competitive in some niche applications (e.g., in Texas and Germany [6]). An analysis of a global production and supply revealed that green hydrogen will be cost-competitive in the long term and could be widely employed in most regions [7].

However, not all hydrogen production from electrolysis is green. Increasing grid-connected electrolyser capacity may lead to additional thermal generation, resulting in additional emissions of CO_2. Currently, most of the “green” hydrogen production capacity in operation and under construction is grid-connected [8]. Grid-connected electrolysers risk generating higher emissions than hydrogen from Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS) when they are not constrained only to use renewable electricity [9]. Even when variable renewable energy (VRE) is selected as the sole power source for grid-connected electrolysers there are worries about the additionality of hydrogen production, i.e., the overall increase in emissions from mobilising additional thermal generation to compensate for the diversion of renewable electricity to the electrolysers [10].

In the context of electrolytic hydrogen within an electrical power system, the additionality refers to the additional operation hours of thermal generators that should have otherwise been avoided without hydrogen production. Previous research has only considered hydrogen's additionality as the additional emission and ignored the additional cost to the system [11]. To quantify the additionality of hydrogen production, the primary method used is to compare the emissions from the optimised generation schedule of a specific power system model with and without hydrogen production [11] [12] [13]. The boundary for the analysis is important, for example, setting hydrogen as the final product [11] or assuming the hydrogen is used for heating in Ireland [12] or for system flexibility demand in Germany [13]. The electricity consumption strategy of the electrolysers is also important and typically involves using either (1) VRE under stricter time-matching, (2) using VRE with no time-matching requirement, or (3) using grid electricity [9]. It was found that no matter how strict time-matching requirements are, additional VRE generation capacity is needed to avoid additional emissions from hydrogen production [14]. A case study for Texas and Florida found that an additional VRE generation capacity matching the average demand from the electrolysers will successfully avoid the additional emissions in the current power system, but may fail to do so when the power system is deeply decarbonised, or a large amount of green hydrogen is produced. [11]

Apart from pricing all the emissions generated from the power system, policymakers use two primary methods to regulate additional emissions from hydrogen production in a power system without carbon pricing. The first requires hydrogen to be produced from a decarbonised power system. The second requires a hydrogen producer to prove their electricity consumption is from curtailment or newly installed VRE capacity. [15] [16] [17]. The cost additionality, namely the cost of additional thermal generation because of hydrogen production, is not accounted for. An analysis of green hydrogen's cost additionality will bring a comprehensive understanding of the fair cost of green hydrogen production, and will quantitatively examine the feasibility of using curtailment for hydrogen production [18], which is seen as the most cost-efficient way to make green hydrogen production with current electricity prices and electrolyser efficiencies.

In this study, we aim to analyse the mechanism of additionality in grid-connected hydrogen production qualitatively and quantitatively. We define a "fair cost" and a "fair carbon intensity" of green hydrogen production to include the impact of additionality in green hydrogen production. We measure the additionality of hydrogen production by two indices: the additional emissions and the cost compared to the baseline scenario without hydrogen production. Three hydrogen production scenarios are analysed for current and future GB power systems under different levels of alkaline electrolyser capacity up to 10 GW: (1) buying grid electricity (referred to as 'grid-electricity" or "on-grid" here), (2) buying VRE generation before the wholesale market (referred to as VRE-ahead) and (3) using curtailed energy (referred to as "curtailment"). Utilising curtailed energy before energy storage, after energy storage but before exporting, and after exporting are also tested (in Appendix 2), but the difference among them is not significant. Grid-connected hydrogen production is divided into clean, additionality and dirty by calculating the difference between three electricity consumption methods. The fair cost and carbon intensity under each method are compared to an example of dedicated VRE generation for hydrogen production in an isolated power system. The result shows that the additional thermal generation not only increases green hydrogen's carbon intensity, but also makes green hydrogen production less cost-efficient. The additional VRE needed to offset the emissions from the hydrogen production is determined, as a new method of accounting for green hydrogen's additionality, since it better illustrates the difficulty of decarbonisation.

Modelling methodology

The additionality of green hydrogen usually refers to the difference in emissions between a power system with and without electrolysers. [11] [12] [13] To fully address the relationship between hydrogen production and VRE generation, the power system model needs to capture the variations in VRE generation accurately [19]. This requires weather data with high temporal and spatial resolution. As the majority of a future electricity system's cost is due to providing energy flexibility [20], and green hydrogen production can be made flexible, the analysis of hydrogen production methodology must be based on a power system model able to quantify the cost of mitigating the variability and intermittency of VRE by different flexibility providers.

Here, we use a model previously described by [20], extended to include green hydrogen generation as shown in Figure 1. The model uses the fifth-generation European Centre for Medium-Range Weather Forecasts (ECMWF) atmospheric reanalysis of the global climate (ERA5) for the UK and nearby seas [21] and the real-time demand and historical demand forecast for 2022 from National Grids[22]. The power system model consists of a unit-commitment stage for all the power sources in the wholesale electricity market and a balancing market to consider the impact of demand forecast error in GB power system. To model the competition among energy flexibility providers in a system heading towards decarbonisation, an agent-based structure for energy storage is introduced. Pumped-hydro storage and battery storage will set the price of their bids based on their utilisation factors (determined iteratively) to recover their investment and then compete against traditional energy flexibility provider (thermal generators and interconnectors). The result of competition between energy storage, interconnectors and thermal generation decides the power system cost under the baseline scenario [20]. Green hydrogen production using different electricity consumption strategies, modelled by using electricity from generators at different stages of the electricity market, is then added to the system. The difference in carbon intensity and system cost between the baseline and the scenario with hydrogen production is then the additionality of hydrogen production. The fair cost and carbon intensity are calculated from this additionality and the capital cost/body emission of electrolysers.

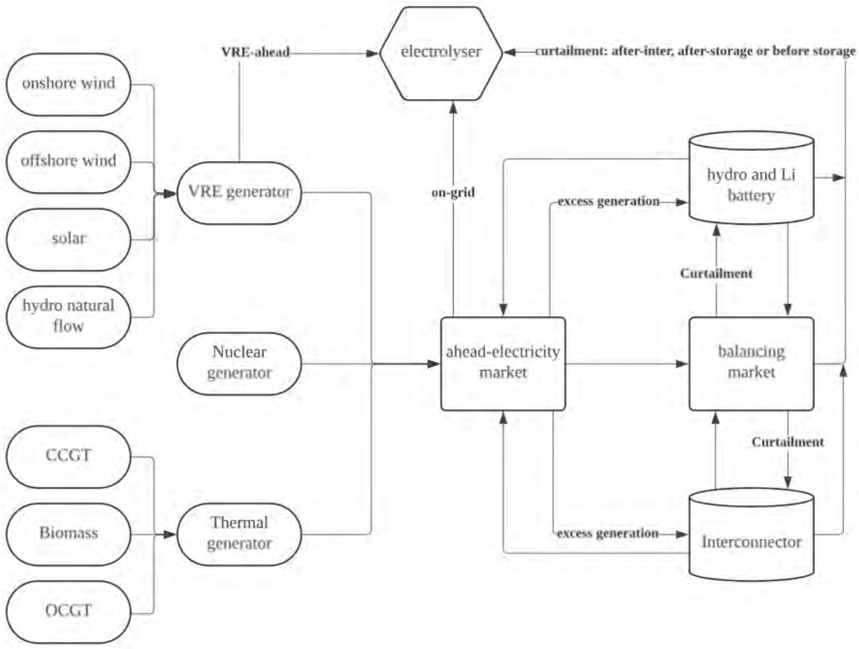

Figure 1: Structure of the power system model and hydrogen production

In a system with high renewable penetration, there will be a significant amount of curtailed energy, which can be caused by predictable excessive generation or demand forecast error. We divide the curtailed energy into excess generation, which arises because VRE generated more than demand, and curtailment, which comes from demand forecast errors. In a power system without hydrogen production, the curtailed energy will first be used to charge energy storage, and then be exported through interconnectors, depending on the availability of storage operators (constrained by their charging and storage limits) and the interconnected power systems (constrained by the historical usage profile of interconnectors). When hydrogen production is considered, the electrolyser has five positions it can take up in the sequence of digesting electricity. The first is to consume VRE generation solely prior to the wholesale electricity market (named VRE-ahead). The second is to buy grid electricity in the wholesale electricity market (named on-grid). The remaining three are to consume curtailed energy prior to energy storage (named before-storage), after energy storage but prior to interconnectors (named after-storage), or after interconnectors (named as after-inter).

This research builds two scenarios, one for the current and the other for the future GB power system, representing a state-of-the-art, highly decarbonised, "clean" power system. The current scenario includes all the generation and storage capacity in operation, while the future scenario also includes all the capacity in operation, under construction and planning (building permitted), and storage capacity in operation and under construction from the renewable planning database of the Department for Energy Security and Net Zero (DESNZ). [23]. This future scenario includes 31.3 GW solar, 55.5 GW of onshore wind, and 36.8 GW of offshore wind, which are at a similar capacity to that envisaged by the UK's Clean Power 2030 Act (up to 50GW offshore wind, 30GW onshore wind and 45-47 GW solar generation capacity) [24]. Table 1 gives details of both power systems.

Table 1: Generation capacity for today's and the future's GB power system

	Baseline	**Future**
Generation Capacity (MW)		
CCGT	28000	28000
OCGT	4146	4146
Biomass	4163	4762
Nuclear	5883	9143
Solar	8687	31351
Onshore	12692	55352
Offshore	9880	36782
Interconnection	8400	14500
VRE total	29779	123485
Total	71971	169536
Energy Storage Power Capacity (MW)		
Pumped-hydro	3223	4337
Battery storage	1614	18221
Total	4837	22548
Model outputs		
Total system cost (GBP/MWh)	54.91	62.3
Carbon intensity (g/kWh)	154.39	44.79

In both scenarios, a gas price of £50 per MWh [25], a biomass price of £80 per MWh, and a carbon price of £60 per ton are employed. Alkaline electrolysers, being the most mature technology, are chosen in this study, with an annual levelized capital cost of £15 per kW per year and an O&M cost of £3 per kW per year.[26] The electrolysers have a ramp-up time of 4 hours and an energy efficiency of 65%. The capacity for green hydrogen production is assumed to reach 10 GW (i.e. the low carbon hydrogen ambition of the UK government by 2030 [26]). A sensitivity test of gas price and electrolyser cost is given in Appendix 2

The additionality of hydrogen production

System cost and emission calculation methodology

Hydrogen's additionality is the additional impact of hydrogen production to the overall energy system. Here we quantify the additional emission (tons of CO_2), and the additional power system cost arising from the additional thermal operation hours caused by hydrogen production, i.e. the difference between system with and without hydrogen production. The power system's cost is the cost of developing and maintaining the power system to meet all electricity demand during the sample year, i.e.

$$C = \sum C_i + \sum_{t=1}^{t=T} [\sum (d_{it} \times S_i) + \sum (g_{it} \times M_{it}) + \sum C_{imt} + \sum (I_{it} \times i_{it})]$$

The power system emission is the CO_2 emitted,

$$e = e_i + \sum_{t=1}^{t=T} \sum (g_{it} * c_i)$$

Here C refers to the cost of having this power system during our modelling periods. C_i is the annualised capital cost and fixed O&M cost of i^{th} generator levelized from its lifetime to the modelling period (one year) in the power system. g_{it} is the delivered generation from the i^{th} generator at t^{th} period, and M_{it} is its marginal generation cost. d_{it} is the discharged amount from i^{th} storage agent at t^{th} period and S_i is a function translating the overall cost of a storage project to a cost for each MWh of electricity, depending on how long it has been stored. Note that the possible employment of hydrogen as energy storage is not considered because currently such planning in UK is trivial and it is less cost-efficient to mitigate the long-term(seasonal) storage demand than short-term (daily) storage demand [20]. i_{it} is the imported electricity through the i^{th} interconnectors at t^{th} period, which can be negative, representing that the system operator is exporting excess VRE generation. I_{it} is its price at the destination (historical price in example year [28]). The agents bid in with their marginal cost (marginal generation cost for generators, storage cost for storage operators and destination electricity price for interconnectors). D_t is the real-time demand, namely the electricity consumed excluding the electrolysers' load at t^{th} period. C_{imt} is the variable operational and maintenance cost of each generator in the system at the t^{th} period. The total modelling periods are 17520 (one year = 17520 half-hours). When calculating system carbon emission (ton CO_2), e_i is the body emission of i^{th} participant in the power system, c_i is the carbon intensity of i^{th} generator coming from UK National Grids Carbon API. [29] to make the result easy to validate with real-world data.

Hydrogen production with 10 GW of electrolyser capacity

In this research, we categorise hydrogen production as either green hydrogen production with no additional thermal generation (clean), green hydrogen consuming thermal generation indirectly (additionality), or green hydrogen consuming thermal generation directly (dirty). The additionality hydrogen can be further divided into external additionality (consuming electricity that should have been exported), future additionality (green hydrogen production consuming VRE generation that should have been used to charge energy storage), and real-time additionality (green hydrogen production consuming VRE generation that should have been used to meet real-time demand).

Given a 10 GW electrolyser capacity, this research tests the impact of grid-connected hydrogen production under on-grid, VRE-ahead, and using curtailed energy before storage, before interconnector and after interconnector consumption strategies. These five electricity consumption strategies are employed to quantify the "clean", "additionality" and "dirty" green hydrogen production by the difference between consumption strategies. The hydrogen produced under the after-interconnector strategy is clean hydrogen production, which has not caused any additional emissions. The difference between the after-interconnector and the after-storage scenarios is the external additionality hydrogen production. Hydrogen produced with external additionality doesn't bring any additional emissions to the GB power system; however, the opportunity to decarbonise neighbouring power systems is lost. The hydrogen with "future additionality" is taken as the difference in hydrogen produced between the after-storage and ahead-storage strategies. This corresponds to electricity being used to produce hydrogen at the sacrifice of losing the opportunity to charge energy storage, which could have been used in future to prevent thermal generation. The difference between VRE-ahead and before-storage is the hydrogen with "real-time additionality". This hydrogen has been produced by VRE generation that should have been used to meet the real-time demand. The difference between on-grid and VRE-ahead is the "dirty" hydrogen, representing hydrogen that has definitely come from thermal generation. Figure 2 shows the amount of hydrogen produced for each of these categories of hydrogen.

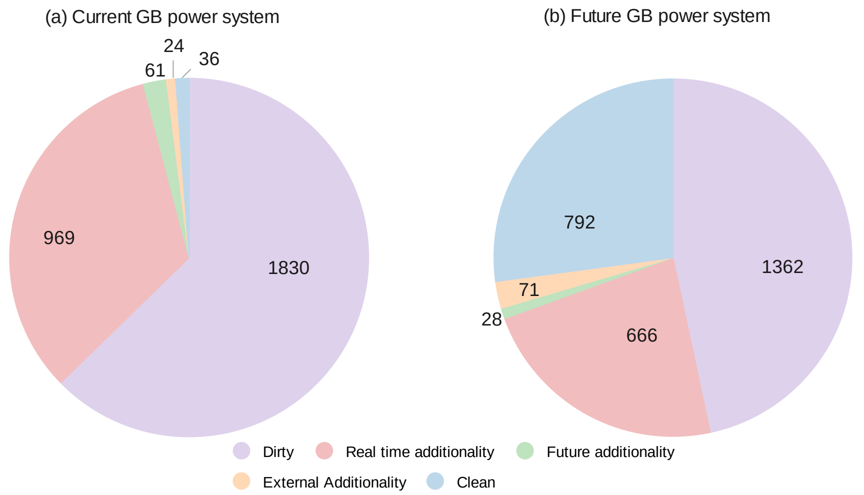

Figure 2: Hydrogen produced (kt/yr) with the 5 electricity consumption strategies in the (a) current and (b) future GB power systems. The total corresponds to that produced by the on-grid strategy.

In the current GB power system (Figure 2a), if 10 GW of electrolyser capacity is connected, the large-scale production of hydrogen will be realised mostly by direct thermal generation. Only a small fraction of the hydrogen produced "on-grid" can be labelled as "clean". Most of the remaining hydrogen is hydrogen with "real-time additionality". In the future GB power system (Figure 2b) when all projected VRE generation capacity is installed, clean hydrogen production from curtailed energy will be more than 25% of the total that could be produced if the electrolyser were "on-grid" and working at full capacity (i.e. clean hydrogen); ~ 25% of the "on-grid" hydrogen can be labelled as hydrogen with additionality. In both scenarios, the hydrogen with future additionality is trivial because energy storage always has the chance to collect curtailed energy to fulfil its stock. The external additionality of hydrogen production rises in the future, but is still not that significant. The small additionalities described as external and future additionally arise from the "after-inter", "after-storage" and "before-storage" scenarios producing very similar results. Hence, the difference between these will not be described further, but for reference, the analyses for these sub-strategies and the sensitivity to electrolyser flexibility are given in Appendix 1.

Origin of the additionality

Figure 3 shows the electricity delivered from each power source in the future scenario using the “on-grid” strategy during the first ten days of April. The shared area above the real-time demand, excluding electrolysers (white line), represents the electricity used for hydrogen production, assuming the cleanest sources of energy are first used to meet real-time demand. On-grid hydrogen production maintains a full load factor for the electrolysers, creating an additional 10 GW of demand above the real-time demand. As can be seen, with “on-grid” electrolysers, a considerable amount of the electricity comes from additional CCGT power, producing considerable additionality. Also shown is the demand when the electrolysers follow the VRE-ahead strategy (black line). Usually, on-grid demand is higher than VRE-ahead because of the dirty hydrogen production. However, there are some periods in which VRE-ahead demand is higher than on-grid demand, because energy storage isn’t sufficiently charged, leading to insufficient supply. The shaded area above the VRE-ahead demand curves gives an indication (to a first approximation) of the sources of electricity that contribute to the hydrogen in this case (the actual distribution of energy sources in the VRE-ahead scenario is given in the supplementary information, and can be seen to be very similar). In a VRE ahead strategy, a significant amount of extra electricity must come from fossil-powered CCGT, creating additionality. In VRE ahead, allocating renewable electricity that should be used to meet real-time demand, forces additional CCGT use at the system level.

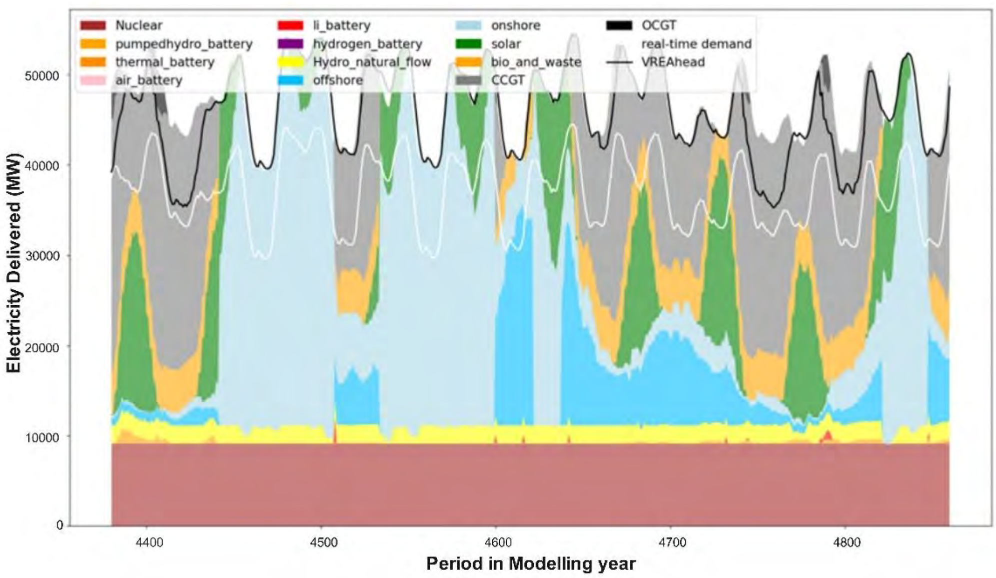

Figure 3: Electricity delivered from each power source in the future scenario using an on-grid strategy during the first ten days of April. The base electricity demand load is represented with a white line and the electricity demand in VRE-ahead mode is represented with a black line.

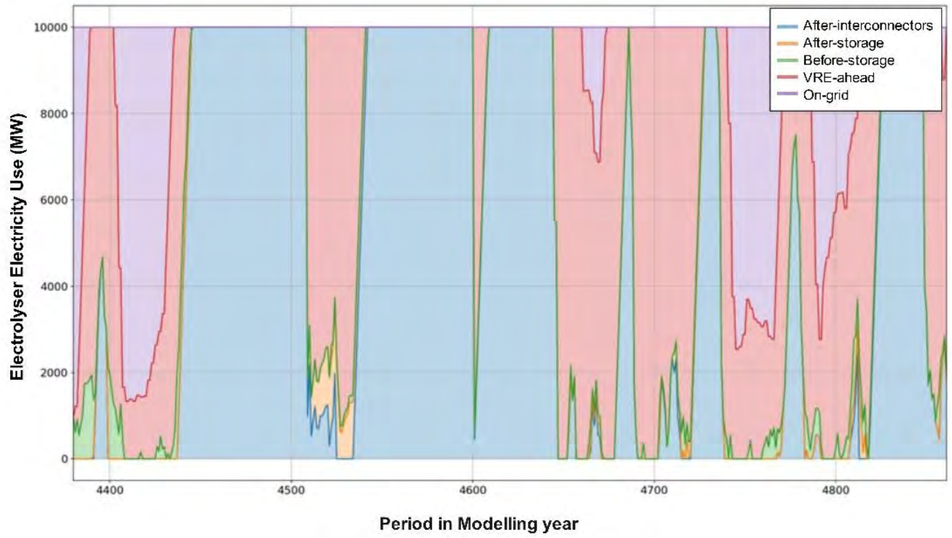

Figure 4: The electricity consumption of the electrolysers under different hydrogen production methods in the future scenario, during the first ten days of April.

Figure 4 shows the electricity demand for only hydrogen in each of the strategies. For example, the "on-grid" strategy is a constant 10 GW of demand. As in Figure 2, the differences between the demands for each scenario here have been allocated to the different kinds of hydrogen - dirty, additionality (real-time, future, external), and clean, and are shown by the shaded areas. Dirty hydrogen production refers to hydrogen production from thermal generation, represented by the purple area in Figure 3b. When hydrogen is constrained only to consume VRE generation, the amount of electricity consumed by electrolysers falls, avoiding dirty hydrogen production. The red area refers to real-time additionality, consuming VRE generation that should have been used for decarbonising the real-time demand. This is avoided by letting hydrogen production consume VRE generation after real-time demand is met. The green and orange areas are future additionality and external additionality, referring to VRE generation that should have been sent to energy storage and VRE generation that should have been exported. The blue area is hydrogen production from curtailed energy and hence is the "clean" part of green hydrogen production.

From system additionality to fair cost and carbon intensity

The difference between emissions and cost with and without hydrogen production allows the additional cost and emissions of hydrogen production to be calculated. The fair cost and emission intensity of hydrogen is defined as:

$$C_H = \frac{(C - C_b) + C_E + C_T}{P}$$

$$c_H = \frac{(e - e_b) + e_E}{P}$$

Here C_H is the fair cost of produced hydrogen, C is the total system cost of the scenario with hydrogen production, and C_b is the total system cost of the base case scenario without hydrogen production. C_E is the cost of the electrolysers and P is the amount of hydrogen produced. C_T is the transmission cost of the electricity, as an electrolyser is a load connected to the power system and previous system cost calculations are supply side. c_H is the fair carbon intensity of hydrogen, e is the power system emission with hydrogen production, e_b is the power system emission of the base scenario without hydrogen production and e_E is the body emission of electrolysers. The transmission and distribution of electricity through the power system is set as £1 per MWh.

Given that the results are insensitive to the flexibility of the electrolysers and the three curtailed energy utilisation methods only generate small variances (see Appendix 2), the (a) fair costs and (b) carbon intensities are only shown on Figure 5 for the curtailment (after inter), VRE-ahead, and on-grid strategies.

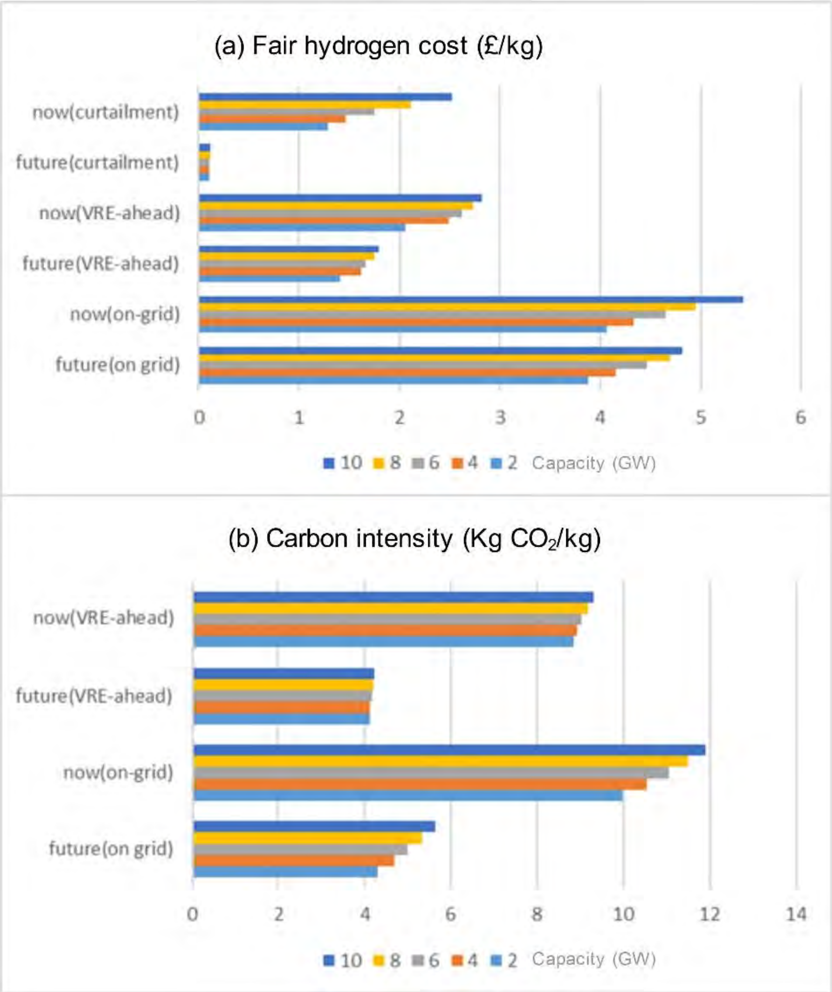

Figure 5: (a) Fair cost and (b) carbon intensity from 2 to 10 GW of hydrogen capacity in the future and current GB power systems

Thanks to the cost savings from free electricity, curtailed energy will be the most cost-efficient method of producing hydrogen, even in today's GB power system. The most cost-efficient strategy of hydrogen production will always be utilisation curtailment despite the low load factor.

The on-grid strategy is always the worst strategy, giving the highest carbon intensity and the highest fair cost. The VRE-ahead strategy leads to a slightly lower carbon intensity and fair cost compared to the on-grid strategy, but it is still far from clean. The average carbon intensity of VRE-ahead, with its high additionality, is around 4 kg/kg, which is slightly higher than blue hydrogen of 3.3kg/kg.[28] The on-grid hydrogen production makes hydrogen more carbon intensive than blue hydrogen, but is still cleaner than grey hydrogen, whose carbon intensity is 9 kg/kg. [31] Additional thermal generation in the VRE-ahead strategy increases the carbon intensity and fair cost because it leads to additional generation from thermal generators with non-zero marginal generation cost. The carbon intensity and cost of hydrogen produced from thermal generation varies because the share of different generators varies in different scenarios. Thanks to the small share of OCGT in GB power system and a significant amount of "clean thermal generation" like nuclear or biomass, the carbon intensity of additional thermal generation is less than that of mainstream gas-fired plants. Still, at the moment, regulating the additionality of hydrogen production is a necessity for GB to be able to claim that green hydrogen is green.

The fair cost of green hydrogen depends on the cost of electrolysers and the cost of electricity. In the curtailment case, the cost of hydrogen production depends solely on the electrolyser's cost. A sensitivity test in Appendix 2 shows how the fair cost of hydrogen production in the future scenario varies between a gas price ranging from £10 to £50 per MWh and an annually levelized electrolyser cost ranging from £18 to £90 per kW. In the future system, using curtailment will always be the most cost-efficient strategy for hydrogen production, no matter how gas and electrolyser costs might vary. In the current system, using a gas price of £10/MWh and an annual electrolyser cost of £18/kW will make on-grid the most cost-efficient hydrogen production solution. This suggests that a low gas price may make gas-fired hydrogen production more competitive than green hydrogen when there is not enough free curtailed energy accessible to the electrolyser. Using a gas price of £50/MWh and an annualised electrolyser cost of £90/kW will make VRE-ahead the most cost-efficient solution for the current power system. This suggests that it is not cost-efficient to introduce too much electrolyser capacity to a carbon-intensive power system, unless electrolysers are cheap enough.

Value of green hydrogen

Fair cost and carbon intensity of green hydrogen production

When a system has high VRE penetration but has yet to be decarbonised entirely, the costs and emissions of additional thermal generation contribute to the majority of green hydrogen production's fair cost and carbon intensity. When electrolysers are connected to the power system, the only strategy to avoid this additionality is to use curtailed energy. To give a benchmark cost, namely the fair cost of green hydrogen production without the disadvantage of additional thermal emission and advantage of free access to curtailed energy, we analyse the cost of a dedicated wind-hydrogen system with VRE generators. A case study of green hydrogen production using dedicated electricity from an onshore wind farm at Edinburgh solely for green hydrogen production was developed (with the cost of wind farms levelized to the hydrogen produced). The wind-hydrogen share was optimised (under the same cost and technical parameters of the main model) to maximise the investment-payback ratio, with the optimal ratio of wind: electrolyser being ~ 1:1.
Table 2 shows the fair cost and fair emission intensity of green hydrogen in the current and future GB power system with 10 GW online capacity, and of dedicated electricity for hydrogen production in Edinburgh.

Table 2: Fair cost and carbon intensity per MWh for 10 GW electrolyser in the GB power system

	Today	Future
On-Grid	£164.16	£147.00
	356.7 kg	169.29 kg
VRE-ahead	£85.84	£55.29
	279.6 kg	118.37 kg
Before-Storage	£79.78	£15.73
	172.2 kg	4.79 kg
After-Storage/Before-interconnectors	£70.93	£14.90
Curtailment (after interconnectors)	£55.23	£5.28
Dedicated electricity (Edinburgh wind)	£28.18	£28.18

In the current GB power system, using dedicated electricity to produce green hydrogen is the most cost-efficient method. This shows that thermal generation adds significant cost to green hydrogen if 10 GW of electrolyser capacity is installed. In the future GB power system, when all planned VRE capacity is installed, there will be enough curtailed energy to properly utilise the 10 GW of electrolyser capacity, producing more cost-efficient hydrogen compared to hydrogen from dedicated electricity.

The results reveal that in the current power system, it is still more cost-efficient to employ VRE to provide cheap electricity to decarbonise the existing load in the power system first, instead of generating green hydrogen. However, in the future GB power system, which has come close to its decarbonisation target, producing green hydrogen using curtailed energy will be more cost-efficient than using dedicated electricity. The comparison between dedicated-electricity hydrogen and curtailment hydrogen shows whether it is worthwhile to digest curtailed energy through electrolysers. There is no point in producing hydrogen through curtailment (e.g. with an electrolyser at a low load factor) when it is less cost-efficient than building a dedicated wind-hydrogen system, whose electrolyser operates at a higher load factor.

Value of green hydrogen in replacing hydrocarbon fossil fuels

From an emission accountant's point of view, the hydrogen produced will be used to displace fossil fuels and fossil fuel-based products in different sectors. However, this process will most likely happen if using green hydrogen is more economically efficient than using hydrocarbon fuels. Table 3 gives the wholesale price, carbon intensity, and annual demand for fossil fuels in the current UK energy system. Even if hydrogen is produced with emissions, it may still reduce the overall carbon emissions of the energy system if the additionality is offset by the savings in emissions gained by displacement.

Table 3:Wholesale price, well-to-wheel life cycle emission and annual demand of fossil-fuel products in GB energy system.

Fuel	Whole-sale Price (GBP per MWh)	Carbon in-tensity (kg CO_2 per MWh)	Annual Demand (Approx. TWh)	Price and de-mand primary source
Natural Gas (ex-cluding Power Sector)	30	439[32]	540	DESNZ Energy Trends
Diesel	68.05	453.67[33]	~280	DESNZ Energy Trends/DUKES
Petrol	74.31	459.86[33]	~130	DESNZ Energy Trends/DUKES
Jet Fuel	61.73	425.41[33]	~119	DESNZ Energy Trends/DUKES
Grey (Blue) Hydro-gen	43.29 (56.61)	270(99) [31]	27	DESNZ / Strat-egy Docs

In terms of the cost per MWh (lower heating value) given in Table 2, the fair cost of hydrogen from dedicated electricity and curtailed energy in the future GB power system is significantly lower than the cost of mainstream fossil fuels. This shows that with current VRE and electrolyser technology, the fair cost of producing green hydrogen without additionality could already cost-efficiently replace fossil fuels (though this does neglect the cost of changing the infrastructure). In the future power system, with an increased penetration of VRE bringing significant curtailed energy to the market, using flexible green hydrogen production to digest the curtailed energy makes hydrogen production even more

cost-efficient. Given that in the future GB power system 52 TWh of green hydrogen from curtailed hydrogen can be produced, 10 GW of electrolyser capacity would allow the GB power system to phase out all grey hydrogen demand. However, the produced green hydrogen is an order of magnitude less than that needed to displace fossil fuels for domestic heating or transportation. Hydrogen from dedicated electricity is a good second choice. Even when there is a construction capacity limit of new VRE generators, as in the future scenario in Table 3, the dirtiest hydrogen (on grid, 118 $kgCO_2$/MWh) is better than fossil-fuel-based products with no carbon capture (270-459 $kgCO_2$/MWh), but the cost is generally higher per MWh displaced.
It is worth noting that under the current carbon pricing scheme in the UK, green hydrogen with additionality will require emission permits, and the cost of these will be allocated among thermal generators. On the other hand, the current UK emission trading scheme (UKETS) does not cover sectors like transportation and blue hydrogen production[34]. When hydrogen is being sold into these markets, hydrogen (with additionality) will face a higher carbon tax than its fossil fuel competitors (whose emissions are not priced) despite its lower emission intensity. This calls for an expansion of UKETS or reasonable compensation for hydrogen when competing against fossil fuel-based products in these sectors.

Additionality offset in the future and current power systems

To decarbonise the power system, the additionality from green hydrogen production has to be avoided, which can be realised by introducing more VRE generation capacity to the system. If all the new VRE can meet the real-time demand currently met by carbon-emitting thermal generation, introducing VRE generation capacity equal to the electricity consumption of green hydrogen production is sufficient to offset the hydrogen additionality. However, with an increasing VRE penetration, there is increased curtailment. The mismatch between the supply and demand means that additional VRE does not necessarily displace thermal generators. This makes it hard to displace the additional thermal generation caused by hydrogen production by installing new VRE generation capacity. System planners and policy makers may be misled as to the difficulty of offsetting hydrogen additionality in a well decarbonised power system. For example, EU policies certify hydrogen as green when it comes from a power system with a lower average carbon intensity.[16]

To visualise the difficulty of offsetting the additionality, we employ an alternative view of the additionality by asking how much VRE would be needed to completely offset the emissions from the hydrogen. Figure 6 shows the carbon intensity in the future and current GB power systems when increasing VRE generation capacity, for 10 GW of electrolyser capacity, compared with the base cases of no hydrogen production.

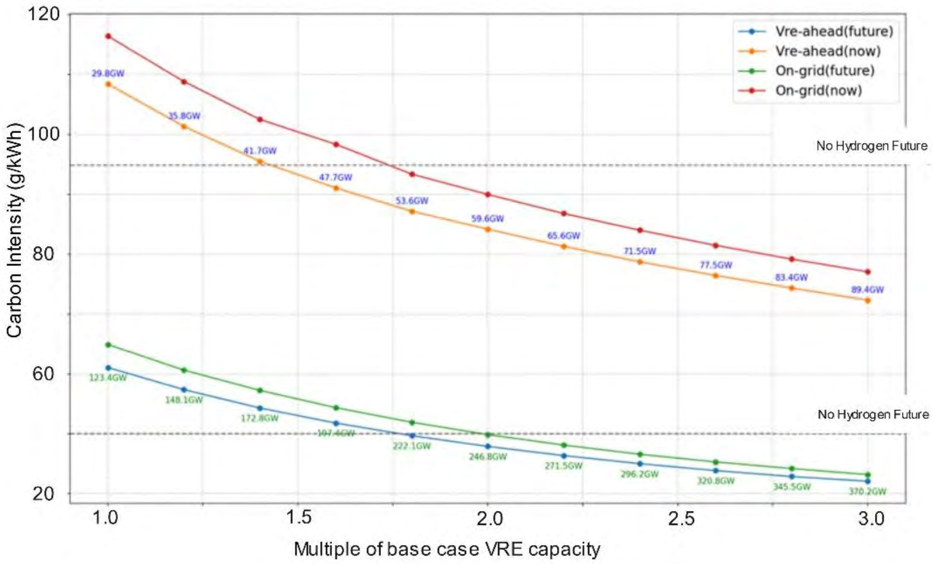

Figure 6: Carbon intensity of future and current GB power system at different multiples of

VRE capacity. In the base case, the "now" and "future" scenarios have installed VRE capacities of 29.8 GW and 123 GW (details in table 1)

By testing different multiples of the VRE generation capacity, it was found that in a power system stepping to decarbonisation (i.e. the current GB power system, with a carbon intensity of 154.39g/kWh), 35% more VRE capacity is needed to offset the additionality of an electrolyser buying time-match VRE generation ahead of real-time demand (i.e. VRE-ahead) and 75% to offset a 10 GW grid-connected electrolyser working at 100% load factor (i.e. on-grid). In a decarbonised system (i.e. the future GB power system, with a carbon intensity of 44.79 g/kWh), 75% more VRE capacity is needed to offset hydrogen's emissions under the VRE-ahead strategy, and 100% more VRE capacity is needed to offset the emissions under the on-grid strategy. Note that because the future system has an installed VRE capacity (123.4 GW) around 4 times as much as today's (29.8 GW), every unit of VRE capacity added to the future scenario is a much smaller fraction of the total than a unit added now. Offsetting a 10 GW electrolyser's additional emissions will be 7-10 times more expensive in the future than in today's system if the cost is valued as how much new VRE capacity is needed to offset the hydrogen's additional emissions to the power system.

Greener "with additionality" hydrogen needs more VRE to offset its additionality. When VRE penetration increases, less marginal green electricity from newly installed VRE will be available to meet the real-time demand, which makes the VRE generation consumed by a constant electrolyser load hard to offset. With the system becoming more decarbonised, the additional emissions from green hydrogen production will fall, but they will be more expensive to offset by newly installed VRE capacity.

Discussion and conclusions

This research divides the grid-connected hydrogen production into clean, additional and dirty by categorising the electricity consumed by hydrogen production using the difference between curtailment, VRE-ahead and on-grid electricity consumption strategies. Through our fair cost calculation, we find that in the future GB power system, when all projected VRE capacity is delivered, using curtailment will be the most cost-efficient and carbon friendly solution for a 10 GW hydrogen production capacity. The produced hydrogen will be enough to replace all grey hydrogen consumption and begin to decarbonise other sectors. The downside of cost-efficient green hydrogen production is the additional thermal generation it causes. The green hydrogen produced from dedicated VRE electricity has a lower fair cost compared to the wholesale market price for oil products and grey hydrogen. On the other hand, hydrogen with additionality may be penalised with a carbon cost even when its carbon intensity is lower than fossil fuels in some sectors (as they are not covered by UKETS). Currently, if using an on-grid strategy, which is the mainstream method of green hydrogen production, the majority of hydrogen production will be dirty and real-time additionality hydrogen production. The clean hydrogen production rises from a trivial level (less than 5%) to around a quarter, if all projected VRE and storage capacity in the GB power system is delivered. This will make on-grid hydrogen production dirtier than blue hydrogen but still cleaner than grey hydrogen in the future GB power system. In today's power system, the average carbon intensity of green hydrogen will be dirtier than that of grey hydrogen. Under the VRE-ahead strategy, green hydrogen will be dirtier than blue hydrogen but cleaner than grey hydrogen, either in today's or the future's power system.

We also find that the newly installed VRE required to avoid hydrogen additionality may be much higher in a more decarbonised power system than in today's system. It is possible that the easy offset of green hydrogen's additionality in today's system and low additional emissions of hydrogen production in the future system will make policymakers underestimate the importance of regulating additionality from hydrogen production. A no-regret case of avoiding hydrogen additionality is to regulate green hydrogen to only consume electricity from newly installed VRE generators. This is equivalent to the dedicated electricity for hydrogen case, if the connection cost is ignored. However, this constraint sacrifices the possibility of using VRE to decarbonise the power system if it is only permitted to sell electricity to a hydrogen producer. If the newly installed VRE is also permitted to sell electricity to the system (assuming that green hydrogen producers will offer a lower price than real-time demand), this will be less efficient than our curtailment case, since only the curtailment from the newly installed capacity can be utilised.

Energy storage potentially competes with hydrogen production for curtailment, but also can work synergistically to reduce the difficulty of offsetting the additionality of hydrogen, e.g. when there is a large unused amount of curtailment. These effects are not readily seen in the current power system; hydrogen does compete with storage for curtailment, as both are limited. In the future scenario, increasing energy storage capacity will reduce the amount of VRE needed to offset hydrogen's additionality, for example, in the model, doubling the storage capacity in VRE-ahead, in figure 6 reduces the multiple of VRE expansion needed to 60%. However, the optimisation between VRE vs energy storage when avoiding additionality requires further investigation.

Our sensitivity analysis shows that using curtailed energy to produce hydrogen will always be sensible, even under a high electrolyser cost assumption, if the total electrolyser capacity in the market is regulated to be below a level that makes enough curtailed energy available. When the gas price is low or curtailed energy is insufficient, gas-fired hydrogen may be more cost-efficient than hydrogen from curtailed energy. In this case, green hydrogen shouldn't be encouraged as the VRE is usefully employed decarbonising the power system first.

Our results suggest that to avoid additionality, hydrogen production should never consume VRE generation that can meet the real-time demand, especially in a more decarbonised power system. A mechanism for trading curtailed energy among hydrogen producers will be necessary to reduce the cost of hydrogen production. Policymakers could consider using green hydrogen from curtailment to decarbonise the whole energy sector, even if the power sector is not strictly decarbonised. On cost and carbon emission arguments, the case can be made for displacing fuels (e.g. gas, diesel) with hydrogen, the bottleneck is the limited amount of curtailment available for hydrogen production.

Surprisingly, making hydrogen production flexible was not found to be important, either because flexibility isn't important, or perhaps because of the assumption of linear ramp-up for the electrolysers, meaning that, as modelled, they are sufficiently flexible to be able to digest curtailed energy. Further work is needed to model the electrolyser start-up and ramp-up process in detail within a power system model.

We draw three lessons. The first is that current VRE and electrolyser costs already permit cost-efficient hydrogen production replacing fossil fuels. However, the additionality, i.e. carbon emissions, of hydrogen production should discourage this. The second is that in a well-decarbonised power system, using curtailed energy from VRE will be the most cost-efficient method for hydrogen production while in a system moving towards decarbonisation, green hydrogen from dedicated VRE electricity may be the most cost-efficient choice. A dedicated system has no operational emissions. However, the carbon additionality for the dedicated system is, in contrast to the curtailment case, not zero if the opportunity cost is considered. The third lesson is that in future power systems with high VRE penetration, a small amount of additional emission from hydrogen production requires a large amount of VRE capacity to offset it. For hydrogen producers, our results point out the cost-efficiency of hydrogen production using curtailed energy. However, this requires a market mechanism to allow the producers to access curtailment, and a gas price above £10/MWh (to make green hydrogen, cheaper than hydrogen from thermal generation), though this number is also sensitive to the electrolyser cost.

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Appendix 1: Difference of hydrogen production among three sub-strategies of curtailment and sensitivity test of electrolyser flexibility

Figure A1 shows the amount of each "type" of hydrogen produced, the fair cost and carbon intensity for 10 GW of electrolysers using either the on-grid, VRE-ahead, before-storage, after-storage and after-inter strategies, when the electrolysers are constrained to ramp up at different rates.

From Figure A1, electrolyser flexibility is not important; this may, in part, be due to the assumption of a linear ramp-up rate and the fact that location is not accounted for. The linear ramp assumption typically used in research [11][12][13] facilitates computation but may overestimate the response rate of an electrolyser. In practice, the start-up of an alkaline electrolyser consists of warm-up, system check and power-up stages. During the warm-up and system check, when the electrolyte is heated to the working temperature, the electrolyser can’t digest any excess electricity and can’t produce any hydrogen. This makes only the last stage of electrolyser start-up linear [35].

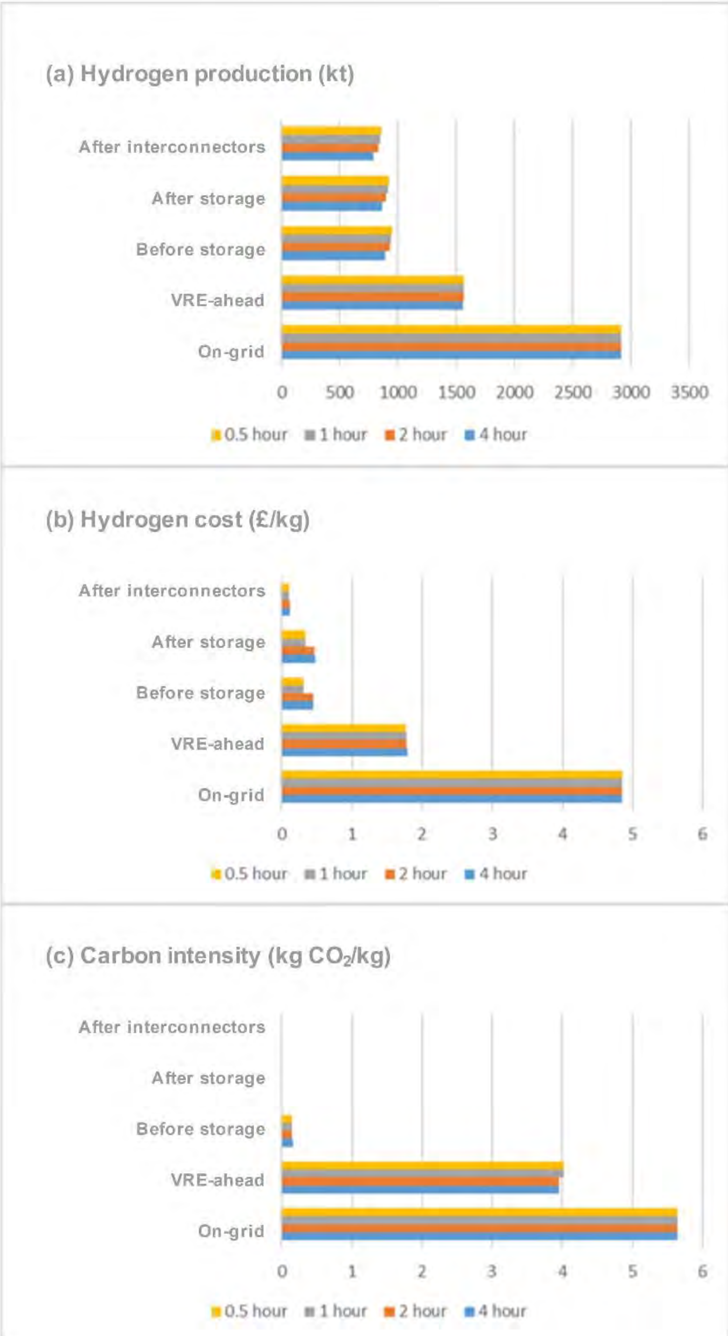

Figure A1: (a) production, (b) fair cost and (c) carbon intensity of 10 GW hydrogen production in the future GB power system. The electrolysers are constrained in how fast they ramp up (linearly) to full power (0.5, 1, 2, or 4 hours, the previous analysis is based on 4 hours).

Appendix 2: sensitivity test of gas price and electrolyser cost

This research assumes that the gas price is £50 per MWh (£14.61 per MMBtu). The annual levelized capital cost of the electrolyser is set as £15 per kW, and its operational cost is £3 per kW. Considering that a low gas price may make thermal generation a more cost-efficient choice for hydrogen production, and the capital cost of the electrolyser may make the curtailment strategy less preferable, a sensitivity test on gas price and electrolyser cost is shown in Figure A2. Figure A2a shows the fair cost of hydrogen with 10 GW of electrolyser capacity when the gas price ranges from £10 per MWh to £50 per MWh, and A2b shows the fair cost of hydrogen when the annualised capital+operational cost of electrolysers ranges from £18 per kW to £90 per kW.

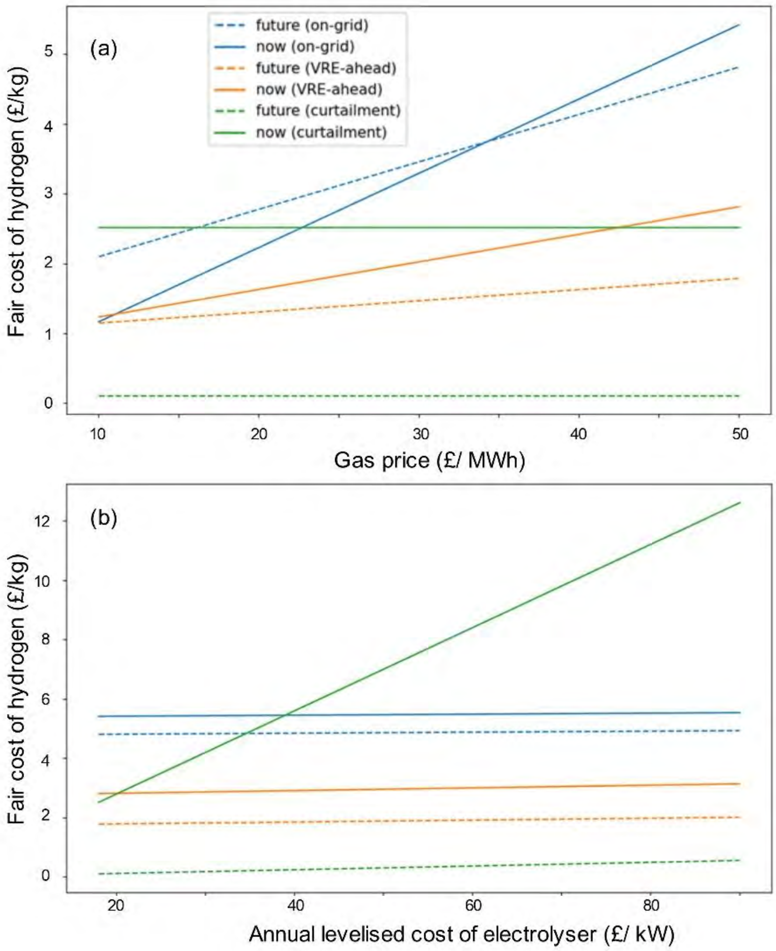

Figure A2: Fair cost of hydrogen for different (a) gas prices and (b) electrolyser prices

For the future system, curtailment will always be the most cost-efficient hydrogen production strategy. For the current system, it is found that when the gas price falls below £11 per MWh, the on-grid strategy will become the most cost-efficient solution for hydrogen production. For a gas price between £11 and £42 per MWh, the VRE-ahead is the most cost-efficient hydrogen production strategy; curtailed hydrogen becomes the most cost-efficient above a gas price of £42 per MWh. An increase in electrolyser cost to above £24 makes VRE-ahead the least cost-efficient strategy now, but in our future scenario, curtailment will still be the most cost-efficient choice for hydrogen production even when the annualised cost of the electrolyser is increased from £18 per kW to £90 per kW.