On effectiveness of current energy policy instruments to make H2 production projects financially viable for developers: case of the UK

Oliver Joy, Jafar Al-Zaili*

Department of Mechanical Engineering and Aeronautics, City, University of London, Northampton Square, London, EC1V 0HB, UK

**Correspondent Author: jafar.alzaili@city.ac.uk*

Abstract

Hydrogen has been identified as a potential gamechanger and ambitious national targets have been announced by many governments. However, the lack of clear policy signals at the country level remains a barrier and significant cost reduction progress is unlikely to be made unless the issue is addressed. The paper aims to assess whether current UK energy policies support an economic case for low-carbon and competitive H2 production. A financial model is developed for hypothetical H2 projects based in the UK. Price assumptions are assigned to a specific set of policies in combination with the key technical considerations for H2 production and estimated return. The study concludes that H2 development featuring electrolysers or carbon capture and storage cannot rely on market forces alone to reach full commercialisation and competitiveness in the UK. While policies improve the economic case for H2 in some key areas, existing frameworks are not ambitious enough to advance the transition to low carbon gas and Blue and Green H2. Moreover, current policies do not sufficiently disincentivise investments in emission-intensive alternatives.

Keywords

Hydrogen; Hydrogen Production; Green Hydrogen; Blue Hydrogen; United Kingdom

1. Introduction

The UK was one of the first countries in the world to establish legally binding carbon reduction commitments toward 2050 under the 2008 Climate Change Act. More than 10 years later, the government has ramped up ambition with a new target of net-zero emissions by 2050 with plans to phase out the most polluting power generation plants and pursue low-carbon technologies. Progress towards these targets is monitored through a series of interim five-year carbon budgets to reduce emissions, which have so far been achieved ahead of schedule.

The UK's climate success can be attributed, in part, to its continued deployment of renewable energy technologies, particularly offshore and onshore wind, over the last two decades.

While significant progress has been made on electricity generation, the country now faces a new challenge: how to provide heating to homes and businesses as well as fuels capable of delivering the high temperatures needed for industrial production that do not jeopardise long-term climate goals. The UK is still heavily reliant on natural gas for power and heat generation (Richards and Al Zaili, 2020). Decarbonisation of this sector will be crucial if the UK wants to remain on track to meet its carbon budgets into the 2020s and beyond (Committee on Climate Change, 2019).

Policymakers are now considering Hydrogen (H2) as a viable solution to the question of low-carbon gas. Until the 1970s, H2 was an important component of gas supply in the UK - then known as "Town Gas" (Demoullin & Dodds, 2013).

With world leaders now committed to decarbonising energy systems, H2 appears to be making a comeback in policy circles with a focus on low-carbon production processes. In 2018, the government launched its Hydrogen Supply Programme to assess the readiness of H2 rollout in the UK. This includes Power-to-Gas (PtG) projects, audits of energy storage capacity and H2 safety assessments in the commercial and residential building stock. Ongoing pilot projects in the UK such as the H21 Leeds City Gate and

HyNet are focused on integrating H2 into homes, businesses and industries with an emphasis on economic viability and safety for consumers (DNV GL, 2018).

The UK already has a myriad of energy policies intended to support clean technologies, disincentivise highly polluting industries and encourage uptake of energy-efficient or low-carbon consumption. This paper will examine to what extent the current crop of UK energy policies supports the economic case for H2 production – blue and green - as part of a distributed energy system to help the country meet its long-term decarbonisation objectives.

It will also seek to identify, within the current UK context, whether Blue or Green H2 presents the better cost option for production, considering carbon-intensity and conversion efficiencies. To achieve this, an economic evaluation of the technology based on current estimates will be supported by a model to assign a cost range to policies such as carbon pricing, capacity markets, emissions performance standards, contracts for difference, transmission reform and some demand-side incentives among others.

The research in this paper is organised in the following format. Section 2 sets the scene for the two technologies. This serves as a brief overview of Blue and Green H2, their respective characteristics and uses. Sections 3 provides a critical analysis on the economic considerations for H2 production in a UK energy system undergoing transition. Section 4 examines how H2 could integrate into existing policy frameworks and make use of government instruments to improve financial viability. This includes the impact of policies designed to discourage fossil fuel use and incentivise low-carbon investments. Section 5 explains the financial model and assumptions used in this research to price the impact of selected policies on H2 viability. Section 6 presents a discussion on the findings of the model, followed by conclusions and policy recommendations in section 7.

2. Hydrogen Production and utilisation

There are two primary forms of hydrogen (H2) production. The first is Blue Hydrogen. A combination of steam methane reforming (SMR) paired with carbon capture and storage (CCS) technology. This is the most mature and mainstream form of H2 production available today. The process involves applying a catalyst and heat to methane to separate H2 from carbon dioxide (CO2). The resulting H2 is often used as a feedstock for ammonia, fertilisers and other chemicals, while the CO2 by-product is released into the atmosphere (Chapman *et al,* 2020*)*. This is a highly polluting process if the CO2 is not captured, and therefore H2 from SMR alone cannot be considered a low-carbon gas. To be classified as Blue H2, CCS, a very expensive and largely unproven technology, would be required. This involves capturing the CO2 at the point of production and storing it underground or at sea in depleted natural gas fields or unused salt caverns.

The second form is Green Hydrogen. This is the process of converting power to gas via electrolysis using output from wind, solar or other forms of renewable energy (Rezaei *et al*, 2021). While the electrolyser industry is still relatively nascent, the environmental benefits of the technology are clear and the very limited emissions at the point of production are driving growth in the sector (Madden & Wilson, 2020). Furthermore, it provides established developers in other technology categories with an opportunity to maxmise potential output. Integrated renewable-hydrogen systems create pathways for expanded use of domestically produced intermittent sources, including wind and solar, with H2 serving as the storage and energy vector (Cottrell *et al,* 2011)

3. The cost of Hydrogen production in a transitioning environment

The economics of Blue and Green H2 development in the UK will be a key barometer for their success going forward. Ambitious climate and energy policies will have a significant impact here too as will wholesale natural gas and electricity prices. On a Levelised Cost of Hydrogen (LCOH) basis today, Blue Hydrogen provides a more attractive cost range when considering production alone. This is primarily based on the large disparity between wholesale electricity and gas prices in the UK. The former averaged approximately £0.11/kWh in 2019 while wholesale gas prices were between £0.02-3/kWh in the same year excluding taxes (Eurostat, 2019). In terms of output, this translates into a production cost estimate of between £3-5/kg for Green H2 while Blue H2 is between £1.50-2/kg even with the efficiency losses accrued with CCS technology installed, currently between 10-15% (Hydrogen Council, 2020). This puts Blue H2 at a distinct advantage to Green H2 given that fuel/electricity costs make up around 70% of expenditure over project lifetimes (Maggio *et al,* 2019).

However, for future cost estimates, it is also important to consider the direction of the UK energy mix over the next 10-15 years in relation to government policy and resource access (BEIS-d, 2019). For example, the cost of SMR-based H2 production today assumes continued availability of UK domestic natural gas. Yet, North Sea resources are gradually depleting (Hall, 2019). Hall argues that UK domestic gas production will fall by 5% a year from 2020 onwards. While continued use of natural gas is consistent with the government's decarbonisation strategy, projected output of 40 billion cubic metres (bcm) in 2021 could fall by three quarters over the next 15 years. This is a pertinent argument to scrutinise the economic costs and sustainability of Blue H2. Increased dependence on overseas imports will likely increase fuel feedstock and transmission costs for Blue H2 significantly, particularly if technology cost reduction does not keep pace with rising prices. This is a lesser concern for Green H2 as electricity could be produced from domestic, mature wind energy at zero-marginal cost or other forms of renewable energy.

It should be noted that the LCOH baseline estimates do not factor in the wider policy environment and the cradle-to-grave emission intensities of each technology. Velaquez and Dodds (2020) argue that lifetime costs of implementation are needed to help producers take informed investment decisions. Without this, it is not possible to reflect the true price of H2 production. For example, CCS does not have a 100% capture rate and therefore, production is still likely to face a carbon cost, albeit discounted. e.g., a steel/cement plant covered under the EU Emissions Trading System (EU ETS) or the UK Carbon Price Support (CPS) of £18 per tonne of CO2 (£/tCO2). Moreover, CCS reduces the efficiency of the conversion process thus requiring greater quantities of natural gas to produce the equivalent amount of H2 (Quarton and Samstali, 2020).

Quarton and Samstali (2020) suggest that CCS is inherently an unsustainable concept due to its limited CO2 capture rates and capacity for storage. The UK has an abundance of natural storage options such as the salt caverns in North West England and depleted gas fields in the North Sea, but these are a finite resource. This implies that mechanisms to recycle captured CO2 will be needed to ensure sustainable CCS facilities. As such, without policy intervention there is no clear business case for CCS technology with some estimates indicating the technology may increase the costs of SMR-based H2 by between 40-100% (Gilfillan *et al.,* 2015). Direct command-and-control policies are needed with tight fiscal rules on tax and emissions to ensure decarbonisation is guaranteed (Nazir, *et al.*, 2019).

For Green H2, the Hydrogen and Fuel Cell Joint Undertaking (HFCJU) calculates that an electricity price over £0.04/kWh effectively excludes Green H2 on a competitive basis with other technologies (HFCJU,2019). UK wholesale power prices are almost three times this amount today while gas is significantly cheaper (HFCJU, 2019). Helm (2017) argues that the UK's high electricity prices are primarily the result of flawed government policies in the past, specifically the lavish spending under the now defunct Renewables Obligation (RO) programme. Ironically, it is the side-effects of this ambitious policy support that could now pose a long-term barrier to Green H2 as governments refuse to support new technologies at any cost.

However, Velaquez and Dodds (2020) suggest that policymakers could take immediate steps to level the playing field for Green H2 at a limited cost to the public purse. For instance, introducing a new Guarantee of Origin (GOs) scheme to certify that grid sourced H2, produced via electrolysis, is from renewable energy output. The revenues from the GOs could be used to deploy more low-carbon technologies or granted to the electrolyser industry as a subsidy. In the near term, this would improve the economics of Green H2 by removing the need for direct co-location with renewable energy plants or long-distance connections. It would also provide electrolyser manufacturers with a longer grace period to reduce capital costs (Bloomberg New Energy Finance, 2020).

While the economics and current policy frameworks may demonstrate clear disparities, it is important to acknowledge that Blue and Green H2 will not necessarily be competing in the same sectors and that cost components alone do not define whether there is an economic case for H2. Glenk and Reichelstein (2019) suggest that Green H2 is already competitive for niche applications such as small-scale community projects and remote off-grid locations at a price of £2.90/kgH2 due to the cost savings achieved in reducing curtailment hours for onshore wind. By maximising the output from onshore wind, this boosts revenues and has positive knock-on effects for LCOH of Green H2 over project lifetimes. However, they also acknowledge that Green H2 may not be ready to compete at industrial level within the next decade (Zhao *et al,* 2018).

Type	Characteristic	Policy drivers	Purpose	Objective	Barrier
Blue H2					
	Low carbon	Carbon Price Support	Low-carbon investment incentive/emission reduction	Polluter-pays-principle/ continued fossil fuel use	Low level of £18 failing to drive low-carbon investment
	Scalable	Emissions Performance Standard	Regulate emission intensity of conventional power generation	Encourage deployment of CCS technology	Does not remove natural gas sourcing or use for power production
	Non-renewable source	Domestic natural gas availability	NA	NA	Competitiveness closely tied to natural gas performance as feedstock
	Viable heat solution	Renewable Heat Incentive	Rewards consumers for using low-carbon heat solution	Phase out natural gas for alternatives	Requires investment and deployment before applicable
	Immature (CCS)	CCS Innovation Programme	Supporting nascent technology in industrial application	Scaling up immature industry to meet climate goals	At £24 million, relatively small pot of funds for projects
Green H2					
	Low carbon	Carbon Price Support	Low-carbon investment incentive/emission reduction	Polluter-pays-principle/ continued fossil fuel use	Low level of £18 failing to drive low-carbon investment
	Renewable source	Contracts for Difference	Dedicated market-based support scheme for RES technologies	Foster cost-competitive low carbon deployment	Competing with mature tech. Negative bidding may price out H2 in future
	Power-to-gas	Capacity Remuneration Market	Create competitive market for flexible, secure power	Ensure affordable security of supply for UK consumers	Competing with CCGT and other more competitive RES producers on price
	Flexible	Balancing Mechanism	Financially rewarding ancillary services (voltage, frequency)	Place system stability responsibility on generators	Lack of revenue and capacity of electrolysers to meet government standards
	Immature (electrolysers)	No electrolyser support	NA	NA	Still expensive relative to other conventional heat technologies
	Small scale	Renewable Heat Incentive	Reward domestic consumers for switching to low carbon heat	Encourages phase out of natural gas use	Limited electrolyser capacities ensure Green H2 distributed solution only

Table 1: Interrelationship between H2 technical characteristics and UK energy policy instruments

4. Policy and technology interaction for green and blue hydrogen

Table 1 summarises the interrelationship between H2 technical characteristics and UK energy policy instruments for both Blue and Green H2. Their technical characteristics have been examined against the relevant policy drivers and the main barriers faced by each of these technical characteristics have been identified.

H2 is widely considered in political circles as a low-emission and sustainable energy source that can contribute to national and international climate targets. It could play a pivotal role in hard-to-decarbonise sectors such as industrial processes and space heating where electrification may be less appropriate or very expensive.

Keay (2018) argues that H2 cannot rely purely on market forces in the short-term and government support in the form of feed-in tariffs (FiTs) will be necessary for continued development. He also suggests the level of this intervention for H2 will be even greater than the past policy support provided for renewables such as wind and solar. This would imply very negative consequences for taxpayers, particularly as the *Cost of Energy Review* commissioned by the UK government in 2017 estimates that historic subsidies for wind and solar will already add over £100 billion to consumer bills by 2030 (Helm, 2017).

However, these arguments give little consideration to the '*polluter pays'* instruments in place to deter new investment in conventional technologies and encourage the transition to low-carbon fuels. Many of these targeted policies did not exist in the early 2000s and therefore technologies such as wind and solar required significant financial inflows to compete with unabated coal and gas. The situation for H2 development is likely to be very different, as many more climate policy instruments are now operational and will likely increase in stringency in the future. For Green H2, Keay (2018) does not acknowledge the probability of higher carbon prices in the medium to long term. As a result, it is imprecise to forecast prospects for H2 based on previous methods to subsidise low-carbon technologies. As evidenced by the introduction of CfDs, policymakers are more fiscally conservative in supporting renewable energies today, and any subsidy must be awarded on the outcome of a market-based or competitive tendering process.

4.1. Impact of 'polluter pays" policies on Blue H2 competitiveness

The technical characteristics of H2 production may weigh on the near-term support and thus limit H2's ability to gain market share. For example, CCS has a CO2 capture rate of between 65-90%. The UK government requires a minimum target of 90% to be achieved for Blue H2 to qualify for regulatory support beyond the pilot projects already in development (BEIS-a, 2020). This benchmark for environmental performance will be critical for CCS's prospects as producers weigh up the cost-benefit of capturing CO2 versus simply paying a carbon penalty in the form of a tax.

Nazir *et al.* (2019) argue that when 90% of CO2 is captured in an SMR process, the cost of CO2 avoided is between £10-20. Based on existing policy, installing the most efficient CCS, in a best-case scenario, would present a limited net gain versus opting to pay the CPS levy. However, in instances where the capture rate is between 65-80%, the cost of sequestering carbon rises exponentially to around £95 per tonne (Bundis *et al*., 2018). This would suggest the government's current carbon price would need to increase by a multiple of five to offset and incentivise investments in the most inefficient CCS projects. As it is unlikely that the CPS or the EU ETS will deliver such levels within the next decade, it is difficult to make an economic case for CCS technology.

Blue H2 may require utilisation and monetisation of CO2 through methanol production or Enhanced Oil Recovery (EOR). Not only would this improve the economic picture for CCS, but it would also ensure that storage capacity is sustainable in the long term. However, such a solution does not advance the case for Blue H2 as a decarbonised energy source on a lifecycle basis. Armstrong and Styring (2015) claim that in most cases the emissions impact of CCS lifecycles, when utilisation is included, is more detrimental than simply burning a fossil fuel resource in the first instance. This is an important consideration as nearby transportation, compression and storage all add to the emission-intensity of CCS projects. If naturally formed caverns are near to a H2 conversion and CCS facility, as with the HyNet pilot in the UK, then the impact of utilisation is muted. But this is unlikely to be the case for all CCS deployment in the future. Therefore, UK policy will need to price in these ‘externalities’ into the overall social cost of carbon. At present there is no policy vehicle to address this, meaning the economic and environmental profile of CCS cannot be fully realised in today’s cost assumptions (Abdin *et al.* 2020).

Emission estimates for unabated SMR without CCS currently stand at approximately 285gCO2/kWh, which ensures it is well below the cap imposed under the UK’s Emissions Performance Standard (EPS) if the H2 produced was intended for power generation (Committee on Climate Change, 2020). The impact of the UK’s EPS has been limited in driving a low-carbon transition. The current cap of 450gCO2/kWh fixed until 2044 excludes unabated coal but modern Combined Cycle Gas Turbines (CCGT) still meet the requirements (BEIS, 2011). As such, there is little incentive to convert to H2 for power production or to invest in CCS technology. Given the government’s aim to phase out coal by 2025, this would leave a 19-year gap where CCGT and natural gas could operate comfortably with unabated emissions unless the EPS limits were revised, or more stringent climate policy applied.

Popa *et al.* contend that power plants, including CCGTs, will need to operate at 100gCO2/kWh if the UK is to meet its net-zero goal by 2050. To achieve this, gas plants should not continue to run without CCS technology beyond 2030 (Popa, *et al*., 2011). This gives power and H2 producers the opportunity to delay installation or conversion plans well into the late 2020s while still adhering to government guidelines. Even then, there is no economic incentive in existing policy beyond the moral compliance argument.

Nazir (2019) and Popa *et al.*’s (2011) arguments demonstrate how policies designed to stimulate change, namely the CPS and EPS, are currently undermining Blue H2 and

CCS integration. While the EPS does not apply directly to H2 production, it dampens industry appetite to invest in new technologies and source alternative fuels. Research and innovation suffer and ultimately, a technology such as CCS remains perpetually uncompetitive due to lack of interest and support.

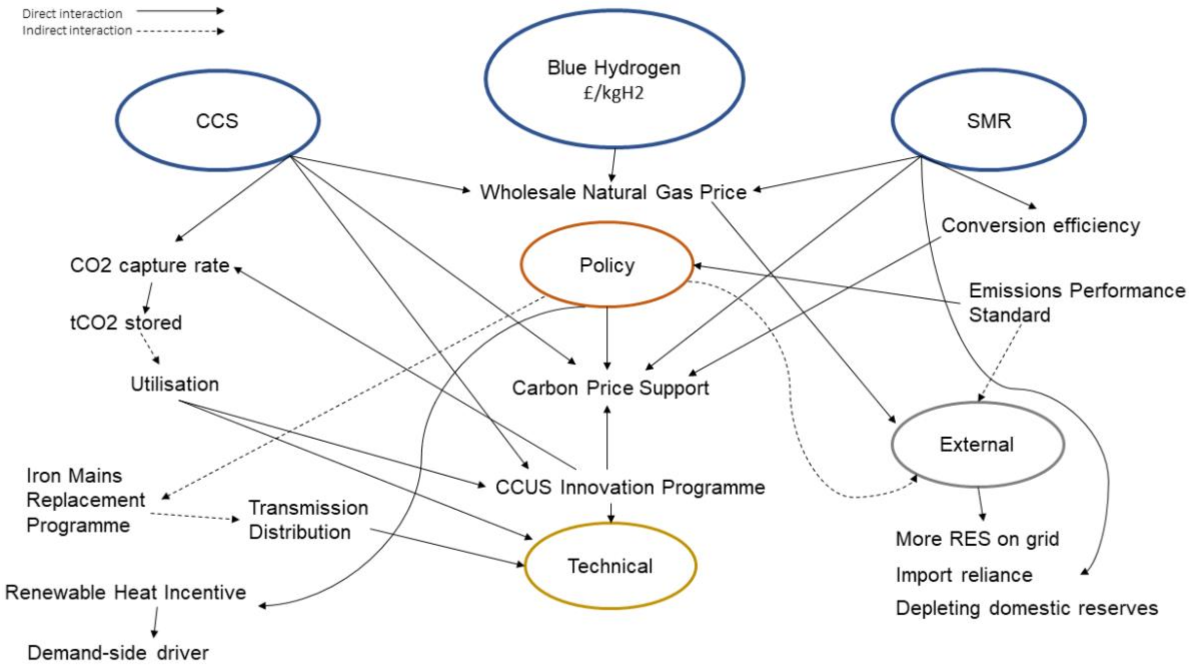

Figure 1: Policy and technical interactions for Blue H2 projects in the UK

4.2. Integrating Green H2 into market-based support schemes

Many of the same policy barriers to Blue H2, whether intentional or not, also apply to Green H2, specifically reduction in technology costs.

Proost (2020) clearly identifies the elements of Green H2's cost profile that need to be addressed from a technical perspective, namely CAPEX, OPEX, optimisation in installation and fuel (electricity) costs. However, he excludes the cost of policy and the indirect impacts of UK regulatory frameworks with regards to supporting technologies. For example, despite the UK's 13.5GW of installed onshore wind capacity, the regulatory environment has not been favourable to developers in recent years (RenewableUK, 2020). Since 2015, mainland projects have been excluded from competing in the CfD tender process and new projects were required to operate on a merchant basis e.g., relying on the wholesale electricity price to deliver profitability. In 2020, onshore wind's exclusion was revoked, and developers can now compete in the CfD process. A return to the feed-in premium (FiP) for onshore wind could be considered a positive for H2-produced via electrolysis, particularly if the government encourages co-location. However, the rapid cost reduction of onshore, a glut of new developers bidding aggressively for government support combined with high wholesale electricity prices, could have the opposite effect for aspiring H2 production.

In such a situation, onshore wind potentially becomes a victim of its own success by paying back the difference between the inflated wholesale price and the competitive strike price. This could even result in negative bidding below £0/MWh between developers. The Department for Business, Energy and Industrial Strategy (BEIS-b, 2020) acknowledged this in its latest CfD design consultation: "*We expect that some of these technologies have the lowest costs and would be able to secure CfDs at strike prices below the average expected wholesale price for electricity, and so over the course of a contract may pay back as much, or more, than they receive in CfD top-up payments."*

The issue of negative bidding is important because it could act as a deterrent to onshore wind deployment in the UK, which in turn would hinder the prospects for cost competitive Green H2. One solution to this market distortion would be to package an onshore wind farm, electrolyser and H2 storage into a single project that can compete in a CfD. While this would result in a higher strike price than a standalone onshore wind project, it would reinstate the CfD as a regulatory mechanism for low-carbon support rather than simply a *de facto* tax revenue instrument for already mature technologies. McDonagh *et al.* (2020) argue that policymakers must examine the holistic benefits that hybrid projects such as PtG offer when considering incentives. These are labelled as '*positive externalities'* such as flexibility, reliability and decarbonisation. Savings resulting from these characteristics far outweigh the high upfront investment costs for PtG projects. By examining these benefits in the UK CfD context, it's possible to argue that while the overall H2 project costs would be higher than a standalone onshore wind project, a PtG installation would still provide multiple system and economic benefits that could not be achieved by a power-only unit.

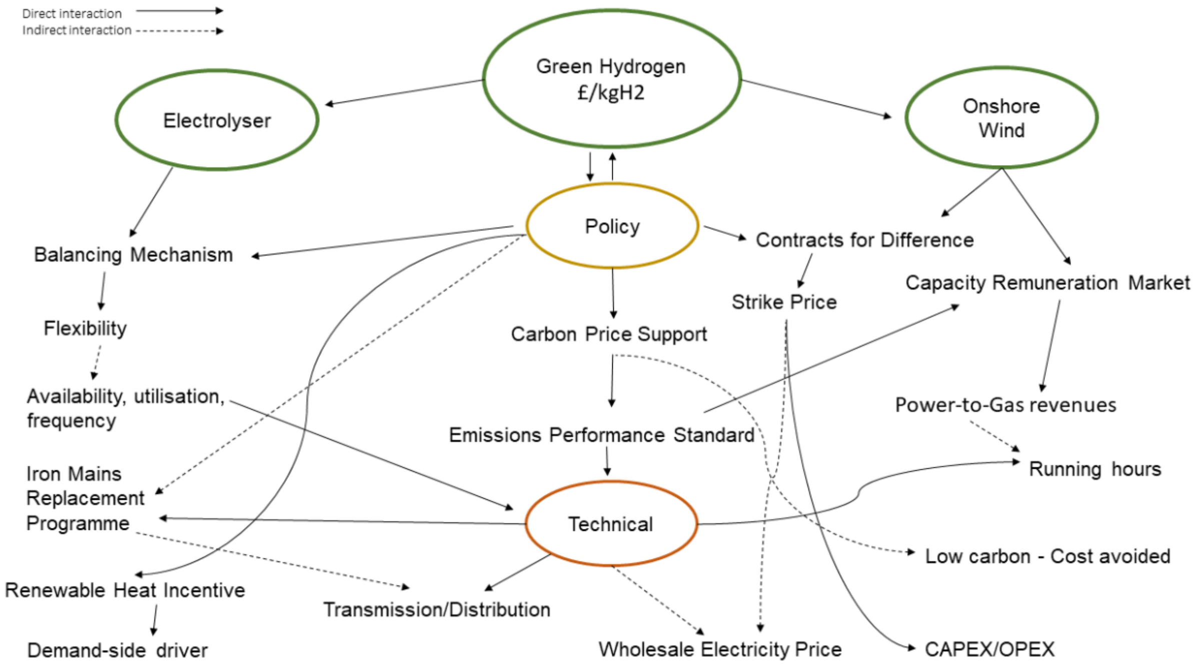

Figure 2: Policy and technical interactions for Green H2 projects in the UK

4.3. Blue and Green H2 in security of supply and balancing responsibility policy

H2 presents a range of system-wide benefits by serving as a low-carbon flexible fuel supply whether produced via a Blue or Green process. Eichman *et al.* (2016) argue that the presence of the capacity (CRM) and balancing markets (BM) could provide a source of much needed revenue to H2 producers. Not only would it prove attractive to existing CCGT operators looking to avoid climate levies such as the carbon tax/EU ETS price, but it would also provide H2 producers with an incentive to sell to third-party generators for power production purposes. Moreover, because the CRM auctions capacity for delivery 1-to-4 years ahead of time, access to this market ensures H2 producers gain visibility on price and volumes, which is crucial for long-term cost reduction and attracting capital investment. This would be particularly valuable for Blue H2 developers seeking alternative markets for hydrogen beyond industrial users (Massol *et al*, 2018). The importance of these market instruments is only likely to grow over the short-to-medium term as variable renewables increase penetration in the power sector and the need to offset intermittency becomes more pronounced.

For Green H2, the challenge is more complex. In theory, an onshore wind farm could establish a dual connection to an electrolyser and the national grid to participate in the CRM separately when H2 production is not possible or required. Moreover, Green H2 could provide ancillary services to the network and earn additional revenues via the UK's BM by participating in frequency and voltage control. Xing *et. al.* (2019) and Alshehri *et al.* (2019) highlight that Proton Exchange Membrane (PEM) electrolysers are very flexible. The technology can ramp up and down to change electricity consumption in less than one second, while shutting down and restarting is possible within only a few minutes. Given the UK's high penetration of renewable energy and relatively low-capacity margin, demand for ancillary services is likely to increase. Not least as the government plans to shutter all existing coal capacity by 2025 and many existing nuclear plants come offline within the next 15 years. Whether small-scale Green H2 producers could harness these policy instruments and revenue streams effectively to improve the economic case for the technology remains to be seen. But producers can take encouragement from the previous performance of other distributed resources, specifically diesel generators, that have secured lucrative long-term contracts on both the CRM and BM in the past.

As a summary of the discussion in this section, the policy and technical interactions for Blue and Green H2 projects in the UK have been visualised in Figures 1 and 2, respectively.

5. A financial model and economic evaluation of hydrogen production

A financial model has been composed for two theoretical projects producing H2, one via an onshore wind farm and electrolysis and the second with SMR and CCS. The model details the relevant technical characteristics and assigns monetary values to policy instruments to assess the impact on the economic case for H2 in the UK. Based on these values, a net present value (NPV) can be calculated for each project to determine overall profitability. The NPV is calculated as the sum of discounted net cash flows:

$$NPV = \sum_{t=0}^{N} \frac{CF(t)}{(1+i)^t} \tag{1}$$

where, $CF(t)$ is the cash flow in time period t, i is the discount rate, and N is the total number of periods (years) in the projects. The initial cash flow, $CF(0)$, represents the initial investment (CAPEX) of the project. For the subsequent periods, the cash flow is calculated as:

$$CF(t) = REV(t) - CAPEX(t) - OPEX(t) \tag{2}$$

where, $REV(t)$ and $OPEX(t)$ are the annual revenue and operational expenditure in time period t, respectively. Any future investment, $CAPEX(t)$, will be deducted from the cash flow of that period. The revenue stream consists of income of direct sale of H2, saving made in carbon emissions, and the income related to the applicable policy instruments.

In this section, the assumptions and cost elements are discussed for Green and Blue H2 production only. The costs and technical characteristics for both technologies are based on current consensus estimates from international institutions and governmental departments including the European Commission-sponsored Fuel Cells and Hydrogen Joint Undertaking (FCH JU), the Department for Business, Energy and Industrial Strategy (BEIS) and the International Energy Agency (IEA) among others.

Not all policies are applicable to both H2 production types and this is discussed further in the findings and results. The key policies assessed include the Contracts for Difference

(CfD), the Balancing Mechanism (BM), Capacity Remuneration Mechanism (CRM) and the Carbon Price Support (CPS). Supplementary policies such as the Renewable Heat Incentive (RHI), the Iron Mains Replacement Programme (IRMP) and the Emissions Performance Standard (EPS) are important contributing factors to lifecycle costs and are discussed as part of a holistic analysis of the policy environment. It is difficult to credibly price the impact of downstream policies on a project-specific basis and for that reason they are not quantified in the model.

5.1. Context and modelling assumptions – Green H2

The Green H2 model assumes a production cost of £3.6/kgH2 based on electricity sourced from a small-scale 50MW onshore wind farm co-located with a 10MW PEM electrolyser (HFCJU, 2015). For the model, a 10% profit margin on the production cost is priced in at wholesale, resulting in a retail value £4/kgH2 and an annual output of 1,300 tonnes (HFCJU, 2019). The profit margin is deliberately modest to ensure the emphasis remains on policy drivers for economic viability rather than forecast market demand.

A capacity factor of 33% is set for the onshore wind farm and a low-end efficiency at 60% for the electrolyser, with 80,000 running hours assigned to the latter (Godula-Jopek, 2015). Lifespans of 15 and 25 years are expected for the electrolyser and onshore wind farm respectively while capital expenditures (CAPEX) for each technology are represented separately in the NPV model at £7.5 million and £61 million (WindEurope, 2019). This is to highlight the impact of pairing a mature and immature technology within the same project.

For policy costs, the CPS is set at £18/tCO2 with the UK government fixing this price until at least the end of 2022 (BEIS-c, 2020)**.** The CPS was included to establish whether there would be any substantial indirect savings as a result of the CO2 avoided by producing electrolytic H2 versus SMR+CCS. It is unclear whether the CPS will increase over the next 10 years to ensure the UK can meet its carbon budgets under its net-zero 2050 commitment (Bui *et. al.*, 2018).

The research assumes that the hybrid nature of the Green H2 project will allow the developers to compete with other renewable energy sources under the CfD. As a result, using the wholesale electricity price in this model is largely irrelevant unless drastic fluctuations jeopardise long-term contract agreements with the state. As discussed in the literature review, mainland onshore wind projects were excluded from the UK CfD in 2017 so there is little evidence to show how cost reduction in the last three years may impact the strike price secured in auctions. On this basis, the research assumes the most recent CfD results for onshore wind of £40/MWh (BEIS, 2015).

The BM run by National Grid also represents an important policy instrument for Green H2. As discussed, the flexible nature of electrolysers means they could also participate in the BM to assist the grid operator in system stability. The research assumes that an electrolyser would be able to offer 10% of its total running hours to availability and frequency control. An additional assumption that only 5% of total runtime would result in utilisation e.g., ramping production up or down to balance the system. For this, the research uses National Grid's 2019 prices: Availability - £7.06/MWh, frequency - £11.50/MWh and utilisation - £44.91/MWh. For this model, the revenues are assumed for a single project, but as electrolysers become more prevalent in the energy system, there may an option for them to act as cooperatives to form a 'virtual power plant' and to share revenues.

The CRM is another vehicle for the onshore wind element of the project to supplement H2 volume sales. The model assumes that the wind farm would have a dual connection to feed the electrolyser and provide power to the grid when available. This research assumes a price of £15.97/MWh based on the government's most recent bidding round in 2019 (BEIS-a, 2019). Like the BM, the model diverts 5% of the onshore wind farm's running hours over its lifetime to the CRM as an additional revenue stream for the overall Green H2 project.

For the purposes of this research, three key variables were adjusted to assess the impact on the economic profile of Green H2 if low-carbon policies were pursued more aggressively. Two variables are policy-related – the CPS and the CfD strike price - and the other is a technical change – the capacity of the wind farm serving the electrolyser. The latter is important as the potential output of the wind farm provides additional opportunities for a Green H2 project to participate in the power as well as the gas market.

The revenue of a Green H2 project therefore is calculated as:

$$REV(t) = P_{H2}.pr_{H2} + h_{wf}.W_{wf}.r_{policy} \qquad (3)$$

where, P_{H2} is the total annual production of H2 in tonnes, pr_{H2} is the unit price of the green H2, h_{wf} is the total number of hours of operation of the wind farm, W_{wf} is the power rating of the wind farm [MW], and r_{policy} is the income through the policy instrument in [£/MWh]. The latter accounts for the CRM, BM and CfD supporting mechanisms.

5.2. Context and modelling assumptions Blue H2

For Blue H2, the model assumes a lower production cost of £1.4/kgH2 with a wholesale price of £2/kgH2 to reflect a 25% profit on every unit of H2 sold (HFCJU, 2015). This higher profit margin reflects the relative competitiveness of Blue H2 production and the need to insulate against fuel price fluctuations. For a realistic assessment, the CAPEX, OPEX and annual production of Blue H2 are based on estimates from HyNet in the North-West of England, a pilot project designed to serve local industrial demand (Cadent, 2019). The figures are significantly higher than those for Green H2 as the annual volumes produced are estimated to be 100 times greater (BEIS-b,2019). Like Green H2, the model assumes a lifespan of 25 years for the SMR processor and an efficiency of 80% (Quarton and Samstali, 2020). There is no lifetime attributed to CCS but a capture rate of 90% of CO2 is accounted for. This is important because a Blue H2 plant would still be subject to the CPS for the 10% of CO2 *not* captured by CCS. A 90% capture performance is also essential for any CCS project in the UK to qualify for government's dedicated fund – the Carbon Capture and Storage Commercialisation Programme (National Audit Office, 2017). Given the wide capture range for CCS, the model allows for this to be varied to illustrate how an inefficient CCS installation would impact the economics of a Blue H2 project. The CCS storage capacity is assumed to be 150 million tCO2 in line with the HyNet project. The storage facility is a naturally formed, onshore salt cavern and the cost of maintenance is included in the OPEX. It is assumed that production, consumption and storage are located close together.

For this research, it was not possible to model the financial impact of this policy incentive as it would require a full picture of the demand-side characteristics. Like Green H2, the Blue H2 model has three variables. Values were altered for one policy variable and two technical variables, namely the CPS, wholesale natural gas price and the price per kg of H2. The revenue of a Blue H2 project is the income of sale of H2. The additional OPEX related to use of natural gas and cost associated with the carbon emission is counted for in the revenue as:

$$OPEX(t) = OPEX_{plant}(t) + C_{NG}.k_{H2-NG}.P_{H2} + u_{CO2}.P_{H2}.k_{H2-CO2}.CPS \qquad (4)$$

where, $OPEX_{plant}$ is the OPEX of the plant excluding the cost of natural gas and carbon tax. The cost of natural gas is C_{NG}in [£/MWh], k_{H2-NG} is the MWhs of natural gas required to produce one tonne of Blue H2, P_{H2} is the annual H2 production. In equation (4), the percentage of non-captured percentage of carbon is denoted by u_{CO2} while k_{H2-CO2} is the generated CO2 [in tonnes] for production of one tonne of Blue H2.

6. Findings and Discussion

6.1 Green Hydrogen

The CfD provides a unique revenue stabilisation framework that allows investors to project what price would be required on a PtG project to deliver profitability over a project lifetime. The model found that a Green H2 project would *not* be profitable at a strike price of £40/MWh under the CfD (see appendix A). Therefore, developers would need to secure a higher level of public support to cover CAPEX and OPEX. It is only when the strike price in the model is raised to £65/MWh, still a relatively competitive price for a new technology, that a Green H2 project could realistically reach profitability (see appendix B). Crucially, the bulk of any revenue would come from the onshore wind farm and this would depend on access to other policy mechanisms. The electrolyser remains unprofitable unless the wholesale price of H2 goes above the £4/kgH2 level or CAPEX is reduced by approximately 25%. The results illustrate how dependent Green H2 and electrolysers are on the cost-competitiveness of onshore wind to deliver zero-marginal cost electricity for PtG conversion.

It is important to consider how a co-located onshore wind farm with electrolyser can improve the prospects for both technologies. For example, improving the economics of a Green H2 project in the near term will rely on sourcing electricity from the cheapest form of power generation available e.g. onshore wind (Bloomberg New Energy). In turn, onshore wind can command higher levels of support under government programmes to offset electrolyser costs while also improving utilisation rates through increased running hours. As discussed, this eliminates the risk of negative bidding in the CfD for highly competitive technologies. To an extent, Green H2 solves this problem by pairing a very mature form of power generation with a very immature form of gas production under the umbrella of a single project bidding in the CfD. The accessibility of the CfD can also provide positive knock-on effects on CAPEX and cost of capital (usually 10%) for a Green H2 project by reducing associated risks of new technologies. Higher utilisation rates for onshore wind can also help to eliminate the curtailment risk. Removing this problem would likely have a positive price impact for the Green H2 installation, developer and public finances under the CfD.

The model found that the CPS has a very limited impact on revenue or savings for Green H2 at a price of £18/tCO2. Green H2 as a production process is almost CO2 free and savings can be quantified in terms of CO2-price-avoided as a result of producing low carbon gas compared to the same volumes produced through natural gas. The results show that these savings from avoided CO2 would be negligible. Even if the CPS was doubled to £36/tCO2, there would still be little incentive to invest in Green H2 on this basis alone as it would not deter investments in conventional generation such as natural gas. As such, the policy pricing - fixed until 2021 - does not lend Green H2 a competitive edge nor does it improve the economic case for investment.

The model assumed that the electrolyser in a Green H2 project could also participate in the BM markets to provide ancillary services. Based on 2019 auction results from National Grid, the model found that a Green H2 project could generate between £180-200,000 in revenue each year by providing availability, frequency and utilisation response to the grid operator. While these revenue estimates are not insignificant, the results show that the BM income would not deliver profitability for the electrolyser as a standalone technology. BM and ancillary service payments per MWh would need to double for an electrolyser to be profitable based on current CAPEX and OPEX costs. However, as electrolyser deployment increases, developers could feasibly cooperate to form virtual power plants that could provide National Grid with a larger source of flexible demand response when needed thus potentially increasing revenues over the long term.

The CRM is another policy-revenue channel open to Green H2 projects by utilising the power-generating asset at times when H2 is not produced. This would involve connecting a wind farm to the power grid in addition to a direct connection to the electrolyser for H2 production. In theory, this would provide the perfect complement to a

Green H2 project by maximising running hours and output from an onshore wind farm. In times of oversupply on the electricity system, H2 could be produced and stored for later use. In times of scarce supply, onshore wind energy could pivot to provide back-up capacity to the grid and receive additional payments for this service.

The results showed that if 5-10% of running hours provided back up through the CRM, the Green H2 project could generate revenues of between £150-290,000 annually at a price of £15.91/MWh. This has a significant bearing on the financial case for Green H2 by further improving the economic attractiveness of onshore wind to offset the immaturity of electrolyser technology. This would also likely have knock-on benefits for the average onshore wind capacity factor across a given year beyond the current 40% assumed for a Green H2 project in this research model. From the results, it is possible to conclude that economic viability of onshore wind and continued cost reduction progress is vital to the feasibility of Green H2 over the long term.

6.2 Blue Hydrogen

For Green H2, there is a myriad of policy instruments for additional revenues through the CRM, BM and CfD. By contrast, the scope of accessible policy instruments for Blue H2 is very limited. However, Blue H2 still appears to be far more cost competitive on a £/kgH2 basis and profitable in terms lifetime revenues. This is largely due to the significant price disparity between low wholesale natural gas and electricity in the UK. Moreover, the higher CAPEX and OPEX of Blue H2 is offset by the vast volumes that can be produced over the project lifetime, which cannot be matched by a PtG installation. Like Green H2, Blue H2 pairs a mature and competitive process (SMR) with a very immature technology (CCS). The result is that profitability is dependent one side of the project to counterbalance the unprofitability of the other.

Despite Blue H2's profitability today, at least 70% of the OPEX is accounted for in fuel costs, specifically natural gas (Collodi *et al.* 2017). This means Blue H2 projects are highly sensitive to changes in availability and price of natural gas. If this were to remain constant, the model suggests Blue H2 would be continuously profitable over its lifetime (see appendix C). However, the prospect that natural gas prices will remain unchanged over the lifetime of a project is highly unlikely. As such, the findings suggest Blue H2 is a high-risk investment today as it is difficult for developers to provide accurate forward guidance on profitability. This is compounded by the absence of revenue stabilisation instruments, such as the CfD, for SMR-produced H2. When the natural gas price is increased by 20% in the model, the Blue H2 project becomes loss-making (see appendix D). To address this, a producer could increase the cost of £/kgH2 at wholesale, but this again would call into question the competitiveness of the Blue H2 technology.

The Committee on Climate Change (2019) expects the price of natural gas to rise by 30% over the next 5 to 10 years, which would present economic challenges to Blue H2 projects unless other revenue streams can be accessed. This forecast is based on three underlying trends: 1) Depleting domestic resources resulting in costlier exploration and extraction activities; 2) Higher penetration of renewables and electrification at the local and national level, creating less demand for gas; 3) Increasing reliance on interconnectors, imports and relatively expensive options such as LNG.

Policies for low carbon transition, specifically the CPS, have little impact on the economics of the Blue H2 project at current levels. From a financial perspective this is positive for the developer because it results in less revenue allocated to decarbonisation taxes. The model suggests a carbon price of at least £50/tCO2 would be required before a Blue H2 project would become unprofitable based on current technology, fuel prices and £/kgH2. Such a price shift is unlikely to occur in the UK in the short-term, but it is possible this could be reached in the next 10-15 years or within the lifetime of a Blue H2 project. As such, developers may be wary of investments today in SMR and CCS that could result in stranded or unprofitable assets over the long-term if the government's net zero agenda gains momentum (Napp *et al.* 2014).

Based on current estimates, Blue H2 would need to sell H2 at a wholesale price of around £2/kgH2 to ensure very modest profitability. This is the upper limit of what is considered cost competitive by policymakers, with the European Commission highlighting a price target of around £1.70/kgH2 within the next five years under its new EU Hydrogen Strategy (European Commission, 2020). This £2/KgH2 figure does not include the strong likelihood that the CPS will rise within the next decade but nor does it consider technological improvements and cost reduction learning curves driven by new supportive policies.

One question mark for Blue H2 is the storage and use of CO2 after the SMR process. The model assumed that approximately 14 million tCO2 could be saved annually with a storage site located close to production, but no monetary value was assigned. The project economics for Blue H2 could change if the CO2 stored could be recycled and commercialised for different purposes such as alternative fuel production of Enhanced Oil Recovery. If this could be achieved, it represents a potential revenue stream for Blue H2 outside of the H2 production and sale. Alternatively, as Blue H2 prevalence in the UK increases, CfD-style schemes could be introduced to incentivise the storage of CO2 at a competitive cost

Finally, the EPS has little impact on Blue H2 as it relates principally to the generation of electricity from fossil fuels. However, its generous limits allow natural gas to be used in the power sector through CCGTs that are CCS-ready. While there are no direct implications for Blue H2 here, it does not advance the case for natural gas phase out as a primary fuel source on a long-term time horizon. As a result, natural gas is not only a feedstock fuel for Blue H2 but also a strong competitor for the wider H2 industry at a time when decarbonisation is high on the political agenda. This research has deliberately avoided addressing the myriad of challenges and opportunities in the downstream sector and demand-side policies. It is important to acknowledge that policies such as the Renewable Heat Incentive could have very positive impacts on the production and the economic case for H2 as consumers are incentivised to use the fuel, but this is an issue for further research.

7. Conclusions

Based on the modelling, the research concludes that there is an ‘economic case’ for both Green and Blue H2 based on existing UK policy, but only in very specific circumstances. Both could feasibly be competitive if channels for additional revenues are fully exploited and if drastic fuel price fluctuations are avoided. Moreover, in early development both production technologies would need to be located close to points of consumption to avoid the costly logistical downstream challenges.

Of the H2 production methods assessed, the model suggests that Blue H2 is the most profitable and competitive technology for deployment today if production and consumption are localised to serve industrial clusters and surrounding communities. While Blue H2could not compete with the direct use of natural gas in homes and businesses, it wouldn’t require high quantities of public subsidies to operate either. Blue H2 is the most likely solution for H2 use in industrial processes largely due to the significant volumes developers can produce annually, an equivalent of3TWhs. These same consistently high volumes are also key to a project’s long-term profitability As discussed in the findings, the current CPS does not present a particularly challenging financial hurdle for investors at today’s level and would need to reach at least £50/tCO2 before a project would face a squeeze on profitability. However, there are more pertinent challenges for Blue H2 going forward that may present significant investment barriers for developers today. These include uncertainty and vulnerability to fluctuating gas prices, which make up a significant share of OPEX. An increasing carbon price would also present competitiveness issues as would failure to monetise CO2 in the long-term or improved efficiency in CO2 capture rates for CCS. These issues taken together could mean that the case for Blue H2 diminishes over time with the risk of stranded assets, particularly as governments introduce more stringent rules on even the lowest levels of pollution.

Green H2 has a unique situation as a PtG technology. As this research has explored, it can benefit financially from the frameworks already in place for electricity generation as well as gas production. The modelling suggests that an onshore wind farm paired with an electrolyser can be profitable. However, only when selling H2 at a premium relative to natural gas or Blue H2 and accessing additional revenue streams through the CfD, BM and CRM. The existing model shows that Green H2 would require a minimum strike price of £65/MWh under the CfD. This is significantly higher than the most recent result of £40/MWh for standalone onshore wind, but still represents a competitive price point for a maturing technology Significant cost reduction is expected in the future as electrolysers grow in capacity and economies of scale deliver lower prices. Until then, Green H2 would be able to secure long-term strike prices, set for 15-20 years, for electricity and H2 production. This is a luxury that is not afforded to Blue H2 projects or natural gas for heating. Arguably, this could provide Green H2 with a competitive edge, particularly if the CPS level is increased in the 2020s. Increased utilisation rates for onshore wind as a result of avoided curtailment and dual participation will also improve project economics and H2 price points.

To summarise, Green and Blue H2 can both play a critical role in the UK government's 2050 net zero target both now and in the future. The policy environment is partially in place but more needs to be done to phase out other financially attractive, but polluting, technologies. Over the next decade, the UK government may consider a variety of new policy instruments and extensions of the current crop of incentives and deterrents that would allow H2 to flourish in a low-carbon economy. These upstream policies could include:

- Full access for electrolysers to participate in existing government frameworks to generate additional revenues and remuneration. For example, providing ancillary services such as voltage and frequency control as a highly flexible technology.
- A market-based tool to incentivize and monetize CO2 capture that will encourage private investment and to drive long-term cost reduction in CCUS technologies. This could take the form of a reverse auction whereby participants offer the most attractive price to capture an allocated number of tCO2.
- Increasing the Carbon Price Support well beyond its current level and a more stringent EPS that incentivises a shift away from gas production for use in power generation and industrial production.
- Continued commitment to wind energy deployment as the cheapest form of new power generation. Long-term regulatory frameworks, such as the CfD, help to reduce costs. Hydrogen deployment will depend on cost-competitive wind energy in the short and medium term to ensure that it is not economically prohibitive.
- A research and innovation agenda that facilitates the scale-up of the electrolyser capacity and power-to-gas technologies that will allow developers to produce larger volumes of Green H2.

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Appendix A: Green H2 model based on access to current UK policy instruments with CfD strike price of £40/MWh

Value	Unit	Figure	Description
Fuel production			
Cost of H2 production	£/kg	3.6	The cost of producing 1 kilogram of H2 via electrolysis and onshore wind
Cost of H2 wholesale	£/kg	4	The price of 1 kilogram of H2 on wholesale market with 10% margin on production
Annual H2 production	tonnes	1,300	Quantity of H2 production from a 10MW electrolyser connected to 50MW onshore wind farm
Electrolyser			
Lifespan	Years	15	Expected lifetime of a PEM 10MW electrolyser
Operational	Hours	60,000-80,000	Estimated running hours for a PEM 10MW electrolyser
Efficiency	%	60	Conversion efficiency of power-to-gas electrolyser from onshore wind to Green H2
Capacity	MW	10	Maximum output of electrolyser
Capital expenditure	£ millions	7.5	Upfront cost of equipment, construction and installation
Onshore wind farm			
Capacity	MW	50	Maximum output of wind farm
Capacity factor	%	33	Actual output of wind farm divided by maximum capacity
Annual production	MWh	144,500	Annual electricity output from onshore wind farm
Capital expenditure	£ millions	61	Upfront cost of equipment, construction and installation
Operating expenditure	£/MWh	15	Cost of OPEX applied to the cost of output in MWhs
Policy costs			
Contracts for Difference	£/MWh	40	Strike price assumption of UK government support scheme for renewable technologies
Carbon Price Support	£/tCO2	18	The carbon floor price. The minimum cost of emitting 1 tCO2 in the UK
BM utilisation (5% hours)	£/MWh	44.91	A remuneration market for an electrolyser to provide flexibility to ensure system stability
BM availability (10% hours)	£/MWh	11.5	A remuneration market for availability to respond to ensure system stability
BM frequency (10% hours)	£/MWh	7.06	A remuneration market for providing frequency control to ensure system stability
Capacity Remuneration Mech.	£/MWh	15.97	A competitive market to deliver defined quantities of power at a set period in the future
Additional financial			
Discount rate	%	5	Discount cash flow over project lifetime of 15 years
Net Present Value (NPV)	**Unit**	**Figure**	**Description**
Electrolyser	£ millions	-1.2	Overall revenues (negative) for lifetime of electrolyser based on values and prices in model
Onshore wind	£ millions	-27.1	Overall revenues (negative) for lifetime of onshore wind based on values and prices in model
Total	**£ millions**	**-28.3**	**Overall profitability estimates of Green H2 project based on values and prices in model**

Comment: NPV must be positive for an investment to profitable

Appendix B: Green H2 model based on higher carbon price assumption and higher CfD strike price of £65/MWh

Value	Unit	Figure	Description
Fuel production			
Cost of H2 production	£/kg	3.6	The cost of producing 1 kilogram of H2 via electrolysis and onshore wind
Cost of H2 wholesale	£/kg	4	The price of 1 kilogram of H2 on wholesale market with 10% margin on production
Annual H2 production	tonnes	1,300	Quantity of H2 production from a 10MW electrolyser connected to 50MW onshore wind farm
Electrolyser			
Lifespan	Years	15	Expected lifetime of a PEM 10MW electrolyser
Operational	Hours	60,000-80,000	Estimated running hours for a PEM 10MW electrolyser
Efficiency	%	60	Conversion efficiency of power-to-gas electrolyser from onshore wind to Green H2
Capacity	MW	10	Maximum output of electrolyser
Capital expenditure	£ millions	7.5	Upfront cost of equipment, construction and installation
Onshore wind farm			
Capacity*	MW	75	Maximum output of wind farm
Capacity factor	%	33	Actual output of wind farm divided by maximum capacity
Annual production	MWh	144,500	Annual electricity output from onshore wind farm
Capital expenditure	£ millions	61	Upfront cost of equipment, construction and installation
Operating expenditure	£/MWh	15	Cost of OPEX applied to the cost of output in MWhs
Policy costs			
Contracts for Difference*	£/MWh	65	Strike price assumption of UK government support scheme for renewable technologies
Carbon Price Support*	£/tCO2	36	The carbon floor price. The minimum cost of emitting 1 tCO2 in the UK
BM utilisation (5% hours)	£/MWh	44.91	A remuneration market for an electrolyser to provide flexibility to ensure system stability
BM availability (10% hours)	£/MWh	11.5	A remuneration market for availability to respond to ensure system stability
BM frequency (10% hours)	£/MWh	7.06	A remuneration market for providing frequency control to ensure system stability
Capacity Remuneration Mech.	£/MWh	15.97	A competitive market to deliver defined quantities of power at a set period in the future
Additional financial			
Discount rate	%	5	Discount cash flow over project lifetime of 15 years
Net Present Value (NPV)	**Unit**	**Figure**	**Description**
Electrolyser	£ millions	-1.1	Overall revenues (negative) for lifetime of electrloyser based on values and prices in model
Onshore wind	£ millions	38.9	Overall revenues (positive) for lifetime of onshore wind based on values and prices in model
Total	**£ millions**	**37.8**	**Overall profitability estimate of Green H2 project based on values and prices in model**

Comment: NPV must be positive for an investment to be profitable

Appendix C: Blue H2 based on current carbon price support and wholesale natural gas price of £25/MWh

Value	Unit	Figure	Description
Fuel production			
Price of natural gas	£/MWh	25	The average cost of natural gas in the UK at wholesale (2019)
Cost of H2 production	£/kg	1.4	The cost of producing 1 kilogram of H2 via SMR with CCS
Cost of H2 wholsale	£/kg	2	The price of 1 kg of H2 on wholesale market with approx. 10% margin on production
Annual H2 production	tonnes	130,000	Quantity of H2 produced from an SMR + CCS facility using natural gas feedstock
SMR + CCS			
Lifespan	Years	25	Expected lifetime of an SMR plant
SMR efficiency	%	80	Conversion efficiency of natural gas to H2
CCS efficiency	%	90	CO2 capture rate of CCS technology
Capital expenditure	£ millions	920	Upfront cost of equipment, construction and installation
Operating expenditure	£ millions/pa	85	Cost of OPEX applied to the cost of output in MWhs
CCS volume capacity	tCO2 millions	150	Storage capacity of the CCS project based on the HyNet pilot project
Policy costs			
Contracts for Difference	£/MWh	NA	NA
Carbon Price Support	£/tCO2	18	The minimum cost of emitting 1 tCO2 in the UK. Blue H2 subject to 10% of price per tCO2
BM utilisation (5% hours)	£/MWh	NA	NA
BM availability (10% hours)	£/MWh	NA	NA
BM frequency (10% hours)	£/MWh	NA	NA
Capacity Remuneration Mech.	£/MWh	NA	NA
Additional financial			
Discount cash flow	%	5	Discount cash flow over project lifetime of 25 years

Net Present Value NPV	**Unit**	**Figure**	**Description**
Total	**£ millions**	**10**	**Overall profitability estimates of Blue H2 project based on values and prices in model**

Comment: NPV must be positive for an investment to be profitable

Appendix D: Blue H2 based on double carbon price assumption and 30% increase in natural gas price at £32.5/MWh

Value	Unit	Figure	Description
Fuel production			
Price of natural gas*	£/MWh	**32.5**	The average cost of natural gas in the UK at wholesale (2019)
Cost of H2 production	£/kg	1.4	The cost of producing 1 kilogram of H2 via SMR with CCS
Cost of H2 wholesale	£/kg	2	The price of 1 kg of H2 on wholesale market with approx. 10% margin on production
Annual H2 production	tonnes	130,000	Quantity of H2 produced from an SMR + CCS facility using natural gas feedstock
SMR + CCS			
Lifespan	Years	25	Expected lifetime of an SMR plant
SMR efficiency	%	80	Conversion efficiency of natural gas to H2
CCS efficiency	%	90	CO2 capture rate of CCS technology
Capital expenditure	£ millions	920	Upfront cost of equipment, construction and installation
Operating expenditure	£ millions/pa	85	Cost of OPEX applied to the cost of output in MWhs
CCS volume capacity	tCO2 millions	150	Storage capacity of the CCS project based on the HyNet pilot project
Policy costs			
Contracts for Difference	£/MWh	NA	NA
Carbon Price Support*	£/tCO2	**36**	The minimum cost of emitting 1 tCO2 in the UK. Blue H2 subject to 10% of price per tCO2
BM utilisation (5% hours)	£/MWh	NA	NA
BM availability (10% hours)	£/MWh	NA	NA
BM frequency (10% hours)	£/MWh	NA	NA
Capacity Remuneration Mech.	£/MWh	NA	NA
Additional financial			
Discount cash flow	%	5	Discount cash flow over project lifetime of 25 years
Net Present Value NPV	**Unit**	**Figure**	**Description**
Total	**£ millions**	**-307**	**Overall profitability estimate of Blue H2 project based on values and prices in model**

Comment: NPV has to be positive for an investment to be profitable

*Numbers in red represent adjusted values to reflect scenario of increased gas price and doubling of carbon price support