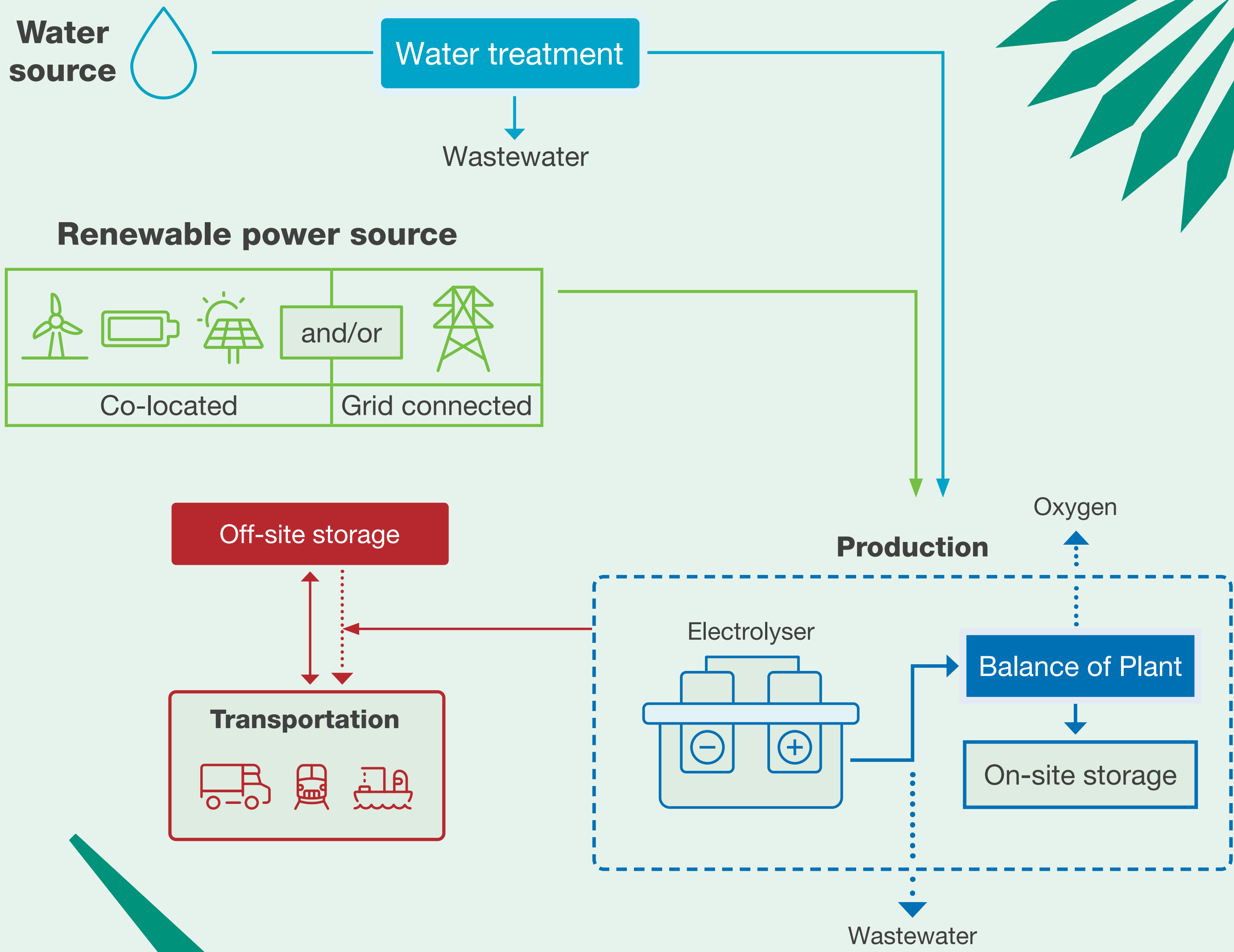
Demystifying the Hydrogen Business Model for Electrolysis



renewableUK

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Introduction

The green hydrogen economy is early in its development, with 700MW electrolyser capacity installed globally in 2022. This is expected to grow significantly, reaching between 175-420GW by 2030.[1] The UK's government recognises the economic opportunity, aiming to produce 10GW low carbon hydrogen by 2030 – with green hydrogen making up half of this – supporting over 12,000 jobs and potentially leveraging up to £11bn in private investment.[2] There is also a milestone target of 500MW low carbon hydrogen by 2025, including 250MW for green hydrogen.

Kickstarting this emerging industry will require initial support from government to de-risk and reduce the financing cost of early deployments. As such, the Hydrogen Production Business Model (HPBM) was introduced as a scheme which guarantees winners in each allocation round a price for the hydrogen they produce over the duration of the contract. Furthermore, it aims to facilitate the discovery of a competitive price for the hydrogen produced in the absence of multiple buyers and sellers, thus stimulating the development of an emerging market.

Nonetheless, the design of the HPBM has come under scrutiny for being overly complex and difficult to navigate for key stakeholders. As such, the primary aim of this guide is to unravel some of this complexity by offering a high-level explainer of how it works. Through interviews with industry, we will also shed light on some issues with specific elements within the scheme's design and provide recommendations to overcome these.

The UK's government recognises the economic opportunity, aiming to produce 10GW low carbon hydrogen by 2030 – with green hydrogen making up half of this – supporting over 12,000 jobs and potentially leveraging up to £11bn in private investment.

1. https://www.iea.org/reports/global-hydrogen-review-2023/executive-summary
2. https://www.gov.uk/government/publications/uk-hydrogen-strategy

Section 1

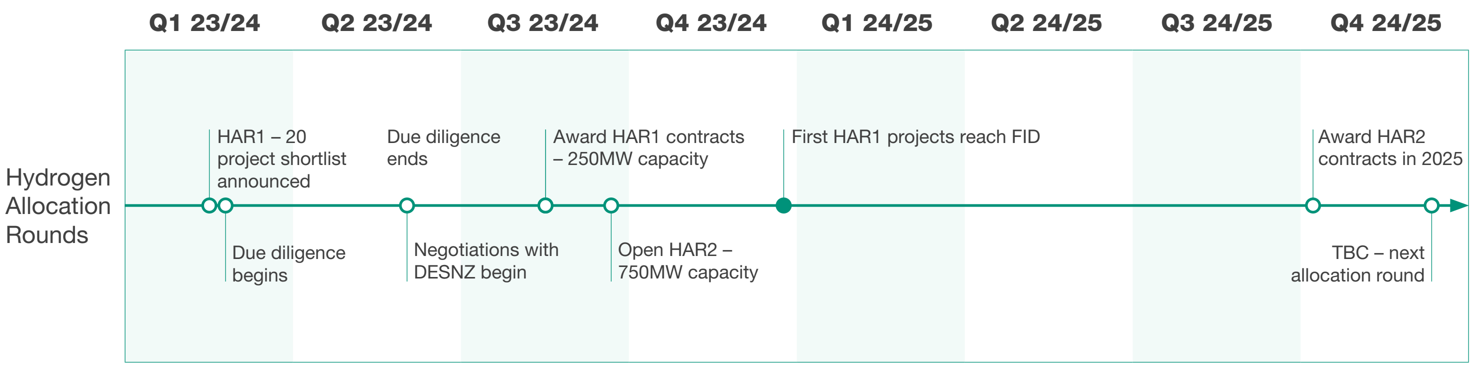
How does Hydrogen Business Model Work

Context

The HPBM is widely welcomed by industry, but it can be complex and difficult to understand for new entrants. Stripping it back to its fundamentals, it has its roots in the power Contract for Difference (CfD) scheme, where a generator receives a fixed price (strike price) for their electricity over a fixed term. This revenue stabilisation mechanism is required because renewable projects, like an offshore wind farm, are highly capital intensive and operate in a market that is known for its price volatility. The guarantee of a fixed price for renewable generators sufficiently de-risks the project allowing for capital investment. As well as revenue stabilisation, the HPBM is also attempting to establish a market for low carbon hydrogen due to it being a relatively new sector. This part is what adds additional complexity to the HPBM over the traditional power CfD.

To date, there has been one allocation round (HAR1) for HPBM support, of which 17 projects totalling 262MW entered negotiations with DESNZ in August 2023 to receive Low Carbon Hydrogen Agreements (LCHA). Indicative timelines indicate that these contracts will be awarded this Autmn, with the first HAR1 projects reaching Financial Investment Decision (FID) by the end of the year. This will be followed by a second allocation round (HAR2) that intends to secure up to 750MW in capacity.

For producers seeking revenue support, they must understand what volumes of hydrogen will qualify for support, and then how to calculate the final cashflow received for those volumes. To help producers on this journey, we have provided a high-level explainer on page 6:



Source: UKIB

Does the hydrogen produced qualify under the HPBM?

The first step is to determine whether the volume of green hydrogen produced and sold qualify for payment under the HPBM. Current proposals stipulate that in order to qualify for payment under the HPBM, the low carbon hydrogen producer cannot sell their volumes to non-qualifying offtakers (i.e. customers), which are currently risk taking intermediaries (RTIs), exporters and/or blends into the gas grid.[3] Producers must therefore sell volumes to final users of hydrogen, thereby highlighting the importance of strengthening demand-side to stimulate early markets.

If the producer has not sold their volumes to a non-qualifying off-taker, the next consideration is whether that volume aligns with the Low Carbon Hydrogen Standard (LCHS), which is detailed here. As of the current writing, the LCHS defines several criteria to determine whether hydrogen can be classified as “low carbon” and qualify for HPBM support. This is set out in the diagram below.

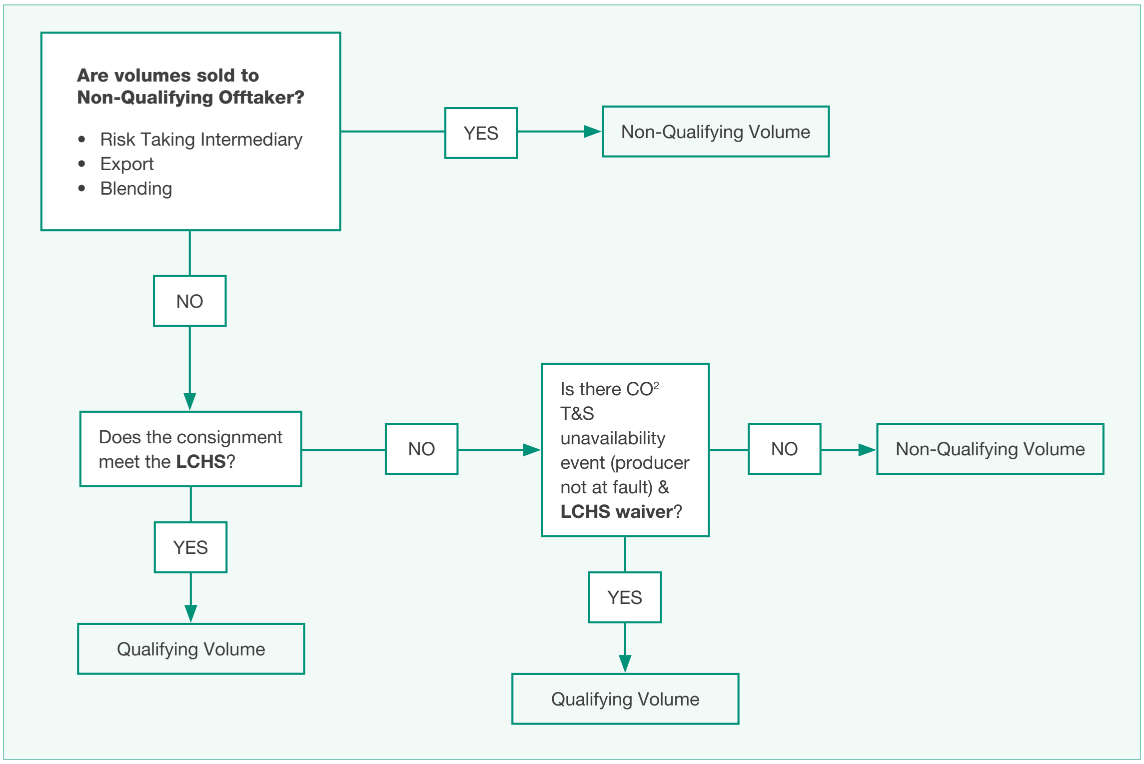
Finally, to qualify for payment, the volumes must not already be claimed under the DfT’s Renewable Transport Fuel Obligation scheme. This is to avoid the same volumes being subsidised by two different schemes.

In this explanatory context, we will illustrate the HPBM using a green hydrogen producer as our primary example. In this scenario, the producer has an electrolyser capacity of 500MW, with a load factor of 70%. It has made sales to two qualifying offtakers: “Offtaker A” and “Offtaker B”. Over one month period, Offtaker A has received 60,000MWh of hydrogen, while Offtaker B has received 40,000MWh, resulting in a combined total of 100,000 MWh sold. Thus, we have determined our reference Volume [V].

Offtaker A = 60,000MWh

Offtaker B = 40,000MWh

V = 100 GWh



3. RTIs have been excluded to prevent the potential of gaming the scheme. This is where a hydrogen producer receives a top-up payment to reach the negotiated strike price, but then sells the hydrogen onto the RTI who sells it at a significantly higher value, creating an additional price differential. This could undermine the fairness ad intended goals of the subsidy program, for example if the producer sells hydrogen to a company which they may have a financial stake or interest in, could result in them benefiting more than just the subsidy top-up they initially receive. Or trading desks and speculators who may purchase subsidised hydrogen at low prices and sell it at significantly higher prices when the market price rises.

How to calculate the amount payable

Due to the nascent stage of the industry, there is not yet an established market for low carbon hydrogen. This introduces complexity into the scheme because, unlike the electricity market which is liquid and underpinned by vast networks connecting multiple users, the HPBM must initially accommodate an emerging market whereby volumes are sold in small quantities via private contracts between producers and users, on private networks. Government has tried to circumvent this by including three elements within the HPBM which attempt to cost-effectively determine the final cashflow needed for support. The final cashflow for green hydrogen developers is the sum of these:[4]

- **Cashflow 1** = Contracts for Difference: Payment to or from the producer, contingent on the reference price and strike price.
- **Cashflow 2** = Price Discovery Incentive: an additional payment to the producer that seeks a higher sales price.
- **Cashflow 3** = Sliding Scale Top Up: Implemented to offset volume risk (e.g. an offtaker going out of business)

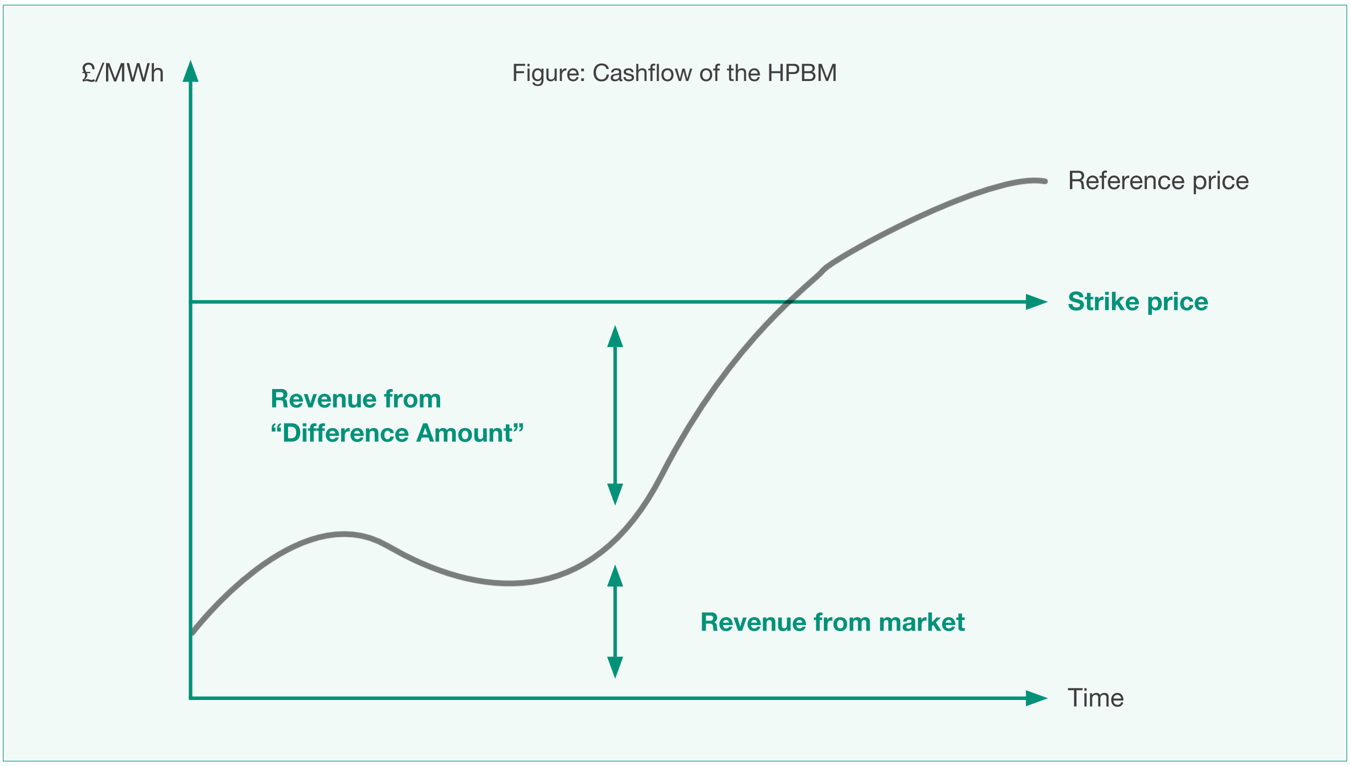
Successful applicants following a HPBM allocation round will receive a Low Carbon Hydrogen Agreement, that includes a strike price. This strike price is designed to enable to project developers to recuperate both fixed (e.g. equipment) and variable costs (e.g. labour, input costs), thereby ensuring a consistent revenue stream throughout a specified timeframe. The strike price for electrolytic projects currently undergoes periodic adjustments to account for inflation.

For our example throughout this paper, the strike price [SP] will be £115 per MWh. We now know our SP and V which we can use to calculate our cashflows.

SP = £115/MWh

4. There are also separate cashflows that are only relevant to CCUS-enabled projects and relate to the use of CO2 transport & storage networks.

Cashflow 1: Contracts for Difference



This cashflow of the HPBM is essentially the traditional CfD mechanism already used by renewable electricity generators, with some caveats. Here, the payment is calculated as the difference between a strike price [SP] and reference price [RP].

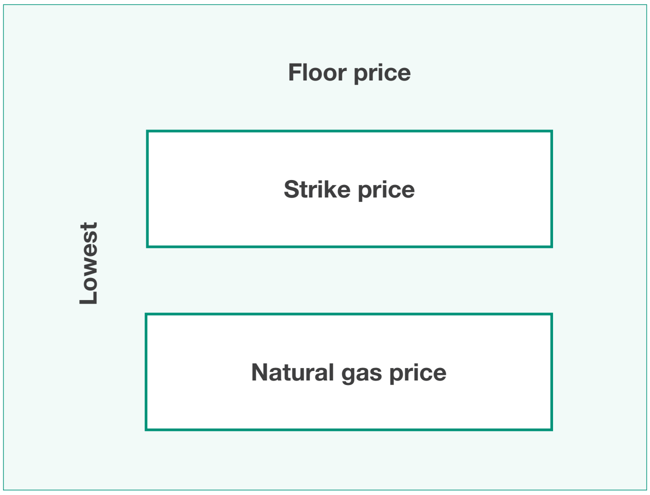
When the strike price exceeds the reference prices, the producer is entitled to receive a top-up payment from the hydrogen counterparty. If the reference price falls below the strike price, the producer is obligated to reimburse the intermediary for the disparity (i.e. pay back the difference).

However, as previously mentioned, there is currently no established liquid market for hydrogen. Consequently, establishing the reference price, which is intended to represent the market price for each unit of hydrogen sold, becomes challenging due to the absence of a readily observable hydrogen market price. As a result, the reference price may vary from one period to another, influenced by several factors.

The reference price used within the HPBM is currently the higher of:

- the price at which the producer sells its hydrogen for, referred to **achieved sales price** for that period, or
- the **floor price** which is the lower of the natural gas price or the strike price in that period.

If there are multiple offtakers, we will have to find a “weighted reference price” depending on prices received for each volume sold. First, we will define the floor price: in our example the natural gas price is £100, therefore lower than our strike price (set at £115/MWh). As it is the lowest of the two, the floor price is set at the natural gas price of £100.



Next, we need to establish our achieved sale prices, which will need to be weighted because our producer was selling hydrogen volumes to two different offtakers at different prices. For Offtaker A it received an achieved sales price of £110/MWh and for Offtaker B we got an achieved sales price of £90/MWh.

To find our overall, weighted reference price for both offtakers volumes, we need to identify their individual reference prices.

- The reference price for *Offtaker A* is the achieved sales price of £110/MWh, as it is higher than the floor price.
- The reference price for *Offtaker B* it is the floor price of £100/MWh as it is the higher than the achieved sales price.

For each offtaker we then need to multiply the corresponding volumes to their individual reference prices, aggregate these totals and divide by the total volume sold, which will produce the weighted reference price of £106/MWh.

Offtaker	Floor price (£/MWh)	Achieved Sales Price (£ /MWh)	Higher of the Achieved Sales Price or Floor Price (£ /MWh)	Volume (MWh)	Weighted Reference Price Calculation
A	100	110	110	60,000	6,600,000
B	100	90	100	40,000	4,000,000
			Total	**100,000**	**10,600,000**
Reference Price (£/MWh) *Weighted reference price/volume					**106**

We can now calculate cashflow one, because strike price is greater than reference price, the project receives the difference between strike price and reference price multiplied by the volume, resulting in a cashflow of £900,000.

V x (SP-RP)

100,000 x (115 – 106)

Cashflow 1 = £900,000

Cashflow 2: Price Discovery Incentive

To disincentivise producers from selling volumes at the cheapest possible price in order to get a greater pay out in cashflow 1, DESNZ have included an incentive which pays a reimbursement for selling at a higher price. In other words, this allows the producer to recuperate some of the losses it misses out on in cashflow 1 by taking an offer from an offtaker which is willing to pay much higher.

Without this mechanism in place, it would be beneficial to take the lower offer in order to get a greater payout in cashflow 1, which is detrimental to the industry at large. The price discovery incentive [PDI] mechanism is therefore there to aid price discovery.

V x PDI

1. If RP < SP, PDI = 10% X (RP – Floor)

2. If RP > SP, PDI = 10% X (SP – Floor)

In our example, cashflow 2 price discovery is calculated by multiplying the volume by PDI. The PDI formula is dependent on the relationship between the reference price and strike price in that period.

In our example, the reference price is less than the strike price and therefore we use the first equation above to set the PDI. PDI is therefore equal to 10% multiplied by the reference price (£106/MWh), minus the floor price (£100/MWh), giving us 0.6. We then multiply 0.6 by the volume (100,000MWh) to give us cashflow 2 of £60,000.

PDI = 10% x (106 – 100)

PDI = 0.6

100,000 x 0.6

Cashflow 2 = £60,000

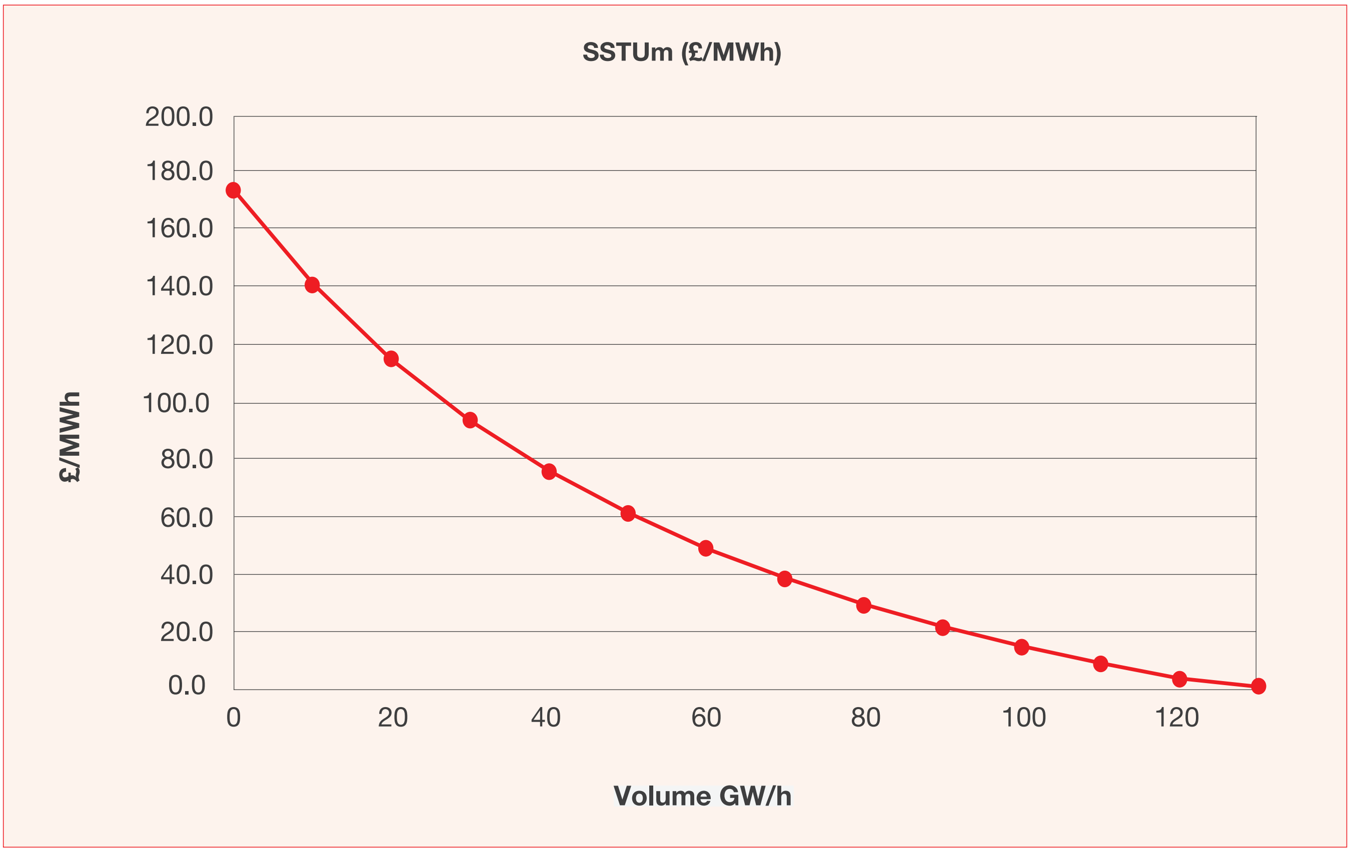
Cashflow 3: Sliding scale

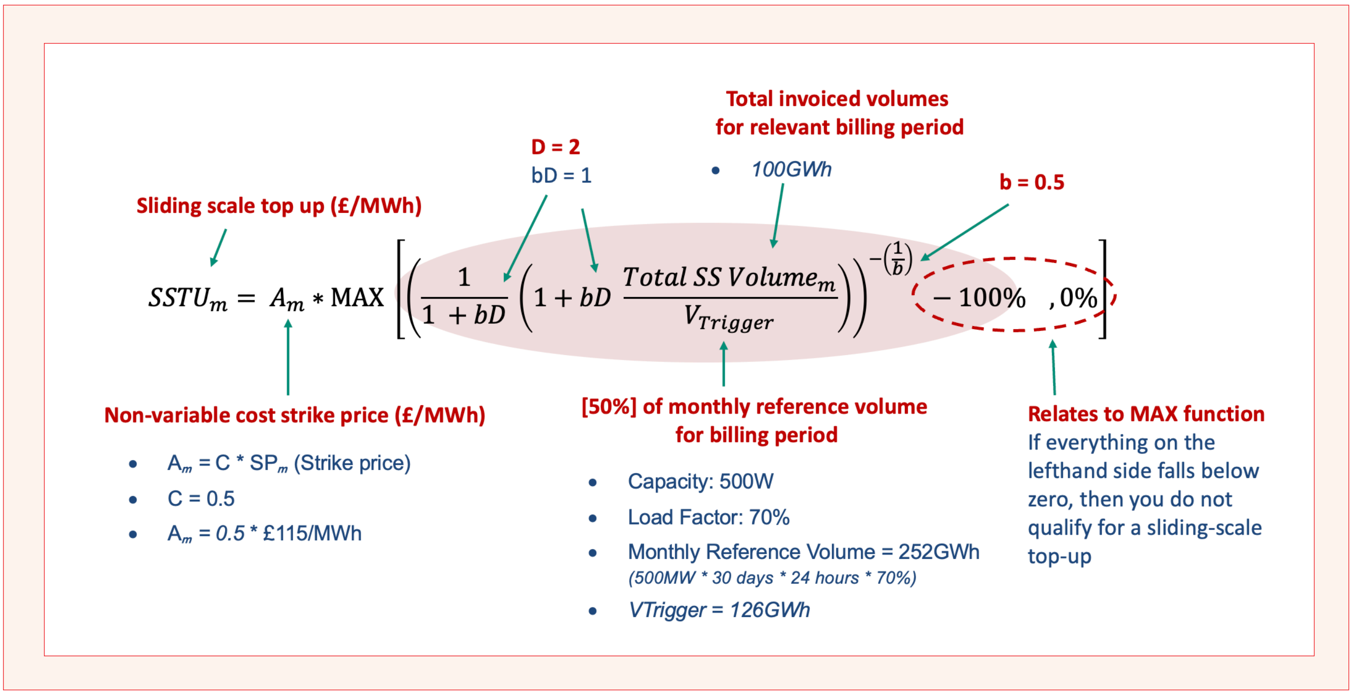
Due to there not yet being a readily available liquid market for low carbon hydrogen, producers are more reliant on contracts with individual offtakers. This presents a risk of not being able to sell enough volumes of hydrogen in order to confidently cover all its fixed costs (e.g. if the offtaker goes bankrupt), known as "volume risk". DESNZ have therefore included a "sliding scale" mechanism within the HPBM that seeks to mitigate volume risk while keeping the onus on producers to seek out offtakers.

Under the mechanism, if monthly (or billing period) volumes of hydrogen sold falls below specified levels, the producer is eligible to receive a top up payment on the hydrogen sold. However, if the producer does not sell any hydrogen no support will be received. The sliding scale is currently proposed to trigger when, due to a "qualifying event", offtaker volumes drop below 50% of the monthly reference volume (which is a pro-rata proportion of the annual sales cap), with adjustments made monthly. A qualifying event is one which reduces all volumes of hydrogen produced, except when it is due to negligence, breach of contract, game cashflows or a facility outage event. A full definition of a qualifying event can be found in the "Low Carbon Hydrogen Agreement Standard Terms and Conditions", here.

Remembering our hypothetical project can only produce 252GWh a month[5] given its load factor and installed capacity, the monthly reference volume. The trigger volume in our example is currently set at 50% the monthly reference volume of 252GWh which results in a trigger volume of 126GWh. Therefore, with only a 100GWh sold this month our project can benefit from a sliding scale top up. From the graph below, we can see that our project will receive approx. £1.4 million for this volume.

5. 30-day month


SSTUm (£/MWh)
£/MWh
200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
0.0
0
20
40
60
80
100
120
Volume GW/h


Total invoiced volumes for relevant billing period
• 100GWh
D = 2
bD = 1
b = 0.5
Sliding scale top up (£/MWh)
$SSTU_m = A_m * \text{MAX}\left[\left(\frac{1}{1+bD}\left(1+bD\,\frac{Total\ SS\ Volume_m}{V_{Trigger}}\right)\right)^{-\left(\frac{1}{b}\right)} - 100\%\ ,0\%\right]$
Non-variable cost strike price (£/MWh)
• A_m = C * SP_m (Strike price)
• C = 0.5
• A_m = 0.5 * £115/MWh
[50%] of monthly reference volume for billing period
• Capacity: 500W
• Load Factor: 70%
• Monthly Reference Volume = 252GWh (500MW * 30 days * 24 hours * 70%)
• VTrigger = 126GWh
Relates to MAX function
If everything on the lefthand side falls below zero, then you do not qualify for a sliding-scale top-up

To arrive at the sliding scale top up amount, we multiply the qualifying volume sold in the month by the sliding scale top up price. For our reference project the sliding scale top price will increase as the volume sold decreases, as seen in the graph above.

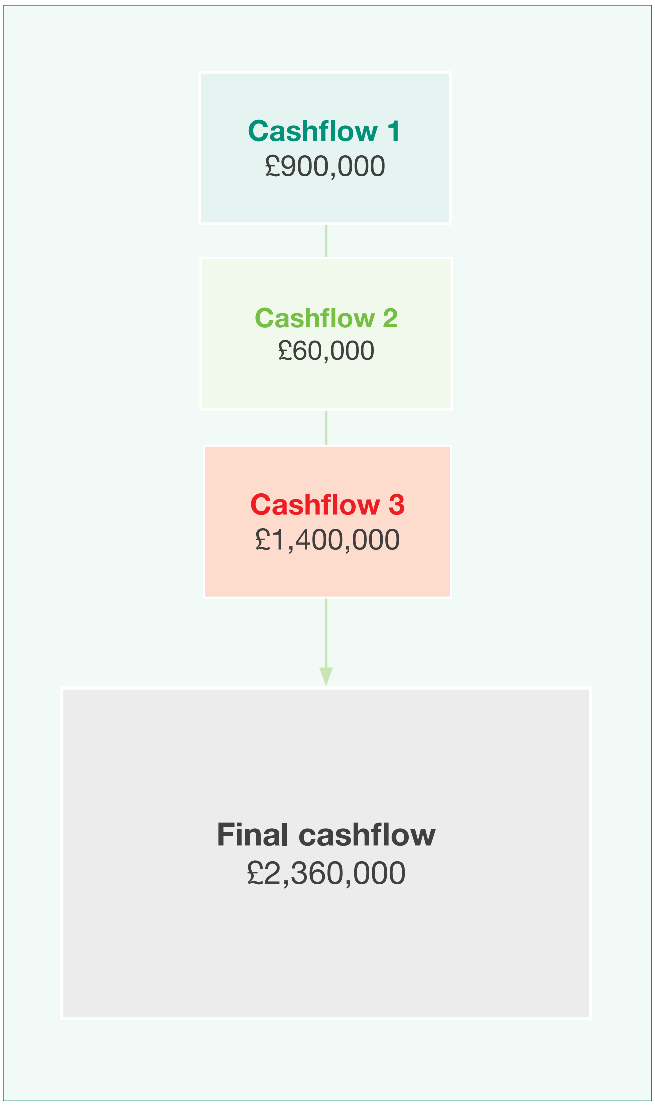
The sliding scale top up for our reference period is £14/MWh and is explained in the labelled formula above. To calculate our total cashflow, we multiply this number (£14/MWh) by the total invoiced volumes for the billing period (100GWh), resulting in £1.4 million.

Please note that as of October 2023 the constants used to shape the sliding scale curve are b = 0.5 and D = 2, bD = 1.

Cashflow 3 = £1,400,000

Sum the final cashflow

Adding our cashflows together brings the total HPBM payment in our example to £2.36 million for this period.



Section 2

Challenges with the Hydrogen Business Model

Being first of its kind, the Hydrogen Production Business Model naturally comes with a set of design challenges that require careful consideration moving forward. RenewableUK firmly believes that subsequent iterations of this model should aim to build upon the lessons learned from prior allocation rounds and the history of renewables within the CfD scheme. This approach will enable us to incrementally enhance its effectiveness, making it more tailored for its intended purpose. The table below sets out some of the challenges and ways to address them.

Element: Moving to completive auctions by 2025

Description

Support through the HPBM is currently awarded through evaluation criteria and bilateral negotiations between industry and government.

However, the government has proposed to transition the HPBM allocation rounds to competitive, price-based auctions by 2025.

Challenge

Implementing competitive auctions too soon without a fully developed supply chain and market players could make it economically unviable for developers to progress their projects.

RenewableUK's view is this proposal ignores the history of CfDs. Before competitive CfD auctions were introduced in 2014, for example, fixed-bottom offshore wind had already benefited from years of subsidies, including the ROC and FID Enabling for Renewable (FIDeR) regimes. This provided business case certainty, allowing early wind projects to trial the technologies, take on higher risk and establish ~4000MW of operational offshore wind projects before competitive auctions were introduced. In contrast, there is currently ~5MW of green hydrogen projects operational in the UK.

Moreover, a hurried transition to competitive auctions could have adverse impacts on creating domestic supply chains for green hydrogen. Wind turbine manufactures, for example, have faced constant pressure to innovate to drive down costs due to a so-called "race to the bottom" incentivised by price based CfDs. This, to some extent, has created shorter lifespan for components (i.e. due to the constant need to innovate) and overseas purchases that have made it challenging for Original Equipment Manufacturers (OEMs) to achieve positive returns on capital.

Recommendation

- The 2020s are the formative years for the UK's green hydrogen economy. As such, the next few allocation rounds will be essential for the green hydrogen economy to become established, ultimately producing the first wave of operational projects that will pull investment and UK-based supply chains.
- While we do recognise the need for price-based auctions in the future in order to drive down costs, the offshore wind experience demonstrates that it is ultimately deployment that catalyses initial cost reduction.
- RenewableUK recommends that while the market is in its infancy, the allocation mechanism for HPBM contracts should progress through bilateral negotiations, prioritising deployment first and foremost. Until a market with mulltiple operational projects has been established, the transition to competitive auctions should be deprioritised.
- For each consecutive allocation round, DESNZ should review against a clear timeline and set of criteria for when competitive allocation should be "triggered". By doing it this way, DESNZ can gather information on projects to inform auction parameters (e.g. Administrative Strike Price once competitive auctions are introduced).

Element: Cap on annual sales volumes

Description

At award of a Low Carbon Hydrogen Agreement (LCHA), a “sales cap” figure is determined that limits the amount of support received for a set volume over the contract period, with the intention to prevent over-subsidy. Note that this may be adjusted throughout.

If volumes sold exceed the permitted annual sales cap, then any excess volumes will be labelled as “non-qualifying” and will not be eligible for support and contribute towards the sales cap.

Challenge

- May contribute towards volume risk by making it challenging to recover from scenarios when demand drops to zero because the producer cannot recuperate this loss if the cap has been, or is at risk of, being exceeded.
- Fixing a ceiling at point of contract negotiation is problematic because it hinders producers from being able to react flexibly to changing generation mixes, particularly when renewables are cheap due to low demand. This reduces its ability to provide ancillary services, boost system security and reduce costs.
- It incentivises fossil fuel use instead of hydrogen because the latter is unable to react flexibly to changing demand and power prices.
- Annual caps introduce additional metering and reporting requirements (and terminations) that increase the producre’s administrative burden and risk.
- It incentivises high liquidated damages provisions placed on EPCs due to the risk of electrolyser delays within target commission windows or under performance.

Recommendation

- Retain the sales cap and remove penalties for breaching the annual cap, but do not pay top up for excess volumes above the annua cap. This will enable electrolyser projects to take on additional offtakers when marginal cost is lower than hydrogen revenue.
- Alternatively, introduce a higher volume cap for projects in the first hydrogen allocation rounds.

Element: Requirement to reach Financial Investment Decision within 3 months

Description

Within the consultation for Hydrogen Allocation Round 2, DESNZ introduced a requirement for successful projects to reach Financial Investment Decision (FID) within three month upon receipt.

DESN has signalled their intention to announce a shortlist of projects by “late 2024” and award contracts “from 2025”.

Challenge

- On the one hand, the proposed timeline is ambiguous about key decision dates (e.g. “late 2024” shortlist) from DESNZ, while on the other it expects developers to reach FID within a specified timescale without foresight and clarity on when the clock will start ticking. Ambiguity around key decision dates create challenges when financing projects and negotiating contracts with the supply chain in advance to ensure timely FID, which creates a higher cost premium. This concern is compounded by the fact that HAR1 was delayed by up to two years.[6]
- Moreover, it is doubtful as to whether the three-month FID requirement is attainable for projects scheduled for Delivery Year 3 (March 2028/29). Under the rules outlined, projects will be required to reach FID within three months of contract award in 2025, and as a result will need procurement contract well in advance of the construction phase. Developers expressed that it would be challenging to secure supplier commitment to contracts that far in advance.

Recommendation

- The three-month period to reach FID upon receipt of contracts is seen as achievable if developers have early visibility on when these decisions will be made to ensure they can make necessary arrangements ahead of time.
- RenewableUK recommends that the process is designed in a manner that facilitates the three-month requirement. DESNZ should establish clear timelines for key decisions and, importantly, stick to those dates. This proactive approach would enhance certainty and reduce risk around meeting the FID date, consequently lowering the associated premium.
- For projects delivering in later Delivery Years, one solution proposed was to calculate the timing of FID retrospectively from the stated COD, taking into account the specific delivery year, as it will vary accordingly.

6. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1144529/hydrogen-champion-report.pdf

Element: Lack of electricity price indexation for green hydrogen producers' strike price

Description

The strike price is currently negotiated between the producer and the government. For green hydrogen producers, it will be indexed to the Consumer Price Index (CPI). By contrast, blue hydrogen producers are also indexed against natural gas prices (their input), providing them a natural hedge against rising fuel costs.

Challenge

- Electricity prices are one of the largest cost components of green hydrogen production. In instances where electricity prices are high, and because the price of hydrogen is capped, this can create periods where it is too costly to operate.
- This adds risk to LCHA green hydrogen projects, making it more costly due to the added requirement to finance this risk premium. Moreover, it means the producer may need a 15-year PPA to offset the risk, thereby forfeiting the producer's ability to use surplus electricity during periods of low power prices.
- This means the government is not necessarily getting value for money for consumers because the largest cost component of an electrolyser is the input cost.
- If the strike price is not indexed against input costs for green hydrogen projects, the developer will need to predict what long-term power prices are going to be. Unless the developer can secure that capacity through a long-term PPA which covers the length of the contract plus build time, it must take an educated view on what power prices will be in the long-term. This is challenging, particularly in the context of potential reforms that could significantly alter prices (e.g. introduction of options such as locational marginal pricing through REMA), and therefore will have implications on the strike price a developer may seek in order to offset that risk.

Recommendation

CPI-only indexation is challenging and costly for green hydrogen developers. RenewableUK therefore encourages government, potentially through a consultant, to continue to explore alternative indexation options for electrolytic projects. We note that some options work for certain projects, and not for others, and as such have provided a list of options for DESNZ to consider:

- Include a material element of strike price indexation based on a form of renewables generation weighted average wholesale price.
- Link the strike price to natural gas, as has been done for CCUS-enabled projects.
- Have an option to sculpt a profile of the annual cap across the 15-year period to reflect forecasted increases in intermittent generation. This could also include having a re-opener, that allows the developer to re-shape the profile if renewable generation is not delivered on time.

Element: Exclusion of Risk Taking Intermediaries (RTIs)

Description

For a hydrogen development to qualify for HPBM support, they can only sell volumes to qualifying offtakers. This excludes RTIs (e.g. traders, shippers, storage providers, aggregators of hydrogen demand)

Challenge

RTIs are a fundamental part of any market for matching supply and demand, and managing that risk on behalf of the producer and offtaker. By excluding RTIs, this increases the risk premium of projects thereby making it harder to develop and finance. The result may be that the producers end up in the sliding scale mechanism more frequently because there is less opportunity to manage volume risk via RTIs.

Recommendation

We have identified two potential solutions:

1. Remove the bar on sales to RTIs for projects being supported by the scheme. A range of elements in the schemes design already protect the government against the risks that have led them to exclude sales to RTIs, and these could be strengthened further in the contract.
2. Or ease the restrictions to allow a certain percentage of RTIs (e.g. 10%). The introduction of RTIs through this method, at this point in time, will increase the administrative burden on producers, however, as it is likely government will want visibility on where sales volumes are going.

Please note that this is a non-exhaustive list and we acknowledge that these solutions do not address government's concerns of subsidy leakage and gaming. RenewableUK therefore offers to continue to engage on solutions on this, and encourages DESNZ to investigate and implement safeguards to prevent gaming but ensure RTIs are eligible.

Element: Reference price natural gas floor

Description

As a liquid market for hydrogen has not yet developed, the reference price for hydrogen uses a substitute as its market reference. This is made up of the price of which the producer sells their hydrogen, capped at the natural gas price floor.

Challenge

- This mechanism exposes LCHA green hydrogen projects to the price of natural gas, which would otherwise be a much lower risk associated with green hydrogen projects. Natural gas prices, for example, were expected at 50MWh, but are now projected to remain at £100MWh.
- Furthermore, if the producer is selling its volumes to non-natural gas users, it makes it more challenging to incentivise those users to switch, and similarly exposes them to natural gas price volatility.
- The reference price is set at month ahead prices, which makes hedging challenging because the producer will need to know the total volume of hydrogen a month ahead of time.

Recommendation

It has been suggested that DESNZ could move the reference gas price to day-ahead or intra-day gas market prices to provide developer flexibility to produce when required and respond dynamically to demand.

For non-natural gas users, it could be based on year-ahead gas prices to provide more stability and reduce exposure to fluctuating natural gas prices.

Element: 5MW eligibility criteria

Description

To be eligible for HPBM support, the producer must have electrolyser capacity of 5MW or over.

Challenge

Due to this requirement, there exists a funding gap for projects that fall below the 5MW threshold and are ineligible for support under the Renewable Transport Fuel Obligation (e.g. because they do not meet its additionality criteria). Consequently, certain projects in the UK may not be able to access government support.

Recommendation

It is advisable for the government to conduct a review and explore alternative approaches to address this gap, thereby extending support to smaller use cases of hydrogen (e.g. refuelling stations).

This could be accomplished by either reducing the threshold or allowing the aggregation of multiple smaller projects to submit joint bids. However, we recognise that this may be hard for DESNZ to manage against the step change the UK requires.

Element: Low price discovery incentive

Description

The price discovery incentive is a top up provided to the hydrogen producer when the total received for the sale of hydrogen is above the price of natural gas. Under current proposals, this is set at only 10% of the additional sales value.

Challenge

The 10% figure is seen as a very low incentive for hydrogen producers to sell above the natural gas floor price. This is likely to lead to higher subsidy costs for government under the scheme.

Recommendation

Increase the prices discovery incentive from 10%. A higher incentive should materially reduce government concerns about sales to RTIs, as with stronger incentives to maximise the hydrogen sales price, producers will always prefer to sell to final users where possible.

Element: Insufficient volume risk provision

Description

The sliding scale volume support is designed to provide a top-up payment if the producer sale volumes fall below 50% of the annual volume cap. However, if they fall to zero then the producer receives no top-up.

Challenge

The sliding scale is only triggered when a significant volume of demand is lost, with project economics suffering considerably. Even then, it does not provide protection for a significant down scenario whereby the offtaker suddenly defaults.

During the early stages of the low carbon hydrogen economy, it is likely that producers will have a single offtaker which means the sliding scale is irrelevant if your offtaker goes bust. Moreover, it is considerably complex and difficult to interpret mechanism.

This volume risk is exacerbated by the sales cap, which puts developers in a difficult position whereby if it producers less hydrogen, it makes it challenging to receive a return on investment, but if it producers more, then it is at risk of its contract being terminated. This is further complicated by the exclusion of RTIs.

Recommendation

- Increase the sales trigger beyond 50% currently proposed (e.g. 75%)
- Apply the top-up to volumes that fall to zero or allow blending to provide an easier alternative to selling the hydrogen if the original offtaker goes bankrupt.
- Significantly step-up efforts to stimulate demand through government incentives that reduce reliance on the sliding scale. This should be coordinated between government departments (e.g. DESNZ, DfT).
- Bring forward the proposed 2025 release date for the Transport & Storage Business Model to enable early development. This will allow liquid markets for hydrogen to develop, where it can be traded to multiple customers. Moreover, rapidly step-up plans to deliver a hydrogen network plan, as part of the wider Strategic Spatial Energy Plan.

Element: Administrative burden of the LCHA

Description

The LCHA contains hundreds of pages that must be navigated, interpreted and filled out by developers. These contracts include sections for different hydrogen production technologies, which means aspects of the LCHA are relevant to some and irrelevant to others.

Challenge

Going through all the detail on the LCHA and the various terms and what it means from a commercial legal perspective is resource intensive. The conflation of different types of technologies into one contract means they are unnecessarily more complex as developers need to judge which sections are relevant to their project.

Recommendation

RenewableUK recommends a review to simplify the LCHA. For example, the level of representations and warranties required, particularly around compliance metering and ongoing and enduring rights of the LCCC to inspect and monitor.

There should be technology specific LCHAs that strip out information that is only relevant to other types of production methods.

Ultimately the whole package should be reviewed by both the LCCC and DESNZ to understand what they need and what they could remove. One action could be to move all warranties and director certificates to a single annual submission.

NOTES

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RenewableUK members are building our future energy system, powered by clean energy. We bring them together to deliver that future faster; a future which is better for industry, billpayers, and the environment. RenewableUK are a UK membership body with a mission to ensure increasing amounts of renewable electricity are deployed across the UK. We support over 450+ members to access UK markets and to export all over the world. Our members are business leaders, technology innovators, and expert thinkers from right across industry.

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