SLAUGHTER AND MAY

Slaughter and May Podcast
Update on the UK Hydrogen Production Business Model: January 2023

OLY MOIR	Hello – my name is Oly Moir, I'm a partner in the energy and infrastructure team here at Slaughter and May. I'm here today with my colleagues Kathryn Emmett and Nicole Hunter-Edgar to discuss some of the latest developments in the UK low carbon hydrogen market specifically focusing on the updates the proposed low carbon hydrogen business model or the HBM which is effectively the subsidy regime that were published by the government shortly before Christmas. We are advising on a number of the first green and blue hydrogen projects in the UK (as well as hydrogen projects overseas), and we've been engaging closely with clients, industry and government over the last six months on the development of the HBM. There is a huge amount of capital ready to deploy in hydrogen - however those projects need to be investable and bankable, and given the nascent state of the hydrogen market, the HBM is crucial in providing the support needed to get the first projects off the ground.
KATHRYN EMMETT	By way of reminder, the UK doubled its ambitions for low carbon hydrogen last year in response to the Russia-Ukraine conflict and is aiming for 10 GW of low carbon hydrogen capacity by 2030. If you're new to this topic, we're going to be building on themes covered in a previous podcast - where we address some introductory matters like the distinction between blue and green hydrogen and then the potential use cases for hydrogen - so do please check that out. We'll include a link to that podcast on the podcast webpage. Now Nicole – it's been six months since our last podcast and it's fair to say that, in that time, there has been a lot of progress.
NICOLE HUNTER-EDGAR	Yes, there has – over the summer, we saw 4 blue hydrogen projects shortlisted for support under the HBM as part of the CCUS cluster sequencing programme. By way of a reminder these projects produce hydrogen from methane gas in a process called steam methane reformation, but then use carbon capture and storage to capture most of the emissions produced and store them permanently offshore. As you can see, these projects are relying on the parallel development, and subsequent operation of, carbon dioxide transport and storage networks – we'll come back to what that means for these projects in practice later. An announcement is expected in the next few weeks as to which of the shortlisted projects will proceed to the final detailed due diligence and

	negotiations phase with BEIS, with the expectation that the first contracts will be awarded in the second half of this year. I should say that existing hydrogen production facilities are entitled to support for the capex and opex costs of retrofitting carbon capture equipment under a different business model, called the industrial carbon capture business model. But that's not the focus of today's podcast.
KATHRYN EMMETT	That's right Nicole, and new build green hydrogen production, which uses low carbon power to produce hydrogen by electrolysis of water, is following a different allocation process. Annual allocation rounds for both support under the HBM and grant funding under the Net Zero Hydrogen Fund have started. The first allocation round closed for applications in October 2022 and contracts are expected to be awarded to the first projects from July 2023. Market engagement in relation to another, second allocation round will start in Q2 this year.
Hydrogen production business model - overview	
OLY MOIR	Thanks both – as you say, it's encouraging that we're edging closer towards a Final Investment Decision being taken on these first projects, albeit there remains a lack of clarity on certain key items such as the funding envelope for these first projects and the process for the second wave of projects (particularly on the blue hydrogen side). But moving away from the allocation process, let's focus on the HBM. After the publication of the first draft Heads of Terms last April, Government held a number of industry workshops over summer and autumn, which culminated in an updated set of heads of terms published in December 2022. That largely reflects the 'minded-to' positions that Government had advertised in those workshops. BEIS is in the process of finalising its positions over the next couple of months, so now really is the crunch point for trying to influence the development of the HBM. Kathryn, before we launch into some of the nuances of the latest positions, for those who are perhaps new to the topic, could you please briefly explain the structure of the HBM support?
KATHRYN EMMETT	Absolutely. To recap - what's proposed for new build hydrogen production plants is a contract for difference called a low carbon hydrogen agreement (or LCHA), based on the CfD for renewables. It's essentially a private contract, expected to be with a company wholly owned by government, the Low Carbon Contracts Company (or LCCC). Under the terms of the contract, for a period of 15 year period, the producer is entitled to a top up of its revenues from the sale of low carbon hydrogen.

	For each unit of hydrogen produced and sold, it will be paid the difference between the sales price agreed with its offtakers and a strike price negotiated with government, reflecting the producer's unit cost of production and an agreed return. Whilst the reference price under the CfD is based on the producer's actual achieved sales price, there will be a floor price, proposed to be the natural gas month ahead price, to guard against the producer agreeing an artificially low price for hydrogen with its offtakers before a market price for hydrogen emerges. This is a two way CfD so it allows for the level of subsidy to adjust as the market matures. As a result if the reference price were to rise above the strike price during the contract term, then the producer would make a payment to the LCCC. This is a new support scheme for low carbon hydrogen production and so will sit alongside existing support available under the Renewable Transport Fuel Obligation scheme (or RTFO). The heads of terms makes it clear that any volumes which are used to claim RTF Certificates are not eligible for support under the HBM – here BEIS is, quite understandably, wanting to ensure that there is no double subsidy paid for the same volumes.
Hydrogen production business model – Strike Price and hedging	
OLY MOIR	Thanks Kathryn. So it's worth digging into the indexation of the Strike Price and how the gas price floor to the Reference Price impacts both green and blue hydrogen producers. Let's start with indexation.
KATHRYN EMMETT	Sure - for a CCS-enabled, blue hydrogen project, most elements of the Strike Price are indexed to CPI. But a proportion of the Strike Price, effectively representing the project's gas input costs, is indexed to the gas price (with an assumed efficiency conversion rate). Because of this link to the gas price, this means that, generally, a CCS-enabled hydrogen producer won't need to hedge its gas input costs. And, because of the gas price floor to the reference price, producers are also likely to be incentivised to tie their hydrogen sales price to the month ahead gas price. Offtakers will therefore be exposed to a variable hydrogen price.
OLY MOIR	And electrolytic hydrogen production plants will have the same gas price floor to the reference price as CCS-enabled producers, but <u>all</u> of their strike price will be linked to CPI as per the renewables CFD.

	Now this means that they will have a harder time managing their electricity input costs. They won't have that in-built hedge to electricity input costs that blue hydrogen producers will to natural gas. To manage this, they will likely seek to enter into fixed price power purchase arrangements either under a direct PPA with a generator, or under an onsite or private wire arrangements. But, like a CCS-enabled hydrogen producer, an electrolytic project is also likely to tie its hydrogen price to the gas price floor. So they will likely have fixed price inputs, but be exposed to variable revenues.
KATHRYN EMMETT	Yes, in all cases hydrogen offtakers will need to manage that variable hydrogen sales price. This is likely to be manageable for large industrial offtakers who are used to procuring natural gas and dealing with input price fluctuations, but it may be harder to manage for smaller offtakers. Issues could also arise for producers if offtakers refuse to accept a price tied to month ahead reference prices, where it may be more used to managing its physical gas using a day ahead price. We should also mention that not all production costs will be supported by and covered within the Strike Price. These will need to be covered in a separate charge to the offtaker, or otherwise borne by the project. For example taxes and duties – including green levies on electricity that are typically added to grid-sourced electricity – are not included in the strike price. Similarly, opex costs for hydrogen transportation is not included in the Strike Price either. This is a key difference to the CfD for renewables, which doesn't distinguish amongst the component parts of the Strike Price.
OLY MOIR	Thanks Kathryn. There are a few interesting other design details which make the instrument quite different from the renewables CfD and have been the subject of a lot of discussion. We're going to focus on these for the rest of the podcast - these are: • the concept of Qualifying Volumes – essentially, which sales will be supported by the HBM; • the volume cap and volume support; and • for blue projects, CO_2 transport and storage network cross-chain risk allocation – that's that co-dependency issue that Nicole mentioned earlier. Nicole, would you like to kick-off our discussion about qualifying volumes?
Hydrogen production business model – qualifying offtakers	

NICOLE HUNTER-EDGAR	Sure, thanks Oly. Listeners will probably be aware that HBM support will only be payable in respect of volumes that meet the Low Carbon Hydrogen Standard emissions threshold of 20gCO_{2e}/MegaJoule$_{\text{(Lower Heating Value)}}$. It's worth noting that this is effectively, therefore, an 'all or nothing' test – either consignments comply with the LCHS or they do not. That is unlike CCS business models for power and industrial carbon capture, where support decreases proportionately when capture rates decrease. It places all the more emphasis on the technology providers that a project is planning to use and the performance warranties on offer. In addition, volumes must also be sold to Qualifying Offtakers. In short: 1. volumes cannot be sold to an offtaker who exports the hydrogen for use outside of the UK (but we note that it seems that if hydrogen is converted to ammonia and exported, that would be OK); 2. volumes cannot be sold to risk taking intermediaries – essentially, anyone who buys hydrogen and on-sells it rather than uses it itself; and 3. volumes cannot be sold to any offtaker who blends the hydrogen into the natural gas network. As you can see, whether an Offtaker is a Non-Qualifying Offtaker depends on how they use the hydrogen.
OLY MOIR	Yes and this means that the actions of a third party (i.e. the offtaker), which is ultimately not within the producer's control, could reduce the hydrogen producer's ability to access the subsidy, and ultimately lead to LCCC being entitled to terminate the LCHA. The concept of risk taking intermediaries is one that some producers struggle with – whilst BEIS ultimately wants to subsidise the end-use of hydrogen, rather than commodity traders for example, the prohibition on selling to anyone other than end-users significantly reduces the flexibility of producers if there is a drop-off in, or fluctuation of, demand from its contracted offtakers – and you could argue it ultimately prevents the price discovery process for a true market price for hydrogen developing. Let's move onto our second issue – volume caps and volume support.
Hydrogen production business model – volume cap and volume support	

KATHRYN EMMETT	Sure. The HBM will restrict both the capacity of the plant and also cap the volume of hydrogen that can be produced. This is different to the CfD for renewables where the installed capacity of the power plant is controlled under the CfD contract, but a generator can essentially produce as much renewable electricity as it likes. Now it is understandable that government want to control and to have a handle on how much subsidy is paid. But the volume cap proposed goes beyond that objective. It caps the <u>total</u> volumes produced by the plant, whether they qualify for HBM support or not. BEIS's argument is that if projects are producing what they call 'excess volumes', that over-production is only capable of being produced as a result of the original subsidy and producers could therefore effectively be receiving a windfall (and it could prohibit the ability of future projects to compete with them). However, this does seem to be a strange outcome for a measure that is intended to stimulate low carbon hydrogen production – so essentially its preventing a facility that is able and willing to produce low carbon hydrogen without direct subsidy from doing so. And it's particularly strange where the price for Non-Qualifying Volumes is <u>also</u> limited to the Strike Price.
OLY MOIR	Thanks Kathryn. So, how does this volume cap work?
KATHRYN EMMETT	Well, when a producer applies for its low carbon hydrogen agreement, it will be required to provide an estimate of its total forecast production over the 15 year support period now this covers Qualifying Volumes, Non-Qualifying Volumes and RTFO supported volumes. Once this total volume of hydrogen has been produced the support payments end - whether or not this is before the end of the 15 year support period or not. This overall contract cap, called the LCHA Production Cap, is then divided by 15 to arrive at an Annual Volume Cap. Producers will have some flexibility to adjust levels of production between years - they will be entitled to produce 25% more or 25% less of the Annual Volume Cap in any year. So far so good, but, the Heads of Terms also include a number of stingers which will make volume management really important: If a producer over produces and exceeds the annual volume cap by more than the permitted 25% (i.e. production exceeds 125% of the Annual Volume Cap) – there are several consequences: 1. first, a producer won't receive any support payments on these excess volumes.

	2. Second, these excess volumes will also be subject to a multiplier of 1.5, so they count more towards the contract volume cap and essentially erode the overall contract cap faster. 3. and finally, and perhaps most importantly, there is also a new termination right if more than 125% of the Annual Volume Cap is produced and sold in any 2 consecutive, or non-consecutive, years.
OLY MOIR	And it is worth noting that there's no materiality threshold on that termination right so even a minor infraction, for example, due to a metering error, may trigger a right to terminate and if that position remains the same, producers will obviously be wary not to stray too close to the 125% annual volume cap.
KATHRYN EMMETT	That's right. On the flip side, if there's any under production below 75% of the Annual Volume Cap in any year, the facility's production volumes are deemed to be 75%. So effectively this limits the producer's ability to make up for under-production in subsequent years and these volumes are forfeited. This could be particularly problematic during the early years because offtaker demand is likely to build up gradually over time and offtakers may not all come onstream at the same time. Their own demand is likely to ramp up as they are converting to hydrogen on a gradual basis rather than as one 'big bang' switch.
OLY MOIR	And the volume cap and collar may also be problematic for green producers using renewable power inputs – some years might not be as windy or sunny as expected, and so these provisions limit their ability to flex production according to their inputs.
KATHRYN EMMETT	That's right. Electrolytic projects are already managing their production carefully so as to be able to match offtaker demand despite their intermittent electricity inputs, so this adds further constraints.
OLY MOIR	On the other hand, as we mentioned last time, the HBM will provide some protection in the event that demand is low. As we discussed on the previous podcast, it's no good getting revenue support for the hydrogen you sell, if you aren't selling much of it. So the government intend to help reduce volume risk by providing a further top up payment for Qualifying Volumes where there are overall low levels of production. The latest Heads of Terms provides more colour in relation to the proposals to help mitigate volume risk, albeit details are limited on the actual quantum of support. BEIS are inviting stakeholder views and

	they have however indicated that the level of support may differ between green and blue projects but will not be individually negotiated.
KATHRYN EMMETT	That's right. Broadly, the trigger for where the volume support is payable depends on a two limb test: 1. firstly whether the level of actual hydrogen volumes produced falls below a threshold – currently the threshold is proposed to be 50% of the Annual Volume Cap we mentioned, prorated on a monthly basis. 2. and secondly that the plant would have produced volumes equal to or exceeding this threshold amount but for an intervening, Qualifying Event. We won't go into that now but the key point is that this is looking to cover a drop-off in volumes sold due to a lack of demand rather than operational issues with the facility. And, for these purposes, <u>all</u> volumes produced are taken into account, including Qualifying Volumes, Non-Qualifying Volumes and RTFO supported volumes. And, in addition, the Heads of Terms indicates that any volume in respect of which the producer has received a take-or pay payment will also be counted. And once the threshold is met, support will be available on a 'sliding scale' basis – effectively, for each unit of production sold the amount of support will increase as the volumes drop. However, the exact shape and quantum of that support has not yet been finalised.
OLY MOIR	Thanks Kathryn. It's fair to say that the reaction from industry to this has not been particularly positive. Demand risk in a very nascent sector and one dependant on government policies to stimulate demand is one of the key risks to projects, and it was expected – or at least hoped – that the sliding scale volume support mechanic that had been advertised by BEIS would provide a base level of support to projects to enable them to meet their fixed costs and service debt, in other words, to continue to operate. However, it is clear that this is not the case, particularly as where volumes sold dropped to zero, there will be no support available (at all) under the HBM. And the really key issue with this is that all plants will have operating parameters below which it cannot operate. Let's say that the minimum turn down rate for a blue hydrogen facility is 35% of its nameplate capacity – that means that if volume demand drops to 34.99%, the plant has to switch-off and the project revenues will effectively be zero. Therefore, the reality is that this volume support mechanic operates in a very narrow band between a plant's minimum

	turn-down rate (or equivalent) and the 50% volume threshold. It's also worth bearing in mind that that 50% volume threshold will be based on the annual volume cap – and this will be less than the nameplate capacity as producers will expect to have fluctuating volumes, with lower volumes in early years as demand ramps-up. So, 50% of the volume cap may be, for example, 40% of the nameplate capacity. So, there is still some work to do to try and refine this mechanic if it is to provide meaningful additional protection to offtakers.
Hydrogen production business model – CO2 T&S cross-chain risks	
KATHRYN EMMETT	Indeed. That volume risk is an example of cross-chain risk – i.e. dependency on a limited number of offtakers. However, blue hydrogen projects have a more significant example of cross-chain risk: they're dependent on the CO2 transport and storage network to store the CO2 it has captured.
OLY MOIR	The previous Heads of Terms didn't include a decision on how to manage CO2 network risks – but a proposal has now been put forwards after a few months of discussion between government and industry in relation to 3 key issues: 1. firstly, CO2 network construction and commissioning delay risk – i.e. the risk that the network is not delivered on time; 2. secondly, CO2 network unavailability – the risk of an outage or capacity constraint which limits the network's ability to take captured CO2; and 3. thirdly, CO2 network abandonment –effectively the risk that the CO2 T&S network is closed permanently. Nicole and Kathryn – would you take us through the proposals please?
NICOLE HUNTER-EDGAR	Sure Oly. In relation to delays to construction and commissioning of the CO2 transport and storage network, if these delays are not caused by the capture project itself, the Heads of Terms follows the proposal for Power-CCS projects under the Dispatchable Power Agreement (or the DPA). Essentially the producer has a choice: • Option 1 is to request that there is a day for day extension of key dates (such as the longstop date for commissioning of the carbon capture plant) and to receive compensation for a limited set of costs. • Option 2 is to request a waiver of the Operational Condition Precedent requiring it to connect to the CO2 network, and start producing hydrogen without capturing emissions (i.e. grey

	hydrogen). The Strike Price would be payable in this scenario and the 15-year support period would start to run. But any capital return element of the Strike Price would need to be paid back and, crucially, the producer would also need to cover the costs of its emissions under the UK Emissions Trading Scheme. The reality is that this is likely to mean that a producer will be operating at a loss. We note that this differs from the DPA, where a generator is entitled to its full availability payment in this scenario.
KATHRYN EMMETT	And once commissioned, any outage or constraint of the CO2 T&S network will also impact the facility. The plant won't be able to export carbon captured to the CO2 network and will also be exposed to the costs of emissions as a result of UK ETS liability. Also the hydrogen produced won't meet the Low Carbon Hydrogen Standard. Now the Heads of Terms does seek to address these issues. Firstly where the outage or constraint of the CO2 T&S network is not the fault of the producer, the requirement to meet the Low Carbon Hydrogen Standard will be waived. Secondly, BEIS are also proposing that the Strike Price will be payable for hydrogen volumes produced, even when the emissions aren't being captured due to a CO2 network outage. If this is during the first 2 years after the date the CO2 network is available, the full Strike Price is payable. This is because there has been a recognition by BEIS that the CO2 network operating risks are likely to be highest in the early years of operations. And then after that 2 year period, the capital return element of the Strike Price won't be payable for hydrogen produced during a CO2 network outage. However, again, crucially, if a producer is not capturing its CO2 emissions, it will have to pay UK ETS costs and there's no compensation proposed to cover these. But if the producer decides to switch-off the plant during the outage because the ETS costs of compliance makes continued production uneconomic, then there's no compensation or any HBM payments payable either.
NICOLE HUNTER-EDGAR	Finally, if the CO2 transport and storage network suffers a total outage or fails to commission, the Heads of Terms provides for a process lasting 36 months in total, similar to the Power-CCUS and industrial carbon capture contracts, before a right to terminate can be exercised by the LCCC. This is a one-way termination right – so there's no right for the producer to terminate in these circumstances.

	If exercised, a termination payment is payable to the hydrogen producer to cover its irrecoverable and unavoidable out-of-pocket expenses. But this is now proposed to be capped at the total capex that has been incurred after the date of the contract (so this is unlikely to result in a project recovering its costs, particularly if termination occurs in the early years). And compensation won't cover all costs – there are a number of exclusions, particularly all financing costs (including break costs), return on equity, ETS costs and any lost revenue. Some contract break costs will be covered, although these will be subject to a sub-cap which hasn't yet been specified.
OLY MOIR	Thanks both. So looking at this altogether this approach being put forward by BEIS really is highly unappetising for blue hydrogen producers and I expect there is more to come on this topic. Without going into the details, it's worth highlighting that the position of a blue hydrogen producer in respect of CO2 cross chain risk is materially worse than that of power producers or industrial emitters under the DPA and ICC CCS business models. CO2 network cross chain risks are key issues that developers and investors will need to understand in the context of their particular project. From discussions we've had to date, I'm confident there will be significant focus on this over the coming months before the full contract terms are published in May.
Conclusion	
NICOLE HUNTER-EDGAR	Yes, as you say Oly, with contract terms only expected in May this year, this doesn't leave much time for review and comment before producers are expecting to be entering into contracts in the second half of this year.
OLY MOIR	Indeed. Engagement by BEIS and industry has been very good to date so, whilst there's a lot of work to be done and a few sticky points, the communication channels are open and we're really looking forward to continuing to work with our clients and to engage with government over the coming months. We'll be sure to keep our listeners updated. Thanks for listening and feel free to reach out by email with any questions or comments.

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