SLAUGHTER AND MAY/

**Transition Technologies - What's Next for UK Hydrogen Production - Episode 2**

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| Oly Moir | Welcome to the second episode in our Hydrogen podcast mini series. We're back specifically to discuss where we landed with the final design of the low carbon hydrogen production business model. In particular the LCHA, so the Low Carbon Hydrogen Agreement being the Hydrogen CFD, which is the main support regime for low carbon hydrogen in the UK. For an introduction to the hydrogen production business model please do listen to episode one of the podcast. I'm Oly Moir a partner in the Energy and Infrastructure Team here at Slaughter and May and I'm joined again by my colleague, Kathryn Emmett, who heads up our Infrastructure, Energy and Natural Resources Knowledge Function. |
| Kathryn Emmett | Hi there. |
| Oly Moir | Hi Kathryn. So in this podcast we're going to dig into the detail of some of the developments in relation to the LCHA and the Low Carbon Hydrogen Standards. In particular we're going to look at a slight softening to the position on non-qualifying offtakers. We'll look at the importance of power procurement for electrolytic, i.e. green projects, and the low carbon hydrogen standard requirements related to that. We will look at volume support and we'll look at progress on cross-chain risks and where we look to be landing on that critical point for the blue projects. I'll be honest, this is a technical topic for those of you who are interested in the details, for everyone else you might prefer to listen to part one. Anyhow with that disclaimer, first, let's talk about non-qualifying offtakers. Kathryn, would you like to start us off? |
| Kathryn Emmett | Happy to. Right, non-qualifying offtakers – it's probably worth recapping on a few concepts. So qualifying volumes, qualifying offtakers, non-qualifying offtakers. Whilst the position on this hasn't changed substantially, it is still a fundamental and very interesting aspect of the design of the hydrogen production business model. So to qualify for support listeners will probably be aware that the hydrogen production business model is only payable if volumes meet the low carbon hydrogen standard emission threshold of 20 grams $CO_2$ equivalent per megajoule measured at the lower heating value. In addition to that, volumes also have to be sold to qualifying offtakers. So, in short, volumes can't be sold to an offtaker who exports hydrogen for use outside the UK or volumes that are sold to risk-taking intermediaries, so this is essentially anyone who buys hydrogen and then on-sells it rather than uses it itself. And then finally, volumes can't be sold to any offtaker who blends hydrogen into the natural gas network. So as you can see, whether an offtaker is a non-qualifying offtaker depends very much on how they use the hydrogen and importantly, if volumes don't qualify for support, so they don't meet that qualifying offtaker requirement or the low carbon hydrogen standard then, they don't get support under the low carbon hydrogen agreement but those volumes still count towards a project's overall volume cap which means that reduces the opportunity for those volumes to be made up later with qualifying volumes. I think the point that we wanted to emphasise on this podcast is that over the past year we've seen a softening of |

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| | one aspect of the non-qualifying offtaker regime in relation to volumes of hydrogen that are sold to so called risk-taking intermediaries, also known as RTIs. So the original RTI definition in the Low Carbon Hydrogen Agreement when it was first published meant that volumes sold to anyone who subsequently on-sells the hydrogen rather than uses it itself aren't supported, or weren't supported, under the Low Carbon Hydrogen Agreement and that essentially meant that the producer was penalised even if their long term end user offtaker didn't use the hydrogen as expected and needed to offload excess volumes in the market. And that could happen for a number of reasons. It could have been unscheduled maintenance or outages which meant the offtaker had more hydrogen than they needed in any month. However, in the latest version of the contract, provided that the offtake contract was entered into for purposes of use of volumes for feedstock or fuel purposes by the offtaker, so the producer signed that contract upfront with the offtaker for fuel or feedstock purposes, then the offtaker won't be deemed to be a risk-taking intermediary just because at some point during that 15 year offtake term, they on-sell those excess volumes to another party. So I think that is overall good news for producers. |
| Oly Moir | That is good news and it's a pragmatic position and certainly to be welcomed although there do remain serious questions as to why the RTI restriction is necessary at all and whether it's proportionate and whether it is in fact potentially holding back price discovery and unnecessarily increasing risk for producers by not giving them this outlet for volumes. |
| Kathryn Emmett | That's such a valid point, Oly, and one that I'm sure we'll pick up with LCP Delta. |
| Oly Moir | Indeed, and the other potential risk mitigant for producers is the ability to blend into the grid if, for whatever reason, you're offtaker cannot take. We still await a policy decision on blending and it's expected the restriction will be loosened in the future but the extent to which that is actually a meaningful risk mitigant will of course depend upon the volumes that can be injected at any given location, the pricing and perhaps we could pick that up with LCP Delta in the next episode as well.<br><br>So from offtake to inputs. Let's look at renewable power procurement. So the cost of electricity is the key economic driver for an electrolytic project. We've been working with projects on their power procurement, strategies and for those interested in particular about how power procurement impacts project economics please do listen to our podcast with LCP Delta in part three. |
| Kathryn Emmett | Yes, well worth a listen. While we're on the topic I think it's also worth reminding everyone that for electrolytic projects a key requirement of the Low Carbon Hydrogen Standard is to evidence that the project has used low carbon power to produce hydrogen. Most projects will be looking to enter into direct PPAs with a generator so that the emissions associated with the power is rated as zero under the LCHS. However, because the strike prices indexed only to CPI and |

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| | not to the power price, projects are exposed to increases in power price and so will be looking to enter into long term PPAs often on a fixed price basis. |
| Oly Moir | That's right, but for electrolytic projects it can be challenging to find a fixed price renewable PPA to match the LCHAs 15 year tenor in the current market, certainly without applying a significant risk premium and because of a production projects' power consumption profile and the intermittency of renewables, there's often a need to source power from multiple renewable projects, or to contract with an aggregator who will do so to achieve the supply needed, which clearly adds complexity because the LCHS requires provision of metering data from each generator showing that the contracted and delivered volumes exceed or match the facility's consumption accounting for transmission losses. So it's hard therefore for aggregators to provide products because of the granularity of information required and the confidentiality obligations and restrictions in existing generator PPAs. Finally, the collateral requirements for a long term fixed price PPA are difficult to manage and are really eye-watering compared to the CapEx costs of the project and that adds further costs to the hydrogen production process. More on that in the next episode with LCP Delta. |
| Kathryn Emmett | While we're on the topic of power procurement, we should say that the Government's Clean Power 2030 Action Plan could mean a substantially decarbonised power system by 2030. But as you said, hydrogen producers will still be keen to fix the price at which power is available to make sure they manage those prices given that their strike price is substantially fixed. But the lack of eligible PPA liquidity is compounded by the fact that a lot of renewable generation in the UK is itself supported by a contract for difference for renewables and so is incentivised to sell its power at the CfD market reference price and not a fixed price. So there will be repowering of existing projects but that now looks like it might also be eligible to be supported under CfDs. Also add to the mix reforms of the wholesale market under the review of electricity market arrangements or REMA programme. So power procurement for electrolytic projects is getting really complicated, particularly in the short term. |
| Oly Moir | Thanks Kathryn. So, changing topic slightly, let's discuss volumes. Support under the LCHA is paid on volumes produced. Unlike the renewables CfD, the LCHA intervenes to limit both the upside and the downside to a degree of volume risk. But arguably the contract's less balanced than was originally hoped. So there are two key points here to discuss.<br><br>Firstly, volume caps and secondly, volume support. So on the first point the LCHA has introduced, or has always had a concept of a volume cap. And that caps the overall volumes of hydrogen supported under the LCHA and also the plant's annual production volumes. For the overall contract cap, the LCHA sales cap, that operates so as to economically cap the upside achievable under the LCHA and it's reduced, that cap is reduced, if the facility is commissioned outside of the target commissioning window i.e. if it's late, by deeming 50% of assumed volumes, that you are assumed that you would have produced in that time period, they assume that would have been produced and sold throughout |

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| | that period of delay, which is effectively a form of delay LDs. And then in each year a permitted annual sales cap applies which is 125% of the production facility's theoretical annual production based on installed capacity which applies a pre-agreed and fixed assumed load factor. Production in excess of that won't be supported, but actually those volumes also count even more towards the overall contract cap meaning that, that has arose faster and in addition if that annual cap is exceeded more than three times over the 15 years the termination right is triggered. So, essentially you do not want to be, and cannot, operate at above the annual sales cap, whether for subsidised or non-subsidised volumes. So, in practice that means for green hydrogen production plants there is limited scope to over produce in years of renewable energy abundance and to make up for lower volumes produced in previous years.<br><br>Secondly, the LCHA provides volume support and this is a distinct factor of the LCHA because unlike an offshore windfarm there is a concern that you may well have a functioning hydrogen production facility but then nobody to actually buy it because hydrogen is very nascent market. The way the volume support works is via a so called sliding scale top up regime and that was introduced to mitigate the risk of a reduction in offtake demand. Essentially, as your volumes drop down lower you'll get paid more for each unit that you sell. This was never intended to cover hydrogen producers, and doesn't cover hydrogen producer's operating risk or technology risk, it's really getting at market demand risk. However, it's fair to say that the level of support provided under this regime is very limited in practice. And if no volumes are sold there are no payments at all made under this regime, or indeed under any other regime, under the LCHA. It's only triggered if production falls below 50% of the reference volume. And so particularly for CCS enabled, i.e. blue hydrogen production, if production falls below the minimum turndown rate of the facility, which will not be that much lower than that 50% threshold, no volume support will apply at all, or indeed any other revenue, under the LCHA. Even where support is available, when you end up plugging the very complex formula through Excel the volume support payment is really quite *de minimis* and, in short, this mechanism, it does not come close to solving the issue of demand risk. So, really we're back to the fundamentals of projects having to focus on a robust offtake strategy. |
| Kathryn Emmett | Yeah, and while we're on the topic of CCS enabled blue hydrogen projects, shall we look at $CO_2$ network risks? |
| Oly Moir | Yes, absolutely and this really is a big differentiator for the UK's approach and it's really the USP of the whole UK CCS business model, not just blue hydrogen. |
| Kathryn Emmett | Yeah, there's been quite a lot of work on issues of cross chain risks under the LCHA and we should stress the position is still not finalised, although we are getting there. As you might recall the focus in relation to cross chain risks is in relation to three key issues, really. So firstly, the $CO_2$ network construction and commissioning delay risks. So that's the risk that the $CO_2$ network is not delivered on time. Secondly, the $CO_2$ network unavailability risk. So the risk of an outage or a capacity constraint which limits the network's ability to take the |

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| | captured $CO_2$ from a production project. And thirdly, a $CO_2$ network abandonment risk. So essentially the risk that the $CO_2$ transport and storage network is closed permanently and earlier than anticipated. So this is an area where there has been a lot of discussion and engagement with Government particularly because of the different approaches across other CCS business models. |
| Oly Moir | Yes, that's right, Kathryn. There have been some pretty hard fought battles on this particular topic. In relation to delays to construction and commissioning of a $CO_2$ TNS network. If these delays are not caused by the capture project itself, the LCHA gives the producer a choice. So option number one is to request that there is a day for day extension of the key dates i.e. the longstop date and the target commissioning window, and to receive a certain amount of limited compensation in the meantime called the $CO_2$ TNS Connection Delay Compensation. So it is more comprehensive than it was and it covers all out of pocket expenses caused by that delay but importantly, still doesn't cover costs under offtake agreements for delay. So, in other words, delay, LDs or equivalent liability owed to offtakers. The big change certainly since we did our previous podcast is that the producer is now also entitled in that scenario to claim what's called a $CO_2$ TCDE Relief Amount, provided that they're not producing hydrogen during that period for which they are claiming, in other words if you're just sitting there. And that new compensation payment means that the producer gets to receive their non-variable costs strike price. In other words that's the fixed costs and the capital return component, i.e the return on capital of the strike price but it excludes variable costs on the basis that those shouldn't be incurred. And that's for production volumes, it's paid for production volumes that could have been produced but for the delay which is calculated based on the assumed load factor and installed capacity estimate. So that is a very big move forward, which effectively provides that protection of lost revenue in the delay scenario.<br><br>There is a second option, option two is to request a waiver of the operational condition precedent that requires a project to be connected to the $CO_2$ TNS Network and effectively press go, so reach your start date, start producing hydrogen without capturing your emissions, in other words, produce grey hydrogen. There the strike price will be payable because your LCHS requirement is waived, and the 15 year support period will start to run but the producer will not be paid any capital return element of the strike price i.e. any return on capital and, crucially, the producer will also need to cover the costs of its emissions under the UK Emissions Trading Scheme and is prohibited from claiming any UK ETS free allowances and the reality is, that means it is highly unlikely that a producer will follow this option because it will just not be economically viable for it to do so. |
| Kathryn Emmett | Thanks Oly. So, once a project is commissioned there's a slightly different regime for an outage or constraint of the $CO_2$ network. As a reminder in this scenario, the hydrogen production plant won't be able to export the carbon captured to the $CO_2$ network and will also be exposed to the ETS costs that you just mentioned. Also, the hydrogen produced, if it does continue operating, won't |

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| | meet the low carbon hydrogen standard because the emissions' intensity will be too high. So the updated position is as follows. Firstly, where the outage or constraint of the network is not the fault of the producer, the requirement to meet the low carbon hydrogen standard will be waived. Helpful. Second, the strike price will be payable for hydrogen volumes produced when the emissions aren't being captured due to the $CO_2$ network outage. So if this is during the first two years after the date that the $CO_2$ network became available, the full strike price is payable but after that two year period the return on capital elements of the strike price won't be payable for the hydrogen produced during a network outage. So, I guess the rationale there being the network will be bedding in in the first two years but after that operations should be more predictable and less likely to occur. |
| Oly Moir | That's right, although outside of the control of the producer. |
| Kathryn Emmett | Absolutely.<br><br>And crucially, if a producer is not capturing it's $CO_2$ emissions it will have to pay UK ETS costs. That could represent a significant cost to the producer, both in respect of its own emissions but also in relation to its liability to the offtaker who contracted to receive low carbon hydrogen that's now receiving grey unabated hydrogen. |
| Oly Moir | Yes, and to address the issue on the ETS costs at least, a new measure has been introduced to cover some of this exposure called "carbon cost protection". Essentially the CCP gives a maximum of 30 days per year of compensation for emissions from the hydrogen production plant which would have been captured but for the $CO_2$ TNS outage. Compensation is triggered in any month if there have been more than 96 reporting units, those are each 30 minutes, so this equates to 48 hours in that billing month in which a $CO_2$ TNS outage relief event has been deemed to have occurred. And that's something to take into account in project models, of course. Alternatively, if the producer decides to switch off the plant during the outage and not produce because, for example, the ETS costs of compliance makes continued production uneconomic, so, if you've capped out above the CCP 30 days' threshold or indeed because the offtaker refuses to take grey hydrogen, there are permitting restrictions on unabated operations or for other market reasons, not technical issues with the facility, there is now also compensation payable snappily called "payment in lieu of hydrogen sales" or "PILOHS". Where that applies, the non-variable cost strike price, so that includes the return on capital component is payable on deemed volumes and those deemed volumes are calculated using the production data over the previous 30 days when the TNS network was above 95% available.<br><br>Naturally, this is very welcome from a producer perspective, it's been a big concession from DESNZ after a lot of discussions with industry. There is a risk with the deemed concept that if volumes are unusually low within that 30 day lookback period for whatever reason, e.g to a planned outage, that would artificially deflate the deemed volumes and the PILOHS protection would be |

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| | reduced accordingly, and the PILOHS payment also does not address any additional liability you have to the offtaker under the offtake agreement for failing to supply. Those risks still sit with, and need to be managed by, the project but aside from that it's certainly quite a big move forward in terms of this new protection that was not there certainly the last time we did this podcast. |
| Kathryn Emmett | Just to reiterate, though, I think in the last publication they did say these are still subject to change, so we have to hope that those will stay in, in the next round.<br><br>So, finally to wrap this up, looking at prolonged outages of the $CO_2$ transport and storage network or where essentially it's had to shutdown because it's just not economically or technically viable, another mechanism kicks in. In this case the LCHA provides for a process lasting 36 months in total. Similar to the Power CCS and Industrial Carbon Capture Contract before a right to terminate can be exercised by the LCCC. So currently this is a one way termination right, so there's no right for the producer to terminate in these circumstances but it will be interesting to see if the changes that have been negotiated in the final position of the Dispatchable Power Agreement that was agreed with Net Zero Teesside actually track into the LCHA. Here, that allows generators to force a termination event after a certain period has elapsed. The trigger for this to be engaged is that there's been a TNS prolonged unavailability event. So this occurs when the $CO_2$ TNS network suffers a total outage or it fails to commission and that failure has been ongoing for six months. Another trigger is that the $CO_2$ network is no longer viable or has had its licence terminated, what's known as a $CO_2$ TNS cessation event. So in this circumstance, if this TNS prolonged unavailability event continues for 12 months, and the situation is still ongoing, then there's a process which ultimately ends up in the LCCC having the right to terminate as we said. And if this is exercised, a termination payment is payable to the hydrogen producer to cover its irrecoverable and unavoidable out of pocket expenses in relation to certain heads of loss. This is capped, importantly, at 110% of the total CapRx payment. This is a pre-agreed amount that's set out in the project's specific part of the LCHA, what's called the front end agreement. You deduct from that the net recoverable value of the facility which may be an operational grey hydrogen production plant, or it might just be scrapped. In any event, whilst equity is generally at risk, the expectation is that giving gearing, lenders are likely to be repaid. |
| Oly Moir | Thanks Kathryn. And it'll be interesting to see on the net recoverable value deduction whether or not the complex mechanics from the Net Zero Teesside Dispatchable Power Agreement track across which effectively guaranteed the termination payment would be at a certain level to repay debt in the world where there was a meaningful net recoverable value definition. So, I suspect the producers will push for that to be tracked across but let's wait and see. |
| Kathryn Emmett | Yeah, as you say Oly, you know, Government is continuing to work on these and engage on the hydrogen production business model for the first CCS enabled projects but also looking forward to the HAR2 projects as well. So the |

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| | framework's going to continually evolve and develop and we'll be sure to keep everyone updated. |
| Oly Moir | And we'll also be sure to discuss some of those potential changes with LCP Delta in our next episode, which will be coming out at the same time as this one.<br><br>So, I think that's it for some of the key takeaways from where we landed on points which remained open on the LCHA. Thanks very much to everyone for listening and feel free to reach out to Kathryn or I with any questions or comments. |
| Kathryn Emmett | Thanks, Oly. |
| Oly Moir | Thank you. |