Constraints Collaboration Project – Show and Listen Webinar Q&A

Questions	Answer
Are generators with intertrip contracts protected from or exposed to penalties in other markets (ancillary services, wholesale, capacity market)? In other words, are they treated like a balancing service or a non-firm connection?	Generators with intertrip contracts are required to declare themselves unavailable for the intertrip service when contracted for response and reserve services. This is to prevent them being tripped off while delivering these other services. Generators can still participate in the wholesale and capacity markets while utilised for the intertrip service. If they are tripped off, then ABSVD will be applied to keep the unit whole in terms of imbalance charges.
To what extent is inter-tripping used for the north of Scotland and is there scope for more use?	We are engaging both Scottish TOs to propose options to develop and intertrip across north and central Scotland (B2/B4). This could be an expansion of the current B6 scheme or a brand new scheme. We are expecting submissions from TOs around April 25 when we can then consider which option to progress
There are several chicken-and-egg problems with getting demand for constraints moving. In particular, decarbonisation of heat by electrification cannot yet show value, and hence the capital investment does not occur and the flexible electrical load does not appear. How are you dealing with things like this?	Decarbonisation of heat is a potential demand source we'd like to engage more with and have some meetings set up soon with some potential developers to understand what they need and how DfC could help them. Our focus for DfC is to find ways to reduce constraint costs, but there are clearly broader benefits which can also be achieved through this scheme, we are talking to Government to ensure this is recognised.
Stephen, can say more about the relative importance of the three limits (voltage collapse, stability, thermal). You mentioned that stability limits are typically tighter than thermal limits. How often are [each] of the factors setting the limit? Thanks.	In terms of importance for system security, all of the services are equally important. If any of these limits are exceeded they could result in significant system disturbance and damage to people and property. A drop in voltage could create a cascade effect causing the system to collapse. Breaching a stability limit would normally lead to protection systems cutting in and the unit tripping off which can take time to resynchronise, particularly in the case of nuclear generators. If the protection systems don't cut in, there is a risk of physical damage to the units which can also present a risk of harm to people. Exceeding thermal limits can also create a risk to safety as when overhead lines heat up, they will sag and if they get too close to street

	lamps, or buildings, etc they can flash over (similar to lightning) which is very dangerous. Regarding their importance in terms of being the active limit on the network, stability is often the limiting factor for the B6 constraint due to having to manage the risk of a double circuit fault taking out one of the two AC coupled circuits that cross the boundary. This impacts stability more significantly than thermally as the thermal limit would include the HVDC link, where the DC coupling would not provide the same stability benefit as the AC circuits.
Is there a table somewhere that gives a translation from the boundary numbers (B4, 6 etc) to the names used in the daily capacity limit data (Scotex etc). It might help!!	We do not appear to have a translation table but we do publish a map showing the named boundaries here: https://www.neso.energy/data-portal/thermal-constraint-costs/constraint_map Page 12 of our ETYS 2023 shows all of the major boundary numbers: https://www.neso.energy/document/286591/download We also have more detailed network maps, for England and Wales here: https://www.neso.energy/data-portal/day-ahead-constraint-flows-and-limits/network_diagram_england__wales And for Scotland here: https://www.neso.energy/data-portal/day-ahead-constraint-flows-and-limits/network_diagram_scotland
Graph made using NESO data suggests that B6 is rarely if ever at the headline 6.6 GW capacity. Is this correct? How does this influence the context of this discussion? Thanks	This year there has been so much wind being constrained off in the north of Scotland which means the volumes of generation reaching the B6 is currently rarely exceeding the limits of this boundary. This prevents us from practically testing some of these solutions however we do expect the utilisation of the boundary to increase once the network reinforcement further north in Scotland are completed.
Would be interested in more detail on use of batteries (there has been a lot of interest in the potential for batteries to help address constraints) Do you also consider battery strategy to optimize constraints under B7,B6 boundaries rather than B4?	There are ongoing projects looking at operational and commercial ways to use batteries to relieve constraint costs: - The commercial workstream is currently confidential but there will be updates released early in 2025. - The operational workstream has investigated options of how to optimise the use of batteries within intertrips and alternative trip case monitoring schemes. - The one thing we are certain on is that a battery charging behind a biting export constraint will provide commercial benefit, we are looking at how to implement this in a fair way. Our Operational Transparency Forum is hosted every Wednesday and will include updates on battery workstreams as well as other operational changes and the opportunity to raise questions. Registration and further information can be found on the webpage: https://www.neso.energy/what-we-do/systems-operations/operational-transparency-forum

How much do you expect to be able to solve day-ahead? I.e. x% reduction in bids acceptance in the BM	This percentage could vary significantly depending on the certainty. In periods of high wind, we could have a high confidence on a proportion of this volume. Where there forecasted volume requiring curtailment is minimal, taking action at day ahead could be entirely wasted as forecast inaccuracies result in the constraint not actually biting. We are continuing to explore what proportion of actions we can confidently forecast at day ahead. The proportion of actions we would consider taking ahead of time would also depend on the expected discount of these actions at day ahead compared to BM options nearer to real time. The greater the percentage saving we expect from taking action at day ahead the stronger justification for acting on lower forecast certainty and procuring an increased volume ahead of time.
How is the cross over between Demand for Constraints and CMP440 (Re-introduction of Demand TNUoS locational signals by removal of the zero price floor) being managed	Removal of zero pricing in Demand TNUOS (CMP440) would remove this incentive distortion resulting in more efficient demand investment but this is uncertain and could come as late as 2026. Even with the reform, Demand TNUOS charges are still dampening signal and may not sufficiently incentivise flexible behaviour of an asset.
On B6 we have a theoretical technical limit of 10-12 GW (I think you said), we have a nominal capacity limit of c. 6.8 GW and over the last 6 months the daily limits have been around 4-5 GW. Meanwhile we have very high constraint volumes and costs. You can see why people are asking the question about what more can be done. Is this just a temporary thing that we will need to grin and bear?	Because our typical B6 limit is ~6GW but the intact capacity is ~12GW - we always have to operate to secure the worst fault. This is a requirement to secure against double circuit fault which is fairly robustly reviewed and approved. The day-ahead limits being published on the data portal for B6 are sometimes low because: we are expecting the boundary to not be congested i.e the forecast flow of power never exceeds the limit, either due to low wind output above the boundary, or due to significant wind being constrained off in the North of Scotland due to network upgrade works. The Day Ahead Engineer will not have invested time at day-ahead to optimise the limit as it will not be active and will not materially affect the operation or actions taken on the system. Rather the Day Ahead Engineer will have invested time optimising other boundaries that we expect to be active to minimise constraint actions and subsequent costs. We are working to clarify what is the best data to present on the portal regarding the B6 boundary.
So we have an interconnector seriously impacting the ability to meet Government targets on renewables and energy self-sufficiency? Are you telling the REMA team about this impact?	Yes. We are feeding this into DESNZ REMA team directly as well as via our NESO REMA team.
Did you specifically look at the the B6 intertrip with regard to renewables or did you include storage. You talk about 'generation' and not clear if you	We studied the system using the existing contracted intertrip providers, which do not include storage. We will be looking at how to leverage storage for constraint management via the Transfer

capture the differences of storage potentially as the constraint flows are not flat over the period an could be beneficial to let storage export in certain periods depending on cost to import in deeper/more expensive constraint	Booster project, and our other project looking at Day Ahead Battery Strategy.
Is there anything you can share on what those valuable learnings for the LCM are?	LCM has delivered a number of valuable learnings; - We have worked closely with Scottish DNO's to better understand the challenges they currently have regarding visibility of Low Voltage Domestic assets and their concerns around the impact of DTU at post code / MPAN level. - This has led to us implementing various processes to ensure we are supporting the DNOs to mitigate network risks including work to improve visibility with a Capacity Envelope and discussions around potential fault escalation procedures for Low Voltage assets. While this hasn't fixed the concern it is a really important discussion. - We Implemented the first 3rd party software as a service platform into NESO Network Control Centre - Learnings around the commercial feasibility / efficiency of a DA constraint market, giving us a better understanding of what price is required for providers to participate. - The clearest learning is how challenging it is for providers to efficiently bid at levels deemed economical vs BM actions
Ed - the two risks for CMM are both related to systems. Load can dispatch in real time with the right automation - this is an aggregator problem and is already solved. Location is a NESO problem - you do not have sufficient operational visibility in ENCC of where demand-side assets are - but that doesn't mean that they move around. They don't. Will you be addressing your visibility of location?	From a timing perspective, where there is benefit to NESO and the provider in dispatching near to real-time, we would naturally seek to do so. If there is sufficient benefit to instructing assets ahead of time, this is also being considered under the opportunities presented by a constraint market. From a locational perspective, for contracted demand-side assets we have to balance practical limitations on the granularity of locational and metering data with the benefits of improved visibility. We are continuing working to assess and improve our locational mapping and visibility. We have a reasonable view of general demand with more uncertainty coming from renewable generation and flexible bidirectional assets like batteries and interconnectors. This creates the main challenge, which is to forecast where and when constraints will bite with the risk that by taking action on a constraint boundary one too far south or in the wrong half hour period, that action could be entirely wasted.
Re Time - have you considered a hybrid approach? Time-ahead actions in the CMM where you have high confidence and then closer to real-time actions in the BM to fine tune. There is clearly	Yes, this could represent a balanced approach and the only viable option for constraint markets as we will not be able to cost-effectively eliminate all requirement for real-time actions. The proportion of actions we can take at day ahead will depend on our confidence in forecasted constraint volumes and forecasted BM action prices to set the counterfactual. We do currently use DFS and LCM to procure

a trade-off between early action ve waiting to the last minute and facing more expensive actions.	flexibility ahead of time from non-BMUs but further justification or mitigation would be needed to allow participation from BMUs given the challenges with gaming we've outlined.
Has there been any progress in considering interconnector participation in the CMM?	There are two potential aspects to interconnector interactions with a constraint market. The first is a challenge regarding visibility and forecasting. Being flexible assets whose positions can move up to almost an hour before real time presents a challenge to forecasting constraints at the day ahead stage. We are always reviewing the tools and processes we have to view and access interconnectors to better manage and reduce this uncertainty. The second aspect is regarding options to use interconnectors to resolve network constraints. Any actions through a CMM will need to take into consideration many factors including potential regulatory implications, impacts on interconnected systems and compatibility with current interconnector constraint management actions such as capacity restrictions (NTCs) or countertrading.
For the next few weeks there are no major planned outages across the B6 boundary, but the Transmission Owner (TO) requires outages starting in week 3 of 2025." If NESO knows that in week 3 of 2025 there will be outages on B6 would it not make sense to start to procure additional flexibility now?	In this hypothetical scenario there is a clear indication that some action to manage constraints may need to be taken. Despite the awareness of the outages, it is still not clear the required volume of constraint management action in each settlement period. For periods where we may expect a requirement we must be able to demonstrate that even when including for any uncertainty, we still had confidence it would be the most cost-effective action. If there is evidence to suggest that taking actions in these timescales could offer a suitably significant cost saving compared to day-ahead or within-day action, please share this with us at box.market.dev@uk.nationalenergyso.com by the 17th of January as part of our request for feedback. Unless we can justify a change, our BAU process is to run the Local Constraint Market where we have confidence in forecasted constraint volumes. Then within day, if need be, buy off generation in the BM and arm the intertrip where possible.
I wanted to flag one thing that Ed said: you said that "when we turn down generators to stop overloading a contract, we must be certain that ….". I would like to push back on that. You can never be certain that a particular action will be better than waiting until nearer real time. But you can consider the certainty / confidence / risk management consequences. That might mean taking an action ahead of time when there is only 90%, 80%, 70% …. confidence that that individual action will deliver	That's a fair comment and perhaps 'certain' is a little strong – maybe as certain as possible. When spending consumer money, we must be very conscious of risks as an organisation, given the complexity in keeping the power flowing. There is always a tension between risk management and innovation/change – which is exactly where we as a team sit. There will be periods where we do have appropriate certainty of some constraint requirements at day ahead and these could be addressed through a CMM. We would also consider taking actions at day ahead where taking some uncertainty was clearly justified by a significant expected cost saving vs taking the action in the BM. There may be some acceptable level of risk that actions could turn out cheaper within day – this risk is almost never zero but taking actions that turn out not to be needed at all very quickly erodes a small or moderate potential saving.

value. But the question shouldn't be whether each individual action leads to a benefit – some may be more expensive than the BM with hindsight – rather weather the totality of all actions, the overall portfolio of actions, is cheaper than the counterfactual. My question is: are you analyzing these options from this 'risk management' perspective? Many thanks.	
So can you confirm what the outcome of your analysis for the CMMs - is the proposal that you will not be implementing new constraint management markets and just keeping LCM?	Currently that is our minded-to position, unless the response to our request for feedback provides strong evidence to support an expansion of the CMM by 17th January. We will continue to facilitate a low-barrier, route to market for non-BM demand-side flexibility via our Local Constraints Market, until December 2025 at the earliest and our Demand Flexibility Service. This approach will continue to explore the potential of flexibility – including demand turn up - and seek to understand whether these sources can compete with other alternative constraint management actions. LCM progress and the broader assessment of Constraint Management Markets through CCP will also be used to inform the development of the flexibility services. Where results from the services, or external conditions, or policy or economic factors support a change or expansion of constraints markets we will review the options available.
WRT gaming issue – Is it not down the strength of NESO's T&Cs and what NESO includes in order to mitigate these risks?	Most gaming, including this example, can be largely mitigated by stricter T&Cs and more severe penalties. However, overly restrictive rules can cause increased pricing as providers account for some level of lost revenue. This impact can be compounded by low liquidity as a result of limited market growth from restricted participation rules or exclusions from participating in other markets. We must also be conscious that this creates an increased burden on our performance monitoring systems and administrative teams.
There is significant work being undertaken by NESO to improve forecast particularly wind – how have the improvements from this project so far fed into your work?	Improved wind forecast does significantly aid our forecasts of when and where constraints will bite, some of these improvements are included in the September data and other improvements should continue to be seen in forecasts going forward. Where wind forecast changes improve our constraint forecast accuracy we will seek to use these to refine our process for evaluating the risks of taking actions through services ahead of time.

Thanks NESO - can I summarise then your last 6 months of work as below...which seems to conclude that none of these worth taking forward?:
 	
• Intertrips - not much scope of benefit in increasing them more as you never know when they'll be used given all the network outages needed to meet CP2030 etc...but a nice option to have for NESO for the occasional day you might need them? But it won't solve the issue and let lots more Wind flow ax constraints
• CMM - more risks than benefits on balance as again NESO never knows how much it needs D-1 and might end up chasing tail/ the mkt....but actually Batteries could do this mkt on both side of the Constraint?
• LCM - biggest issue is the (low) prices you are able to offer (trade off to curtailing wind c.£45/MWh) compared to DNOs (can offer up to £600/MWh as they trade off Network investment). Ed sort of alluded to this (although this price issue not in your slides!?)
 	
fair and accurate summary?
	We see potential in some options to be taken forward but we have not committed to any projects - we are still investigating if these could be feasible.
	
	Below is the summary:
	
	• Technical options to increase the flow over boundaries:
	  ○ Extended intertrip scheme: We're exploring the development of intertrip schemes beyond B6 and have future plan in place for intertrip scheme in East Anglia (EC5). To do this, we're engaging both Scottish TOs to propose options to develop an intertrip across north and central Scotland (B2/B4). This could be an expansion of the current B6 scheme or a brand new scheme
	  ○ Day ahead battery strategy: Project is underway to investigate operational solutions to improve the effectiveness of using batteries to optimise constraints and provide customer value. The existing case study is focusing on optimising the B4 constraint
	  ○ We are continuing with the innovation project about a transfer booster scheme in Q2 2025
	
	• Constraints Management Market:
	  ○ We're taking Demand for Constraints (or long term CMM) forward for detailed design and CBA in January 2025
	  ○ Further engagement is underway with various types of demand facilities (e.g., electrolysers, data centre, heat network, industrial electrification). We're specifically looking for demand projects with target commercial operation date (COD) before 2030, the ability to flex their operation within short notice dispatch period (within hours), and the ability to provide a large volume of demand to help manage constraints.
	  ○ Industry proposals claim short term CMM would enable participation of new technologies and increase certainty for participants by taking actions ahead of real time which may then lead to lower price, but we see some material risks compared to the proposed benefits. These significant risks are difficulty predicting constraints due to demand and wind forecast uncertainty, increased gaming potential with additional BMUs, complexities around procuring replacement energy at day ahead which undermines co-optimisation for stability, voltage and positive reserve
	  ○ Industry is welcome to submit feedback on any assumptions, interpretations, risks or proposed benefits which have not been captured (before 17th January 2025).

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<td>Does NESO see an opportunity to expand the geographical scope of the LCM to south of the B6 boundary to test in a controlled manner whether a CMM can tackle ‘replacement energy’ costs?

2. Could a shifting the current intra day instruction window in the LCM closer to real time, again in a controlled manner, be an opportunity to test the most optimum timeframes for procurement in a CMM?</td>
<td>These are both options we have been considering.

Currently the procurement of stability, voltage and margin often require additional generation to be procured. There are instances where we procure generation for the sole purpose of replacement energy but in more cases than not if we did not co-procure these services we would have to unwind these CMM actions to procure the other services. As we enhance our suite of day ahead services and more of volumes are procured through these services, we may find there is more potential for a day ahead procurement of replacement energy through a CMM.

There is some improvement in forecasts as we move from day ahead to 12 or 6 hours ahead of real time, however there is still significant uncertainty in requirements. We may be able toc consider a within day CMM however we would want to be sure that any improvements in forecast certainty weren’t outweighed by disadvantaging assets which may benefit from increased notice (one of the two main benefits we are considering being offered by a CMM). This is an area where feedback from asset owners and operators which may have a material impact on the economic merits of a CMM we would request are shared with us at box.market.dev@uk.nationalenergyso.com by the 17th of January. General feedback on LCM timings can be provided to box.futureofbalancingservices@nationalenergyso.com</td>
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<td>Also we need to see the Economics/ prices that might be attained that we've been asking for since Jan.24 when project started - e.g. what are these "mismatches you highlight between what you believe the value to consumers to be and what the benefit is for participants" that you mention in slide 6?</td>
<td>We have combined the LCM data with some BM SCOTEX data which we are able to share. LCM is VWA for all bids and BM data is VWA for accepted bids, both are historical averages for months across 23/24.

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<tr><th>Month</th><th>BM VWA bids</th><th>LCM VWA bids</th></tr>
<tr><td>08/23</td><td>£67</td><td>£108</td></tr>
<tr><td>09/23</td><td>£64</td><td>£110</td></tr>
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