Public

Constraints Collaboration Project Update

19 December 2024

Introduction

Agenda	Timings	Speaker
Introduction	2 mins	Becky Hart
Project Update	2 mins	Alifa Starlika
Topic 1: Demand for Constraints	5 mins	Alifa Starlika
Topic 2: Intertrip System Study and Q&A	40 mins	Steve McAllister Shadi Khaleghi
Topic 3: Constraints Management Market review and Q&A	40 mins	Ed Farley Gus Clunies-Ross
Next steps	2 mins	Alifa Starlika

NESO National Energy System Operator

Introduction: Today's speakers

Becky Hart

Alifa Starlika

Steve McAllister

Shadi Khaleghi

Gus Clunies-Ross

Ed Farley

NESO National Energy System Operator

Objectives

Objectives of this session

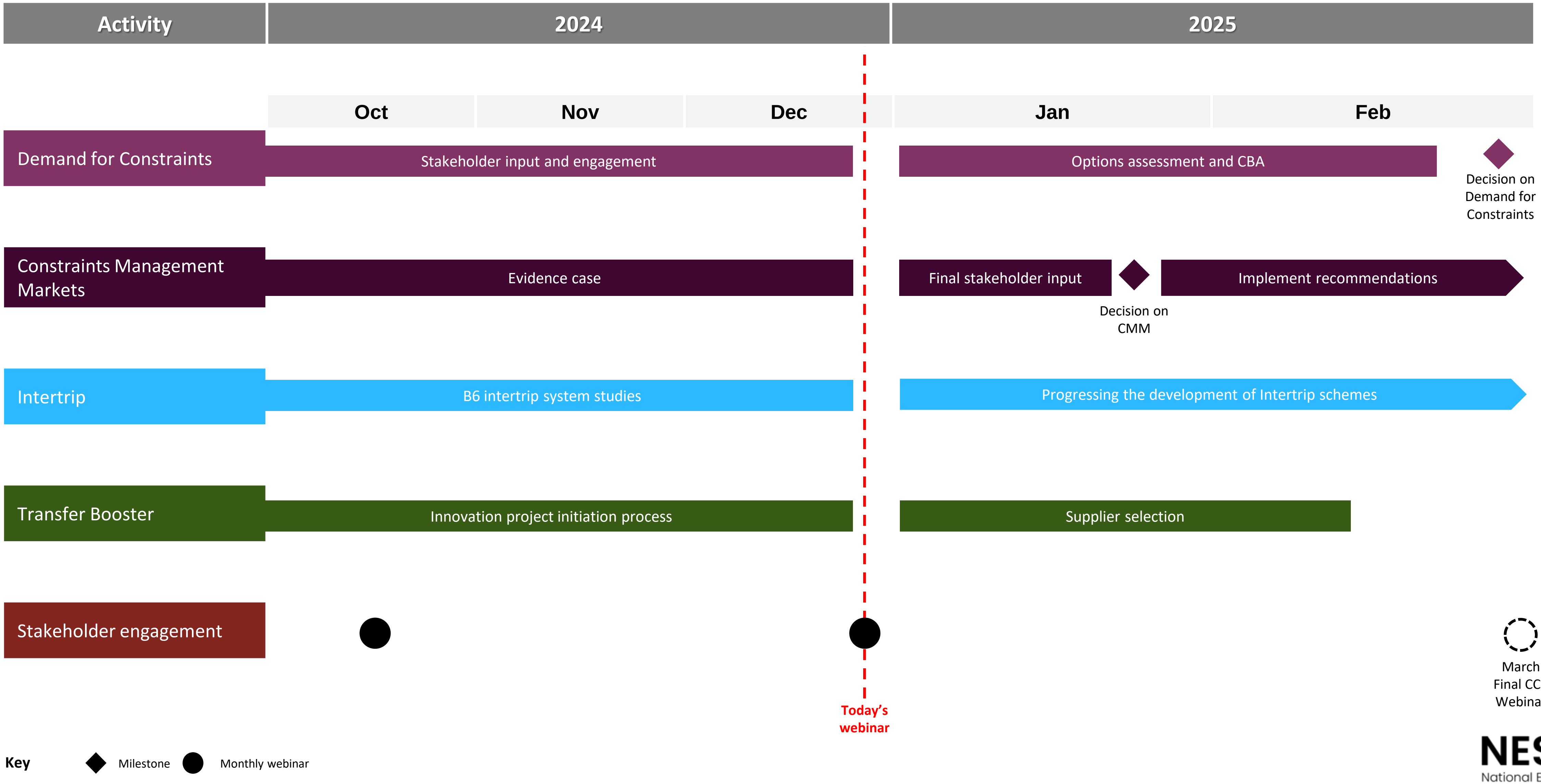
1. To share updates on the four workstreams of the Constraints Collaboration Project

2. To share findings on the Intertrip system study and present NESO’s assessment of the potential of short-term constraints markets

3. To provide industry the opportunities to ask questions and share insight

NESO National Energy System Operator

Project update: delivery plan and timeline



Disclaimer: These dates are indicative, and we reserve the right to alter these timelines at any stage in the process.

NESO National Energy System Operator

Since our last webinar, we've progressed our thinking on Demand for Constraints

Potential benefit

- Demand for Constraints has potential to address the issue of no locational pricing and dampened locational siting signal for demand due to the current £0 price floor applied in demand TNUOS. This means that large demand sources do not benefit from locating close to the supply and have no incentives to operate flexibly to support constraint management.
- Use of the DfC could reduce curtailment costs and ensure productive use of otherwise curtailed renewable generation.

Stakeholder Engagement

- 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.

Identified challenges

- There is a mismatch between what we think represents value to the consumer and expectations of some of the potential participants.
- A lack of flexible, large demand centres planning to come online before 2030 means there are concerns if there will be any suitable participants.
- Are there other types of demand sources we need to explore?

Next Steps

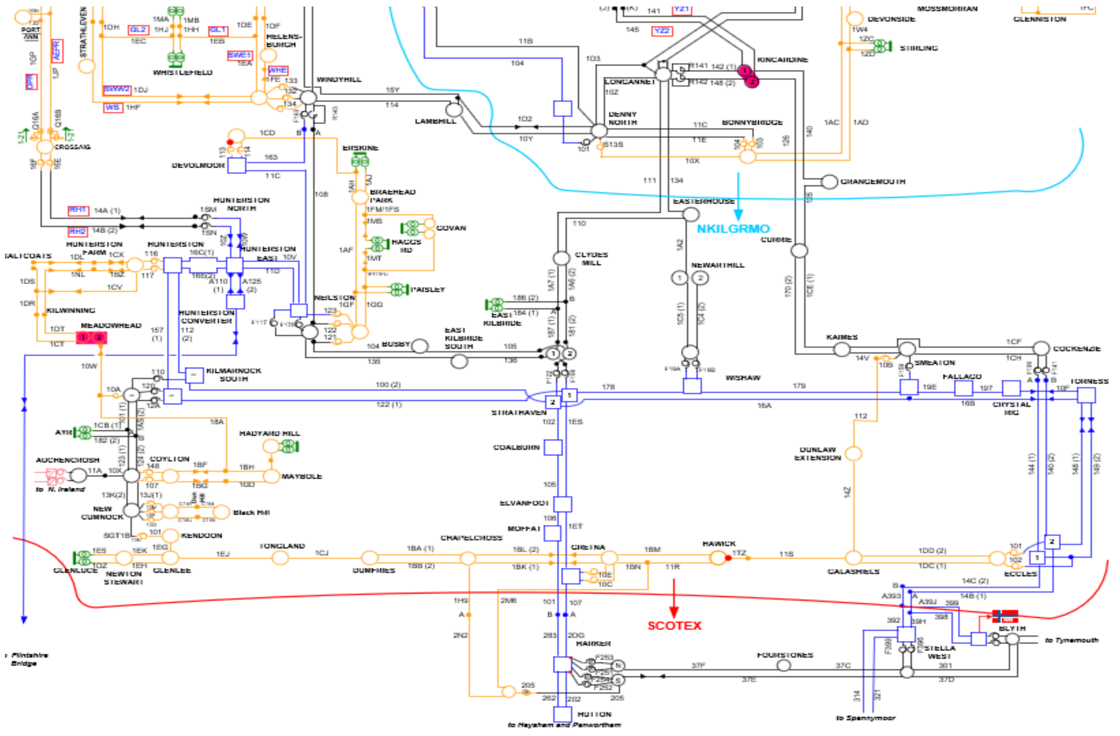
- In January 2025, we will assess Net Consumer Benefit of different potential service designs for DFC:
  1) A fixed utilisation tariff (£/MWh for excess electricity consumed) from demand facilities to NESO.
  2) A utilisation tariff based on an agreed percentage discount from spot price from demand provider to NESO.

Discussion

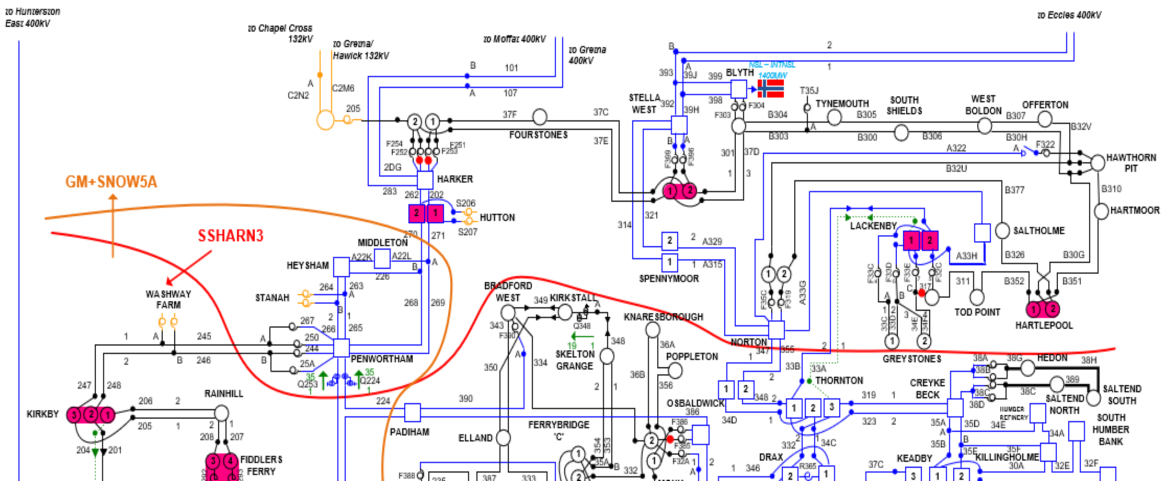
Topic 1: Findings from Intertrip System Studies

Increasing the B6 flows moves the congestion to neighbouring regions

B6 Boundary, also known as SCOTEX



B7 Boundary, also known as SSHARN3



NESO National Energy System Operator

NESO has been working on system studies looking into the current use of the B6 intertrip

Objectives of the study

1. Understand best practice when arming B6 Intertrip
2. Use off-line system studies to investigate the maximum/optimum amount of generation to arm.

Drivers	Description
How much the contracted wind is generating	We can only arm what is generating, e.g. if 800MW from a contracted pool of 1500MW was actually exporting MW, this would be a physical limit on volume available to be armed.
Achieving a balance between volume armed on intertrip, and manual post-fault generation reduction	Arming generation to intertrip costs an arming fee. If not using intertrip, we plan to manage boundaries by taking post-fault generation reductions if the fault happens, which will incur cost only if the fault happens. Therefore once we determine the flow limit and type of constraint across a boundary, we must also determine the optimum volume to arm to intertrip, in conjunction with how much generation we would plan to reduce in 10-20 minutes post-fault.
Largest generation loss size we are currently managing on the system	The volume armed on intertrip should not exceed the largest securable infeed loss managed at that time on the system. We need to ensure the amount of generation we might 'lose' on intertrip does not cause unacceptable frequency deviation.
Network reinforcements	The extensive works to upgrade the transmission system in the North of Scotland are causing significant constraints which means B6 is not congested, i.e., much generation is constrained off before it gets to the B6 area. Information on the daily constraint limits, and expected flows across them, can be found on our Data Portal Day Ahead Constraint Flows and Limits | National Energy System Operator .

We currently arm the B6 intertrip scheme infrequently, and when we do, arming a significant amount of generation does not necessarily result in an increase in the flow-limit on the boundary across B6

Findings

Arming a significant amount of generation does not materially increase the flow-limit on the boundary due to the complex nature of this limit: For example we could get a B6 limit of c. 5500 MW including 1000MW armed I/T and also get the same limit with 500MW armed I/T plus a plan to de-load 500MW of generation post-fault, the best value for the consumer is the latter. This is because we would only be paying for 500MW of arming fees, and making the judgement that the fault is fairly unlikely to happen and therefore the deload and replacement energy costs are not likely to be incurred.

Arming a significant amount of generation to enable increased flows across B6 leads to post-fault overloads on other system boundaries, both in Scotland and in the North of England. There are other significant system boundaries immediately above and below B6, (e,g, NKILGRMO and SSHARN3). Whilst we wait on re-enforcements to these boundaries to be delivered and/or existing intertrip to be extended to cover them, flowing more power across B6 often moves congestion to these neighbouring boundaries.

The flow-limit we can achieve on B6 is sensitive to factors, such as the outage pattern on the system, flow patterns across the region, and what generation is operating. The limiting factor can and often does change, and can be set by thermal capability of the system, voltage collapse, or stability (both dynamic and transient/'pole-slipping' of generators).

Initial off-line studies indicate that the stability limit can be slightly increased following the deployment of a new synchronous condenser in the central B6 area. We will pursue this by using operational tools to monitor stability once the asset is commissioned to validate the off-line studies, ensuring that when/if we allow the flow to increase over the boundary, we maintain system security.

NESO National Energy System Operator

Actions are underway to enhance the use of Intertrip scheme

Exploring the development of Intertrip schemes beyond B6:

- 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.

Future plan in place for Intertrip scheme in East Anglia (EC5):

- We have a tender ongoing for an enduring service for Intertrip capability in East Anglia. This will build on the current interim contracts we have with some generators and will include an upgrade to the scheme to allow tripping in stability timescales (200ms) from the current 10sec deload.

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.

Q&A

Discussion

Topic 2: Constraints Management Market Evidence Case

A simplified overview of Constraint Management Markets (CMM)

A day ahead (or closer to real time) CMM can be designed in different ways, so we have broken it into the different features and have assessed the relative opportunities and risks are associated with each.

FEATURE	Procure generation turn down or demand turn up ahead of time	+ Procuring replacement energy by increasing generation or turning down demand	+ BMU participation in CMMs
AIM	Resolve network congestion above/inside a constraint boundary	Procurement ahead of time will be cheaper than in real-time	Expand market participation beyond smaller non-BM assets
PROPOSED BENEFIT	Enabling participation of new technologies; More certainty for participants		Providing more certainty could lead to lower prices
RISK	Uncertainty of constraints volume means inadvertent higher costs	Uncertainty of constraints; Inability to co-optimise	Potential for gaming may lead to higher consumer costs

Resolving network congestion by curtailing generation or turning up demand

The primary use case for a CMM is to resolve network congestion by reducing the flow of power over a boundary. The BM is currently the primary tool for this, but implementation of additional CMM potentially provides the opportunity to access this more competitively from alternative sources.

Proposed Benefits:

- To reduce costs associated with managing thermal constraints by:
  - Providing greater revenue certainty ahead of time leading to lower bid prices.
  - Increasing competition by enabling participation from more asset types leading to lower bid prices.

Learnings from Local Constraints Market (LCM)

- LCM was introduced in December 2023. Bids are currently invited for two constrained boundaries between Scotland and England.
- The majority of volume procured to date (165MW in total) is domestic demand turn-up which would otherwise be unavailable in the BM in real-time. However, procured volumes are lower than initially expected.
- Progress has been made in enabling participation, including: min. participation thresholds, permitting asset metering, ABSVD opt-out, DNO coordination.
- We and the industry have taken many valuable learnings from LCM and will continue to explore further improvements in 2025.

Risks:

- Taking actions further ahead of real-time increases the likelihood that information used to aid decision-making is inaccurate.
- This results in a variable level of uncertainty which NESO have to manage in relation to:

  TIME - The optimum period where a constraint management action would be most effective.

  LOCATION - The optimum location where a constraint management action would be most effective.

- These variables are influenced by many things, including forecasting errors and further intraday market trading, including on interconnectors.

Procuring replacement energy by increasing generation or turning down demand

An additional use case for a CMM could be to replace bulk energy volume on the other side of a constraint following actions taken to resolve network congestion. The BM is currently the primary tool for this, but implementation of additional CMMs provides the opportunity to access this more competitively from alternative sources.

Proposed Benefits:

- To reduce costs associated with replacing energy as a consequence of managing thermal constraints by:
  - Providing greater revenue certainty ahead of time leading to lower bid prices.
  - Increasing competition by enabling participation from more asset types leading to lower bid prices.

Risks:

Previous issues associated with time and locational elements of uncertainty

+

- Inability to co-optimise the procurement of replacement energy with other energy/system actions in real-time.
  - Stability & voltage
  - Positive reserve
- Not being able to co-procure is likely to result in higher costs to the end consumer

Expanding participation beyond smaller, non-BM units to include BMU competition

The current base case assumption for CMMs is that they seek to enable participation for assets which don't currently participate in the real-time market used for balancing and constraint management (BM). Proposals for additional CMM features raised throughout CCP include the opportunity to expand the participation rules to include BMUs.

Proposed Benefits:

- To reduce costs associated with curtailing or replacing energy to manage thermal constraints by:
  - Providing greater revenue certainty ahead of time leading to lower bid prices.
  - Increasing competition by enabling participation from more asset types (e.g., BMUs) leading to lower bid prices.

Risks:

Previous issues associated with time and locational elements of uncertainty

+

- An added potential for gaming may be present if market participants are able to hedge their bets across multiple markets which seek to procure the same product.
  - The provision of baselines in the BM limits the opportunities for poor market conduct, however introducing a new revenue stream ahead of time may undermine this.
  - Perverse incentives and opportunities for gaming could increase the likelihood that some actions could otherwise be avoided and consumers pay more.

NESO
National Energy System Operator

On balance, we foresee the risks associated with introducing additional CMMs outweigh the proposed benefits

How do you feel about the CMM evidence case? What have we missed?

Key: Proposed benefits | Risks

NESO National Energy System Operator

Q&A

Next steps

For CMM, by 17th January, please let us know:

- Feedback on any assumptions, interpretations, risks or proposed benefits which have not been captured
- If you would like more detail on the analysis or a follow up conversation.

We will review feedback and update our findings, with a plan to share final assessment and recommendations for next steps in March 2025.

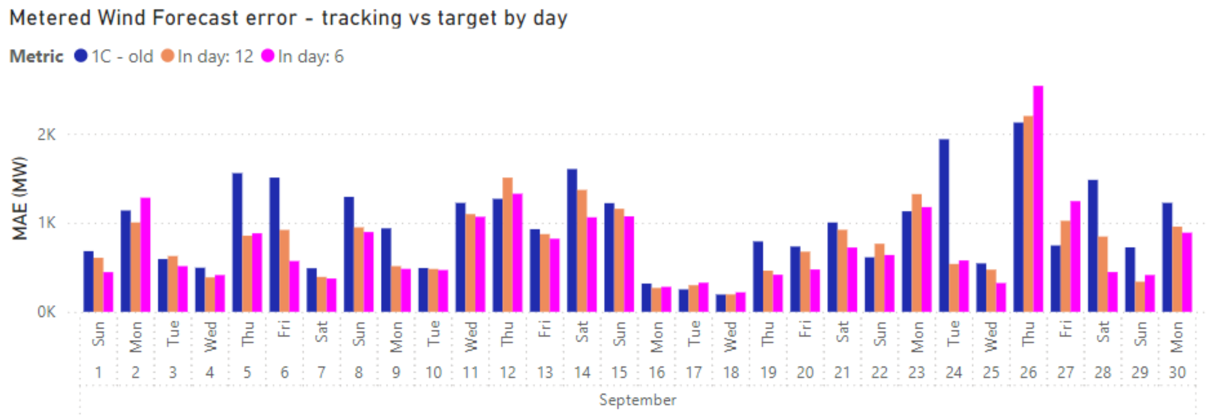
NESO will continue with the innovation project about a transfer booster scheme as well as evolving existing services (e.g. Local Constraint Market, intertrip schemes) to help manage constraint actions in a simple coherent way, which results in savings to the consumer

NESO National Energy System Operator

AOB

Annex

Example #1 of time uncertainty: wind forecast errors



National wind forecast Mean Absolute Error (MAE) and Absolute Percentage Error (APE)

Period	0900 D-1 MW (APE)	12h lead time MW (APE)	6h lead time MW (APE)
SP48 26/09	1826 (10.4%)	1179 (6.8%)	3480 (20%)
SP13 26/09	3688 (21.5%)	3409 (19.9%)	3168 (18.5%)
Sept average	974 (5%)	800 (4.2%)	745 (4%)

Analysis

What is the issue?

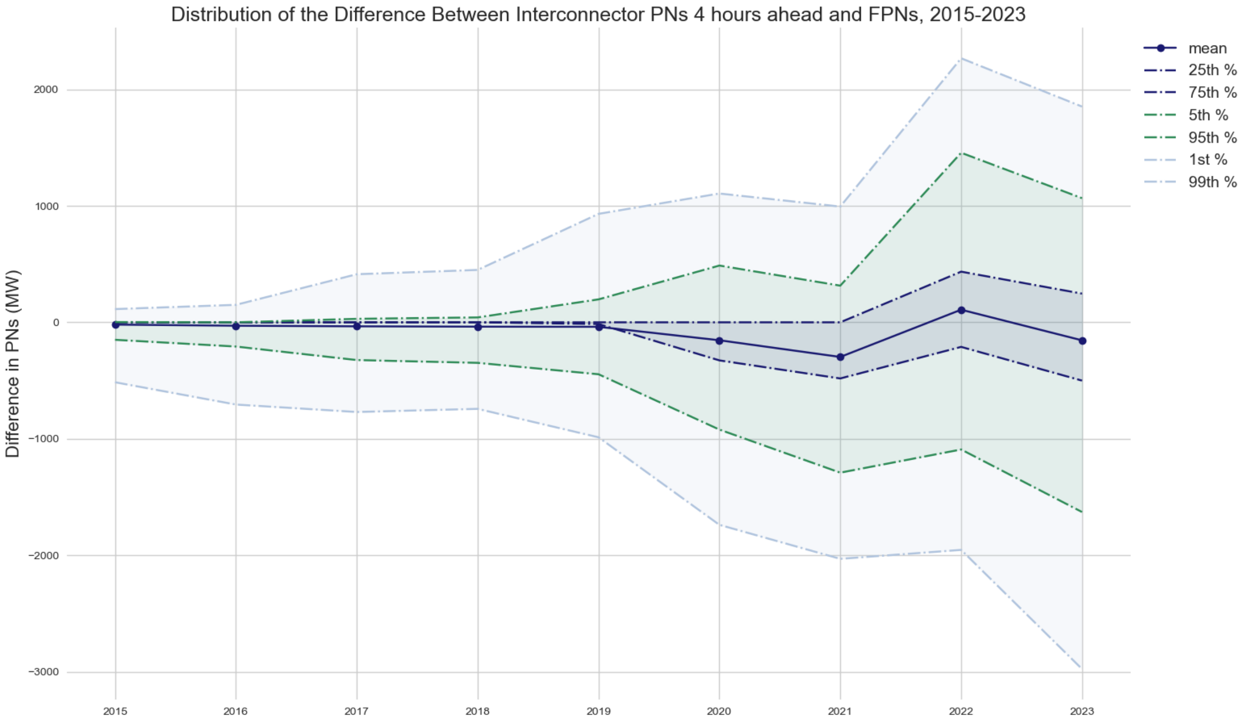
- Forecasting wind far in advance of real time possesses risk of significant uncertainty/errors
- The situation is exacerbated with difficulty in forecasting when and where constraints will occur
- Other factors can cause large ‘error’ from day ahead, i.e. self-curtailment due to CfDs
- Wind errors can have significant implications on Real Time operations and associated costs
- This typically improves as we approach real-time but even at 6 hours lead time the error can still be high

How are we trying to address this?

- We are actively improving accuracy of forecast through continuous review of the methodology and capability should result in improved accuracy.

NESO National Energy System Operator

Example #2 of time uncertainty : interconnector flows forecasts



Analysis

What is the issue?

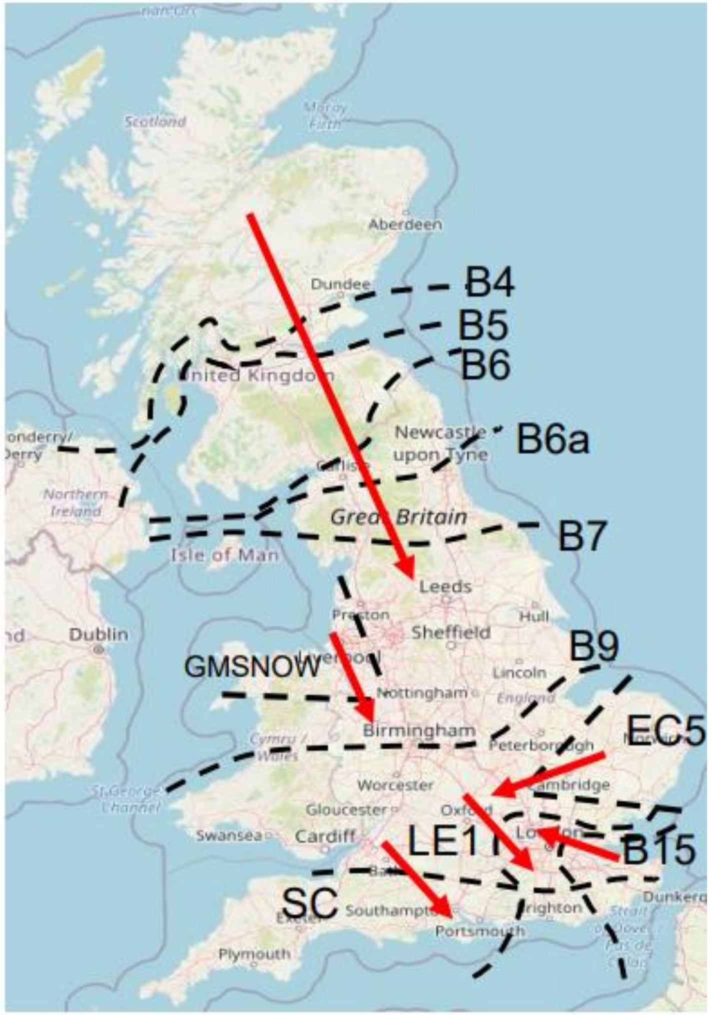
- NESO's view of interconnector flows can change significantly during the day
- The percentage of time in the year that the change in interconnector PNs - 4 hours ahead vs 1 hour ahead (FPNs) - is within the range on the Y-axis
  - i.e. the green dotted lines are the 5th and 95th percentile, meaning 90% of the time the change in IC PNs to FPNs is within the green shaded area
- How frequently we see these differences, and how large the differences are, is increasing with time. This makes forecasting IC flows challenging
- Changes in interconnector flows can significantly influence network flows and can mean under/over forecasting availability of network capacity. This adds to the uncertainty as to whether actions taken in CMM ahead of time would be the most effective ones.

How are we trying to address this?

- NESO has the following constraint management actions: capacity restrictions, countertrading and SO-SO trades, the use of all of which are under review for adaptation to a more renewables-based system.

NESO National Energy System Operator

Example #3 of location uncertainty: Changing boundary limits



Example of boundary flows, taken from NESO Operational Transparency Forum 18/12/24

Analysis

What is the issue?

- The fundamental drivers of boundary limits are the physical capability of circuits, and the location of generation and demand.
- These are determined by:
  - Physical capability of circuits: If a circuit faults, or has to be removed from service at short notice, this will impact the planned boundary flows.
  - Location of the generation and demand: If the generation or demand patterns change between planned and operational timescales, the flow capability of the boundary may change. Interconnectors being both generation and demand have a big impact here.
  - Closer to real-time operations: limits can often be increased. For example, NESO may re-assess a post-fault action plan and decide to increase the limit accordingly to release more power across the boundary.

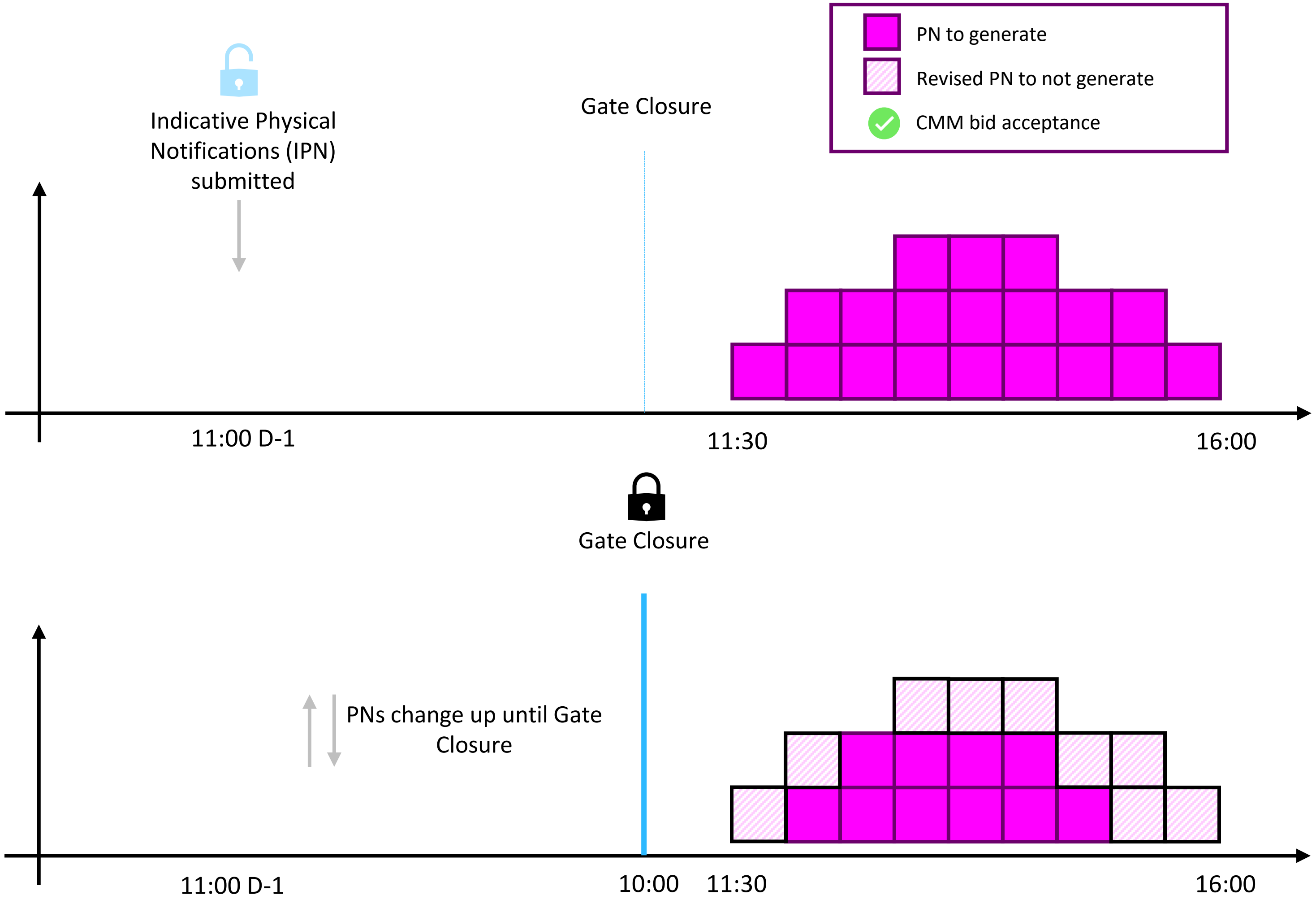
What are the implications?

- Boundary limits can change significantly within day, which adds to the uncertainty of managing constraints before real-time.

Example #1: Gaming risk for BMU participation in CMMs (1/4)

<u>Why is baselining relevant for BMUs?</u>

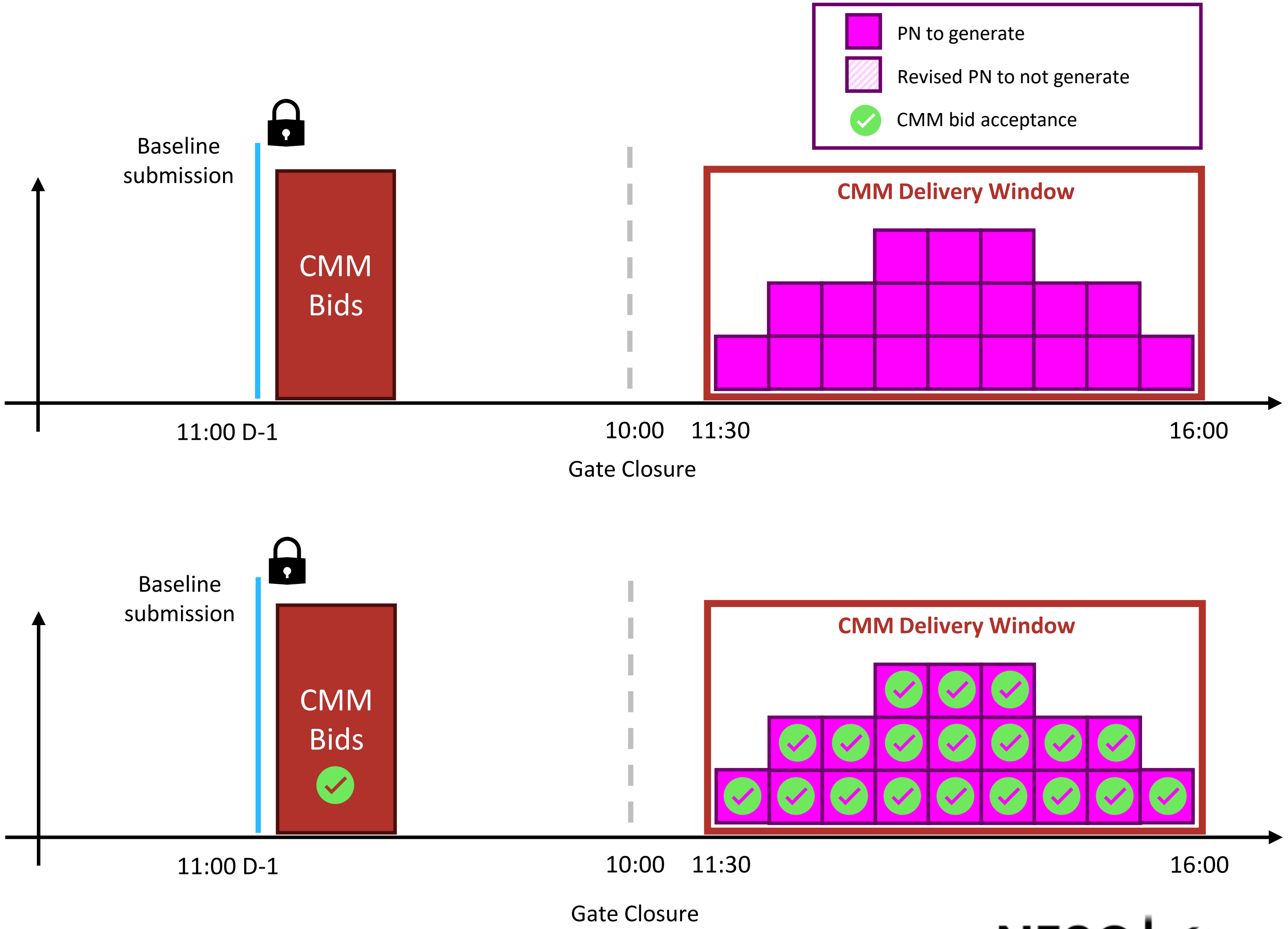
- The functioning of the BM is predicated on the concept that BMUs submit Physical Notifications to NESO to indicate an intention to generate/consume. Units also submit Bid Offer prices to indicate prices to move away from that baseline.
- PNs are submitted voluntarily ahead of time by market participants. Indicative PNs (IPNs) are received by NESO from all BMUs at 11:00 the day before the operational day (D-1).
- BMUs are free to change these IPNs between 11:00 D-1 and gate closure to reflect planned changes in output.
- At gate closure, 60 minutes ahead of the start of the forthcoming settlement period, these PNs become Final Physical Notifications (FPNs) and can no longer be changed.



Example #1: Gaming risk for BMU participation in CMMs (2/4)

<u>What could BMU participation in a CMM mean?</u>

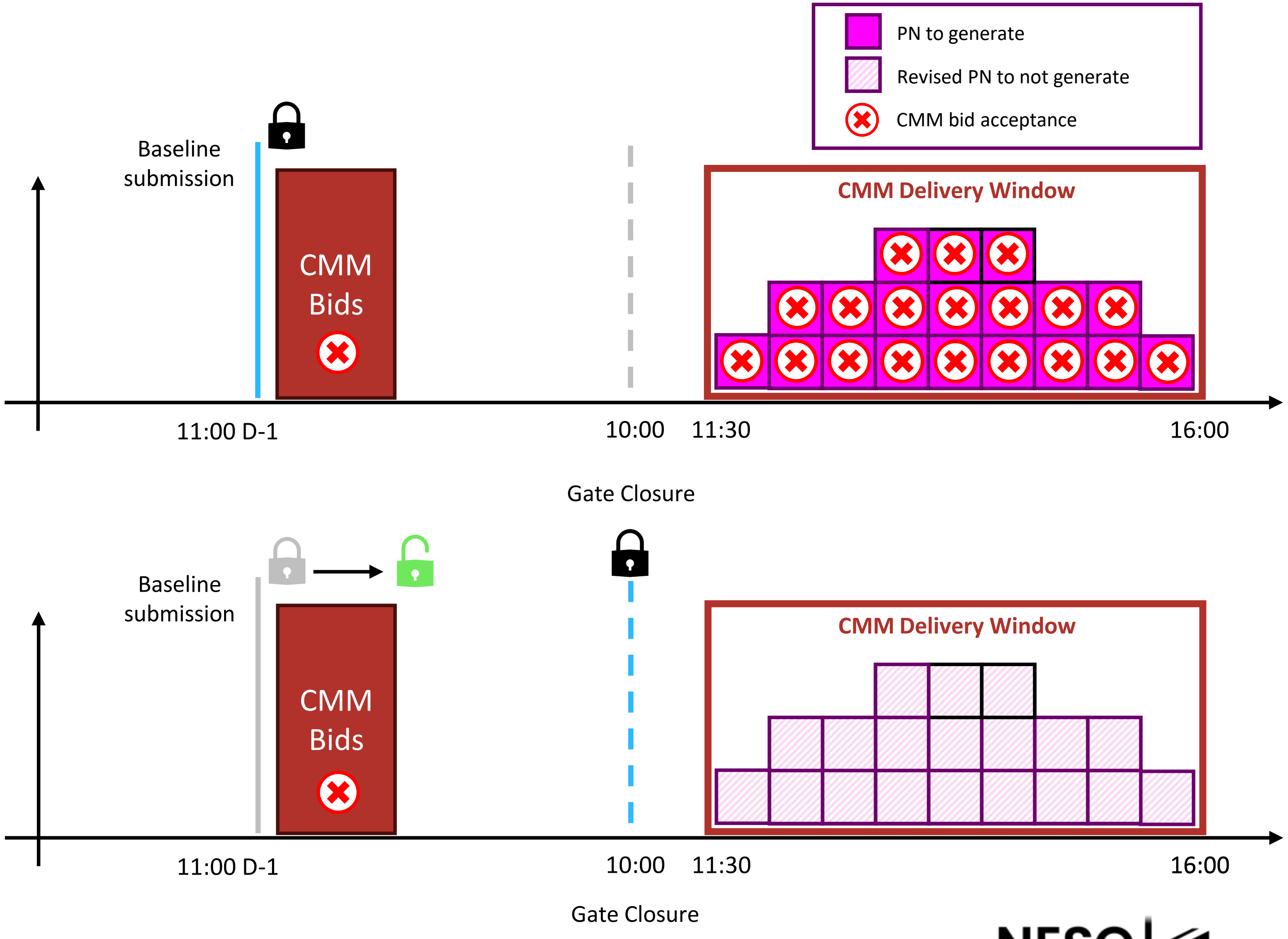
- CMMs provide a signal to generators (demand) to curtail (increase) output against a pre-determined baseline.
- Units participating in a CMM would therefore need to declare their intentions to generate/consume as part of the procurement process.
- For BMUs, this would mean submitting intentions to generate/consume (PNs) at day-ahead.
- If a generator BMU submitted positive PNs at day-ahead, was expected to be behind a network constraint, and was cost competitive in a CMM, there is a likelihood they could be curtailed via a CMM with guaranteed compensation.
- This would mean that the nominated baseline should remain unchanged between D-1 and the CMM delivery window so that the BMU can demonstrate performance against this when curtailing output.



Example #1: Gaming risk for BMU participation in CMMs (3/4)

Why might this present a gaming risk?

- This example works on the assumption that units are submitting information which accurately reflects their expected running patterns. The previous slide shows how this would work well in the case of a CMM.
- Equally, if the same generating BMU submitted positive PNs and was not behind a network constraint – or was not cost competitive in a CMM – they would not be selected or compensated via a CMM ahead of time.
- As per grid code, this asset would be then free to revise their PN (e.g., down to zero) up until gate closure without restriction.
- We think this introduces an additional risk for gaming where units might be incentivised to submit false intentions to run at day-ahead in order to attract a CMM payment.



NESO National Energy System Operator

Example #1: Gaming risk for BMU participation in CMMs (4/4)

How might gaming materialise?

- To build on this example, a generating unit could submit an intention to generate at the day-ahead stage without having yet traded any volume in a market. This intention to run could be assessed as part of a CMM and if the bid was deemed competitive, compensation could be paid to the generator to unwind a position which had not yet actually been established. Paying to unwind a position which has not yet been established does not deliver consumer value.

How does this differ from current BM participation?

- This risk is much lower under the current arrangements because at gate closure, there is confidence as to whether a unit is genuinely intending to run or not.
- There are limited incentives to falsely submit PNs because units are either:
  a) Expected to deliver on intentions to run at unprofitable levels, or be penalised via imbalance charges
  b) Compensated for curtailment by the SO at pre-agreed bid prices which will recover their marginal costs.
- There is no opportunity to re-nominate a new baseline beyond this assessment in the BM as it has become final at gate closure, unlike if this decision was taken at the day-ahead stage through a CMM.

How do we manage this risk for non-BM units today in LCM?

- The risk that participants try to game baselines exists in LCM today. However, it is mitigated by a requirement for all registered LCM participants to submit metered data to NESO, irrespective of whether they are contracted or not.
- This data can then be used to inform whether a baseline provided at D-1 has been artificially established versus metered output during the LCM delivery window.

Thank you!

NESO
National Energy System Operator