Transmission Charging Methodologies Forum and CUSC Issues Steering Group

Meeting 131 - 02 February 2023

ESO

Agenda

1	Introduction, meeting objectives and review of previous actions **Claire Huxley - ESO**	10:30 - 10:35
2	Code Administrator update **Paul Mullen - Code Administrator ESO**	10:35 - 10:40
3	Enduring Fixed BSUoS Arrangements **Naomi De Silva - ESO**	10:40 - 10:55
4	Payment timescales for Monthly Invoices **Nick George - ESO**	10:55 - 11:05
5	GB Connections Reform (verbal update) **Mike Oxenham - ESO**	11:05 - 11:15
6	TNUoS impact on investment decisions **Binoy Dharsi – EDF Energy**	11:15 - 11:55
7	AOB and Meeting Close **Claire Huxley - ESO**	11:55 - 12:10

TCMF Objective and Expectations

Objective
Develop ideas, understand impacts to industry and modification content discussion, related to the Charging and Connection matters.
Anyone can bring an agenda item (not just the ESO!)

Expectations
Be respectful of each other’s opinions and polite when providing feedback and asking questions
Contribute to the discussion
Language and Conduct to be consistent with the values of equality and diversity
Keep to agreed scope

Review of previous actions

ID	Month	Agenda Item	Description	Owner	Notes	Target Date	Status
23-01	Jan 23		ESO to look at the introduction of a “CUSC Modification Issues Log”	Claire Huxley		Feb	Open

Code Administrator update

Paul Mullen – Code Administrator ESO

Key Updates since last TCMF

New Modifications

- **CMP408** (Notice and fix period for BSUoS) - Proceeding to Workgroup with Nominations to be open 6 to 27 February 2023 and 1st Workgroup on 15 March 2023. High priority)
- **CMP409** (CMP363/364 TNUoS Demand Residual charges for transmission connected sites with a mix of Final and non-Final Demand (CMP363) and definition changes (CMP364) Housekeeping) – To be implemented 1 April 2023 once objections window (3 to 24 February has closed)

Decisions

- **CMP401** (Maintaining Non Half Hourly (NHH) charging arrangements for Measurement Classes F and G) – Original approved 27 January 2023. To be implemented 1 April 2023.

Consultations

- None currently open

Other

- **CMP344** (Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology) – Final Modification Report to be sent to Ofgem 8 February 2023
- **CMP396** (Re-introduction Of BSUoS on Interconnector Lead Parties) – Independent Legal Opinion expected w/c 6 February 2023
- **CMP394** (Exempt electricity storage assets in positive Transmission Network Use of System zones from payment of generation charges) - Withdrawn 27 January 2023
- **CMP402** (Introduction of Anticipatory Investment (AI) principles within the User Commitment Arrangements) – 1st Workgroup held 23 January 2023

Useful Links

For updates on all “live” Modifications please visit our “Modification Tracker” here

Ofgem’s expected decision date / date they intend to publish an impact assessment or consultation, for code modifications/proposals that are with them for decision is here

For summary of key decisions at latest Panel please click here

CUSC 2023 - Panel dates

CUSC	Panel Dates	Papers Day	Modification Submission Date	(TCMF) CUSC Development Forum
January	27 (Face to Face Meeting)	19	12	5
February	24	16	9	2
March	31	23	16	9
April	28 (Face to Face Meeting)	20	13	6
May	26	18	11	4
June	30	22	15	8
July	28 (Face to Face Meeting)	20	13	6
August	25	17	10	3
September	29	21	14	7
October	27 (Face to Face Meeting)	19	12	5
November	24	16	9	2
December	15	7	30/11	23/11

Enduring Fixed BSUoS Arrangements

Naomi De Silva - ESO

Proposed Work

TCMF subgroup

**CMP408:
3 month notice period mod**

- Bring notice period in line with that of WACM5 CMP361 per industry expectation over the last several months
- Strike the appropriate balance between providing suppliers with sufficient notice and mitigating risk of inaccuracy in a forecast set further in advance
- Voted through to workgroup at January Panel as high priority

Investigate enduring fund and P level solution

- Assess the benefits of various probability (P) levels for the creation of an industry fund, including the interactions between the P level at which the fund is set, the fixed tariff period, the notice period, and the risk of tariff reset
- Assess implications for the size of the fund and cost to consumers
- Consider future mechanisms for return of potential excess industry fund monies

Clean up mods to align legal text after CMP308 and fixed BSUoS mods

- Tidy up of legal text in CUSC sections 3 and 14, definitions and guidance
- Not essential for implementing fixed BSUoS

Background

- In September 2022, Ofgem’s minded to position was CMP361 WACM5: 3 months notice, 12 months fixed, industry fund set at P99 level.
- This was re-evaluated when it was found P99 would result in a large industry fund that potentially erodes the benefits of fixed BSUoS (as a fund is funded by consumers at a high cost of capital)
- This is because BSUoS costs became higher and more volatile (due to wholesale prices)
- Under CMP361, there were limited WACMs with a lower industry fund, and the CUSC limited raising new WACMs or a similar modification with new options while CMP361 was awaiting decision
- The CUSC also limited a new similar modification being raised within 40 days should CMP361 be rejected
- WACM3 of CMP361 was approved to allow implementation of fixed BSUoS from 1 April 2023. This has a shorter fixed period, 6 months, and a longer notice period, 9 months. Due to timings, the 9 month notice period was not implemented in practice for this April
- Now we need to look at what the enduring solution should look like...

Rationale for CMP408 progressed separately

- The original CMP361 analysis by Frontier/LCP in summer 2021 focused on overall benefits of fixed BSUoS and did not consider how to split the combined fixed/notice period.
- Additional analysis undertaken by Frontier for Ofgem's September 2022 minded-to considered the impact of forecast horizon, comparing two options related to Ofgem's minded-to for simplicity: Option 1: 12 months notice, 3 months fixed and Option 2: 3 months notice, 12 months fixed.
- Option 2 was found to be have greater benefits, reflecting that forecast accuracy is generally better the closer you get to delivery
- The analysis did not update to the latest higher, more volatile BSUoS costs but we would expect this conclusion to hold
- In the interests of moving forward quickly, CM408 was raised to change the notice period to 3 months
- We don't yet have a clear solution around industry fund (which relates to fixed period) hence the need for a TCMF subgroup to cover these rather than immediately raising a mod

On alignment

- However, we understand that if the notice period was changed, but the fixed period remained at 6 months this would reduce the overall period for which suppliers had certainty over below 15 months, with implications for suppliers and contracts with customers
- It would also reduce the risk of a tariff reset within the fixed period…

Therefore to support alignment between CMP408 and the options proposed by the TCMF subgroup, we propose:

- These are held on the same day, with membership of both encouraged
- Mods changing fixed period and notice period to consider the same implementation date, currently proposed to be 1 April 2024 within CMP408
- Based on Panel feedback, we will be updating the CMP408 ToR to allow consideration of the fixed period should WACMs need to be raised in the future

Next steps are to determine the timetable for CMP408 and subgroup meetings and set out a clear scope for the latter

Payment timescales for Monthly Invoices

Nick George - ESO

Background

- ESO are implementing a new billing system (known as STAR)
- First charge type to be billed from STAR will be AAHEDC in Feb 2023 (for billing period Oct-Dec 2022)
- TNUoS Demand will follow from 1 Apr 2023 to coincide with TDR changes, and further charges will follow later in 2023/24
- As part of this project, we have ensured robust business continuity arrangements are in place, but have identified a risk with the wording of the payment due date for monthly invoices in CUSC which we would like to fix

CUSC 6.6.1 – invoicing and payment

- Summary of CUSC 6.6.1:
  - Recurrent monthly charges (TNUoS + Connection charges), STTEC and LDTEC shall be invoiced by 15th day of the month for which the charges relate
  - Payment is due by:
    - If invoiced on 1st day of a month, the 15th day of the same month
    - If invoiced after 1st day of a month, the 15th day of the following month
- In practice invoices are issued on 1st day of month. They cannot be issued earlier because it would cause VAT issues.
- However, if there was a delay in billing of a day (or more), due date goes back a whole month
- Payment receipts are required to make monthly payments to TOs, OFTOs and other parties
- Propose change such that payment is due on later of (i) 15th day of the month; or (ii) 14 days from dispatch of invoice.
- This would align with STC Section E paragraph 4.3 (later of 16th day or 15 days from dispatch of invoice) allowing for existing 1 day lag between payments.

GB Connections Reform (verbal update)

Mike Oxenham - ESO

TNUoS impact on investment decisions

Binoy Dharsi – EDF Energy

The urgent investment signals required for renewables need to be delivered through a rolling long term fixed TNUoS proposal

January 2023

GB electricity market design could benefit from improved locational signals

Locational signals are an important aspect of market design

- Locational signals are an important part of market design delivering overall lower system costs.
- They can provide signals on where to site new generation and demand optimising the amount of network infrastructure needed (which is particularly critical this decade as the power sector decarbonises),
- And they can provide real time signals on when to generate or take demand to optimise system operational costs.

The existing market design could be improved

- The current market design provides locational siting signals through network charging (TNUoS) and network losses (TLMs).
- These are unpredictable meaning their effectiveness is limited.
- The current market design provides no locational dispatch signal which reduces efficiency.

There are though limits to the value that locational signals can provide

- Siting of new low carbon generation will be dictated by a number of significant other issues: not least location of sea bed leases, wind speeds, and planning.
- But a predictable locational siting signal will support more effective decisions at the margin leading to overall lower system costs in decarbonising the power system.
- Similarly, it is important to note that the existing wholesale market already provides a strong signal on when to dispatch which enables generators and demand to make rational choices in general. This could be improved by providing a locational element to the signal which is particularly important to large interconnectors.
- But, once low carbon generation is connected to the network there is a limit to the value in providing locational dispatch signals

NGESO recommends radical market reform proposing nodal pricing but urgent action is needed now

Firstly it is critical that there is a step change in network investment this decade

Second more pragmatic reforms should be considered as alternatives to nodal pricing:

- Nodal pricing reveals the value of electricity at high locational and temporal granularity and is a solution to addressing network constraints.
- Nodal pricing would be a very significant market reform with material implementation issues and long timescales, and, as yet, it is not clear that the theoretical benefits of such a reform would be delivered.
- There are low-regret actions that could be taken now which could improve locational signals within the existing market framework and these should be prioritised.

1. Long-term locational siting signal could be delivered by making TNUoS more predictable

    - The current TNUoS charge provides a locational siting signal but needs to be made more predictable to be useful and support efficient low carbon developer investment decisions.
    - Reform is important now given the scale of low carbon generation deployment this decade [~50+GW; 100s £ms investment].

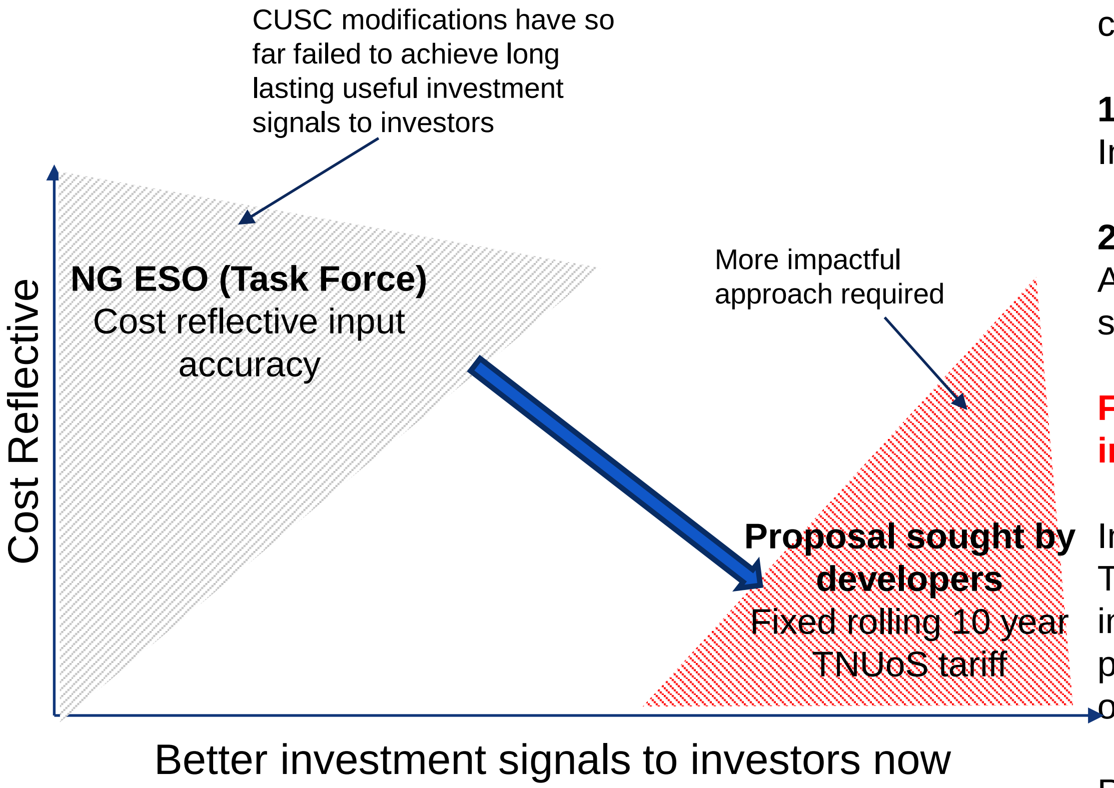
2. Locational dispatch signals could be improved by developing ESO's Local Constraint Market

    - Constraints are currently costing consumer ~£1bn a year and this is expected to increase before transmission investment is delivered later this decade.
    - While the key issue is transmission investment and the scope to reduce transmission constraints is limited, the ESO are proposing a Local Constraint Market to access smaller scale flexibility at times of high wind. This will provide some level of mitigation and is welcome but should be expanded to encourage locational flexibility.

Achieving TNUoS predictability requires a more impactful change in approach

In July 2022 the TNUoS Task Force commenced with the following statement made by Ofgem.

> The Task Force should be in a position to have a number of proposals within 6 months to address the following questions:
> **1) How do we make TNUoS a better investment signal to investors?**
> **2) How can we make it more predictable for demand users and provide the right signals?**



There are two approaches to make TNUoS a better investment signal but only one that can bring meaningful and immediate assurances to developers.

1) Input driven (cost reflective) - the current approach
Improve the methodology of the inputs that feed into the charging model

2) Fixing tariffs for a longer period
A fixed forecast for a period of time will give investors/developers a useful investment signal (Investment case to construction phased can take up to 7 years)

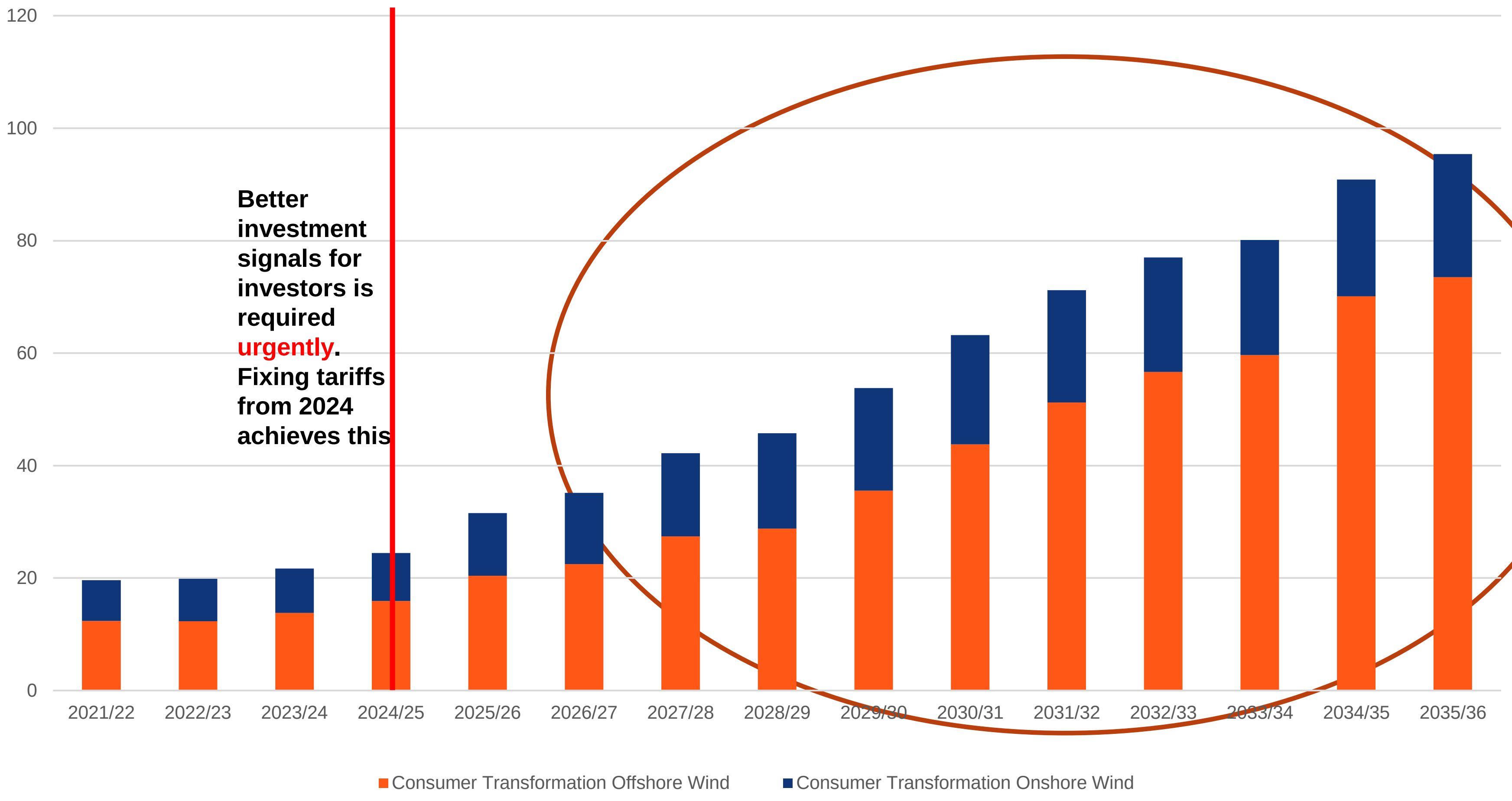
Fixing TNUoS on a rolling (10 year) basis is the only viable option to address the immediate concerns of developers

Improving the cost reflective inputs within the charging model is a continuous process. There have been numerous open governance (CUSC modification) attempts to improve inputs. These changes generally do not last for the duration of an assets investment phase. In addition, the model is complex and non-linear, resulting in highliy volatile outputs. The short duration & volatility create uncertainty and additional risk to projects.

Predictability of TNUoS charges is a key first step for the emerging debate on the absolute costs of TNUoS, which are forecast to increase in northern areas of GB. The outcome of this debate will be a central factor in the amount of low carbon generation that is delivered over the next decade, compared to the ambitious UK targets.

Wind capacity is going to quadruple this decade with investment decisions for majority yet to be taken

Future Energy Scenarios wind capacity, GW



FES 2022 Consumer Transformation is used for reference in the FES 2022 data. Transmission connected capacity only

- The timeframe for the investment case for wind starts up to 7+ years in advance (the pre-development period is 4-5 years and the construction is a further 2 – 3 years).
- CfD auction round 5 to be held in 2023 is targeting wind delivery from 2026+
- ~50GW (from 2027) have no certainty on TNUoS costs
- TNUoS is a key signal for investment decisions and CfD bids
- Developers need certainty of TNUoS costs urgently

Key Risks from TNUoS cost uncertainty
Inefficient bids into government support schemes (e.g. CfDs) could add costs to consumers:-

- through higher risk premium
- some investors may be unable to make the target investment return and cancel CfDs, replaced by alternatives with a higher cost for consumers
- Alternative to bidding is to postpone investment decisions – with risk of an investment hiatus & threat to delivery of UK net zero targets

Summary

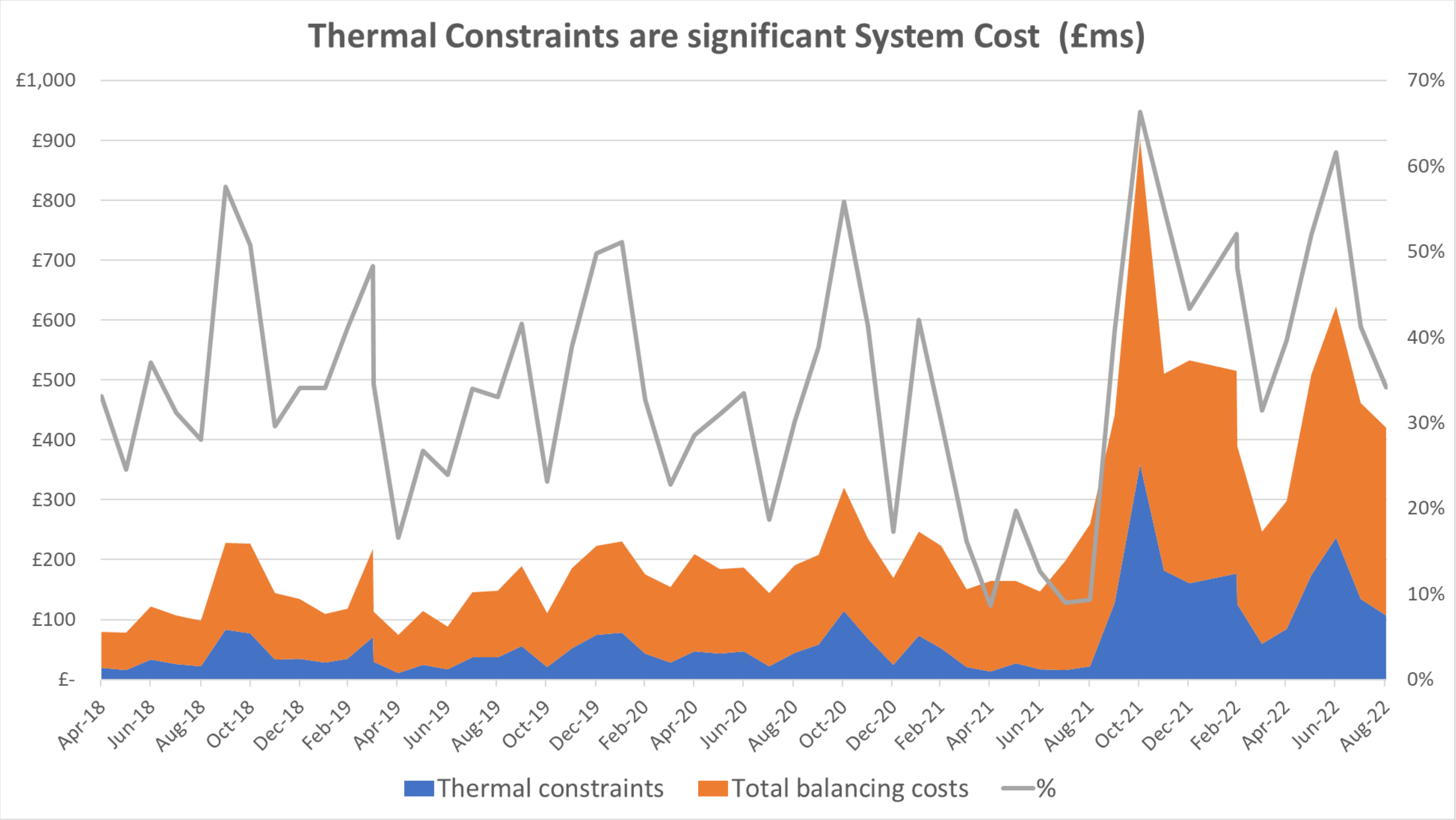
- A different approach to providing developers with TNUoS cost certainty is required now (given the significant future transmission investment forecast by NG ESO) – fixing tariffs for a longer period of time is the only solution that can achieve this certainty.

- Inputs that feed into the charging model are continuously under review through CUSC modifications and the complex model produces volatile outputs, resulting in too much uncertainty and risk for developers & existing operators.

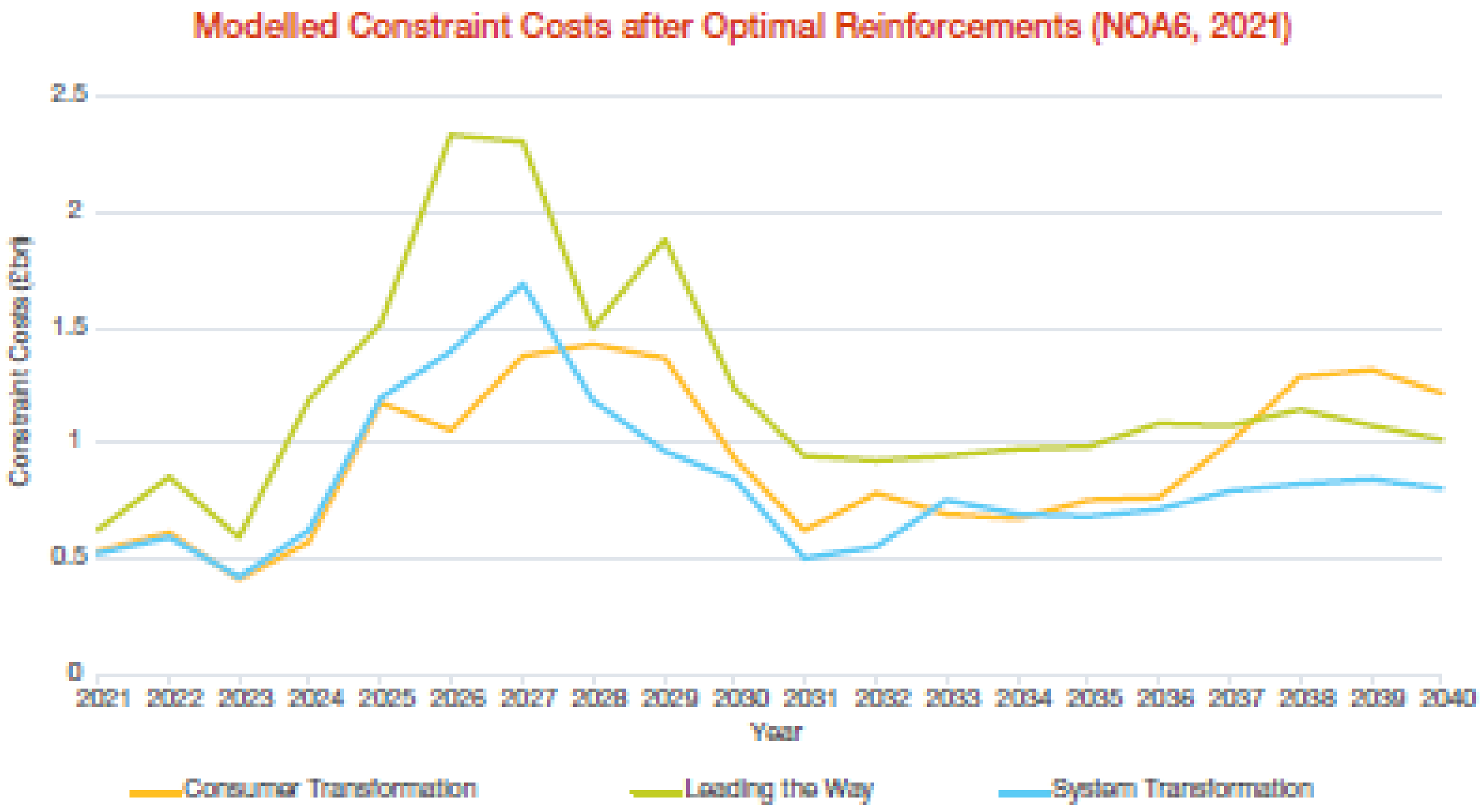
- Forecasted increases to the absolute costs for northern GB connected generation can be brought more into focus, once longer term fixed charges are committed to.

Appendix

Transmission network constraints have been growing significantly in real terms (£1.9Bn for Oct 21- Sept 22)

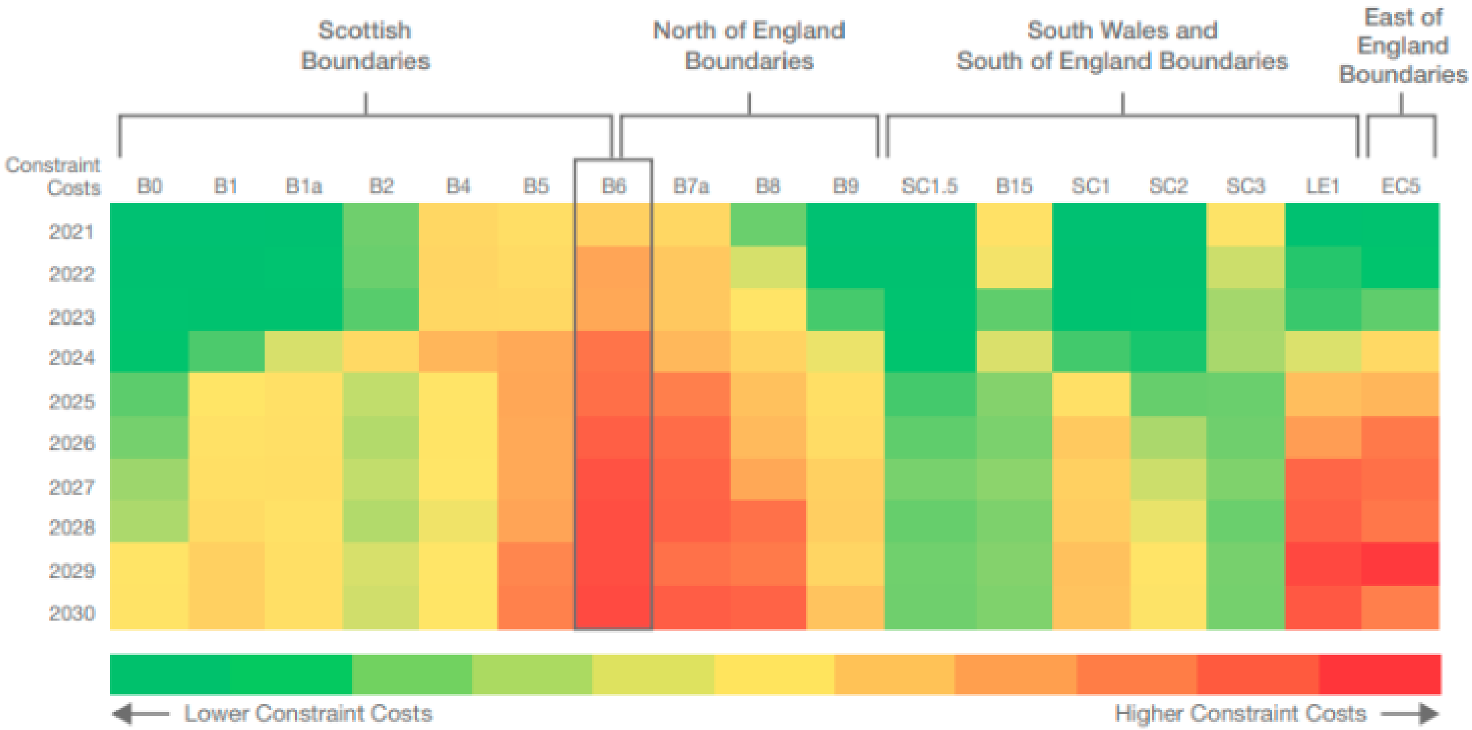


Constraint costs are expected to materially increase in future due to delays in transmission network build, before falling back to a higher sustained level (~£1bn pa)



Looking forward, ESO projections indicate that transmission congestion costs will rise steeply in the first half of this decade and could reach an annual cost of £2.3bn per year by 2026. Costs reduce in the late 2020s when investments in the transmission network will facilitate the transfer of more renewable generation to southern demand centres, but remain substantially higher than historic levels.

Transmission constraints costs are driven by specific transmission boundaries



[Source: Electricity Ten Year Statement (ETYS) 2020]

AOB & Close