# Transmission Charging Methodologies Forum and CUSC Issues Steering Group

Meeting 106

9th July 2020

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# Agenda

| | | |
|---|---|---|
| 1 | Introduction, meeting objectives **Jenny Doherty - NGESO** | 10:30 – 10:35 |
| 2 | Code administrator update **Paul Mullen - NGESO** | 10:35 – 10:50 |
| 3 | TCR Update **Grahame Neale - NGESO** | 10:50 – 10:55 |
| 4 | BSUoS / TNUoS Covid Support Update **Jenny Doherty – NGESO** | 10:55 – 11:05 |
| 5 | ETYS Potential Modification **Katharina Birkner - NGESO** | 11:05 – 11:20 |
| 6 | Pathfinder assessment costs **Katharina Birkner / David Preston / Will Kirk-Wilson - NGESO** | 11:20 – 11:50 |
| 7 | Error Margin in the TNUoS G/D split calculation **Jo Zhou - NGESO** | 11:50 – 12:00 |
| 8 | Tertiary Connections **James Stone - NGESO** | 12:00 – 12:20 |
| 9 | AOB **Jenny Doherty - NGESO** | 12:20 – 12:30 |

# Code Administrator Update

Paul Mullen, NGESO

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# Authority Decisions/Implementations Summary (as at 8 July 2020)

**Authority decisions since last TCMF**

- CMP345 WACM2 and CMP323 Original both approved 23 June 2020 and implemented 25 June 2020
- CMP337/338 Original approved 3 July 2020 and will be implemented 1 April 2024
- CMP303 rejected 3 July 2020 The Authority determined that, given the approval of CMP337/CMP338, CMP303 and its alternatives would be unnecessary and inefficient.

**CMP320 expected w/c 6 July 2020**

**CMP280 to be decided on alongside CMP334 (which supersedes CMP280)**

**Update on timing of CMP292 decision expected summer 2020**

# Modifications with Authority for decision (as at 8 July 2020)

| Modification Number | What is this Modification doing | Implementation Date |
|---|---|---|
| CMP320 | Islands that have a MITS Node but are served by a single circuit radial link are exposed to non-cost reflective charging of a 1.8 Security Factor rather than the application of a 1.0 Security Factor. This proposal will apply a 1.0 Security Factor in that situation. | 1 April 2021 |
| CMP280 | Remove the liability from storage facilities  to the TNUoS Demand Residual tariff element (CMP280). | 1 April 2021 |
| CMP292 | Looking to ensure that the charging methodologies are fixed in advance of the relevant Charging Year to Electricity System Operator to appropriately set and forecast charges. | 1 April 2021 |

# Panel Update

## June – 9 June 2020

- Unanimously agreed that **CMP345** Workgroup met its Terms of Reference

## June – 15 June 2020

- Recommended by majority that none of the **CMP345** Original or WACMs 1-8 were better than Baseline

## June – 26 June 2020

- **2 new Modifications presented**
  - **CMP346 -** Price Control Updates to Charging Parameters – Panel by majority agreed that this should follow self-governance and could proceed to Code Administrator Consultation
  - **CMP347 -** Offshore Local TNUoS Tariff Clarifications – Panel unanimously agreed that this should follow self-governance and could proceed to Code Administrator Consultation
- Unanimously agreed that **CMP317/327** and **CMP339** Workgroup has met its Terms of Reference

# Panel Update (as at 8 July 2020)

## July Panel

- **31 July 2020**
  - **1 new Modification** likely to be raised:
    - Consequential Modification following implementation of CMP323
  - **0 Workgroup Reports**
  - **5 Draft Final Modification Reports** (CMP317/327, CMP324/325, CMP333, CMP334, CMP339) being presented to Panel for Panel recommendation vote. Will then be sent to Ofgem for decision.
  - **1 Draft Final Modification Report** (CMP342) being presented to Panel for Panel determination vote. 15 working days Appeals window will then be opened prior to implementation.

# In Flight Modification Updates

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# In flight Modifications (as at 8 July 2020)

**0 open Workgroup Consultations**

- CMP343/340 to be issued 10 July 2020

**3 open Code Administrator Consultations, 2 to be issued**

- CMP342 closes 10 July 2020
- CMP317/327 and CMP339 (close 20 July 2020)
- CMP346 and CMP347 to be issued w/c 20 July 2020

6 CUSC Workgroups held in June

- 8 held across CUSC and Grid Code
- 11 to be held across CUSC (5 CUSC), Grid Code, SQSS and STC in July

For updates on all "live" Modifications please visit "Modification Tracker" at: https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc

# Prioritisation Stack

All Modifications previously in Tranche 2 and 3 were prioritised

Panel took into account Proposer’s views and placed in one of 5 categories – High, Medium to High, Medium, Low to Medium and Low

Prioritisation will be reviewed at Panel on a monthly basis with deep dive on a quarterly basis (next deep dive October 2020)

# CUSC Workgroups for next 3 months (as at 8 July 2020)

### July

- CMP343/340 – 1 and 7 Jul
- CMP335/336 – 6, 20 and 24 Jul

### August

- CMP343/340 – 11 and 12 Aug
- CMP328
- CMP344

### September

- CMP328
- CMP344
- CMP311
- CMP326
- CMP330

See Notes explaining what each Modification is seeking to achieve

# 2020 Dates

# CUSC 2020 Workgroups and Panel dates

| CUSC - Workgroups | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| March | 6 | 12 | 20 | 26 |
| April | 3 | 9 | 15 | 23 |
| May | 8 | 14 | 22 | 28 |
| June | 5 | 10 | 15 | 25 |
| July | 10 | 16 | 24 | 30 |
| August | 7 | 13 | 21 | 27 |
| September | 4 | 10 | 18 | 24 |
| October | 9 | 14 | 23 | 29 |
| November | 6 | 11 | 16 | 23 |
| December | 30/11 | 7 | 17 | 21 |

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

# TDR Update

Grahame Neale – NGESO

# BSUoS / TNUoS Covid Support

Jenny Doherty, NGESO

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# Alignment with SQSS: gross demand data in locational demand tariff calculations for TNUoS

Katharina Birkner
July 20

**Follow up from January TCMF**

# The TNUoS revenue and tariff model and the defect

**Follow up from January TCMF**
**TNUoS DCLF ICRP Model**

Calculates the marginal costs of investment in the transmission system required as a result of increase in demand or generation at different points on the network
Signals indicate whether adding an increment of generation at a specific location (node) will increase or decrease system flows and impact system investment
14 demand zones based on the locational signal and demand at each node within the zone

- The locational signal at each node is weighted by the demand
- Locations with larger amounts of demand / generation have a greater impact on the zonal tariff

**Defect**

- Defect of accuracy of locational signals due to the increase of embedded generation was identified by GSR016
- Transmission capacity requirements for wider system boundaries were based on the net transmission system demand, embedded small and medium generation was not adequately represented in transmission planning studies
- This led to a skewed view of the required transmission capacity
- GSR016 moved from using net to gross demand to ensure small & medium embedded generators were included such that the system design can provide an adequate level of capacity
- TNUoS locational signals are no longer aligned with SQSS since GSR016

# Proposed Solution realigns TNUoS tariffs with SQSS

- Treat Embedded Generation in the same way as transmission connected generation through the use of gross demand within the transport and tariff model
- This would ensure all locational signals are taken into account for TNUoS tariffs (CMP282 set negative GSP points to zero)

**Data**
This modification creates opportunity to review most suitable demand data source for TNUoS locational data
Currently DNO provided week24 data is used – challenges around standardization of assumptions and governance (DNOs have different assumptions and use different scenarios for this data set)

<u>Recommendation to move to ETYS data (FES input)</u>
**Input**: Elexon billing data, adjustment for what's metered on the system, assessment of generation is added (including microgeneration, and subsidy holders) 5 year forecast excluding FES scenarios
**Audit**: process recently reviewed by internal auditors, only minor edits requested
**Governance**: inputs and assumptions publicly available, extensive stakeholder feedback
FES Network working groups set up to start aligning with DNOs on assumptions and consistent modelling
**Benefits**: consistent use of the same or similar scenarios, direct and auditable link between ESO data and charging, smoother data process, more transparency

# Review of available net demand and gross demand information

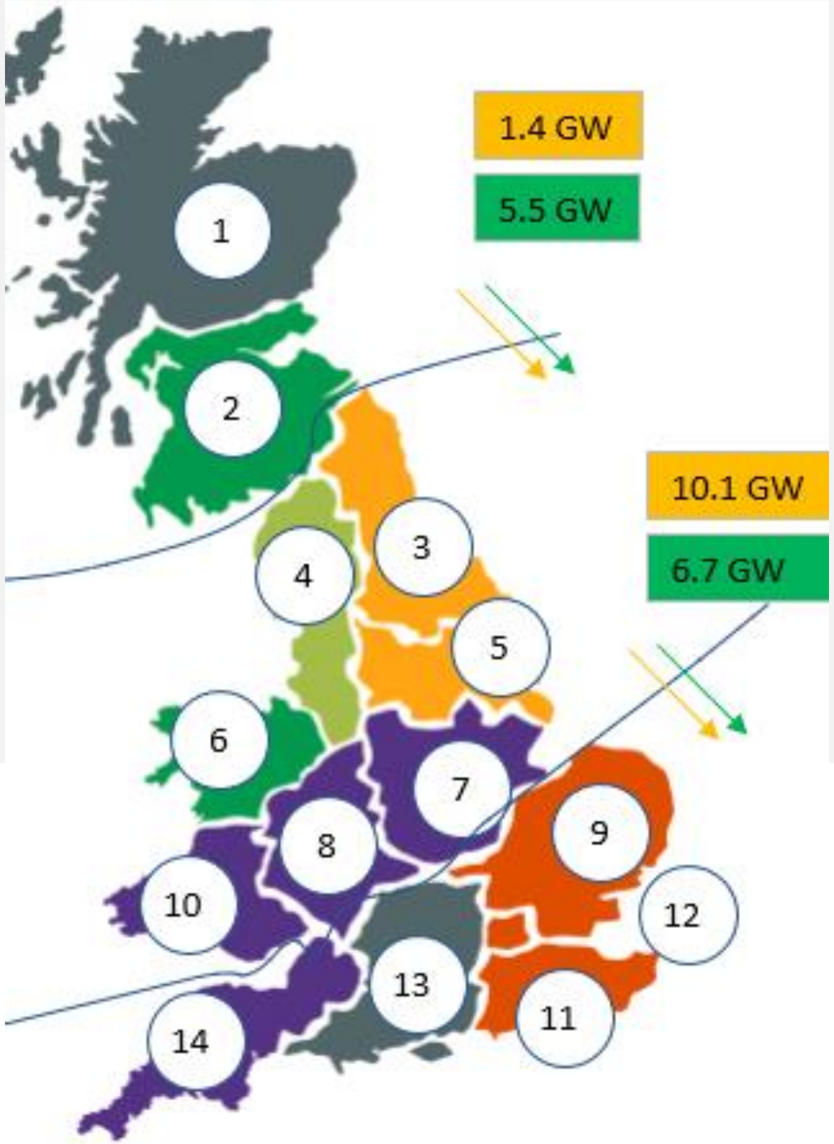
The preliminary analysis results are sensitive to input data

High level assumptions based on indicative information (based on week 24 data from DNOs)

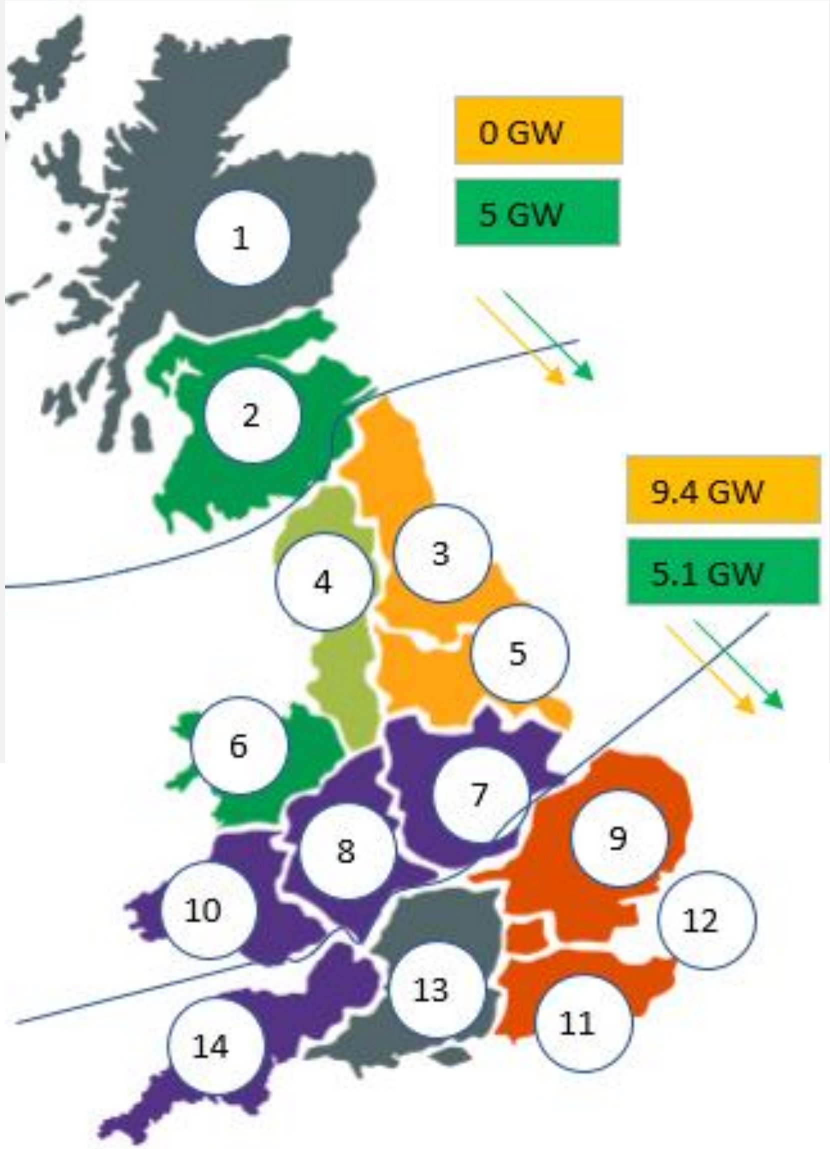
- Generation tariffs decrease in the north and increase (or less negative) in the south
- Demand tariffs increase in the north and decrease in the south
- Overall, the locational tariff profile from north to south appear to be "flatter"
- The “flatter” tariffs thus led to lower revenue recovery from locational tariffs, and gen residual is now less negative

# Indicative impact assessment (net demand vs gross demand)

net demand flows




gross demand flows




Peak security

Year round shared

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# Next steps

Any questions or feedback?

- Suggested change approach: work group

# Pathfinder assessment fee cost recovery

Katharina Birkner
David Preston
Will Kirk-Wilson
July 20

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# System needs are changing

The system is increasingly more complex to operate due to the energy system transformation.

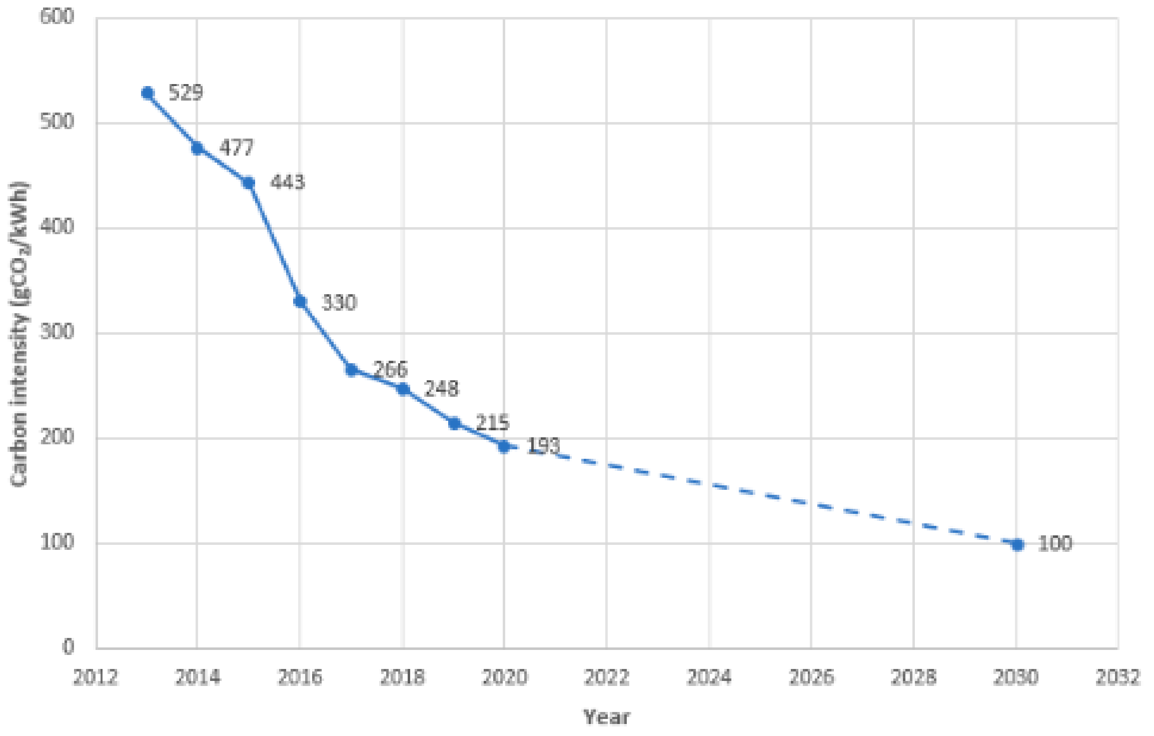
This increases ancillary service costs.  For example:

- Voltage costs are rising with **£340m** spent over the last three years.
- Inertia costs are increasing.  17/18 spend of **£60m**. 18/19 spend of **£150m**. 19/20 spend of **£210m**.

This summer has been challenging operationally and costs in 20/21 are likely to be higher.  So far (Apr-May) we have spent **~£40m** on voltage and **~£80m** on inertia.

Transmission system demand has been low and generation has been dominated by non-synchronous generation (solar and wind).  Both these conditions will appear again in the future as the growth in decentralised and decarbonised generation increases.

Today we will talk about how Pathfinders are looking to reduce the exposure to increasing BSUoS costs.

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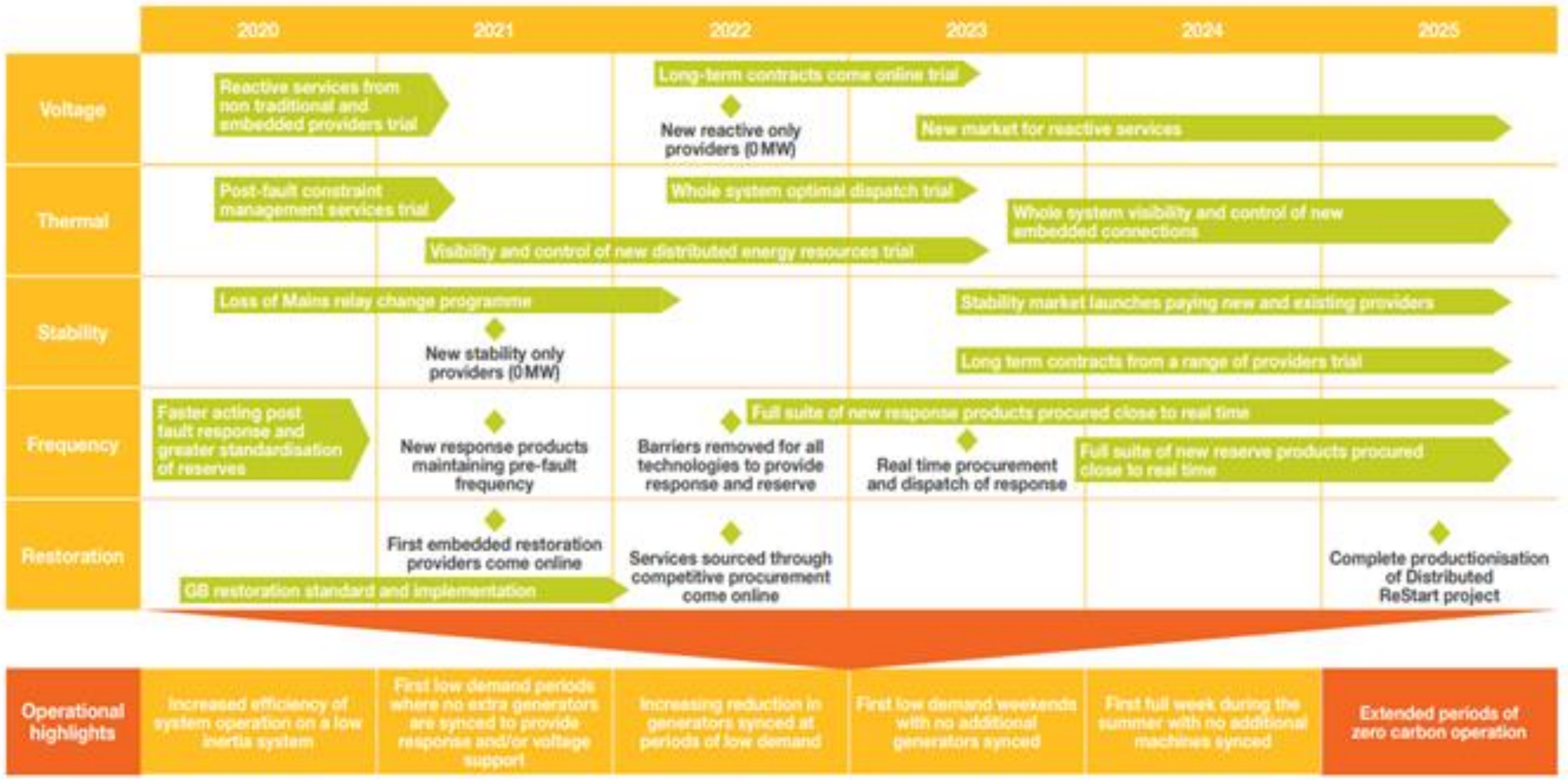
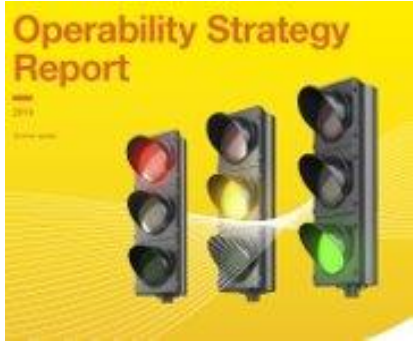
# What are we doing about it...

At the end of December we published an update to our Operability Strategy Report. It contained our operability milestones and overviews on all the work going on to meet the operability challenge. However Pathfinders are a significant part of the answer.

Challenge is split into 5 categories: Stability, Voltage, Frequency, Restoration and Thermal.

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# Pathfinders are a big part of the answer...

Pathfinders are looking for new ways to answer the operability challenge.

- Enabling competition between market solutions and the more traditional TO/DNO network solutions.
- We are working with service providers, TOs and DNOs for new whole system solutions.
- The process is supported by TO and DNO network assessments.

**This ensures whole system solutions and minimises costs to end consumers.**

The following pathfinders are in train:

  - Stability phase 1
  - Stability phase 2
  - Voltage Short Term Mersey
  - Voltage Long term Mersey
  - Voltage Long term Pennines
  - Constraint Management

- Stability pathfinder phase 1 was the first of its kind anywhere in the world.
- Very significant benefits –
  - Forecast BSUoS saving of up to **£128m** over the 6 year period for stability phase 1
  - Unlocking competition is expected to result in net benefits of **£125.5m** a year from 22/23 according forward plan

# Pathfinder challenges

This innovative approach creates a new market by engaging market participants, running tenders and addressing challenges that hinder fair competition as they are identified – learning by doing

Section 9 of the Electricity Act 1989 states it is the duty of each licence holder to "*develop and maintain an efficient, co-ordinated and economical system"* of electricity transmission.

One challenge that was identified was how to conduct a technical feasibility assessment of different technologies in an efficient and timely manner, ideally avoiding the requirement for connection agreements pre-tender result to avoid unnecessary cost for participants and avoid creating barriers to entry.

- TOs and DNOs are not funded for such assessments
- The ESO preferred solution is to recover these costs through BSUoS, as the benefits will be primarily felt by BSUoS payers as a reduction in their cost

The assessment costs for the short-term Mersey tender were **£69k**, the costs for the long-term Mersey were **£125k**. The benefits to voltage managements costs are already in the **£ millions**.

# What does the CUSC say?

CUSC section: 14.29.5 states:

*“BSUoS charges comprise the following costs:*

- *(i) The Total Costs of the Balancing Mechanism*
- *(ii) Total Balancing Services Contract costs*
- *(iii) Payments/Receipts from National Grid incentive schemes*
- *(iv) Internal costs of operating the System*
- ***(v) Costs associated with contracting for and developing Balancing Services***
- *(vi) Adjustments*
- *(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.*
- *(viii) BETTA implementation costs”*

We think it's appropriate to recover these costs through BSUoS as per CUSC section 14.29.5v due to the following:

- Pathfinder services are specifically referenced in NG ESO C16 Procurement Guidelines (2020) as are all balancing services NG ESO procures.

- The technical feasibility assessments allow us to “develop” a more effective balancing service by delivering increased consumer value through enhanced competition. Alternatives would lead to reduced savings to BSUoS. Precedent through recovery of Black Start stage B feasibility costs through BSUoS.

# Other options considered

- When deciding how to structure the indicative technical analysis for Mersey tenders we focused on an approach that would optimize participation and avoid any barriers to potential competition, such as participants requiring a connection or being exposed to feasibility costs, whilst ensuring technical compliance
- We continue to believe that the NGESO coordinated approach to meet these criteria within an appropriate time frame and ensure the best outcome for end consumers through minimising BSUoS costs, especially where technical solutions from different providers are targeting the same location / point of connection
- We hope to take lessons from this experience into the future voltage and stability events. However, we have considered a number of alternatives including:-

| Alternative | Key Challenges |
|---|---|
| Require a connection agreement to be in place to participate in the tender | • Unnecessary / speculative connections & impact to queue<br>• Increase in time, costs and likely loss of competition |
| Request that the participant engage with the DNO / TO to generate indicative technical feedback | • Loss of consistency across participants and costs duplicated<br>• Feasibility cost would be borne by each participant |
| Require all participants to pay an application fee | • Challenges in being able to develop equitable fees<br>• Likely loss of competition and multiple alternatives offered |

# Summary

- expected BSUoS savings through introduction of competition of **£125.5m** per year from 22/23
- expected costs of technical feasibility studies – less than £1m across all Pathfinders
- proposed approach: feasibility study cost recovery through BSUoS

# Any questions?

# Contact

Please contact Will Kirk-Wilson with any feedback or comments at william.kirkwilson@nationalgrideso.com by July 17th 2020.

# Error margin in the TNUoS G/D split calculation

Jo Zhou, National Grid ESO

July 20

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# What is the TNUoS G/D split?

**The EU gen cap**

- There is a limit on the average transmission network charges we can levy on generators
- The limit is €0 ~ 2.50/MWh, set in Commission Regulation (EU) No 838/2010
- We forecast the TWh volume from TNUoS-liable generators, and then apply the €[0, 2.50] range, using £/€ forecast, to work out the maximum total charge (£m) we can levy on generators

**The error margin and the G/D split**

- The EU gen cap sets the maximum total charge (£m) on generators
- We then apply a % error margin, to reduce the cap by the error margin (circa 15-20%), to mitigate risks of breaching the EU cap caused by errors between forecasts and actual outturn
- The rest of TNUoS revenue will be paid by suppliers

# What determines the error margin

- Based on historical data in the past five whole years (thus for year 20201/22, we use data from years 2015/16 – 2019/20)
- Data include generation £m revenue and generation output TWh, and the % error are calculated by using (actual – forecast )/ forecast
- generation revenue error is further adjusted by the "systemic error", which is the average of past five years' generation revenue error%
- The tariff error is then worked out by applying –

$$\frac{1 + \max(\text{absolute}((\text{generation revenue error\%}))}{1 - \max(\text{absolute}(\text{generation output TWh error\%}))} - 1$$

# Calculation of the tariff error margin for 2021/22

**Generation Revenue (£m)**

| Year | Forecast | Actual | % Error |
|---|---|---|---|
| 2015/16 | 612 | 559 | -8.7% |
| 2016/17 | 453 | 430 | -5.1% |
| 2017/18 | 390 | 370 | -5.2% |
| 2018/19 | 430 | 391 | -9.2% |
| 2019/20 | 404 | 344 | -14.6% |

| Systemic Error |
|---|
| -8.6% |

| % Error offset by the systemic error |
|---|
| -0.1% |
| 3.5% |
| 3.4% |
| -0.6% |
| -6.1% |

| Max. Gen Rev. Error |
|---|
| 6.1% |

**Generation Output (TWh)**

| Year | Forecast | Actual | % Error |
|---|---|---|---|
| 2015/16 | 285 | 250 | -12.2% |
| 2016/17 | 269 | 248 | -7.9% |
| 2017/18 | 251 | 247 | -1.5% |
| 2018/19 | 253 | 234 | -7.5% |
| 2019/20 | 230 | 220 | -4.1% |

| Max. Gen Output Error |
|---|
| 12.2% |

$$\frac{1 + max\ (absolute((generation\ revenue\ error\%))}{1 - \ max\ (absolute\ (\ generation\ output\ TWh\ error\%))} - 1$$

**Tariff error margin**

=(1+6.1%) / (1-12.2%) -1

=120.8% - 1

We then round the figure down, to 20%

# Summary

- The error margin was introduced since implementation of CMP224 (Cap on the total TNUoS target revenue to be recovered from Generation Users)
- Based on your feedback, we are clarifying the procedure to calculate the error margin
- The calculation methodology is in the draft of the relevant alternatives for CMP317/327 (removing generator residual and excluding assets required for connection)
- We intend to publish the calculation as part of our August TNUoS tariff 5-year view, and in future TNUoS tariff forecast publications

# Tertiary Connections

July 2020

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# Background…

- Super Grid Transformers (SGTs) have two windings, being the primary winding and the secondary winding. The primary winding is the coil that draws power from the source and the secondary winding is the coil that delivers the energy
- Transformers are classed as Connection Assets based on sole use principles and only used by a single customer (i.e. DNO) with these assets being charged to that customer
- There are cases where additional connections can be made to the windings at a Grid Supply Point (GSP) which are known as tertiary connections
- Since 2018, NGESO and NGET have received numerous applications for connections
- To accommodate these applications and provide economic and efficient connections, NGESO and NGET have provided offers that would utilise tertiary windings on transformers that are Connection Assets for use by the DNO
- Dependent on interpretation, the addition of a tertiary at a GSP results in all assets being ‘shared’, which by definition would classify them as infrastructure assets with costs then being recovered via TNUoS

# How does a tertiary impact the network…

- A recent NGESO system study has established that the impact on physical power flows on the network will be witnessed whenever the connected tertiary units are operating
- This impact is witnessed on power flows both over the tertiary-connected SGT and any other SGTs at a site i.e. the SGT with tertiary generation connected will pull unequal power from the network which in turn means the other SGTs should be de-rated in case of a fault
- The magnitude of the impact on power flows will vary by site depending on several factors including; GSP size; number of tertiary connections; typical tertiary running patterns; and network topology
- It is also evident that these types of connections can change the overall MW boundary limits at a GSP dependent on what the tertiary is doing i.e. where a tertiary is a battery storage unit it could either be off, or generating, or charging as demand load

**System studies show a tertiary connection impacts power flows over all SGTs at site**

# CUSC Principles: Definitions of connection & infrastructure assets…

14.2.2 **Connection charges relate to the costs of assets installed solely for and only capable of use by an individual User.** These costs may include civil costs, engineering costs, and land clearance and preparation costs associated with the connection assets, but for the avoidance of doubt no land purchase costs will be included..

14.2.4 The first step in setting charges is to define the boundary between connection assets and transmission system infrastructure assets.

14.2.5 In general, **connection assets are defined as those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party** (i.e. “single user assets”). For the purposes of this Statement, all connection assets at a given location shall together form a connection site

14.2.6 Connection assets are defined as all those single user assets which:

a) for Double Busbar type connections, are those single user assets connecting the User’s assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay;

b) for teed or mesh connections, are those single user assets from the User’s assets up to, but not including, the HV disconnector or the equivalent point of isolation;

c) for cable and overhead lines at a transmission voltage, are those single user connection circuits connected at a transmission voltage equal to or less than 2km in length that are not potentially shareable.

14.2.7 **Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are single user assets under the same Bilateral Connection Agreement.**

# NGESO interpretation of 'use'…

- NGESO have approached the interpretation of 'use' (where a tertiary connects) from a technical viewpoint and how the physical power flows on the network are impacted
- The use of connection assets at a GSP is based on sole use principles i.e. assets are being used by a single customer so these assets are charged to that customer
- A tertiary generator injects MWs onto the network which flow on both sections of the SGT and all other SGTs at site - we believe this is demonstration that a tertiary is then 'sharing' all assets at the GSP
- Tertiaries also impact the overall operation of the GSP and use the capacity of the network itself - this means the assets at that GSP are being 'shared', which by definition must be deemed infrastructure assets
- The overall MW boundary limits at a GSP also change dependent on what the tertiary is doing i.e. where a tertiary is a battery unit it could be off, generating or charging as demand load

**It is evident that all SGTs at a GSP are effected by tertiaries and as such should no longer be classified as sole use assets**

# Counter argument…

- An alternative argument has been made that only the SGT to which the tertiary is connected should become an infrastructure asset with the others at the GSP remaining as connection assets
- The concern is one of principle, that reclassifying all assets as infrastructure and socialising the costs via TNUoS may have the unintended consequence of removing the direct economic cost signals to the DNOs if and when they request increases to capacity (i.e. a new SGT)
- It is NGESO’s belief that this is not the case as DNOs should apply ‘whole system’ thinking to all investment decisions to ensure the most economic and efficient outcome. So, before any request to increase capacity they will need to ensure they have exhausted all other options including flexibility solutions and even other TO solutions

# Summary

- The CUSC stipulates that a connection asset is only for sole use
- Analysis demonstrates that all SGTs at a site are impacted by a tertiary connection
- Following the principles set out in the CUSC, we believe that all SGTs at a site where there is a tertiary connection should become infrastructure assets as they are no longer sole use

# Key ask from stakeholders

- Do you agree that the current NGESO interpretation of asset classification aligns with the principles set out in the CUSC?

# AOB & Close