Charging Futures
Reforming electricity charging together

TNUoS Task Force

Meeting 7

27th July 2023

Agenda

10:00 – 11:15

- 10:00 Introduction & Welcome
- 10:05 Action Review
- 10:15 Backgrounds & Reference Node: Further Considerations & Analysis
- *11:15 Break*

11:30 – 12:30

- 11.30 Shared/Not Shared: Deep Dive
- *12:30 Lunch*

13:15 – 14:45

- 13.15 Shared/Not Shared: Feedback & Further Discussion
- 13.45 Data Inputs: Deep Dive
- *14:45 Break*

15:00 – 16:00

- 15:00 Data Inputs: Feedback & Further Discussion
- 15:30 Workstream Plan
- 15:55 Next Steps & Close

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Action Review

Jon Wisdom

Actions from Meeting 6

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
1 26.06	3-7	How much of each background represents different regions	Frontier/LCP		Mtg 7	Open
2 26.06	3-7	The historic scaling factors that set the CBA for the current backgrounds need to be shared with Frontier/LCP	JS, NW to explore with ESO.	CBA information shared with Frontier	Mtg 6	Closed
3 26.06	3-7	Results of weighting circuits in the modelling to be shared with the Task Force (i.e. to show no significant change)	*Frontier/LCP*		Mtg 7	Open
4 26.06	3-7	Explore possibility of identifying similar backgrounds with different interconnector flows. Information to be shared with the consultants from the ESO in relation to the BSUoS (Balancing Services Use of System charge) Task Force work relating to this.	*Frontier/LCP and JS*	NW and JS to provide BSUoS IC work but possibility another FES scenario to be run might meet the request	Mtg 7	Open

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Actions from Meeting 6

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
5 26.06	3-7	Can indicative monetary values be provided for the impacts of the different backgrounds on differently-sized projects.	*Frontier/LCP*		Mtg 7	Open
6 26.06	3-7	Consider whether there is an impact of other types of storage being included in the technology types of background.	*Frontier/LCP*		Mtg 7	Open
7 26.06	3-7	Additional analysis shared on metrics used to compare volatility between actual and estimated charges.	*Frontier/LCP*		TBC	Open
8 26.06	3-7	Consideration of a wider range of charging years in the data set.	*Frontier/LCP*		Mtg 7	Open

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Actions from Meeting 6

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
9 26.06	3-7	For examples shared by the consultants (e.g. changes in Predictability for CCGT) can change be expressed in monetary terms.	*Frontier/LCP*	Covered in Action 5		Closed
10 26.06	3-7	Bring together the Task Force representatives and the ESO SQSS Review team (when in a position to do so) to discuss potentially parallel/overlapping interests.	*JS, SS to explore with BD*		TBC	Open
11 26.06	8-10	Consultants are to explore the questions raised on zoning	*Frontier/LCP*	Considering what adding more zones would do to the existing Ref. Node work?	Mtg 7	Open
12 26.06	8-10	Revisit ESO work on embedded generation in relation to the transport model and share with the Task Force if relevant.	*JS & NW*		To consider as part of demand generation element of next work package	Open

Actions from Meeting 6

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
13 26.06	8-10	The consultants are to check results showing limited change in the non-shared Year Round scenario when the reference node was changed	*Frontier/LCP*	LCP to provide an email update	Mtg 7	Open
14 26.06	12	Task Force members are to engage industry colleagues and stakeholders and feed back at the next virtual meeting (incl. substantive effects on other work)	*Task Force*		Mtg 7 or August virtual mtg (depending on when responses received)	Open
15 26.06	12	Draft the defect for backgrounds ahead of the next virtual meeting	*JS, JT, LJ*		August virtual mtg	Open
16 26.06	12	Draft the case for change on the Reference Node ahead of the next meeting	*BD, JT, colleague of AM*		August virtual mtg (possible initial draft for Mtg 7)	Open
17 26.06		Update from OTNR sub-group	*JT*		Mtg 7	Open

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Open Actions from Meetings

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
3 17/05	3	Share the question re: Technology Type & users' capabilities aid in constructing backgrounds with Frontier-LCP for consideration.	Nicola White	Ongoing	w/c 29 May	Open
4 17/05	3	Assign the 20 defects in the shortlist to their Categories & how they are linked. Scopes of work for each category/grouping to be created. Task Force asked to review this list with work packages assigned across the group	James Stone, Nicola White	Update to be shared at Mtg 7	Aug virtual mtg Mtg 7	Open
6 17/05	7	ESO to proceed with the wider-remit zoning modification	James Stone	Drafted but further review needed	August	Open
1 26/04	1	Provide update on recruiting Non-Domestic user reps to Task Force	James Stone & Nicola White	Discussions ongoing for a named rep	Mtg 7	Open
3 26/04	3	Decision re: involving OTNR in Task Force discussions	Harriet Harmon	JT to provide update on OTNR sub-group at next TF session	Mtg 7	Open

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Open Actions from Meetings

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
8 26/04	7	Further work on design vs cost reflectivity to be presented at Mtg 6	James Stone & Nicola White	Further updates in Mtg 7	Mtg 7	Open
9 26/04	7	Technical input needed on deviation from SQSS and legal implications	James Stone & Nicola White	Email due from JS and NW	Mtg7	Open
10 26/04	7	Investigate more granular data sources for DNO embedded distribution to support the methodology & analytics	James Stone	Need to identify the data needs before exploring sources	Mtg 8	Open
11 26/04	8	Actions allocated across the TF group for topics progressing for further development or into draft modifications	James Stone	Packages to be agreed and volunteers sought	Post Mtg 7	Open

Charging Futures

Analytical Support: Overview and Context

Frontier & LCP

- An overview and context in relation to the TNUoS charging methodology including; current approach to calculating TNUoS charges; scope of the review undertaken; and detail of the modelling tools used to carry out the quantitative analysis for the project.

TNUoS Taskforce analytical support

Initial findings presentation to the Taskforce

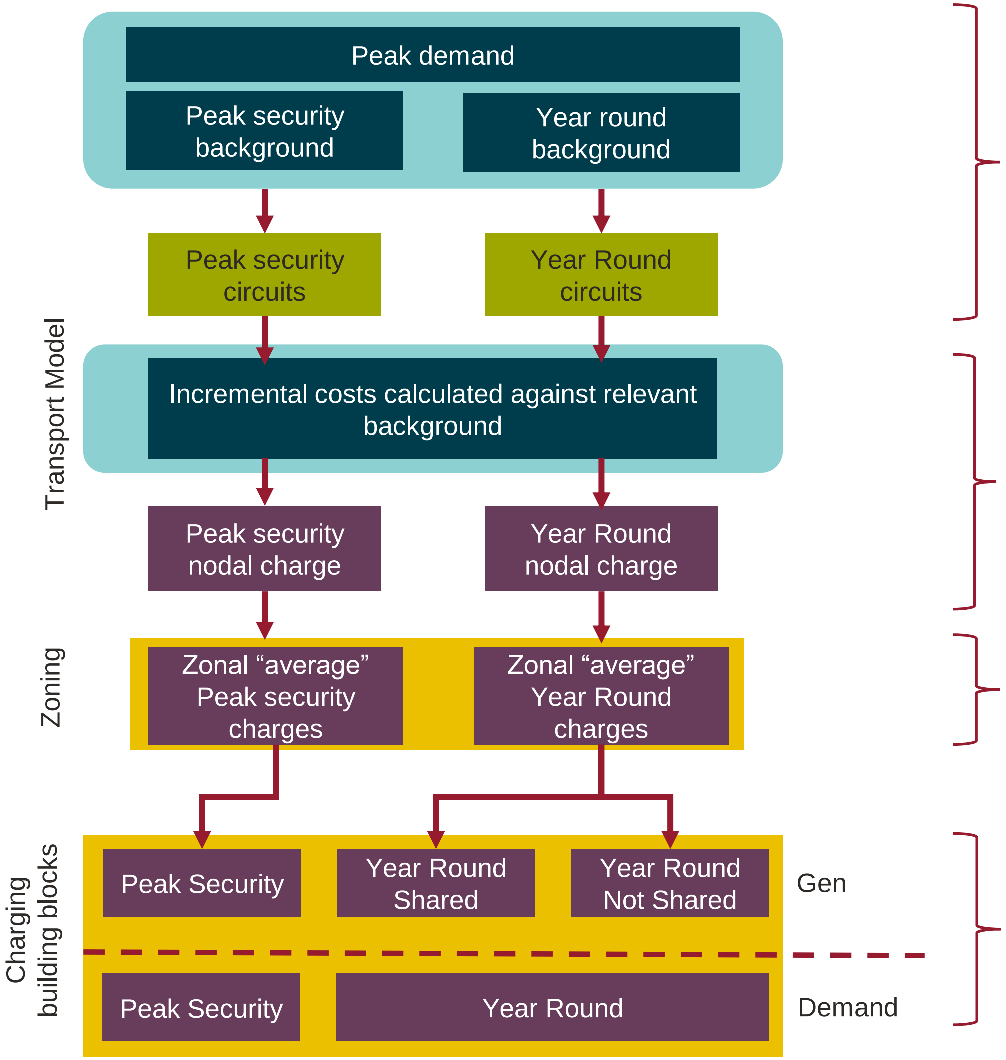
27th July 2023

This slidepack has been prepared for the purposes of supporting discussions with the Taskforce and therefore should be considered as a work in progress

ESO commissioned an analytical assessment on the following areas related to TNUoS charging methodology

AREA	BRIEF DESCRIPTION	
Backgrounds	Review appropriateness of current backgrounds and assess the implications for cost reflectivity and predictability of the possible changes to the backgrounds.	*Covered in June initially. Pending issues covered today*
Reference node	Describe the rationale for the current demand weighted reference node, set out considerations for alternatives and test the impact of moving to a generation weighted reference node.	
Shared/not shared elements	Review of the shared/not shared elements of the Wider tariff and whether they continue to be based on appropriate and cost-reflective assumptions.	*To be covered today*
Review data inputs	Assess potential improvements of issues with the data inputs identified by ESO.	

Overview of the current approach to calculating TNUoS charges



Identification of network cost drivers

- Transport model calculates flows over the network given a measure of peak demand and two different generation profiles (technology mix set according to CUSC)
- Network effectively 'sized' to meet modelled flows
- Circuits allocated to background with drives highest flows i.e. the background which represents the 'cost driver' for that circuit
- Data inputs related to generation and demand forecasts, annual load factors and transmission owner data

Calculation of incremental costs

- Calculation of incremental costs (MWkm * expansion constant) by adding 1MW generation (increasing demand down at all other nodes) for each node
- Incremental demand cost is the inverse of the generation charge
- Reference node is used for determining the modelled flow of power over the network in response to adding 1MW of generation at a node. Implicitly this:
  - allocates the split of charges between generation and demand charges; and
  - partially determines the split between shared and not shared charges in a zone (by reference to the cumulative boundary sharing factors between the generation node and the reference node).

Zoning

- Generation and demand weighted Peak Security and Year Round charges are calculated for each generation and demand zone.

Charging building blocks

- For generation, Year Round charge split into shared and non-shared based on share of low carbon generation in zone. Gen tech specific charges calculated from building blocks
- Demand charges based on sum of Peak and Year Round charges

Current charging building blocks by technology

Intermittent e.g. Wind, Tidal

Wider Tariff = [Annual Load Factor (ALF) × Year Round Shared] + Year Round Not Shared + Generator Residual

- Intermittent generation only drives costs in the Year Round scenario
- Costs in the Year Round scenario depend on the share of low carbon in the zone. If the low carbon share is low, then YRS charge is larger and the YRNS charge is smaller reflecting greater “sharing”

Conventional Low Carbon, e.g. Nuclear, Hydro

Wider Tariff = Peak + [ALF × Year Round Shared] + Year Round Not Shared + Generator Residual

- Low marginal cost generators will generate at peak and year round, so pay Peak Security and Year Round charges.
- Costs in the Year Round scenario depend on the overall share of low carbon in a zone. Low marginal cost generators will not reduce output in response to intermittent generation, so do not receive a discount on the YRNS element.

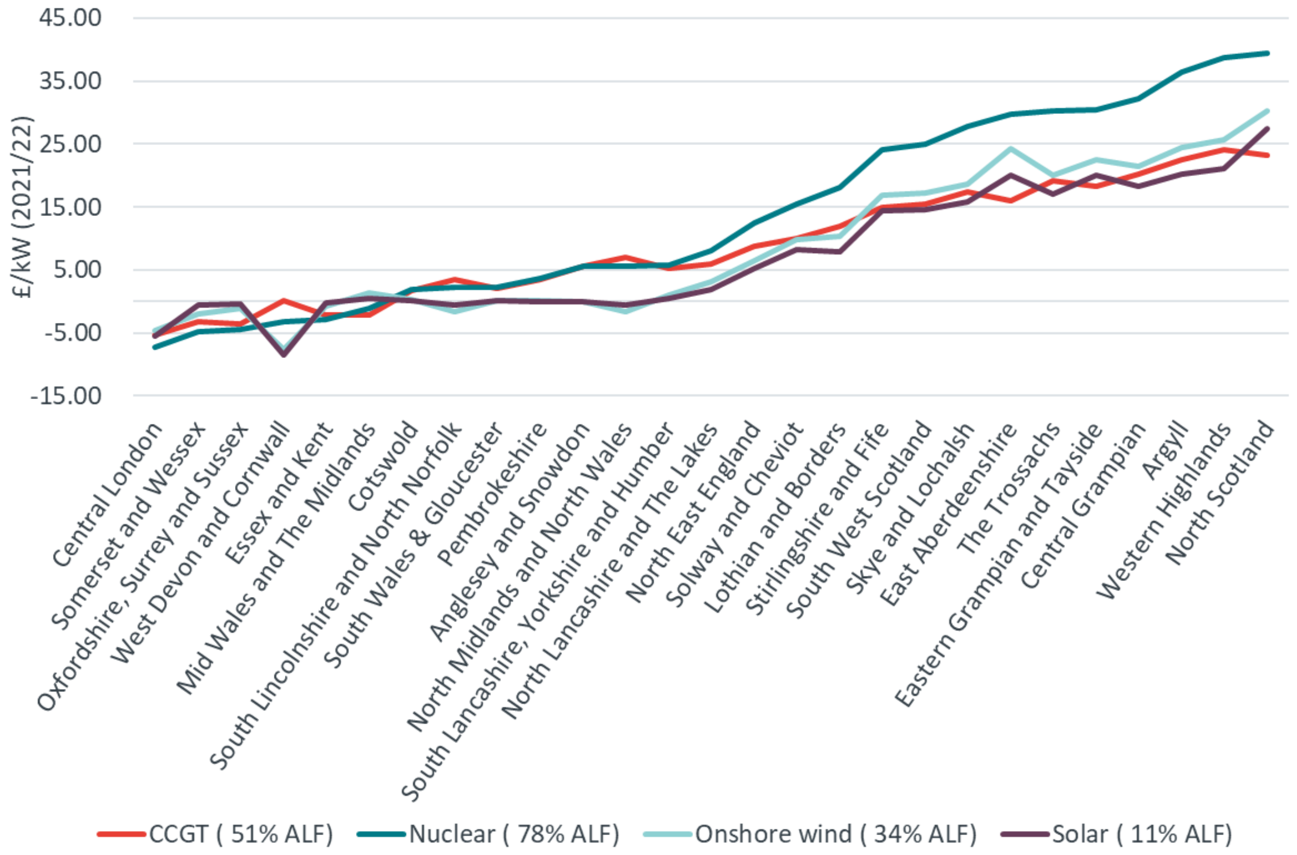
Conventional Carbon, e.g. Coal, Oil, Gas, Pump Storage

Wider Tariff = Peak + [ALF × Year Round Shared] + [ALF × Year Round Not Shared] + Generator Residual

- Dispatchable plants will generate at peak, so pay Peak Security charges
- Positive marginal cost plants will self curtail if there is lots of low carbon generation. Therefore, they pay Year Round charges pro-rated by ALF reflecting “sharing” with intermittent generation.

Technology specific generation TNUoS charges

Wider Generation TNUoS by technology / ALF



Source: TNUoS Five-Year View 2021/22 to 2025/26 - Tables and Figures

Conventional generation (CCGT, nuclear)

Difference between CCGT and nuclear TNUoS charges driven by:

- differences in ALF
- application of ALF to Year Round Not Shared element for CCGT rather than TEC

Intermittent generation (wind, solar)

- If solar were to face G TNUoS rather than D TNUoS, its £/kW charges would in general be lower than onshore wind due to lower ALF. However, given fixed Not Shared element, solar £/MWh charges much higher than wind
- “Sharing benefit” results in lower onshore wind and solar charges in midlands, though gap to CCGT declines as Not Shared element is more important in northern zones

Overlap between ESO buckets and Ofgem's scope of review

We have mapped the four priority areas for review set by National Grid ESO and Ofgem's initial scope for the Task Force according to Ofgem. We conclude that there is a high degree of overlap, but it also highlights areas currently out of scope of this work

National Grid ESO

1. Review appropriateness of backgrounds / Review changes (and impacts) introduced via TransmiT
2. Review of the shared/not shared elements of the Wider tariff and whether they continue to be based on appropriate, cost-reflective assumptions
3. Review data inputs
4. Review of the Reference node

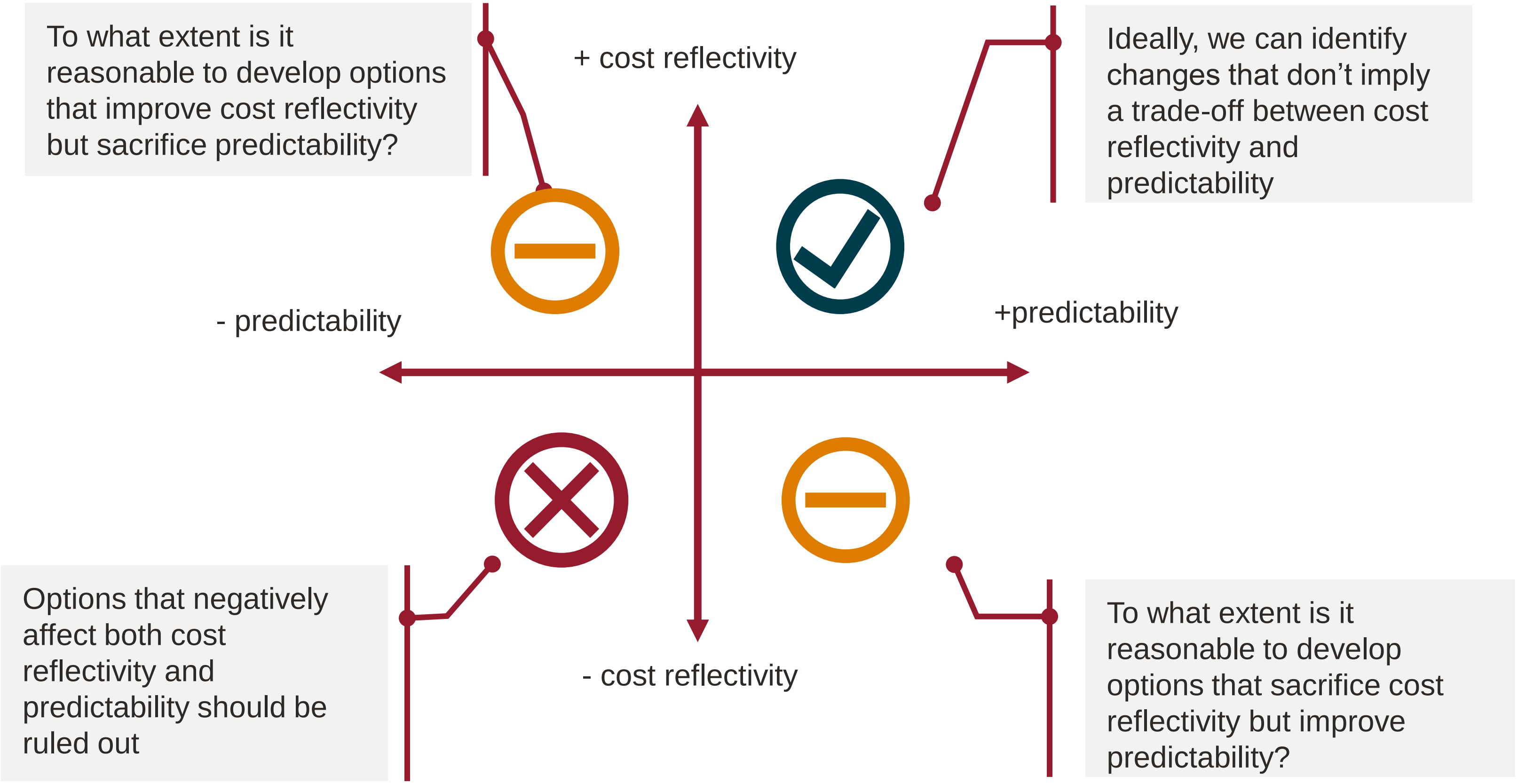
Ofgem

- 3 — *"Reviewing the **data inputs** into the current locational TNUoS methodology to identify and quantify their effect on the predictability of TNUoS tariffs as a long-run investment signal, suggesting improvements as deemed necessary."*
- 1, 2 — *"The calculation of the **wider TNUoS charge components** (exclusive of the 'Adjustment Tariff' used to support compliance with the Limiting Regulation), and the approach to **zoning**."*
- 1 — *"How closely the TNUoS methodology should align with the 'real world' operation of the transmission system (in the context of the intention of TNUoS being to provide a **long-run marginal cost signal**, not a short-run or operational signal)."*
- Identification, consideration, and suggestions/recommendations of **new inputs into the TNUoS locational methodology** (e.g., signalling excess/insufficient capacity).
- 3 — *"Existing data inputs such as **Charging Bases** and **Error Margin Calculations**"*
- 4 — *"Determining **which elements of TNUoS charges should be paid by distributed generators** with a clear, system-based rationale for any differences in treatment between classes of generators."*
- *"Appropriate **treatment of island connections, and some Offshore developments** including (solely in this context) the definition of a MITS Node, with consequential consideration of appropriate zoning methodologies for islands and Offshore (notwithstanding the longer-term position is subject to change in the context of other potential market reforms)."*
- 1, 3 — *"Determining any changes which will **simplify the methodology** and make it more approachable to new market participants."*

There are some areas of Ofgem's scope that are clearly excluded from ESO's proposed focus (treatment of spare capacity, treatment of island connections). For other areas there is a lot of overlap. However, it is necessary to further define the scope in these areas given that overlaps are typically only partial.

A key focus of this work consists of identifying improvements to cost reflectivity while also improving predictability for investors

While we will seek to identify options that improve cost reflectivity while also improving predictability, it may be that many options will imply a trade-off between the two, that we will need to understand.



Modelling tools

We have used two main modelling tools to carry out the quantitative analysis for this project.

Stochastic dispatch model

Overview

LCP Delta's EnVision modelling framework is a stochastic dispatch model of the GB power market, modelling hourly generation against a range of demand and renewable generation patterns.

Inputs

The model takes in 20 years of historic wind and demand data to stochastically simulate plant dispatch.

Market backgrounds could be either LCP's Central scenario or selected from NGESO's FES scenarios.

Outputs

The model will produce detailed generation and demand data for any specific simulated hour, which can be utilised to study the range of possible loading conditions on the network.

LCP Delta Transport Model

Overview

This model closely replicates the calculations of National Grid ESO's Transport and Tariff (T&T) model.

Model adaptations

The model can be adapted to consider changes to the charging methodology, including:

- One or many alternative background scenarios
- Changes to data inputs and model parameters
- Altering the fundamental calculations e.g. reference node

Outputs

The model can output metrics in granular detail (at a nodal or circuit level) or zonal level.

These could include metrics which are typically not produced by the NGESO T&T model, where relevant.

Backgrounds & Reference Node: Further Considerations

Frontier & LCP

The objective of this session is to discuss:

- Further work undertaken (including analysis) in relation to additional areas for consideration/questions posed by the Task Force during previous discussions on Backgrounds and Reference Node.

Our backgrounds approach does not replicate the CBA approach used to develop the scaling factors in the SQSS, but there is a degree of consistency in the approaches

Previous 'pseudo-CBA' approach

- Previous work recommended that a 'pseudo-CBA' approach be used to identify the transmission boundary capabilities and/or reinforcement options that minimise the net cost of transmission infrastructure
- The idea of this approach was to **define a set of scaling factors** that, when applied into a network model, could be used to **determine the optimal level of network build on a particular boundary**
  - **These flows may or may not trigger investment** – it depends on the balance of constraints they trigger versus the network investment cost
- This approach informed the current Year Round background
  - The year round scenario is intended to allow for building the network to manage the cost of network constraints efficiently.
  - *The peak scenario was based on a requirement to be able to meet demand in a winter peak scenario without relying on intermittent sources of generation, i.e. it is not about the management of constraints*

LCP/FE approach taken to derive backgrounds

- The principle underpinning our approach has been to **identify the set of scaling factors) that results in the highest flows over across each network element**
- In principle, these scaling factors should also be the **scenarios in which it is most likely that network investment would be triggered**
  - This reflects a degree of consistency with the 'pseudo-CBA' approach. While, in principle, we could assess all possible scenarios to identify the single best scenario that stresses each element, this is not practical in reality
  - Therefore, we have selected two scenarios that are best representative of what results in maximum flows on network elements, and which broadly reflect a peak scenario and the a year round scenario
- In the charging model, the network is then "shrink wrapped" around these flows and it is assumed that any incremental flows trigger investment.
- There is **no element of CBA which would happen in reality**
  - However, this is the case under both the current year round background and our proposed updated version.

Source: NETS SQSS Review Group, Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, July 2010

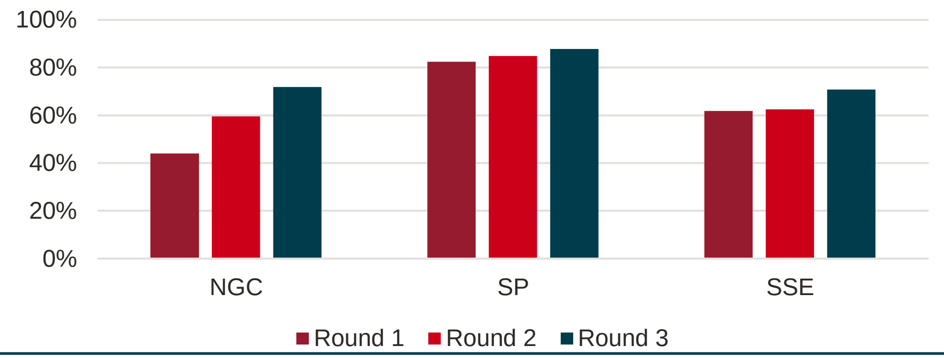
Additional analysis on selected representative backgrounds - 2025

	Most representative backgrounds (2025, NGESO FES ST scenario)		
Technology	*Round 1*	*Round 2*	*Round 3*
Biomass	68%	68%	3%
OCGT	0%	77%	0%
CCGT	21%	95%	0%
Hydro	64%	64%	0%
Interconnectors	48%	59%	-80%
Nuclear	100%	100%	100%
Wind Offshore	87%	4%	87%
Wind Onshore	81%	4%	77%
Pump Storage	0%	92%	-73%
Battery Storage	0%	24%	-49%
Demand (MW)	50,547	50,770	26,508
Cumulative % represented	59%	67%	76%
NGC % represented	44%	60%	72%
SP % represented	82%	85%	88%
SSE % represented	62%	62%	71%

Notes on additional analysis

- **Weighting the representation of circuits by the MWkm of those circuits did not change the top three backgrounds selected.** It is possible that if other or more periods had been sampled, this may not be true.
- The table shows the split of the storage load factors for these periods into battery storage and pumped storage. The key factors which affect their behaviour are the price in each period relative to others, their storage capacity, their round trip efficiency and the horizon over which they arbitrage.
- The table and chart below also show the split of circuit representation between TO regions.

Cumulative % of circuits well-represented by TO region



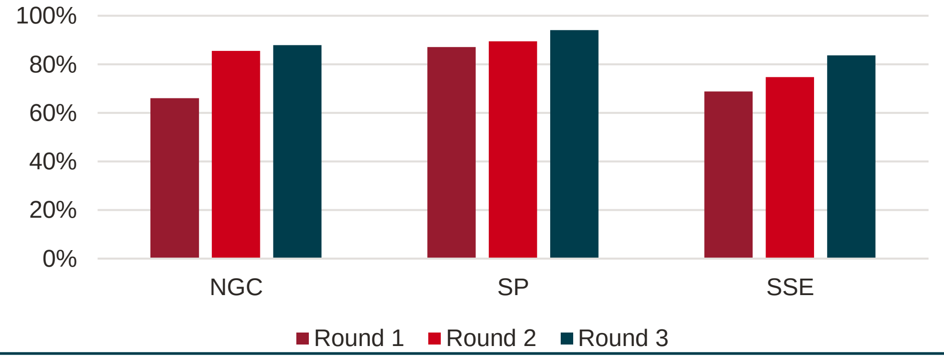
Additional analysis on selected representative backgrounds - 2035

	Most representative backgrounds (2035, NGESO FES ST scenario)		
Technology	*Round 1*	*Round 2*	*Round 3*
Biomass	99%	100%	99%
OCGT	0%	40%	0%
CCGT	0%	94%	0%
Hydro	52%	64%	59%
Interconnectors	-93%	90%	-81%
Nuclear	100%	100%	100%
Wind Offshore	71%	30%	75%
Wind Onshore	62%	2%	20%
Pump Storage	0%	0%	0%
Battery Storage	0%	0%	0%
Demand (MW)	61,552	72,121	56,608
Cumulative % represented	72%	84%	88%
NGC % represented	66%	86%	88%
SP % represented	87%	89%	94%
SSE % represented	69%	75%	84%

Notes on additional analysis

- **Weighting the representation of circuits by the MWkm of those circuit did not change the top three background selected.**
- For both 2025 and 2035, the best representation of circuits is seen for the SP region in South Scotland. The representation of the NGC region (England and Wales) is substantially improved by the addition of the "peak" proxy scenario in Round 2.
- In these periods, we see no discharge from storage due to the particular periods sampled. This would lead to paying no charges, which should be considered against charging principles for storage.

Cumulative % of circuits well-represented by TO region



Relative impact of the ALF discount is greater the further generation is from the reference node

1
The charging methodology means ALF has a bigger impact further from the reference node

- ALF discount is applied to the Year Round charges
  - just YRS for intermittent
- Therefore, when Year Round charges are at their largest absolute value (either +ve or –ve) the level of the ALF has a bigger impact
- Under a D-weighted reference node this means it has the largest impact in northern zones

[See next slide for illustration]

2
This is true under a D-weighted or G-weighted reference node

- A G-weighted reference node effectively moves the reference node further north
- Thus the relative difference in charges between high ALF and low ALF plants in northern zones is narrowed
- However, a northern shift in the reference node increases the impact of ALF in far southern zones as generation TNUoS charges are reduced with some becoming more negative.

3
At a general level the dynamic makes sense

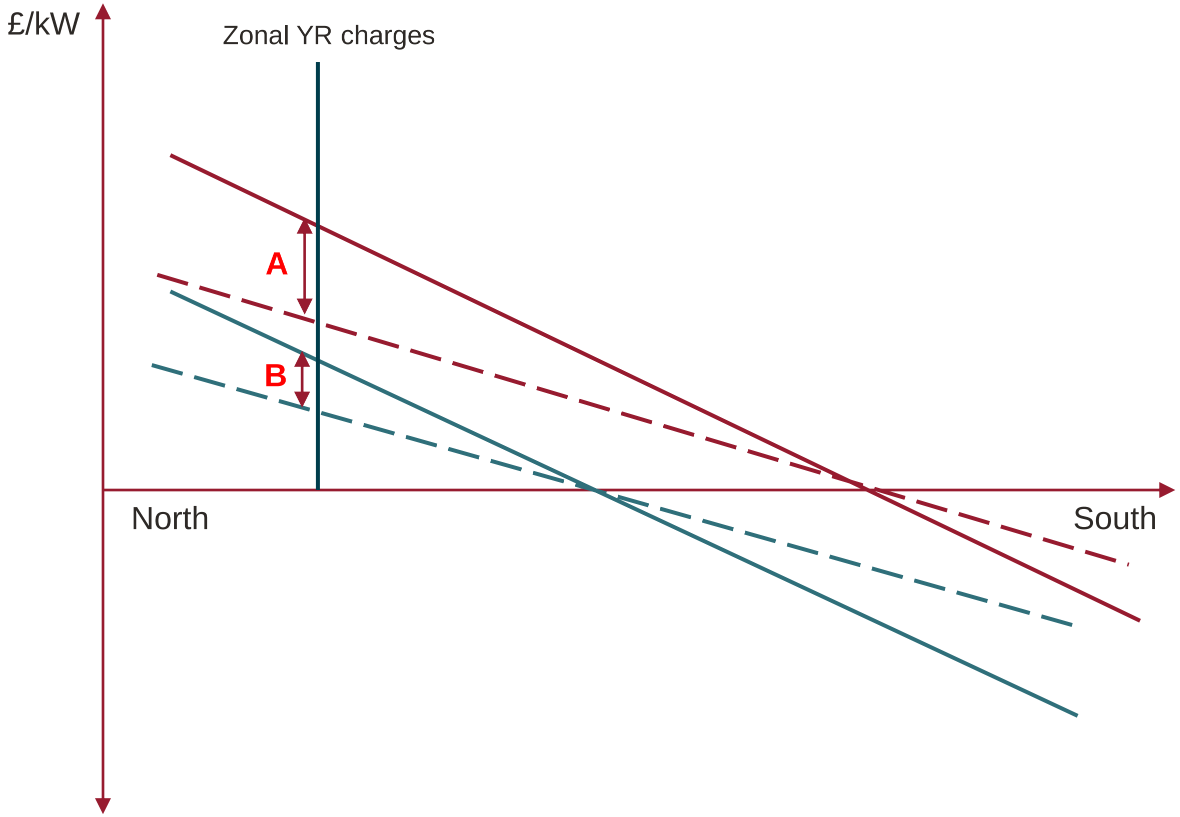
- Generation in zones far from the reference node have the largest (absolute) charges because adding incremental generation in those zones drives the largest (absolute) changes in incremental MWkms
- Thus in those zones the likelihood of a generator driving incremental MWkms is more important, and this is broadly what ALF proxies for

4
D-weighted or G-weighted could both be cost reflective

- For a given zone (e.g. zone 1) D-weighted and G-weighted reference nodes imply different scales of ALF impacts on charges
- Each of these can be appropriate depending on whether you believe that incremental network expansion follows the path implied by the D-weighted or G-weighted reference node.

Illustration: implication of ALF for different approaches to the reference node

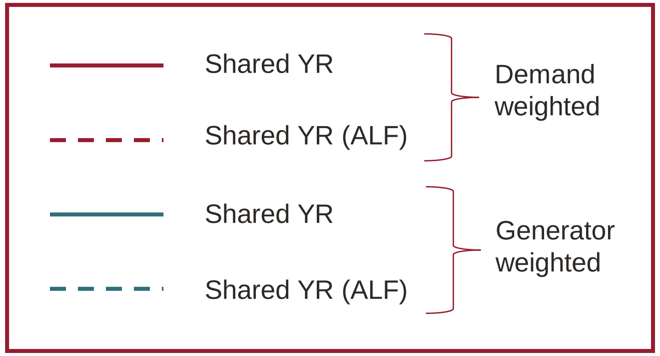
Indicative zonal charges



Cost reflectivity of the size of ALF discounts

A can be considered cost reflective if you believe that generation is added to meet increases in demand

B could be cost reflective if you think that for a given demand additional generation displaces other generation



Charging Futures

Reforming electricity charging together

Break

Next session starts at 11:30

N.B. Analysis shared is work in progress

Shared/Not Shared Elements: Deep Dive

Frontier & LCP

The objective of this session is to provide:

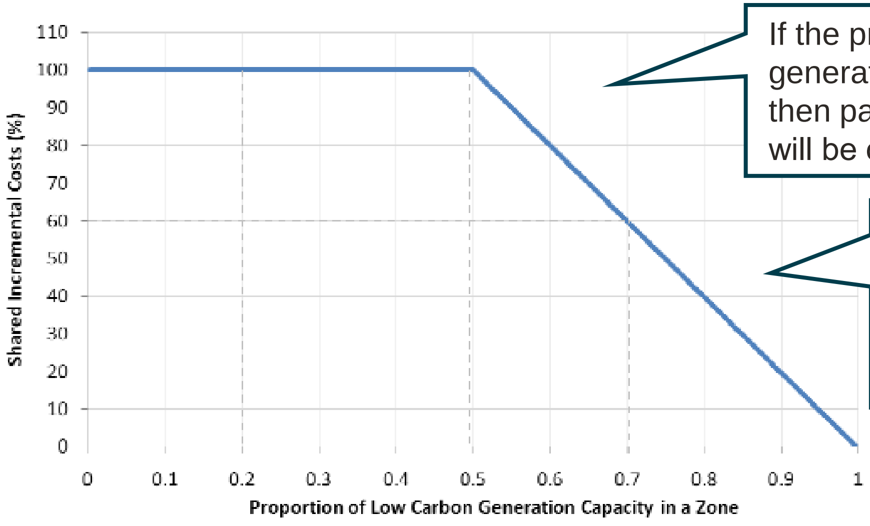
- Further level of detail on the review undertaken in relation to sharing arrangements, the assessment to date including; approach taken, conceptual thinking, and initial conclusions.

The current arrangements provide a discount on charges based on the ability of different generators to share transmission capacity

The Year Round tariff is split into two elements: 'shared' and 'non-shared' based on a generators' ability to 'share' transmission capacity

- Conceptually, the ability of generators to 'share' transmission capacity is determined by the extent to which, prior to any redispatch actions by ESO, output by generators within a zone is positively or negatively correlated. For example: Wind plants are likely to be generating at the same time (i.e. when the wind blows) in a given location and so cannot share transmission capacity by utilising it at different times.*
- The current methodology seeks to reflect this by providing a discount on the Year Round element of network charges based on the ability of generation assets within a zone to "share" transmission capacity
- The level of discount is determined by Boundary Sharing Factors which are a function of the share of low marginal cost capacity in a zone.

Calculation of Boundary Sharing Factors



If the proportion of low carbon generation in a zone exceeds 50%, then part of the Year Round tariff will be classed as 'non-shared'

The proportion of the Year Round tariff that is non-shared will increase as the shared will increase as the percentage of low carbon generation increases

Classification of generation technologies

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (ex. PS)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

'Carbon' vs 'low carbon' classification is really about zero/low marginal cost vs positive marginal cost. Hence biomass is classified as carbon

Solar is not included in the technology list in the CUSC, but we assume it would be categorised as low carbon

* This approach is based on the outcomes of the 'pseudo-CBA' which defined a set of scaling factors that, when applied into a network model, could be used to determine the optimal level of network build on a particular boundary.

The rationale for sharing is derived from the fact that an approach based on a limited set of backgrounds is a simplification of reality...

Overarching aim is to develop charges based on backgrounds against which network investment is most likely to be triggered

This is intrinsically linked to the use of the different backgrounds, and the extent to which these are representative of the full range/distribution of possible generation patterns that may occur

- In theory, N number of backgrounds could be applied to fully represent the range of scenarios in which maximum flows are achieved for each network element i.e. in the extreme a different background could be derived for each network element.
- In this example, charges could be derived as follows:
  - Incremental generation is added to each node against each background to estimate the MWkms triggered.
  - Incremental costs (MWkm*ExpC) would then be paid by generators according to their likelihood of generating in each background i.e. generator pays incremental cost at their node, multiplied by the load factor for the relevant background.
  - ➢ This would capture the extent to which a technology is generating in a period that drives constraints, and hence adds to incremental investment costs.

This approach would have a number of advantages, in particular:

- There is no need to apply ALF in calculating charges, since load factors are specific to all scenarios in which plants generate
- There is no need to apply sharing factors, since the impact of a high concentration of low carbon generation would be reflected in the particular scenarios represented by each of the backgrounds for each network element

However, in practice this is not feasible / practical since:

- This is a forward-looking exercise and therefore subject to significant uncertainty
- Practicality / time intensity of applying specific charges across a large number of backgrounds / scenarios

...and in this context there is a logic supporting its inclusion

The current Year Round background is intended to represent a wide range of possible scenarios which have different technology mixes, patterns of generation, load factors etc. It is only in this context that the sharing factors and discount (ALF) are potentially appropriate, and are intended to enhance how reflective the Year Round scenario is of a much broader set of scenarios

Under this approach:

- The charge is multiplied by ALF, as a simple proxy for the effect that a specific plant has on constraint costs and hence network investment.
- Sharing factors are used to calibrate when a discount based on ALF is appropriate.

ILLUSTRATIVE EXAMPLE - No use of sharing factors

A wind plant with an ALF of 30%, would face a single charge as follows:

Wider tariff = **ALF (30%)** × **Year Round** + **Generator residual**

i.e. without the use of sharing factors, the charges assume that the costs imposed on the network by a wind plant are proportional to its ALF. For zones with high wind penetration, this is likely to understate the true costs imposed on the system by the wind plant because periods of congestion are correlated with wind output.

ILLUSTRATIVE EXAMPLE – Impact of sharing factors

Zone with:
10GW wind
0GW thermal

- 100% low carbon generation, congestion (and hence investment case for network) driven entirely by wind
- Incremental 1MW of wind, due to its correlation with existing output, will trigger investment related to its full capacity (i.e. *no discount is appropriate*)

Zone with:
5GW wind
5GW thermal

- 50% low carbon generation, so assumption there is 'perfect' sharing, such that congestion driven part by wind and part by thermal.
- Incremental 1MW of wind, only part of investment case for reinforcement (i.e. that related to correlated output of wind) on boundary (i.e. *discount is appropriate)*

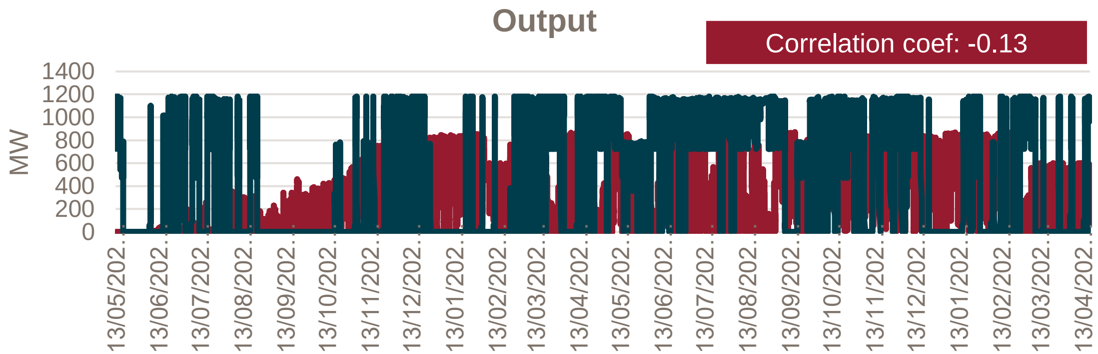
- Therefore, a particular technology mix in a zone could imply 'sharing' and hence a discount is reasonable.
- Key driver of sharing relates to merit order, but merit order outcomes are set in the national market (not locally) such that the extent of sharing may differ locationally.

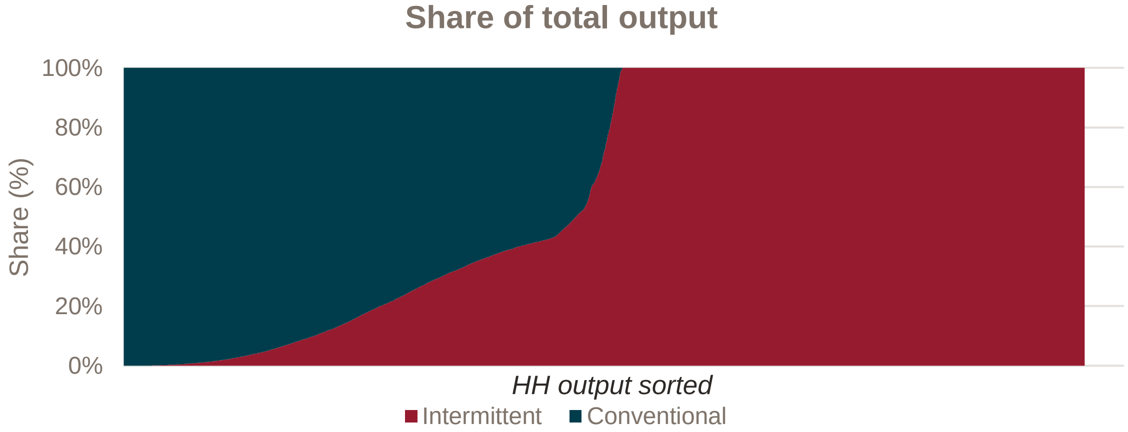
While sharing is not a perfect approach, there is a logic supporting its inclusion in the methodology.

As an illustration, we reviewed historic data to identify the extent of sharing, however the results are inconclusive

- We take the Half-Hourly FPNs for each unit in a particular zone
- We then group the output into different technology types (i.e. intermittent and conventional)

EXAMPLE: Zone 2 (13th April 2021 – 17th April 2023)





Zone 2 includes 3 offshore wind units (since mid-2021) and a CCGT plant

	Offshore wind	Battery	OCGT	CCGT
MW capacity	900	-	-	1,180

- The combined capacity of intermittent plant is 900 MW (43%) and 1,180 MW (57%) of conventional plant

- The correlation coefficient during the period is slightly negative (-0.13).
- During 49% of the timeframe considered there was only one type of technology generating.
  - Out of this time, 95% of the time intermittent plants generated some output while conventional units had a FPN of 0.

Sharing is likely to still be relevant under our new proposed ‘Year Round’ background

The aim in using sharing factors is to try and proxy for the ‘constrained ALF’ of a marginal MW of a given technology at a given location (assuming optimised transmission build)

Strictly, the relevant definition of a “constrained period” refers to a period when there is a constraint on any zone boundary between the generating asset and demand zones

EXAMPLE:

If, in an optimised system, a new 1MW of plant:

- never generates during a constrained period (i.e. ‘constrained ALF’=0)….
- … then it is not contributing at all to marginal network build

- always generates during constrained periods (i.e. ‘constrained ALF’=100%)…
- … then it is fully contributing to marginal network build based on its TEC

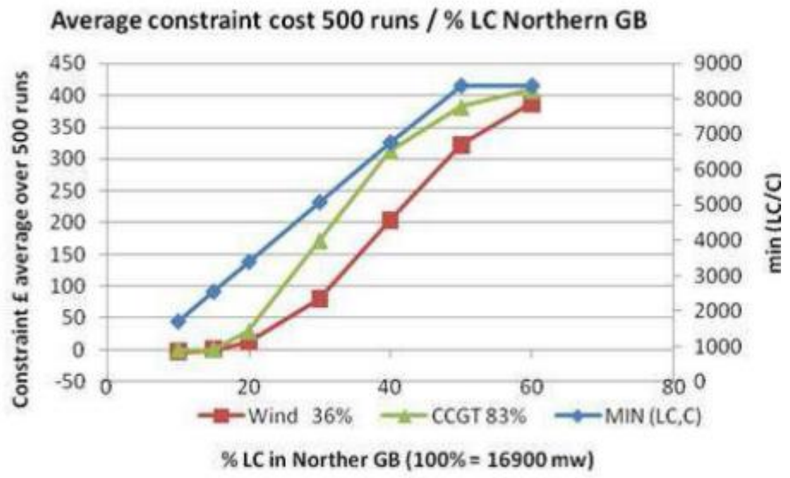
Based on this logic, the principle of sharing is still relevant under our new proposed Year Round background

- Given that the Year Round background we define is effectively seeking to proxy for a large number of scenarios…
- … the average load factor of technologies in all the scenarios that the Year Round background is trying to proxy for is subject to uncertainty
- However, fundamentally, the ‘constrained ALF’ concept still applies:
  - it is more likely that where there are large volumes of wind in a given zone, these are likely to be a driver of constraints and therefore will have a ‘constrained ALF’ that is greater than their average annual ALF
  - conversely where there is little wind in a zone, it may not be a driver of constraints - its generation may be uncorrelated with constraints and therefore its ‘constrained ALF’ may reasonably be expected to be closer to its general ALF

However, there remains a question as to the precise calibration of the sharing factors and therefore whether this could be improved upon

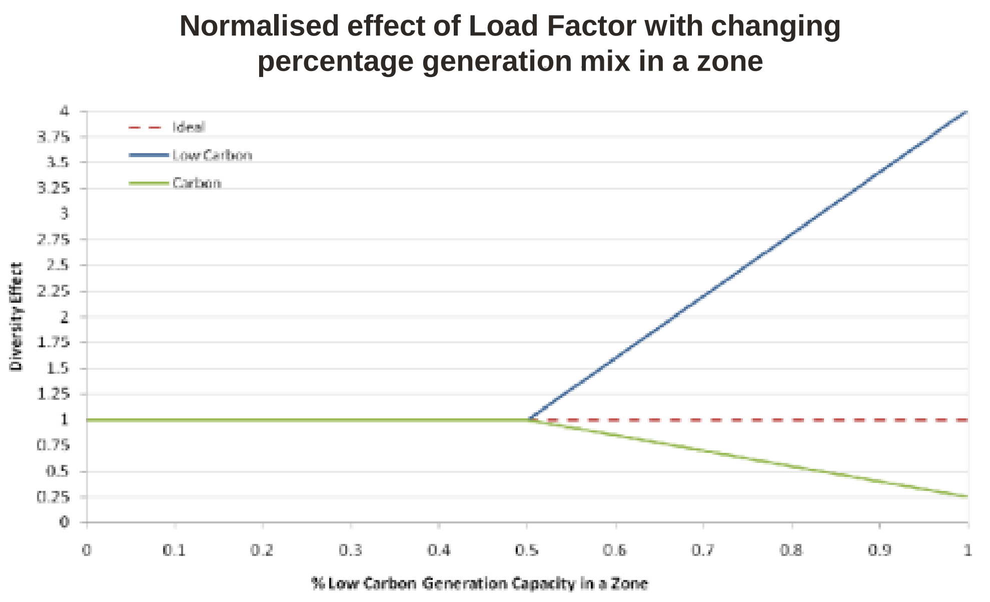
Project TransmiT considered an illustrative scenario.

This kept the volume of GB generation constant, while moving low carbon plant south of the B7 transmission boundary until the volume of low carbon plant north of B7 was 10%. Generation was then moved north of B7 to test the load incremental cost relationship.



- For volumes of low carbon plant below 10%, the relationship to load factor was weak, as only a few scenarios resulted in constraint action being required.
- Between 20-35% of low carbon plant behind a boundary, the load factor relationship was linear. Above 35% the relationship deteriorated such that at 50% low carbon plant behind a boundary, the low carbon volume needed to be multiplied by 2 to have the same effect as carbon plant.

It seems that this analysis formed the initial basis for the 50% Boundary Sharing Factors that are applied….



…. however, the rationale for using this precise sharing function is not entirely clear from this evidence

It therefore remains challenging to determine how sharing factors should be calibrated and therefore whether the current calculation would need to be recalibrated (both with the current or new Year Round background)

Source: Project TransmiT: Decision on proposals to change the electricity transmission charging methodology; Stage 06: Final CUSC Modification Report – Volume 1 – CMP213 Project TransmiT TNUoS Developments (June 2013), p 33-38

While the precise calibration of sharing factors is hard to determine, we can see that storage may be treated incorrectly under any Year Round background

- The current approach treats pumped storage as carbon generation, i.e. sharing applies in the same manner as set out through the illustrative example on the earlier slide.
- However, such an approach to sharing may be less appropriate for zones with storage:
  - A conventional thermal plant can ramp up and down to full capacity to 'share' with low carbon generation, i.e. it is negatively correlated with wind
  - Storage can however go further than this by adding to or drawing on capacity (in addition to wind capacity). In this way, storage can help to aid sharing by reducing congestion and constraint costs on the network
  - Therefore, the impact of low carbon generation on constraints may be overstated and therefore the sharing factors may not be correct.
- This is true in both the current Year Round background and our proposed updated Year Round background.

ILLUSTRATIVE EXAMPLE – Impact of sharing factors with pumped storage (PS)

Zone with:

10GW wind
0GW pumped storage

- 100% low carbon generation, congestion (and hence investment case for network) driven entirely by wind
- Incremental 1MW of wind, due to its correlation with existing output, will trigger investment related to its full capacity (i.e. *no discount is appropriate*)

Zone with:

5GW wind
2GW pumped storage

- Under current categorisation, 71% low carbon generation (wind), so assumption there is 58% sharing, such that congestion driven part by wind and part by PS (as on earlier slide)
- However, PS can either add to or draw 2GW of generation, such that total contribution is in fact 4GW
- This implies low carbon generation contribution of 55% rather than 71% as above, which in turn implies a sharing factor of 90%.

- Classification of pumped storage as carbon generation currently understates the level of sharing
- This in turn overstates the level of congestion driven by low carbon generation

An alternative approach to sharing that allows for the 'double count' of storage may therefore be required/appropriate to capture its ability to adding to or drawing on capacity

This could be the difference between the TEC and the maximum import limit (MIL)

Similar considerations are likely to also apply to flexible demand

Conclusions

Conclusions:

- From a conceptual perspective, the rationale for sharing still seems relevant under the current Year Round background, or any improved 'Year Round' background that intends to represent outcomes over a range of different scenarios that may occur.
- Therefore, while a discount remains appropriate in some circumstances, the sharing factors applied should only be considered as a representation of the concept and will not perfectly reflect the true extent of sharing.
  - One aspect where sharing may be currently less appropriate relates to storage. To the extent that storage can add to or draw on capacity (in addition to wind capacity), the sharing factors for low carbon generation may not currently be appropriate, such that an alternative approach to sharing that allows for this 'double count' of storage will be required

Key remaining questions:

- Sharing can only ever be an approximation, but the rationale for using the precise sharing function is not clear from historic documents i.e. how the current sharing factors were calibrated, and therefore it is unclear whether these could be improved upon;
- In future, the sharing function is likely to have a smaller impact on charges as wind comes to dominate more and more zones, so sharing may become less relevant (or the not sharing elements may start to dominate).

Discussion of sharing factor assessment

Does the evidence support retaining the current approach?

Is their further analysis required and, if so, what?

Or is an alternative more appropriate?

Charging Futures

Reforming electricity charging together

Lunch

Next session starts at 13:15

Shared/Not Shared Elements: Feedback & Further Discussion

Frontier & LCP

The objective of this session is to discuss:

- Shared/Not Shared analytical assessment and identify any additional considerations or further areas of work that may be required.

Discussion of sharing factor assessment

Does the evidence support retaining the current approach?

Is their further analysis required and, if so, what?

Or is an alternative more appropriate?

N.B. Analysis shared is work in progress

Data Inputs: Deep Dive

Frontier & LCP

The objective of this session is to provide:

- Further level of detail on the assessment undertaken in relation to methodology data inputs and implications for charge volatility and predictability, including the approach taken, conceptual analysis as well as initial conclusions.

ESO has identified some potential concerns regarding the implications of certain data inputs for charge volatility and predictability

1 ALFs	ALFs are calculated as a rolling 5 year average and so significant changes in the values are smoothed over time creating some stability year to year. However, in the context of rapidly changing load factors (due to technological advancements etc) it is considered that ALFs may need to be reviewed in terms of both the appropriateness of the calculation [i.e. ALF = max (HH, PFN)], as well as the 5-year frequency.
2 Charging bases	The ESO demand charging base forecast process aims to ensure accurate recovery of revenue with the charging base forecast continually refined until final tariffs are published (each January). Considerable movements to charging bases have been witnessed in recent years with industry suggesting this element should be "locked down" in advance. There may be merit in reviewing the ESO processes and this option to lock down the forecast at an earlier stage. Any changes should consider the impact on revenue recovery (and onshore TOs' cashflow needs to be fully understood) as well as any Price Control / licence implications.
3 Week-24 data	All DNOs provide their "best view" of the likely nodal demand in the Week 24 forecast, however, the practice may not be consistent across the 14 regions and or DNOs. In addition, the forecast provided by the DNOs is based on net demand (not gross demand) which is inconsistent with SQSS. There could be alternatives to the DNO data to consider, for example use of network planning data such as the Electricity Ten Year Statement (ETYS) or the ESO Future Energy Scenarios (FES) which does not rely on DNO 'forecasts'.
4 Demand forecasts	There are inconsistencies between the method of forecast on demand charging bases (by zones and associated demand assumptions), and the DNO's forecast of nodal demand that are used to set locational tariffs which may cause issues. The charging base forecast is based on a Monte-Carlo model, while the Week 24 data are provided by DNOs – with the former focussing on revenue recovery, while the latter focuses on transparency.
5 TO data	▪ The locational tariffs are dependent on a set of parameters which are reviewed every 5 years by Ofgem (during the RIIO Price Control period) – this refresh can cause some considerable near-term change to the tariffs between price control periods and volatility in TNUoS. ▪ In addition, there are some project-specific items that the ESO are not able to publish (e.g. cost of HVDC links) which reduces transparency to industry. (we note that these items are related to expansion factors and CMP 315/375 are dealing with this issue)

Annual Load Factors (ALFs): averaging period

1

Issue

- Some stakeholders have expressed the view that the annual load factors (ALFs) used for determining generator TNUoS charges should have a shorter averaging period. A key rationale being that ALFs are rapidly evolving due to the evolution of the system e.g. declining load factors for thermal plant as renewable capacity is expanded.

Analysis

- If annual load factors are rapidly evolving, then the current approach of using the last 5-year average of ALFs may not be a good proxy for estimating the ALFs for the next charging year (t), which is the relevant driver for network costs. To consider this issue, we have compared the accuracy of using a 5-year average with applying the previous year's ALF.
- We gathered a series of actual ALFs from 2010/11 to 2021/22. This series allows us to construct a 5-year moving average series since 2015. For each year t, we calculate the correlation coefficient of:
  - ALF_t and ALF_{t-1} *(Approach 1)*
  - ALF_t and $ALF_{\text{last 5-year average}}$ *(Approach 2)*

Approach	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Approach 1	0.87	0.79	0.87	0.81	0.91	0.88	0.78
Approach 2	0.88	0.90	0.86	0.92	0.93	0.93	0.91

- For all the tariff years analysed with the exception of 2017/18, the last 5-year average has a higher correlation with the ALF of year t than using the previous year.
- We note that if the load factor of a plant is declining significantly, then relying on 5 year rolling average will mean that its charge remains higher than its true impact on network costs, and could accelerate closure.
- If we consider only CCGTs (for which it could be argued that its load is declining due to increases in RES), the last 5-year average has a higher correlation for all the years considered. The difference is even higher than for all technologies.

Approach	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Approach 1	0.80	0.75	0.82	0.80	0.86	0.82	0.68
Approach 2	0.83	0.86	0.85	0.90	0.91	0.90	0.87

Conclusions and implications

- Based on this we conclude that charges would have been, overall, less cost-reflective if the methodology used a shorter averaging period. This also applies if we consider only CCGTs.
- In addition, moving to a one-year average could increase any incentives on some plants to create an artificially low ALF to minimise future charges.

Annual Load Factors (ALFs): FPN and metered output

1

Issue

- The current method for calculating historical ALFs (which inform estimated future ALFs) uses the higher of FPN and metered output (HH data).
- The concern is that this may systematically over-state the load factor for intermittent plants.

Analysis:
Assessment of changing the current approach

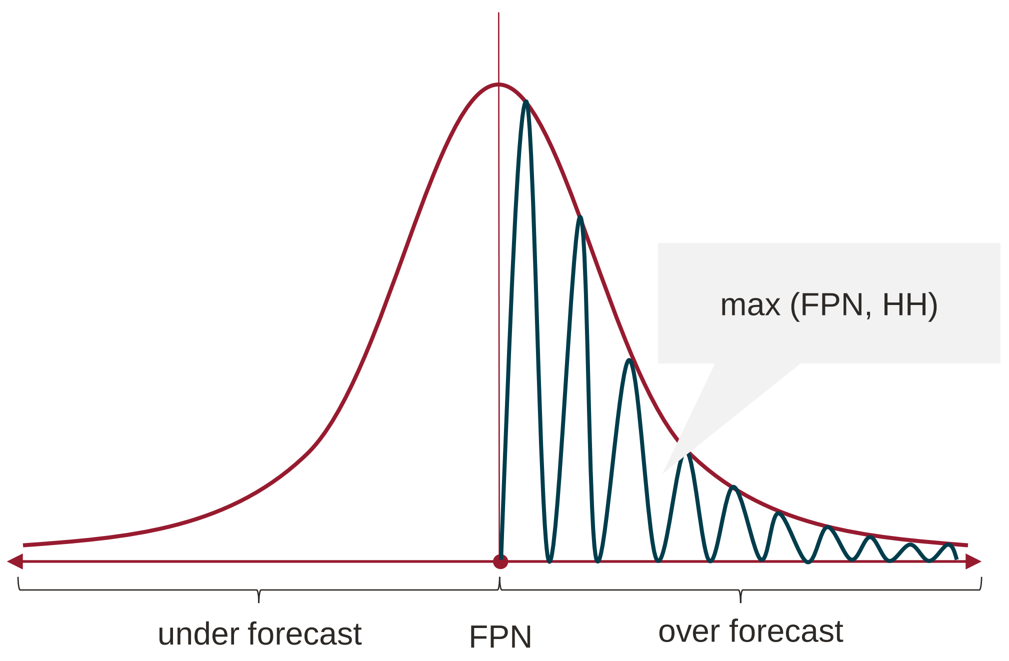
- The CUSC confirms that the max (FPN, HH) is the required approach but does not provide the rationale behind this approach.
- Conceptually, ALF should perhaps reflect output before any adjustments due to network congestion.*
- If ALF was based on HH metered output alone, there is a risk that HH data reflects adjustments to manage congestion.
  - In one extreme, if metered output was zero due to 100% curtailment, then ALF would be zero and the generator would face no charge despite driving congestion and hence network costs.
  - In another extreme, if a plant was not expected to generate (FPN = 0), but the plant is redispatched to resolve a network constraint, a generator in a positive charge zone would face a charge despite operating only to relieve network stress.
  - Thus, using HH data alone could, in some circumstances, be inappropriate as it would lead to charges that do not reflect their true impact on congestion and hence network costs.
- If on the other hand, ALF was based on FPN data alone, there is a risk that plant forecast errors result in differences in their actual output and their FPN. This is particularly the case for intermittent technologies.
  - However, if forecast errors are unbiased (i.e. errors equally likely to be positive or negative and are on average 0), then using the FPN would represent a reasonable basis on which to set ALF, and suggests that taking the maximum of metered output or FPN could over-state the ALF.
- In the following slides we assess with more detail the appropriateness of using only FPNs against using the max (FPN, HH) for intermittent and conventional plants.

* This is because it is used to represent generation in the Year-Round scenario and there is no redispatch necessary in the Year-Round scenario as the network is assumed to be 'shrink wrapped' to the size of the flows over the network elements. However, such an approach may also raise problems as we explore in later slides.

The use of the maximum between the FPN and HH for intermittent plants creates a number of issues...

1

Illustration of the issue when considering max (FPN, HH)



Situation with no curtailment

- Assuming an unbiased distribution of forecast errors for intermittent plants, using the maximum between the FPN and HH output for setting ALF will lead to an upwards biased ALF.

Situation with curtailment

- In practice, when wind is curtailed, the FPN is the max of the FPN and HH data. Therefore, this is equivalent to just taking the FPN.

- There could be an argument for switching to using only FPNs for intermittent generation as this would address the issue of upward bias in the current approach.
  - In principle this could create an incentive to underforcast FPNs for wind in order to reduce TNUoS charges.
  - However, this incentive is likely to be very weak.
    - It would expose the party to more volume risk
    - It would also only change the TNUoS charge slowly and very marginally due to the 5 year averaging of data

For conventional plants, there are merits in considering FPNs only in zones with positive charges and keeping the current approach for zones with negative charges

1

Positive charge

Max (FPN, HH)	FPN only
Increases TNUoS charges for a situation in which the plant is resolving a constraint. This could create marginal distortions in the merit order of BM bids for energy balancing reasons.	No increase in charges if a plant resolve a constraint. Market rules mitigate risk of under forecasting FPN incentive.

Turned off due to constraints (FPN > HH)

Max (FPN, HH)	FPN only
Both are equivalent	

Max (FPN, HH)	FPN only
Assuming there is no forecast error, both are equivalent. If there are forecast errors then the max function results in a higher ALF and thus higher TNUoS charge/credit	

Turned up due to constraints (FPN < HH).

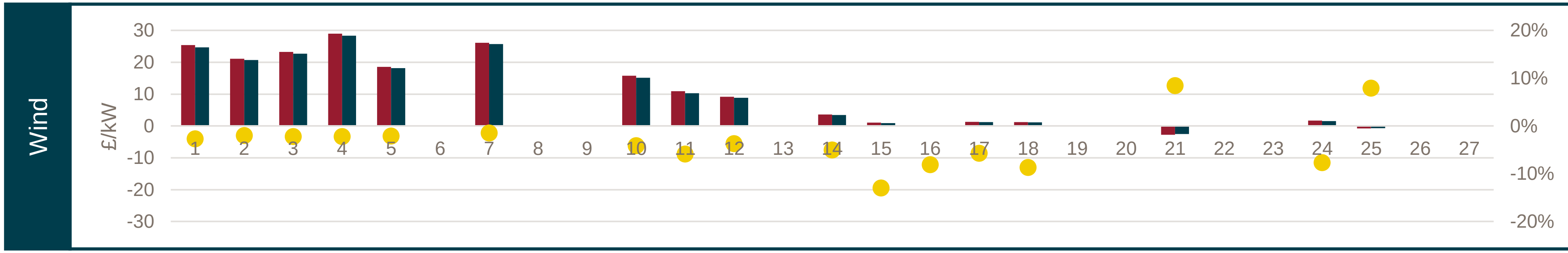
Max (FPN, HH)	FPN only
Peaking plants that FPN at close to zero are calculated to have a positive ALF due to redispatch actions. This provides a locational investment incentive. However, it could marginally distort the merit order of BM bids for energy balancing.	A peaking plant that resolves constraints would receive no investment signal to locate in zones with the most negative charges.

Negative charge

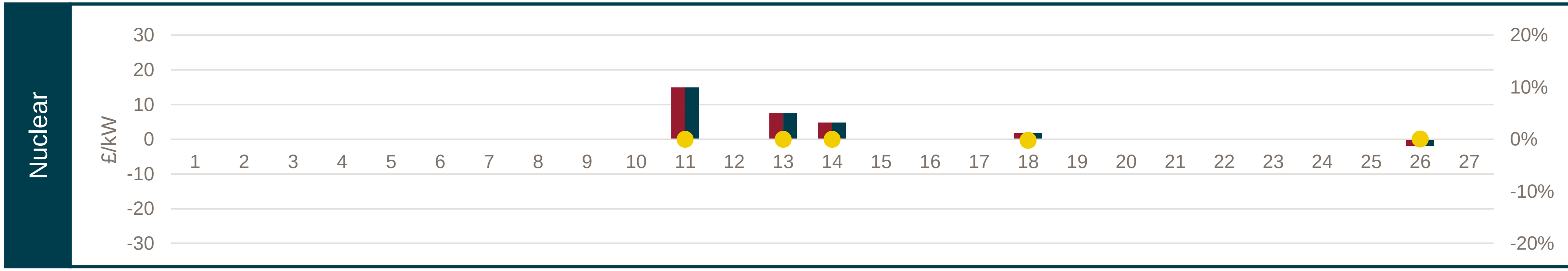
In summary, for plants which are turned up to resolve constraints, the max function potentially increases charges unfairly for plants in positive charge zones, but provides a valuable investment signal in negative charge zones

Impact of switching to using FPN on the year-round components of the tariff

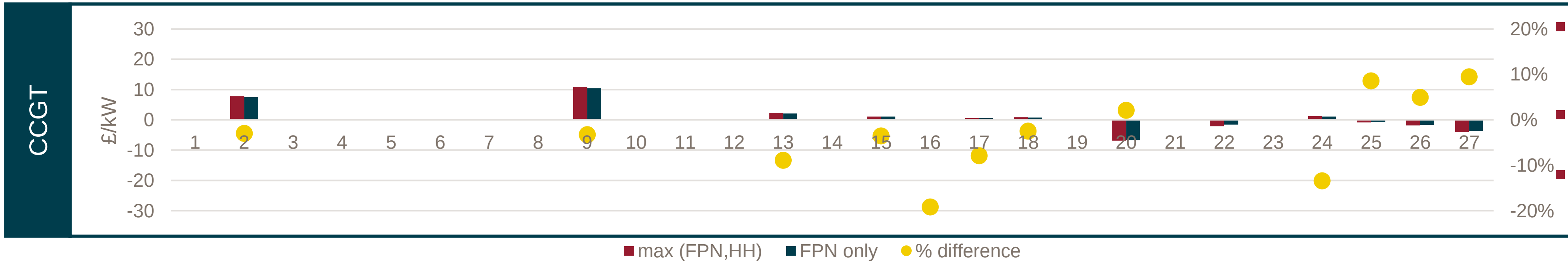
1



- Limited impact in positive charge zones.
- Increase of up to 10% in negative charge zones (though small change in absolute terms)



- No change in ALF in nuclear. Therefore the impact of switching to FPN would be null.



- Reduction of up to 20% in positive charge zones.
- Increase of up to 10% in negative charge zones
- Small change in absolute terms

Note: We have calculated the year-round components of the generation wider tariffs with FPN data and max (FPN, HH) data for 2021/22. The data was provided by ESO.

Charging bases

Issue

- The ESO demand charging base forecast process aims to ensure accurate recovery of revenue and continues to refine the charging base forecast until final tariffs are published (each January). Considerable movements to charging bases have been witnessed in recent years with industry suggesting this element should be "locked down" in advance.

Analysis

- We have compiled the charging bases from the tariff period 2016/17 until 2023/24. The following table shows the average change between preliminary forecasts and final demand forecasts*:

Charging bases	2016/2017	2017/2018	Net to gross	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024
NHH Demand	-0.2%	**6.0%**		0.5%	0.0%	2.5%	2.3%	1.6%	-2.3%
Total Average Gross/Net Triad	-0.4%	-2.2%		-0.3%	0.0%	0.1%	-0.1%	0.3%	-1.0%
HH Demand Average Gross/Net Triad	**-7.7%**	**-14.5%**		-1.5%	0.0%	**4.2%**	**-4.0%**	1.1%	**-6.1%**

- **Shift from net to gross demand forecasts:** the most significant changes (>5%) from preliminary to final forecasts happened in the tariff periods where charging bases were based on net demand.
- **Main drivers of changes in recent tariff periods:** in 2021/22, the reduction in forecasts was driven by demand suppression due to COVID-19, while in 2023/2024 they were caused by the downturn in the economy and latest demand outturn data.

Conclusions and implications

- We have observed a reduction in forecast changes after the shift from net to gross demand. However, we have detected that some significant variations persist in more recent years. This raises the question of whether this volatility is a reason for the charging base to be locked further in advance in order to increase the predictability of tariffs.
- However, we note that the demand forecast does not feed into the residual anymore (which may have been a key driver of the original concern), and that the impact on locational charges is much less clear as it feeds through the backgrounds onto charges.
- Finally, in terms of investment decisions, this volatility between provisional and final charges is less important than the lack of predictability of final charges over project life.

*We first calculate the relative change between each preliminary forecast and the final one and then we average the changes of all the preliminary forecasts.

Week 24 data

3

Issue

- All DNOs provide their "best view" of the likely nodal demand in the Week 24 forecast, and the practice may not be consistent across the 14 regions and or DNOs. In addition, the forecast provided by the DNOs is net demand (not gross demand) which is inconsistent with SQSS which has moved away from net demand and now uses gross. There may be the need to consider alternatives to use of DNO data for example use of network planning data such as the Electricity Ten Year Statement (ETYS) or the ESO Future Energy Scenarios (FES) which does not rely on DNO 'forecast' (which may no longer be fit for purpose).

Analysis

- We have read the Guidance Notes for Network Operators Submission of Grid Code Data 2011 – 2012 (Incorporating changes for Grid Code B/07 Modifications) with the aim to asses the degree of prescription that DNOs have to follow for elaborating their Week 24 forecasts:
- According the basic principles, each DNO provides annually the Week 24 forecasts making ***"its own judgment on the appropriateness"*** of its forecasts.
- We note that on these general principles there is a lack of guidance on the assumptions that the DNOs must follow. However, the potential for discrepancies are reduced by the fact that National Grid provides in advance the date and time at which the annual peak demand is expected to take place:
  - *"By calendar week 17 National Grid provides all Network Operators* ***with date and time of the annual peak*** *of the GB Transmission System Demand."* National Grid considers *"average weather conditions pertained throughout the year"*
- Inaccurate forecasting of Week 24 data affects cost reflectivity because it leads to an incorrect spatial distribution of demand. Moving to other network planning data could remove inconsistencies and improve transparency, which may help in terms of tariff predictability. However, ETYS and FES is not at a nodal level, and ultimately, it would be necessary to assess whether DNOs are better placed for forecasting demand at a nodal level.

Conclusions and implications

- We can conclude - given the absence of prescriptive principles in the Guidance Notes - that DNOs can follow different methodologies for estimating Week 24 forecasts. Therefore, there is some potential to homogenise the estimation methods of the different DNOs by modifying the Guidance Notes. Still, the potential for discrepancies is reduced if National Grid provides in advance the date and time in which the peak demand is expected to occur.
- The scale of any possible improvement is unclear and untestable ex ante.

Inconsistent demand data

4

Issue

- There are inconsistencies between the method used to forecast demand to estimate the charging base (by zones), and DNOs' forecasts of nodal demand that are used to set locational tariffs. The charging base forecast is based on a Monte-Carlo model, while the Week 24 data are provided by DNOs – with the former focussing on revenue recovery, while the latter focuses on transparency.

Analysis

- The different measures of demand serve different purposes:
  - The ESO zonal Triad demand forecast is required for determining the demand charging base, and hence relates to cost recovery.*
    - We understand that ESO prefers to use its own demand forecasts because Week 24 data is only provided annually while the ESO's forecast can use the latest trends in data to provide more confidence to ESO over revenue recoverability.
  - Week 24 nodal data is used in the Transport Model as part of the backgrounds to assess peak flows.
    - We understand that the Transport model uses Week 24 data because it provides nodal level demand. ESO considers that DNO's are better placed for estimating the nodal demand than the ESO given the level of granularity that is required.
- It is difficult to assess in quantitative terms the impact of homogenising the demand data that feeds into the Transport and Tariff models.
- However, we consider that there are sound reasons for the inconsistency between the data sources for the transport and the tariff models.

Conclusions and implications

- We conclude that homogenizing the demand data in the Transport and Tariff models could be at the expense of reducing cost-reflectivity (because DNOs are better placed for nodal demand estimation) or tariff recoverability (because ESO data is more up-to-date). The loss in either of these areas should be assessed against the gains of using the same data source, but it is difficult to assess the impact in quantitative terms.

*Although we note that since residual charges are no longer dependent on Triad demand levels, recoverability risk will have reduced.

TO data: near-term changes in data inputs

5

Issues identified

- Transmission Owner (TO) data - the locational tariffs are dependent on a set of parameters which are reviewed every 5 years by Ofgem (during the RIIO Price Control period) – this refresh can cause some considerable near-term change to the tariffs between price control periods and volatility in TNUoS.

Assessment

- The main data inputs that are reviewed during the RIIO Price Control period (i.e. every 5 years) are:
  - Weighted Average Cost of Capital (WACC) (14.15.65)
  - Onshore Wider Circuit Expansion Factors (14.15.70)
  - Transmission Running Cost (TRC) factor (14.3.19)
  - Offshore Circuit Expansion Factors (14.15.84)
  - The Locational Onshore Security Factor (14.15.90)
- We consider that there are three options for addressing the negative effects near-term changes;
  - **Updating the data inputs annually**: This would reduce the current lumpy nature of adjustments, smoothing out changes in TNUoS charges. However, it in respect of some of the data items (e.g. WACC) it would represent a fundamental change to the regulation of the networks with possibly wide reaching consequences.
  - **Applying a one-year lag after the price control period**: although this option would not reduce the volatility, it would give more notice to stakeholders on of changes in tariffs. At the same time, cost-reflectivity would be preserved (with a one-year lag).
  - **Freeze charges for investors over longer periods.** This may be worth considering but is out of scope of our work for the taskforce

Conclusions and implications

- We have not identified an easy and palatable option to address this challenge within the scope of our work for the task force.
- Applying a lag could ameliorate the impact of near-term changes without excessively sacrificing cost-reflectiveness of the tariffs. However, even this limited change could create significant cashflow issues for the TOs and therefore could have wide ranging consequences.

In summary, beyond a potential change to the ALF calculation, we have not identified a strong case for change among the remaining issues

1 ALF

- Suggestion that faster adjustments to ALF may be more appropriate is not clearly supported by the available data.
- The use of the maximum between the FPN and HH creates an upward bias in ALFs for some plants
  - Switching to using only FPNs in for intermittent plants could be more appropriate.
  - For conventional plants, there are merits to keep with the current approach for zones with negative charges.
- The impact of switching to using FPN would be moderate in most of the zones.

2 Charging base

- Short term (<1 year) forecasting errors in charging base measures appear to have reduced following the move to gross charging, although some errors remain.
- Variations in charging base no longer directly affects residual charges
- Effect on locational charges is likely to be marginal and directional impact is unclear
  - Impact is through implied changes in network flows
- Short term demand forecast errors likely have limited impact on long term investment (key question is unpredictability of final charges over project life)

3 Week 24 data

- Given the absence of a fully prescriptive methodology for DNOs to follow there may be some inconsistencies in Week 24 forecasts between different DNOs
- This could be narrowed if more prescriptive guidance is issued.
- However, the scale of any possible improvement is unclear and untestable ex ante.
- Information regarding specific date and time of peak demand reduces potential for discrepancy.

4 Inconsistent Demand Data

- The different measures of demand serve different purposes:
  - ESO Triad demand forecast is required for determining the demand charging base, and hence relates to cost recovery.
  - Week 24 nodal data is used in the Transport Model as part of the backgrounds to assess peak flows.

5 TO Data

- We understand this issue to primarily refer to the update of TO data in line with the regulatory cycle (5 years)
- There are no clear palatable alternative options.

Discussion of data inputs analysis and conclusions

In respect of each question on data inputs:

Does the evidence support retaining the current approach?	Is their further analysis required and if so, what?	Are there alternative options that you consider require more consideration?

Charging Futures
Reformings electricity charging together

Break

Next session starts at 15:00

Data Inputs:
Feedback & Further Discussion

Frontier & LCP

The objective of this session is to discuss:

- Data Inputs analytical assessment, and identify any additional considerations or further areas of work that may be required.

Discussion of data inputs analysis and conclusions

In respect of each question on data inputs:

Does the evidence support retaining the current approach?

Is their further analysis required and if so, what?

Are there alternative options that you consider require more consideration?

Workstream Plan

James Stone & Nicky White

The objective of this session is to discuss:

- The proposed workstream plan for the 8 priority areas for review.
- Agree and allocate areas for review for progression across the Task Force members.

Creating the Workstream Plan

The ESO and Task Force members have further assessed the key areas for review and a proposed workstream plan has now been created using the following approach:

1. **Scope of works:** for each category this includes a review of the individual defects collated by the Task Force and agreeing a list of the key considerations and questions that need to be answered.
2. **Interdependencies:** highlighting any relevant links or interactions with individual items or other categories.
3. **Indicative timelines:** the scope of works has then been further reviewed considering whether questions can be answered on a principles basis or require further analysis as well as consultancy output to date - a relative length of time for review for each category was then agreed.

Scope of work by category

- **Backgrounds (TF Priority 1)**
  - Extent of current backgrounds impact on predictability.
  - Impacts on cost reflectivity/predictability if adding/removing scenarios.
  - Should TNUoS be based on a future network or the network we currently have?
  - If based on the future network - should it reflect the NOA ?
  - If based on network we have - should charging backgrounds be split from the SQSS and what are the implications of this?
  - Should backgrounds be locked down and how often should they then be reviewed?
  - To what extent should smart reinforcement (i.e. non physical assets) be reflected in the methodology?
  - To what extent will a change to the tech types impact accuracy of the signal?
  - If there is a case to change/add individual technology types what does this mean for the current model?
  - In principle how should energy flows be modelled – dynamic vs static – how does this impact any intended signal?

- **Signals (TF Priority 2)**
  - What does a meaningful signal look like for different users?
  - What is the current strength of signal – is it too strong and how this links to absolute charges.
  - Understanding the HND framework solution – to build upon
  - Locational investment signals for offshore –understand what has been done elsewhere (OTNR workstreams etc)
  - Principles for locational demand charges i.e. should signals be investment/operational & level of visibility of signals for various size users
  - Consider the nature of demand – assess current assumptions of how demand responds to locational signals – are they valid?
  - Are Triads still fit for purpose –do they need to change / consider an alternate?
  - Long-term fixing of TNUoS and the impact on signals
  - Impact of fixing on levels of cost reflectivity i.e. consider pace at which network changes and investment timescales.
  - Appropriateness of negative locational charges for generation, and or demand – consistent treatment.
  - Should the application of the floor at zero be reviewed?

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Scope of work by category continued

- **Data inputs (TF Priority 3)**
  - Identify data inputs that drive volatility
  - Magnitude of volatility determines focus for review - are there alternative data sets that can be used?
  - Review Security Factors – should it apply to intermittent?
  - Review of Annual Load Factors (ALFs)
  - Scaling Factors – negative scaling issues and revisit math
  - ACS - is this still the right measure/proxy for peak demand?
  - ACS - is the link to temperature as strong as it was? Do wider weather conditions need to be taken into account? If need to derive differently how would this be achieved – use of FES?
  - How transparently can data be shared – is there indeed a need to improve transparency?

- **Reference Node (TF Priority 4)**
  - Is the current approach to the reference node still correct - clarify defect & why it needs to change
  - Alternatives - articulate why these are preferred, why fundamentally better than current regime
  - Alternatives - identify possible consequences/impacts of these changes on charges/predictability.
  - Are there additional options than those considered as part of the consultancy analysis?
  - Fundamentally how should any reference node be weighted?
  - In principle do we consider demand is there to absorb generation or generation is there to meet demand?
  - If adding generation to the system is it matched by additional demand, or does it displace other ‘existing’ generation equally.
  - Consider changes to zoning and how this may impact reference node suitability.

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Scope of work by category continued

- **Absolute vs Relative (TF Priority 5)**
  - What is meant by available capacity i.e. is it linked to constraints or do we mean within the unconstrained network?
  - Consider then if TNUoS should reflect available capacity?
  - If we need to reflect available capacity – do we need to consider system where capacity restrictions exists?

- **Technology type (TF Priority 6)**
  - Is it appropriate to treat different technology types differently?
  - If there should be different treatment what level of granularity do we need in terms of technologies?
  - Do we have the correct generation categories?
  - Could FES be used to identify improvements to these (e.g. it already provides view of what tech types the network is being designed for).
  - Storage – consider how it uses the system – inc. Long duration vs Short duration
  - Inclusion of demand technology types?
  - Review of generation capabilities by category

- **Sharing (YNRS/YRS) (TF Priority 7)**
  - Is the current approach to YRNS/YRS appropriate
  - Is it calibrated correctly?
  - Is it considered to still be suitable for a future network with significant renewables?
  - Storage consideration - does this change/enhance winds ability to share?

- **Distributed Generation (TF Priority 8)**
  - Should 132kV generation all be in the transport model?
  - Should DG face TNUoS – and interactions with level of access provided/products
  - If the model considers DG as well as Transmission connected what issues are there with data/what data is required?

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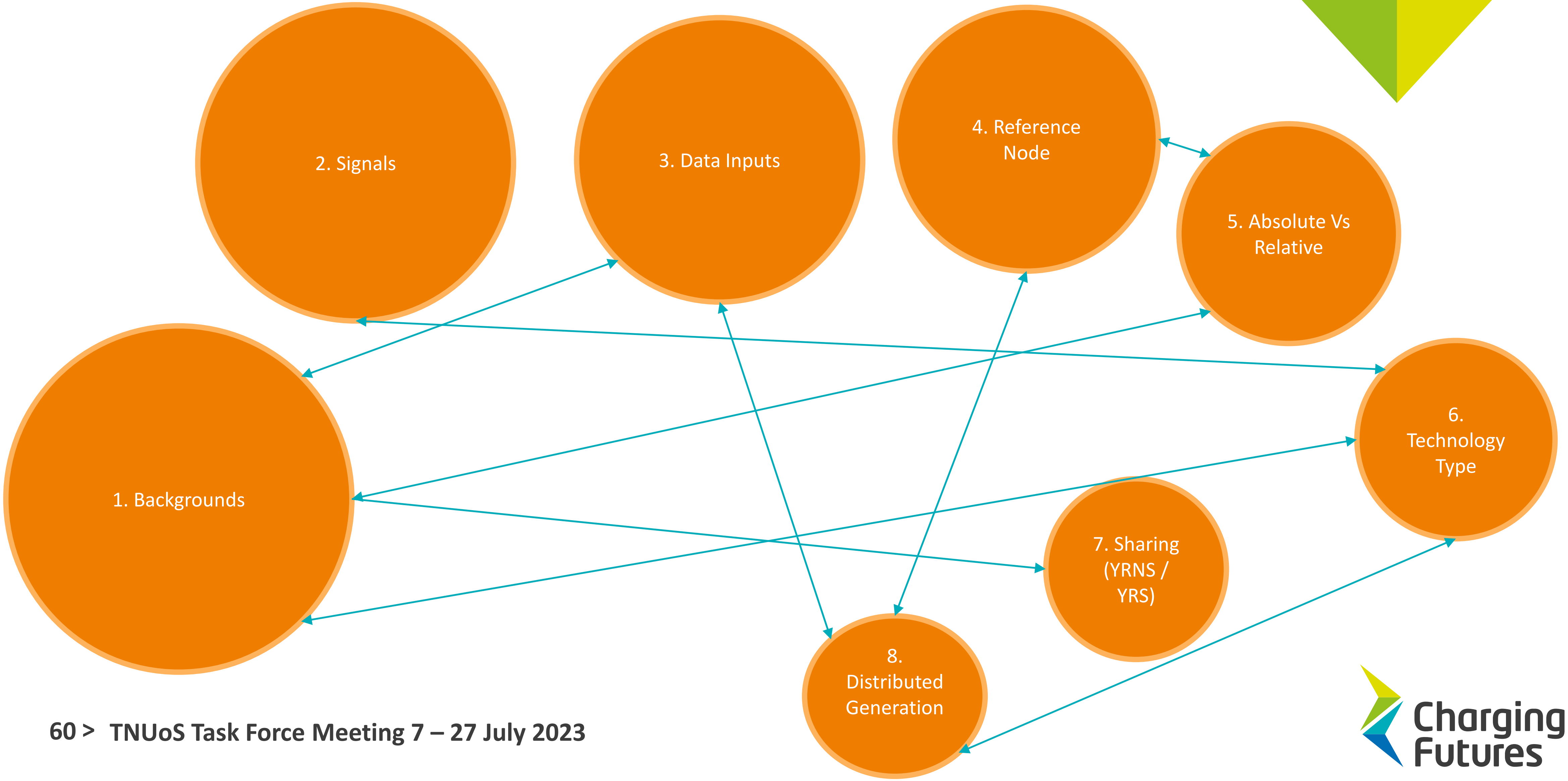
Potential interactions between Workstreams



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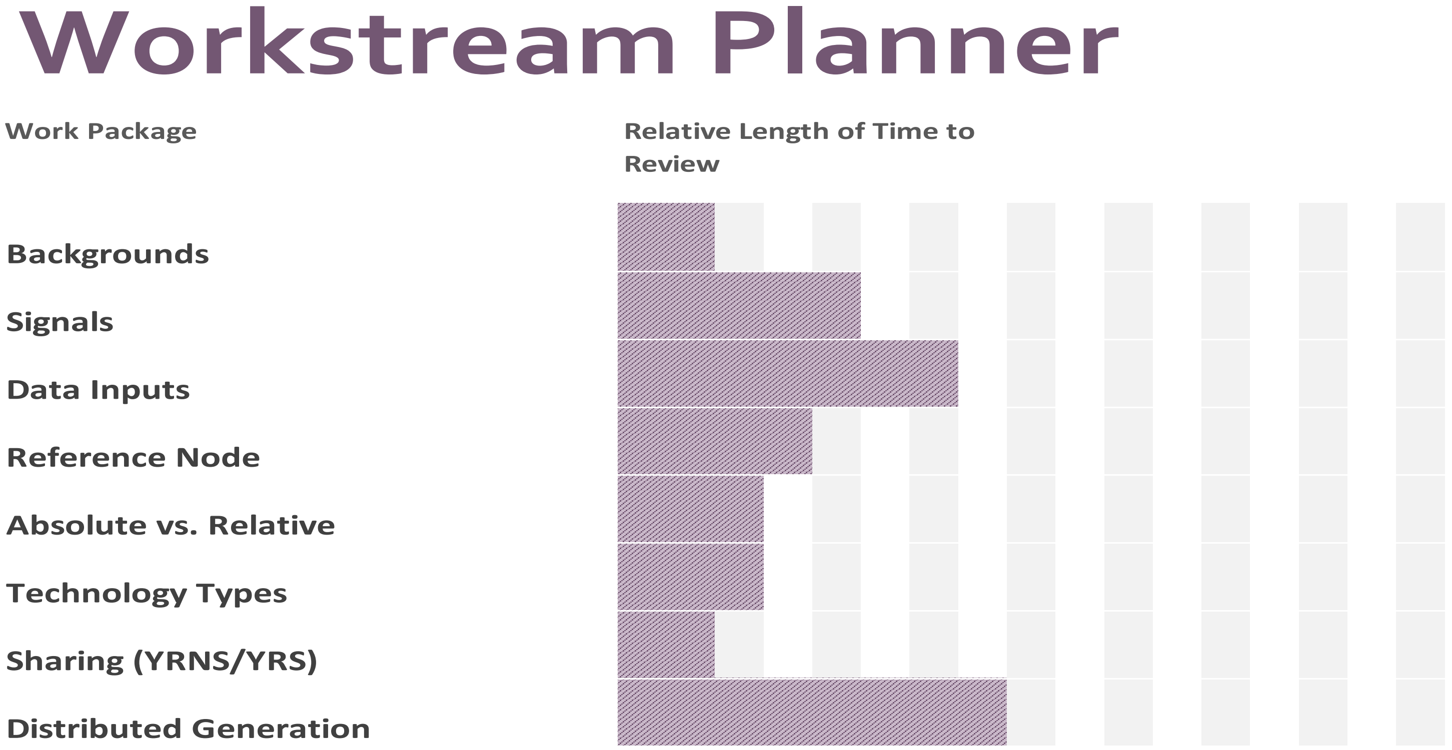
Indicative relative timeline to review



- ➢ **Now we have a view of the scope and potential time to review each category we need to agree and allocate these workstreams across the Task Force members to progress**

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Next Steps and Close

Jon Wisdom

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Reforming electricity charging together

Thank you