Charging Futures

Reforming electricity charging together

TNUoS Task Force

Meeting 6

26th June 2023

Agenda

10:00 – 11:15

- 10:00 Introduction & Welcome
- 10:05 Action Review
- 10:15 Backgrounds: Deep Dive
- *11:15 Break*

11:30 – 12:30

- 11.30 Backgrounds: Feedback & Further Discussion
- *12:30 Lunch*

13:30 – 14:30

- 13.30 Backgrounds: Feedback & Further Discussion continued
- 14.00 Reference Node: Deep Dive
- *14:30 Break*

14:45 – 16:00

- 14:45 Reference Node: Feedback & Further Discussion
- 15:15 Defects Update: Quick Wins & Workstream Plan
- 15:50 Next Steps & Close

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Action Review

Jon Wisdom

Actions from Meeting 5.5

ID/ date	Agenda Item	Description	Owner	Notes	Target Date	Status
1 17/05	3	Check for any overlap between Frontier-LCP work on ALFs and work done in CMP331 and CMP393	James Stone, Nicola White		TF Mtg 6	Open
2 17/05	3	Information from 2022 Task Force meetings relating to Absolute vs Relative is to be shared with the Task Force as a reminder of definitions agreed	Elana Byrne, Deborah Spencer	James Stone to advise	w/c 29 May	Open
3 17/05	3	Share the question re: Technology Type & users' capabilities aid in constructing backgrounds with Frontier-LCP for consideration.	Nicola White		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		TF Mtg 6	Open
5 17/05	6	Doodle polls to be shared with the Task Force to ascertain appropriate dates for future meetings	Elana Byrne, Deborah Spencer		19 May	Open
6 17/05	7	ESO to proceed with the wider-remit zoning modification	James Stone		TBC	Open

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Open Actions from Meetings

1 26/04	1	Provide update on recruiting Non-Domestic user reps to Task Force	James Stone & Nicola White		TF Mtg 6	Open
3 26/04	3	Decision re: involving OTNR in Task Force discussions	Harriet Harmon		TF Mtg 6	Open
4 26/04	3 & 7	Points for further consideration by Frontier-LCP and the Task Force	James Stone & Nicola White	To share with Frontier-LCP	TF Mtg 6	Open
6 26/04	5	Any further questions or gaps in the analysis needing consideration to be shared with ChargingFutures@nationalgrideso.com for Frontier-LCP to prepare for the next deep dive mtg	Task Force		TF Mtg 6	Open
7 26/04	5	Review additional information re: sharing factors (not covered for time)	Task Force		TF Mtg 6	Open
8 26/04	7	Further work on design vs cost reflectivity to be presented at Mtg 6	James Stone & Nicola White	To be discussed with BA and passed to Frontier-LCP	TF Mtg 6	Open
9 26/04	7	Technical input needed on deviation from SQSS and legal implications	James Stone & Nicola White		TF Mtg 6	Open
10 26/04	7	Investigate more granular data sources for DNO embedded distribution to support the methodology & analytics	James Stone		TF Mtg 6	Open
11 26/04	8	Actions allocated across the TF group for topics progressing for further development or into draft modifications	James Stone		Post TF Mtg 6	Open

Charging Futures

N.B. Analysis shared is work in progress

Analytical Support: Overview and Context

Frontier & LCP

The objective of this session is to provide:

- 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

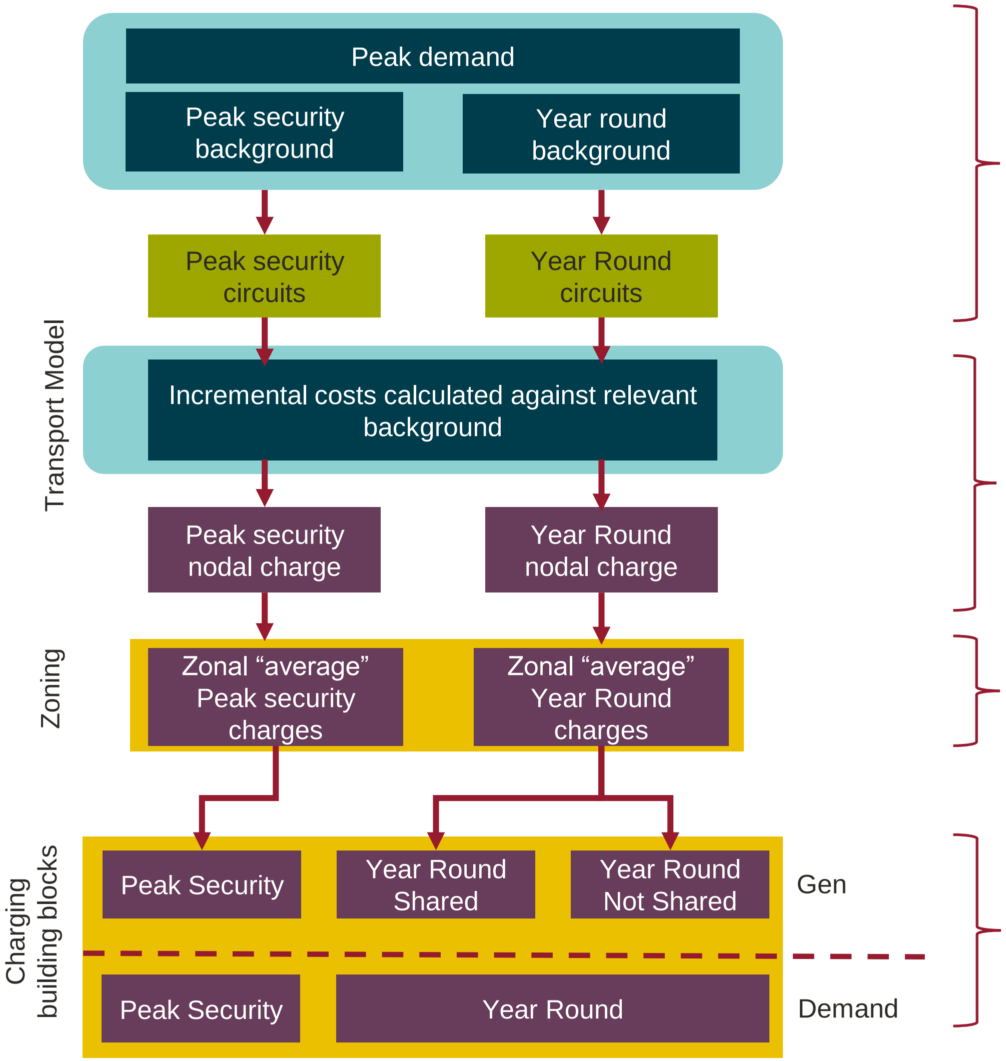
26th June 2023

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 today's discussion*
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 in July*
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

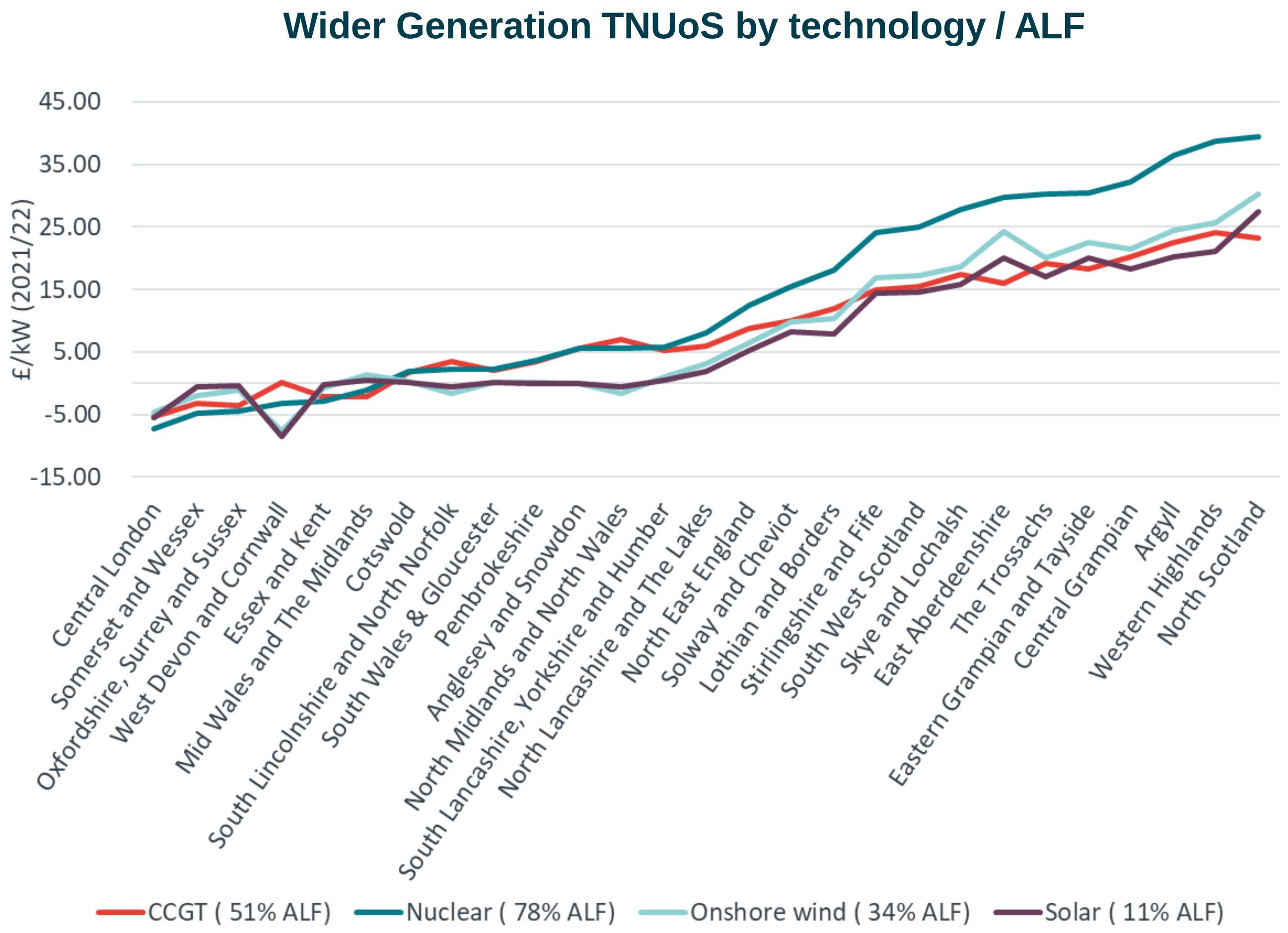
- Low marginal cost generators will generate at peak and year round, so pay Peak Security and Year Round charges.
- Costs in the Year Round scenario depend on the overall share of low carbon in a zone. Low marginal cost generators will not reduce output in response to intermittent generation, so do not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



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

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

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

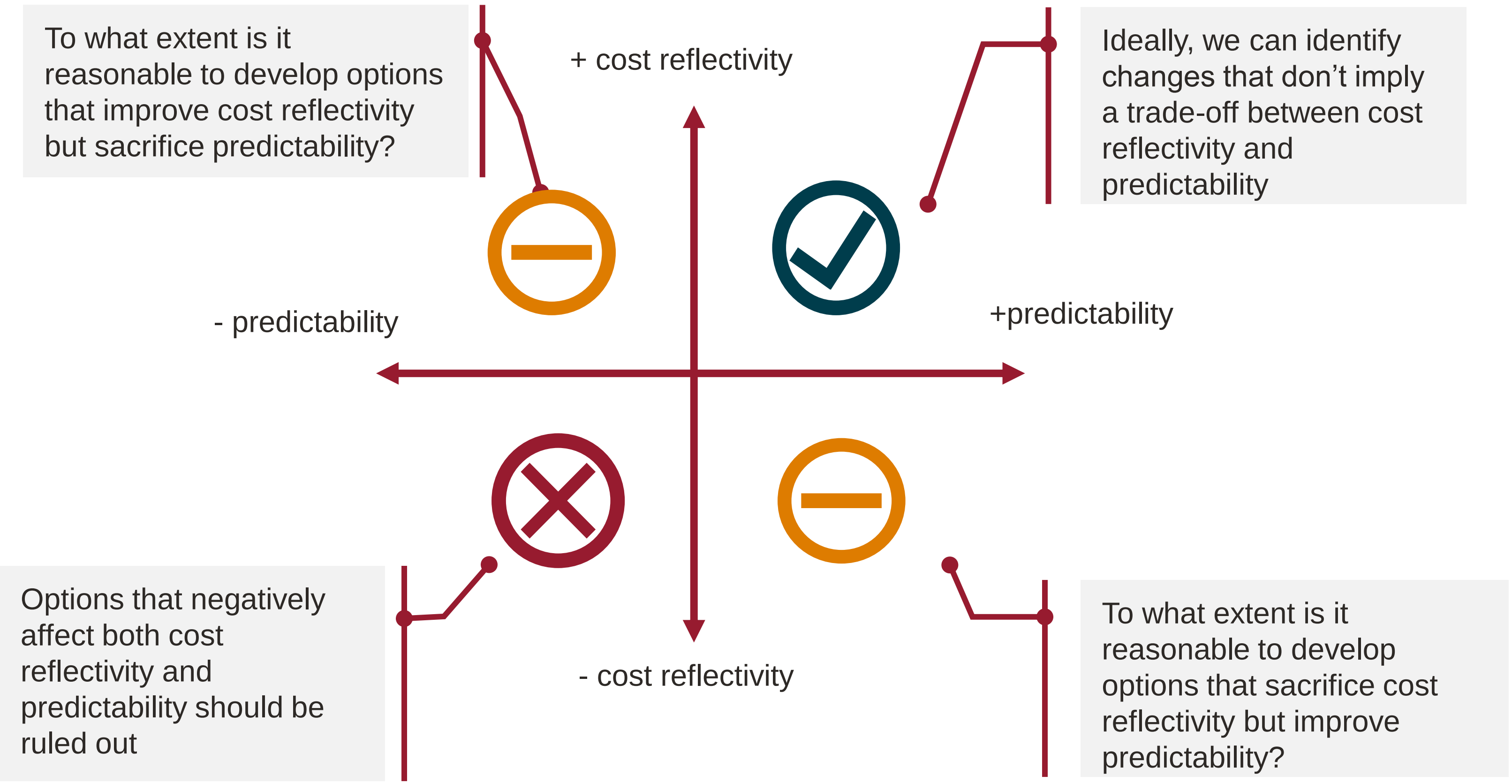
	National Grid ESO
1	Review appropriateness of backgrounds / Review changes (and impacts) introduced via TransmiT
2	Review of the shared/not shared elements of the Wider tariff and whether they continue to be based on appropriate, cost-reflective assumptions
3	Review data inputs
4	Review of the Reference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

Analytical Support: Backgrounds

Frontier & LCP

The objective of this session is to provide:

- Further level of detail on the analytical assessment to date including; approach taken, conceptual issues considered, practical alternatives/options; and analysis in terms of charging impacts.

The underlying motivation for the backgrounds is derived from the SQSS

Security standard

- The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner.
- The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year.
- The Security Standard uses a **Demand Security Criterion** and an **Economy Criterion** to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

(14.14.7 Methodology)

Demand Security Criterion

- The Demand Security Criterion requires sufficient transmission system capacity such that **peak demand can be met** through generation sources as defined in the Security Standard

(14.14.8 Methodology)

Peak security background

Economy Criterion

- Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to **meet varying levels of demand efficiently**. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

(14.14.9 Methodology)

Year round background

Our review of the generation assumptions raises some questions as to their suitability now and in future…

The current methodology for identifying the cost drivers of network investment assumes two possible generation mixes

Transport Model assumptions

- Peak demand can be met by different generation mixes depending on intermittent output at peak, resulting in different possible patterns of flows across network
- Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. These scaling (or load) factors and generation plant types may be reviewed from time to time.

Transport Model generation backgrounds

Generation plant type	Peak security	Year Round
Intermittent	Fixed (0%)	Fixed (70%)
Nuclear & CCS	Variable	Fixed (85%)
Interconnectors	Fixed (0%)	Fixed (100%)
Hydro	Variable	Variable
Pumped Storage	Variable	Fixed (50%)
Peaking	Variable	Fixed (0%)
Other (Conventional)	Variable	Variable

Suitability of generation background assumptions

- The two backgrounds represent two possible draws of generation patterns that could meet a certain level of demand. However,…
- …it is not clear that these are the generation patterns most likely to occur, or that they are the generation patterns most likely to drive network costs should they occur.
- There are questions whether the following assumptions are appropriate:
  - Interconnector flows are 0% at peak, 100% 'year round'
  - Storage 50% in 'year round'
  - No merit order of generation, all 'variable' techs are scaled equally
  - All intermittent generation treated the same despite widely varying load factors and generation patterns
  - Load factors assumed for the 'Year Round' background (e.g. 70% for intermittent) are inconsistent with the technology ALFs used later in the charge calculation (This is partially a consequence of the "year round" background being scaled to peak demand rather than average demand)
    - In addition, assuming the fixed load factors listed for the Year Round Scenario may not be possible in future years as fixed generation is likely to exceed peak demand.
- Beyond the current backgrounds, there may also be a case for considering additional backgrounds to increase cost reflectivity without adding significant complexity.

...and there are also similar questions related to the suitability of demand background assumptions

The current methodology for identifying the cost driver implicitly assumes a link to peak demand in both backgrounds

Transport Model assumption

- Peak demand is key driver of network costs
- A single demand background is used based on peak transmission system demand

“Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".”

Suitability of peak demand assumptions

- Cost driver is actually peak flow – historically peak demand reasonable proxy…
- ...but, network costs (in some locations) may be driven by periods of high intermittent generation flows and low transmission demand (i.e. due to high solar/wind DG output)
- This raises a number of key questions:
  - Is peak demand still a reasonable proxy for peak flow?
  - Does peak flow occur on certain parts of network outside of peak demand?
  - It is really an empirical question about the extent to which national peak demand correlates with local peak flows

The use of backgrounds can only be a proxy for reality, but improving or expanding the number of backgrounds could improve their representation

Conceptual issues – what is the use of "backgrounds" attempting to do?

- The conceptual challenge is to identify the background which drives max flow over each network circuit.
- Assuming max flows will only occur at times of peak demand, a fully detailed way to identify network cost drivers would be to:
  - model all possible combinations of generation patterns that could occur at times of peak demand with a likelihood greater than some minimum threshold;
  - tag circuits to each of these scenarios; and
  - calculate incremental costs for each of these scenarios
- The two generation backgrounds that are used currently, effectively attempt to proxy for this logic in a simplified way.
- However, maximum flows across some circuits will likely occur in non-peak demand periods.
- Therefore to fully generalise the methodology, it would be necessary to repeat the modelling of all possible combinations of generation patterns for all possible levels of demand

Practical alternatives

- It is unlikely to be practical to fully model the implied TNUoS charges arising from every combination of generation and demand that could occur with more than a de minimis probability.
- Even if this were feasible, the majority of the combinations would likely not result in a max flow across any network circuits and thus not flow through to the charges calculation
- Therefore some degree of simplification is always likely to be appropriate.
- We do have the capability to review network element loading on an hourly basis for some forward looking model runs
- This can be used to identify a limited number of archetypal scenarios (back grounds) which tend to result in maximum (or near maximum) flow over network elements.
- Fully modelling a limited number of additional scenarios could help to improve cost reflectivity of charges in a practical way
- We consider it is likely to be most productive to focus archetype scenarios on those that are most likely to occur and most likely to produce maximum flows across network circuits, given prior knowledge about the electricity system.

- Modelling of network flows in future years can offer insight into the appropriate backgrounds
- Archetype backgrounds can be selected and compared with the current peak security and year round backgrounds

We have carried out an assessment on the appropriateness of using alternative backgrounds, and its impact on the level of charges and predictability

We first consider cost reflectivity…

- We assess the extent to which current backgrounds are representative of maximum network flows, and…
- …consider possible alternative backgrounds that are more closely aligned with maximum network flows.
- We consider the implications of this analysis for whether to apply a single background, two backgrounds (i.e. current approach), or additional backgrounds.

…then look at the impact on the level of charges…

- Using National Grid's 2021/22 transport model inputs, we assess the implications to the level of charges of changing to more representative backgrounds, either keeping two backgrounds or applying a single one.
- We show the results for a representative CCGT tariff and a representative wind tariff for each zone.

… and on predictability

- Where we are considering possible changes to the backgrounds, we also want to understand any implications for predictability.
- We assess the implications for tariff volatility of applying two backgrounds or a single background.
- Specifically, we compare the evolution of tariffs over the last five years when using the two existing backgrounds against:
  - a Peak only; and
  - a Year-Round scenario.

...our analysis suggests that updates to the current backgrounds could be appropriate in order to improve cost reflectivity

Cost reflectivity

- The analysis suggests that Year Round and Peak Security type backgrounds are likely to remain relevant, though their representativeness can be improved with changes to specific assumptions.
- If a single background was favoured, a Year Round type scenario could be most appropriate going forward, although this could entail a small reduction in cost reflectivity, relative to two backgrounds. For example, charges would be expected to increase for wind as circuits previously tagged to Peak Security are now tagged as Year Round.
- The marginal benefit of adding a third background is much reduced compared to adding a second background, particularly in 2035.
- Irrespective of whether this analysis is considered to support a change, an update to the backgrounds is likely to be required in future e.g. due to "fixed" generation exceeding demand.

Level of charges

- The impact of using more representative backgrounds appears to be relatively limited, either using two alternative backgrounds or a single alternative.
- This suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- In addition, if the €2.50/MWh cap is binding then the adjustment tariff may also reduce the impact of changes further.

Predictability of charges

- The predictability analysis suggests that there are no clear implications for year to year volatility from applying one (Year Round) or two backgrounds, which may suggest no material change in predictability of the tariffs.
- Although moving to a single background would remove one area of uncertainty in the tariff calculations (i.e. the tagging of circuits to a particular background).
- There appear to be volatility implications if adopting only a peak background, however, this would be inconsistent with the cost reflectivity analysis.

...however, our initial view is that the implications of change for the level and volatility of charges may be relatively limited

We assess the extent to which the current backgrounds are likely to represent the true cost driver (max flow) on each network element

Methodology for obtaining the most representative backgrounds

1. We ran LCP's dispatch model using NGESO's FES ST scenario for 2025 and 2035 to obtain load factors on assets for every hour of the year
2. Selected 96 periods (2 days per month, 4 hours per day) to cover a wide range of situations and ran all of these "backgrounds" through LCP's version of the transport model
3. Find the maximum flow across each circuit from all 96 backgrounds
4. Identify the backgrounds that give a 'good' representation of the most circuits

Identifying a 'good' representation of circuits

- Our approach to identifying the most "representative backgrounds" is to identify ones with as many of the circuits as close to their maximum flow observed in that year.
- We defined "representation" for a background as the percentage of circuits that are flowing at 90% or more of their observed maximum flow in that background.
- In other words, if a circuit is 50% representative, then in that background, 50% of the circuits are flowing at 90% or more of their maximum flow in that year.

Peak and Year Round type backgrounds are important but their representation potentially can be improved with changes to the assumed generation mix (2025)

Cost reflectivity

	Current backgrounds		Most representative backgrounds (2025, NGESO FES ST scenario)		
Technology	*Peak*	*Year-round*	*Round 1*	*Round 2*	*Round 3*
Biomass	88%	27%	68%	68%	3%
OCGT	88%	0%	0%	77%	0%
CCGT	88%	27%	21%	95%	0%
Hydro	88%	27%	64%	64%	0%
Interconnectors	0%	100%	48%	59%	-80%
Nuclear	88%	85%	100%	100%	100%
Wind Offshore	0%	70%	87%	4%	87%
Wind Onshore	0%	70%	81%	4%	77%
Pump Storage	88%	50%	0%	58%	-61%
Demand (MW)	52,417	52,417	50,547	50,770	26,508
Individual % represented	32%	33%	59%	27%	15%
Cumulative % represented	32%	43%	59%	67%	76%

Current Peak and YR scenarios do not provide a very good representation for over half of the network.

Similar to YR

Similar to peak

Representative backgrounds identified (2025)

- In the identified representative backgrounds, the percentage shown is the average load factor observed for the particular technology in that scenario from LCP's dispatch modelling.
- The most representative background observed, shown as "Round 1", gives a 'good' representation of 59% of circuits.
- The "Round 1" background is somewhat similar to the year-round background, with high wind, biomass and nuclear load factors, and lower gas generation.
- "Round 2" gives the greatest increase to representation of circuits when combined with Round 1. Round 2 is somewhat similar to peak, but with variation in load factors across the fleet and interconnectors importing.
- "Round 3" has lower demand and high wind load factors leading to demand from pump storage and export via interconnectors.

Peak and Year Round type backgrounds are important but their representation potentially can be improved with changes to the assumed generation mix (2035)

Cost reflectivity

	Current backgrounds		Most representative backgrounds (2035, NGESO FES ST scenario)		
Technology	*Peak*	*Year-round*	*Round 1*	*Round 2*	*Round 3*
Biomass	138%	-70%	99%	100%	99%
OCGT	138%	0%	0%	40%	0%
CCGT	138%	-70%	0%	94%	0%
Hydro	138%	-70%	52%	64%	59%
Interconnectors	0%	100%	-93%	90%	-81%
Nuclear	138%	85%	100%	100%	100%
Wind Offshore	0%	70%	71%	30%	75%
Wind Onshore	0%	70%	62%	2%	20%
Pump Storage	138%	50%	0%	0%	0%
Demand (MW)	72,121	72,121	61,552	72,121	56,608
Individual % represented	23%	54%	72%	32%	19%
Cumulative % represented	23%	62%	72%	84%	88%

Current Peak and YR backgrounds do not make sense in 2035 when load factors would be over 100% or under 0% for generating technologies

Similar to YR, but below peak demand

Similar to peak

Marginal impact

Representative backgrounds identified (2035)

- In the identified representative backgrounds, the percentage shown is the average load factor observed for the particular technology in that scenario from LCP's dispatch modelling.
- The most representative background observed, shown as "Round 1", gives a 'good' representation of 72% of circuits.
- The "Round 1" background is somewhat similar to the year-round background, with high wind, biomass and nuclear load factors, and no gas generation. However, demand is slightly below peak.
- "Round 2" gives the greatest increase to representation of circuits when combined with Round 1. Round 2 is somewhat similar to peak, but with variation in load factors across the fleet and interconnectors importing at near full capacity.
- "Round 3" is similar to round 1 and has only a marginal impact.

We have assessed the implications to the level of charges of changing to more representative backgrounds, either keeping two backgrounds or applying a single one

Models used

- LCP's Dispatch model:
  - Run to obtain load factors for alternative backgrounds (Rounds 1-3) previously identified.
- LCP's transport model:
  - Running existing and alternative background scenarios to obtain tariff components.
- National Grid ESO's transport model:
  - Used to calibrate LCP's transport model to align tariff prices.

Assumptions/Caveats

- NGESO's FES System Transformation scenario assumptions were used for modelling 2025 with LCP's Dispatch model.
- Tariff components have been modelled using generator and network assumptions from NGESO's 2021/22 Final Tariff Model.
- Due to the apparent low incremental benefit of adding further backgrounds, only one and two alternative background scenarios were modelled to give tariff components.
- The adjustment tariff has not been included in calculations of example generator tariffs as this dampens the effect of changing backgrounds and makes the difference between charges less visible.

Calculations of tariff components and example generator tariffs

- Tariff components are calculated in the same way in National Grid's transport model and LCP's transport model.
- Representative tariffs for generators have also been calculated in the same way, although the adjustment tariff (generator residual) has not been included:

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

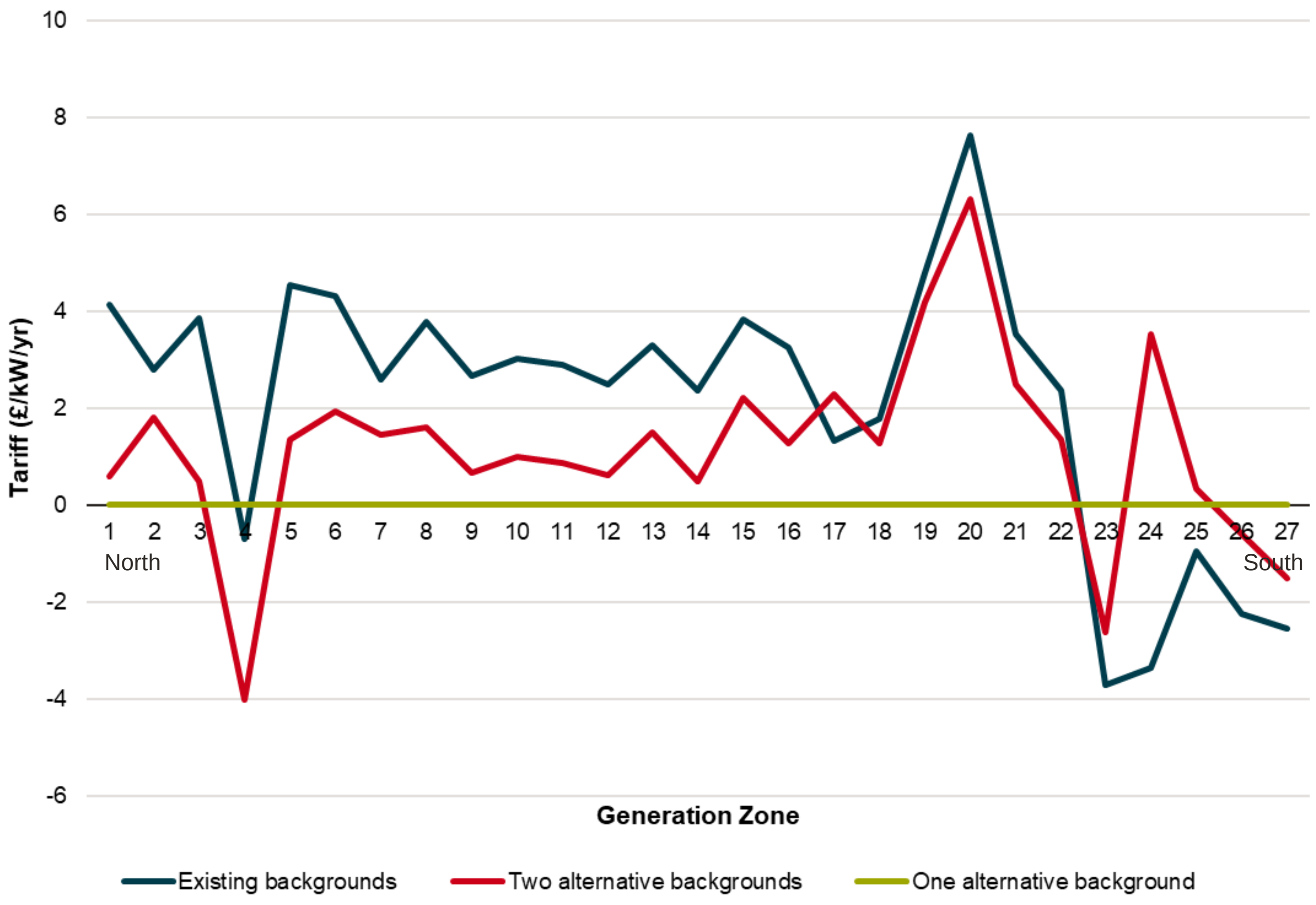
Wider Tariff = Peak + [ALF × Year Round Shared] + [ALF × Year Round Not Shared] + Generator Residual

Intermittent e.g. Wind, Tidal

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

Impact of alternative backgrounds

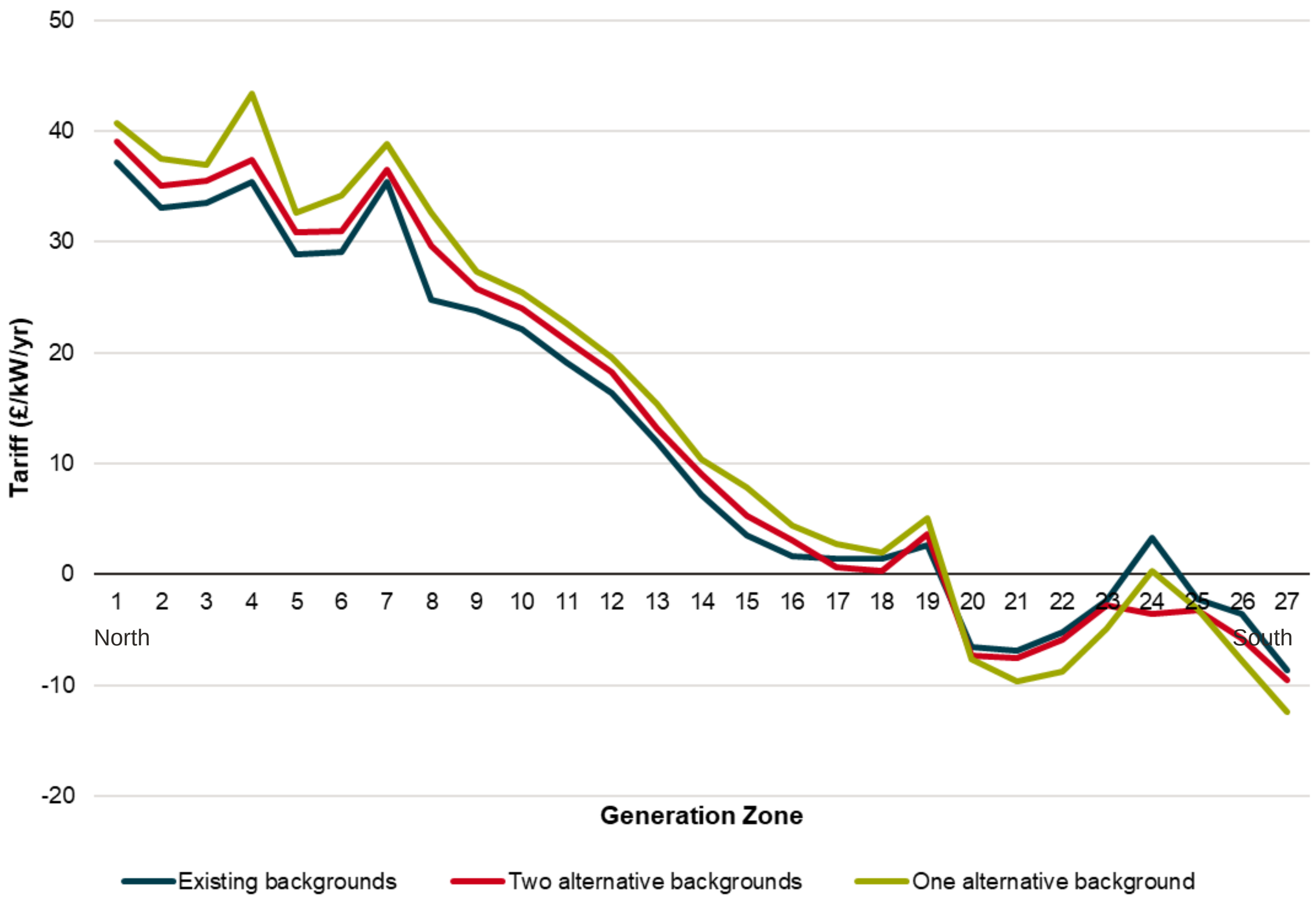
Peak tariff



- The peak charges under both existing and the two alternative backgrounds result in a similar spatial distribution in peak tariffs.
- The alternative backgrounds result in lower charges in northern and midland zones and higher charges in southern zones.
- Our assumed approach to a single background is to apply a year-round type background and therefore we have not derived a peak type tariff.

Impact of alternative backgrounds

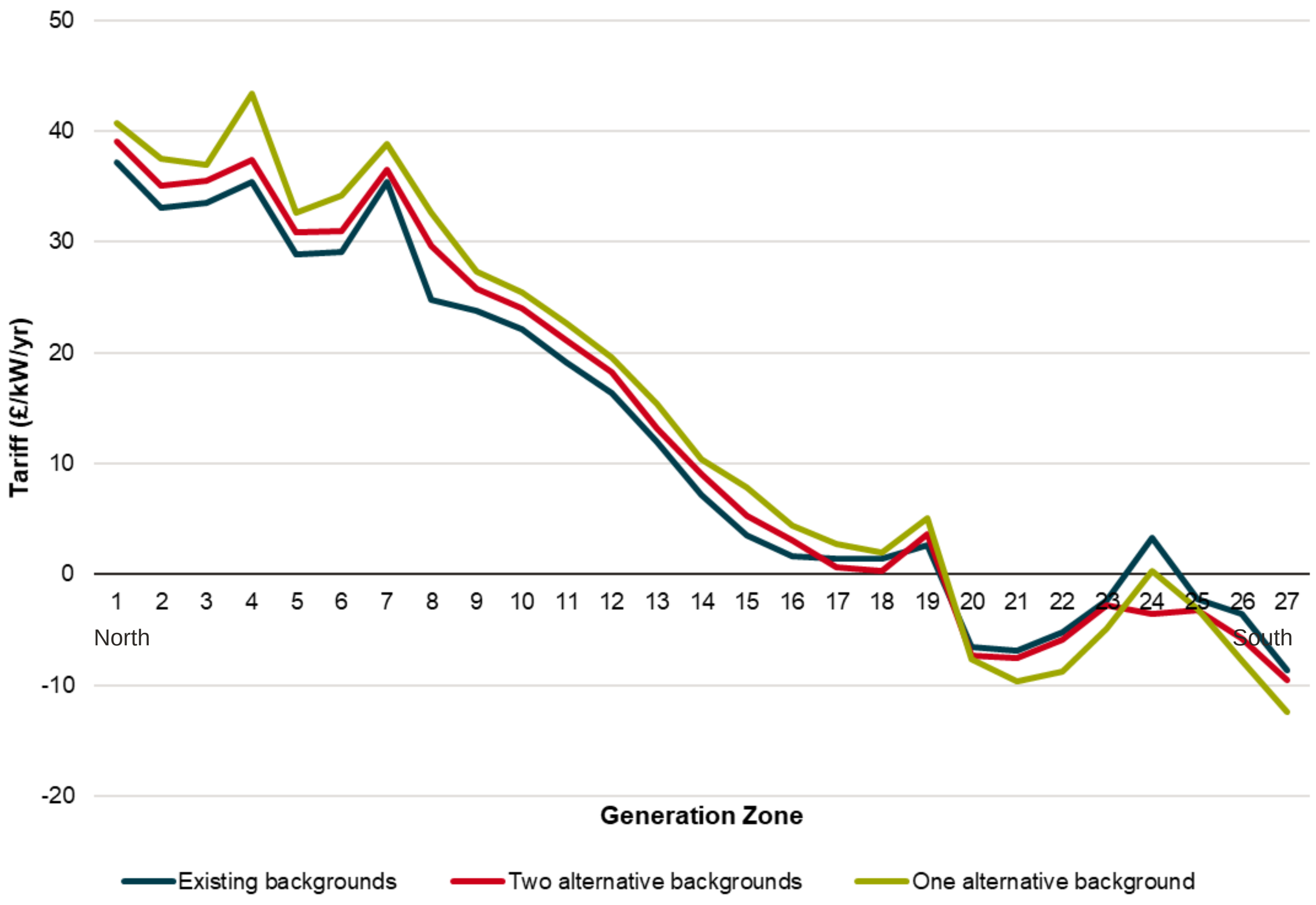
Year-Round tariff



- The spatial distribution of the year-round tariffs does not significantly change under the alternative approaches.
- Applying a single alternative background results in the highest year-round tariffs in the northern zones, and the lowest in the most southerly zones.

Impact of alternative backgrounds

Year-Round tariff

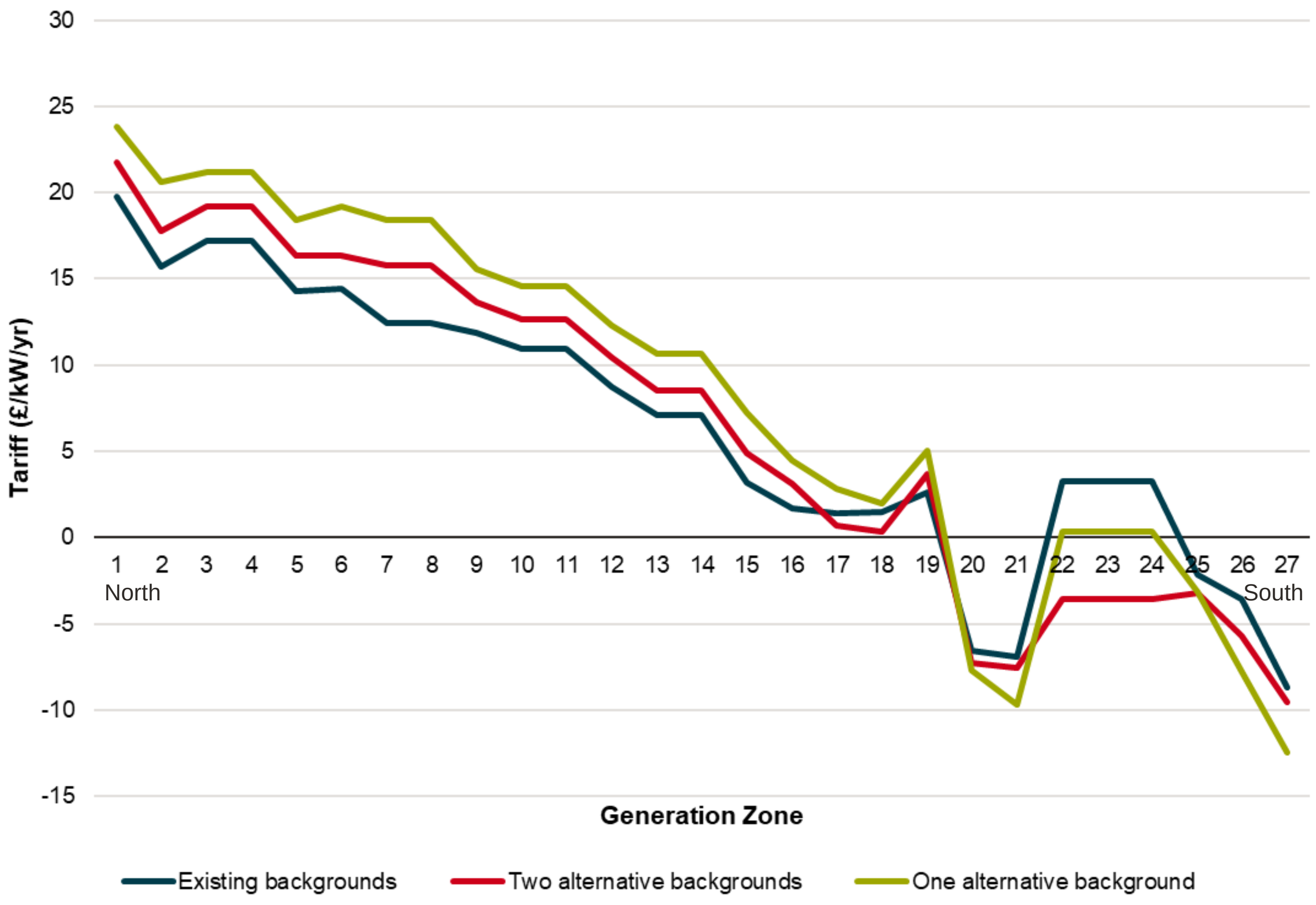


- The spatial distribution of the year-round tariffs does not significantly change under the alternative approaches.
- Applying a single alternative background results in the highest year-round tariffs in the northern zones, and the lowest in the most southerly zones.

Level of charges

Impact of alternative backgrounds

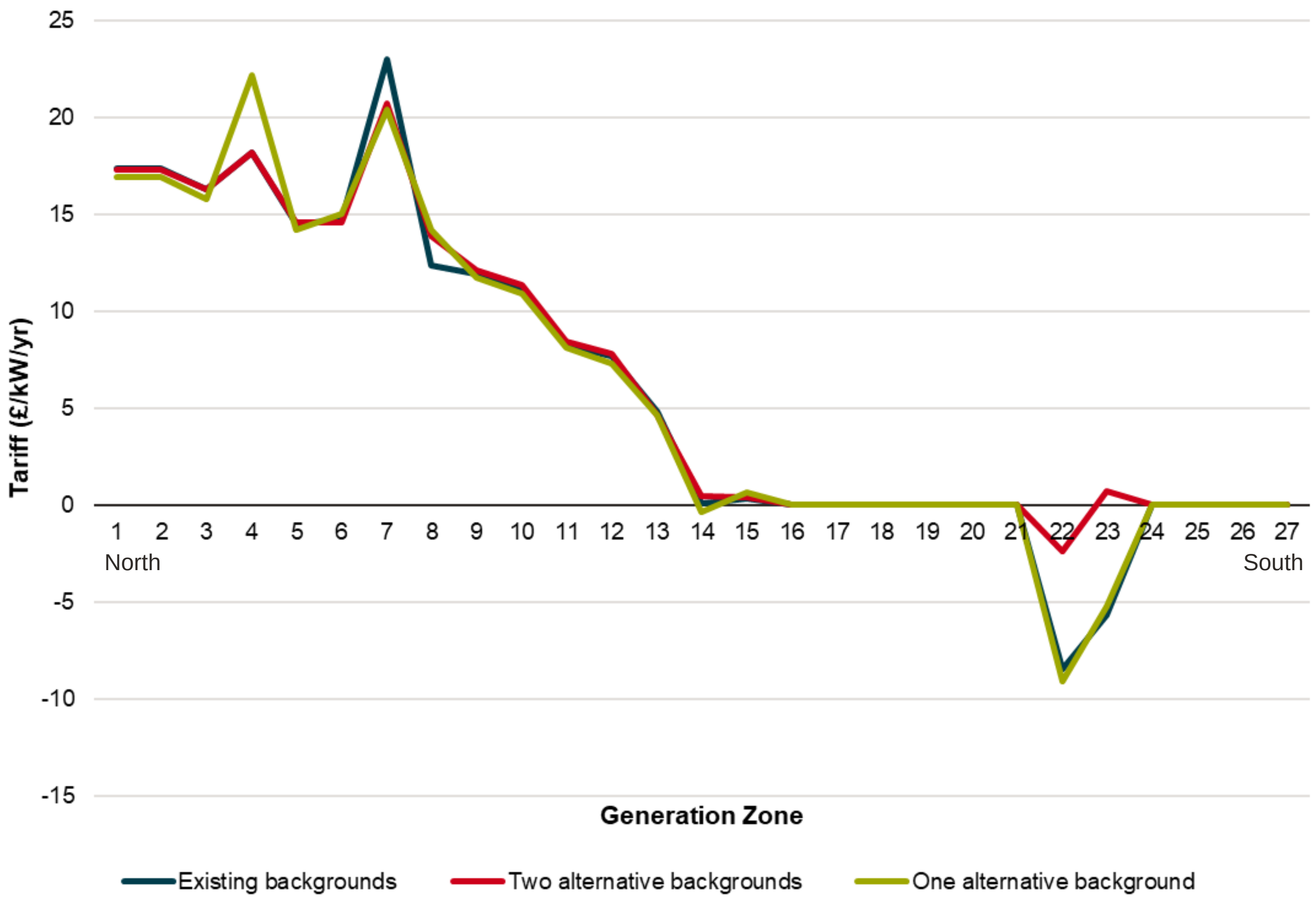
Year-Round Shared tariff



- The same trend is followed with all background combinations.
- The majority of the change in the year round tariff is passed through into the year-round shared tariff given the relatively high Boundary Sharing Factors across most zones i.e. the share of low carbon in the model in many zones is relatively low (i.e. below 50%).
- The one alternative background scenario has the highest charges in north Scotland, and the lowest in the far south.

Impact of alternative backgrounds

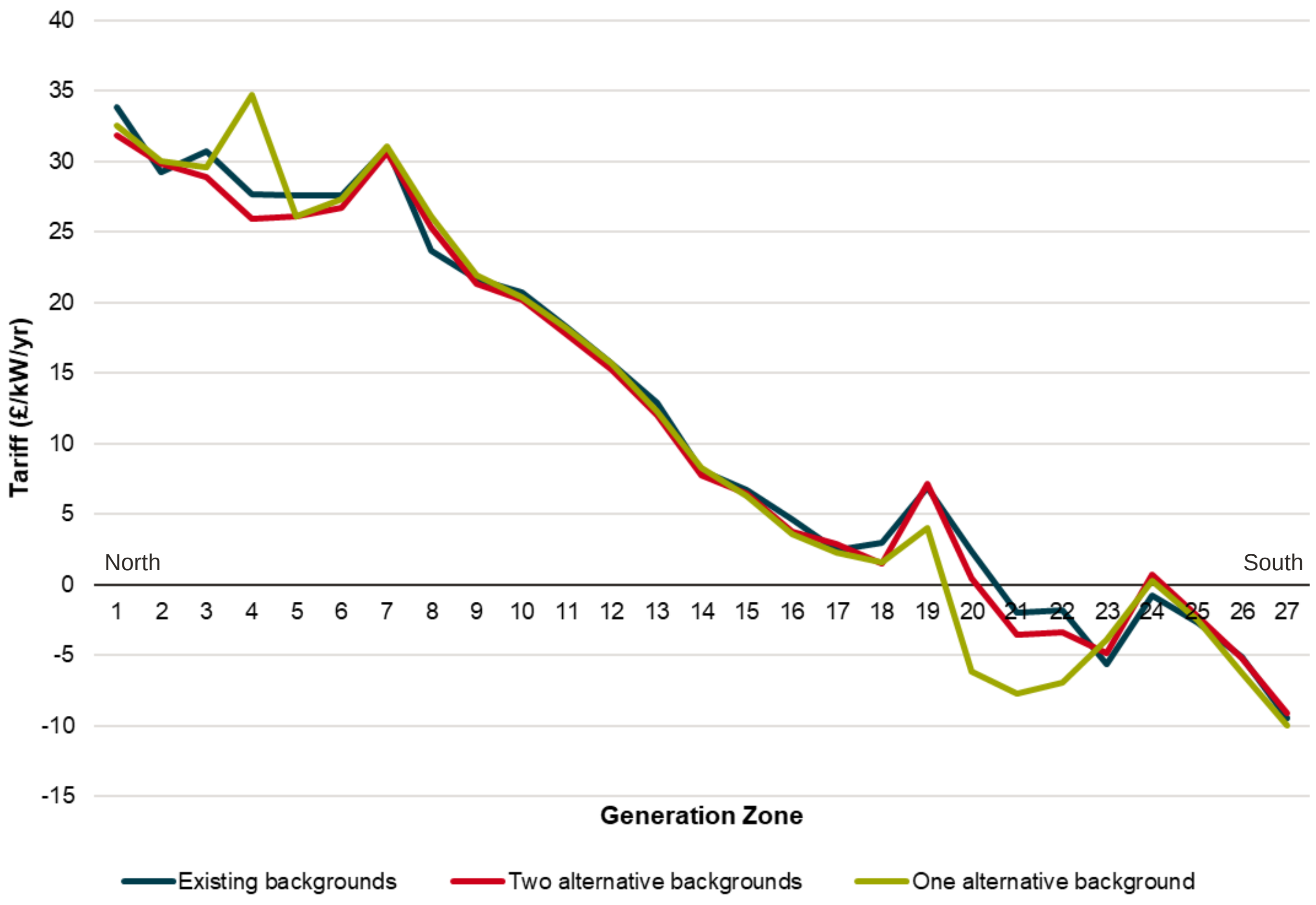
Year-Round Not-Shared tariff



- Changing the backgrounds has a relatively smaller effect on the year-round not-shared tariff, given relatively fewer boundaries with *not shared* elements.

Impact of alternative backgrounds

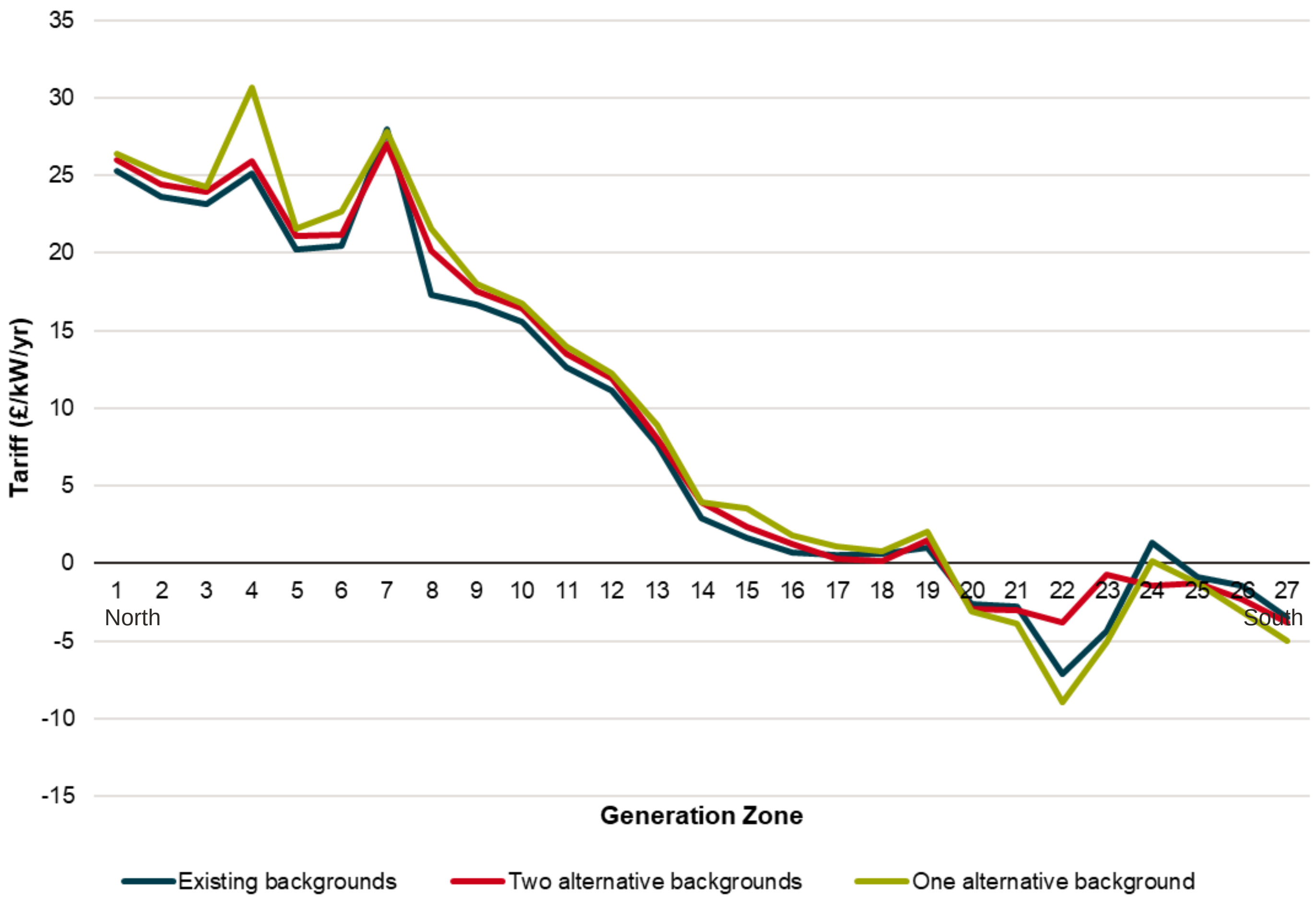
Representative CCGT tariff (ALF 80%)



- Even with different tariff components, the overall CCGT tariff remains very similar despite the changes in backgrounds. The changes to the peak and year-round tariffs appear to be largely offsetting
- This suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- These calculations do not include the adjustment tariff, which could (if the €2.50/MWh cap is binding) reduce the impact of changing background scenarios further.

Impact of alternative backgrounds

Representative wind tariff (ALF 40%)

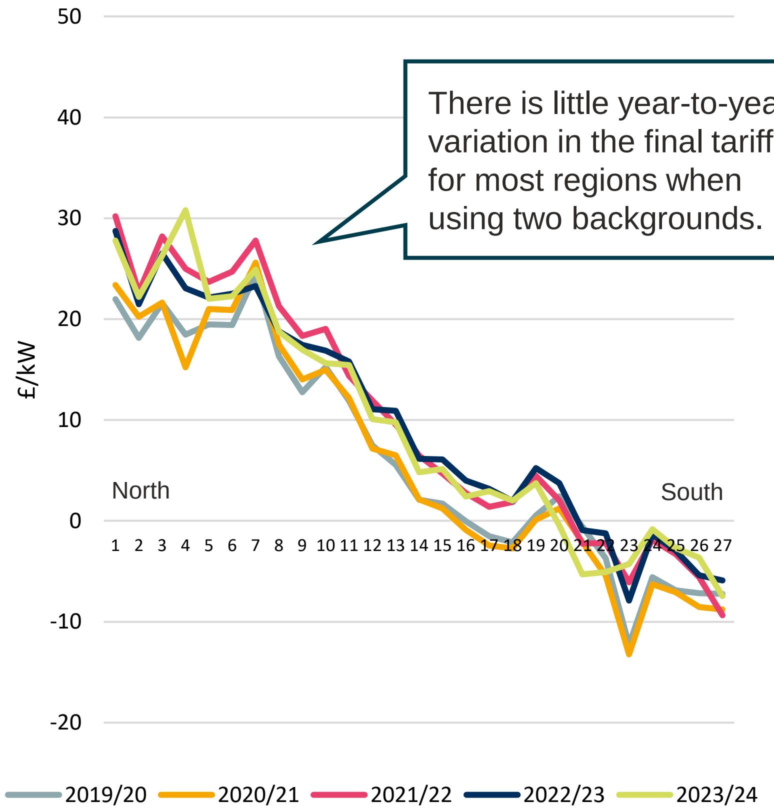


- Similar to the representative CCGT tariff, the overall wind tariff remains very similar despite the changes in backgrounds.
- As before, this suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- The wind charges do increase slightly in Northern and Midland zones under the single background, due to more circuits being tagged to the single background paid by wind.
- These calculations do not include the adjustment tariff, and therefore, any changes may be reduced is the cap is binding.

For a CCGT plant, volatility of charges only appears to be materially affected if applying a single peak scenario...

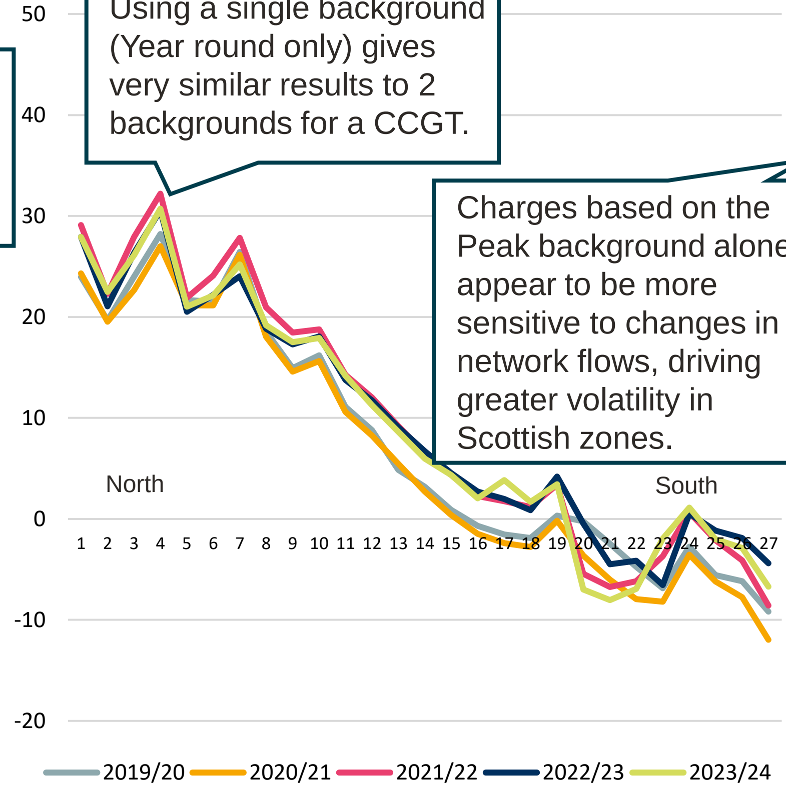
Predictability

Wider tariff, CCGT – both



There is little year-to-year variation in the final tariff for most regions when using two backgrounds.

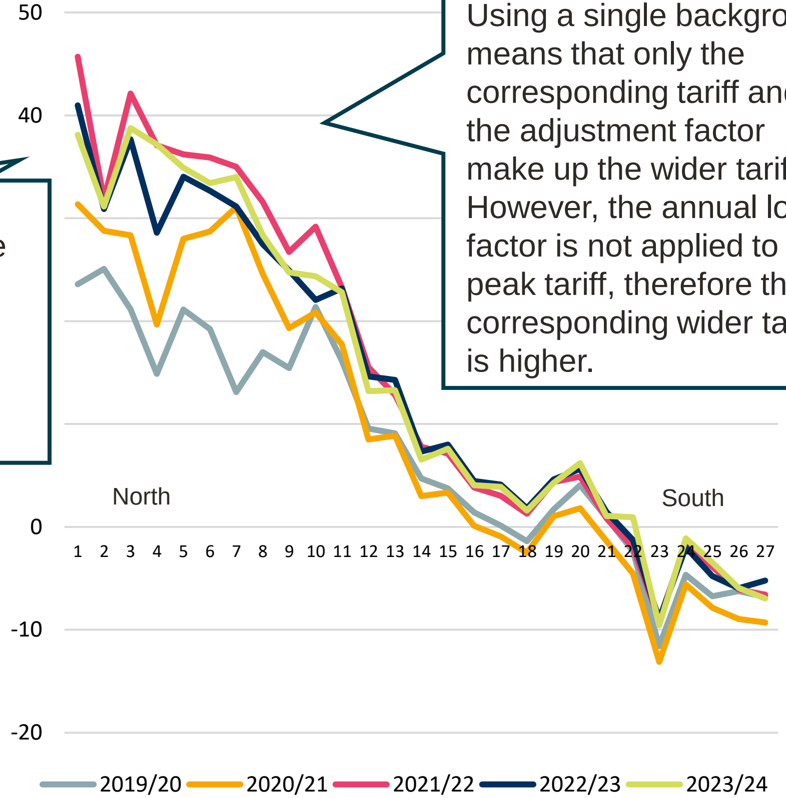
Wider tariff, CCGT – Year round only



Using a single background (Year round only) gives very similar results to 2 backgrounds for a CCGT.

Charges based on the Peak background alone appear to be more sensitive to changes in network flows, driving greater volatility in Scottish zones.

Wider tariff, CCGT – peak only



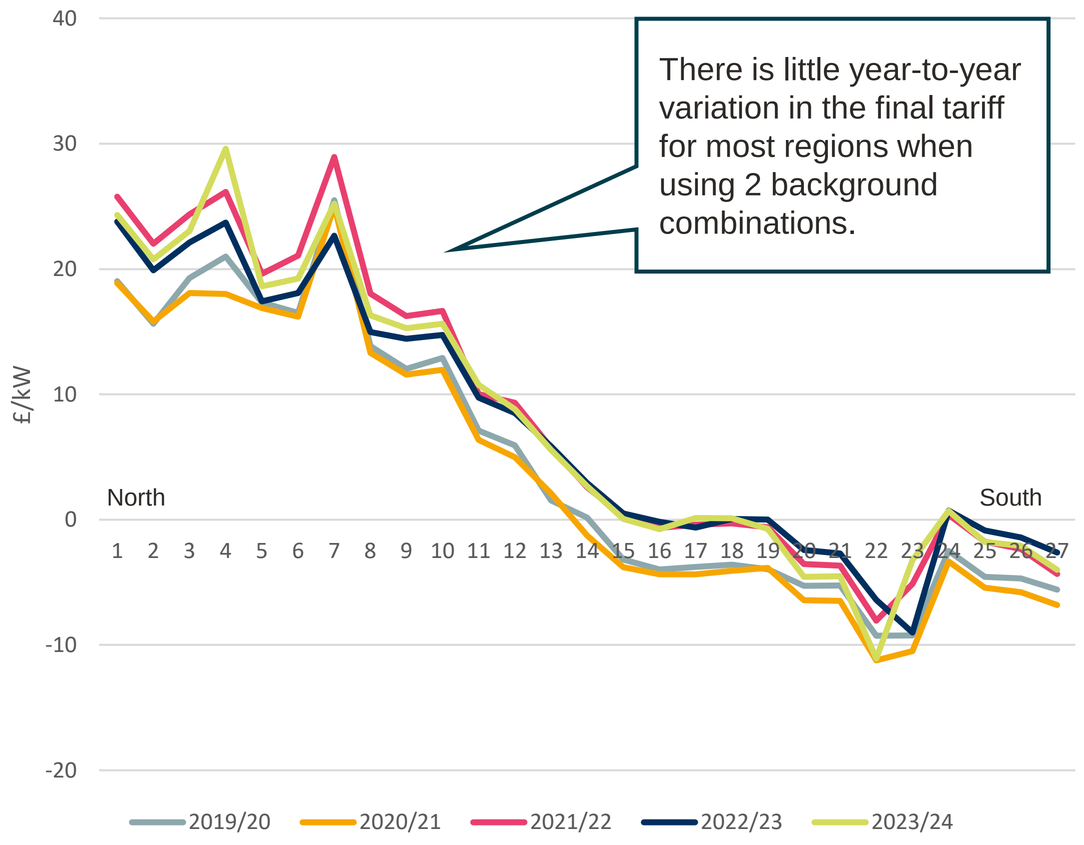
Using a single background means that only the corresponding tariff and the adjustment factor make up the wider tariff. However, the annual load factor is not applied to the peak tariff, therefore the corresponding wider tariff is higher.

**Assuming a 70% annual load factor for CCGT plant. In the year-round only background, all circuits are labelled as year-round, and vice versa for the peak-only background.*

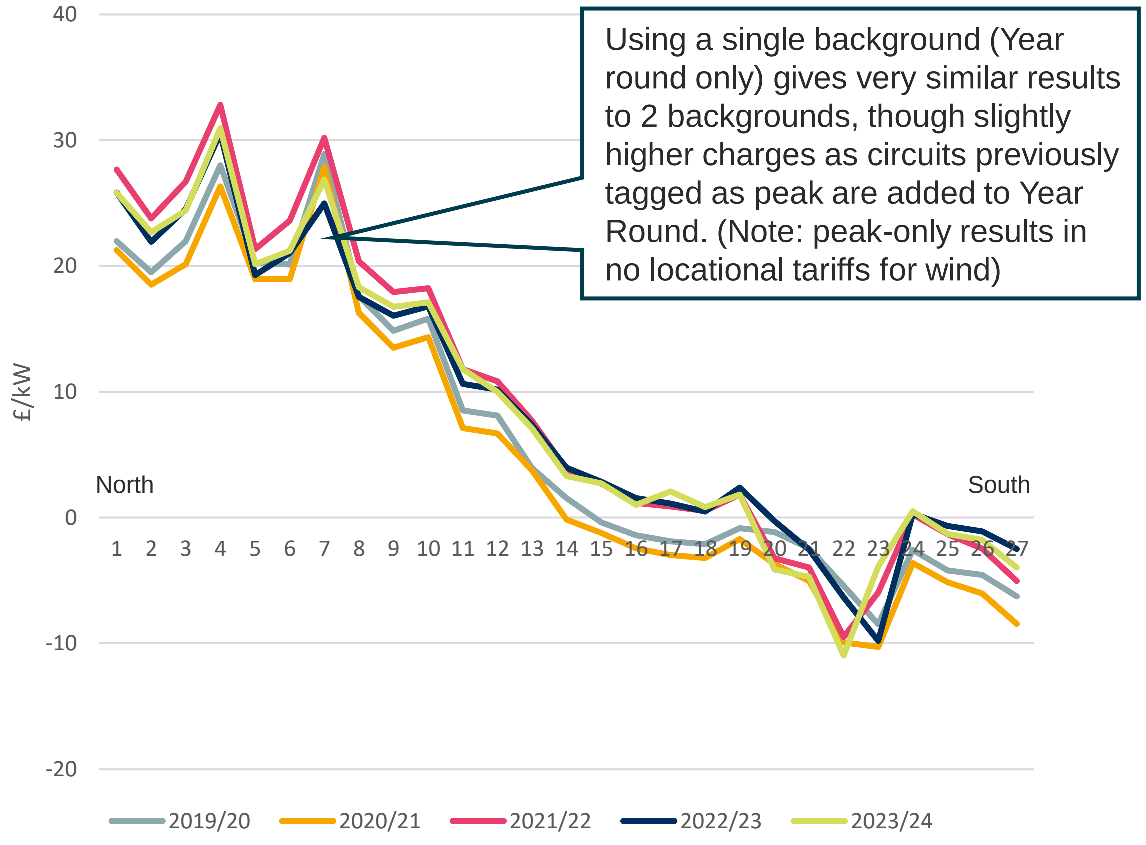
…for wind, we find limited impact on volatility from applying a single background, although there is an implication for the level of charges

Predictability

Wider tariff, wind – both



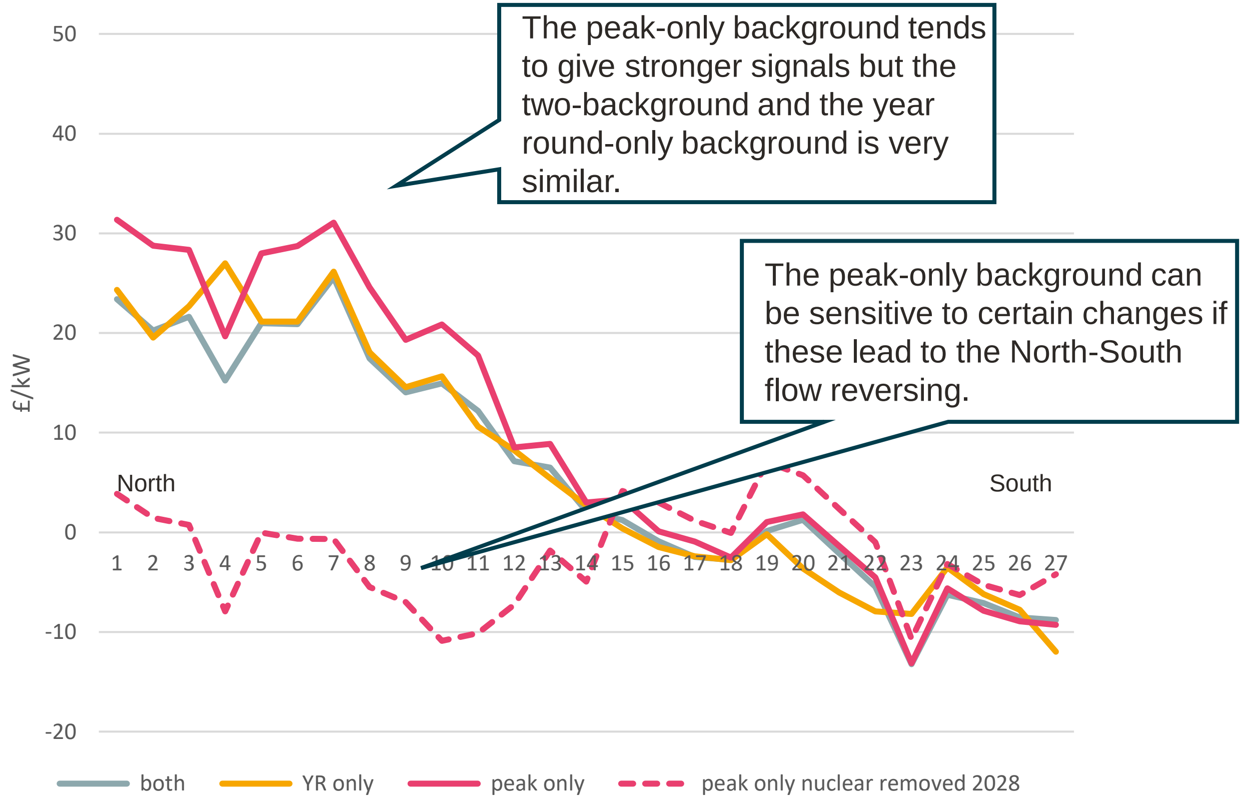
Wider tariff, wind – Year round only



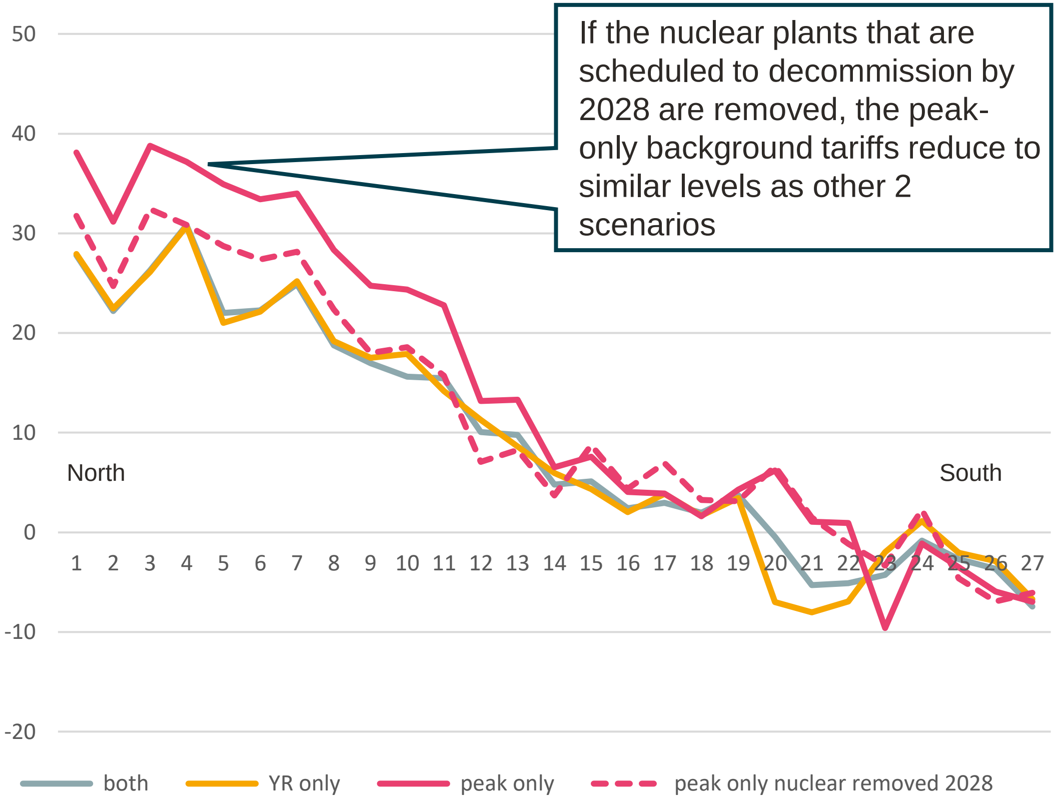
Assuming a 40% annual load factor for wind plant

Predictability analysis – the year-round only background closely tracks the existing approach, but the peak-only background is more sensitive

Wider tariff, CCGT – 2020/21



Wider tariff, CCGT – 2023/24



**Assuming a 70% annual load factor for CCGT plant*

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Break

Next session starts at 11:30

Backgrounds: Feedback & Further Discussion

Frontier & LCP

The objective of this session is to discuss:

- Backgrounds analysis, assumptions, initial conclusions, case for change and identify if there are further areas of work required

Discussion of backgrounds analysis and conclusions

Overall approach to the assessment

Possible questions for discussion:

- What questions do the Taskforce members have regarding the overall approach?
- and particular assumptions made?
- What further analysis would Taskforce members like to see?

The case for change

Possible questions for discussion:

- Do Taskforce members agree with the initial conclusions that have been drawn from the analysis?
- Is there a case for change?
- Is further analysis required before firmer conclusions can be drawn? If so, what?

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Lunch

Next session starts at 13:30

Backgrounds: Feedback & Further Discussion continued

Frontier & LCP

Discussion of backgrounds analysis and conclusions

Overall approach to the assessment

Possible questions for discussion:

- What questions do the Taskforce members have regarding the overall approach?
- and particular assumptions made?
- What further analysis would Taskforce members like to see?

The case for change

Possible questions for discussion:

- Do Taskforce members agree with the initial conclusions that have been drawn from the analysis?
- Is there a case for change?
- Is further analysis required before firmer conclusions can be drawn? If so, what?

Analytical Support: Reference Node

Frontier & LCP

The objective of this session is to provide:

- Further level of detail on the analytical assessment to date including; original rationale for the current reference node approach, issues considered regards the choice of reference node, options for change; and analysis in terms of charging impacts.

What is the reference node?

The reference node is a concept in the Transport model that determines how flows on the network are assumed to adjust to a marginal increase in generation at a location.

- The Transport Model contains a representative map of the GB transmission system with around 900 nodes
- Each node has *demand* and/or *generation capacity* that creates a ‘baseline’ system
- TNUoS charges are derived by adding generation capacity and measuring the impact on the network of revised system flows
- 1MW of generation capacity is added to a node. As the system must balance 1MW is also added to demand in the model
- The current reference node is a demand weighted distributed reference node.
  - This means that the 1MW increment to system demand is spread across all the demand nodes in the system in proportion to their contribution to total demand
  - It also means that the reference node is relatively “closer” to demand than generation, making average demand charges = 0, with positive recovery from generation

Original rationale

Explanation and future application

Pre TransmiT

- Pre TransmiT the choice of reference node was arbitrary but it had no effect on final charges.
- "Re-referencing" (which adjusted charges until the desired D/G split was achieved) meant that absolute levels of charges arising from the reference node were irrelevant and the relative locational signal in ones zone was not affected by the reference node anyway.

Post TransmiT

- A review of Project TransmiT documentation provides the following explanation for the current distributed generation approach:
  - "*the use of two background criteria in the Transport Model, the rereferencing process will become more involved. In order to simplify this… as much as possible, it is proposed to use a distributed reference node… [based on the]…proportions on each demand node in the Transport Model.*"*

Conclusion

- The original rational for the adoption of a distributed demand weighted reference node appears to be that:
  - A single demand node has previously been used
  - Adapting this to a distributed demand weighted node allowed for simplification of the calculation of tariffs
- It is not clear to what extent alternatives were considered during the TransmiT process

Simplification is likely to continue to be a relevant criteria. However, this must be considered alongside the issues that arise from the choice of reference node in combination with other features of the charging methodology.

- *Source: Project TransmiT: Electricity Transmission Charging Significant Code Review, Initial Report of the Technical, Working Group September 2011, page 61

Summary of potential issues to consider regarding the choice of reference node

Relative G/D cost recovery

- The reference node determines the relative cost recovery between G and D. Therefore, could choose to move reference node if targeting a different relative split (though any split must be consistent with €2.50 cap*)
- However, this can be more easily achieved through ex post adjustment to achieve €2.50 cap.

Impact of 'floored at zero'

- The relative location of the reference node affects the absolute value of the locational charge and therefore the extent to which floored at zero is binding for users that face DTNUoS (i.e. floored at zero would have a smaller impact if there was greater recovery from demand)

Competition

- Possible concerns about competition between different types of generation (TG, DG, BTMG) due to differences in cost recovery between G and D
- Moving the reference node would not change the relative raw charges calculated for TG vs DG and BTMG at a particular location (i.e. incremental costs calculated in Transport Model for G and D are equal and opposite for each node). Differences arise due to other factors such as zoning, and ALF.
- However, it would affect the extent to which floored at zero binds and thus the scale of the distortion it induces.

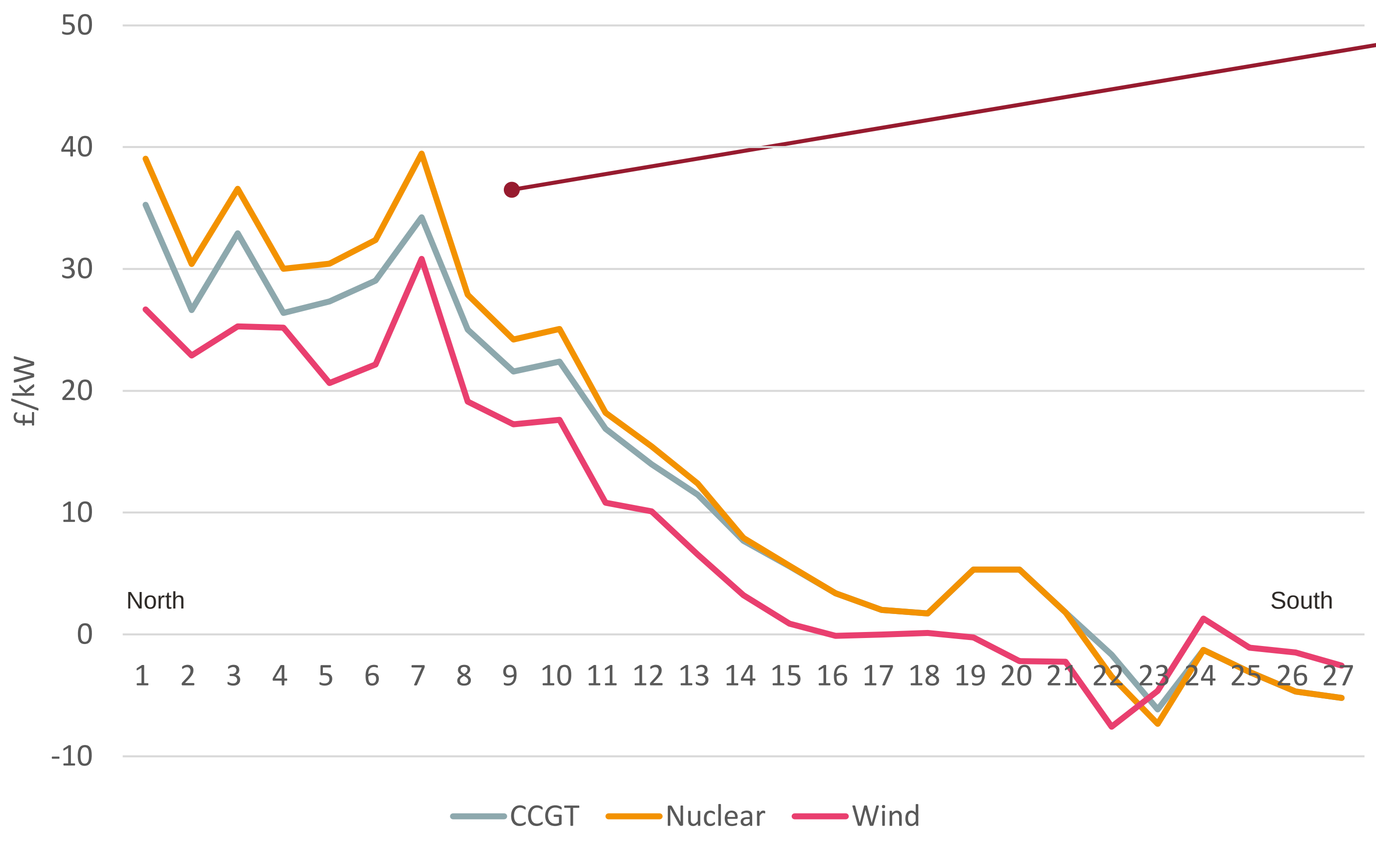
Impact of ALF

- The difference in the ALF based discount on network charges, depending on location (they are larger if further from the reference node), may be perceived as distorting competition between technologies.
- Moving the reference node would result in these discounts changing, and it is unclear whether this can be described as cost reflective

*Commission Regulation (EU) No 838/2010 restricts the annual average transmission charges paid by electricity generators in Great Britain to the range of €0/MWh to €2.50/MWh. This was introduced to try to provide a level playing field for competition between generation capacity in different EU states.

Impact of the reference node on the relative charges for high and low ALF technologies

Wider Locational TNUoS Charges



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

The gap between high ALF (nuclear) and low ALF (e.g. onshore wind) is larger the further from the reference node.

This is because ALF is applied as a multiplier to the absolute value of the year round charge.

This means that:

- generation far from the average location of demand faces higher charges;
- the difference in charges for high and low load factor plant varies by location:
  - close to the ref node, high and low ALF plants face similar charges; and
  - far from the ref node, low ALF plants face significantly lower charges than high ALF plants.

Reference node options

01 Single Reference Node

- Assumes that additional generation is always matched by additional demand in a single location
  - Selection of location is arbitrary
- Given arbitrary selection of reference node location, this is unlikely to be a cost reflective approach

02 Distributed Generation

- Assumes that additional generation always displaces other generation evenly
  - Formally this assumption is that new generation leads to retirement of existing generation rather than one new investment displaces an alternative new investment
- Zero average generation charges & +ve average demand charges
  - Low ALF generators receive no average discount
  - Reduced 'FAZ' distortion to TG vs DG & BTMG because of higher average demand charges
- Arguably a cost reflective approach
- Possibly less stable than demand weighted and implies a different reference node for the peak and year round scenarios

03 Add demand to the same node as generation

- Assumes that additional generation is always matched by additional demand in the same location. This would imply that no new network build would be required.
- Would imply no locational charges for any technologies.
- Unlikely to be a cost reflective approach

04 Retain distributed demand

- Assumes that additional generation is always matched by additional demand at the average location of demand
  - Logic is that increasing demand is met by generation at a location
- Zero average demand charges & +ve average generation charges
  - Low ALF generators retain average discount
  - Current 'FAZ' distortion to competition between TG vs DG & BTMG
- Arguably cost reflective
- Possibly more stable than a generation weighted approach
  - Currently implies a single reference node for both peak and YR scenarios

Although absolute charges would change if there was a move to a distributed generation based reference node, the differential impact of the ALF discount by zone would remain.

While there is not a clear conceptual case for choosing option 2 or option 4 over each other, we have tested the implications for charges of distributed generation and demand weighted reference nodes.

Detail of demand and generation weightings for the reference node

For G-weighted reference node, there is a question about how to set the weightings. In principle, a range of approaches could be taken. For the purpose of our analysis, we have defined an approach that is as conceptually similar to the current D-weighted approach

D-weighted reference node

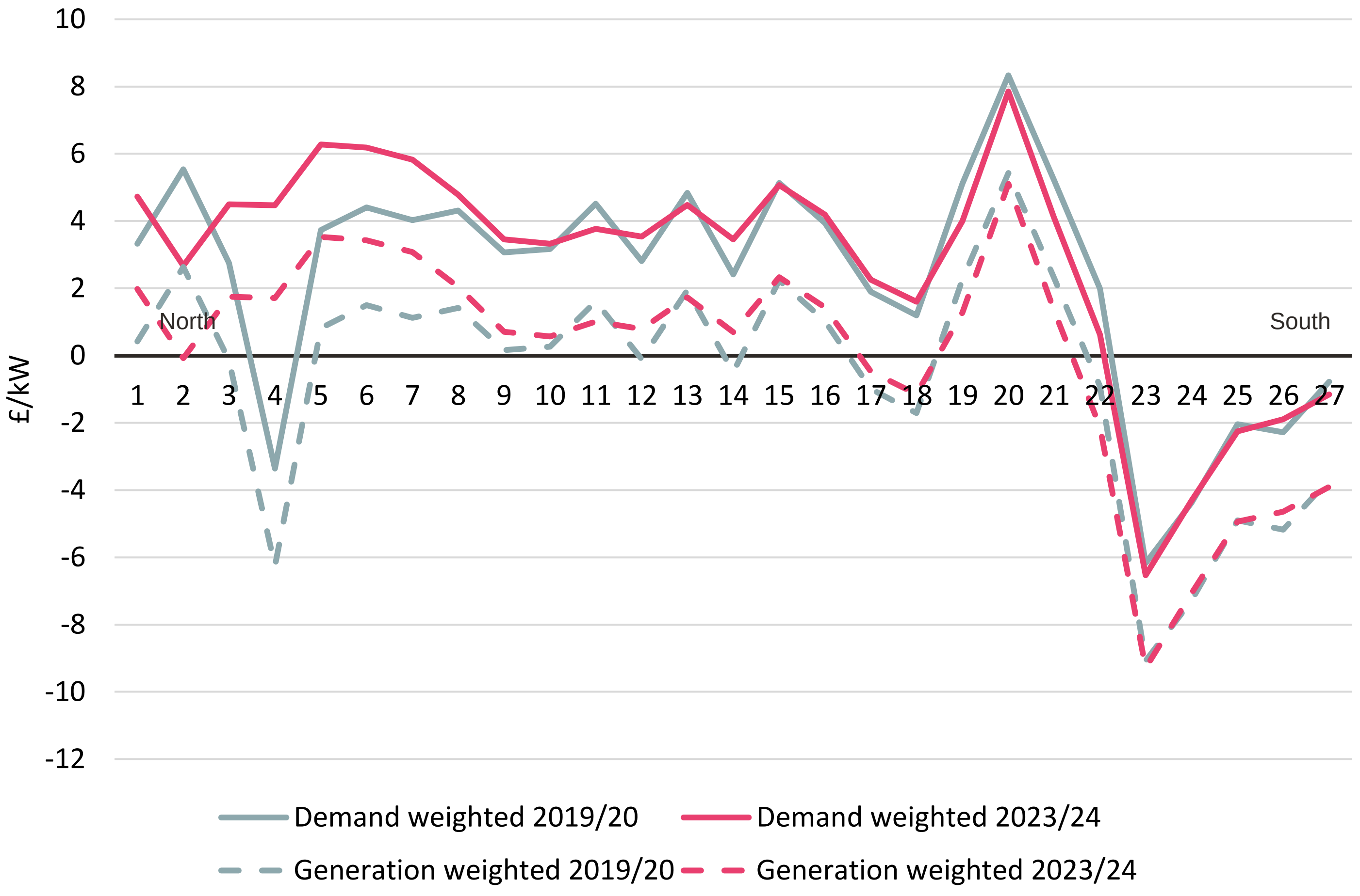
- 1MW of additional generation at a node, is assumed to be matched by 1MW of demand, spread across all nodes in proportion to demand at each node
- Both backgrounds (peak and YR) assume peak demand
  - Therefore, the locational pattern of demand is the same in each background, allowing for a single D-weighted reference node to be used
- The locational weightings for each node are equal to the share of peak demand at each node.

G-weighted reference node

- 1MW of additional generation at a node, is assumed to displace 1MW of generation, spread across all nodes in proportion to generation at each node
- The peak and YR backgrounds assume substantially different generation backgrounds
  - Therefore, the locational pattern of generation is different for each background and effectively, two G-weighted reference nodes are necessary (one for each background)
- For each background, the locational weightings for each node are equal to the share of generation produced at each node in that background

Changing the reference node weighting changes each tariff component

Peak security tariff

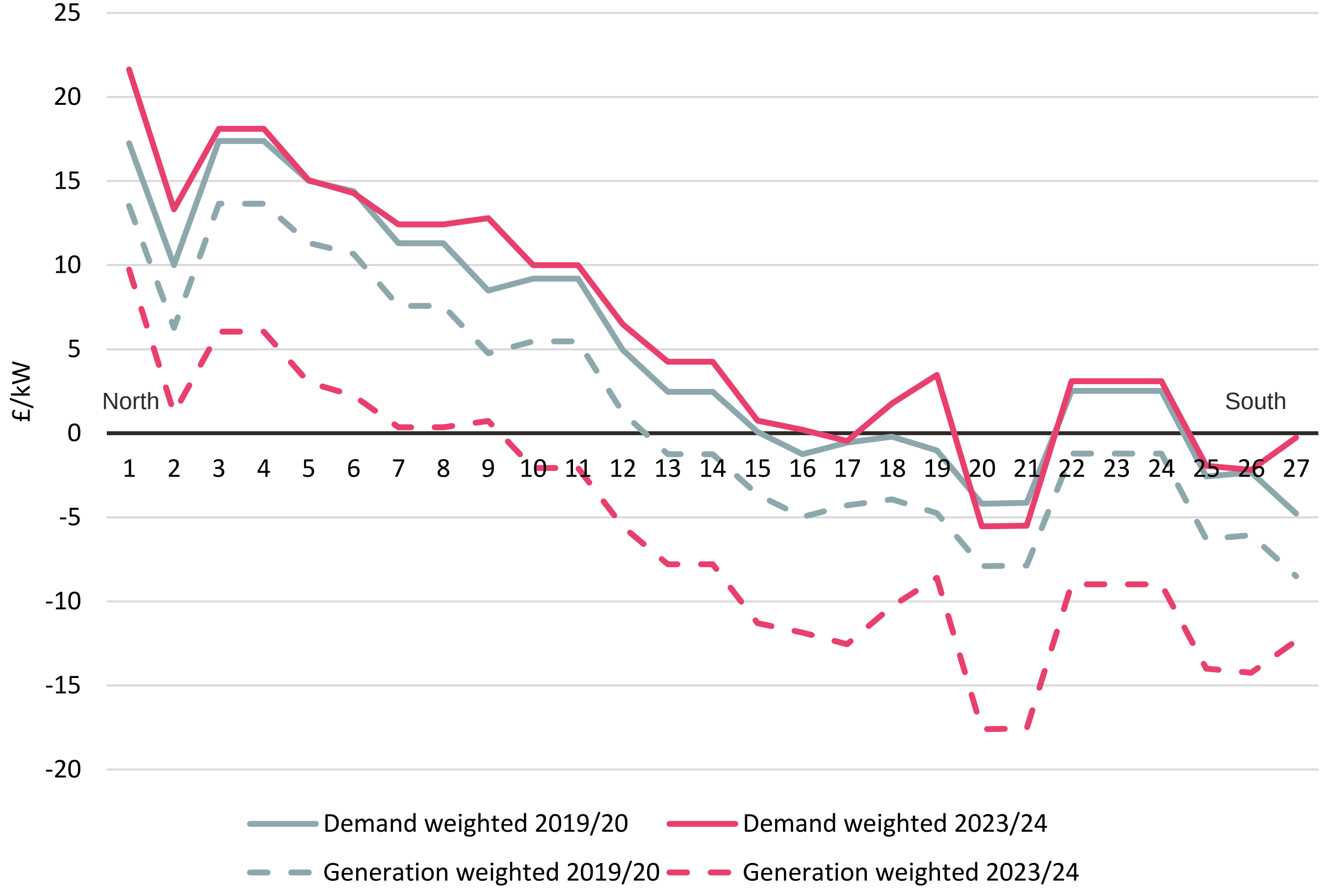


Peak security tariff

- Using a generation-weighed reference node results in lower final peak security tariffs than using the demand-weighted reference node, as peak generation is weighted further North than demand.
- This reduction is consistently £1/kW-£3/kW across all zones. This means that the overall variation between zones does not change with the different reference node.
- Over time, there is little change in the final peak security tariff, as the geographical distribution of peak generation relative to demand does not substantially change between 2019/20 and 2023/24.

Changing the reference node weighting changes each tariff component

Shared year round

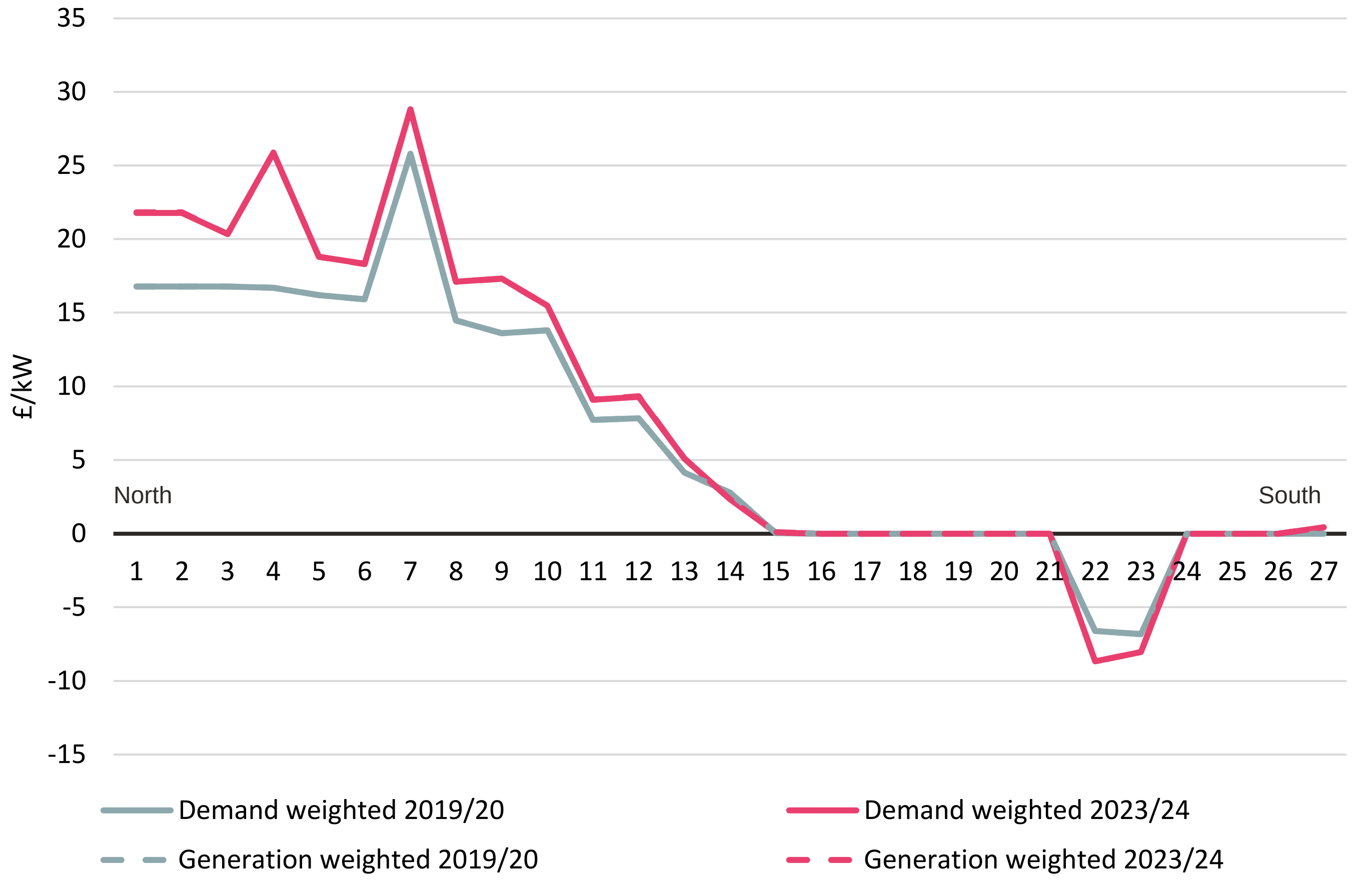


Shared year round

- The generation weighted reference node reduces the shared year round tariff component for each zone compared to the values returned by the demand weighted reference node.
- This reduction is only £3/kW-£7/kW in 2019/20, but it is £10/kW-£15/kW in 2023/24.
- This is because the geographic distribution of demand stays relatively stable over time but wind penetration disproportionately increases in the North.
- This means that while the shared year round tariff component does not change substantially between 2019/20 and 2023/24 if using the demand weighted reference node, there may be larger differences over time if using the generation weighted reference node.

Changing the reference node weighting changes each tariff component

Not shared year round

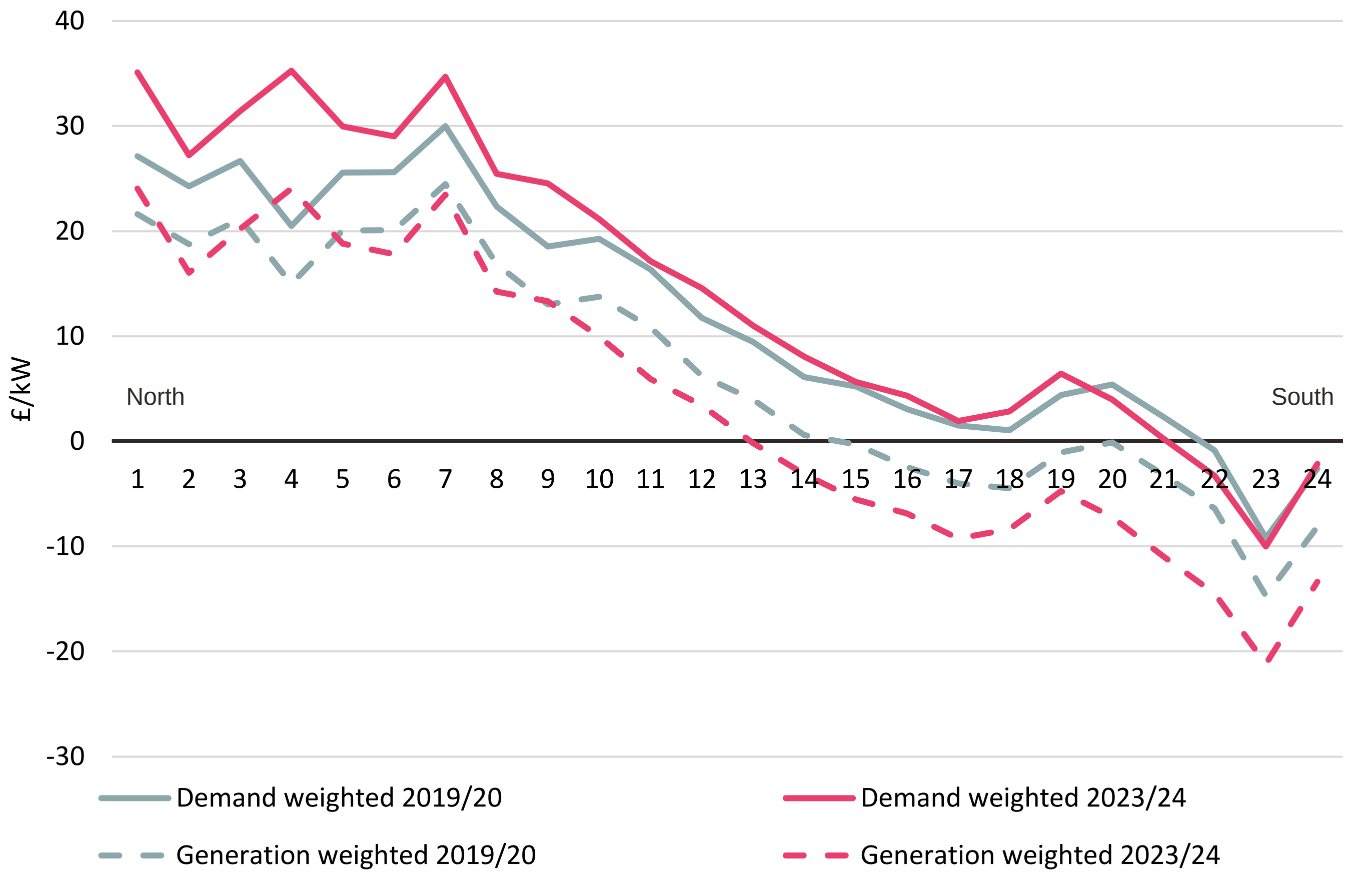


Not shared year round

- Changing the reference node has a relatively smaller effect on the year-round not-shared tariff, given relatively fewer boundaries have not-shared elements.
- There is a slight increase in this tariff component over time in Northern zones.

This has an impact on the wider tariffs, as well

Wider tariff – representative CCGT plant (ALF 70%)



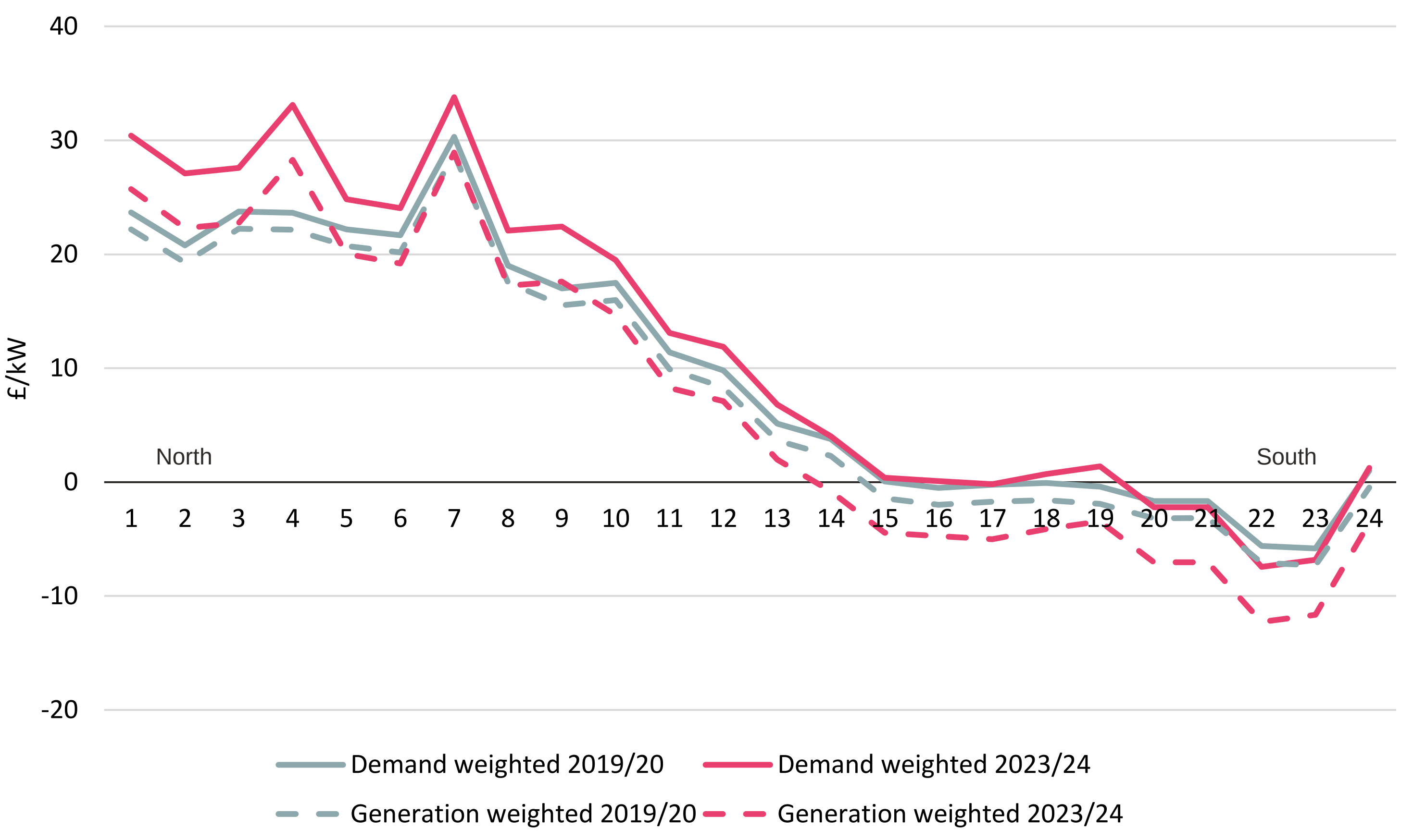
**Assuming a 70% annual load factor for CCGT plant.*

Wider tariff – CCGT

- Wider tariffs for CCGTs are lower for all zones and both tested years when using the generation weighted reference node.
- The calculation does not include the adjustment factor, which would reduce the impact of the change in approach to the reference node if the €2.50/MWh cap is binding.

This has an impact on the wider tariffs, as well

Wider tariff – representative wind plant (ALF 40%)



**Assuming a 40% annual load factor for wind plant.*

Wider tariff – wind

- The wider tariff for wind follows a similar pattern to the wider tariff for CCGTs, in that it is lower across all zones when using the generation reference node.
- However, the size of this difference is smaller, as the reduced final peak tariff component does not affect wind plants.
- This calculation does not include the adjustment factor, which would which would reduce the impact of the change in approach to the reference node if the €2.50/MWh cap is binding.

Changing from the status quo would imply a significant change to charges

Charges under a Demand Weighted Reference Node

- As most tariff components for most zones change slowly, wider tariffs are also quite stable over time with some slow changes.
- Charges in the North remain high and do not vary substantially over the years.
- There is some variation in the South, this can be sensitive to different backgrounds and generation mixes.

Charges under a Generation Weighted Reference Node

- Charges would immediately change quite substantially in this case, as both the final peak security tariff and the shared year round tariff are lower.
- There is also more year-on-year variability as the shared year round tariff is getting lower over the years. This drives a substantial and accelerating decrease compared to current tariffs.
- While this reduces charges for high-carbon assets in the North, it has a much smaller impact on intermittent assets.

In principle, there are other more complex ways that the generation weighted reference node weightings could be implemented. So far we have not assessed their impact on charges. We anticipate that to do so, would require significant additional analytical effort so important to test the appetite among Taskforce members.

We do not find a strong rationale to move away from the current approach to the reference node. Whilst, a generation weighted reference node might arguably be cost reflective, it would imply a significant change in charges and it is not clear that it is more cost reflective than the current approach.

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Break

Next session starts at 14:45

Reference Node: Feedback & Further Discussion

Frontier & LCP

The objective of this session is to discuss:

- Reference node assessment and identify if there are further areas of work required before a conclusion could be made.

Discussion of reference node assessment

Does the evidence support retaining the current approach?	Or is an alternative more appropriate?	Is further analysis required before a conclusion can be made, if so what?

Defects Update: Quick Wins & Workstream Plan

James Stone & Nicky White

Defects Update: Quick Wins & Workstream Plan

A further assessment of the eight packages of work prioritised at the previous Task Force meeting has now commenced. This review is looking at:

1. Key questions to be answered for each category
2. Potential scope of work including; specific goals, tasks to be delivered, additional follow on questions that may need to be answered
3. Links and interactions with other individual items and or packages
4. Consider if items or packages can be progressed in tandem - depending on linkage
5. Potential time to review each package - driven by approach required and ease of alignment to related principles or if area needs significant debate/analysis

➢ **ESO are progressing with TF volunteers to assess the plan collaboratively**

Charging Futures

Next Steps and Close

Jon Wisdom

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Thank you