Charging Futures
Reforming electricity charging together

TNUoS Task Force

Meeting 12

25th January 2024

Agenda

10:00 – 16:00

- 10:00 Introduction & Welcome
- 10:10 TNUoS locational demand charges
- 11:30 Break
- 11:45 TNUoS locational demand charges
- 13:00 Lunch
- 14:00 TO data walk through feedback
- 14:15 Data Volatility
- 14:45 Break
- 15:00 Data Volatility
- 15:30 AoB
- *16:00 Close*

TNUoS locational demand charges

Luke Davison and Sam Street

TNUoS locational demand charges

Potential reforms to peak and year round TNUoS charges

25 January 2024

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Project scope

Project objective

1

- Assess what are the **network cost drivers** around which network charges should be structured.
- This involves understanding the **forward looking costs** that should be reflected in charging methodology

2

- Given cost drivers, we consider the most effective way for charges to send an **efficient signal** to network demand users.
- This should bring about network cost reductions through **incentivising efficient actions**.

Assumptions and scope

- Our focus is on demand users, and we do not consider whether charges on generators are appropriate.
- We do not focus on the transport model and its derivation of incremental costs. Therefore:
  - We do not consider whether separating the Peak and Year-Round backgrounds remains the right distinction.
  - We take the charges by region as given.
- We instead consider how the incremental costs identified within the transport model are levied on demand

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In principle, cost reflective TNUoS charges should reflect "forward looking" costs

Minimising total system costs

- Market participants should face the costs that they impose on the system
- They then take these costs into account in all of their investment and operational decisions.
- In other words, charges should be *cost reflective*

Cost reflective network charges

- To internalise costs in the decisions of market participants:
  - *forward looking costs* must be reflected: these can be changed by future behaviour; and
  - *incremental or marginal* costs, not average costs.

In the context of networks, charges should therefore relate to behaviour that increases or decreases the network flows that drive changes in network investment

Project TransmiT identified two backgrounds representing different triggers incremental network investment

Project TransmiT recognised two potential drivers for new network investments…

Peak security flows

- Investment required to ensure network security when overall demand is at peak.
- In other words, the peak flows over some assets coincide with peak demand.

Year round flows

- Investments driven on network elements due to a CBA i.e. optimal balance between congestion and network investment.
- This is a recognition that peak flows over some assets may not coincide with peak demand.

…however, demand charges do not recognise any differences between backgrounds

- Project TransmiT predominantly focused on generation, allocating costs associated with each background to different technologies depending on the likelihood that different generating technologies would affect required network investments in either background.
- Demand received less focus and Peak and Year Round are simply summed and charged on peak demand (Triad for HH and 4-7pm demand for NHH).
- This suggests little consideration given to role of demand in causing (or alleviating) constraint costs and therefore investments under Year-Round background.

Note: we assume that these backgrounds remain appropriate reflections of the conditions that drive network investment. If the assumptions for the backgrounds are updated then the conclusions in the report are likely to remain appropriate. However, if the underlying principles for the backgrounds change, or new backgrounds are introduced reflecting different drivers of costs, then further work would be required to consider how that should be reflected in charges.

Demand charges should therefore be set in a manner reflective of the drivers of network cost in each background

Peak charging

- Peak demand is an important driver of network investment for some assets to secure the network at peak
- Therefore charging on the basis of peak demand is likely to remain important for assets tagged as Peak Security
- For the purposes of this work we have assumed national peak demand is a reasonable proxy for peak flows over all Peak Security assets wherever they are located.
- However, it is worth noting that peak demand may vary in timing nationally, suggesting it may be feasible to think about locally determined peak based charges.

Year Round

- Consumption during periods of congestion is an important driver of network investment for some assets.
- Therefore, it is likely to be appropriate to materially change the basis on which Year Round costs are currently charged
- In other words, charges should shift away from peak demand to a measure of consumption during periods of constraints in order to penalise (reward) demand for its role in causing (or alleviating) constraint costs.

In the following sections we consider the options for setting charges reflective of each cost driver.

It is likely to be the case that TNUoS charges should avoid sending operational signals

In theory TNUoS charges could lead to operational and investment efficiency benefits. However, it would be very hard to deliver operational efficiency benefits, suggesting that reforms should avoid operational signals and target investment efficiency benefits

TNUoS charges that send operational signals are likely to distort dispatch…

- In a national wholesale market (with network charges), the BM is the primary source for organising efficient re-dispatch.
- Demand which is dispatched in the BM receives an operational signal related to congestion.
- However, there is potentially a missing signal for non-BM demand (or demand not dispatched in BM) since they are not exposed to BM prices i.e. demand is only exposed to the national price, rather than a price reflective of congestion (as it would be if it were accepted in BM)
- In theory, TNUoS charges could be applied so that in combination with a wholesale signal, demand is exposed to an efficient operational signal (which in turn results in efficient investment signal) which minimises overall system costs
- However, this is unlikely to be feasible because:
  - Estimating of cost reflective TNUoS charges is subject to uncertainty – they may be right on average but distort dispatch in any specific half-hour;
  - Charges can only be cost reflective in relative terms – truly cost reflective absolute charges will vary by half-hour (i.e. absolute values are driven by the location of the reference node - a decision to move the reference node would have a material impact on the absolute value (potentially switching it from positive to negative), and it is unclear why that would be cost reflective)
- In time, this missing signal may become less important as more demand gains access to the BM through aggregation
- ***As a result, TNUoS operational signals could interfere with otherwise efficient BM dispatch.***

…suggesting charges should focus on investment efficiency

- TNUoS charges are the primary means by which locational investment signals are sent in a national market.
- Demand should be incentivised to locate in helpful locations from the perspective of reducing Peak Security and Year Round costs, but without affecting its dispatch.
- In other words, demand charges should reward different types of demand based on how they typically respond to wholesale and BM market signals in periods that drive network investment costs.

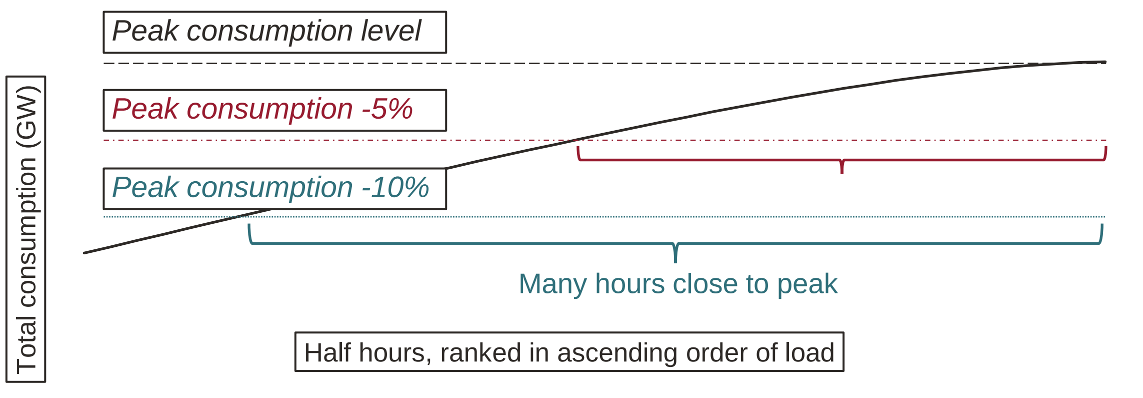
*"An operational charge would need to signal the costs of scarce network capacity in particular locations, in real time. To be accurate, such charges would need to be derived from a robust whole system model that is synchronised with, or able to accurately simulate, wholesale, balancing and flexibility markets" Ofgem 2024**

**Open letter on strategic transmission charging reform, Ofgem, 2023*

Agenda

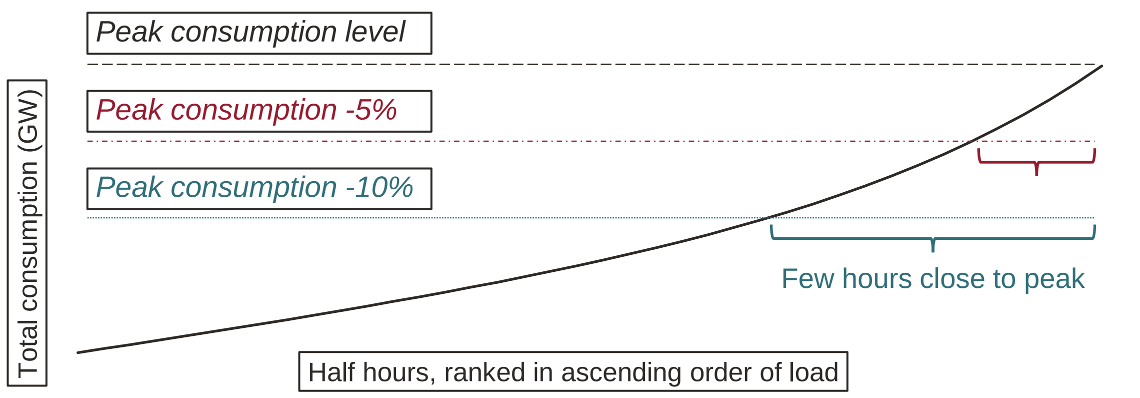
When choosing appropriate Peak Security charging methodology, it is important to consider the gradient of the load duration curve

Shallow load duration curve:



- Broad base of hours where consumption is close to peak i.e. consumption across many hours is important potential drivers of future Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption across a broad base of peak hours.**

Steep load duration curve



- Relatively few hours where consumption is close to peak i.e. consumption across only a few hours is important potential driver of Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption in only a few peak hours**

Ultimately, the shape of demand is an empirical question which could be investigated further (see slide 30)

If charges are based on actual peak consumption then there is a significant risk of operational distortions, particularly if charges target a small number of hours

Approach to charge	Most suitable if…	Investment signal	Operational signal
Charge based on consumption in ***relatively few periods*** (e.g. three like Triad)	Steep load duration curve	▪ Assuming a steep load duration curve, signal penalises/rewards based on consumption in hours which drive costs ▪ Signal may be distorted if actually shallow load curve i.e. consumption across more hours is cost driver	▪ If based on actual consumption, sends a strong operational signal to reduce consumption in these hours. ▪ Therefore, might need to consider options to remove operational signal while maintaining investment signal *(we discuss two options in following slides)*
Charge based on consumption across ***many periods*** (e.g. 4-7pm winter hours)	Shallow load duration curve	▪ Assuming a shallow load duration curve, signal penalises/rewards based on consumption in hours which drive costs ▪ Signal may be distorted if steep load curve i.e. consumption over fewer hours is cost driver	▪ If based on actual consumption, any operational signal is diluted across many hours. ▪ Options to remove operational signal therefore less critical.

If operational signals are less of a concern, then Triad approach remains a suitable option

If concerned about avoiding operational signals, and options to remove the signal are unappealing, diluting the signal over many hours should be preferred

(1) Reducing operational incentives - TNUoS could be levied based on charging behaviour across multiple years, instead of just one

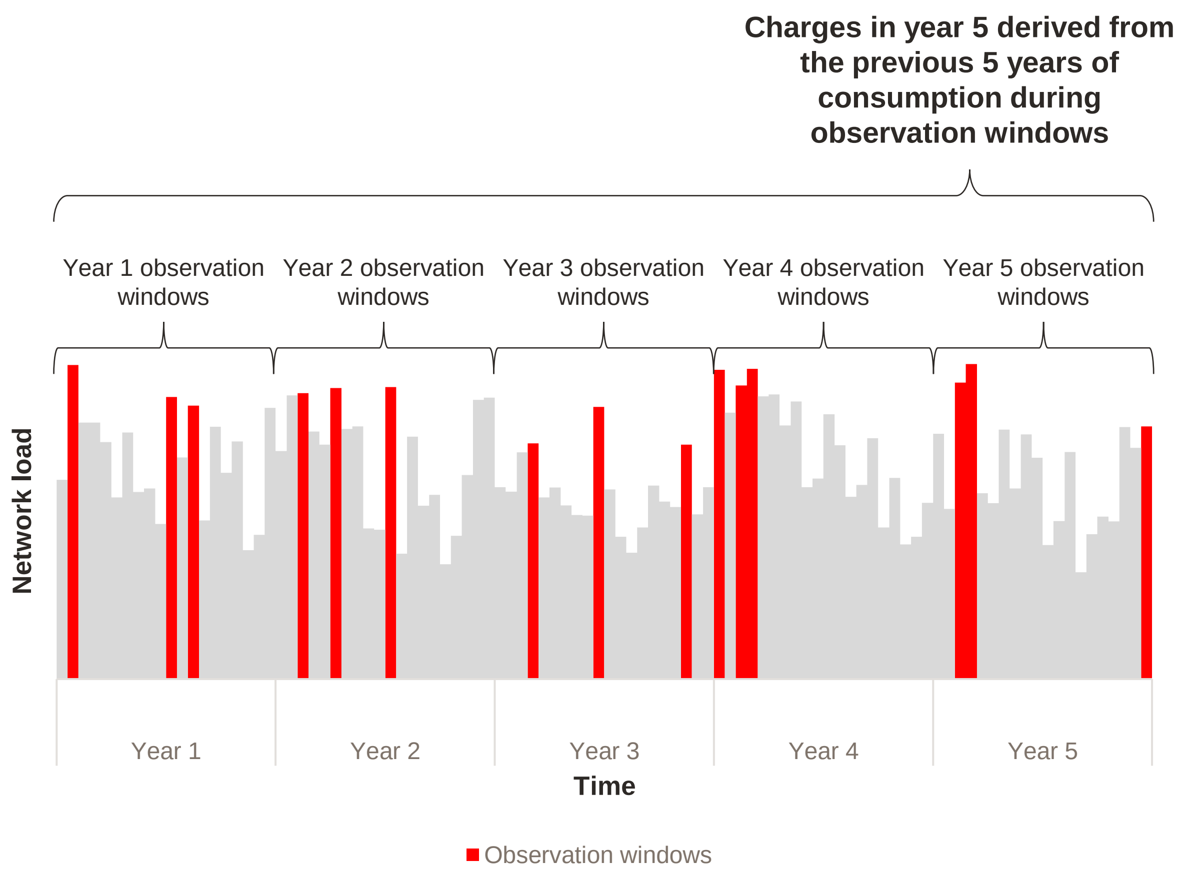
Description:

- Until now we have assumed that charges will be levied based on consumption during observation windows for a single year each time.
- However, alternative exists in which charges are based on consumption across multiple historic years.
- An example could be for it to be based on consumption during observation windows for the last 5 years as shown on RHS.

Impact on incentives:

- Would reduce operational incentives, whilst maintaining locational investment signals.
- Operational incentives reduced somewhat because the impact on each user's TNUoS charges will be lagged over several years. Users will give these future years less importance because the future will be discounted by the WACC of each user.
- **However, operational signal remains reasonably strong given strength of operational signal in each hour**

Example of how this may work



(2) Reducing operational incentives - TNUoS could be levied based on assumed consumption for different groups

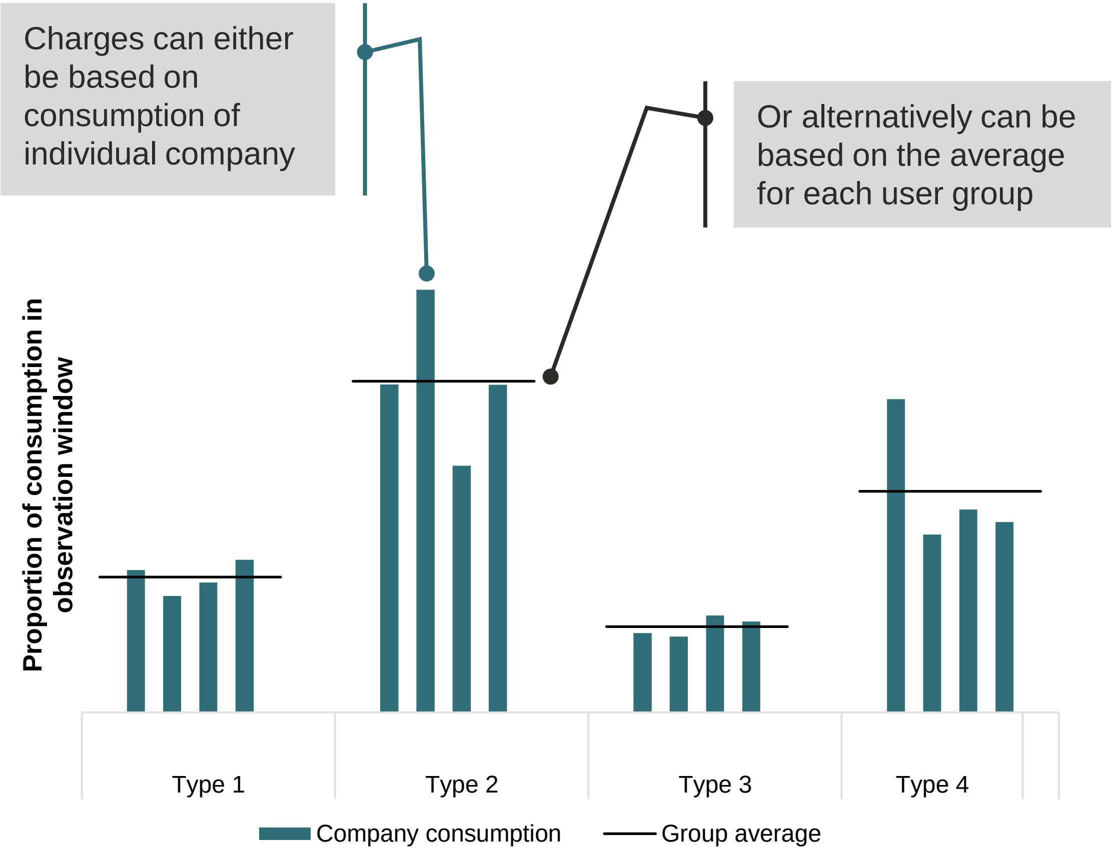
Description:

- Previous slides assumed that charges will be based on users' individual consumption during the observation windows.
- However, an option exists to levy charges based on the consumption of different user groups, categorised by industry or by electricity use type (e.g. data centre, glass factory, domestic, etc.)
- Charges would be based on average consumption in relevant hours across these different user groups as shown on RHS.

Impact on incentives of charging based on user type's consumption:

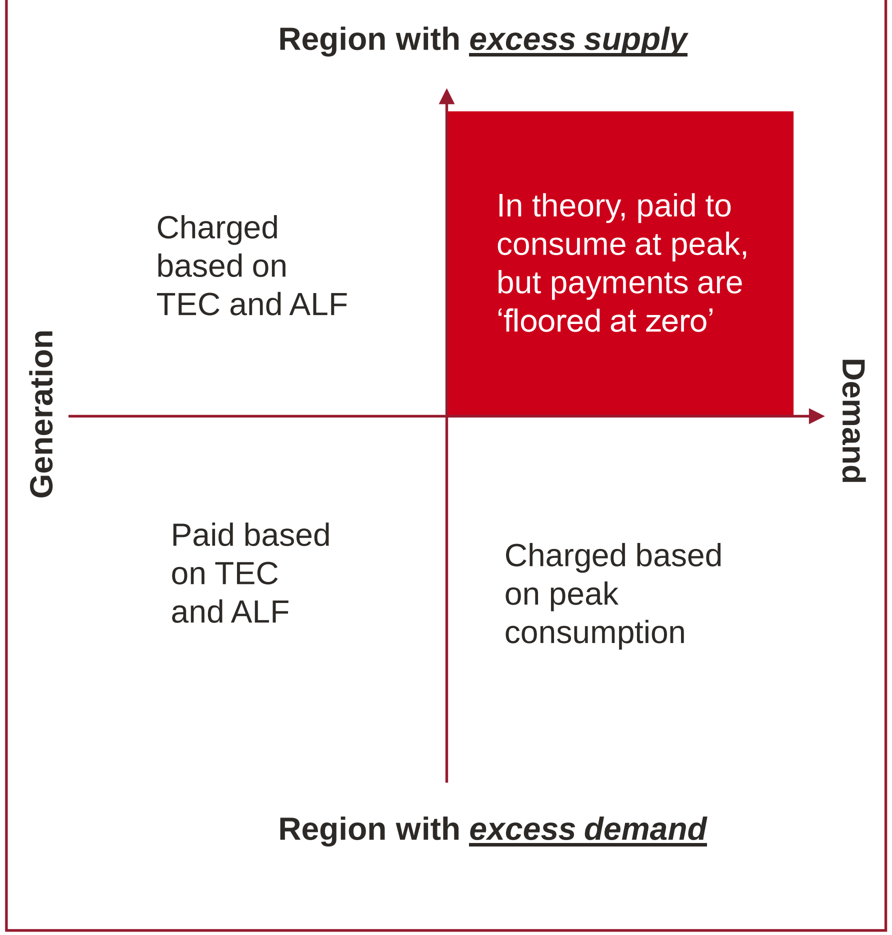
- **This approach would strongly dilute any operational incentives**, because each individual's consumption patterns would have a negligible effect on its group's load profile and hence its charges.
- However, locational investment incentives would remain (albeit less directly related to individual profiles), and these would account for the investor's likely consumption behaviour, provided consumption within each user group is similar.

Example of how this may work



Concerns that led to “floored at zero” are less relevant if the operational signal is much diluted

Charges are currently “floored at zero”



Removing floored at zero would restore important investment signal

- Charges currently floored at zero, to avoid incentivising increased peak consumption, which Ofgem worries will impact on security of supply.
- It leads to **inefficient investment signals** – Demand is insufficiently incentivised to locate close to sources of supply.
- If significantly reducing / removing operational signals then floored at zero is much less of a concern.
  - If setting charges based on a broad base of hours, incentive to increase demand remains but it is much diluted so less likely to be of concern
  - If setting charges based on deemed consumption/banding then operational signal removed
- From an efficiency perspective, removing floored at zero is beneficial.

Summary of conclusions for Peak Security charging

- There is a clear rationale for levying peak security charges on peak demand.
- Approach should be based on charging consumption in hours which drive network costs – therefore the shape of the load duration curve can inform which the most important hours are
- Historically, the approach has been to send operational signal to reduce demand in these hours. However, if this is deemed inefficient, then the design should consider how to limit/reduce operational signal while maintaining investment incentive.
  - If charge based on actual consumption in relatively few hours (e.g. because load duration curve is steep), the strong operational signal remains. This can potentially be mitigated somewhat by rolling average over a number of years, or reduced significantly by a 'deemed' demand approach. The latter option can be challenging to implement.
  - If charge is based on actual consumption over broad base of hours (e.g. 4-7pm winter hours), the same options to reduce operational signal could apply, but concern is much reduced due to dilution of operational signal.
- Floored at zero removes important investment incentive in negative charge zones. By removing/reducing operational signal, rationale for floored at zero should also be reduced.

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Introduction to year round charges

Year round costs are driven by demand in constrained periods, not peak demand periods

- Year-round charges are currently levied based on customer demand during peak demand periods (either triad for HH or 4-7 for NHH).
- However, in principle year-round costs relate to the network investment required to alleviate network constraints.
- Therefore, for charges to be cost reflective, they should be levied against hours when there are constraint costs, since **this is what drives the investment need.**
- Therefore, separate methodologies could be used to charge for year-round and peak costs.

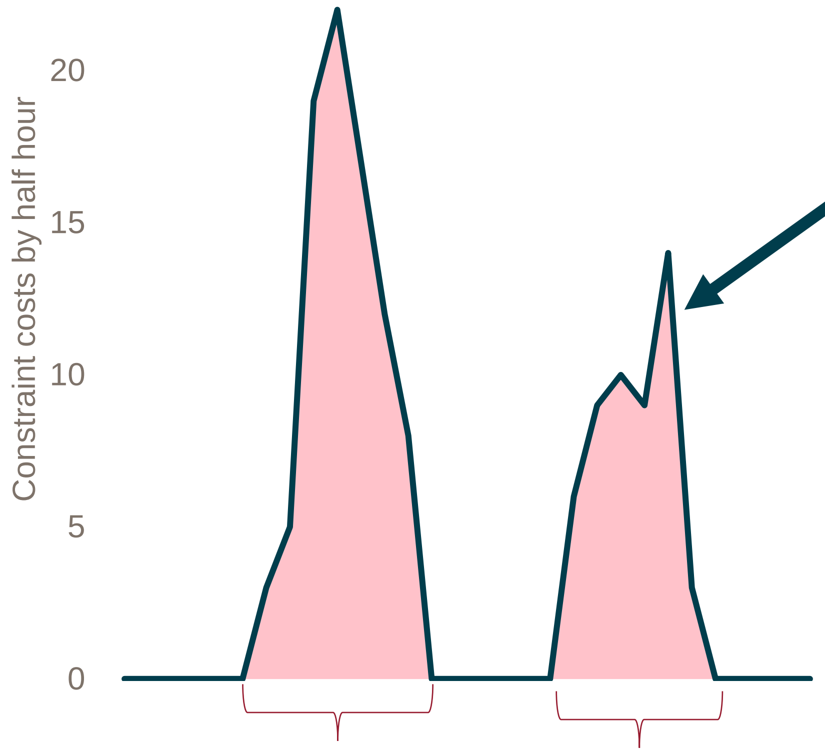
Implementation considerations:

- What hours should year-round charges be levied against?
- Should all charging hours be treated the same or should there be some weighting of different charging hours?
  - If there is weighting of different hours, what metric should be used?
- Should the hours that charges are levied against be set ex ante or ex post?
- Should the charging methodology incorporate additional features to reduce operational incentives?
- Should “floored at zero” be retained for year-round charges?

These considerations are explored in the following slides

All constrained hours are relevant for year-round costs, rather than just hours of maximum constraint

Hypothetical constraint costs over time



Periods that contribute to constraint costs

Year-round costs relate to the sum of constraint costs

- Year-round costs relate to the optimal network investment required to efficiently alleviate constraint costs.
- Constraint costs vary over time, as represented by the line in the graph.
- Network investment to alleviate constraint costs is **not driven by the peak level** of constraint costs, rather it is driven by the total of constraint costs across all periods, as represented by the pink shaded area.

All constrained hours are relevant but not equally

- A 1MW increase in demand will have an impact on constraint costs in **all hours that the network is constrained.**
- However, the marginal cost of alleviating constraints in each constrained hour will vary depending on the actions the ESO must take to resolve the constraint.
- It is likely that when constraints are larger overall (deeper), the marginal cost to resolve the constraint will be larger because the ESO will have already exhausted the cheaper options for alleviating constraint

Basic options for charging year round identifying which hours and allocating year-round costs

Average demand in all hours	Average demand in constrained hours only	
	Unweighted	Weighted by a metric
1	2	3
■ Simple to implement ■ Easy to understand ■ Sends minimal (very diluted) operational signal ■ Likely more cost reflective than charging based on peak demand ■ Abstracts from the distinction between consumption during constrained hours (which affects required network investment), and consumption in other hours (which does not)	■ Charges based on average consumption during all constrained hours. ■ Would send only a small operational signal (assuming there are many constrained hours in a year) ■ Sends more targeted cost reflective investment signal but not fully cost reflective.	■ Charges based on weighted average consumption in constrained hours. ▫ Options for weighting approach discussed in slide 26 ■ May send a modest operational signal in most periods but may send stronger incentives when constraints are higher. ■ In principle sends a more targeted and cost reflective investment signal.
Analogous to a Load Factor style approach	**Analogous to a "Constrained Load Factor" style approach**	**Analogous to a "Constrained Load Factor" style approach with further adjustment**

We assess each of these options in the following slides

Average demand in all hours may be a reasonable charging methodology for many sources of demand

- A user with a demand profile that is uncorrelated with constraints/constraint costs would **expect** to incur the same YR charge or receive the same YR credit on average under each of the three charging approaches considered.

Assessment for demand **uncorrelated** with constraints

- Demand faces a cost reflective locational investment signal
  - If demand is uncorrolated with constraints, then expected demand in any constrained period is equal to an average annual level of demand
- Any operational signal is significantly diluted (because it is spread across all hours in a year)
  - Averaging of demand over previous years (similar to the ALF calculation for generation TNUoS) could further reduce operational incentives

Assessment for demand **correlated** (+ve or –ve) with constraints

- Demand will not face a fully cost reflective locational investment signal
  - Demand sources that that are correlated with constraints/constraint costs will have higher average demand in constrained periods than on average across the year
  - Thus, taking an annual average will understate their contribution to (relieving) constraints
- Operational signals will be minimal and can be further reduced if necessary

Correlation of demand with constraints is an empirical question.

Demand correlated with constraints is likely to be flexible (e.g. storage, H_2 production).

We consider options 2 and 3 for these demand users.

Under Option 1 the observation periods are set ex ante by definition

For options 2 and 3 there is a choice about whether to define the observation periods ex ante or ex post

Focus of cost allocation	Ex ante or Ex post
1 Consumption across all hours i.e. charge driven by load factor	**Ex ante** *When considering an all hours approach the ex-ante ex-post distinction is less relevant*
2 Consumption across constrained hours **(unweighted)**	**Ex ante or Ex post** *When considering a subset of hours i.e. "constrained hours" then whether these are determined ex post or ex ante matters. In this context ex ante likely to be relatively short-term signalling.*
3 Consumption across constrained hours **(weighted)**	

Option 2 allows for a better targeted locational investment signal for flexible demand

- Option 2 would concentrate the operational signal in fewer hours compared to Option 1. However, assuming there are still a significant number of constrained hours in the year, the signal will still be weak in contrast to the peak demand signal.
- The operational signal could be dampened further by taking averages or adopting a deemed approach.
  - Rolling averages may offer a sufficient dampening as signals will be weak already.
- Option 2 would make the year round locational investment signal better targeted and better able to recognise the benefit flexible demand technologies provide in reducing constraint costs relative to other demand users.
- In principle, Option 2 could be implemented on an ex ante or ex post basis.

Ex ante

- ESO would specify in advance, which periods it anticipated would be constrained and therefore which periods are observation windows for calculating YR charges.
  - Allows for a more targeted operational response to the charge (which is likely to be undesireable).
- Demand for charge setting purposes, would be measured in some non-constrained hours (due to forecast error).
  - This would include periods without BM actions. This could reduce the cost reflectivity of the charge because flexbile demand may respond to BM actions in constrained periods.

Ex post

- ESO would measure demand in periods that were observed to be subject to constraint.
  - The operational signal would be weaker (but affects more hours) than for an ex ante approach because of uncertainty over which hours will be measured
- Measured demand would reflect the impact of BM actions.
  - This is important because BM actions are likely to be a driver of correlation between constraints and flexible demand.
    - TNUoS generation charging arrangements for peaking plants in negative generation charge zones provides precedent for charges to be based on post BM action positions.

Targeting charges on demand in constrained periods ex post presents an additional challenge

Local vs national constraints

- The previous discussion is based on a simplified concept of constraints which effectively assumes that:
  - a “constrained hour” is any hour with a constraint nationally; and
  - that national constraints are well correlated with local constraints.
- However, it is unclear if national and local constraints are well correlated.
  - If they are not, then for the signals to be truly cost reflective measurement of a “constrained hour” would need to be done at a local level.
- It may be possible to test empirically whether local and national constraints are typically well correlated (see slide 32)

If constrained hours are weighted (Option 3), there are different sub-options for how this weighting should be done

Theoretically better

Weighting metric	Notes
Marginal cost of alleviating constraints (£/MW)	▪ Consumption in periods of most expensive constraints to resolve is weighted highest. ▪ Theoretically most reflective of the basis for year round charges. ▪ May risk spurious accuracy, unclear if data necessary to calculate is available.
Total constraint cost by half hour (£)	▪ Consumption in periods with the highest total constraint costs is weighted highest. ▪ Likely to be a good proxy for periods of high marginal constraint costs. ▪ Data necessary to calculate should be available (at least ex post).
Total constrained volume by half hour (MW)	▪ Consumption in periods with the deepest (MW) constraints is weighted highest. ▪ Likely to be a reasonable proxy for periods of high marginal constraint costs. ▪ Simpler to implement.

Simpler to understand/implement

Additional variations are possible that would count demand in all hours where constraints exceed an agreed minimum threshold

Option 3 would further improve the targeting of the locational investment signal

- Option 3 would further sharpen operational signal in some periods relative to Option 2.
  - This may require additional mitigation.
- Option 3 would make the year round locational investment signal better targeted at the true driver of year round costs.
- In principle, Option 3 could be implemented on an ex ante or ex post basis.

Ex ante

- ESO would specify in advance the metric value for periods it anticipated would be constrained
  - Allows for a more targeted operational response to the charge (which is undesireable).
- The requirement for a more granular forcast likely increases ESO's forecast error (relative to Option 2)
  - As with Option 2 this would risk inconsistency between the actual conditions in the BM in an observation period and the conditions effectively assumed when calculating charges.

Ex post

- ESO would measure demand in periods and weight these observations in a way that is consistent with the BM conditions that prevailed in each period.
  - The operational signal would be weaker (but affects more hours) than for an ex ante approach because of uncertainty over which hours will be measured
- This means that the demand measured for flexible demand sources could reflect the impact of BM actions.
  - This is important because BM actions are likely to be a driver of correlation between constraints and flexible demand.

Option 3 could increase cost reflectivity further. However, it is unclear whether Option 2 and Option 3 would result in materially different charges for flexible demand. It may be possible to assess this question empirically (see slide 31). If charges would be similar, then Option 3 may add significant additional complexity for little practical benefit.

Strong rationale for removing floored at zero for year-round charges

Mis-incentives removed:

- Current rationale for flooring charges at zero is to avoid incentivising consumption at peak, given year round charges currently levied against “triad” half hours.
- However, our proposal is to move charges away from triad half hours and where appropriate, further reduce operational signals.
- With this potential mis-incentive at peak removed, there is less rationale for floored at zero to remove operational incentives for negative demand charge zones.

Removing “floored at zero” can reinstate an important locational investment signal reducing constraint costs and network investment:

- Inefficient investment signals: Incentivising consumption close to supply can significantly reduce future constraint costs and hence network build relative to consumption located further away from generation.
  - Floored at zero significantly reduces this incentive.

Summary of conclusions for Year Round charging

- In principle, year-round costs relate to network investment required to alleviate network constraints. Costs spread across all constrained hours are therefore important (not just those hours of highest constraint).
  - Operational signals arising from possible reformed Year-round charges are likely to be more diluted than the operational signals possible from peak demand charges because of the large number of relevant hours.
- **Option 1:** is relatively simple, and likely to be improvement on current charges based on peak.
  - However, it abstracts from a lot of diversity in the ability of different sources of demand to reduce constraints e.g. flexible demand can focus consumption to target or avoid constrained hours depending on location.
- **Option 2:** has the potential to improve cost reflectivity as it is more targeted at hours that drive network costs.
  - However, consideration must be given to the issue of the difference between local and national constraints
  - Whilst an ex ante approach is possible in theory it is unlikely to be a suitable approach because it will involve some error in identifying periods of constraints. This will understate the correlation (+ve or –ve) of flexible demand with constraints because flexible demand will respond to locational BM signals only when there actually are constraints. Thus, an ex post approach is more likely to be suitable.
- **Option 3:** has the potential to improve cost reflectivity further. However, it also further increases complexity.
- **Overall**, a simple approach (Option1) may be reasonable for most types of demand but a more sophisticated approach (Option 2 or 3) may be suitable for certain sources of flexible demand.
- Floored at zero should be removed to return the locational investment signal.

Agenda

Potential empirical tests – Peak Security related

Test	Rationale	Methodology
Shape of load duration curve	▪ As discussed in slide 11, the optimal choice of methodology may be affected by how many half hours have consumption close to peak consumption levels. This is determined by the gradient of the load duration curve.	▪ Source HH consumption data, over multiple years. ▪ Produce descriptive statistics to determine: ▫ How many half hours have consumption within 1%, 5%, and 10% of consumption during peak half hour. ▫ Ratio of consumption in peak half hour to the 2nd, 3rd highest, etc. ▪ There, is the potential to augment this with forecasts of the future distribution of demand by half hour.

Potential empirical tests – Year-Round related (1/2)

Test	Rationale	Methodology
Assess prevalence of constrained periods	▪ In the extreme, if all hours are constrained, then there is no difference between Option 1 and Option 2 ▫ It would also be the case that the operational signal is maximally diluted ▪ If actually the majority of hours are constrained, then there may be less benefit of implementing Option 2 over Option 1	▪ Statistical analysis of historic constraint data over a 5 year period to determine prevalence of constraints ▪ There, is the potential to augment this with forecasts of the future prevalence of constraints
Assess variation in constraint metrics	▪ In the extreme, if all constrained hours are constrained equally, then there is no difference between Option 2 and Option 3 ▪ More realistically, if there is little variation in the level of constraints between constrained periods then there may be less benefit of implementing Option 3 over Option 2 ▫ Effectively charges would be similar for flexible demand under Option 2 and 3	▪ Statistical analysis of historic constraint data over a 5 year period to determine the variation in the level of constraints (as measured by the proposed metrics) within constrained hours ▪ There, is the potential to augment this with forecasts of the future prevalence of constraints
Assess correlation of aggregate demand with constraints	▪ Option 1 provides a reasonable charging methodology for demand that is uncorrelated with constraints. ▪ Therefore, if it can be shown that aggregate demand is broadly uncorrelated with constraints (e.g. constraints are driven more by wind patterns) then it allows for simplification of the charging methodology	▪ Statistical analysis of constraint data and demand data over a 5 year period to determine the correlation of electricity demand with constraints. ▪ There, is the potential to augment this with forecasts of the future correlation of system demand with constraints

Potential empirical tests – Year-Round related (2/2)

Test	Rationale	Methodology
Correlation between GB wide and localised constraint levels	▪ If local and national constraints are well correlated then the calculation of charges (under options 2 and 3) can be simplified and can rely on a national measure of constraints. ▪ However, if local and national constraints are not well correlated, then it would be necessary to use a local measure of constraints for options 2 and 3 to achieve cost reflectivity	▪ Statistical analysis of constraint data over a 5 year period to determine: ▫ The main network constraints to consider (e.g. B2, B7 etc) ▫ The correlation of constraints over the key boundaries with constraints at the national level.

Charging Futures

Reforming electricity charging together

Lunch

Next session starts at 14:00

TO data walk through feedback

Brendan Clark

Data Volatility

Luke Davison

Contribution to TNUoS charge volatility from TNUoS methodology and data inputs

Agenda

Inputs

01

TNUoS inputs

- What inputs from the transmission operators add to volatility of TNUoS charges?

02

Locational charge volatility

- What is the impact of the following factors on locational charges
  - Generation ALF
  - Week 24 data
  - Generation TEC
  - Network model
  - Inflation impact via the EC

03

Residual charge volatility

- How has the setting of allowed revenue for transmission operators created volatility
- What is the impact of the “k” factor on TNUoS volatility?
  - Will the implementation of TDRs fixed banded charges reduce the “k” factor in the future?

04

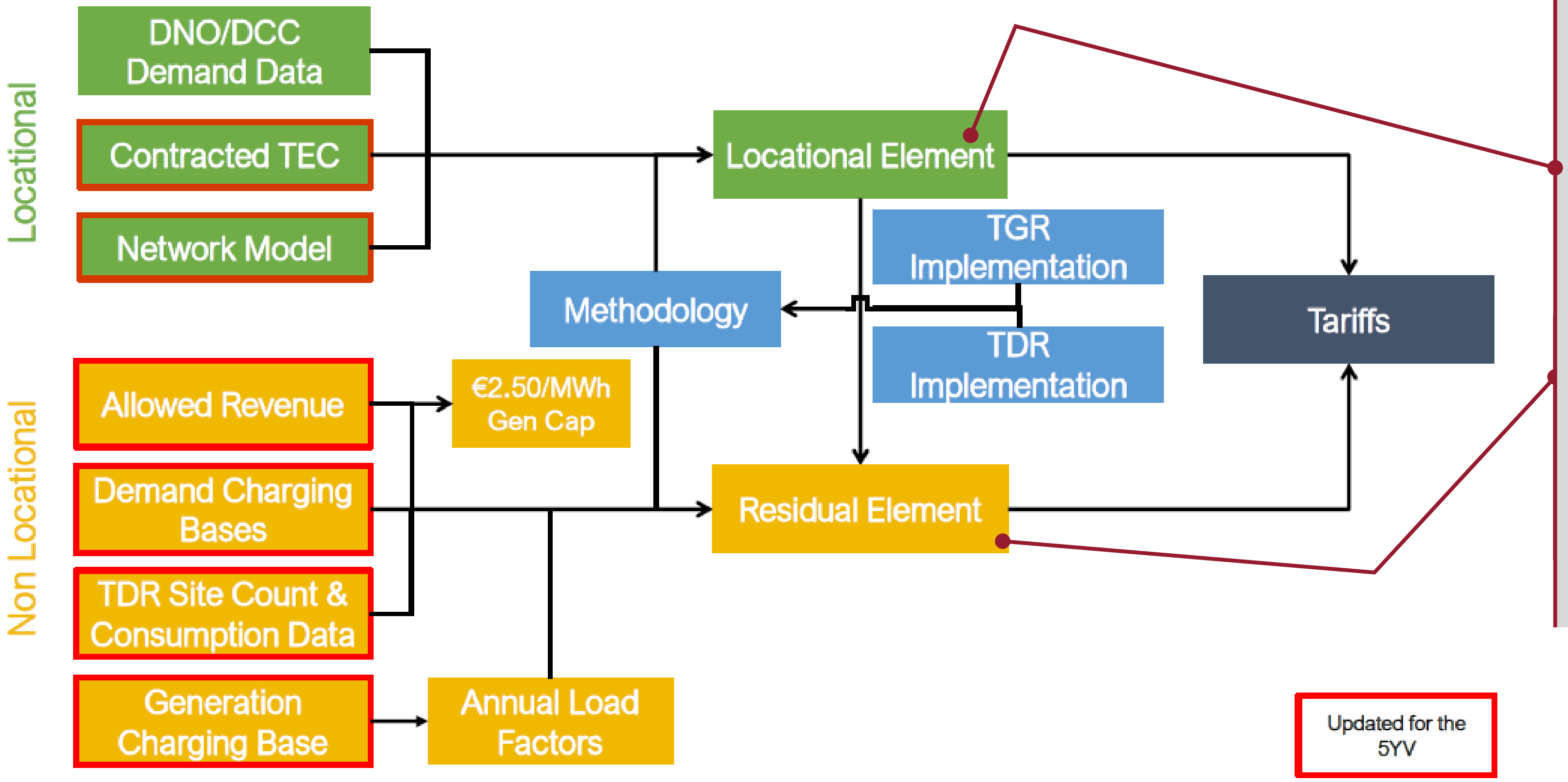
Effect of risk margin “y”

- What is the effect of the G/D split risk margin on volatility?

Agenda

Inputs to TNUoS tariffs

ESO sets TNUoS tariffs to achieve two distinct purposes. To reflect the incremental cost that generation and demand connecting at different locations impose on the network and to recover the total allowed revenues of the offshore and transmission owners.



- TNUoS charges are levied on a zonal basis and have a locational and a non-locational element.
  - The locational element reflects the long-run forward looking marginal cost of a change in generation or demand at a particular point on the network, levied on all generator and demand users
  - The non-locational element is recovered through the Transmission Demand Residual Tariff and ensures that the TOs can recover their total allowed revenue.

Source: NGESO, webinar slides (May 2023). Our scope is the wider generation tariff (i.e. locational and residual), but not the local tariffs for generation, local substation tariffs or circuit tariffs, embedded network system charges, or offshore local tariffs.

Data inputs identified in the CUSC

The CUSC describes a number of factors that affect the level of TNUoS charges from year to year, and which feed into tariffs directly and indirectly

ESO has identified the highlighted factors as being key drivers of recent charge setting volatility.

Factor	Description	Frequency of updates
Demand data	ACS nodal demand, **forecast system peak**	ACS Demand updated once a year (week 24 data). Tariff model peak demand updated four times a year (April, August, Draft and Final).
Generation	**Forecast TEC**, scenario nodal generation	Updated for the October TEC register once a year which is used for Draft (November) and Final (January) charge setting. ESO uses its own forecasts for Initial and August charge forecasts.
Other transport model inputs	Expansion constant, locational security factor	Fixed in absolute or real terms for the duration of the price control.
Allowed revenue	Mainly from TOs, inputted as a pass-through for the ESO	Four updates per year reflecting revised TO forecasts
Changes in the T network inc. demand and generation patterns	Circuits between nodes, route lengths	Updated annually based on the ETYS, and in
ALF	Annual output/(TEC*8760)	Updated annually based on 5 years of data
TDR sites	Site counts for each of the 22 charging bands	Updated at least annually.

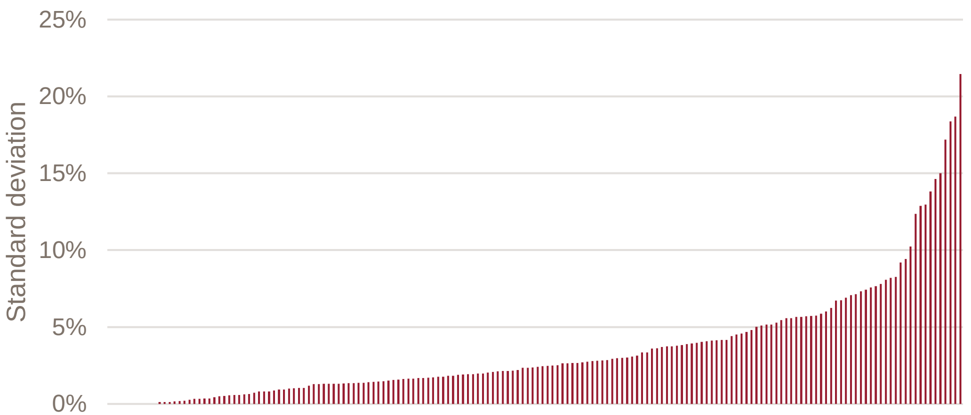
** Generally, the number moving of sites between bands should be low. However, in the last two years there have been a number of movements of sites between bands as sites have declared as non-final demand and undergone charging band interventions, the ESO expects* the number of sites to stabilise going forward.

Agenda

Overall, the volatility of definitive ALFs has been low, and its impact on wider tariffs is quite limited

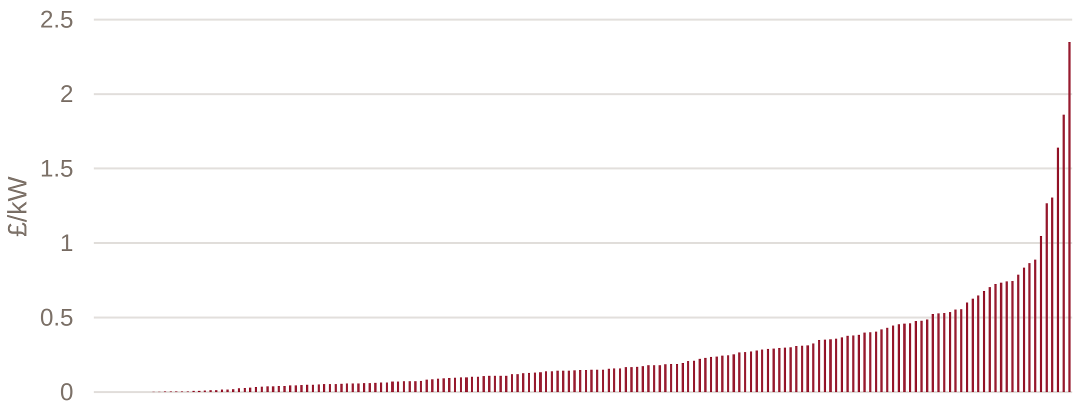
Volatility – Standard deviation of ALFs

- We have compiled the definitive ALFs of the current units for the period 2016/17 to 2023/24.
- The average standard deviation is 4% and the average ALF is 38%.
- Units with higher standard deviation (>15%) are: DUNGENESS B (Nuclear), LYNEMOUTH (Biomass), RATCLIFFE-ON-SOAR (Coal), USKMOUTH (Coal) and WEST BURTON (Coal).
- We observe that the average year-on-year difference between ALFs is slightly higher for the first year when the plant is commissioned (3.6% vs 2.6%).



Sensitivity - Standard deviation of wider generation tariffs (*ceteris paribus*)

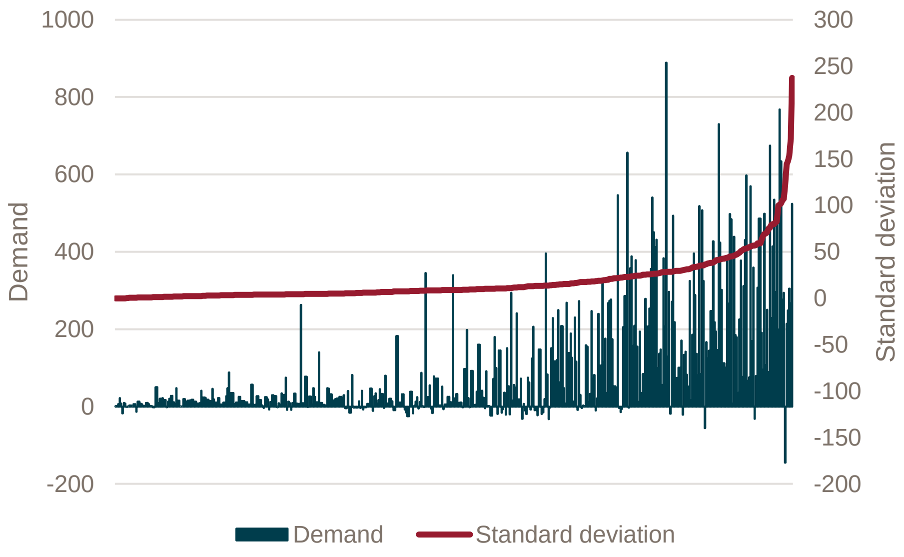
- We have applied the definitive annual ALF of each unit according to each zone assuming the 2023/24 generation wider tariffs (ceteris paribus analysis).
- Then we calculate the standard deviation of the resulting wider tariff for each unit during the period 2016/17 to 2023/24.
- The average standard deviation is at £0.3/kW, while the average generation wider tariff is at £8.9/kW.
- Units with higher standard deviation (> £0.1/kW) are: CORRIEGARTH (Onshore Wind), DORENELL (Onshore Wind), DUNMAGLASS (Onshore Wind), LYNEMOUTH (Biomass), PETERHEAD (CCGT_CHP), USKMOUTH (Coal).



Week 24 data has been volatile in the last years, with the standard deviation representing ~65% of the average demand on each node

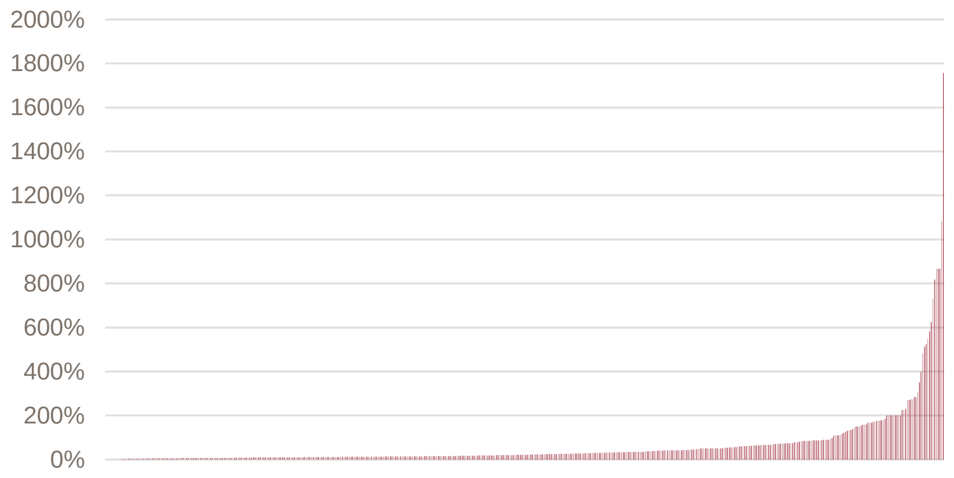
Volatility - Standard deviation of Week 24 data

- We have compiled the Week 24 data of the current nodes for the period 2019/20 to 2023/24.
- The average standard deviation is at ~18MW (we exclude the nodes with 0 demand).
- The following charts show the standard deviation and the average demand for each node.

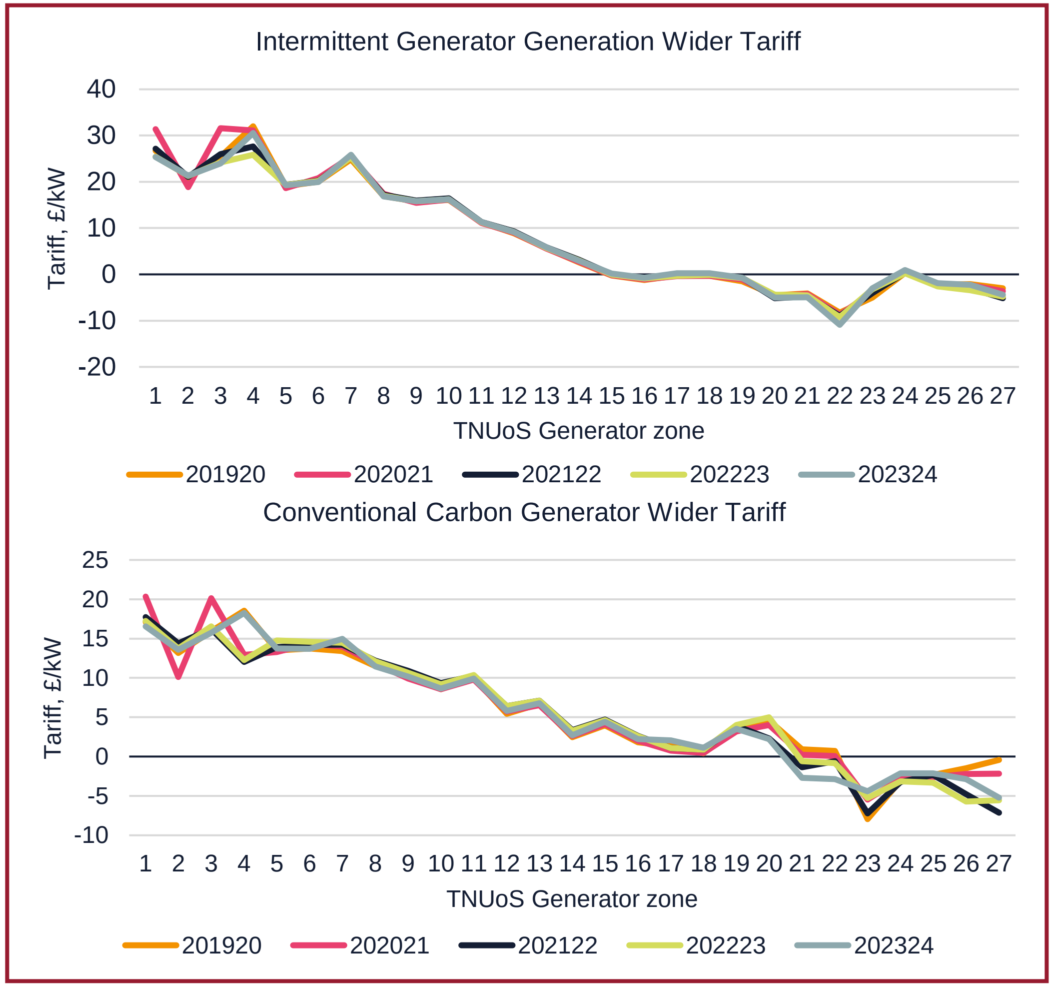


Volatility - Standard deviation as a % of average demand of Week 24 data

- We have calculated how much the standard deviation represents out of the average demand on each node.
- We can observe that the standard deviation sits at 65%, on average, out of the average demand for each node.
  - The following nodes are above 300%: LYND1Q, BERB20, FAUG10, EKIS20, NETS10, CAIN20, WIBA20, DRAX40, GLRO20, CEAN1Q, DALM10, MACD10, CUMB1R, CUMB1Q, CLAC1Q, TARL1Q.



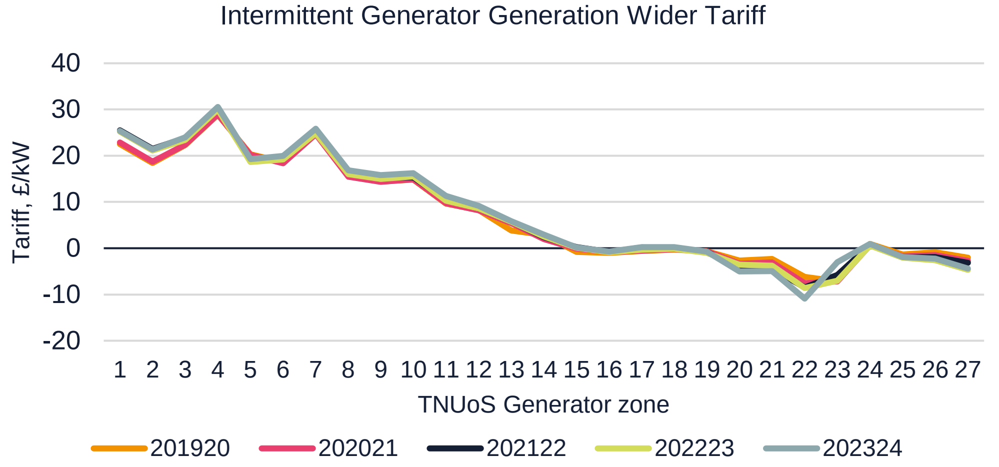
Changing the Week 24 data only has a significant impact on tariffs at the extremities of the network, by changing tagging and sharing

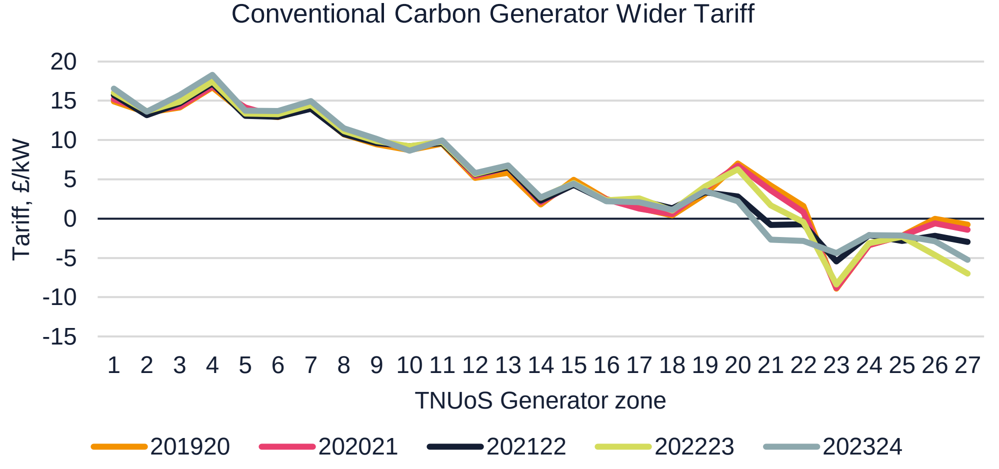


Volatility from Week 24 data

- To show the impact of Week 24 data on volatility, we have transformed the Week 24 data from the T&T models for each charging year between 2019/20 and 2022/23 so that they can be used in the 2023/24 charging model.
- The charts show the results from the 2023/24 T&T model using the Week 24 data from charging years 2019/20 to 2023/24.
- The impact of changing the Week 24 data is largest at the “ends” of the network – in North Scotland and South England.
- Changes in circuit tagging drive changes in this analysis. i.e. when the background which causes highest flow on a circuit changes.
- For circuits in the Midlands, the maximum flow is dependent on the distribution of demand and generation over a large number of nodes both North and South of the circuit. This means that they are relatively unaffected by changes in Week 24 data and their tagging is unlikely to change.
- Meanwhile, the tagging for circuits at the “ends” of the network will change more readily with changes in nodal demand. The tagging of these circuits then has most impact on tariffs in their own zone and those nearby.

Plant mix is a key driver of volatility in peak tariffs in Southern England, with a smaller impact through sharing factors in other zones

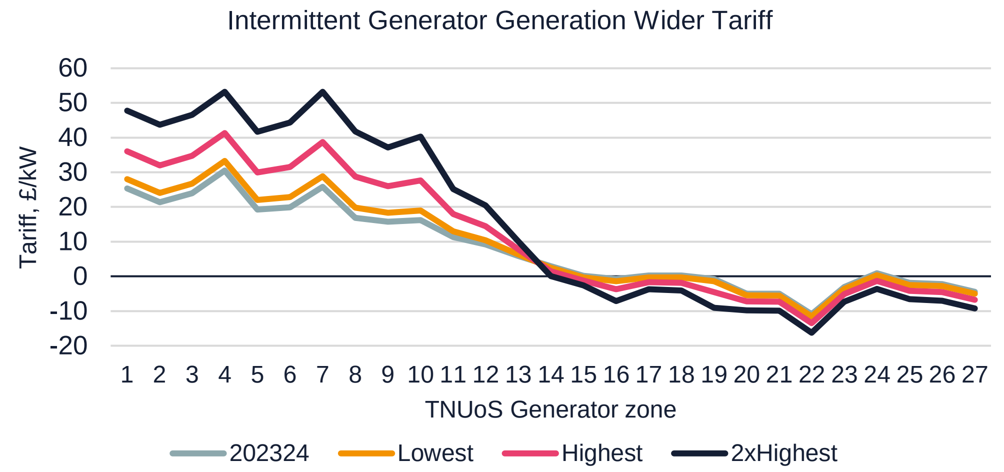


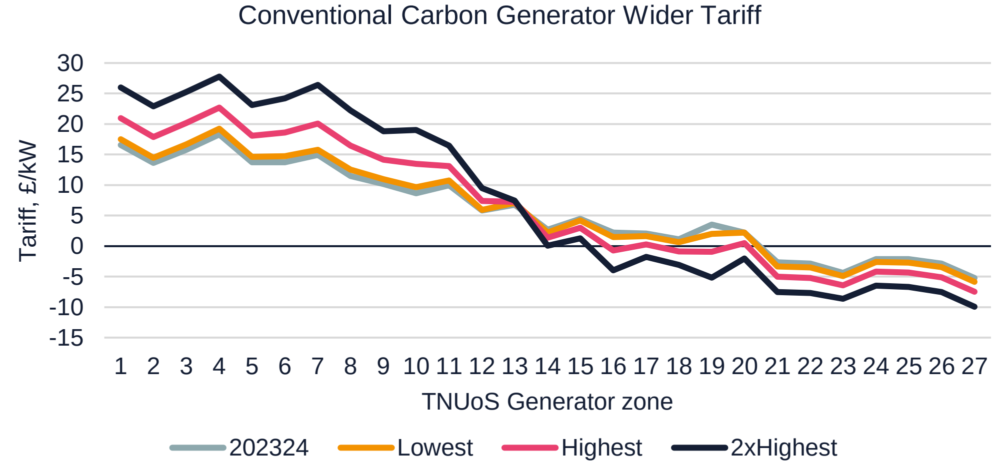


Volatility from the plant mix

- To show the impact of changing the plant mix on volatility, we have taken a similar approach as for Week 24 data, applying the plant mix of each charging year to the 2023/24 T&T model.
- As for the Week 24 data, the charts show that the impact of changing the plant mix is largest at the "ends" of the network – in North Scotland and South England.
- For Scottish zones, the main driver of the changes is the change in the sharing factors. Higher levels of renewable deployment result in less sharing and higher tariffs for intermittent generators.
- In Southern zones, the changes are also driven by changes in how the circuits are tagged between the peak and year-round backgrounds, which leads to substantial volatility for conventional carbon generators in those zones.

The cost of large network reinforcements is a significant driver of charge volatility and is not easily predicted

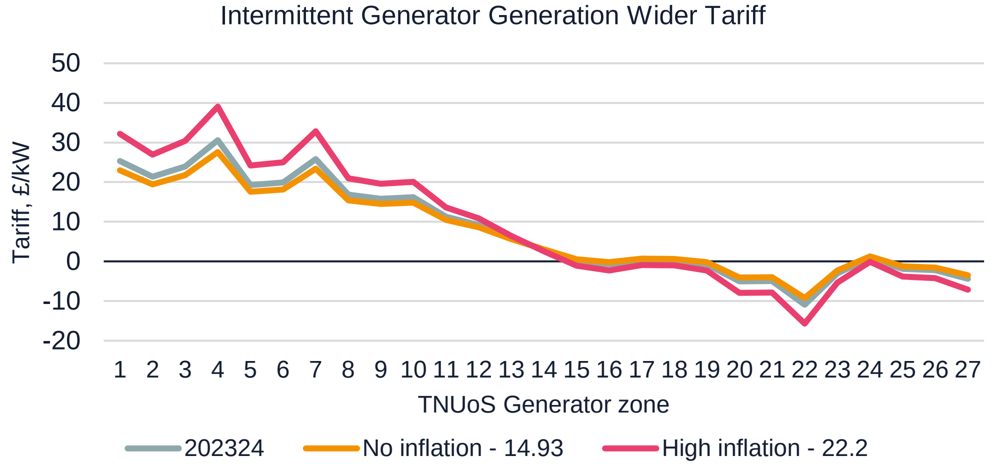


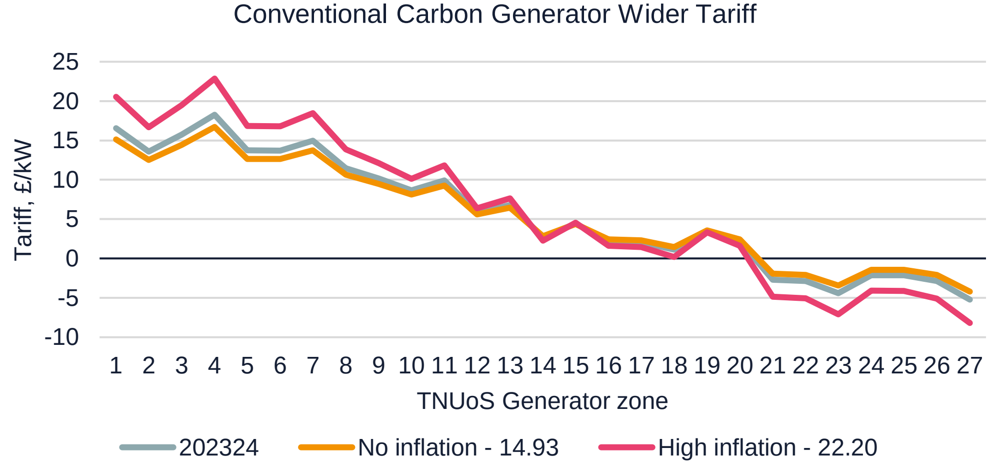


Volatility from network assumptions

- To test the impact of network assumptions on volatility, we have considered the impact of adding a new HVDC bootstrap between Peterhead and Drax with a rating of 2GW in the 2023/24 T&T model.
- These assets have their own specific expansion factors, reflecting the cost of those particular investments. However, the exact values are not known until these circuits enter the model due to commercial sensitivity.
- For existing HVDC assets already in the T&T model, we have a low (4.66) and a high (14.69) expansion factor which provides an indicative range.
- We have tested the impact on tariffs of adding the new HVDC bootstrap at the low and high expansion factor, as well as at twice the high expansion factor.
- Using the low expansion factor has a relatively small impact on tariffs, indicating that this is a good estimate of the average cost of the alternative onshore reinforcement between Peterhead and Drax.
- However, the higher values show that single reinforcements with high expansion factors could be a significant source of volatility in the strength of the locational signal sent by TNUoS charges.

Inflation of the expansion constant under CMP353 creates volatility, but is easily understood. Other inflationary impacts may be more volatile and less predictable.





Volatility from inflation

- Under CMP353, the expansion factor was fixed at the RIIO-T1 level and has risen with CPI inflation through RIIO-T2. We have considered the impact of inflation by calculating charges in 2023/24 if:
  - There had been no inflation during RIIO-T2
  - If inflation had been high throughout this period (2021-23 levels)
- The expansion constant has a directly proportional impact on the peak, year-round shared and year-round non-shared tariffs. This is offset by the adjustment tariff (when the tariff cap is breached), because the generator tariff cap does not rise with inflation.
- Therefore, while inflation of the expansion constant does lead to volatility, its impact is relatively predictable.
- However, the cost of network reinforcement may not rise in line with CPI inflation. When the expansion constant and expansion factors are reviewed, they may change significantly and the impact is likely more volatile and less predictable (as the cost of individual reinforcements is not public knowledge).

Agenda

The ESO passes through the MAR from TOs into its transmission network charges

TO allowed revenue is a pass-through item in ESO's calculation of TNUoS residual charges

ESO special licence condition list the formula for the maximum revenue to be recovered by the ESO

$$TO_t = PT_t + DIS_t + TS_t + NICF_t + SIFF_t + LAR_t + ADJ_t + K_t$$

PT_t is the allowed pass-through term and allows costs to be passed on to users and is defined by a further formula

$$PT_t = LF_t + ITC_t + Term_t + \underbrace{TSP_t + TSH_t + TNGET_t}_{} + TOFTO_t + OFET_t + TICF_t + TICP_t + BD_t$$

The relevant terms of TO revenue that affect the TNUoS residual charges include the amounts notified to the ESO by each of the onshore TOs (offshore TO revenue does not form part of the TNUoS wider tariff).

These three terms also account for around ¾ of total TNUoS collections.

TO MAR updates appears to be a key driver of TNUoS residual charge volatility

This is despite factors in the RIIO framework that partially smooth the impact of totex changes

RIIO uncertainty mechanisms (e.g. ASTI) drive considerable volatility in TO MAR

- TNUoS tariffs are calculated annually with final tariffs for the financial year published by the end of the preceding January.
  - Tariffs can in theory be updated part way through a financial year (called effective tariffs).
    - The last time this happened was 2010/11
- Updates in the TOs MAR forecasts appear to be key driver of changes in charges from year to year
  - ASTI and LOTI* projects that imply significant changes to totex (at least £100m each) are not included in any TO forecast until Ofgem approves the projects.
    - In RIIO-ET2 Ofgem applies the ASTI framework to 26 onshore projects worth round £20bn in network investment
  - Large changes in totex imply significant changes in MAR.
    - This is even after the effect is partially mitigated by the RIIO framework

Fast Money & Slow Money

- The majority (around 80%) of any change in TO totex is capitalised and added to the RAV
  - Thus, around 80% of the impact of a change in totex is spread out over 23-45 years
  - Only around 20% is allowed as fast money, impacting charges fully in the next tariff year

*Large Onshore Transmission Investment (LOTI) and Accelerated Strategic Transmission Investment

ESO's maximum revenue, as per its special license conditions, includes terms that correct for over/under recovery of revenues in previous years

The key terms are the "k" factor and the "ADJ" term

ESO's k factor

$$K_t = (TO_{t\text{-}1}\text{-}TNR_{t\text{-}1})(1+I_{t\text{-}1}+1.15\%+PRP_{t\text{-}1}PRA_{t\text{-}1})$$

- K_t has been set to zero in the ESO's special licence conditions 1 April 2022.
  - Effectively this has moved to the Transmission Owner's special license conditions (see next slide)

ESO's ADJ term

The DISC term effectively excludes the ADJ terms relating to passthrough items (e.g. TO revenue) from being double counted in the ESO's ADJ term.

$$ADJ_t = (TO_{t-1} - TO^*_{t\text{-}1} - DISC_{t\text{-}1})(1 + I_{t-1} + 1.15\%)$$

- The ADJ_t term for the ESO corrects for differences between the revenue targeted by the ESO in the previous tariff year and the revenue that, with the benefit of hindsight, ESO should have targeted for the year.
- However, we understand that this term is typically small (only £8m in 23/24 tariffs) because it only relates to differences in revenue in respect of non-passthrough elements while the vast majority of revenue collected by ESO is related to pass through items (e.g. Transmission Owner revenue).

The correction terms in ESO's license conditions are not significant drivers of volatility in elements of the wider TNUoS

*The 1.15% is set by Ofgem as an additive to SONIA (I_t) and is fixed for the whole price control.

TO's maximum revenue, as per its special license conditions, also include "k" and "ADJ" terms

These correction factor terms have been significant drivers of volatility in TNUoS residual charges

TOs' k factor – corrects for differences between target revenue and revenue received

$$K_t = (AR_{t-1} - RR_{t-1})(1 + I_{t-1} + 1.15\%)$$

AR_t is the allowed TO revenue and RR_t is the recovered revenue from transmission network services. *I_t* is the average value of SONIA to proxy the risk-free interest rate

- Actual revenue passed through to the TOs' varies from the target TO revenue. This is because TNUoS tariffs are fixed in January ahead of the regulatory year but then volume drivers (e.g. customer numbers in bands) vary relative to forecasts values.
- TOs' k factor adjusts tariffs for the future year to true up for observed variation in revenues recovered vs target revenue recovery.

TOs' ADJ term – corrects for, in hindsight, errors in target revenue

$$ADJ_t = (ADJR_{t-1} - ADJR^*_{t-1})(1 + TVM_{t-1})$$

Where the ADJR is the adjusted revenue term and the ADJR is the most recently published term by the Authority prior to the start of the regulatory year. TVM is the time value of money*

- TOs must provide ESO with target revenue values for the regulatory year ahead of final tariff setting in January each year.
- Revenue targets are based on TO forecasts of key parameters that affect TO MAR. This includes forecasts of:
  - totex spend, inflation, and tax policy.

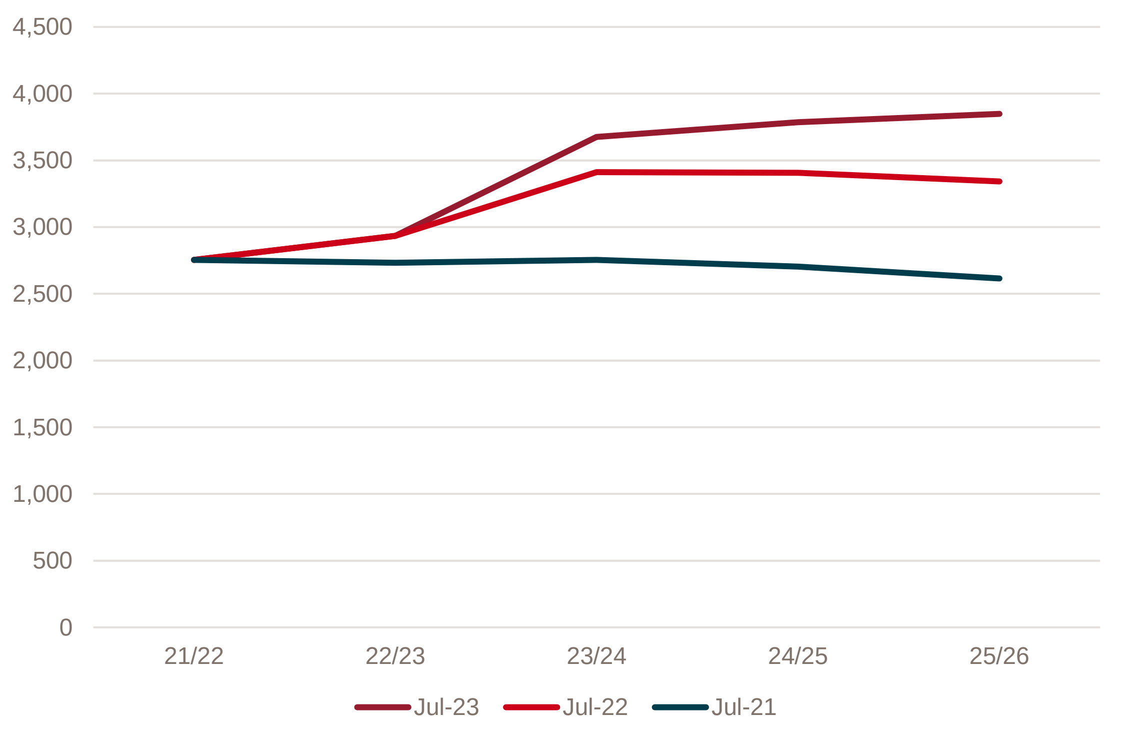
The ADJ term means that when there are changes that affect TO MAR for current years as well as future years, the effect on year to year changes in TNUoS charges for the next year can double up.

- If a factor means that TO MAR needs to increase by £10m per year this will:
  - Directly increase TO MAR next year by £10m
  - Indirectly increase TO MAR next year by a further £10m via the ADJ term to account for the fact that, in hindsight, the TO MAR forecast was too low for the current tariff year

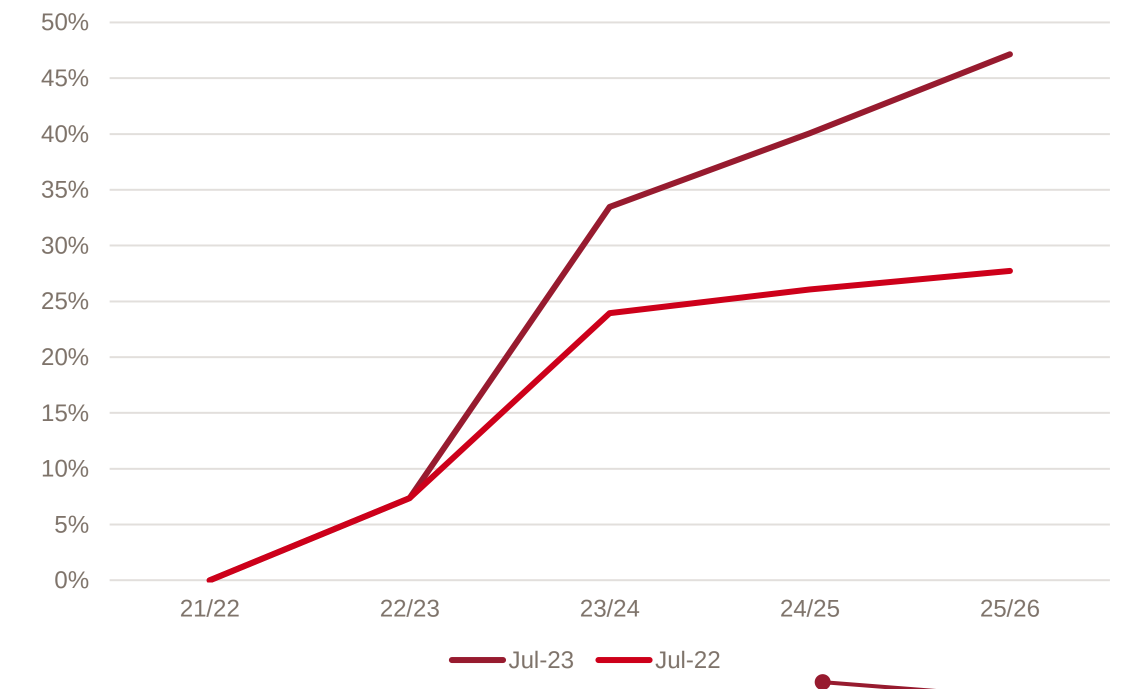
TO's maximum revenue – year to year

The net effect of changes in totex, adj and k can be seen in the changes observed in TO allowed revenue over time. The net effect is substantial over time

Allowed TO Revenue – forecast by PCFM date (£m)



% change in TO allowed revenue relative to July 2021 forecast



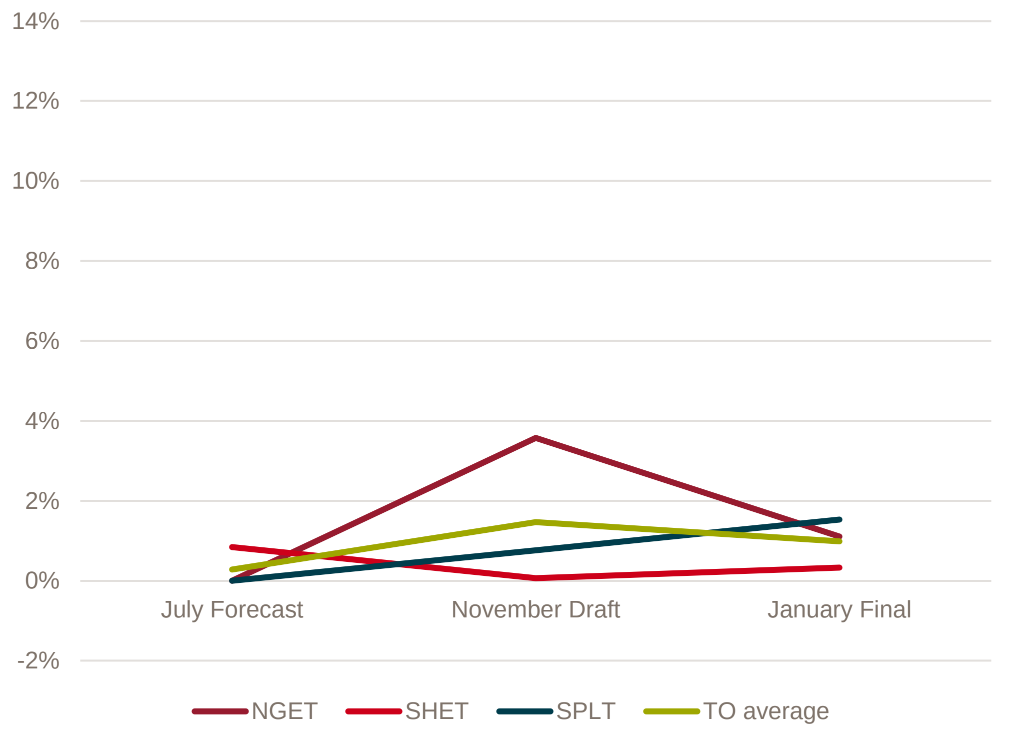
The PCFM is updated regularly. The percentage changes show the difference in forecast value for each year with the base value as the forecast from July 2021

Source – PCFM as published by Ofgem : https://www.ofgem.gov.uk/publications/et2-price-control-financial-model

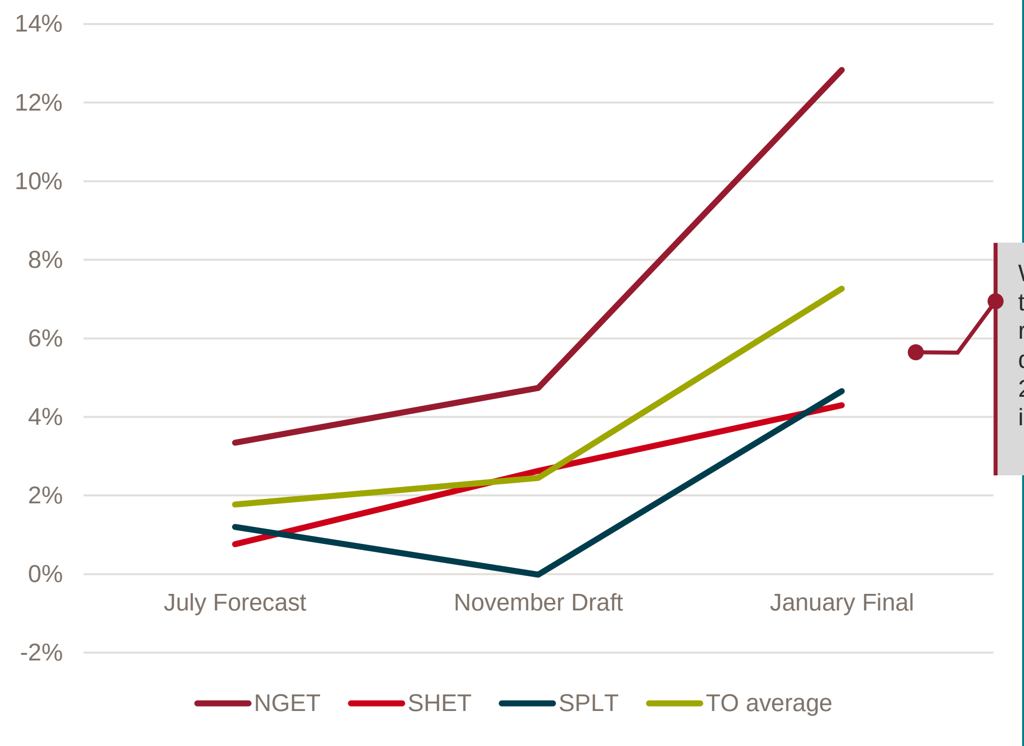
TO's maximum revenue – within year

Forecast TO revenue is less volatile between forecasts within year than between year but large changes are still possible

Variation in TO Allowed revenue from initial forecast for 2022/23 charging year



Variation in TO Allowed revenue from initial forecast for 2023/24 charging year



We have graphed the only two most recent years of full data as data for 2024/25 was incomplete

- In 23/24 TO MAR increased by 7% from initial forecasts in April 2022 to final charge setting in January 2023
- We understand that a significant share of this increase was driven by revisions to inflation estimates in a period of high inflation

Source – PCFM as published by Ofgem : https://www.ofgem.gov.uk/publications/et2-price-control-financial-model

Impact of TCR (CMP343) on forecast accuracy and hence the K factor

TCR changed the basis on which residual charges are levied on customers, but it is too early to conclude whether the K factor would necessarily be reduced as a result

TCR changed basis on which costs are recovered, and therefore changed the forecasts ESO needed to make…

…expectation is that forecasts required for TCR should be more stable/accurate

Pre-TCR

- Residual charges recovered based on consumption during peak (Triad) demand
- Therefore, **accurate charge setting required an accurate forecast of peak demand**

Post-TCR

- Revenue to be recovered from each of the 22 bands (based on expected total consumption in band) / number of sites in band
- Therefore, **accurate charges require accurate forecast of the number of sites**

[Note: Errors in the allocation of revenue to different bands does not drive under or over recovery, but it may raise a fairness question]

Assessing uncertainty

- Uncertainty in the number of sites in each band is driven by:
  - New sites connecting; or
  - Existing sites closing or moving between bands.
- Moving bands, has been a source of some changes as the new arrangements have bedded in, but not expected to be a significant driver of uncertainty in future.
- However, in general the expectation is that forecasting site counts (i.e. new connections and closures) should be relatively easier than forecasting total peak demand.

- ESO agrees with this expectation, but does not have the data yet to confirm either way, it is too early to say if this will reduce "k"

Agenda

The G/D split methodology is designed to ensure that TNUoS tariffs comply with regulation that limits average generation charges to €0–2.50/MWh

An 'Adjustment tariff', incorporating a risk margin, is used to ensure that the revenue recovered from generation falls within this range

The Adjustment revenue is calculated according to the below formula:

$$AdjRevenue = (GO * ((CapEC * (1 - y)) * ER)) - GCharge(Forecast)$$

Where:

- *CapEC* is the €2.50/MWh limit
- *y* is the error margin to adjust capEC.
- *GO* is the forecast generation output into the transmission network for the financial year t
- *ER* is the forecast £ to € exchange rate, taken from the latest OBR forecast published prior to the 31st October in *t-1*
- *GCharge(forecast)* – is the total forecast TNUoS revenue to be recovered from generators (minus charges for physical assets required for connection).

The error margin “y” is applied to the Adjustment Tariff to reflect expected revenue and output forecasting accuracy

This error margin is expressed as a percentage value. It compares the revenue forecast deviation and the total energy forecast deviation

$$y = (1 + \text{ErrorGenRev}) / (1 - \text{ErrorGO}) - 1$$

- *ErrorGenRev”* is the highest absolute % error in generation revenue collection, minus the average percentage error in generation revenue collection for the past 5 full years
- *Error GO”* is the highest absolute percentage error in generation TWh outputs from the past 5 full years (year 6 to 2 inclusive).

Table 24 Generation revenue error margin calculation

Calculation for	2024/25		
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2017/18	-5.2%	2.4%	-1.5%
2018/19	-9.2%	-1.6%	-7.5%
2019/20	-14.6%	-7.1%	-4.1%
2020/21	-13.2%	-5.6%	7.5%
2021/22	4.3%	11.9%	9.5%
Systemic error:	-7.6%		
Adjusted error:		11.9%	9.5%
Error margin =			23.6%

Adjusted variance = the revenue variance - systemic error
Systemic error = the average of all the values in the series
Adjusted error = the maximum of the (absolute) values in the series

- The table shows the calculation for determining the error margin “y” as calculated in the ESO’s April forecast of tariffs for 2024/25.
- From 2018-19 to 2024-25* the calculated value of the risk margin has ranged from 14% through to 31.4%%.
- The impact on the revenue recovered from generation due to a change in the error margin has been simulated by ESO in its forecasts. In its forecast for the 2019/20-23/24 period the ESO calculated the impact of a fall in the error margin from 21% to 10%:
  - The result was between an additional £56m and £50m which could have been recovered from generator tariffs (reducing demand tariffs).
    - We update this analysis in the following slide.

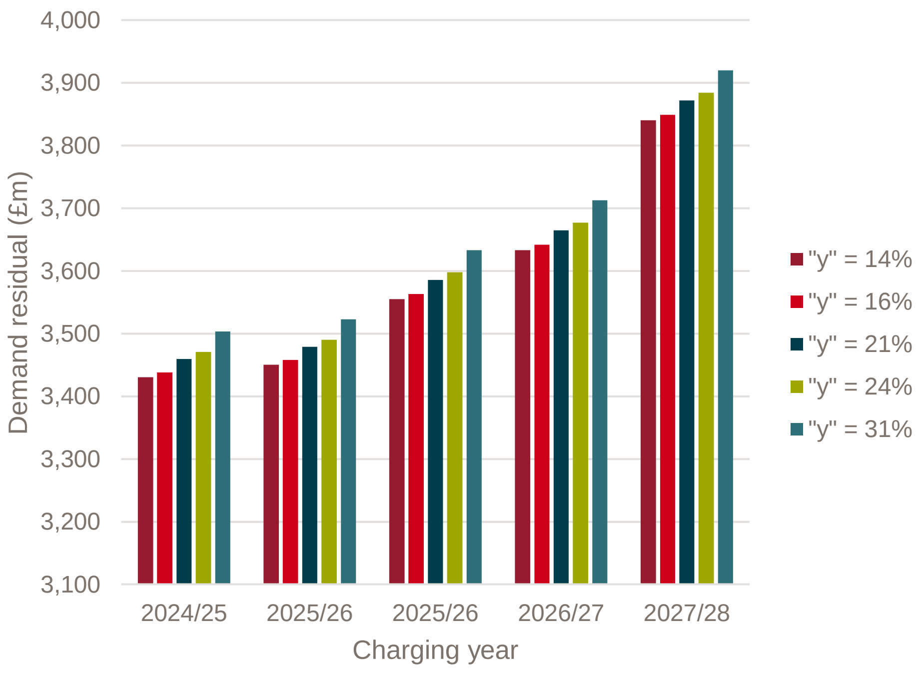
Source – ESO, Five Year View of TNUoS for 2024/25 to 2028/29 | April 2023

** The November Draft charges for 2024/25 have an error margin of 31.4%*

Variation in the error margin leads to a variation in generation and demand charges, with greater proportional impacts on generation charges

Sensitivity analysis using the ESO's charge forecasts but varying the "y" term within the bounds observed since 2018/19 illustrates the impact of the "y" term.

Demand residual for different values of "y"



Impact of variation in "y"

- Based on ESO's April 2023 forecast of 24% for the error term, the demand residual is around £3.5 bn to £3.8 bn over the period 2024/25-2027/28.
- In July ESO's forecast of the "y" term changed from 24% to 31%.
  - This increased the demand residual for 2024/25 by £30m
    - A 1% increase in the demand residual and a 7% decrease in revenue recovered from wider generation charges
- Considering the full range of observed "y" terms since 2018/19 (14%-31%) gives a broader range of possible impacts on charges

% variation in charges implied by range of observed "y"	24/25	25/26	26/27	27/28	28/29
demand residual	2%	2%	2%	2%	2%
wider generation charges	17%	15%	12%	9%	8%

Agenda

Conclusions

Locational volatility

- ALF is not a major contributor to locational charge volatility
- W24 data is highly volatile but only has significant impact on locational tariffs at network extremities
- Plant mix also drives volatility in locational charges at the network's extremities
- Inflation drives volatility in locational tariffs via the EC but this may be easier to forecast than other network charging parameters
- The cost of large reinforcements are hard to predict and are a significant driver of locational charge volatility

- Parameters that drive locational charge volatility could be fixed for longer periods of time.
- However, this would risk reducing the cost reflectivity of locational charges.

Residual volatility

- Variations in TO MAR are a significant driver of residual charge volatility
  - This is inherent in the RIIO-ET2 framework (ASTI projects)
- K and ADJ terms can also cause near term volatility in network charges
  - Combine with fixing tariffs for a year in advance, the ADJ term can emphasise swings in residual charges
- CMP343 is expected to reduce the impact of the k factor on charge volatility
  - However, this has yet to be demonstrated empirically

- Given the RIIO-ET2 framework, there is inherent volatility in residual revenue requirements that cannot be eliminated but need to be allocated
- The current charging rules allocate this cashflow risk to consumers/suppliers
- Elements of this risk could in principle be reallocated to the SO/TOs by fixing charges for longer or fixing some parameters for charge setting purposes for longer

G/D split risk margin

- The methodology of updating the "y" term to reflect changes in forecasting confidence for revenue and generation output introduces the potential for additional volatility in demand residual and wider generation tariffs

- The "y" term could be fixed (hence fixing a target €/MWh value below €2.5/MWh) instead of being variable. However:
  - If "y" is fixed too low this would increase the risk that the limiting regulation is breached and retrospective tariff adjustments are required; or
  - If "y" is fixed too high this would increase the share of TNUoS paid for by demand.

Next Steps and Close

Jamie Webb

AOB

- TCMF rota

Date	TF Rep
02/11/2023	John Tindal
23/11/2023	Binoy Dharsi
04/01/2024	No update
01/02/2024	
29/02/2024	Grace March
04/04/2024	

- Charging Futures updates
- Subgroup closure report

Charging Futures
Reforming electricity charging together

Thank you