Charging Futures

Reforming electricity charging together

# TNUoS Task Force

## Meeting 8

15th September 2023

# Agenda

**10:30 – 11:45**

- 10:30 Introduction & Welcome
- 10:35 Action Review
- 10:45 OpTIC Model: Overview & Feedback
- *11:45 Break*

**12:00 – 13:00**

- 12.00 OpTIC Model: Feedback & Further Discussion
- 12:30 Consultancy Support: Further Considerations & Analysis
- *13:00 Lunch*

**14:00 – 15:00**

- 14.00 Backgrounds Case for Change: Overview
- 14.30 Backgrounds Case for Change: Feedback & Further Discussion
- *15:00 Break*

**15:15 – 16:30**

- 15.15 Signals Workstream: Initial Thinking
- 15.45 Absolute vs Relative Workstream: Initial Thinking
- 16.15 Next Steps & Close



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# Action Review

## Jamie Webb

# Actions from Meeting 7.5

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 1<br><br>18/08 | 2 | Backgrounds Case for Change to be shared with the Task Force for review and comment | JS | | Mtg 8 | Open |
| 2<br><br>18/08 | 2 | Consider using initial workstream proposals as alternative format for information to stimulate stakeholder feedback. | Task Force | Discuss in Next Steps of Mtg 8 based on what's shared | Mtg 8-10 | Open |
| 3<br><br>18/08 | 4 | Ownership and timings defined for the OTNR Sub-Group closure report | JS | Closure Report to be shared with TF once complete (NP @ESO) | October | Open |



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# Actions from Meeting 7.5

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 5<br>18/08 | 7 | A one-page report for the Charging Futures website to summarise the reference node modification plans and individuals involved. | JS | To also reflect any further views not captured at TF meeting 7.5 and provided as part of action 4 above. | 15 Sept | Open |
| 6<br>18/08 | 7 | Draft modification proposal to be raised. | JT | | Mid-Oct<br>(JT to advise) | Open |
| 7<br>18/08 | 7 | BAU update to TCMF with ESO/Propose to agree who will present the Reference Node proposal to relevant TCMF. | JT, JS/CP | Topic to be added to TCMF Sept agenda for BAU update, Oct agenda to present mod | 31 Aug (TCMF 7 Sept for BAU update) | Open |
| 8<br>18/08 | 8 | Co-ordinate with project leads about deliverables ahead of Mtg 8 | JS | Check whether the Backgrounds workstream scope of work includes scaling as a consideration | 30 Aug | Open |

# Actions from Meeting 7.5

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 9<br>18/08 | 8 | Share draft 'negative scaling' modification proposal with the Task Force to review prior to submission | JS/MC | JT and Backgrounds workstream to link with this project for updates | Q4 2023 | Open |
| 10<br>18/08 | 9 | Review the current modification tracker for a version to feature in future Task Force meetings or shared for visibility. | JS, CP, DS, EB | An overview to alert workstreams of mods to consider | Mtg 8 | Open |



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# Open Actions from Meetings

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 1<br>27/07 | 3 | Consider whether updating the 'pseudo-CBA approach' to scaling factors is currently feasible with the data available and whether case for change should include the analysis from the consultants | JT | Consider as part of Backgrounds case for change | Mtg 8 | Open |
| 2<br>27/07 | 3 | Provide a viewpoint as to the extent to which scaling  factors currently mitigate volatility | Frontier/LCP | | Mtg 8 | Open |
| 3<br>27/07 | 3 | Consider whether backgrounds are complicating understanding of how charges work or a necessary element of the cost reflectivity of the model. | Task Force | | Mtg 8 | Open |
| 6<br>27/07 | 5 | Review past calculations for sharing to provide a recommendation for what work would be feasible now | Frontier/LCP | Information shared by SL 28 Jul | Mtg 8 | Open |
| 7<br>27/07 | 5 | Consideration of renewables in sharing (wind vs wind, treatment of solar). | Frontier/LCP | JS to assess information needed | Mtg 8 | Open |



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# Open Actions from Meetings

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 8<br>27/07 | 5 | Exploration of turning off sharing to see impacts on final charges and volatility | Frontier/LCP | | Mtg 8 | Open |
| 9<br>27/07 | 8 | Consider calculating using a 5 year average rather than current 5 year method | Frontier/LCP | | Mtg 8 | Open |
| 11<br>27/07 | 8 | Consider the information available to share with consultants & TF re: potential new ESO products and impacts on FPN, and possible new data input modification | JS | | TBC: updates can follow after final internal reviews of proposed products | Open |
| 12<br>27/07 | 8 | Absolute values to be shared for the impact of using FPN only on Year Round components of the tariff. | Frontier/LCP | Material impacts possible for different scales of plant | Mtg 8 | Open |
| 13<br>27/07 | 8 | Contact DNOs for information on key assumptions used in their Wk 24 forecasting. | JS, NW | | Mtg 8 | Open |



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# Open Actions from Meetings

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 14<br>27/07 | 8 | Consider aligning Week 24 data with the SQSS change and move to gross demand. | JZ | | Mtg 8 | Open |
| 15<br>27/07 | 8 | Contact TOs for a view on what data inputs could be more regularly updated (re: locational tariff calculations) with a material impact and their view on revenue being deferred for a year | JS, NW | Will form part of wider Data Inputs workstream and discussion | Ongoing | Open |
| 5<br>26/06 | 3-7 | Can indicative monetary values be provided for the impacts of the different backgrounds on differently-sized projects. | Frontier/LCP | | Mtg 6-10 | Open |
| 7<br>26/06 | 3-7 | Additional analysis shared on metrics used to compare volatility between actual and estimated charges. | Frontier/LCP | | TBC – Frontier need a steer on what is required | Open |



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# Open Actions from Meetings

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 10<br>26/06 | 3-7 | Bring together the Task Force representatives and the ESO SQSS Review team (when in a position to do so) to discuss potentially parallel/overlapping interests. | JS, SS to explore with BD | To feed into case for change if required | TBC | |
| 11<br>26/06 | 8-10 | Consultants are to explore the questions raised on zoning | Frontier/LCP | Considering what adding more zones would do to the existing Ref. Node work? Clarity needed around the definition for zones & differing from sharing factors. Frontier to provide additional note for pack? | Mtg 8 | |
| 12<br>26/06 | 8-10 | Revisit ESO work on embedded generation in relation to the transport model and share with the Task Force if relevant | JS & NW | To consider as part of distributed generation element work package | Ongoing | |



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# Open Actions from Meetings

| ID/ date | Agenda Item | Description | Owner | Notes | Target Date | Status |
|---|---|---|---|---|---|---|
| 14<br>26/06 | 12 | Task Force members are to engage industry colleagues and stakeholders and feed back at the next virtual meeting (incl. substantive effects on other work) | Task Force | TF decision on format and whether workstream proposals will serve this purpose | Ongoing | Open |
| 1<br>26/04 | 1 | Provide update on recruiting Non-Domestic user reps to Task Force | JS & NW | Discussions ongoing for a named rep. Non-Domestic Supplier forums updated by JS | Ongoing | Open |
| 8<br>26/04 | 7 | Further work on design vs cost reflectivity to be presented at Mtg 6 | JS & NW | Feedback from legal and SQSS to be shared by JS via feed into case for change relating to Backgrounds | Mtg 8 | Open |
| 10<br>26/04 | 7 | Investigate more granular data sources for DNO embedded distribution to support the methodology & analytics | JS | Need TF to identify the data needs before exploring sources (part of Distributed Generation work) | TBC | Open |



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# OpTIC Model: Overview & Feedback

## Joe Dunn & All

**The objective of this session is to provide:**

- An overview of ‘OpTIC’ - a potential alternative to the current Transmission Network Use of System (TNUoS) model.
- Opportunity for Task Force members to provide initial feedback & thoughts in relation to the potential change to the use of the OpTIC model.

# OpTIC

Optimised Transmission Investment Cost

## *Proposed Alternative Transmission Charging Methodology*

*SPR Grid & Regulation, SP Corporate Regulation*

September 2023

SCOTTISHPOWER

# Purpose and Contents

**To provide an overview of OpTIC as a potential alternative to the current TNUoS methodology and to receive feedback in relation to the use of the OpTIC model.**

Journey to Date

Proposal & Features

Methodology

Findings

# Journey to date

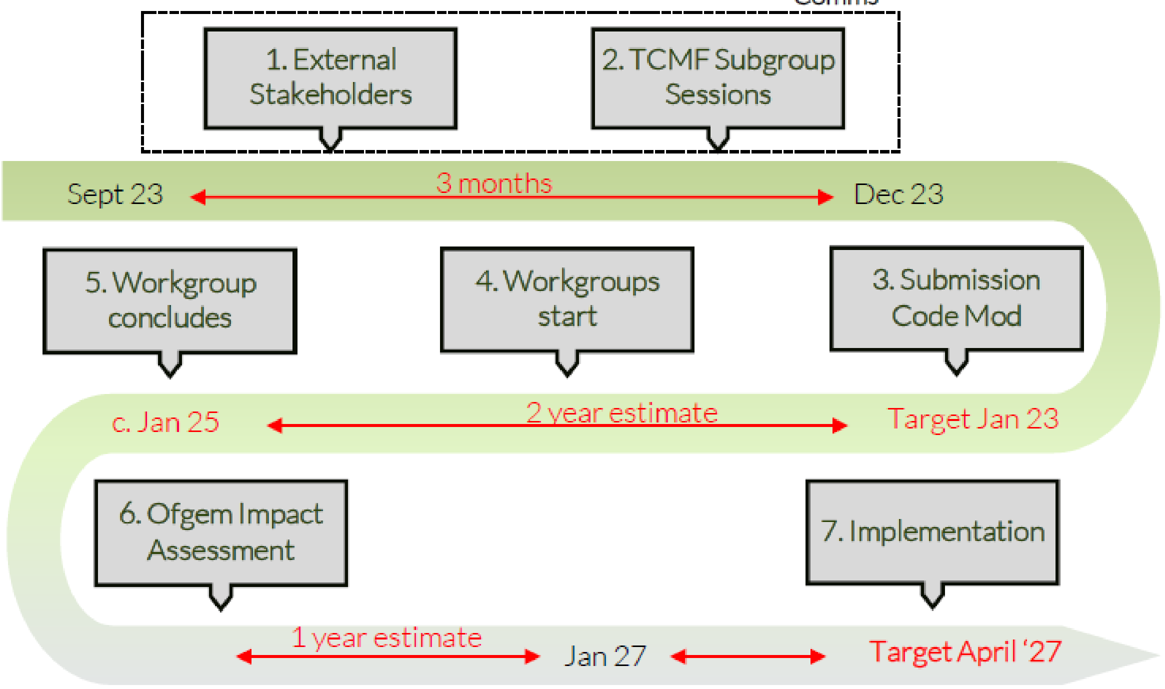
# Journey to Date

The transmission charging methodology requires reform to remain fit for the future net zero system.
Alternative developed to address the challenges faced by ICRP using modern economic modelling aligned with planned future network.

## SP's proposal journey

- In anticipation of the TNUoS Task Force *(prior to REMA/LMP publications)*, ScottishPower started exploring reform options and TNUoS alternatives to address volatility and cost reflectivity.
- Output from our work made it clear to us that the TNUoS challenges and defects called for improvement beyond small tweaks to the methodology.
- As a TNUoS alternative was being developed and socialised, REMA and LMP were being assessed by NGESO and Ofgem (FTI work).
- As SPR socialised OpTIC it became evident that reform required improvement to address the short-run signal also.
- OpTIC was designed to address the long-run marginal cost signal and to sit independently of other reform including LMP.
- SPR have since triggered a piece of work to sit alongside OpTIC to consider improvements to operational dispatch (BM Reform).

## Illustrative Route to implementation




**OpTIC only addresses the long-run locational signal. Other reform is required to address short-run operational dispatch inefficiencies.**

# Proposal & Features

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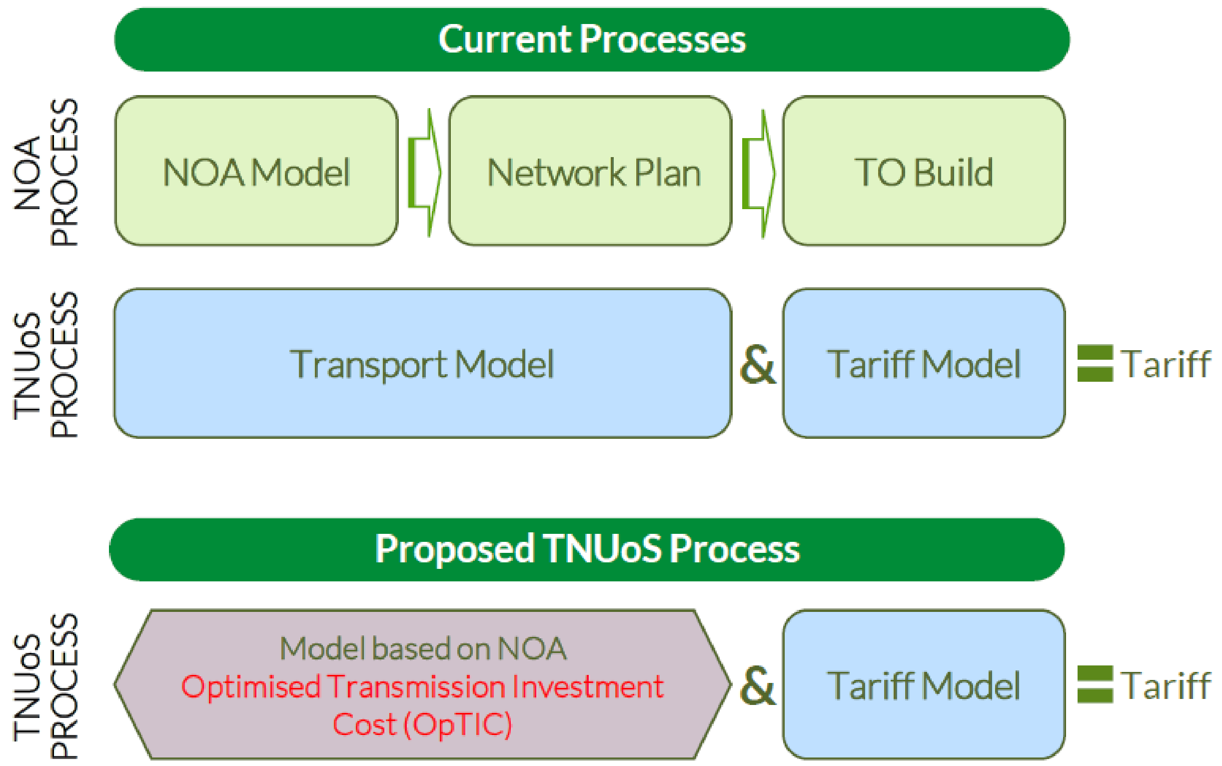
# Modification Proposal

Incremental changes over the past 20 years have not yet developed a methodology fit for a net zero future and the Transport and Tariff model has become increasingly complex.

## Modification Proposal

- The proposal will replace the 'transport' module in the T&T model, with an **economic optimisation model based on the NOA**. (OpTIC).
- OpTIC bases charges on the **optimised planned future network** and a **zonal system**.
- The solution establishes an appropriate signal (charge) to **reflect the locational value of electricity**, improving/removing existing defects in the TNUoS methodology.
- The methodology is not impacted by **delays or advancements** in grid reinforcement.
- The OpTIC methodology would offer the following:
    i. To continue with **national wholesale pricing**, and
    ii. **fixed annual zonal charges**.




**The OpTIC proposal realises the benefits of locational signals and provides a long run marginal cost associated with optimised planned future network investment.**

# Key features

The alternative charging methodology called OpTIC (Optimised Transmission Investment Cost), presents a viable alternative to TNUoS while replicating the potential siting benefits associated with LMP.

## Summary

- OpTIC incorporates the **changing pattern** of demand and generation which drives differences in electricity value by location and over time.
- OpTIC charges reflect how **locational values deviate from the national market price** in an optimised multi-year model of the GB system.
- Conceptually, the charge will be **long run based on the NOA**, which is understood to provide accuracy of forecast for up to 10 years.
- Locational values are calculated assuming **optimum network configuration**, i.e. not affected by delays or under-investment in network capacity.
- Trident Economics demonstrated that **PLEXOS** could be used to estimate an annual charge that provides equivalent long-run signals to LMP.

## Charging Objectives

The OpTIC solution addresses the objectives of charging:

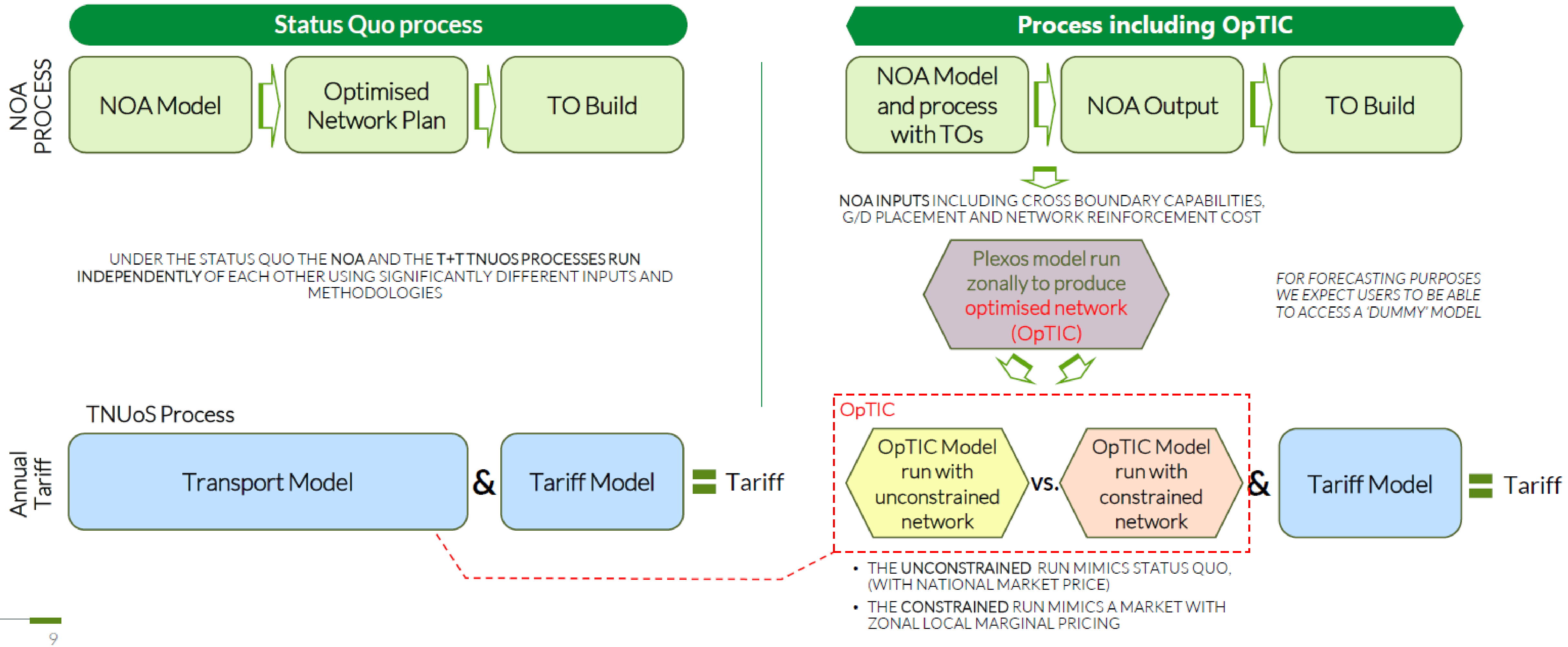
- **Reflects how the transmission system is actually built** – OpTIC charges reflect transmission system users' costs relating to how the network is planned.
- **Locational signal** – OpTIC gives an investment signal and therefore asset siting benefits by incorporating constrains costs.
- **Cost Reflective** – OpTIC charges reflect the long-run marginal cost and are therefore cost reflective for a future system.
- **Predictability & stability** –The charges will be stable unless there are large changes in demand and generation locations and/or network investment costs.
- **Transparency** – A version of the model can be made available to industry and used to forecast future transmission charges.

**Charges are based on an optimised planned future network meaning that users are not be exposed to delays to, or failure to deliver, transmission build, which they are unable to manage.**

# Methodology

# Approach: Status Quo TNUoS vs OpTIC

OpTIC seeks to amend TNUoS charging to reflect optimised planned future network aligned with the Network Options Assessment (NOA). The NOA is the ESO's economic recommendations for the future electricity system and therefore which network reinforcement projects should receive investment - and when.



# Calculation: OpTIC to Annual Tariff (£/kW)

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OpTIC Model run with unconstrained (UC) network

vs.

OpTIC Model run with constrained (C) network

UC (i) Hourly operating profile of relevant technology (generation/demand) *assuming not constrained off*, i.e. pre-BM

UC (ii) *National Market Price* on an hourly basis

C (i) Hourly operating profile of relevant technology (generation/ demand) in each zone assuming constraints, i.e. *post-BM (optimal dispatch)*

C (ii) *Zonal electricity price* on an hourly basis

Generator example

Estimated annual Revenue based on *national price*

$$\sum^{8760}\left[\text{UC (i)} \times \text{UC (ii)}\right] \div \text{TEC} = 1$$

Estimated annual revenue based on *zonal price*

$$\sum^{8760}\left[\text{C (i)} \times \text{C (ii)}\right] \div \text{TEC} = 2$$

$$\text{Annual Tariff* (£/kW)} = 1 - 2$$

*A Generator's Zonal OpTIC charge is determined by the difference between 1 and 2:*
*1. The sale of energy at national market price of electricity, and 2. A local (zonal) value of electricity based on an optimised network.*
*(Leaving the generator making revenue based on the local value of electricity in an optimised transmission system)*

**This can be applied to different generator and demand types*

# Demand– charging proposals to be considered

Proposals may change demand charging significantly relative to status quo – work required to progress potential approaches

**Demand charges**

The demand charge could work in a similar way to the generation charge.

- Domestic: charge set based on the demand profiles for the different types of domestic demand, charged on consumption.
- The move to Half Hourly (HH) settlement should be considered
- Non-domestic: charge set based on representative demand profiles, charged on consumption.
- The demand residual could remain charged as per TCR and recent modifications.
- Households with EVs, Economy 7, businesses with hydrogen electrolysers etc. could have different demand profiles and hence be charged differently.

**Negative charges**

- Initial thinking is for negative charging to be allowed in constrained areas to encourage demand such as hydrogen electrolysers to site to relieve constraints.
- On windy days, the price is likely to be negligible with a national market price and therefore the demand would also be encouraged to operate effectively.

**Charging base**

Current proposal would discontinue peak charging for the following reasons:

- Demand patterns are changing and peak demand is less predictable than it has been historically, can occur outside the triad window; and is likely to change further with electrification.
- Transmission system investment is increasingly being driven by factors other than peak demand.

**Approach should consider how different users are charged according to their impact on the network.**

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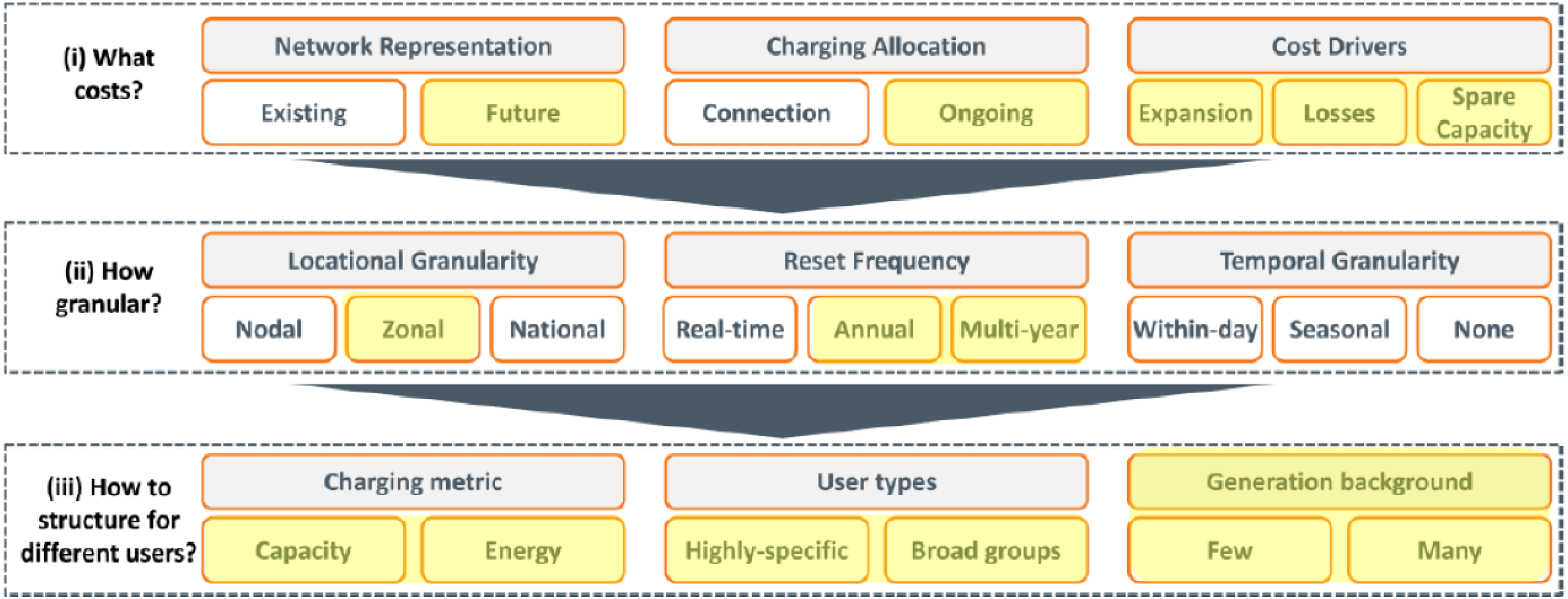
# Ofgem’s Design framework: transmission network charges*




**Considering where OpTIC sits against the design framework from Ofgem’s September ‘23 charging reform letter.**

*https://www.ofgem.gov.uk/publications/open-letter-strategic-transmission-charging-reform

# Findings

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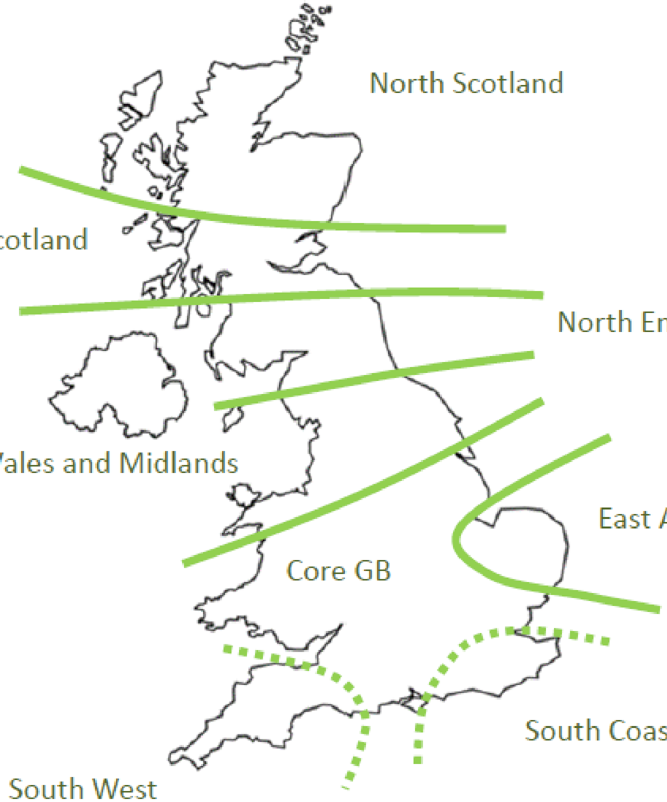
# GB Model Developed by Trident Economics using PLEXOS




## Approach

- Eight zones were defined based on major transmission system boundaries and locations of expected material low carbon generation expansion.
- Generation and load for each zone based on an average of the *Consumer Transformation and System Transformation scenario from the National Grid Future Energy Scenarios.*
- Future interconnector trade approximated by:
  - deriving hourly prices on key interconnected systems *(France for French and Belgian interconnectors, Germany for others)*
  - Allowing the GB optimisation to import or export based on those prices relative to the appropriate [zonal] GB price.
- Illustrative OpTIC charges were calculated. These showed price variation by region for different system users ie different generator and demand types.
- Assuming optimal transmission network, OpTIC and LMP charges are the same.

**The initial OpTIC findings present a less severe charging gradient between the North and South.**

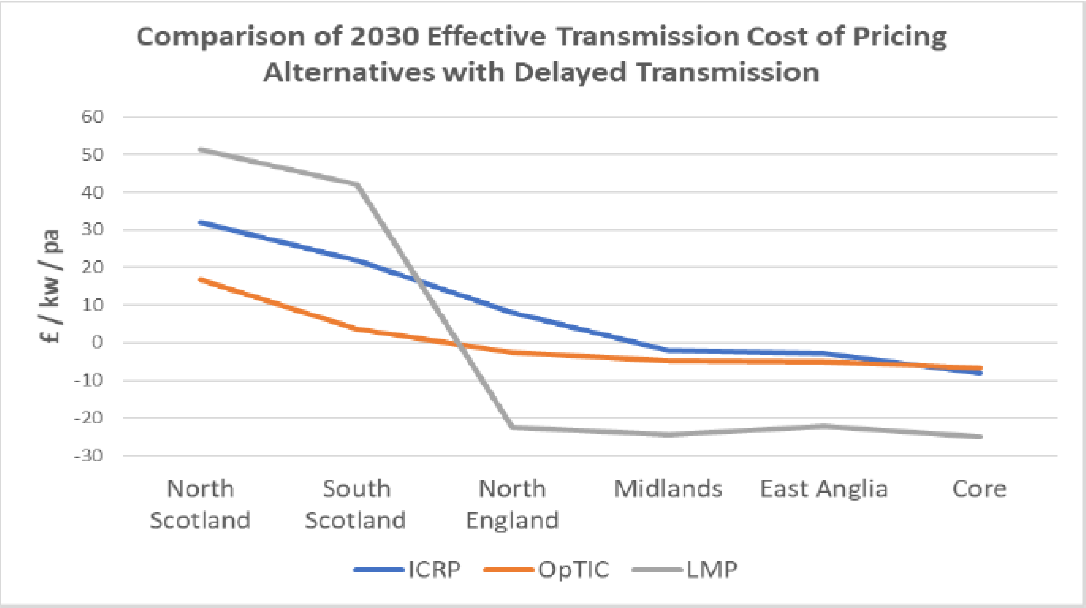
# OpTIC -Impact of transmission delay

Users have no control over transmission build, therefore charges should not be impacted by delayed or anticipatory investment.

## Delayed transmission network build

- Scenario run to show transmission build delay with capacity capped at 9GW behind the South Scotland to North England boundary with an optimised addition of 13.5GW.
- Delayed transmission expansion results in a reduction in revenue for Scottish offshore wind generators under LMP causing local prices to be depressed by the inability to export power south.

| **2030 Transmission Cost** *(with delayed transmission)* | | | |
|---|---|---|---|
| £/kW | ICRP (27/28) | OpTIC | LMP |
| **North Scotland** | +25 to +40 | 16.61 | 51.37 |
| **South Scotland** | +20 to +25 | 3.66 | 42.04 |
| **North England** | +2 to +15 | -2.70 | -22.49 |
| **Midlands** | -1 to -3 | -4.81 | -24.45 |
| **Core (inc south west & south coast)** | -5 to -12 | -6.66 | -25.05 |
| **East Anglia** | -3 | -4.98 | -22.31 |




*Results produced by Trident Economics*

**Results show impact of a delay comparing current ICRP, OpTIC and LMP (Optic and LMP £/kW charges derived as per slide 12)**

*(when transmission build is optimised, there is no difference between the expected outcomes of LMP and OpTIC)*

# Positives and other considerations

In relation to the defects currently being addressed by the TNUoS Task Force, OpTIC provides a number of positives.

## Positives

- OpTIC reflects available capacity/ capacity restrictions and considers constraint costs, providing a signal that is both relative and absolute and removes the need for security factors.
- All technology types can be covered, with OpTIC using individual technology specific characteristics. Therefore, there is no need for backgrounds, ALFs, scaling factors or sharing proxies.
- The data sources mirror those used in the NOA with outputs from the FES, consistent with the NETS SQSS and will therefore align with the HND (inc. HNDFUE and CNSP going forward).
- As OpTIC uses the optimal network to derive charges, it, in effect, provides a long-run signal focussed on the end goal of transmission investment. This smooths the signal over time meaning that only significant changes can cause volatility.
- There is no requirement for a 'reference node'
- Because OpTIC mirrors NOA optimisation, the long-run signal produced is cost-reflective (neither too strong nor too weak)

## Other considerations

- Local circuits
- Offshore transmission
- Link to distribution charges
- Interconnectors
- Impact on NOA, NOA process and other areas such as CNSP, FES etc for example in areas such as stakeholder involvement
- Half Hourly settlement

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# Break

Next session starts at 12:00

# OpTIC Model: Feedback & Further Discussion

## All

**The objective of this session is to:**

- Provide any further feedback in relation to the 'OpTIC' model.

# Consultancy Support: Further Considerations & Analysis

## Frontier & LCP

**The objective of this session is to discuss:**

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

# TNUoS Taskforce analytical support

Further Considerations & Analysis

15 September 2023

# Agenda


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# Agenda


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# We have assessed the following issues raised during the last TF meeting

| | |
|---|---|
| Backgrounds | ▪ Update calculations to include additional charging years in the reported output.<br>▪ Further explanation of the implications of -ve load factors implied for the current peak and year round (note)<br>▪ Treatment of PV in the transport model (note) |
| Reference node | ▪ Single vs multiple reference nodes (note) |
| Shared/not shared elements | ▪ Calculate tariffs with sharing turned off.<br>▪ Consider if sharing methodology is consistent with an LRMC signal |
| Data inputs | ▪ Sensitivities on different number of years for the volatility analysis.<br>▪ Forward-looking analysis of the volatility using future tech load factors.<br>▪ Consider interaction of ALF with new ancillary service products. |
| Other | ▪ Volatility and predictability analysis of historical charges. |

# Agenda


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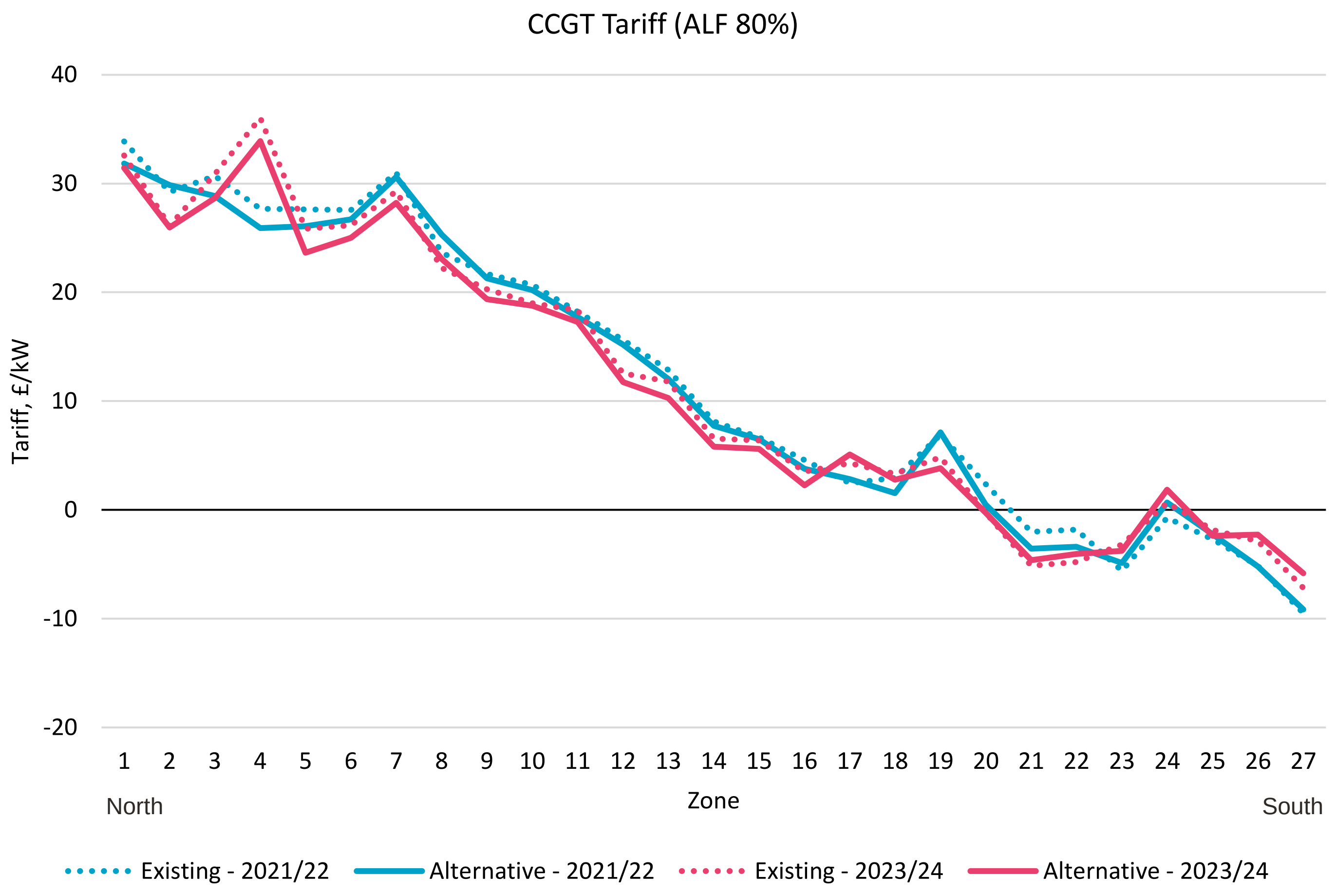
# Impact of alternative backgrounds in different charging years

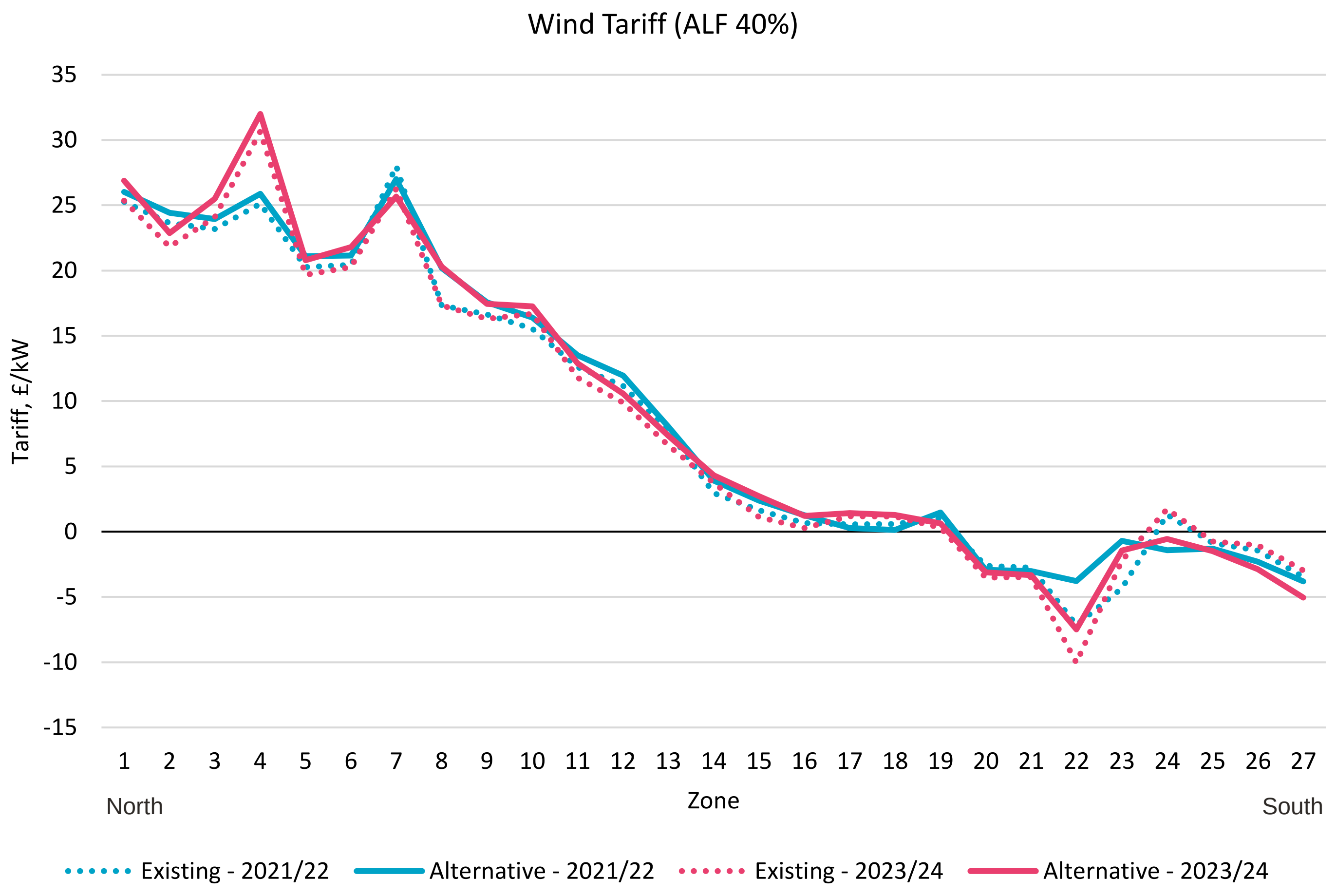
## Representative CCGT tariff (ALF 80%)




- In previous analysis, we showed that changing to use the two alternative backgrounds had limited impact on tariffs in 2021/22. While the changes may be large in absolute terms for projects, the overall trend of tariffs between zones is largely unchanged.
- We have extended this analysis to look at 2023/24 as well, to understand whether this result is true in different charging years.
- The chart shows the tariff for a CCGT with ALF 80% in each charging year using both the existing backgrounds and two alternatives.
- We conclude that the change of backgrounds also has a limited impact in 2023/24.

# Impact of alternative backgrounds in different charging years

## Representative Wind tariff (ALF 40%)




- The chart shows, as on the previous slides, the tariff for an offshore wind project with ALF 40% under both sets of backgrounds in each charging year.
- As seen for the CCGT, the conclusion that the alternative backgrounds have a limited effect on the pattern of charges between zones is valid for both charging years.

# Agenda



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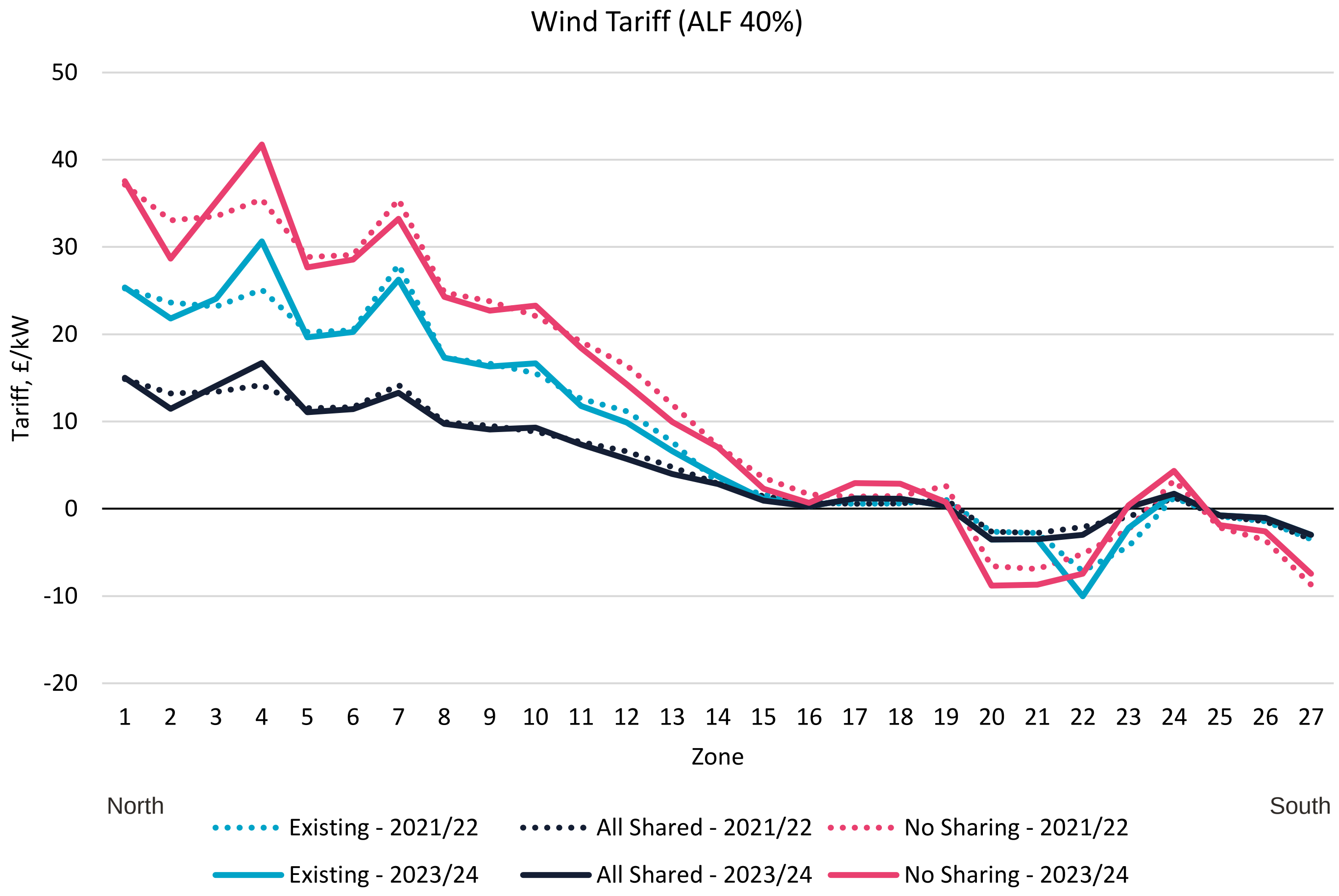
# Fixing sharing factors in tariff calculations

## Setting sharing to 0% (no sharing) and 100% (all shared)




- We were asked what the impact of fixing the sharing percentage at either 100% (all shared) or 0% (no sharing) would be and whether this might reduce volatility.
- The charts shows the tariffs for a wind project with ALF 40% when the full year-round tariff is shared ("all shared") and with no sharing ("no sharing") in 2021/22 and 2023/24 against the current methodology.
- The change in tariffs between charging years is, proportionally and directionally very similar to the existing methodology. This suggest that sharing is **not a key driver of volatility** though it is much more impactful in some zones than others and **these zones would experience greater volatility** if there was less sharing.
- A similar patterns occurs for conventional low-carbon as sharing has the same interaction with ALF. Note that for conventional carbon technologies, this has no impact as ALF is applied to the both year-round tariff components.

# TF Members queried whether the sharing factor methodology is consistent with the principle of sending an LRMC signal

***The sharing methodology relies on annual data on the Carbon, Low Carbon split in each zone and plant load factors, which will change year to year. This raises the question of whether relying on short-run data is inconsistent with the purpose of sending a long-run signal.***

### "Sharing" proxies for a real impact on LRMC

- The ability of a technology to share network does have an impact on long-run incremental costs
- Not appropriate to ignore it, so it is important to make an assumption on sharing

### Methodology uses short-run operational data

- The methodology uses actual historical ALF to proxy for future ALF
- The Carbon, Low Carbon mix is used to set Boundary Sharing Factors, which drive the extent to which sharing is considered to have an impact on long-run costs

### Impact is likely to be limited

- Using a 5 year rolling average for ALF limits sensitivity to actual market conditions
- The current methdology means changes in generating assets 'next' to existing assets has a limited impact on sharing factors and network charges. A plants charge reflects the generation mix in all zones upstream and downstream of them*

### Not a clear alternative to consider

- An alternative would be to use modeled projections that reflected an efficient balance of generation, demand and network capacity.
- Modeling efficient spatial generation investment decisions may be subject to uncertainty

In summary, the use of operational data is a proxy for real long-run impacts. However, while this may not be entirely consistent with the concept of LRMC, the charges are unlikely to be very sensitive to short-run changes in operational data, and we have not identified a clear implementable alternative.

* Downstream refers to zones closer to the slack node.

# Agenda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# Annual Load Factors (ALFs): averaging period

**Issue**

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

**Initial analysis**

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

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

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

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

**Conclusions and implications**

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

# Annual Load Factors (ALFs): averaging period

Additional analysis

- Stakeholders suggested to consider the sensitivity of using different years (i.e. not only the binary option of 1 year vs last-5 year).
- We have calculated the correlation between the last 2, 3 and 4 years average and the actual ALF. The following table shows the results.

| Years | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|---|---|
| Previous year | 0.87 | 0.79 | 0.87 | 0.81 | 0.91 | 0.88 | 0.78 |
| 2 years | 0.97 | 0.97 | 0.95 | 0.97 | 0.95 | 0.98 | 0.97 |
| 3 years | 0.94 | 0.93 | 0.90 | 0.95 | 0.93 | 0.94 | 0.95 |
| 4 years | 0.92 | 0.91 | 0.87 | 0.93 | 0.93 | 0.93 | 0.92 |
| 5 years | 0.88 | 0.90 | 0.86 | 0.92 | 0.93 | 0.93 | 0.91 |

- The higher correlation is obtained when considering the last two years. The approach of averaging the previous 3 years also attains higher levels of correlation than the remaining approaches.

Conclusions and implications

- Based on the updated analysis, strictly speaking we can see that considering an intermediate option between the current approach and using the previous year could result into higher cost-reflectivity.
- However, the differences between 2 and 5 years are relatively small, and any decision to adopt a shorter averaging period for the assessment of ALF would need to consider the trade offs.
  - Shorter ALF averaging periods would increase charge volatility
  - Shorter ALF averaging periods would also increase the risk of dispatch distortions (not quantified but in principle we could seek to quantify this).

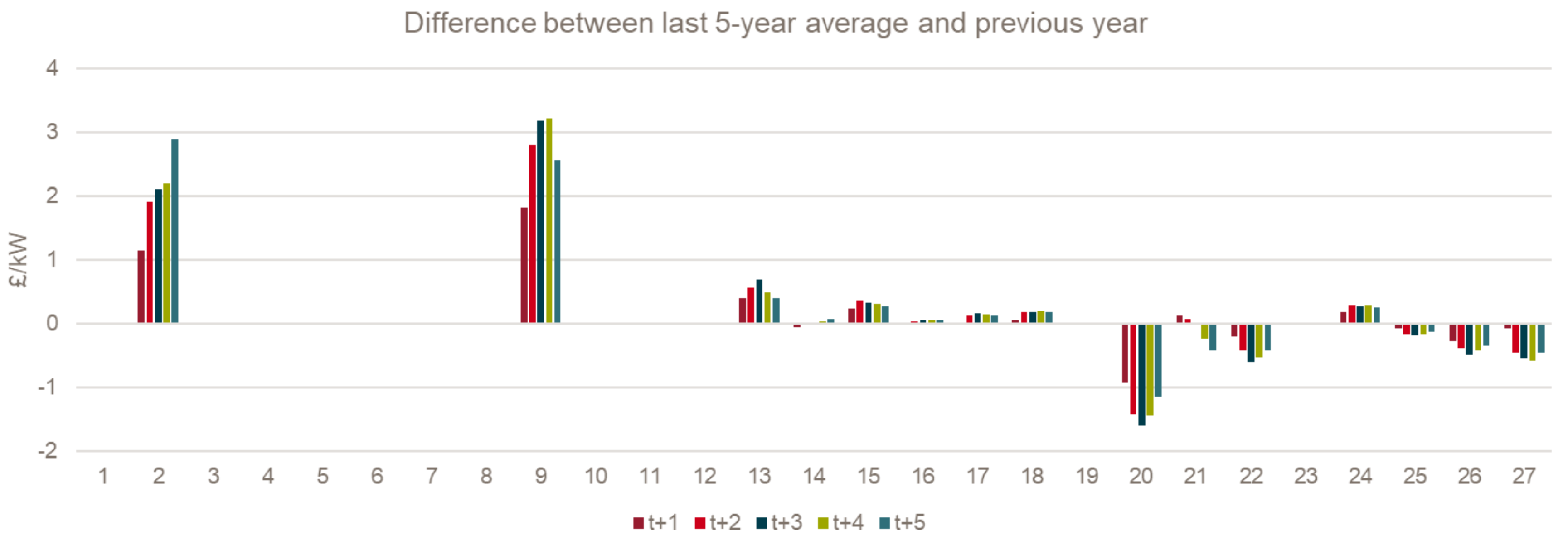
# Annual Load Factors (ALFs): declining impact

**Issue**

- In the context of the current approach of using the previous 5 years to calculate the ALF, some stakeholders expressed the need to undertake a forward-looking analysis on the impact of rapidly declining ALFs for thermal plants.

**Analysis**

- As an illustration we have assumed a 20% annual reduction of ALF on CCGT plants over the next 5 years.
- We have calculated the wider tariffs using the current approach and using the previous year.
- The chart shows the difference between both approaches on the wider tariff.




**Conclusions and implications**

- Outside of Scottish zones the impact on charges of the current approach vs a 1 year lag is generally less than £1/kW
- In Scottish zones the impact of moving to a shorter trailing average would be larger, due to higher charges:
  - For Peterhead in zone 2 the difference could be around £1.2m per year
  - For Grangemouth in zone 9 the difference could be around £0.15m per year
- Therefore, there is at least the potential for significant impacts on some plants faced with rapidly declining ALFs.

# The introduction of a new balancing service could reduce the benefits of switching to using only the FPN for setting the ALF

*These are preliminary conclusions. We need to obtain further knowledge of the mechanism from the ESO.*

## Case for switching to using FPN only

- In the previous TF meeting we identified that there may be merit in changing the current approach for calculating the ALFs under some circumstances.
- The current approach takes the highest value between the HH output and the FPN.
- With this approach, assuming that there is an unbiased distribution of forecast errors for **intermittent plants**, there will be an upward bias in the ALF estimation.
- In the case of **conventional plants in positive charge zones**, if the plant is redispatched to resolve a network constraint, it will face a charge despite operating only to relieve network stress.
- These issues could be addressed by taking only the FPN value for setting the ALF.

## Impact of introducing a new balancing service

- It was discussed in the taskforce meeting that National Grid ESO is planning to introduce a new balancing service that would contract in advance of gate closure.
- With this service the FPN would already reflect an adjustment to manage congestion. This could potentially create two impacts:
  - Switching the method to using FPNs only in zones with positive charges would mean plants would be charged for resolving a constraint as the FPN would be higher as it takes into account the balancing action. This is the same issue we were trying to resolve by switching to FPNs.
  - This cost would be reflected in bidding for the new service i.e. bids would increase.
- The extent to which these effects are important will depend on the volumes contracted through the new balancing service.

# Agenda



| # | Topic | Page |
|---|---|---|
| 1 | Issues for further consideration and analysis | 3 |
| 2 | Backgrounds | 5 |
| 3 | Sharing factors | 8 |
| 4 | Data inputs | 11 |
| **5** | **Other** | **16** |

# Historical evolution of average wider locational tariffs

*The simple average of tariffs shows that tariff in recent years have remained stable and at similar levels to the 2007-2012 period. However, there has been some volatility during the previous decade. In particular, tariff years 2016/17 is a significant outlier. We also observe a significant gap between intermittent and conventional plants in 2017/18 and 2018/19, in contrast to other years.*

Average locational tariffs (£/kW) for a representative intermittent and conventional plant

# Historic volatility – YoY changes

Intermittent plant (ALF: 40%)

*All regions experienced significant volatility in tariff years 2016/17 and 2017/18. Significant volatility was also experienced in Southern regions throughout the early to mid 2010s and in some Midlands and Northern regions in the latter part of the decade.*

| | 2005/2006 | 2006/2007 | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| North Scotland | | -2% | 5% | 3% | -3% | -5% | 4% | 2% | 16% | 9% | -8% | -53% | 81% | 22% | -15% | 4% | 15% | -6% |
| East Aberdeenshire | | 1% | 5% | 3% | 3% | -5% | 3% | 2% | 13% | 1% | -8% | -55% | 103% | 0% | 0% | 6% | 13% | -8% |
| Western Highlands | | -2% | 7% | 3% | 3% | 10% | -2% | -4% | 19% | 8% | -17% | -54% | 92% | 24% | -11% | -1% | 12% | -8% |
| Skye and Lochalsh | | -42% | 49% | 3% | 3% | 10% | -2% | -4% | 37% | 12% | -15% | -57% | 67% | 26% | -4% | -8% | 21% | -8% |
| Eastern Grampian and Tayside | | 0% | 7% | 2% | 1% | 7% | 0% | -3% | 23% | 12% | -8% | -54% | 93% | 18% | -11% | 3% | -3% | -9% |
| Central Grampian | | 0% | 7% | 2% | 1% | 7% | 0% | -3% | 12% | 11% | -1% | -52% | 103% | 3% | -8% | 3% | 7% | -12% |
| Argyll | | 1% | 9% | 3% | -7% | -1% | 2% | 1% | 31% | 13% | 10% | -21% | 60% | -26% | 36% | 2% | 1% | -19% |
| The Trossachs | | -8% | 9% | 3% | -7% | -1% | 2% | 1% | 16% | 12% | -2% | -56% | 130% | 4% | -9% | 2% | 7% | -14% |
| Stirlingshire and Fife | | 4% | 7% | 2% | 1% | -4% | 2% | 0% | 15% | 10% | -5% | -64% | 138% | 16% | -9% | 3% | 7% | -9% |
| South West Scotlands | | 6% | 30% | 3% | 4% | -2% | 2% | -6% | 33% | 6% | -4% | -55% | 135% | 16% | -15% | 0% | 7% | -13% |
| Lothian and Borders | | 3% | 11% | 3% | 1% | -4% | 0% | 1% | -5% | 11% | -6% | -63% | 135% | 16% | -21% | 2% | 1% | -2% |
| Solway and Cheviot | | 12% | 80% | 4% | 1% | -5% | -3% | 2% | -13% | 15% | -9% | -65% | 123% | 18% | -12% | 0% | 9% | -11% |
| North East England | | 10% | 4% | 8% | -1% | -6% | -5% | -5% | 3% | 14% | -13% | -92% | 589% | 12% | -10% | 30% | 2% | -5% |
| North Lancashire and The Lakes | | 14% | 5% | 7% | -3% | -4% | -6% | 9% | 23% | 22% | -15% | -65% | 42% | 17% | -18% | -13% | 12% | -2% |
| South Lancashire, Yorkshire and Humber | | 14% | 5% | 7% | -3% | -4% | -6% | 9% | 4% | 20% | -18% | -89% | -42% | 21% | -28% | 105% | 86% | -28% |
| North Midlands and North Wales | | 23% | 4% | 11% | -5% | -3% | -4% | 18% | 13% | 19% | -21% | -96% | -305% | -5% | 21% | -133% | 143% | -13% |
| South Lincolnshire and North Norfolk | | 23% | 4% | 11% | -5% | -3% | -4% | 18% | -24% | 33% | -36% | -92% | -156% | 15% | 57% | -162% | 316% | -127% |
| Mid Wales and The Midlands | | -8% | 62% | 17% | -9% | -2% | -16% | 39% | 2% | 45% | -41% | -94% | -160% | -53% | 68% | -765% | 73% | -29% |
| Anglesey and Snowdon | | 3% | 3% | 6% | -22% | -3% | -4% | 11% | 10% | 16% | -10% | -95% | -266% | -42% | 4% | -260% | -39% | 30% |
| Pembrokeshire | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | 174% | 18% | -9% | -118% | 45% | 15% | -1% | 10% | 31% | -27% |
| South Wales & Gloucester | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | 44% | 30% | -12% | -132% | 49% | 12% | -3% | 15% | 34% | -19% |
| Cotswold | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | -98% | 1838% | -72% | -2270% | 16% | 9% | 0% | 17% | 5% | -18% |
| Central London | | -4% | 4% | -1% | 23% | -15% | 16% | 95% | -67% | -15% | 38% | -3% | -8% | 18% | 4% | 4% | -31% | 109% |
| Essex and Kent | | 43% | 15% | 34% | -79% | 411% | -49% | 248% | -92% | 649% | -152% | -267% | -34% | 6% | 17% | 13% | 21% | -12% |
| Oxfordshire, Surrey and Sussex | | -27% | -48% | -94% | 9287% | -37% | 117% | -41% | 53% | -51% | 206% | -76% | 76% | 7% | -10% | -8% | -21% | -54% |
| Somerset and Wessex | | -1% | 47% | -37% | 28% | -35% | 71% | -53% | 78% | -11% | 46% | -73% | 48% | 9% | -33% | 12% | 3% | -36% |
| West Devon and Cornwall | | 14% | -6% | 0% | -22% | -20% | 31% | -19% | -9% | -9% | 24% | -73% | 34% | 7% | -9% | 12% | 44% | -43% |
| **Average** | | **-3%** | **15%** | **5%** | **-1%** | **6%** | **-3%** | **2%** | **20%** | **14%** | **-12%** | **-62%** | **103%** | **10%** | **-7%** | **2%** | **9%** | **-11%** |

# Volatility – YoY change

Conventional plant
(ALF: 50%)

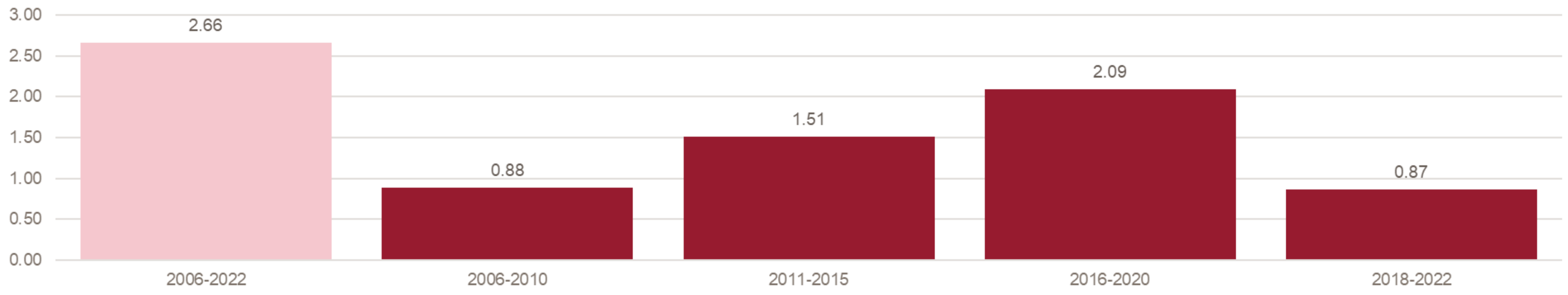
*All Scottish regions experienced significant volatility in tariff years 2016/17 and 2017/18. Significant volatility was also experienced in Southern regions throughout the early to mid 2010s.*

| | 2005/2006 | 2006/2007 | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| North Scotland | | -2% | 5% | 3% | -3% | -5% | 4% | 2% | 16% | 9% | -8% | -72% | 102% | -2% | 33% | 10% | 13% | -5% |
| East Aberdeenshire | | 1% | 5% | 3% | 3% | -5% | 3% | 2% | 13% | 1% | -8% | -76% | 140% | -16% | 65% | 14% | -7% | -6% |
| Western Highlands | | -2% | 7% | 3% | 3% | 10% | -2% | -4% | 19% | 8% | -17% | -75% | 123% | 6% | 33% | 5% | 14% | -7% |
| Skye and Lochalsh | | -42% | 49% | 3% | 3% | 10% | -2% | -4% | 37% | 12% | -15% | -91% | 175% | 11% | 91% | -13% | 43% | -9% |
| Eastern Grampian and Tayside | | 0% | 7% | 2% | 1% | 7% | 0% | -3% | 23% | 12% | -8% | -76% | 145% | 7% | 25% | 12% | -1% | -7% |
| Central Grampian | | 0% | 7% | 2% | 1% | 7% | 0% | -3% | 12% | 11% | -1% | -62% | 96% | -25% | 43% | 11% | 2% | -11% |
| Argyll | | 1% | 9% | 3% | -7% | -1% | 2% | 1% | 31% | 13% | 10% | -56% | 81% | -57% | 165% | 8% | -5% | -17% |
| The Trossachs | | -8% | 9% | 3% | -7% | -1% | 2% | 1% | 16% | 12% | -2% | -68% | 135% | -17% | 35% | 11% | 2% | -13% |
| Stirlingshire and Fife | | 4% | 7% | 2% | 1% | -4% | 2% | 0% | 15% | 10% | -5% | -89% | 366% | 7% | 35% | 15% | 5% | -6% |
| South West Scotlands | | 6% | 30% | 3% | 4% | -2% | 2% | -6% | 33% | 6% | -4% | -71% | 164% | 18% | 2% | 3% | 3% | -14% |
| Lothian and Borders | | 3% | 11% | 3% | 1% | -4% | 0% | 1% | -5% | 11% | -6% | -67% | 138% | 7% | 8% | 8% | -9% | 10% |
| Solway and Cheviot | | 12% | 80% | 4% | 1% | -5% | -3% | 2% | -13% | 15% | -9% | -82% | 190% | 33% | 3% | 5% | 13% | -10% |
| North East England | | 10% | 4% | 8% | -1% | -6% | -5% | -5% | 3% | 14% | -13% | -78% | 230% | 10% | 12% | 16% | -5% | 12% |
| North Lancashire and The Lakes | | 14% | 5% | 7% | -3% | -4% | -6% | 9% | 23% | 22% | -15% | -60% | 21% | 25% | -2% | 16% | 15% | -13% |
| South Lancashire, Yorkshire and Humber | | 14% | 5% | 7% | -3% | -4% | -6% | 9% | 4% | 20% | -18% | -24% | -9% | 12% | 5% | 6% | -5% | 21% |
| North Midlands and North Wales | | 23% | 4% | 11% | -5% | -3% | -4% | 18% | 13% | 19% | -21% | -16% | -20% | 2% | 11% | -4% | 2% | 20% |
| South Lincolnshire and North Norfolk | | 23% | 4% | 11% | -5% | -3% | -4% | 18% | -24% | 33% | -36% | -15% | -20% | -1% | 5% | -7% | 6% | 82% |
| Mid Wales and The Midlands | | -8% | 62% | 17% | -9% | -2% | -16% | 39% | 2% | 45% | -41% | -15% | -36% | 9% | 16% | 8% | 63% | -12% |
| Anglesey and Snowdon | | 3% | 3% | 6% | -22% | -3% | -4% | 11% | 10% | 16% | -10% | -29% | -35% | 15% | 4% | 1% | 23% | 4% |
| Pembrokeshire | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | 174% | 18% | -9% | 31% | -9% | -3% | -1% | -2% | -36% | 20% |
| South Wales & Gloucester | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | 44% | 30% | -12% | 49% | -15% | -5% | -4% | -11% | -97% | 551% |
| Cotswold | | 7% | -10% | 1% | -35% | -155% | -22% | 194% | -98% | 1838% | -72% | 804% | -39% | -18% | -32% | -92% | -467% | -108% |
| Central London | | -4% | 4% | -1% | 23% | -15% | 16% | 95% | -67% | -15% | 38% | -16% | 37% | 25% | 6% | -1% | -41% | 29% |
| Essex and Kent | | 43% | 15% | 34% | -79% | 411% | -49% | 248% | -92% | 649% | -152% | 160% | 36% | 2% | -3% | -9% | -33% | -11% |
| Oxfordshire, Surrey and Sussex | | -27% | -48% | -94% | 9287% | -37% | 117% | -41% | 53% | -51% | 206% | -32% | 42% | 9% | 5% | -26% | -9% | 13% |
| Somerset and Wessex | | -1% | 47% | -37% | 28% | -35% | 71% | -53% | 78% | -11% | 46% | -41% | 37% | 8% | -11% | 10% | 15% | 16% |
| West Devon and Cornwall | | 14% | -6% | 0% | -22% | -20% | 31% | -19% | -9% | -9% | 24% | -70% | 43% | 9% | 0% | 18% | 112% | -33% |
| **Average** | | **-3%** | **15%** | **5%** | **-1%** | **6%** | **-3%** | **2%** | **20%** | **14%** | **-12%** | **-67%** | **85%** | **-7%** | **35%** | **7%** | **3%** | **-5%** |

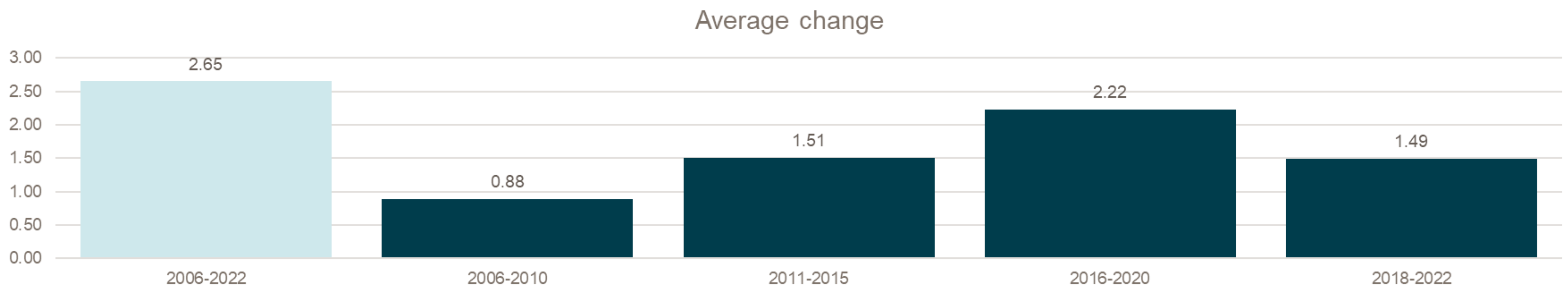
# Volatility – Standard deviation

*During the 2006-2022 period, the average locational tariff have been around 8£/kW. The standard deviation shows that around 68% of the tariffs have fallen within the range of 5.4£/kW and 9.6 £/kW. The 2016-2020 was a period of higher volatility, and it decreased in the period 2018/2022.*

Intermittent plant (ALF: 40%)




Conventional plant (ALF: 50%)



# Volatility – Ranking (1=highest tariff; 27=lowest tariff)

Intermittent plant (ALF: 40%)

*Despite volatility in the absolute charges being particularly concentrated in particular years and regions, changes in the relative charges is more widely spread across years and regions, though there is a high degree of stability in many regions.*

| | 2006/2007 | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| North Scotland | 1 | 1 | 1 | 1 | 3 | 3 | 3 | 3 | 3 | 2 | 3 | 2 | 1 | 4 | 2 | 3 | 1 |
| East Aberdeenshire | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 7 | 7 | 7 | 8 | 7 | 7 | 5 | 5 |
| Western Highlands | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 2 | 2 | 3 | 4 | 4 | 2 | 3 | 3 | 4 | 4 |
| Skye and Lochalsh | 8 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 5 | 3 | 2 | 4 | 2 | 2 |
| Eastern Grampian and Tayside | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 5 | 6 | 6 | 4 | 5 | 5 | 7 | 7 |
| Central Grampian | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 5 | 3 | 5 | 6 | 6 | 6 | 6 |
| Argyll | 6 | 7 | 7 | 9 | 8 | 8 | 8 | 7 | 7 | 4 | 1 | 1 | 6 | 1 | 1 | 1 | 3 |
| The Trossachs | 6 | 7 | 7 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 9 | 8 | 8 | 8 | 8 |
| Stirlingshire and Fife | 9 | 9 | 9 | 7 | 7 | 7 | 7 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 9 |
| South West Scotlands | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 10 | 10 | 10 | 9 | 9 | 7 | 9 | 9 | 9 | 10 |
| Lothian and Borders | 10 | 10 | 10 | 8 | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Solway and Cheviot | 14 | 11 | 11 | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| North East England | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 15 | 13 | 13 | 13 | 13 | 13 | 13 |
| North Lancashire and The Lakes | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 13 | 14 | 14 | 14 | 14 | 14 | 14 |
| South Lancashire, Yorkshire and Humber | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| North Midlands and North Wales | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 18 | 18 | 18 | 19 | 19 | 19 | 20 | 20 | 20 | 19 |
| South Lincolnshire and North Norfolk | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 19 | 19 | 20 | 18 | 18 | 18 | 18 | 19 | 18 | 20 |
| Mid Wales and The Midlands | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 21 | 21 | 21 | 20 | 17 | 17 | 17 | 18 | 17 | 18 |
| Anglesey and Snowdon | 13 | 14 | 14 | 14 | 14 | 14 | 14 | 15 | 15 | 15 | 17 | 20 | 20 | 19 | 17 | 19 | 17 |
| Pembrokeshire | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 17 | 17 | 17 | 24 | 22 | 24 | 24 | 23 | 23 | 23 |
| South Wales & Gloucester | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 20 | 20 | 19 | 23 | 24 | 23 | 23 | 24 | 24 | 25 |
| Cotswold | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 23 | 23 | 22 | 26 | 27 | 27 | 27 | 27 | 27 | 26 |
| Central London | 26 | 26 | 26 | 27 | 27 | 26 | 27 | 26 | 26 | 26 | 27 | 26 | 26 | 26 | 26 | 26 | 27 |
| Essex and Kent | 20 | 20 | 20 | 20 | 20 | 23 | 20 | 22 | 22 | 23 | 14 | 15 | 15 | 15 | 15 | 15 | 15 |
| Oxfordshire, Surrey and Sussex | 21 | 21 | 21 | 21 | 24 | 24 | 24 | 24 | 24 | 24 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Somerset and Wessex | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 22 | 23 | 22 | 22 | 22 | 22 | 22 |
| West Devon and Cornwall | 27 | 27 | 27 | 26 | 26 | 27 | 26 | 27 | 27 | 27 | 25 | 25 | 25 | 25 | 25 | 25 | 24 |

# Volatility – Ranking (1=highest tariff; 27=lowest tariff)

Conventional plant (ALF: 50%)

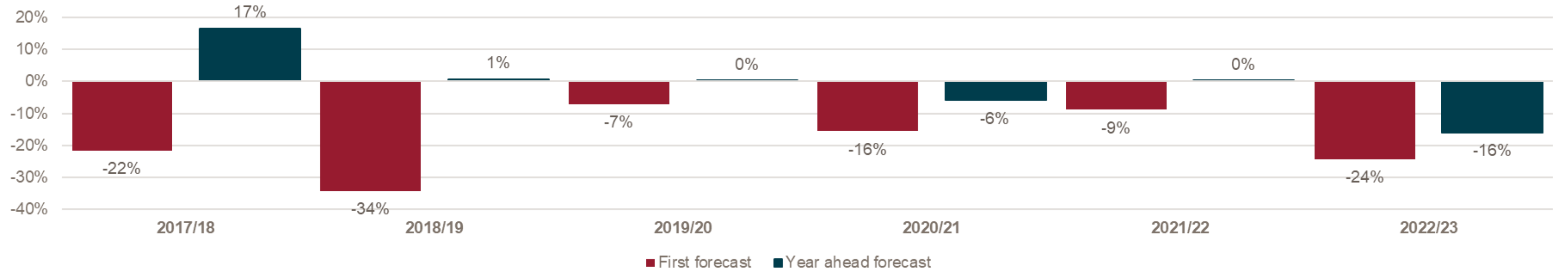
*Despite volatility in the absolute charges being particularly concentrated in particular years and regions, changes in the relative charges is more widely spread across years and regions, though there is a high degree of stability in many regions.*

| | 2006/2007 | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| North Scotland | 1 | 1 | 1 | 1 | 3 | 3 | 3 | 3 | 3 | 2 | 4 | 3 | 1 | 2 | 2 | 1 | 1 |
| East Aberdeenshire | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 7 | 9 | 7 | 8 | 6 | 6 | 7 | 6 |
| Western Highlands | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 2 | 2 | 3 | 5 | 5 | 3 | 3 | 3 | 2 | 2 |
| Skye and Lochalsh | 8 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 16 | 12 | 12 | 8 | 11 | 6 | 7 |
| Eastern Grampian and Tayside | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 5 | 8 | 6 | 4 | 5 | 5 | 5 | 4 |
| Central Grampian | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 2 | 2 | 5 | 4 | 4 | 4 | 5 |
| Argyll | 6 | 7 | 7 | 9 | 8 | 8 | 8 | 7 | 7 | 4 | 1 | 1 | 11 | 1 | 1 | 3 | 3 |
| The Trossachs | 6 | 7 | 7 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 6 | 4 | 7 | 7 | 7 | 8 | 8 |
| Stirlingshire and Fife | 9 | 9 | 9 | 7 | 7 | 7 | 7 | 9 | 9 | 9 | 21 | 10 | 9 | 10 | 9 | 10 | 9 |
| South West Scotlands | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 10 | 10 | 10 | 12 | 8 | 2 | 9 | 8 | 9 | 10 |
| Lothian and Borders | 10 | 10 | 10 | 8 | 10 | 10 | 10 | 11 | 11 | 11 | 13 | 9 | 6 | 11 | 10 | 11 | 11 |
| Solway and Cheviot | 14 | 11 | 11 | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 18 | 14 | 10 | 12 | 13 | 12 | 13 |
| North East England | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 19 | 13 | 13 | 13 | 12 | 13 | 12 |
| North Lancashire and The Lakes | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 15 | 17 | 16 | 16 | 16 | 14 | 16 |
| South Lancashire, Yorkshire and Humber | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 11 | 15 | 15 | 15 | 15 | 16 | 14 |
| North Midlands and North Wales | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 18 | 18 | 18 | 14 | 19 | 19 | 19 | 18 | 18 | 18 |
| South Lincolnshire and North Norfolk | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 19 | 19 | 20 | 17 | 20 | 20 | 20 | 20 | 20 | 19 |
| Mid Wales and The Midlands | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 21 | 21 | 21 | 22 | 22 | 21 | 21 | 21 | 19 | 20 |
| Anglesey and Snowdon | 13 | 14 | 14 | 14 | 14 | 14 | 14 | 15 | 15 | 15 | 7 | 18 | 17 | 17 | 17 | 15 | 15 |
| Pembrokeshire | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 17 | 17 | 17 | 3 | 11 | 14 | 14 | 14 | 17 | 17 |
| South Wales & Gloucester | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 20 | 20 | 19 | 10 | 16 | 18 | 18 | 19 | 21 | 21 |
| Cotswold | 22 | 22 | 22 | 22 | 21 | 20 | 21 | 23 | 23 | 22 | 20 | 21 | 22 | 22 | 22 | 22 | 22 |
| Central London | 26 | 26 | 26 | 27 | 27 | 26 | 27 | 26 | 26 | 26 | 27 | 27 | 27 | 27 | 27 | 26 | 27 |
| Essex and Kent | 20 | 20 | 20 | 20 | 20 | 23 | 20 | 22 | 22 | 23 | 25 | 25 | 24 | 23 | 24 | 23 | 23 |
| Oxfordshire, Surrey and Sussex | 21 | 21 | 21 | 21 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 25 | 25 | 23 | 24 | 24 |
| Somerset and Wessex | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 26 | 26 | 26 | 26 | 26 | 25 | 26 |
| West Devon and Cornwall | 27 | 27 | 27 | 26 | 26 | 27 | 26 | 27 | 27 | 27 | 23 | 23 | 23 | 24 | 25 | 27 | 25 |

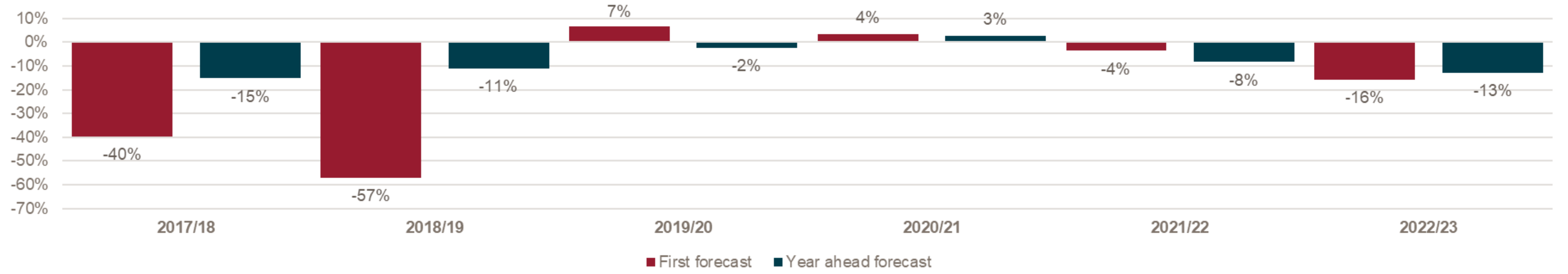
# Predictability – First and previous year forecast vs Actual tariff

*From an investment perspective predictability of tariffs is important over a longer horizon. Typically, ESO's first published forecast (i.e. 5-years ahead) has typically overestimated the final tariff, with accuracy improving in subsequent forecasts. The degree of error in long-term forecasts has diminished compared to 2017/18 and 2018/19 tariffs*

Difference between forecasted and final tariff.* Intermittent plant (ALF: 40%)




Difference between forecasted and final tariff.* Conventional plant (ALF: 50%)




**A negative (positive) value means that there was an over(under)forecast relative to the final tariff. The tariff considered is the result of calculating the simple average of the tariffs in the 27 regions.*

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# Lunch

Next session starts at 14:00

# Backgrounds Case for Change: Overview

## John Tindal

**The objective of this session is to provide:**

- A high-level overview of the draft ‘backgrounds case for change’ including; the defect(s) identified, pros and cons of any change, initial recommendations and observations, and evidence to demonstrate the reasons for change.

# Case for change:
# Backgrounds

# Frontier Economics and LCP modelling

## Current SQSS scaling factors

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| 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 |

CUSC - SECTION 1 (nationalgrideso.com)

- **Round 1**: Year Round scenario with high demand
- **Round 2:** Peak Security scenario with highest demand
- **Round 3**: Additional Year Round scenario with low demand
  - Flexible assets act as a sink for generation e.g. Interconnectors exporting surplus energy storage importing to store surplus energy

## Frontier/LCP modelling

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

| Defect area | Case for change | Case against change | Initial recommendations and observations |
|---|---|---|---|
| **Improve the Year Round generation background ?** | **Improve scaling factor: more cost reflective of CBA**<br>Year-Round background reflects economic trade-off between congestion vs network reinforcement across all periods. Potential improvements:<br><br>**Renewables**: current 70% is much higher than ALF<br>**Conventional**: need a floor at zero %<br>**Interconnectors**: more likely to be float, or exporting<br>**Storage**: more likely to be importing<br>**Demand turn-down**: Not in year round conditions<br>**Demand turn-up**: Should turn up in year round conditions | Changing scaling factors would be inconsistent with SQSS. Charges should reflect how the network is planned.<br><br>Need better transparency regarding network planning between SQSS Economy criteria, NOA, new strategic planning | 1) Charges reflect incremental flows and already do not match background scaling factors. Charges are already different e.g. shared/non-shared split and station specific ALF<br><br>2) Use a CBA to review scaling factors for generation and flexible demand<br><br>3) Year Round maximum flow is not an appropriate proxy for CBA flows, because maximum flow will be systematically greater than CBA flow<br><br>4) SQSS needs reviewed as well |
| **Improve the Peak Security generation background ?** | **Improve scaling factors: better reflect usage**<br>**Renewables**: Often use network in peak demand periods. TNUoS scaling could be consistent with Capacity Mechanism derating.<br>**Interconnectors**: | For network security, the SQSS is the key driver of network investment, so Peak Security charges should reflect SQSS. Contrasts with Year-round, where CBA takes precedence over the SQSS for economy investments.<br><br>Charges reflect contribution to network investment cost, not network usage alone<br><br>SQSS models system with zero wind to identify network investment in a specific security stress-test scenario, not an "average" scenario | Consider if SQSS Demand Security criteria should align with Capacity Mechanism de-rating factors, especially for renewables and interconnectors |
| **Different treatment of demand between the backgrounds** | **Change Year Round demand**<br>Peak Security should reflect Peak conditions, while Year Round should be more reflective of bulk energy flows | It is relative gen and demand that matters for load flows.<br><br>Scaling factor values were chosen given the demand assumption to match a CBA. Different demand would require different scaling factors to still be consistent with CBA, which may cancel out the effect of changing demand | Large overlap with "Signals" workstream. Consider overlaps before concluding |
| **Change the number of backgrounds** | Less backgrounds would be simpler<br><br>More backgrounds could be more cost reflective | Additional cost reflectivity likely to be small, not material to investment decisions and complexity of more backgrounds would be disproportionate<br><br>The most representative range of scenarios aligns with trends for maintaining a Year-Round/Peak output and demand. | Consider if it is more sufficient to appropriately update a single Year Round background, or if there would be a benefit in using additional Year-Round backgrounds e.g. at different levels of demand and/or intermittent generation. |

# Backgrounds Case for Change: Feedback & Further Discussion

## All

**The objective of this session is to:**

- Provide any further feedback in relation to the case for change.
- Capture pros and cons relating to the case for change - agree if this is sufficient to now progress.

# Feedback & Discussion on Case for Change

Any further considerations (pros and cons) that need to be captured?

Does the evidence support the proposed change(s)?

Is the 'draft change' sufficient to allow a modification to be drafted?

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# Break

Next session starts at 15:15

# Signals Workstream: Initial Thinking

## Paul Jones

**The objective of this session is to provide:**

- A high-level view and discuss the output from the ‘Signals’ workstream discussions including; any initial views on defects and principle based questions; and recommended approach and next steps to progressing this package of work.

# TNUoS Taskforce Signals Workstream

Brendan Clark, Lauren Jauss, Paul Jones, Aled Moses, Simon Lord, Graham Pannell, John Tindal

## Initial Thinking

18 September 2023

# Workstream's Proposed Overall Scope and Objectives

- To define characteristics and definition of timely, useful, cost reflective investment signals for different users, that reflect each site's impact on transmission investment costs throughout the assets lifetime
- To define desired outcomes from other workstreams, and conduct final review at the end of the Taskforce process to check the deliverables meet the Signals workstream criteria
- Estimated 2-3 months of subsequent meetings required to document detailed principles and outcomes, and make recommendations for new modification proposals

# Taskforce Issue 20
# Locational investment signals for offshore

### Defect(s)

- Extension of unmodified onshore charging methodology to offshore will result in all offshore proposed HND meshed network being classified and charged as local circuits to offshore generators, even though the network will be shared by Users onshore and offshore.

### Initial View of Principles

- Level playing field – non discriminatory treatment; Technology agnostic
- Sends useful price signals that only discriminate based on the users impacts on the transmission system
- Which asset's charges and/or capacities are to be included in the calculation of the Adjustment Tariff (i.e. Connection Exclusion) is in no way dependent on how assets are classified for charging purposes (i.e. cannot be used to limit volatility of TNUoS charges)
- What is the definition of MITs offshore? What the network does and how it is used/planned is more important than a definition around the number of circuits.  Could have different definition for onshore/offshore/different voltages....

### Recommended approach / next steps

- Examine whether lack of wider charges offshore would be cost reflective and consistent with the principles of wider charging onshore.

# Taskforce Issue 21
# Long-term fixing of TNUoS

### Defect(s)

- The high degree of uncertainty in future TNUoS cost signals has limited benefit because future changes to forecast are often not aligned to timing of investment decisions. This uncertainty adds risk capital costs to investments which are passed through to consumers.

### Initial View of Principles

- Signals must be effective & useful and create the right incentives for both investment and closure decisions.
- There is no benefit to TNUoS if the signal cannot be factored into any investment decisions
- Fixing charges will convey an obligation as well as a right.
- Different users should be able to fix for different periods based on relevant eligibility criteria
- Users should have flexibility to be able to fix charges to align with investment decisions
- Adjustment Tariff will need to be floating to protect users without fixed TNUoS from unpredictability / volatility

### Recommended approach / next steps

- Document high level principles, objectives & criteria for fixing (for what sites, when, for how long?) to support CMP413 & make any further recommendations / raise proposals not covered by this mod.

# Is it appropriate to have negative locational charges for generation? For demand? What signals should demand TNUoS send, and how?

## Defect(s)

A. Demand is negative generation and vice versa, but TNUoS signals are not equal and opposite, due to the demand adjustment and the wider charge demand floor, which can distort investment behaviour

B. Sites are no longer simply only demand or only generation, and they can be of multiple technology types, so TNUoS models and charges are too simplistic to be able to correctly represent material reality

C. Demand triad measure is an operational signal that can distort power market bidding behaviour

D. SQSS is out of date and no longer fully defines NOA, so TNUoS charges are not reflective of actual or optimal investment drivers.

## Taskforce Issues 22, 23, 24 CONTINUED

# Is it appropriate to have negative locational charges for generation? For demand? What signals should demand TNUoS send, and how?

### Initial View of Principles

- TNUoS reflects the long-run incremental cost of the transmission system (i.e. the physical assets), not operation of the transmission system; and provides a long-run marginal signal. Other mechanisms should provide operational signals.
- Demand and generation locational signals can both be negative, but no single time period should deliver a negative total cost of final demand to a consumer (which would incentivise wastage).
- Measurement of transmission system impact/use (e.g. triads) should be consistent with CBA background scenarios

### Recommended approach / next steps

- Consider whether charges should be reflective of SQSS, NOA, optimal ideal transmission investment or something else? (for discussion with technology workstream).
- Consider how complex sites should be represented – is it appropriate to charge for them in a different way to how they are considered when then network is planned?
- Any new set of backgrounds needs to include representation of the cost/benefit of demand, including not only at ACS peak, but also off peak if there is an impact on transmission investment to support principles and/or implementation of CMP405

# Absolute vs Relative Workstream: Initial Thinking

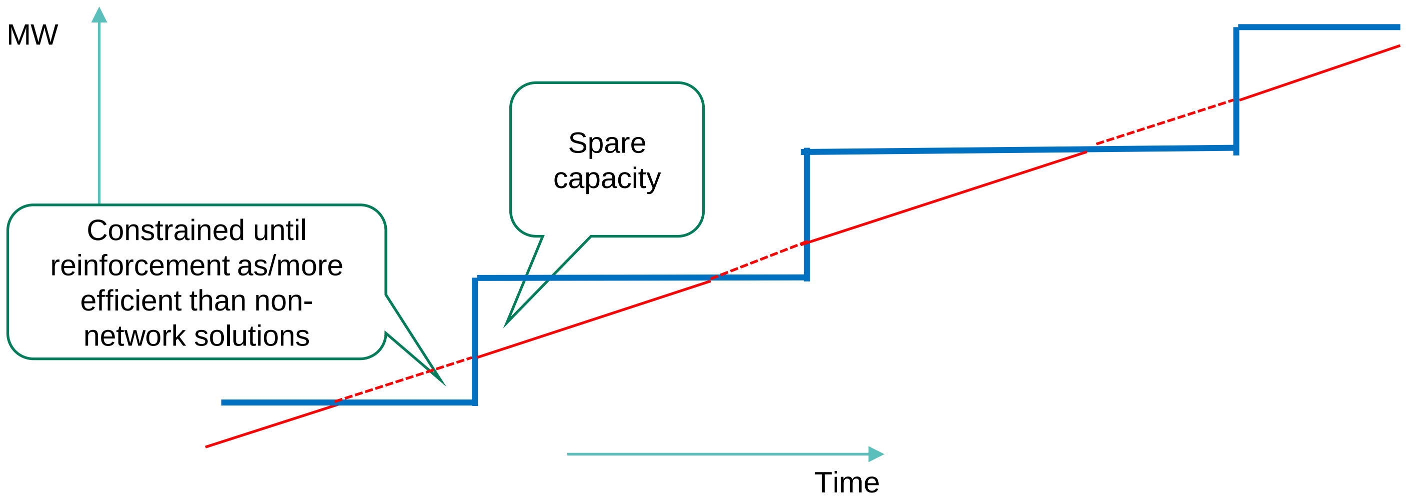
## Grace March

**The objective of this session is to provide:**

- A high-level view and discuss the output from the 'Absolute vs Relative' workstream discussions focusing on the initial thinking in terms of the treatment of spare capacity.

# Treatment of spare capacity

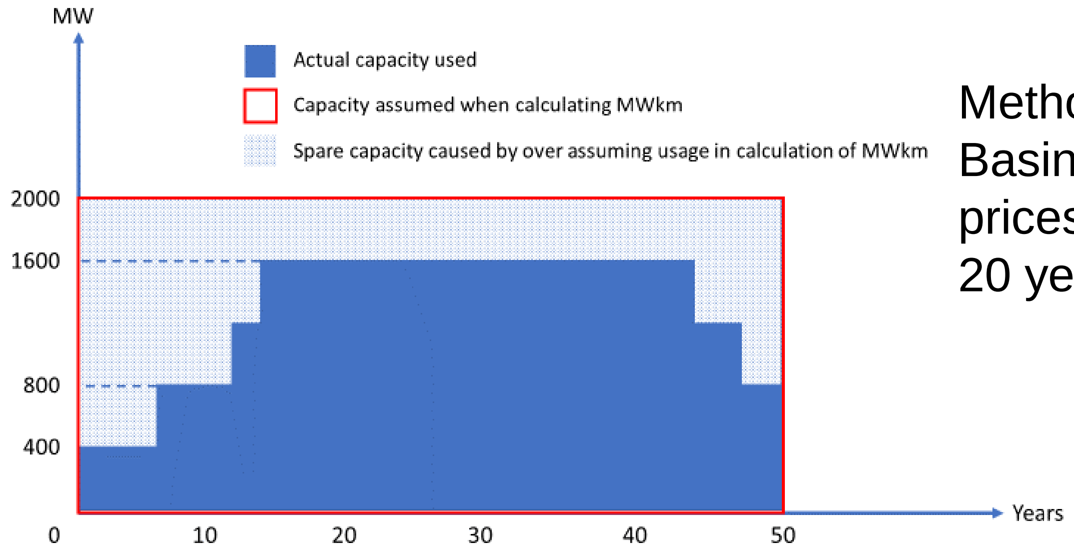
**Physical capacity (blue) vs example utilisation (red)**




Model assumes that TOs build efficient network based on SQSS criteria
£/MWkm is *incremental* price i.e. assumes network reinforcement is precise, when physical capacity is stepped- because can't build exactly 1 MWkm
Model therefore ignores both areas between blue and red line, and red dotted and blue line
In long term view, blue line should average to red line
Averaging means that parties are not charged the full cost of triggering a "step" investment, but neither do they use spare capacity for free
Constraints are valued through Balancing Mechanism – need to avoid double counting

# Treatment of spare capacity




Methodology assumes full utilisation – lowest £/MWkm
Basing £/MWkm on actual utilisation will result in volatile prices e.g. £/MWkm at ten years is twice that at £/MWkm at 20 years

If existing capacity is ‘free’, signals to close/free up existing capacity are lost. Pricing TNUoS to reflect capacity required would

a) Require knowledge of capacity required in advance (e.g. over available capacity, size or number of circuits required)
b) Closely resemble Deep connection charges (e.g. user who triggers reinforcement would pay for all of it). Network assets last longer than generators, so second generator would pay nothing.

Transmission Users’ assets are typically expected to be outlived by Transmission Asset ‘assigned’ lifetimes (e.g. 25 years vs transmission investment costs annualised over 50 years), so there is an inherent assumption in the annualization factor that new Users will utilise and pay for capacity that is existing, and therefore existing capacity is not free.

The TNUoS conceptual model includes assumption that Users pay for what they use – effectively leasing or renting capacity from the TOs. Any cost inefficiencies associated with lumpy investments (e.g. excess transmission capacity/stranded investments) should not be met by Users but by those responsible for developing and planning the network.

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# Next Steps and Close

Jamie Webb

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# Thank you