Making a positive difference
for energy consumers

Access SCR

Challenge and Delivery Group update

26/03/2021

Aim of today's session

The purpose of this session is to:

- Provide an update on project progress overall, including timings
- Update you on our latest thinking ahead of possible early minded to decisions on some policy areas and get your feedback

Time	Item	Lead
10:00 – 10:05	Introduction	Andrew Self
10:05 – 10:15	Project update	Jon Parker
10:15 – 10:35	Access rights	Josh Haskett
10:35 – 11:40	Connection boundary	David McCrone
11:40 – 11:50	**Break**	
11:50 – 12:55	Transmission charges	Beth Hanna
12:55 – 13:00	Next steps	Andrew Self

We welcome your comments and feedback via www.slido.com using the event code **#SCR2021**. We will stop periodically through the presentation to review the comments.

Project update

Project update

- We informed the CG and DG last year that we had decided to delay our minded to consultation. This was in light of:
    - **Links with the development of flexibility markets**. A number of you fed back how important it is to have a clear overall vision for how flexibility will be valued. We said there was value in holding off issuing our minded to proposals on access until it is clearer.
    - **Wider transmission charging considerations**. We said there was a need to consider wider issues that have arisen with transmission charges before issuing our transmission charging proposals.

- Work on the different SCR workstreams has continued during this time and we are planning to publish a minded to consultation in May/June covering the connection boundary and transmission charging for small distributed generation.
    - Our work has concluded that our **access rights and connection charging reforms** are likely to be low regret under different pathways and so we are bringing forward an earlier minded-to consultation on these areas. We also see value in setting out our thinking on **TNUoS reforms for distributed generation**.
    - Full chain flexibility work has strongest interactions with the general direction of **TNUoS and DUOS reforms**, given the need to consider the role of ongoing network charges in sending flexibility signals relative to other mechanisms. We are continuing to work through these interactions and will update further at a later session.

Access rights

What are access rights? The nature of users' access to the electricity networks (for example, when users can import/export electricity and how much) and how these rights are allocated.

Current arrangements	Proposed future arrangements
• Traditionally users have little choice. • DNOs have begun offering "flexible connections" which have allowed users to get a cheaper or quicker connection, but have no defined cap on the extent to which they can be interrupted.	• A choice of well-defined access right choices. • This could help support more efficient use and development of network capacity. • Whilst still ensuring that users get the level of access that meets their needs.

We have focused on three access choices:

1. **Non-firm:** Choices about the extent to which users' access to the network could be restricted.
2. **Time profiled:** This would provide choices other than continuous, year round access (eg off-peak access).
3. **Shared:** Users across multiple sites in the same local area, to obtain access up to a jointly agreed level.

Identified access right changes are for distribution only and not for small users.

Non-firm

- Options will be defined in relation to the % of time that users are willing to be curtailed.
- Users will be able to identify the percentage of total access rights that are non-firm.
- Valued through connection charges.

Time-profiled

- Users would be able to identify the percentage of their total access rights that are time-profiled.
- Users could request to have either have no access or non-firm access during the “peak” period.
- Valued through connection charges and DUoS capacity charges.

Shared

- ENA Open Networks are taking forward trials alongside the trading of access rights.
- This will allow for further exploration and consideration of the issues that we have identified (eg concerns about level of take-up and practicality concerns).

Propose network operators develop a common, clear and consistent approach to monitoring and enforcement of access rights.

Access rights – approach to development

We're confident that access rights reform is a low-regrets option in the context of potential future market and system changes. We'll include our proposed approach to access rights in an early minded-to consultation in May.

- We recognise that implementation/codification of access rights will benefit from coordinating with changes to the connection boundary and DUoS. We therefore propose to implement the changes (including codifying the choices) as part of the final SCR direction.
- However, we think there *could* be scope for DNOs to begin to trial improvements in coordination with their Open Networks work (eg on flexible connections and the sharing/trading of access rights).
- This potentially includes improving curtailment information for non-firm/flexible connections, and improving choices for connectees (eg time-profiled access options).
- We will continue to consider whether there may be a case for more fundamental changes to distribution access – eg financially rights/connect & manage – in line with our work on our full-chain flexibility strategy.

Q&A

- Views on proposals
- Views on links to Open Networks programme ahead of full implementation

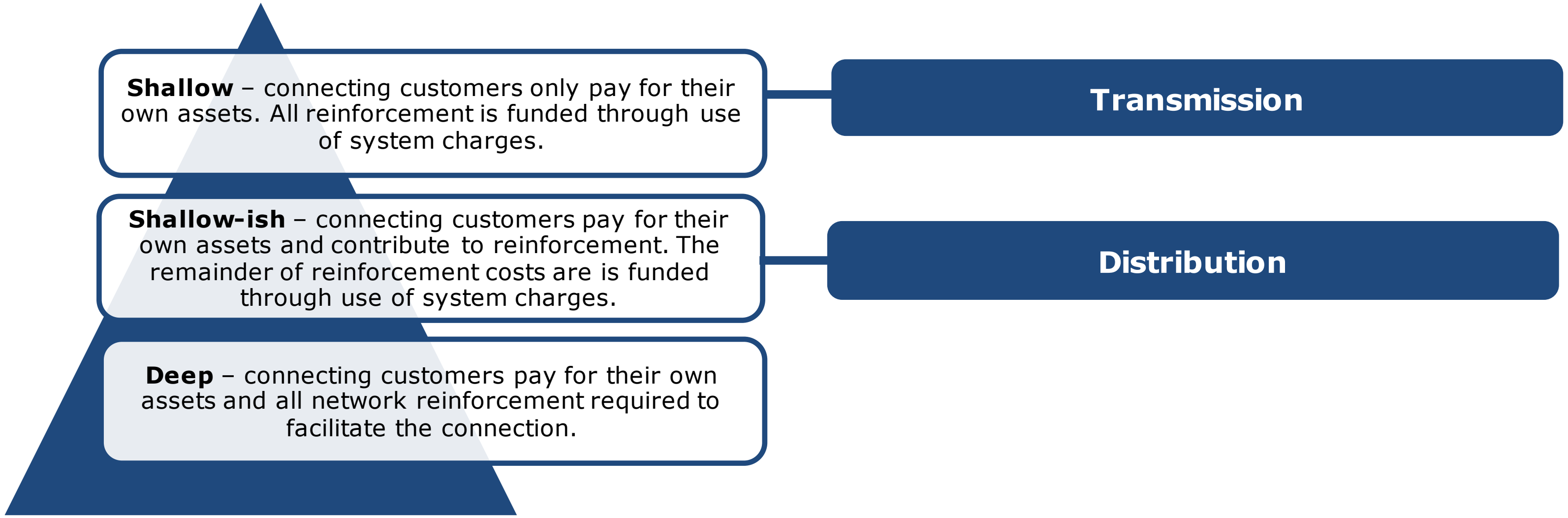
Connection boundary

Connection boundary - overview

These slides set out our current assessment of the issues caused by the connection charging arrangements and the options for reform. Modelling has given us insights about the cost from removing the locational signal, while the rest of our assessment considers the trade-off that making a change could have benefits that outweigh those costs.

A customer’s connection charge is determined by the connection charging boundary. The connection boundary is the extent to which customers pay for their connection, including their contribution to any reinforcement that is required to facilitate their connection. Customers connecting at distribution currently face a “shallow-ish” boundary.

We are assessing the case for making the boundary more shallow for demand and or generation (including whether it should be the same for both).



We previously highlighted the strong interactions between connection and DUoS charging. Given we are delaying our decisions on DUoS, we have tested the resilience of the different connection charging options against different possible outcomes on DUOS. We think that publishing an early minded-to position on connection charging on this basis has benefits (eg, in terms of planning ahead of RIIO-ED2), rather than waiting any longer.

The aim of the Access SCR is to ensure that electricity network access and forward-looking charging arrangements result in electricity networks being used efficiently and flexibly, reflect users' needs and allow consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. Our concerns that the current connection charging arrangements may be preventing this relate mostly to our first and second guiding principles under the SCR.

What outcomes are we trying to achieve?	Arrangements support the efficient use and development of system capacity	Arrangements reflect the needs of consumers as appropriate for an essential service	Arrangements are practical and proportionate
What are the issues with the current connection charging arrangements?	• Current arrangements can provide signals which can encourage users to locate in cheaper parts of the network, but **these may be excessive and could slow down attempts to achieve Net Zero**. • The current arrangements **tend to result in incremental reinforcement**, without taking into consideration wider network needs. The current arrangements **make flexibility unattractive** as a means of facilitating new connections to customers and DNO. • Different arrangements at transmission and distribution are **creating distortions and or impacting competition between generators**.	• Once heat pumps and EVs become mainstream, their use will become essential. Some but not all of this work is DNO funded. Where it is not, (eg, where existing customers need to go above 100A), **current arrangements mean users could face drastically different costs depending on when they are able to connect**.	• Our assessment is mainly focused on the efficiency and consumer impacts. • We think **a change could be relatively straightforward to implement** with modest implementation costs (although this would be more complex if some form of user commitment was required).

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Connection options

Results subject to final QA

26/03/2021

Key outputs and model limitations

Contents

- In this slide pack, we provide key outputs relating to:
  - Distribution network costs under different connection boundary options, modelled against two scenarios and two DUoS options.
  - Sensitivities with different flexibility costs.
- Outputs are in terms of Net Present Value of distribution network costs (discounted to 2023), after accounting for capitalisation of future capital cost.
- These costs are determined with *exogenously defined uptake scenarios for LCTs.*
  - Our model does not account for the impacts of different connection policy options on these levels of uptake.
- We also provide:
  - a brief summary of the methodology we have used to assess these costs
  - Some reflection on the modelling including:
    - benefits that are not captured within our quantitative modelling approach
    - our approach and assumptions
    - the importance/influence of charge and cost model design
- **We completed modelling of the options in w/c 15th March. We are continuing to process and carry out final QA of outputs.**
- **Results are subject to final QA**

Reminder: Overview of modelling approach

- We combine several models to capture the wide range of effects under consideration:
  - **Tariff models**: DUoS and TNUoS models (external to this project).
  - **Market model:** To observe impacts on dispatch and the wholesale market.
  - **Distribution network model:** To estimate impacts on distribution network reinforcement costs.
  - **Impact assessment model and bespoke analytical modules:** To bring together results and consider impacts on revenues, support scheme requirements, etc.
- Our analysis of the Connection boundary options is conducted using the Distribution model.
- We model all options under the CT and SP scenarios.

- **See the pack from the CG and DG in July 2020 for more detail on our modelling approach**

Key limitations

Technology uptake is defined exogenously within a FES scenario.

- This means we can't capture any benefits that different boundaries might have for uptake, which could be impacted by the options.

We don't model non-financial locational signals that could be sent such as timescale delays, or capacity heatmaps that might encourage users to locate in certain areas.

- This might mean that the model overstates the impacts of changing the connection boundary.

Our modelling of locational decision-making is relatively simple with respect to expectations about future charges (especially when these might flip from credits to charges and vice versa due to capacity decisions).

- We may refine this aspect of the methodology for future modelling runs, although it is unlikely to be possible to model this in much more detail.

Headlines

Headlines: A shallower boundary leads to less efficient decisions

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- A shallower boundary leads to increased system costs. This is because the locational investment signals for new capacity are dampened.
  - Modelled results suggest that a shallower boundary (with an amended voltage rule) leads to a relatively modest disbenefit.
  - This is also true of a hybrid option (shallow for demand, shallow-er for generation)

- This is in line with expectations: “properly” determined deep connection charges should provide strong locational signals.

- Our sensitivity results also show that with a higher cost of flexibility, the overall cost of the distribution network would increase.
  - Ofgem is considering whether flexibility services could be more effective with different connection boundary depths.

- **Results are subject to final QA**

Headlines: Locational DUoS charges may offset this to an extent

- The larger increases in NPV with a shallower boundary are associated with the counterfactual DUoS, rather than the Ultra-Long Run cost model.

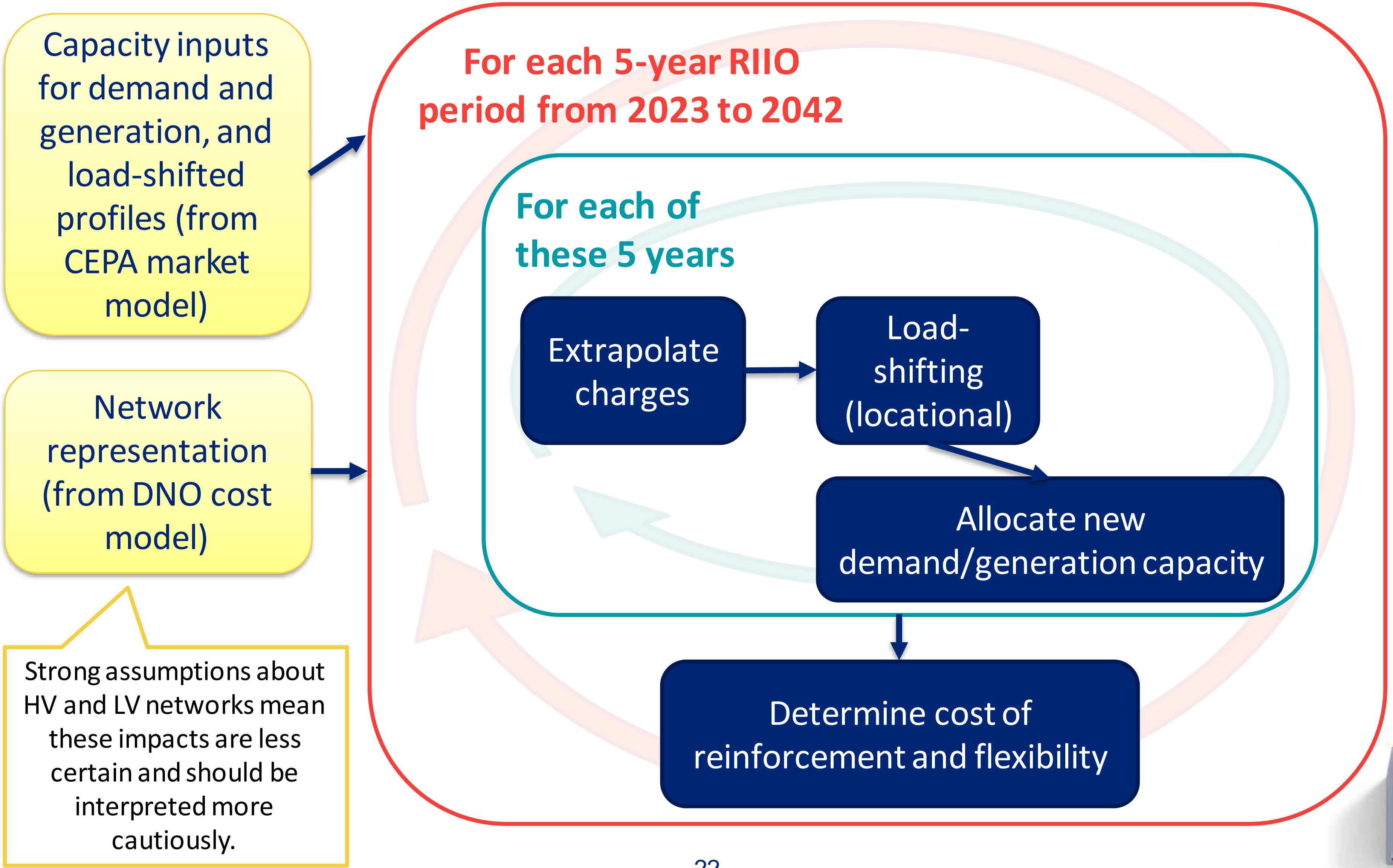
- This also aligns with expectations: the more closely DUoS aligns with a deep connection charge, the less impact there will be on locational decisions.

- The extent to which this is possible in practice depends on how cost-reflective the DUoS tariffs are.
  - Ofgem is still considering options for DUoS reform.
  - Some of these options (e.g. spare capacity indicators, more locational granularity) could further offset the distribution network disbenefit of a shallower connection boundary.

- **Results are subject to final QA**

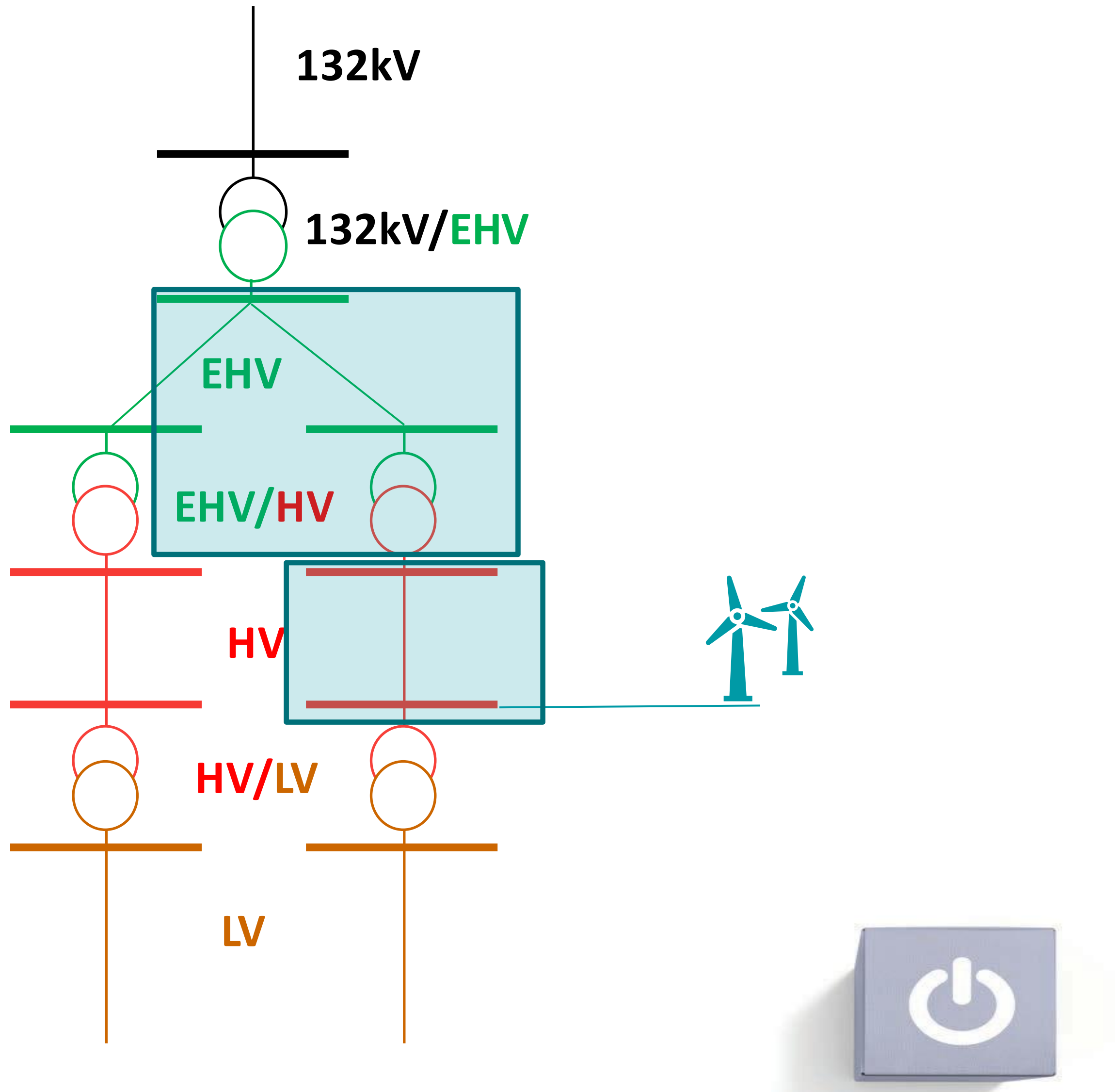
Context

Reminder: Overview of approach



Connection charge options

- Under the **counterfactual**, we use the current voltage rule (essentially, the current voltage level and the one above).
- The option which **amends the voltage rule** would mean customers only face connection charges for reinforcement for the voltage level to which they are connected.
- The option which introduces a **shallow connection charge** would remove any connection charges associated with reinforcement.
- There is also a **hybrid option**, which is completely shallow for demand and modifies the voltage rule for generation
- These connection signals would be considered against DUoS charges when users make locational investment decisions.



DUoS Options

- We have modelled the connection options against two DUoS backgrounds:
  1. The counterfactual CDCM and EDCM charges
  2. Charges set using a notional version of a possible DUoS Policy change

- In the counterfactual, these charge signals vary by voltage level but are assumed not to affect location decision:
  - In reality, EDCM charges are locational, but our understanding is that these are not accounted for due to perceived volatility.

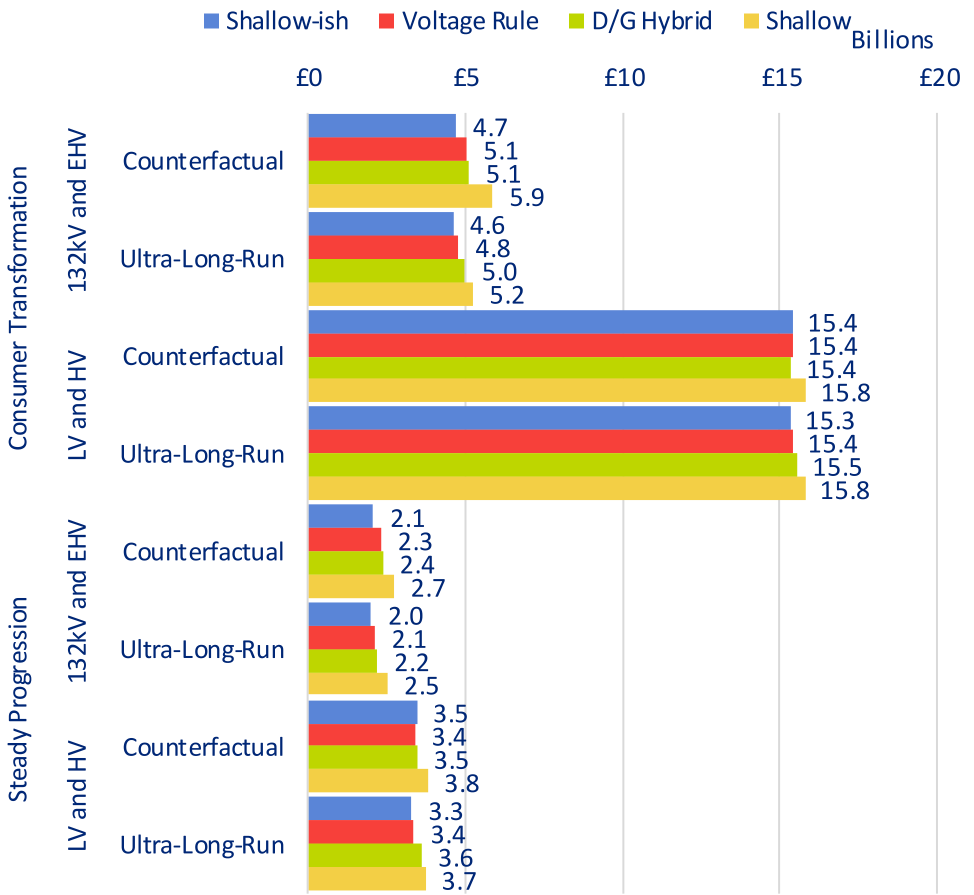
- The notional policy option has the following features:
  - Initial £/kVA unit costs are averaged across voltage levels
  - There is no spare capacity indicator
  - The allocation of costs to different timebands varies locationally
  - Unit costs are averaged by BSP (or GSP) group

- ***The DUoS option is likely to change further for the final DUoS results.***

Results

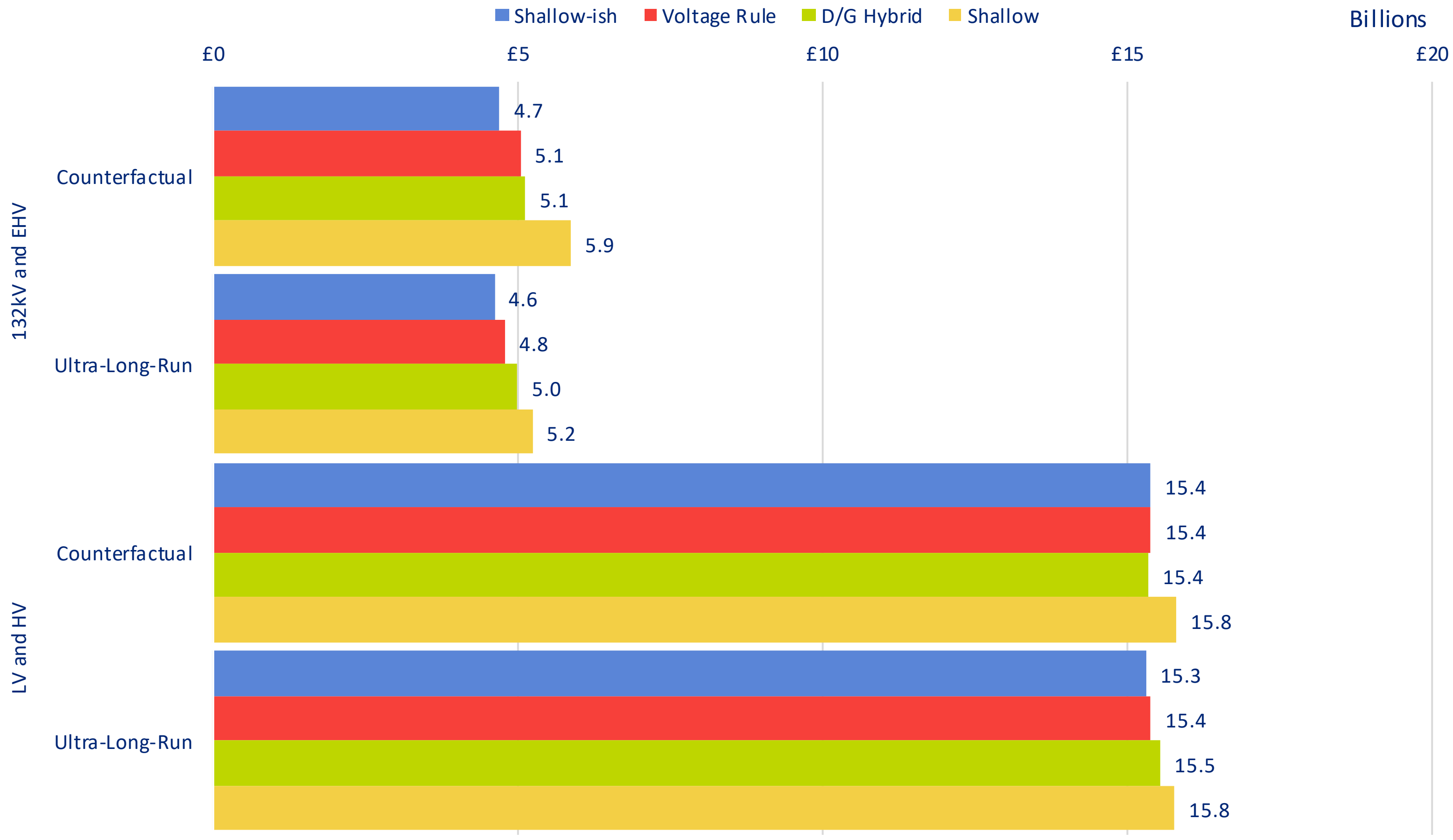
Distribution network costs

- As expected, a shallow boundary leads to a higher modelled network reinforcement cost.
- A shallower boundary (with the amended voltage rule) also leads to an increase in cost, although the difference in NPV is not as severe.
- Locational charges offset the increase in system costs to some extent, especially for a completely shallow boundary.



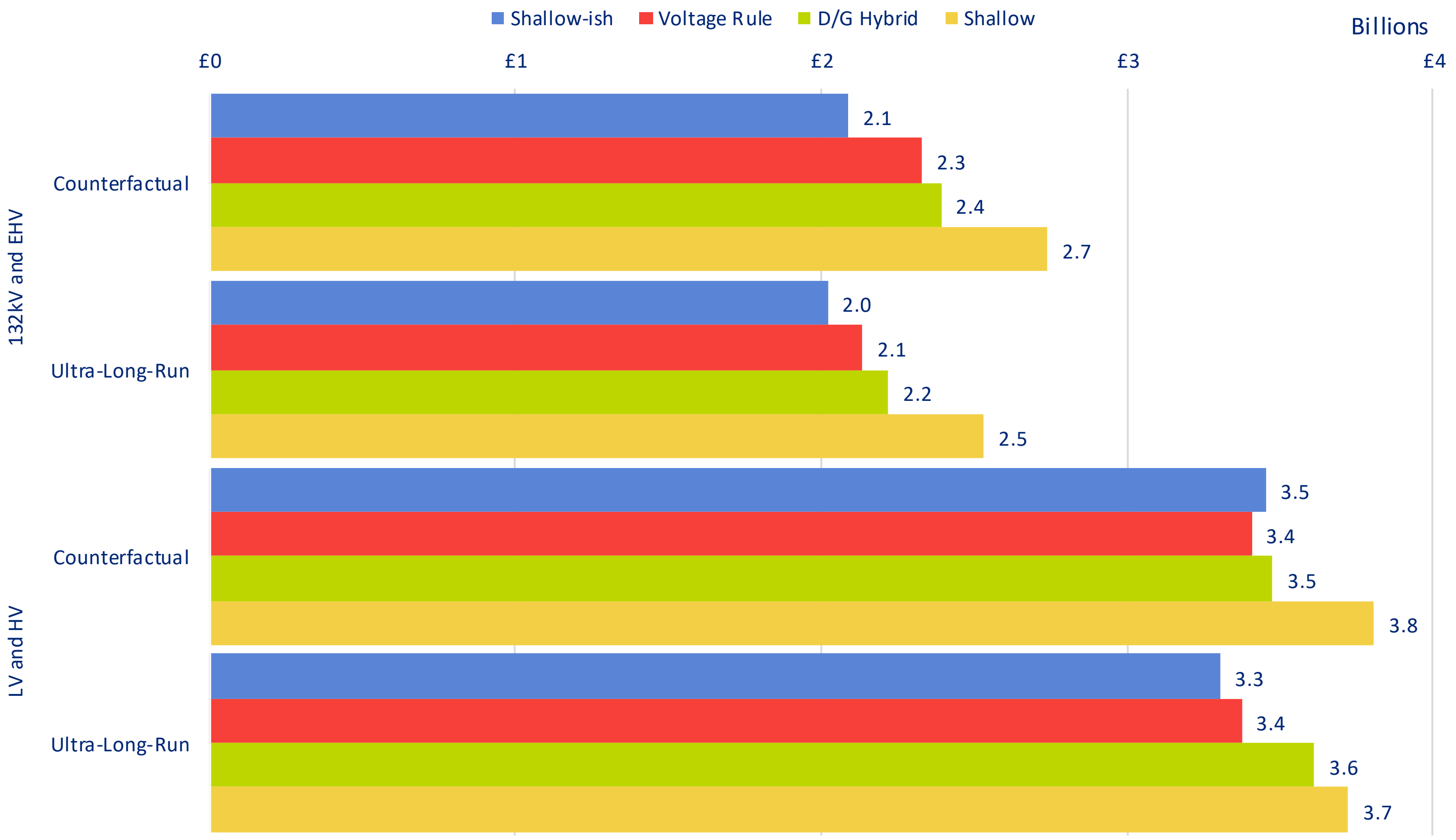
The efficiency of DUoS charges as a locational signal depends on the extent to which they replicate the signals from deep connection charges – Ofgem will be exploring this in more detail with later policy analysis.

Distribution network costs - CT



Shallower connection charges lead to increases in distribution network cost.
In general, Ultra Long Run DUoS offset this cost increase to an extent.

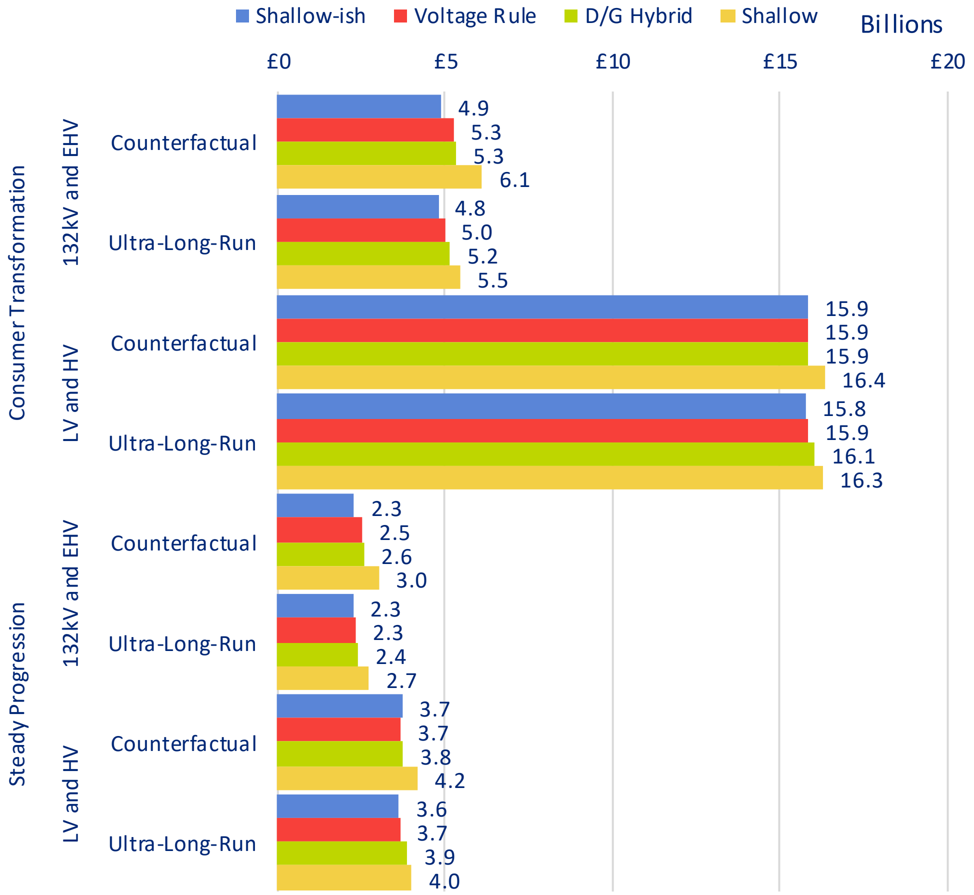
Distribution network costs - SP



Shallower connection charges lead to increases in distribution network cost.
In general, Ultra Long Run DUoS offset this cost increase to an extent.

Flexibility sensitivity

- We have explored a sensitivity where the baseline cost of flexibility is doubled, from £10,000/MW to £20,000/MW*
  - This is to aid Ofgem thinking about how efficiency of flexibility services might relate to depth of connection boundary.
- With a higher cost of flexibility, we observe a systematic increase in the NPV of distribution costs, either due to:
  - Flexibility not being used, and more expensive reinforcement being chosen instead, or
  - Flexibility still being used, but at a higher cost.



*The cost of flexibility is assumed to decrease over time, and to be higher at lower voltage levels.

Importance of cost reflectivity and charge design

- The suitability of DUoS charges as a stand-in for deeper connection charges depends on the extent to which the former can replace the signals from the latter.
- The more cost-reflective the DUoS charges are, the less disbenefit will materialise from making connection charges shallower.
- Some exploratory runs of the model suggest that the disbenefit is reduced with higher granularity and spare capacity indicators, compared to the option that has been modelled for these early runs.
  - Ofgem will consider the design of the DUoS options in more detail as part of subsequent policy decisions.
- In addition, there are other gaps in the charges used within the modelling which are going to be addressed for the final DUoS runs, such as the current lack of charges for generation at the voltage level of connection. These gaps may lead to unexpected and/or unintended results.

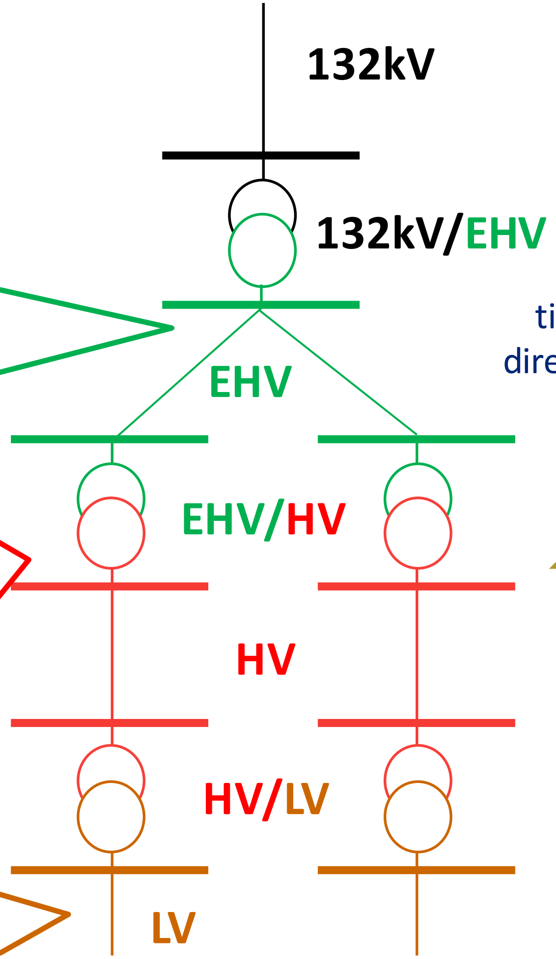
Annex – methodology reminder

Reminder: Network representation

- Storage
- Solar PV
- Wind farms
- Other generators (e.g. thermal)
- Large non-domestic customers

- Storage
- Solar PV
- Wind farms
- Other generators (e.g. thermal)
- Large non-domestic customers

- Domestic
- Non-domestic customers
- EVs
- Heat pumps
- Rooftop solar



We consider six timebands for each direction of power flow

Reverse power flows due to generation

Power flows to meet demand

Flows from lower to higher voltage levels increase due to losses

Flows from lower to higher voltage levels decrease due to diversity

Assume that all of the HV and LV networks below a primary are homogenous – **strong assumption** but consistent with cost model and proportionate considering available data. ***Means HV and LV impacts are less certain and should be interpreted more cautiously.***

Locational decision making

- Our modelling of locational decision-making is quite abstract. There are many factors that we cannot model such as non-financial signals sent by DNOs, or other factors that influence location decisions such as transport links, generation load factors etc.
- We have incorporated assumptions and constraints within the model to guide the model towards more realistic outcomes, as described below:

Limit how much user capacity can be deployed on each voltage level in a single year (max 1 new connection), and over a 5 year period (max 2 new connections)

Restrict generation in more urban areas e.g. wind only allowed in the most rural settings – (with some exceptions where necessary for the model to find a solution)

Limits on how much capacity can move between voltage levels, and also between BSP/GSP groups. These limits are strongest for new large demand capacity, and weaker for new generation.

Wind, solar, utility scale storage etc not on LV or HV/LV networks

Strongly disincentivise decisions that would lead to very extensive reinforcement (e.g. which would require more than 2 additional reinforcements of an existing asset) to represent the possibility of connection delays.

UK
Queens House
55-56 Lincoln's Inn Fields London
WC2A 3LJ UK

T. **+44 (0)20 7269 0210**
E. info@cepa.co.uk

www.cepa.co.uk

Australia
Level 20, Tower 2 Darling Park 201
Sussex St
Sydney NSW 2000

T. **+61 2 9006 1307**
E. info@cepa.net.au

www.cepa.net.au

cepa-ltd

@cepaltd

Arrangements should support efficient use and development of system capacity

Is the connection charge providing an effective signal to users?

The current arrangements may not be providing an effective signal, potentially being too strong for some network users, while not giving others any signal at all.

Is the signal too strong?

- Under the status quo for distribution charges, it is the sole locational signal for most distribution connections and so removing it would lead to some additional network costs as users locate in more expensive areas of the network.
- However, it might risk creating barrier to investment. Especially in cases where we think behaviour change is unlikely.
- Could potentially over-signal costs in combination with forward-looking ongoing distribution charges.

Is it the only way to influence investment decisions?

- The connection charge is a clear upfront charge known at the point of investment, but ongoing charges can also influence investment decisions.
- We do note however that generation do not face any DUoS charges today, even in areas where they would contribute to network costs.

Does the signal reach the right users?

- **It only signals value to the marginal user** of changing investment plans once network capacity is reached.
- **Users who use up capacity before that point receive no signal** but can still act to save costs.
- It **provides no signal about long-run costs of maintaining the network** and does not provide any investment signal to users whose actions can help offset need for reinforcement in that area.

This previously led us to reduce reinforcement costs recovered through connection charges and rely more on use of system charges instead:

- **Transmission** "Plugs" – it was argued that TNUoS charges, derived on an incremental cost basis rather than connection charges based on an actual cost basis, would provide more efficient signals.
- **Distribution** – we moved from deep to shallowish charges for generation in 2003 as the benefits for competition supported a change. However, until or unless DUoS provide appropriate cost reflective signals, it remained appropriate to retain some form of locational signal within connection charges.

Arrangements should support efficient use and development of system capacity

Are the current arrangements acting as a barrier and slowing down the transition to Net Zero?

There is evidence of current connection costs acting as a barrier to new connections (in particular, for example, the roll-out of EV charging infrastructure). We will continue to look for more evidence as part of our decision making.

ENA Green Recovery

The ENA have issued a call for evidence (closed 19 March) looking for "shovel-ready" projects that will support the Green Recovery and address key Government policies such as net zero and the decarbonisation of transportation.

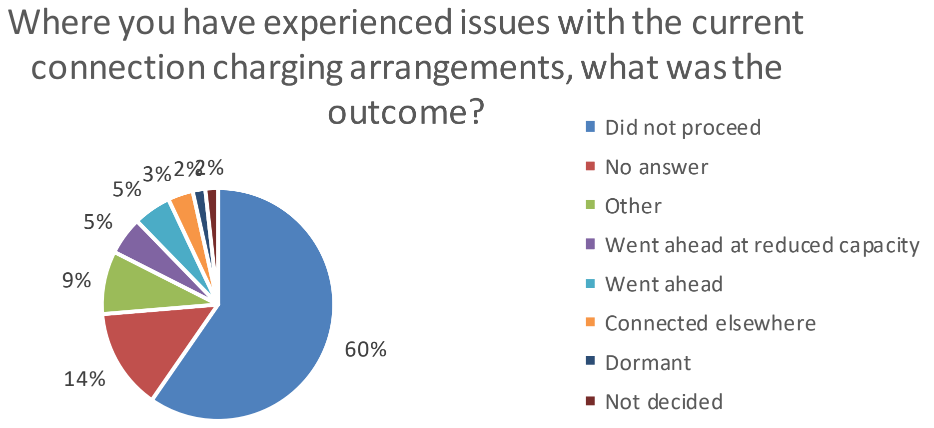
This funding is aimed at **new projects that are struggling to be justified due to network infrastructure costs**, rather than those that can or have already been paid for.

Stakeholder feedback

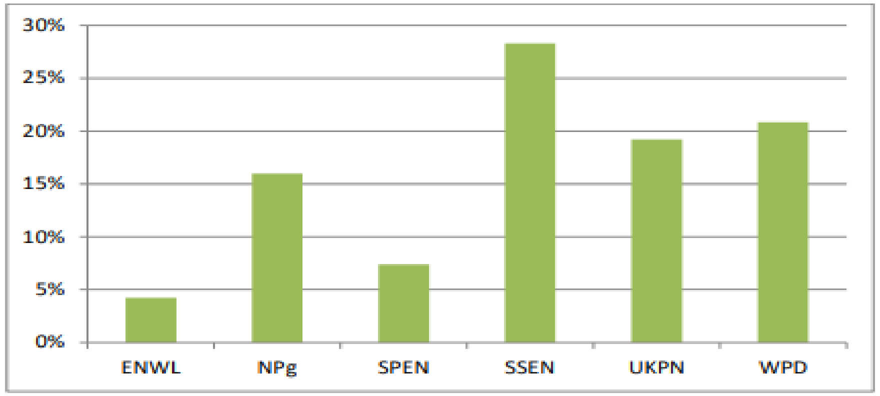
Infrastructure is regularly noted one of the main barriers preventing people being able to meet targets around EV uptake. Network users feel it is highly unfair that **the one that triggers the reinforcement bears the high cost** (BEIS roundtable, 2020).

Local authorities' report to DfT on EV strategies and the barriers they were facing. **One third (25 out of 75) said grid constraints and connection costs were a barrier**.

Logistics UK (representing fleet operators) report for government – grid capacity was highlighted by members as a concern / barrier.



Feedback received from EV charging installers, renewable generators and other stakeholders on issues experienced with current arrangements (more detail in annex).
Source: SCR Challenge Group, Charging Futures, BEIS OLEV stakeholder distribution list, 57 responses, 2019.



Acceptance rates reported for DG connection offers
Source: Ofgem, Unlocking the capacity of the electricity networks, 2017.

Arrangements should support efficient use and development of system capacity

Do the current arrangements limit DNOs from being able to develop their networks in a more efficient way?

The current arrangements may result in incremental reinforcement as the means of facilitating new connections. The current arrangements may be a barrier to using flexibility as a means of facilitating new connections (rather than reinforcing the network).

DNOs are discouraged from strategic investment and considering the wider needs of their network.

- Consequential staged applications corresponding to step increases in demand may lead to inefficient network investment rather than holistic network solutions. The **piecemeal nature of connections-driven investment may not enable DNOs to respond to a true picture of the need for increased capacity**, or provide long term signals for the full value to customers and networks of flexibility or investment.
- The current boundary means that DNOs recover much of the funding for connection-led reinforcement only once users pay connection charges. **DNOs can invest ahead of need but the risk not fully recovering their costs gives them a strong incentive to wait** until they receive connection requests, rather than act in advance.
- **Current arrangements may lead to a coordination failure**. Connection charges with reinforcement included are often considered unaffordable, so generators are left to no proceed with their project or choose a reduced capacity or non-firm connection. Alternatively, generators that can delay are able to free ride on those willing to pay for reinforcement. With shallower charges, a more efficient outcome can be achieved with the DNO managing network capacity through strategic investment based on understanding of the demand from a wider group of customers.

DNOs do not use flexibility as a means of facilitating new connections.

- **The current arrangements may be a barrier to DNOs being able to use flexibility to facilitate new connections**.
- Under the current boundary DNOs need to recover the cost of new network capacity through charges to individual customer connections. This works for traditional reinforcement as the cost is known upfront. The cost of flexibility to facilitate to support new connections would vary over time and so would require the customer to accept an uncertain (and uncapped) liability to be settled retrospectively.
- **All DNOs have reported issues** with using flexibility to facilitate new connections. One trial showed there were significant potential bidders for a simple generation turn down/demand turn up product if it is funded – but **no appetite from connection customers due to this risk**.
- A more shallow connection boundary would transfer this risk onto DNOs who are best placed to find most efficient way of funding the work needed to facilitate the connection (ie, comparing build and non-build solutions).

Arrangements should support efficient use and development of system capacity

Are arrangements distorting competition between generators?

Different arrangements exist at transmission and distribution. This could be influencing investment decisions and or impacting competition between generators connecting at different points on the network.

Issue	What is the issue?
Recovering the cost of transmission work triggered by customers at different voltages/locations	• Transmission Attributable work (eg upgrading a Grid Supply Point) triggered by a distribution connection is currently charged to the connection customer within the DNO's connection charge. This can be prohibitively expensive and prevent connections from going ahead. • Reinforcement work at 132kV in Scotland is funded by TNUoS in Scotland, whereas it is included within the upfront connection charge in England and Wales. This could lead to a distortion between generators in different parts of GB.
Potential distortions between distribution and transmission connected generators	• If we introduce generation dominated areas under our DUoS reforms, Distributed Generation (DG) could face higher costs beyond what is cost reflective (compared to those at transmission) if they are charged a combination of connection charges (including a contribution to reinforcement) and reformed DUoS. • This could create a distortion in favour of transmission connected generation.

Scenario	What charges do they face?	Impact of possible changes
Generator connecting at 132kV in Scotland **(transmission)**	• User does not face any connection charge for shared transmission works (unlike at distribution). • Pays local circuit TNUoS charge and wider circuit TNUoS charge.	• Unaffected by connection charging changes
Generator connecting at 132kV in England & Wales **(distribution)**	• Under our TNUoS proposals, the generator would face TNUoS charges. • Will also pay connection charge for any reinforcement needed to 132kV network	• Removing voltage rule (ie "shallower") would mean no longer face differential charges for transmission network • If we did not go fully shallow, we would need to ensure our DUoS reforms do not lead to relatively higher charges than transmission connected generation.

* Transmission voltages: England and Wales: above 132kV (275kV and 400kV), Scotland: 132kV and above

Focus in on households

Could arrangements be a barrier/cause significantly different cost impacts for different households?

Once heat pumps and EVs become mainstream, their use will become essential. Some but not all of this work is DNO funded. Where it is not, (eg, where existing customers need to go to above 100A), current arrangements mean users could face drastically different costs depending on when they are able to connect.

Government's Ten Point Plan sets out an ambition of installing 600k heat pumps each year by 2028. The CCC's Sixth Carbon Budget forecasts a total of 5.5 million heat pumps installed in homes by 2030, of which 3.3 million are in existing homes.

We are concerned that customers may face lower or higher costs depending on when and how they are able to connect. DNOs currently fully fund reinforcement carried out to allow the installation of all equipment at an existing premises fused at 100A or less subject a number of conditions. Where the customer has to go above 100A, the customer will face some or all of the cost of any reinforcement that is triggered.

We expect 100A to be sufficient for the majority of customers, but not all. We are attempting to gather evidence about the number of households - and particularly those from lower income deciles - that may need to go beyond 100A if installing an EV charger and heat pump. Evidence we have seen so far suggests that this will be a non-trivial number.

We think there would be benefits in terms of some connections coming onto the system sooner than otherwise possible. These would offset some of the cost of changing the connection boundary.

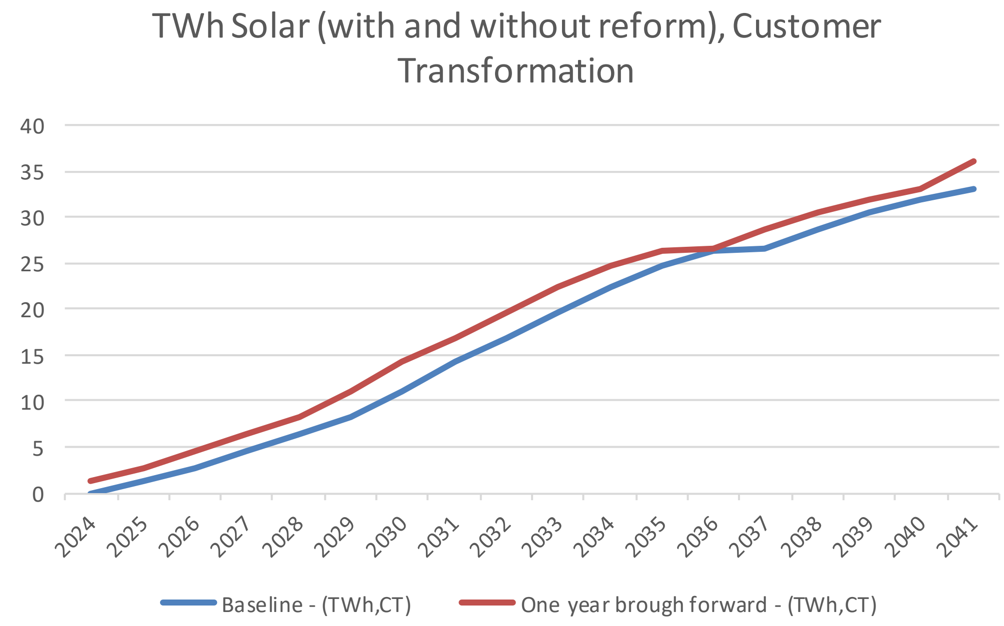
We are looking at ways of quantifying the possible benefit if our proposals bring forward certain types of connections by one (or more) year(s).

However, it is difficult to model the impact of charging changes on a diverse range of business models, so instead we are seeking to get an indication of the potential benefits by quantifying the value that would be achieved if the changes were able to accelerate take-up by a year.

In the example here, we can identify a potential benefit as more solar generation connects to the system and displaces thermal generation sooner than if we did not make a change.

This can be expressed in terms of the cost of carbon saved and compared against the cost of moving more shallow identified in CEPA TNEI's modelling.

We plan to repeat this for other types of generation and, where possible, demand. At this stage however, our expectation is that a one year advance in connections is unlikely to be greater than the modelled increase in network costs if we go fully shallow without DUoS reforms. **We would welcome views on how we can further develop our off-model analysis to quantify the benefits of a change.**



FES Scenario	CT	LTW	ST	SP
NPV (central) - £m	98	83	69	67
NPV (high) - £m	148	125	105	100

We are continuing to work through the arguments for and against making a change to the connection boundary, as well as the trade-offs, ahead of determining our minded-to proposals for consultation.

As well as the connection boundary, we are continuing to assess what other changes we might want to make:

- **Deferred payment**: we think the risk of bad debt and possible negative impacts for competition in connections outweigh any benefits introducing deferred payment terms would bring.
- **Liabilities and securities**: we are continuing to assess whether introducing some form of user commitment is appropriate to protect consumers from the cost of inefficient investment. However, anything we introduce must be proportionate and take into account for the scope for re-use of assets.

We welcome the CG and DG's views, particularly on:

- Our assessment and the arguments for and against making a change
- Any further evidence we should take into account

Break

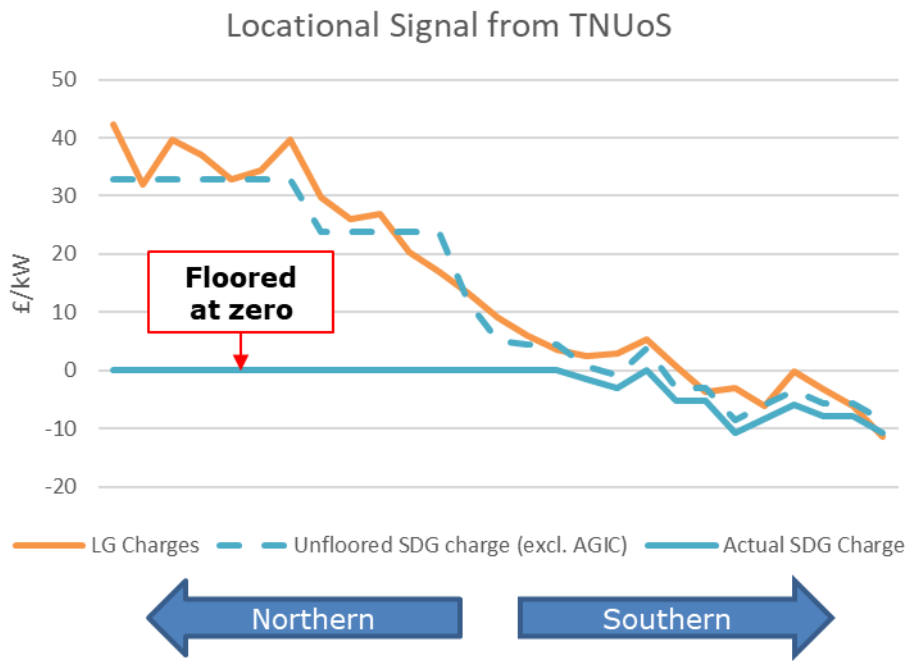
TNUos charges for small distributed generation

Session overview

- The purpose of this session is to provide an update on our assessment of the impact of applying TNUoS charges to SDG:
  - Reminder of why we are considering this issue as part of the Access SCR including our assessment against the Guiding Principles
  - Outcomes of CEPA TNEI's impact assessment modelling
  - Implementation options, including how this change fits within the context of other work we are doing around the need for a wider review of TNUoS charges and full chain flexibility

Is there a distortion?

- A 2018 change to planning standards means small distributed generation (SDG) is classified as generation, rather than negative demand. As a result, SDG is considered to contribute equally to transmission network costs as large generation (transmission connected and distributed generation of 100MW)
- However, LG and SDG face TNUoS charges that are set under different methodologies:
  - LG charges are:
    - Applied as a fixed £/kW for transmission entry capacity
    - Credits generally apply in the south, with charges in the Midlands and north
  - SDG charges are:
    - The inverse of the forward looking element of demand charges applied to export during Triad (embedded export tariff (EET))
    - Floored at zero, meaning no charges are levied



- The difference in TNUoS approach between LG and SDG creates a boundary distortion that incentivises users to connect as SDG rather than LG if possible to avoid high charges in Scotland or maximise credits in England
- *Note: the changes we are considering are largely with regards to charging generation TNUoS to SDG, rather than treating SDG as generation in the transport model, as a result of the SQSS change.*

- We previous set out possible options to improve cost reflectivity of SDG charging

Retain inverse demand charges, but remove floor	Apply generation TNUoS to SDG on the same basis as it is applied to LG	Apply local circuit charges to DG that make use of them
✓ More cost-reflective than existing regime ✖ SDG charges remain different to larger generation ✖ Some dispatch distortions remain ✖ Practical issues ✖ Impacts on some existing generators	✓ Most cost-reflective, likely to lead to more efficient siting and dispatch of plant ✓ Simplified, harmonised charges ✖ May require changes to generators relationships with other industry parties ✖ Impacts on some existing generators ***IA modelled option***	✓ Improved cost-reflectivity ✓ Harmonised charges, removing remaining distortion ✖ Practicality issues with including in IA modelling ***Separately assessed***

- Although removing the floor from the EET would be more cost reflective than the current approach, it would retain differential treatment between LG and SDG
- Some generators (e.g. Scotland) would face charges for exporting during Triad
- Instead, we decided to model an option that applies the same TNUoS charges to all generation, except for generation under 1MW

- This issue is too locationally specific to include in our impact assessment modelling
- We are separately assessing options to address and expect to consult on this, as part of our minded to decision

Assessment against SCR principles

Arrangements support efficient use and development of the energy system

Charging all SDG on an equivalent basis to LG would better reflect network cost drivers as defined by SQSS, and so should **support the efficient use and development of the energy system**. Some of the impacts we expect to see include:

- Creating a level playing field for investment, removing the current distortion that could lead to inefficient sizing or siting decisions, resulting in changes in:
  - the balance between >100MW and <100MW projects being brought forward in Northern areas
  - the generation mix, with more solar or offshore wind, or some onshore wind relocation south
- Creating a consistent set of operational signals for plant above and below 100MW leading to more efficient wholesale and capacity market outcomes

Any changes are practical and proportionate

- It is likely to be impractical to charge all SDG on an equivalent basis to LG. We think 1MW is a practical cut-off for the charges which would deliver much of the benefit because:
  - Users of this size can take part in the BM and wholesale market without aggregation
  - We believe the ESO has better data on >1MW generators than those below, from the DNOs' embedded capacity registers
- We are working through options for how revenues can be collected from SDG, including identifying where there are existing contractual relationships in order to minimise the changes needed
- We are currently assessing whether there is a need for a wider review of TNUoS charges to address issues that have become clearer since the SCR launched. As part of this, we are weighing up the potential disruption from introducing changes now that may change again under a wider review.

Challenge and Delivery Group

TNUoS SDG option

Results subject to final QA

26/03/2021

Contents, approach and limitations

Contents

- In this slide pack, we:
  - Provide a brief reminder of approach and summarise key model limitations.
  - Summarise key outputs relating to:
    - Locational investment impacts
    - System wide impacts:
      - Market price impacts
      - Transmission network reinforcement and constraint management
      - Conventional plant dispatch
      - Renewables curtailment
    - Impacts on producer revenues
    - Consumer welfare: NPV and break down of NPV

- **We completed modelling of the options in w/c 15th March. We are continuing to process and carry out final QA of outputs.**
- **Results are subject to final QA**

Reminder: Overview of modelling approach

- We combine several models to capture the wide range of effects under consideration:
  - **Tariff models**: DUoS and TNUoS models (external to this project).
  - **Market model:** To observe impacts on dispatch and the wholesale market.
  - **Distribution network model:** To estimate impacts on distribution network reinforcement costs.
  - **Impact assessment model and bespoke analytical modules:** To bring together results and consider impacts on revenues, support scheme requirements, etc.
- In this pack we focus on outcomes under the main CT scenario. We are also processing results under the SP sensitivity scenario.
- We model in calendar years for an appraisal period of 2024 to 2040. We interpolate between three spot years (2024, 2029 and 2040).

- **See the pack from the CG and DG in July 2020 for more detail on our modelling approach**

Key limitations

- We build several assumptions into our model. Some of the key limitations are below:

Assumption	Impacts on modelled outcomes	Mitigation
Total capacity of each technology for transmission and distribution level is set by the relevant FES scenario.	Our modelling does not include a feedback loop which takes revenues for different technology types and 're-balances' the generation mix.	Development of analytical tools to analyse revenue impacts on different types of technologies and estimate the impact on subsidy support requirements.
Bounding of locational allocation: Many technologies can change location in our model. However, the ability to move is 'bounded' relative to a central case.	Several drivers of locational decisions are not captured in the model. We 'bound' locational allocation to reflect these broader limitations. In reality, capacity may be able to re-locate to a lesser or greater extent than allowed in our modelling.	Agreed with Ofgem to incorporate relatively broad bounds so that technology re-allocation is not overly constrained.
Simplified representation of transmission network: Transmission reinforcement and constraints are estimated based on a sub-set of key constraint boundaries within the market model.	Our market model has been adapted to consider impacts across key constraint boundaries but may not fully represent constraint actions and their evolution over time.	Qualitative consideration of the potential for underestimation of constraint actions and transmission network investment costs.
No feedback loops between transmission network development, behaviour and DUoS/TNUoS charges.	Changes in behaviour may affect tariff residuals rather than being reflected in tariff impacts for consumers/producers.	For transmission tariffs, we calculate the level of tariff residual and how this changes under each option to estimate the change to the residual.

Headlines

Headlines: Positive impacts align with Ofgem expectations

- We observe many of the benefits from the TNUoS SDG option (‘T_var’) that Ofgem intends:
  - We see some movement of distribution-connected capacity closer to demand centres
  - This generally leads to small efficiencies in dispatch:
    - Less transmission network investment
    - Lower constraint management costs
    - Reduced curtailment of renewables
    - Reduction in use of dispatchable technology
    - Lower carbon emissions

- **Results are subject to final QA**

The TNUoS SDG option appears to drive many of the expected benefits

Headlines: Important unintended consequences

CEPA economics matters

- However, we also observe some important unintended consequences:
  - We see a small but consistent increase in the demand-weighted average wholesale price, in turn increasing the price paid by consumers.
  - This increases producer revenues from the wholesale market.
  - BUT, the change in Generator TNUoS tariffs and Distributed Generation loss of EET credits drives an overall reduction in revenues for some producers.
  - RES support scheme costs increase to maintain the same level of renewable capacity of each technology.
  - Non-RES plant respond to higher wholesale price periods and non-RES 'missing money' falls under the option.
  - We also observe an increase in the tariff residual under the option.
- **Results are subject to final QA**

Under the assumption that the increase in the tariff residual is passed through as tariff reductions for producers and consumers, we observe a positive NPV from the option under CT.

Generation and storage locational investment

Summary of locational investment impacts

- Within defined bounds, we allow new capacity of several technologies (particularly RES) to choose where to locate in our model. Choices are based on revenue maximisation.
- Relative to the baseline, we observe the following general trends for locational investment in new capacity under the TNUoS option:
  - Little change in allocation of transmission-connected capacity.
  - More movement of distribution-connected generation, predominantly onshore wind and solar.
  - Movement away from Scotland and northern England to midland and eastern zones.
    - C. 11% reduction in connection of new distribution-connected onshore wind in Scotland over the period.
    - C. 13.5% reduction in new distribution–connected solar in northern England (not including BtM solar).
  - Little movement of capacity in southern and south-western zones.

System wide impacts

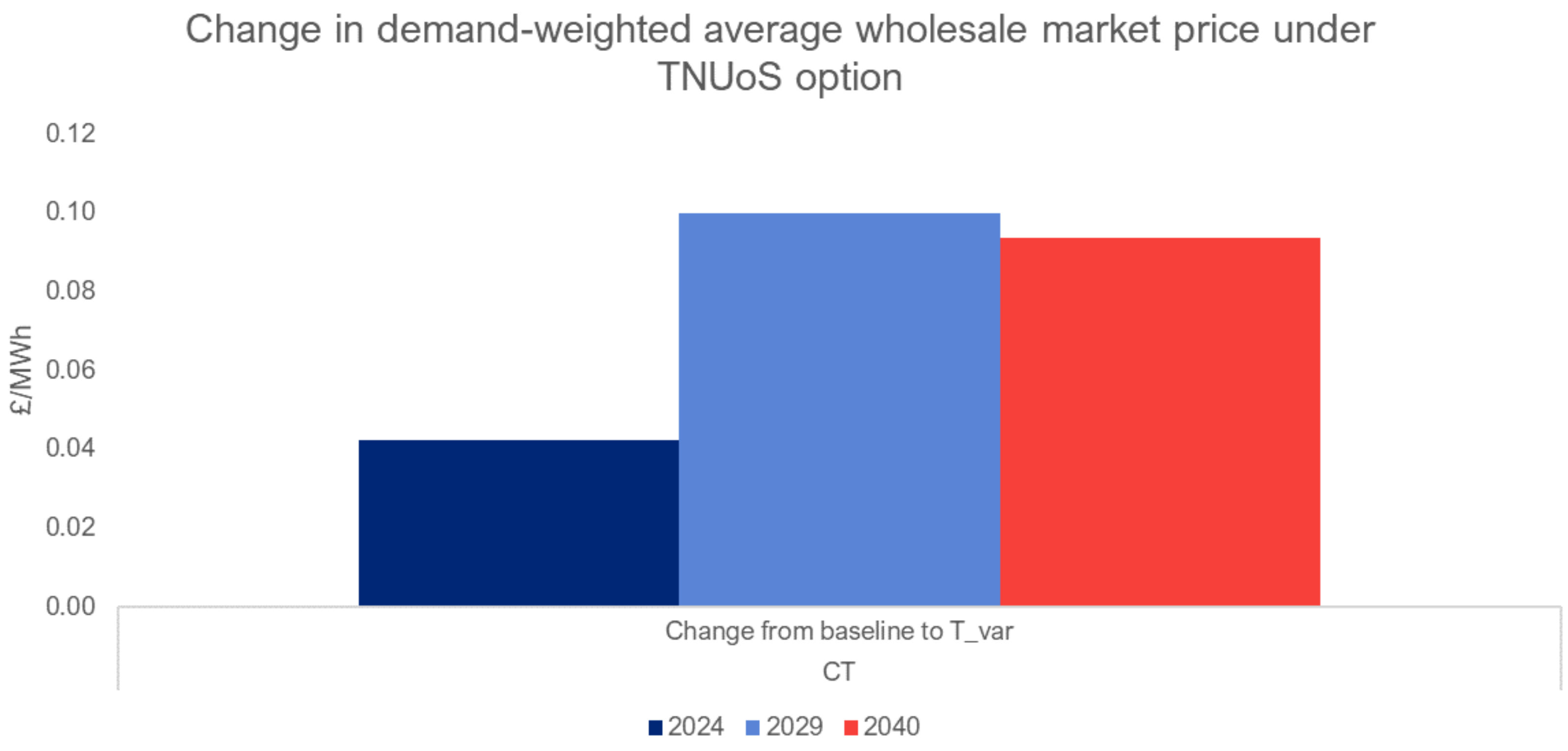
System wide impacts

- In this section we consider:
    - Wholesale market prices
    - Transmission network reinforcement
    - Constraint management costs
    - Dispatchable technology
    - Curtailment of renewables

- Observations:
    - We see an increase in the demand-weighted average wholesale price, driven by a removal of the EET credit in particular.
    - We observe a reduction in transmission network investment and constraint costs.
    - We see more efficient dispatch with:
        - less use of conventional generation for balancing and congestion management; and
        - reduced curtailment of renewables.

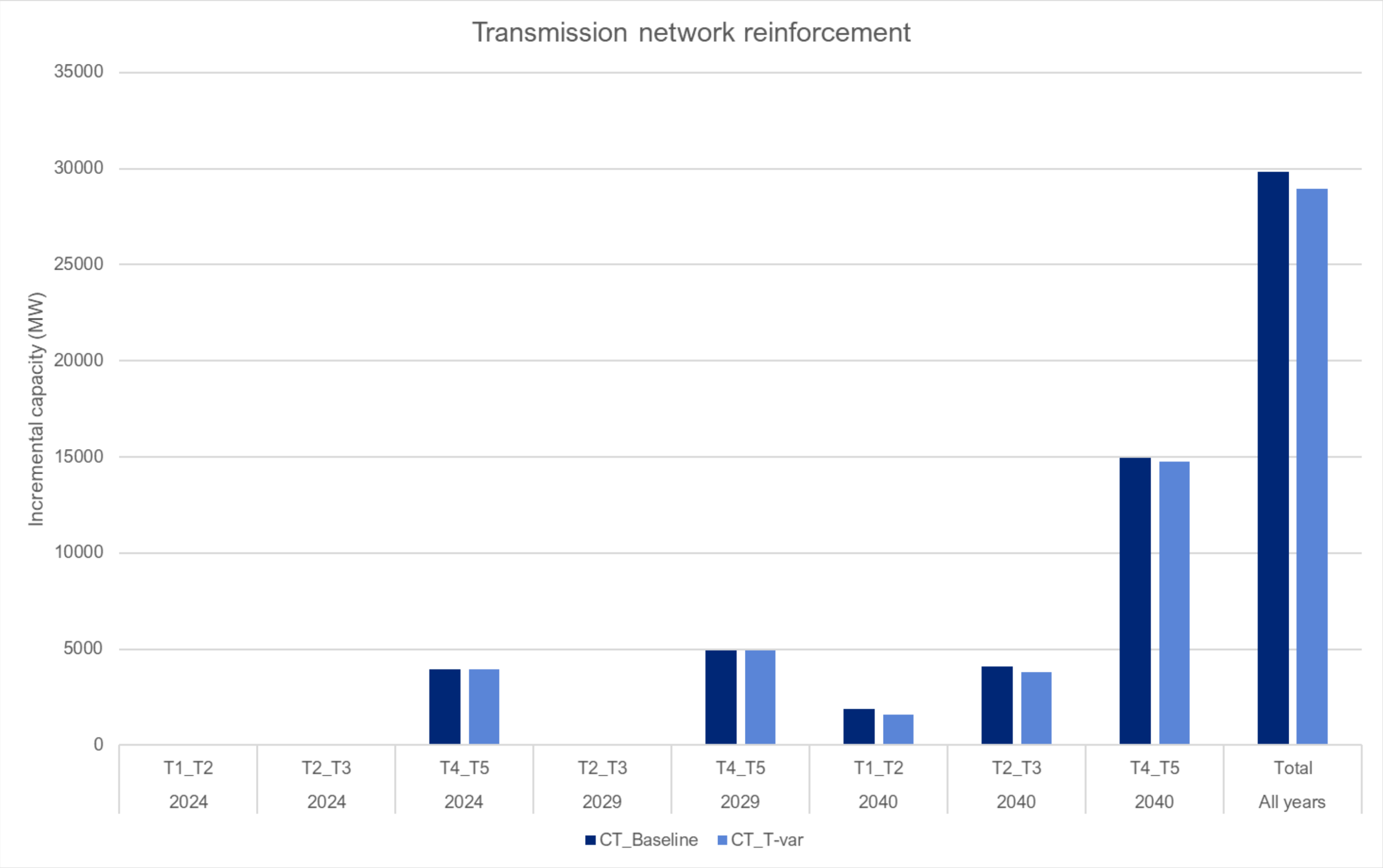
- **Results are subject to final QA**

System- wide impacts: market prices



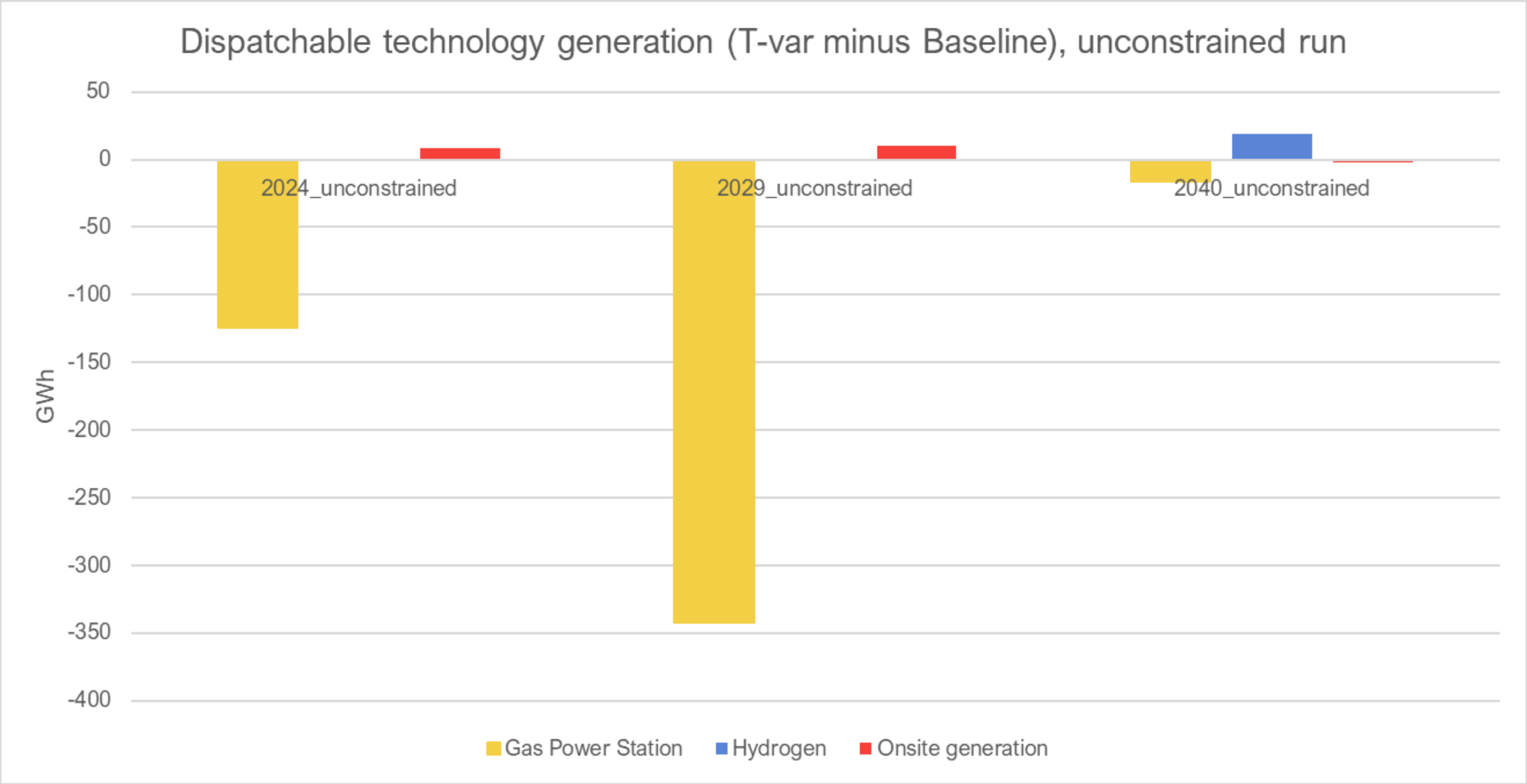
We observe a small but consistent increase in the demand weighted average wholesale price under the TNUoS option. This is a second order effect, driven by changes to the price of embedded generation participating in the market, particularly during triad periods.

Transmission network investment



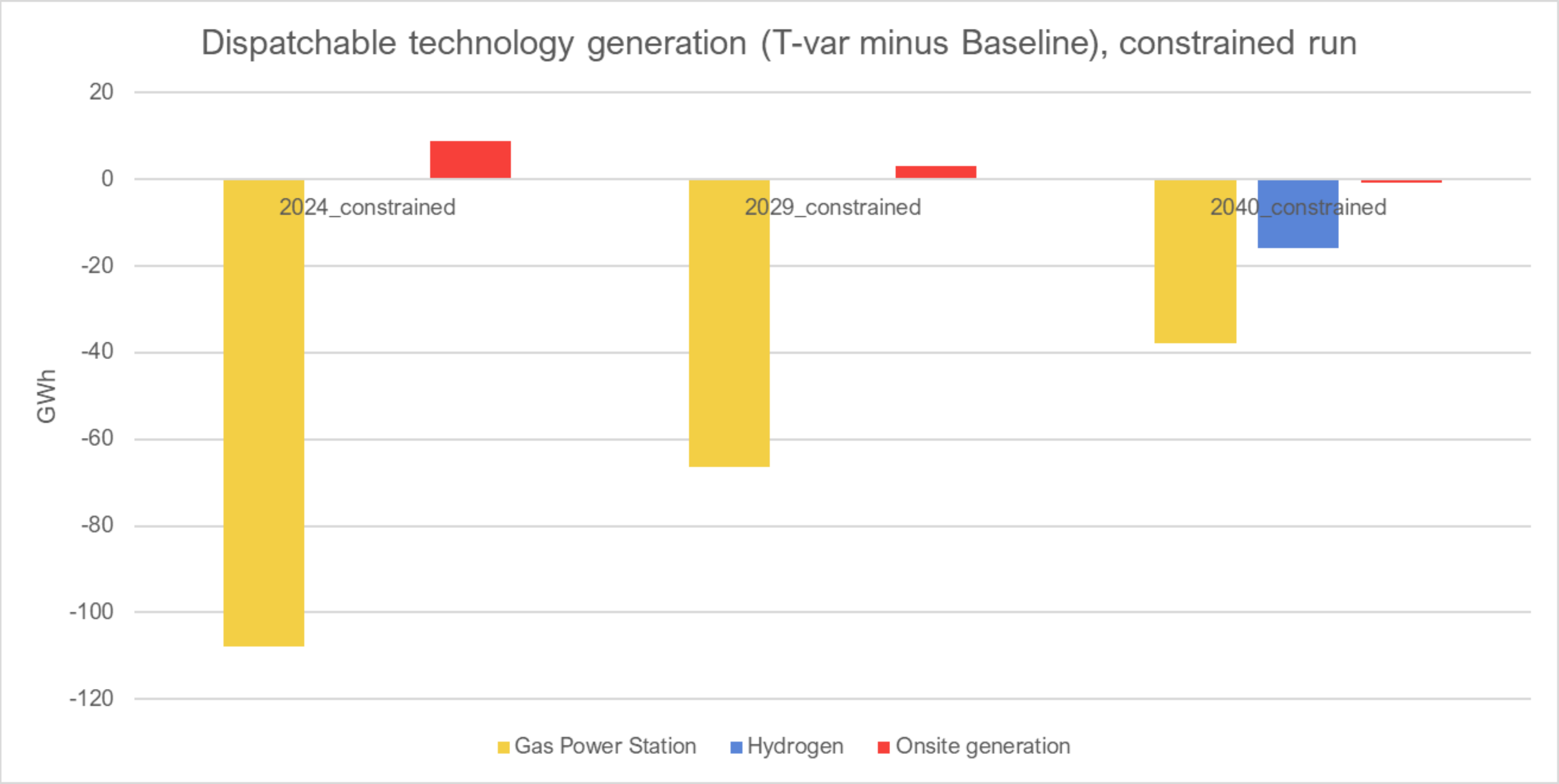
More efficient allocation of generation allows for a small reduction in transmission network capacity. We also observe a reduction in constraint management costs of c. £160m (£2021).

Dispatchable technology relative to baseline (unconstrained)



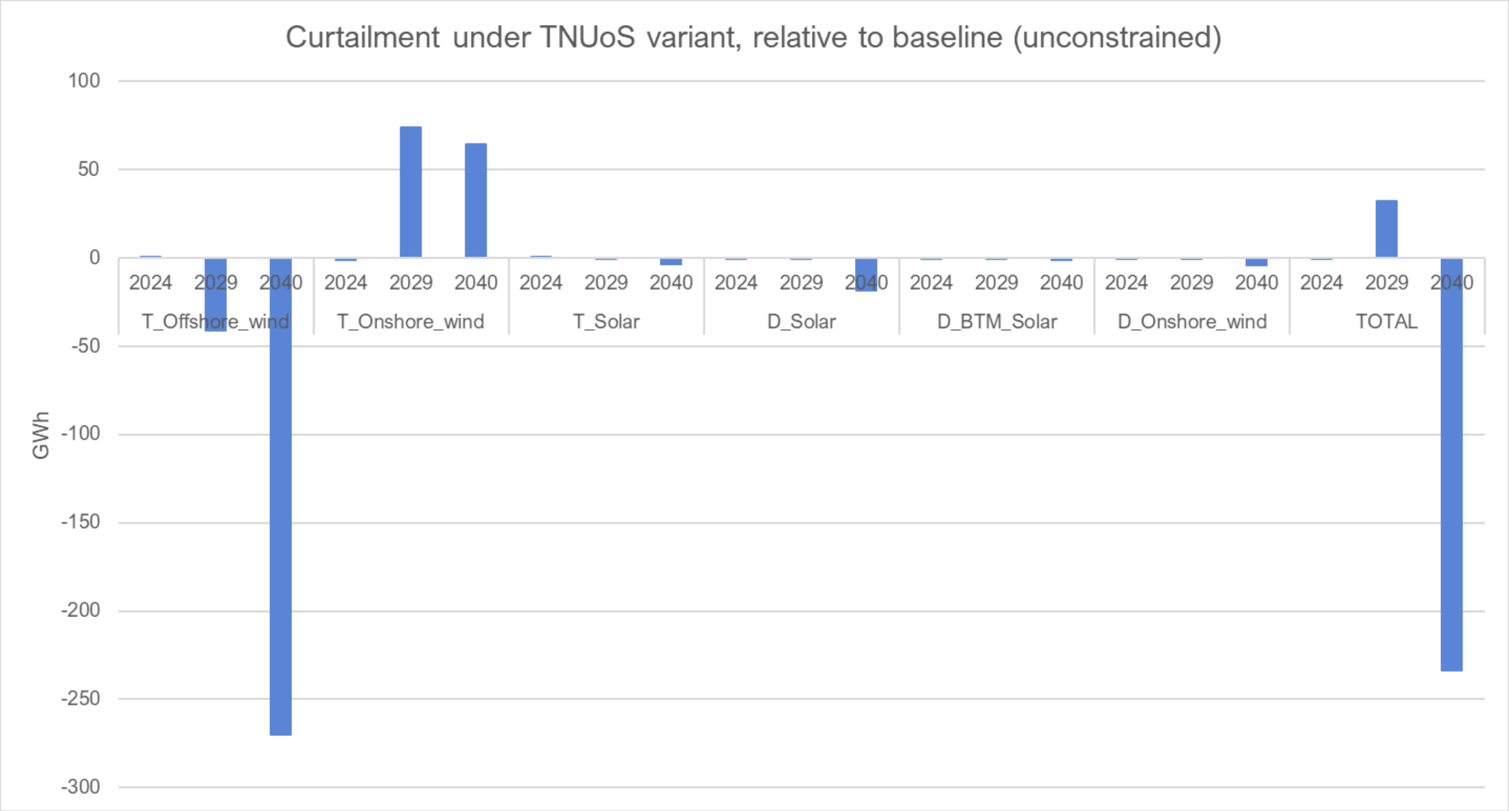
Our 'unconstrained run' represents the wholesale market.
We observe a reduction in the use of dispatchable technology for supply/demand balancing purposes.

Dispatchable technology relative to baseline (constrained)



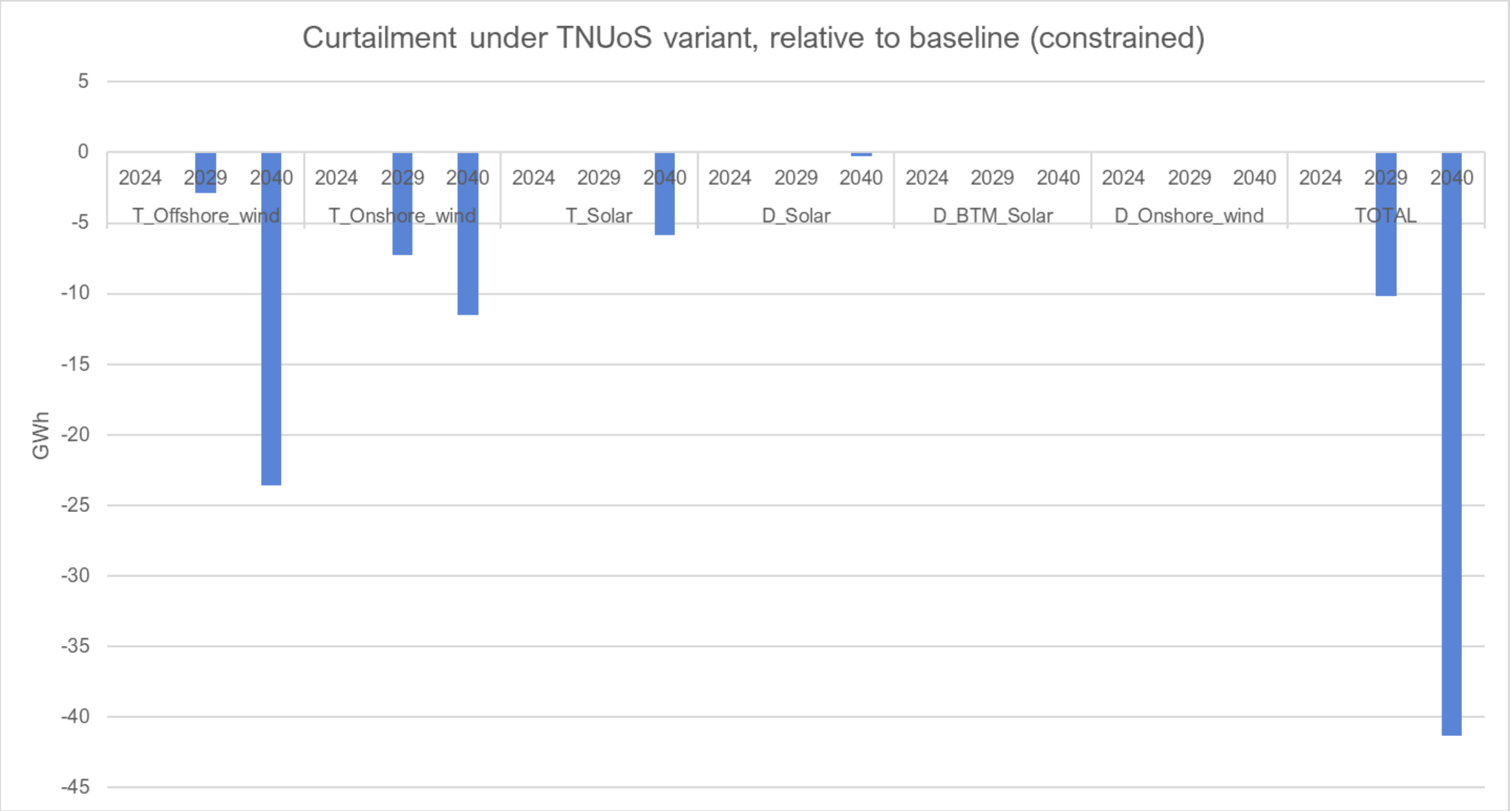
Our 'constrained run' represents actions for managing constraints.
We observe efficiencies in dispatch from conventional technologies driven by the change in allocation of capacity.

Renewables curtailment relative to baseline (unconstrained)



We observe very small changes in curtailment of renewables, driven by changes to embedded generation dispatch and demand profiles. We see very little change in in 2024, a small increase in 2029 driven by onshore wind. We see a small decrease in 2040 driven by offshore wind.

Renewables curtailment relative to baseline (constrained)



Impacts on curtailment for constraint management reasons are relatively small. However, note that the trend for a reduction in constraints is in spite of the lower levels of transmission network investment in 2040 in particular.

Producer revenue impacts

Change in producer surplus by technology and zone

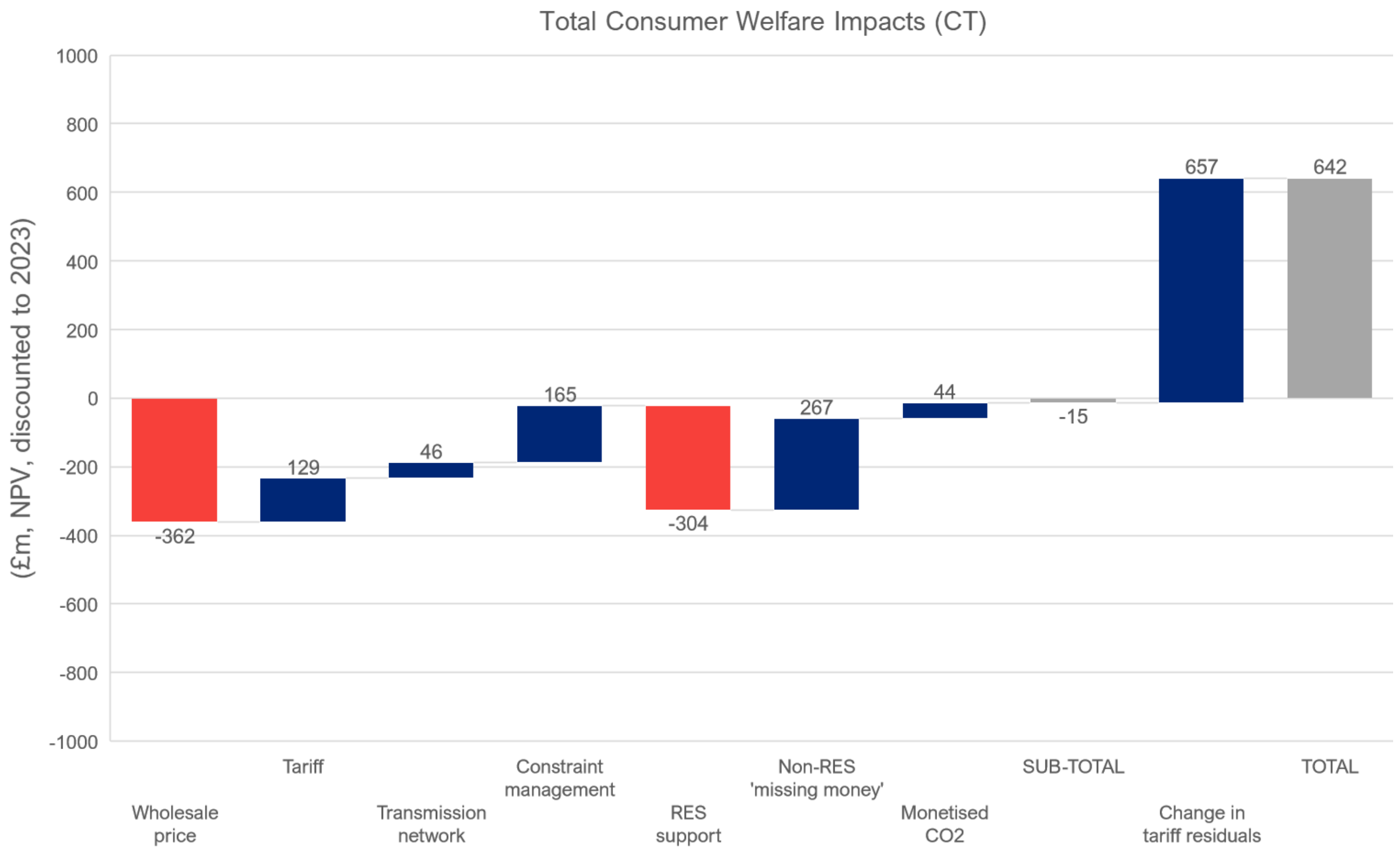
- Our modelling allows us to observe expected impacts on producer revenues of different technology types, and in different locations.
- These producer revenue impacts combine tariffs and captured wholesale market prices.
- They do not include any support scheme payments which are considered separately.
- We observe the following impacts from the policy option:
  - A reduction in revenues for renewable generators in Scottish distribution zones, and to a lesser extent, transmission zones.
    - This drives the reallocation of distribution connected RES capacity observed previously.
  - An increase in producer revenues for renewables in central distribution zones and in transmission zones outside of Scotland.
  - In general, a small increase in revenues for dispatchable generators.
  - The greatest revenue increases are in zones around the centre of the country.

Consumer welfare

Consumer welfare

- We present the consumer welfare impacts on the next slide. We find the following:
  - **Consumers pay a little more for wholesale electricity overall, driven by signals for embedded generation and removal of the EET credit during high demand periods.**
  - There is a small reduction in tariffs paid by consumers.
  - Consumers benefit from a reduction in the costs of reinforcing the transmission network and managing constraints.
  - **Overall, a decrease in total RES producer revenues increases the amount of subsidy required through support schemes to retain RES capacity at levels included in CT.**
  - But flexible plant respond to higher average wholesale prices, leading to a reduction in 'missing money' of non-RES plant.
  - There are small CO_2 benefits driven by more efficient dispatch and lower RES curtailment.
  - There is an increase in the tariff residual. In practice, we would expect this to be reflected in lower producer and/or consumer tariffs.
  - Note that impacts on distribution network costs are being processed and will be included in future reporting.
  - **Results are subject to final QA**

Total consumer welfare impact (CT, NPV, £m 2021)



Assuming that the tariff residual is reflected in reduced tariff costs to consumers and producers, we observe a positive NPV of c. £640m under CT (£m 2021)

UK
Queens House
55-56 Lincoln's Inn Fields London
WC2A 3LJ UK

T. **+44 (0)20 7269 0210**
E. info@cepa.co.uk

www.cepa.co.uk

Australia
Level 20, Tower 2 Darling Park 201
Sussex St
Sydney NSW 2000

T. **+61 2 9006 1307**
E. info@cepa.net.au

www.cepa.net.au

cepa-ltd

@cepaltd

Potential for wider review of TNUoS charges

- We decided to launch a focused review of TNUoS as part of the Access SCR to consider:
  - Charging for SDG, as the growth in SDG highlighted a distortion in the charging arrangements
  - Demand charges, given how unpredictable the current Triad-based charging is and the fact it does not reflect network peaks.
- Since then increasing questions have been raised about whether the price signals provided by the wider TNUoS methodology will be fit for purpose in the future for the late 2020s. For example, we note questions around:
  - Tariff volatility stemming from the current transport model and approach to zoning, including the expansion constant, as highlighted by some urgent modifications raised by the ESO
  - Other potential reforms to the transport model, including whether there would be benefit in signalling spare capacity on the network and if the peak and year round backgrounds are still fit-for-purpose
  - Whether the methodology produces the right signals for demand and particular technologies, such as storage.
- We expect to seek industry input on the issues and how they could be addressed in due course.
- We will take the potential need for this review into account in our decision on SDG charging.

Implementation options

Option	Implementation approach	Assessment summary
Immediate	• Raise mods immediately • Start applying as soon as feasible (e.g. two years)	• Addresses the distortion in the shortest amount of time • Most straightforward to implement, as applies immediately to all SDG • Does not allow any time for users to reflect changes in commercial arrangements
Phase	• Raise mods immediately • Phase the impact over a number of years (e.g. 25% in year 1, 50% in year 2, 75% in year 3, 100% in year 4) • Could consider phasing just for existing projects	• Would start to address the distortion between LG and SDG and signals, although a portion remains for several years • Gives generators time to manage their commercials before they face the full impact of the changes • Consistent with our implementation approach for other changes with potentially significant impacts (e.g. CMP264)
Delay – fixed date	• Raise mods immediately • Defer start date (e.g. three years)	• Gives generators time to manage their commercials before they face the full impact of the changes • Reduces the need for investors to include regulatory risk premiums for some projects • Retains the distortion for several years, meaning generators are not facing the cost of their impact on the transmission network
Delay – link to wider review	• Undertake wider TNUoS review • Raise mods to implement this change and outcome of review together • Could include a backstop date for implementation, for if review is delayed/makes no changes	• Stakeholders have told us that there are a range of further issues with TNUoS that need to be addressed. We are considering approaches for reviewing these issues and will need to consider whether we want to link implementation of this change to wider TNUoS reform • May increase regulatory uncertainty, where change is known but timing and scale of impact is unknown
Grandfather *(potential add-on to other options)*	• As with “Immediate” option, but only applicable to new generation from a certain date • Could limit grandfathering for existing projects to [15] years from original connection, so that changes still influence repowering decisions	• Limits impact on generation that connected in response to the signals sent under the current charging arrangements until end of current investment period • Administratively complex and could be seen as arbitrary, as introduces a new boundary between different SDG • Would prevent any changes, such as arising from a wider review, applying to a significant amount of existing SDG

Next steps

Next steps

- Publish early minded-to consultations
    - Expect DNOs to take them into account in their final business plans
- Expect to hold CFF/Challenge group session(s) to discuss content in more detail
- Latest on what we are saying about FCF/then what want to say about DUoS