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for energy consumers

Access and Forward Looking Charges SCR

Challenge and Delivery Group

Ofgem
9 November 2020

Aim of today's session

- The purpose of this session is to:
  - Provide an update on project progress overall, including timing
  - Fill you in on our latest thinking on each policy area and get your feedback
  - Give a brief update on the IA modelling

Agenda

Time	Item	Lead
13:00 – 13:05	Introduction	Andrew Self
13:05 – 13:35	Project update	Jon Parker
13:35 – 14:15	TNUoS charging	Andrew Malley Harriet Harmon
14:15 – 14:20	**Break**	
14:20 – 15:05	DUoS charging	Beth Hanna
15:05 – 15:35	Connection charging	David McCrone
15:35 – 15:40	**Break**	
15:40 – 15:55	Access rights	Josh Haskett
15:55 – 16:25	Impact assessment	Amy Freund
16:25 – 16:30	Next steps and close	Andrew Self

Project update

Overview of project activity

Options refinement	• Developing additional detail on options
Building evidence base	• Seeking additional evidence to support case for change and options evaluation • Will feed into our qualitative assessment of options using our guiding principles
Tariff modelling	• CEPA/TNEI (under their contract with DCUSA) have produced forecasts of DUoS tariffs under our reform options • NG ESO have produced forecasts of TNUoS tariffs under our reform options
Impact assessment modelling	• CEPA/TNEI (under a contract with Ofgem) have developed and been running their models to provide insights for our impact assessment
Engagement	• Continued bilaterals with parties providing evidence to support our impact assessment

We have been working on the basis of publishing our minded to proposals for consultation by the end of this year. However, we have been reviewing this in light of:

- **Links with the development of flexibility markets**. A number of you have fed back how important it is to have a clear overall vision for how flexibility will be valued. We are gearing up our work on developing this vision – working with BEIS – and think there is value in holding off issuing our minded to proposals on access until it is clearer
- **Wider transmission charging considerations**. We think there is a need to consider wider issues that have arisen with transmission charges – including the potentially significant change to the "expansion constant" – before issuing our transmission charging proposals

As a result, we have decided to delay our consultation to next year.

We intend to provide further chances to feed in ahead of our consultation. This will include an opportunity for industry to understand the IA modelling.

A key timing interaction is with DNOs' RIIO-ED2 business planning. We will be engaging with the DNOs to develop a plan to manage this interaction.

TNUoS reforms

- The purpose of this session is to:
  - Recap our policy options
  - Update the group on our work since July, including some high-level impacts
  - Set out some of the issues we are currently considering, including
    - Interactions with Net Zero
    - Impacts and the potential for transitional arrangements
    - Links to other TNUoS works outside the SCR

We previously set out possible options for SDG charging.

Move to generation TNUoS (without any cap)	Retain inverse demand charges, but remove cap	Apply local circuit charges to SDG that make use of them
✓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	✓More cost-reflective than existing regime ✖SDG charges remain different to larger generation ✖Some dispatch distortions remain ✖Practical issues ✖Impacts on some existing generators	✓Improved cost-reflectivity improved ✓Harmonised charges ✖Practicality issues

Modelled Option

We asked NG ESO to provide us with modelled tariffs for SDG above 1MW to allow us to assess the policy impacts of a policy of SDG facing generation TNUoS. Our work this summer has been to understand the impacts and practicalities of these options, and has focused on:

- The effect of each option on the relative signals users at different voltage levels face;
- The impacts on example users, and on the users currently connected to the system;
- The practical implications of the options and their proportionality;
- The likely impacts on investment and the case for any mitigations or transitional arrangements; and
- The interactions with other AFLC project areas (e.g. DUoS impacts) and the wider context

TNUoS reform could lead to more efficient system use and development

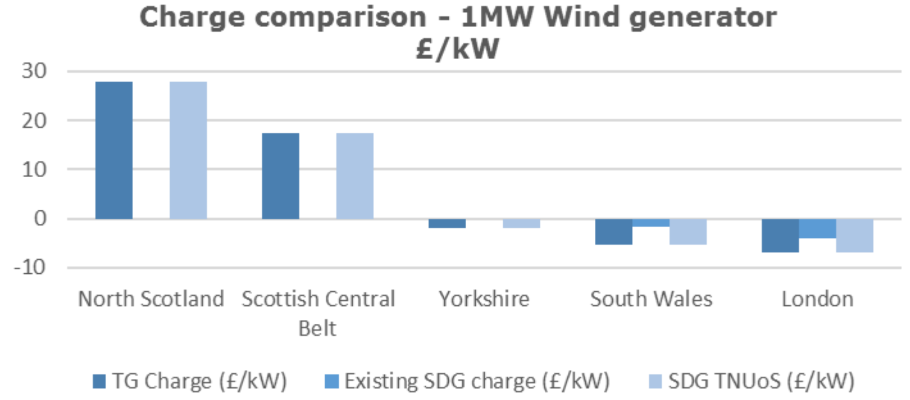
What we are proposing and why

- SDG charges differ from TG/LDG charges by up to £30/kW in some areas, and present users with operational signals that aren't present in the generation TNUoS charges. This means SDG:
  - Face **different cost information** for siting/investment decisions
  - Face **different running incentives** from larger users
- Sending a consistent signal by charging SDG in the same way as large generators should lead to **more efficient investment signals** and system benefits from **more efficient siting of new projects**. Given the high cost of transmission reinforcements, these benefits are potentially very large.
- Sending consistent operational signals should enable **more efficient flexibility markets** as all participants will face similar network incentives.

Nation / Generation Type	Initial est. impacts (£m/Year)
Scotland	**c£52m**
Renewable	£37m
Other	£15m
England & Wales	**£4m**
Renewable	-£10m
Other	£15m
Grand Total	**£56m**

Initial est. impacts (£m/Year)	Scotland	England & Wales	GB Total
CHP	£0.2	£0.6	£0.7
Conventional	£0.2	£17.8	£18.0
Hydro	£7.4	-£0.5	£6.9
Offshore Wind	£0.5	£0.3	£0.8
Onshore Wind	£31.5	-£4.7	£26.9
Other Renewable	£1.9	£6.4	£8.3
Solar	£9.9	-£16.7	-£6.8
Storage	£0.0	£1.0	£1.0
Grand Total	**£51.7**	**£4.2**	**£55.9**

This table and chart shows the annual charging impacts from a move from the EET to generation TNUoS charges, based on 2023/4 tariffs in £millions. NB – Impacts use ESO LF assumptions. Conventional LF of 0.2% driver of impacts on those users.



This chart shows the difference in charges between EET users and users facing generation TNUoS charges for an indicative 1MW wind user

Impact of the changes

- While this is likely to lead to more efficient location and dispatch for new users, existing users may see increased costs they cannot respond to.
- Based on DNO capacity registers, we think existing plant could face charge increases in excess of £50m p/a, based on 2023/4 charging estimates and existing, connected users.
- Scottish impacts fall mainly on wind, while in E&W there are sizable reductions for solar.

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Interactions between our Access decision and broader charging questions

- **We expect locational signals to be part of any wider reform conversation around Net Zero**
  - **Significant new generation investment** will be needed for net zero transition. We will take our net zero commitment and the wider decarbonisation and policy context into account.
  - We expect a range of reforms to come forward, to ensure we are **sending the right signals to new generation investors**.
  - We think that **cost-reflective locational signals and consistent signals for SDG and large generation** will be a core part of this and are vital to ensure net zero at least cost.

- **We are considering the impacts of the proposed change on existing SDG in our assessment and decision**
  - Depending on existing infrastructure, repowering of existing generation sites may aid efficient net zero investment beyond what is reflected in the locational charge, so we must consider this in our assessment
  - Existing generators generally can't move in response to locational signals, but can change capacity levels or the way they use the system in that location, such as by adding storage or reducing levels of capacity. New generators may be constrained on location by planning or environmental requirements. We should take these different dynamics into account.

- **We are still considering the role of the reference node**
  - We have considered stakeholder feedback on the reference node and are still considering whether proposed changes to the node would lead to more efficient use and development of the system as per the SCR principles.

- **We are considering the case for transitional arrangements**
  - We have historically considered the bar for transitional arrangements such as phased implementation or grandfathering/legacy arrangements to be high, and this remains the case here.
  - We are interested in stakeholder feedback on the potential need for any transitional arrangements, and particularly any evidence that such arrangements would improve efficiency or facilitate the Net Zero transition, such as in the case of repowering of existing sites, or arrangements that account for wider developments, reviews or processes in the industry

- Do you consider there to be justification for transitional arrangements, and could any arrangements lead to more efficient development or use of the system?

Break

DUoS charging

DUoS charging – overview (1/2)

Methodology element	Counterfactual	Reform option(s)
Cost model	• EDCM – incremental model, with charges that signal the location and timing of reinforcement • CDCM – ultra long-run (ULR) model, with charges that do not vary to reflect where or when reinforcement is forecast to be needed	• ULR model that reflects the cost to reinforce or replace the network in each location over the long term
Charging zones	• EDCM – bespoke nodal charges • CDCM – single charge for all customers in each category within a DNO region	• Zonal charges, based on which Bulk Supply Point (~800) or primary (~5,800) substation a user is connected under, for all users
Extent that charges vary to reflect spare capacity	• EDCM – signals timing and location of future reinforcement (e.g. charges will be higher the shorter the time until reinforcement is forecast to be needed) • CDCM – no signal about time to reinforcement	• Option to discount asset costs in locations where reinforcement is unlikely to be required for significant period of time • Spare capacity threshold is set at 40%, recognising that, after this point actions may need to be taken to avoid reinforcement. The discount then applies in proportion to spare capacity (e.g. if the asset has 65% spare capacity, it would be discounted by 25%)
Asset costs	• EDCM – load flow modelling • CDCM – assets to service a notional 500MW of additional demand	Reflects actual network asset mix • EHV – specific assets at each location, based on connectivity • HV and LV – total cost of assets connected to each primary
Operating costs	• EDCM – allocated to capacity charges on the basis of customer-specific network use factors • CDCM – 100% of direct and 60% of indirect allocated to voltage levels, based on asset values	• 100% of direct and 60% of indirect costs are allocated between voltage levels, proportional to asset costs.

DUoS charging – overview (2/2)

Methodology element	Counterfactual	Reform option(s)

Time bands	• EDCM –
	  • Seasonal “super red” volumetric charges, which typically apply in winter between 4-7pm. These are not faced by all customers, as they depend on the outcome of load flow analysis and only apply in locations where reinforcement is expected to be needed soon
	  • Year round capacity charges
	• CDCM – year round RAG time bands that apply to volumetric charges
		• These are currently set up as six monthly seasonal (summer and winter) charge periods, though we may further refine these:
		  • Peak from 1500-1900
		  • Day from 0700-1500 and 1900-2300
		  • Night from 2300 to 0700
		• Charges in each time band are determined by allocation factors that are applied to the £/kVA costs. These factors are based on peak net power flow, as a proportion of overall peak net power flow, and are set such that time bands with peak flow:
		  • Above 95% of the overall peak are assigned an allocation factor of four
		  • Between 70% and 95% of the overall peak are assigned an allocation factor of one
		  • Less than 70% of the overall peak are assigned an allocation factor of zero.

Equal and opposite charges and credits	• EDCM – generation receives credits, where f-factors indicate a benefit (e.g. most intermittent aren’t eligible for credits) and in locations where reinforcement is expected to be needed soon • CDCM – all generation receives credits for export	• Equal and opposite charges and credits in each time band, based on the dominant flow measured in each season • The charges or credits faced are determined by the allocation factors described above and could result in a customer facing charges in one season and credits during another. • Setting the allocation factors to start from 70% means we should avoid charges and credits flipping back and forth between years in response to signals.

Summary of movements in revenue between voltage levels

These revenue impacts are indicative of some options and do not represent final policy

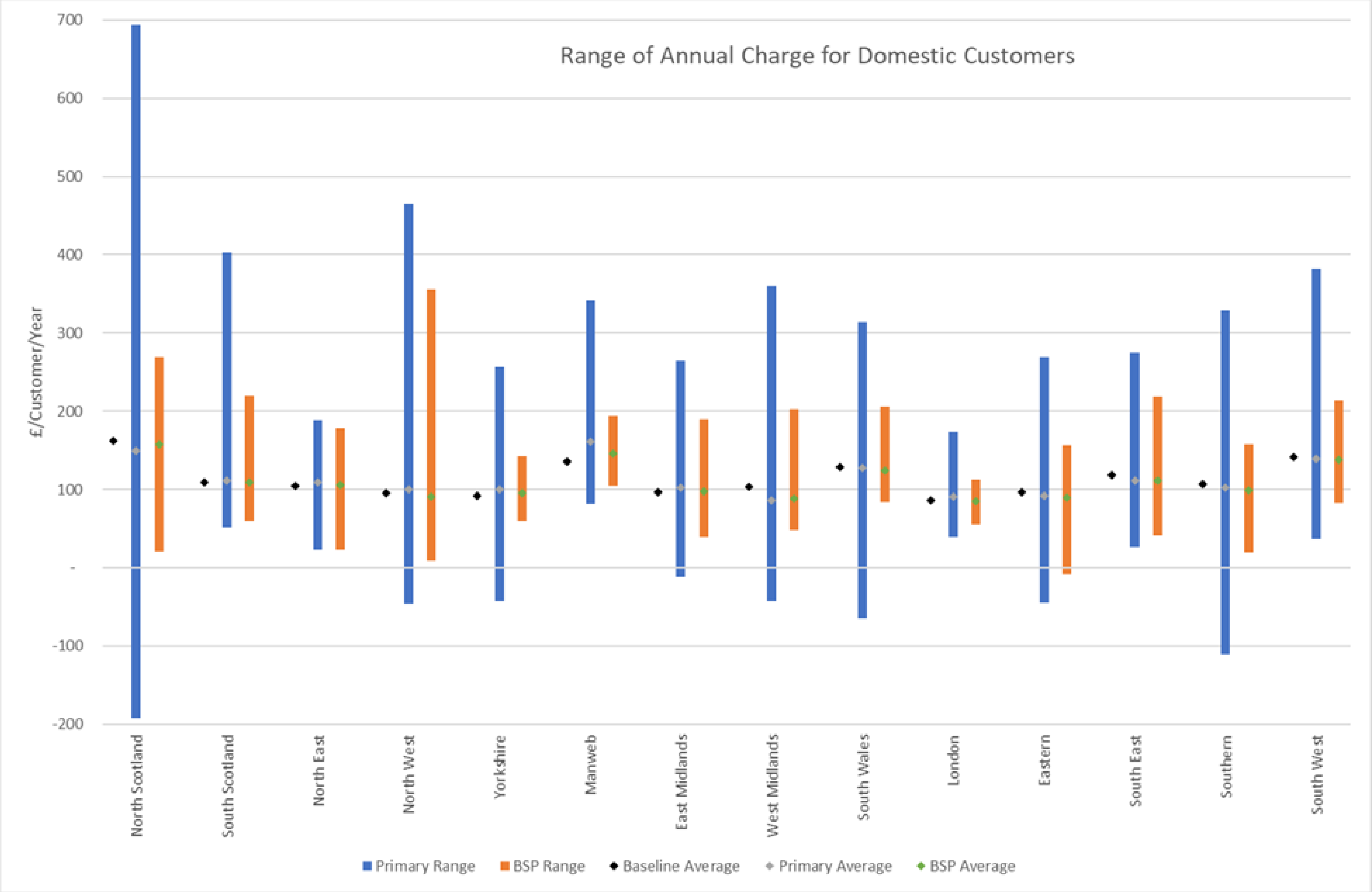
- We have undertaken initial modelling to identify the impact of the cost model changes on tariffs faced by different customer categories
- The DNOs have had to apply a number of assumptions to produce some of the locationally varying data used in the tariff model
- **These impacts should be viewed as indicative only and we may make additional changes to the cost model and data before our minded to decision**.

Customer Group	Baseline Revenue (£mn)	IA Revenue (£mn)	Variance to Baseline (£mn)	Variance to Baseline (%)
LV Domestic Demand	3,065.1	3,050.2	-14.9	-0.5%
LV Small Non-Domestic Demand	871.1	835.6	-35.5	-4.1%
LV Large Non-Domestic Demand	1,117.9	1,275.1	157.2	14.1%
LV Sub Demand	177.9	185.4	7.6	4.3%
HV Demand	1,200.2	1,099.3	-100.9	-8.4%
EHV Demand	193.9	236.0	42.1	21.7%
Unmetered Demand	95.1	98.6	3.5	3.7%
LV Generation	-11.9	-14.4	-2.5	21.4%
LV Sub Generation	-0.6	-0.8	-0.1	22.5%
HV Generation	-66.2	-59.5	6.7	-10.1%
EHV Generation	17.4	-45.7	-63.1	-362.6%
Total	6,659.8	6,659.8	0.0	0.0%

- This table shows the movement in revenue between customer groups under our reforms (primary level with spare capacity) on a GB-wide basis. Overall, less revenue will be recovered from small users, but this varies by DNO region.
- HV customers will face lower charges and credits, due to asset costs being weighted more towards LV under the cost model than the 500 MW model, while larger LV customers will be the opposite effect.
- The most significant impacts are at EHV, due to the move from the incremental EDCM. We are still analysing the outputs to understand the impact changes in the methodology have had and identify any potential impacts due to the data used.

These tariff impacts are indicative of some options and do not represent final policy

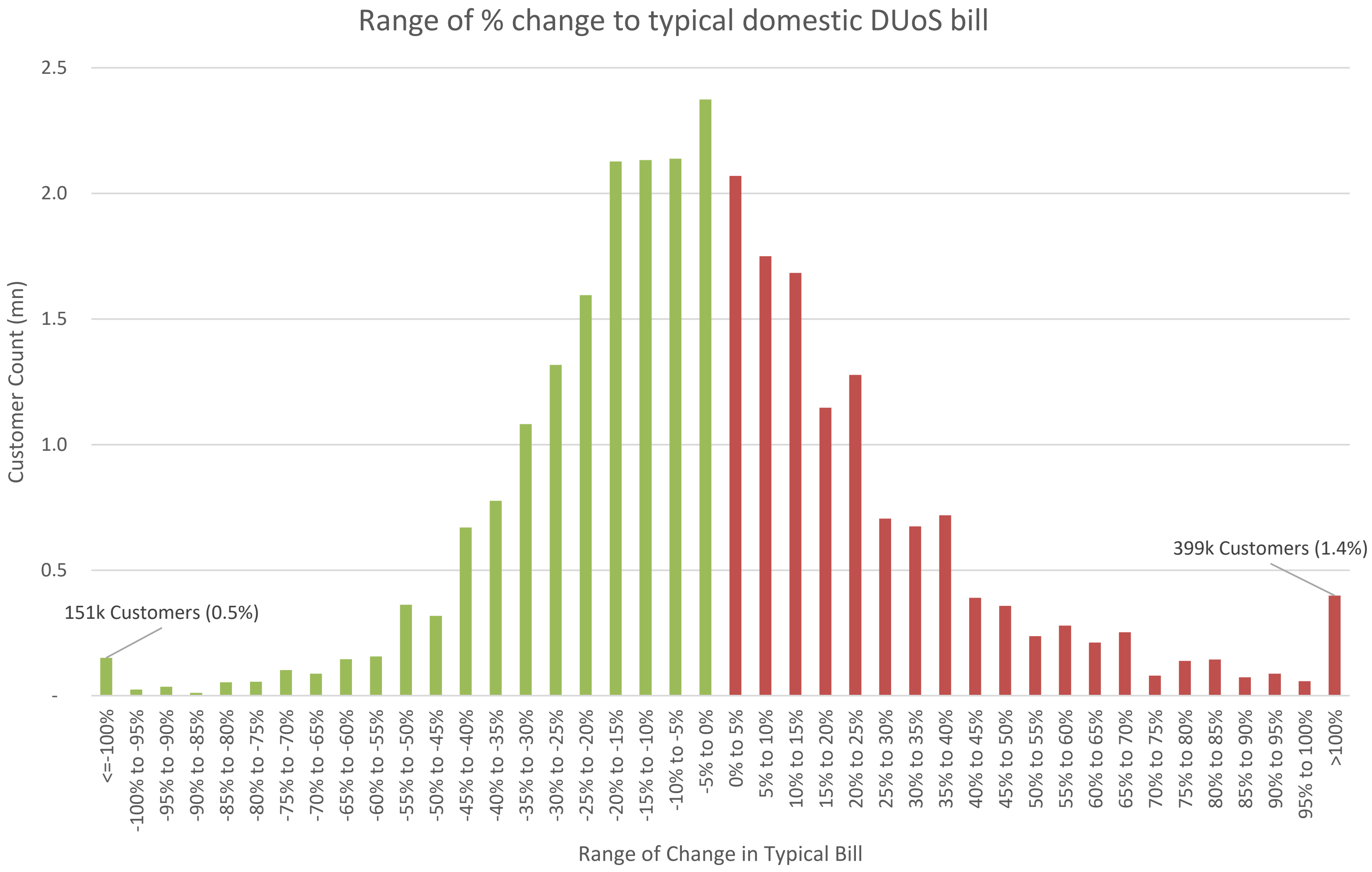
- We have produced initial tariffs that illustrate the impact of applying charging zones at the BSP and primary level.
- The following graph shows the range of **total DUoS bills** that would apply to domestic customers in each DNO region:
    - The cost model assumptions have not resulted in significant changes to average charges
    - In most cases, apply BSP level charging zones would significantly reduce the impact, but some customers would still face much higher charges (up to £350 in ENWL's region)
- The relative range of tariffs is also similar for LV and HV connected demand customers and so we have not included separate graphs.



The Common Tariff Obligation means that it is not currently possible to apply charging zones in North Scotland for domestic customers

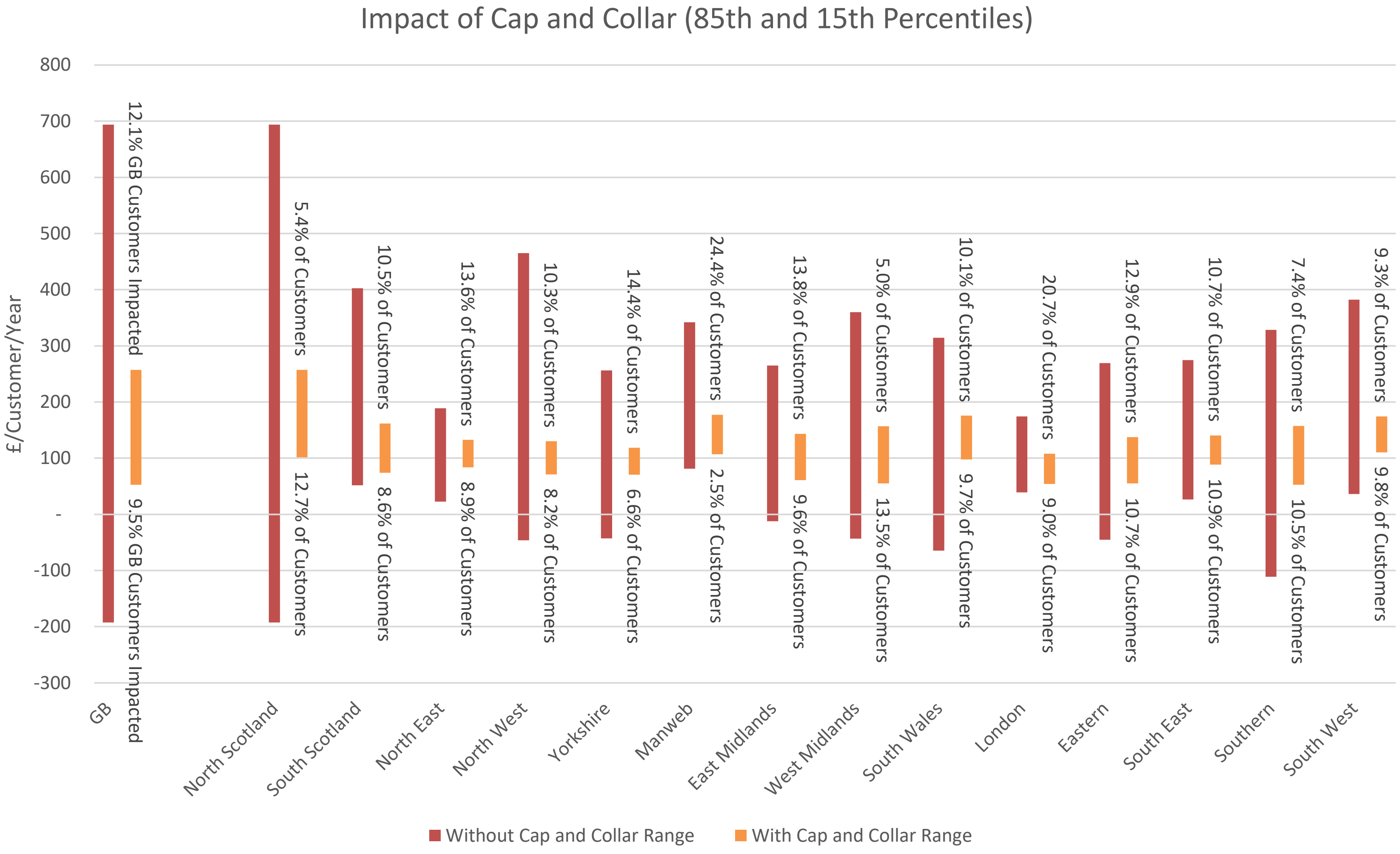
These tariff impacts are indicative of some options and do not represent final policy

- In addition to the range of annual bills, the other key consideration is the number of customers who are affected
- This chart shows the range of **changes in typical domestic DUoS bills**, with primary granularity and a spare capacity indicator. It can be seen that most customers face a change in their bills of +/-30%. However, there is still a large number of customers who would face bill increases of more than 100%
- We recognise that significant bill changes could have adverse impacts for those consumers, especially those in vulnerable situations, and are unlikely to be justified.
- We are therefore considering a cap and collar on charges. Considerations include:
  - Applicable customer categories
  - Where to set the cap and collar.



These tariff impacts are indicative of some options and do not represent final policy

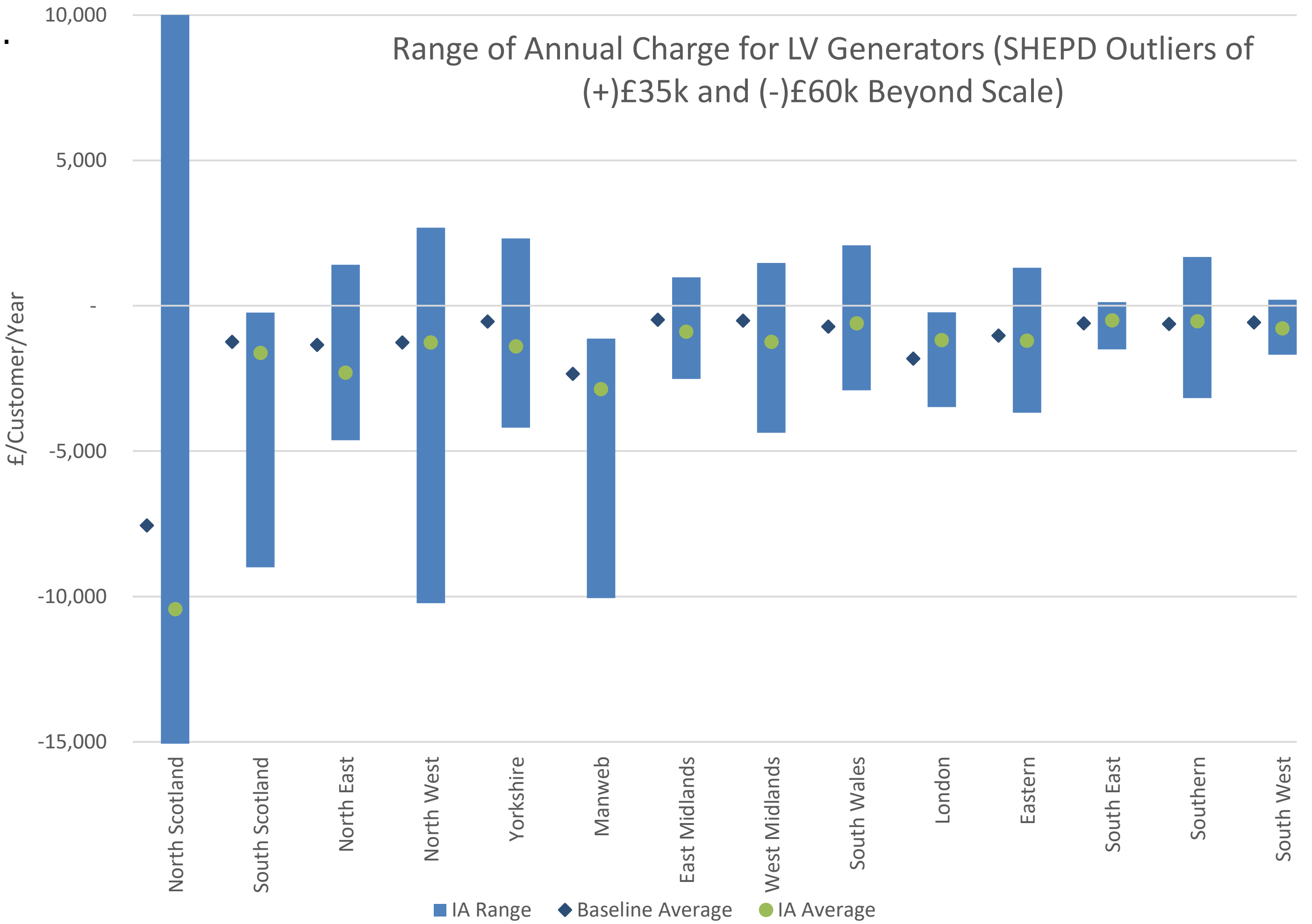
- This chart illustrates the impact on the range of **typical domestic DUoS bills** that applying a cap and collar has. It is set at the 15th and 85th percentile and has a significant impact that reduces the highest typical bill faced by a domestic customer from £700 to approximately £260.
- The cap and collar also mean that 12% of customers across GB are protected from the full cost of the local network (although it also means that domestic customers will not receive credits)
- The advantage of this mitigation is that, within the cap and collar, it keeps the locationally varying signals between primaries connected to each BSP.



These tariff impacts are indicative of some options and do not represent final policy

Although some generators would receive much higher than average credits, a number of generators will face net charges.

DNO Region	LV Generators Facing Charges	% LV Generators Facing Charges
GB Total	527	7.0%
North Scotland	81	10.5%
South Scotland	0	0.0%
North East	7	3.0%
North West	7	2.6%
Yorkshire	29	5.2%
Manweb	0	0.0%
East Midlands	36	4.8%
West Midlands	11	1.6%
South Wales	73	17.6%
London	0	0.0%
Eastern	65	7.3%
South East	2	0.5%
Southern	186	27.1%
South West	29	3.3%

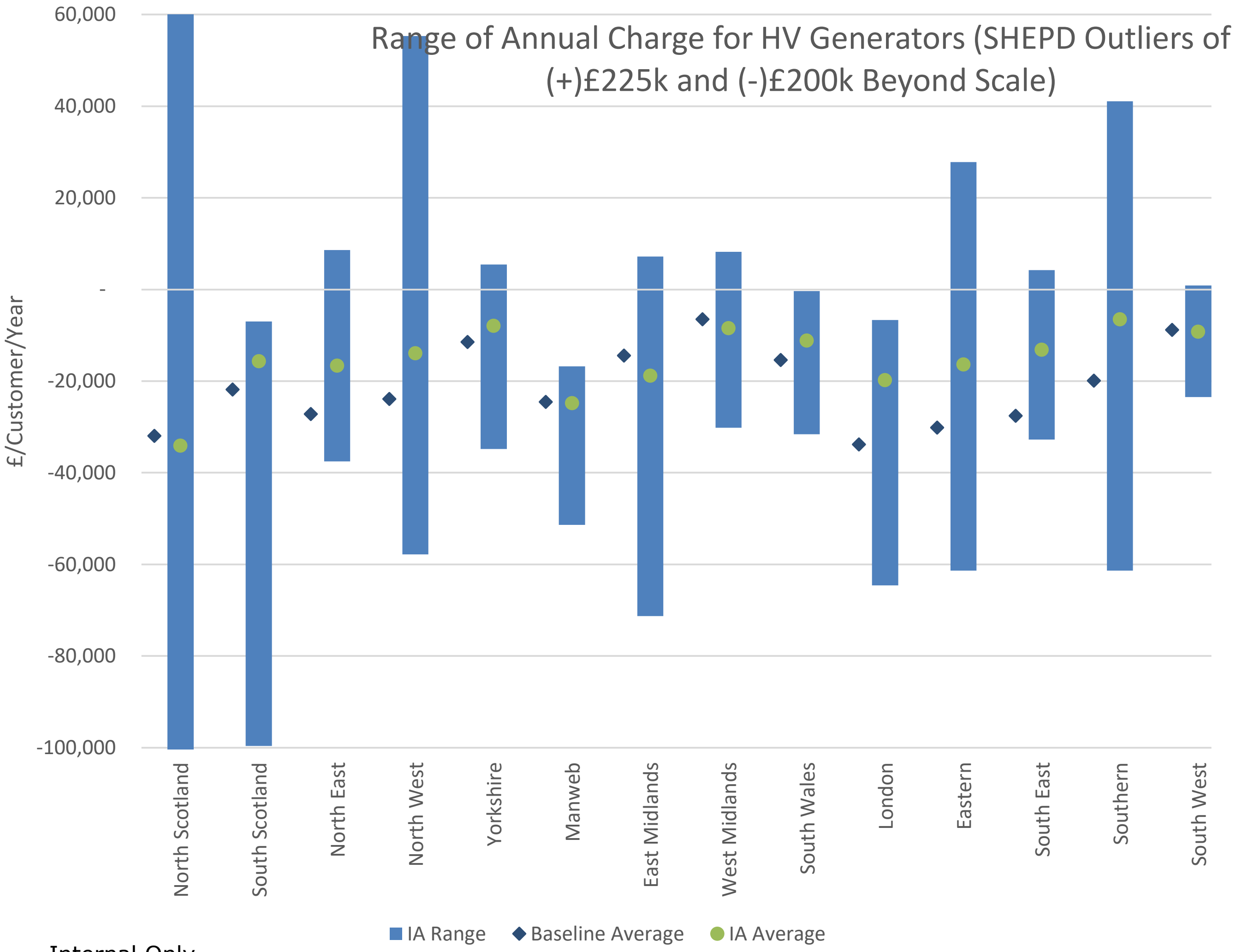


HV Generators
Initial analysis of spread of change in DUoS bills

These tariff impacts are indicative of some options and do not represent final policy

Although some generators will receive much higher than average credits, a number of generators will face net charges.

DNO Region	HV Generators Facing Charges	% HV Generators Facing Charges
GB Total	232	6.8%
North Scotland	56	15.6%
South Scotland	0	0.0%
North East	11	7.6%
North West	16	5.6%
Yorkshire	30	11.5%
Manweb	0	0.0%
East Midlands	19	4.0%
West Midlands	1	0.4%
South Wales	0	0.0%
London	0	0.0%
Eastern	39	14.8%
South East	1	0.8%
Southern	56	25.7%
South West	2	0.8%



- Should we also apply a cap and collar to larger users? What about the trade off between improving cost reflectivity of charges and mitigating the impacts in locations with the highest charges?

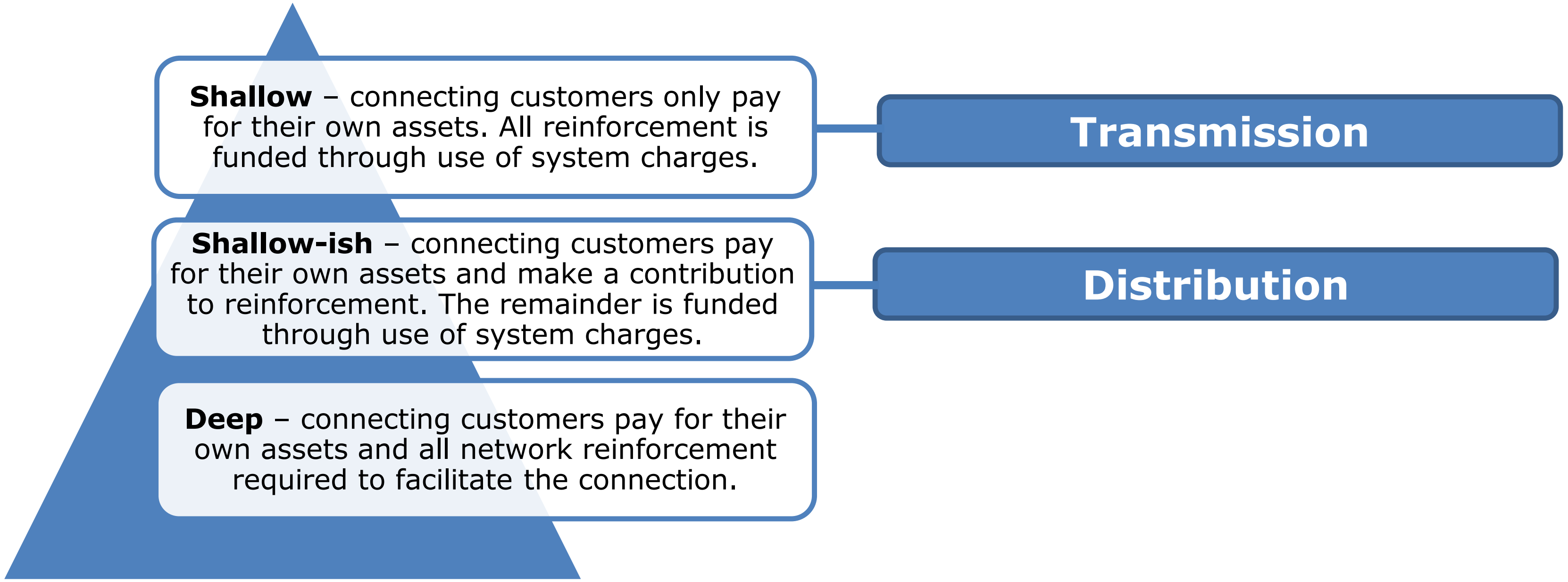
- Do you have any evidence to support different ways to set the parameters used in the cost model (e.g. measurement of spare capacity)?
  - If so, please get in touch at: FutureChargingAndAccess@ofgem.gov.uk

Connection boundary

Session overview

- The purpose of this session is to :
  - Recap our policy options
  - Set out our current thinking on how far we think we can change the boundary, given the DUoS changes we are considering
  - Set out a summary of our emerging thinking on the case for change

What is the connection charging boundary? The extent to which customers pay for their connection, including any reinforcement that is required.



We are considering whether to change the arrangements at distribution:

- **Move to a "shallower" boundary:** reduce the contribution to reinforcement in the upfront connection charge.
- **Move to a "shallow" boundary:** remove the contribution to reinforcement in the upfront connection charge.
- **Introduce alternative payment terms (with or without a change to the boundary):** (a) allow users to defer payment of their connection charge post-connection, and or, (b) introduce a requirement for liabilities and or securities.

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Distribution connection charging boundary options - reminder

Component	Baseline	Shallower	Shallow
Voltage rule	• Connection customers contribute to reinforcement at the same voltage level as connection plus the one above	• Connection customers contribute to reinforcement at the same voltage level	• Connection customers do not contribute to reinforcement
High Cost Cap	• DG pays for all reinforcement above £200/kW (after application of the voltage rule)	• DG pays for all reinforcement above £200/kW (after application of the voltage rule)	• Connection customers do not contribute to reinforcement • Could be kept as a mitigating measure if the impact on DUoS is high
Security Cost Apportionment Factor (CAF)	• Connection customer's share is based on their contribution to the overall new network capacity	• Connection customer's share is based on their contribution to the overall new network capacity	• Connection customers do not contribute to reinforcement
Fault level CAF	• Connection customer's share is based on their contribution to the overall new fault level capacity	• Connection customer's share is based on their contribution to the overall new fault level capacity	• Connection customers do not contribute to reinforcement • Considering whether it would be appropriate to keep this given difficulty signalling these costs through DUoS
Transmission reinforcement	• DNOs pass through cost of transmission reinforcement to the connection customer in the connection charge	• Cost of transmission reinforcement triggered by a distribution connection funded through DUoS	• Cost of transmission reinforcement triggered by a distribution connection funded through DUoS
Deferred payment	• Connection charges can be staged but must be paid before energisation	• We are not minded to make any changes to this	• We are not minded to make any changes to this
Liabilities and securities	• No requirement to agree liabilities or provide security	• Current view is that might be unnecessary if connection customer is still contributing to reinforcement costs	• May be a stronger case for introducing something for larger users but must be proportionate and consider potential for re-use of assets

Based purely on cost reflectivity, how far could we reduce connection charges given the DUoS changes we are considering?

What signals are being sent through reformed DUoS?	EHV costs		HV costs		LV costs	
User connected at:	**Costs specific to area?**	**Need for reinforcement specific to area?**	**Costs specific to area?**	**Need for reinforcement specific to area?**	**Costs specific to area?**	**Need for reinforcement specific to area?**
EHV	Yes	Yes – if there is a spare capacity discount	N/A	N/A	N/A	N/A
HV	Yes	Yes – if there is a spare capacity discount	Average HV costs for BSP/primary*	No – no spare capacity indicator	N/A	N/A
LV	N/A	N/A	Average HV costs for BSP/primary*	No – no spare capacity indicator	Average LV costs for BSP/primary*	No – no spare capacity indicator

* Assumes we don't introduce any mitigating measures which averages this across a larger number of customers. If we do, it weakens the argument for moving more shallow

- For an EHV connected customer:
  - EHV costs can be signalled through DUoS, meaning a shallow boundary is possible and still allows charges to provide signals to customers.
- For a HV connected customer:
  - DUoS charges would have more limited accuracy as to HV costs, so there could still be a role for connection charges to signal reinforcement costs. However, these could be reduced – eg charging for HV reinforcement costs only, and with a 50% reduction in CAF.
- For a LV connected customer
  - DUoS charges would have more limited accuracy as to HV and LV costs, so there could still be a role for connection charges to signal reinforcement costs. However, connection charges could be reduced, eg with a 50% reduction in CAF
- We are still considering whether there is a case for going shallower/shallow, even when this would entail a reduction in cost reflectivity relative to the baseline – see next slide.

Is cost a barrier to entry?

- Based on historic data, we have not seen compelling evidence that reinforcement costs are an undue barrier.
- A change to the boundary will only affect the contribution to reinforcement. The average element of the overall connection charge apportioned to the customer is low (~5% of total cost in accepted offers, rising to ~10% of those Not Accepted).
- The proportion of offers Not Accepted also do not vary significantly whether reinforcement is required or not – the exception to this is LV demand connections where the % Not Accepted increases when work at higher voltages is required.
- However, we are continuing to investigate whether a change may help facilitate decarbonisation as future connections driven by LCTs, and increased renewable generation, increases the need for network intervention.

Do the current arrangements limit opportunities for more efficient system development?

- We think going further than our DUoS reforms suggest could would result in inefficient outcomes. However, we think this is a trade-off with helping facilitate decarbonisation faster. We will continue to examine how well LV and HV users can actually respond to different signals and how significant a loss removing this from the connection charge would be.
- We think it could be difficult to implement flexibility solutions whilst still providing certainty of costs for connecting customers - and step increases in demand lead to a reactive piecemeal approach to network investment
- A shallow(er) boundary would give DNOs freedom to make the best strategic investment decisions, as combinations of ANM, flexibility and conventional reinforcement based on what was the most cost effective solution across the market.

Do different arrangements at transmission and distribution lead to distortions or influence investment decisions?

- We have not seen strong evidence that having different boundaries at transmission and distribution are leading to distortions or influencing investment decisions.
- We think there may be a case for recovering transmission reinforcement costs through DUoS (currently recovered from the connection customer). Combined with a shallow boundary, this would mean that all work at 132kV is treated equally across GB (ie, reinforcement costs signalled and recovered through use of system charges).

- Do you think we should consider going further if it would help facilitate decarbonisation, even if it is at the expense of weakened signals? Please explain why.

- We are also keen to understand what evidence exists of users' ability to respond to signals within the connection charge. We also want to understand how this varies between types of user and at different voltage.

    - If you have evidence which you think would help our assessment please send it to: FutureChargingAndAccess@ofgem.gov.uk

Break

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 no defined cap on the extent to which they can be interrupted. Flexible connections have allowed users to connect cheaper or quicker connection.	• 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:

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

Access rights choices – summary of emerging thinking

Non-firm

- Proposing to introduce new arrangements at distribution only. At transmission non-firm options already well defined and provide certainty to users, and financially firm rights (with connect and manage with respect to transmission constraints) are available.
- Not available for small users.
- Not proposing to introduce financially firm access/connect and manage at distribution as part of the Access SCR.
- 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.

Time-profiled

- Proposing to introduce new time-profiled access at distribution only. Not received feedback that transmission arrangements need amending.
- Not available for small users.
- 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.

Shared

- Propose to do further trialling and testing of shared access via the ENA Open Networks alongside 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).

Greater compliance with access rights necessary to deliver system benefits. Propose network operators to develop common, clear and consistent approach to monitoring and enforcement of access rights.

We could reflect a users' access rights via UoS charges, connection charges or both

Non-firm

We propose to reflect non-firm access rights **via connection charges only.**

Reasons:

- We can accurately reflect the extent to which a non-firm user triggers upfront reinforcement as part of connection charge.
- However, it has proved difficult to reflect accurately reflect the extent to which non-firm access rights avoids ongoing need for reinforcement via UoS charges.
- Concerned that inaccurately valuing access rights via UoS charges could introduce distortions in procurement of flex markets.

Implications

- Moving the boundary shallow/shallower may reduce financial incentive for users to obtain non-firm access rights. Where we move to a shallow connection, a non-firm connection could still facilitate quicker connection.
- Non-firm access rights must align with high-level guidance (% of time willing to be curtailed), but exact level of access can be tailored to reflect local network conditions and stakeholders preferences.

Time-profiled

We propose to reflect users' time-profiled access rights **via connection charges and UoS charges**

Reasons:

- We can accurately reflect the extent to which a time-profiled user triggers upfront reinforcement as part of connection charge.
- We can also accurately reflect the extent to which time-profiled access rights avoids ongoing need for reinforcement via the time-profiled capacity charge element of DUoS.

Implications

- Users can still agree tailored/bespoke time-profiling of access rights.
- However, for DUoS charges, the user would be allocated to the most appropriate time-profiled capacity charge.

- Do you agree with our emerging thinking on how to value access rights, including the distinction between non-firm and time-profiled access rights?

- We welcome further thoughts on the interaction between how we value access rights and emerging flexibility markets. Please send these and any other comments to: FutureChargingAndAccess@ofgem.gov.uk

Impact assessment

Access and Forward Looking Charges SCR

Challenge Group

9th November 2020

Context

Update

- Since the last CG we have been building the models to reflect Ofgem's finalisation of policy and requirements
- We started running and testing the models in early September
- The modelling suite is large and very complex. This posed initial runtime and solvability challenges which we have now overcome
- We have produced runs of core options and are currently processing the large amounts of data and engaging with Ofgem on initial results
- We will communicate findings to the CG in line with Ofgem's updated project timescales

Touch points with Delivery and Challenge Groups

January

- Initial discussion of scope and high-level approach

February, March

- Further discussion of modelling approach

July

- Final discussion of methodology ahead of modelling

November

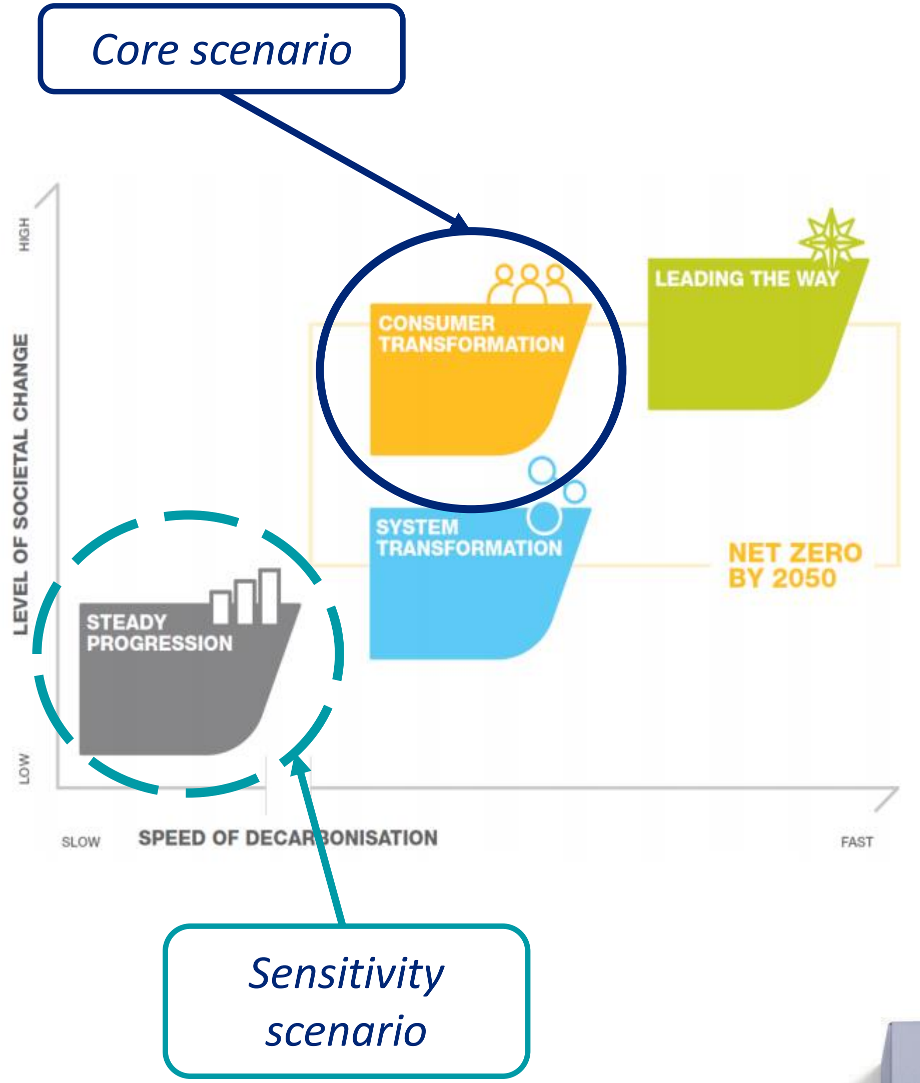
- Short update/reminder on key elements of approach

TBC

- Communication of results

Update on scenarios

- We will model impacts of the options under two of the FES
- Ofgem has asked us to model the **Consumer Transformation** scenario:
  - Meets Net Zero targets
  - Includes more significant societal and demand side change
- …and a **Steady Progression** sensitivity scenario:
  - ‘Worst case’ decarbonisation scenario in which Net Zero targets are not met



Key outputs

Summary of key outputs

Consumer impacts
Static distributional impacts (assuming no behaviour change)
Network charges
Absolute bill impact by user archetype
Bill impact as % of income by user archetype (Residential only)
Equity weighted bill impacts (Residential)
Dynamic distributional impacts (incorporating behaviour change)
Behavioural response by user archetype (i.e. load shifting)
Impact of changes in DAM price (by user archetype)
Impact of changes in applicable tariff (by user archetype)
Impact of behaviours on bills

Generation impacts
Operational impacts
Network charges
Generation mix
Effective price captured in the market
Investment and closure impacts
Revenue impacts
Impact on costs of RES support to meet any revenue shortfall
Impacts on costs of Capacity Market to meet any 'missing money'
Locational investment decisions

Summary of key outputs

System-wide impacts
Carbon emissions
Impact on CfD costs to enable installed capacity included in Net Zero scenario
Carbon emissions based on operational generation decisions (but with fixed installed capacity)
Other
DAM price
Estimated costs of constraint management and costs of transmission network reinforcement

Distribution network impacts
DNO costs
Distribution network reinforcement
Use of flexibility services (simplified)
Generation/Demand
Locational decisions
Connection voltage level

Model functionality

- To capture these outputs, we have developed a modelling framework with multiple functionalities. The *tariff model* incorporates:
  - **Distributional analysis** of tariff impacts on approximately 250,000 user archetypes (by location and tariff type) per option per spot year.
  - We intend to focus distributional analysis on the initial spot year

Model scale: Over 7 million data point outputs per spot year for each model run

Model functionality

- To capture these outputs, we have developed a modelling framework with multiple functionalities. The ***market model*** incorporates:
  - **Systems analysis** of seven aggregated transmission zones and 14 distribution zones with hourly granularity
  - Incorporation of **behavioural responses** to prices and tariffs for generators, consumers and consumer technologies
  - Analysis of **transmission network constraints** and **transmission network infrastructure investment**
  - Analysis of **renewable generation curtailment** and **carbon emissions** resulting from dispatch decisions
  - **Endogenous locational allocation** of renewable generation capacity and storage, using FES regional breakdown as a starting point
  - Consideration of impacts on **low carbon support schemes** and the **capacity market**
  - **Interconnector flows**
  - **Dynamic distributional analysis** of impacts on consumers, storage and generator archetypes (over 600 archetypes by location and technology)

Model scale: Between 15 and 20 million data point outputs for each model run

Model functionality

- To capture these outputs, we have developed a modelling framework with multiple functionalities. The *distribution model* incorporates:
  - **Models 23,000 assets on the distribution network with 10 different technologies**
  - **Allocation of generation and demand capacity** across the distribution networks
  - **Consideration of behavioural response** across the distribution networks
  - **Distribution network reinforcement** requirements and costs
  - Use of **contracted flexibility** as an alternative to reinforcement
  - Optimisation of **costs of new connections**
  - **Access rights options**

Model scale: Over 25 million data point outputs per model run

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Next steps

- Your feedback continues to help the development and assessment of options.
- We will continue to engage with the CG and DG over the next few months and will confirm details in due course.
- Please send any further evidence and feedback to us directly at: FutureChargingandAccess@ofgem.gov.uk

Appendix

Appendix - Recap on Demand TNUoS position

Our review considered the following refined options for Demand TNUoS charges.

Status Quo	Time of Use charging		Agreed Capacity
Winter Triad / Year round TOU	**For all users**	**With seasonal Triad for large users**	
Large users face charges based on their demand in three Triad peak demand periods, while smaller user pay volumetric charges on 4-7pm units ✓Status quo, well understood ✓Provides signal users can respond to ✖Triad is avoidable and may not reflect user impact at other times of the year ✖4-7 units may not reflect periods of high demand costs efficiently	*All demand users pay seasonal summer/winter volumetric charges on their 4-7pm units* ✓Broadly retains equal and opposite charges for whole demand market ✓Accessible signals for users ✖More granular timebands would need model changes, and so are out of SCR scope. ✖Periods of high demand cost may not be reflected	*Small demand users pay seasonal summer/winter volumetric charges on their 4-7pm units, large users face seasonal Triad-type peak use charges.* *As with all user ToU, and* ✓Triad retains well understood signal users can respond to ✓Seasonal Triad charges less avoidable and may better reflect user impact at times outside Triad window ✖More complex, split market signals	*Users face charges based on their maximum agreed import capacity as agreed with their DNO* ✓Indicator of a user's potential peak use of transmission within the year ✖Necessary changes out of SCR scope, and so cannot be taken forward at this point

Refined policy options for modelling based on ESO tariffs

NG ESO provided us with modelled tariffs which are feeding into the CEPA modelling.

Ofgem is the Office of Gas and Electricity Markets. We are a non-ministerial government department and an independent National Regulatory Authority, recognised by EU Directives. Our role is to protect consumers now and in the future by working to deliver a greener, fairer energy system.

We do this by:

- **working with Government, industry and consumer groups to deliver a net zero economy at the lowest cost to consumers.**
- **stamping out sharp and bad practice, ensuring fair treatment for all consumers, especially the vulnerable.**
- **enabling competition and innovation, which drives down prices and results in new products and services for consumers.**

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