Making a positive difference for energy consumers

Challenge Group meeting– 9 June 2020

Objective of this session:

- Provide a general update on our Access SCR and our proposed engagement with you over the coming months
- Seek feedback on DuoS and charge design option definition and assessment.

These slides represent initial preliminary thinking. We are still developing our thinking and are keen for you to input into it.

General update - Access SCR

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Objective of Access Significant Code Review (SCR): We want to ensure electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general.

- We launched the Access SCR in December 2018. The scope is:
  - Review of the definition and choice of transmission and distribution access rights
  - Review of distribution connection charging boundary
  - Wide-ranging review of Distribution Use of System (DUoS) network charges
  - Focussed review of Transmission Network Use of System (TNUoS) charges
- We are assessing options against three key guiding principles. We will need to consider trade-offs between these guiding principles:
  - Supporting efficient system development
  - Reflecting energy as an essential service
  - Practicality and proportionality of implementation

- Thank you to those who responded to our survey regarding your availability to continue engaging with us. As most respondents indicated they would be able to continue engaging in some capacity, we expect that this means that we will continue to receive input from industry on our reforms.

- Instead of organising full day meetings, we are organising shorter webinars on specific topics.
  - We have second session tomorrow on access rights, connection boundary and packaging of options.
  - We intend to hold further sessions later this month on our focused TNUoS reforms and our approach to developing the Impact Assessment
  - We will continue to engage with the CG over the next few months (e.g. as we develop our IA)

- We are keen for these sessions to be interactive:
  - We have a series of Menti questions throughout the presentation to get your feedback– open it now on your phone or another tab on your computer (https://www.menti.com/)
  - Please put yourself on mute. If you have a question or comment as we present – please add it into Menti.

- Please email any comments on these sessions or comments/evidence on our proposed reforms to **FutureChargingandAccess@ofgem.gov.uk**

- **Please be aware that this CG session is being recorded and will be available to those that can't attend right now.**

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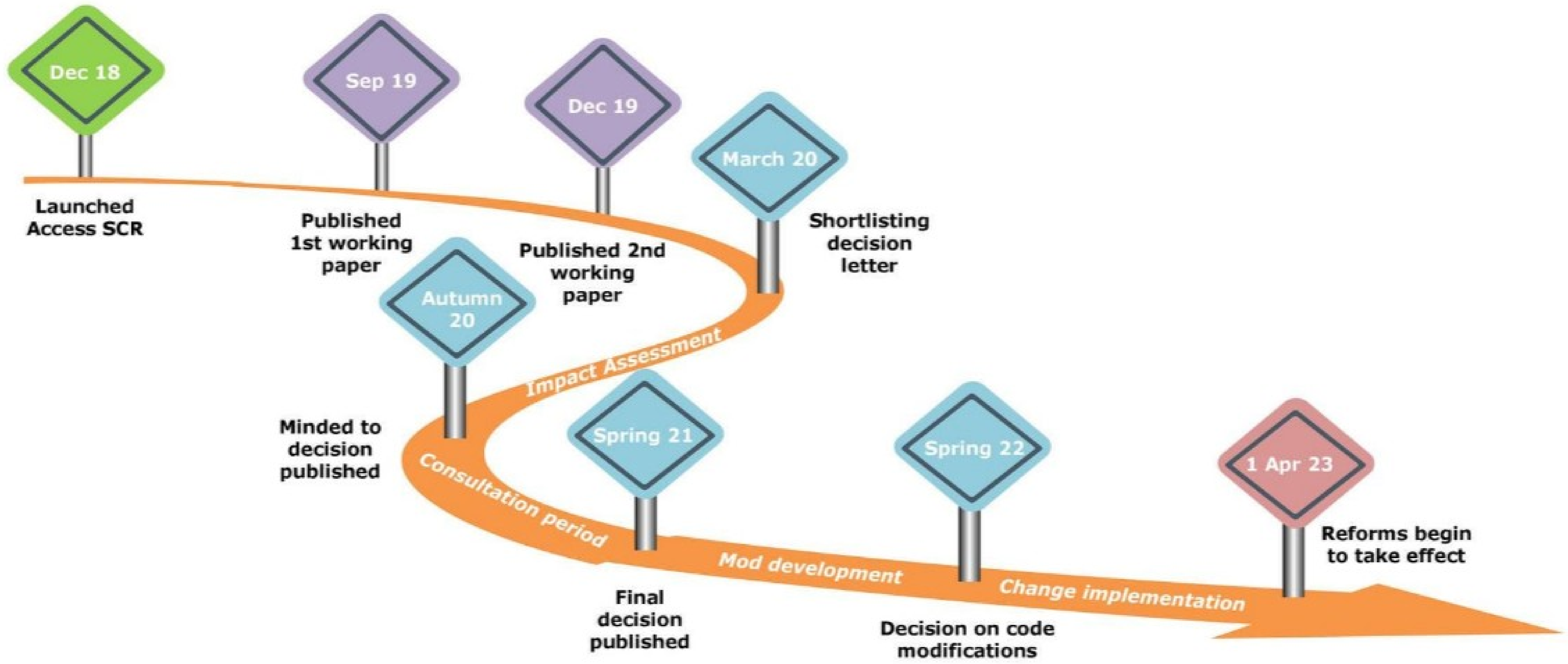
Overall timeline

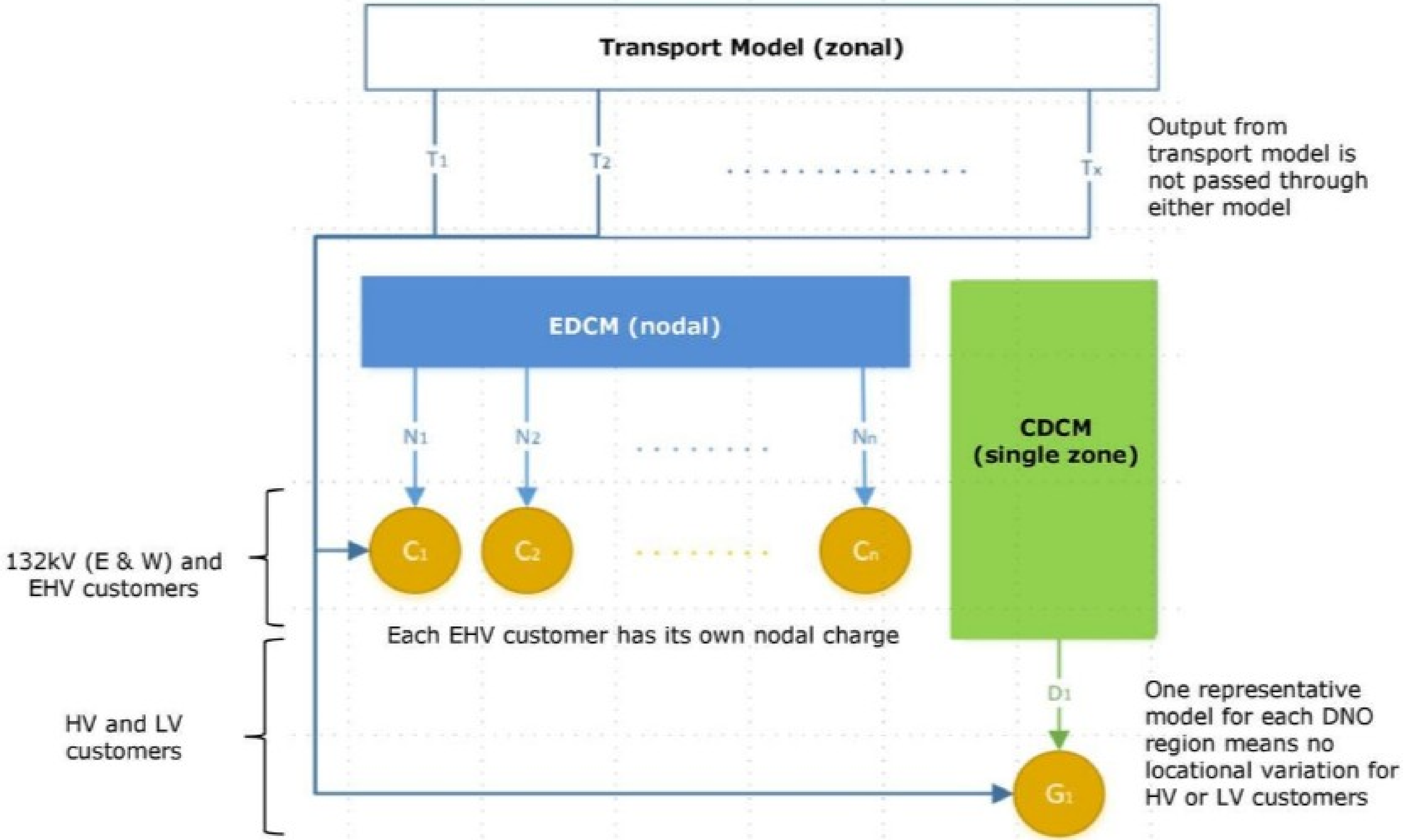
The last time we met was prior to the COVID-19 lockdown. We intend to continue our future charging and access reforms broadly in line with previous plans. At this stage we are only anticipating slight adjustments to timings, as set out on subsequent slides, but will keep this under review.

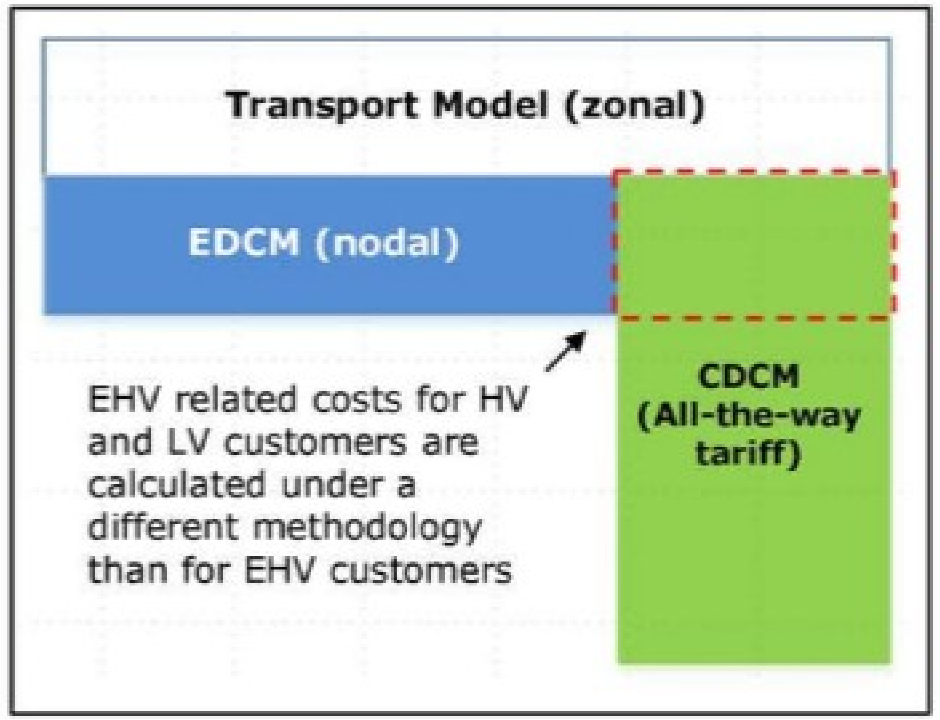


DUoS cost model and charge design options assessment

- The purpose of this session is to:
  - recap what the current arrangements are and the issues being assessed
  - Provide an update on our ongoing assessment and an indication of possible decisions
  - Seek your views on the following issues:
    - Developing a spare capacity indicator
    - Identifying generation dominant areas
    - Applying the right level of locational granularity
    - Designing the charges faced by larger users
  - Obtain any other feedback you have on our assessment to date.

Recap of current arrangements
Cost models





- **Transport model** applies to costs associated with use of the transmission network
- **EDCM** applies to users connected at EHV (22kV up to 132kV in England and Wales), or customers connected to a substation where the infeed is at 22kV or above.
- **CDCM** applies to users connected below 22kV.

Transport Model	EDCM	CDCM
• Ultra long-run model • Applies in relation to transmission costs • Load flow modelling used to calculate flows in relation to an additional 1MW of generation at each node on the network • Charges reflect the cost of rebuilding the network each year • Nodal costs are grouped into zonal charges	• Incremental model • Applies to customers connected at EHV • Complex power flow modelling used to determine the incremental impact that individual customers have on the network • Allocation of operational costs is also influenced by each customer's estimated use of the network • Highly bespoke, nodal charges	• Ultra long-run model, based on a 500MW "increment" • Applies to customers connected at HV and LV • Based on a generic model that estimates the marginal cost of building a network to accommodate the generic increase in demand • No locational granularity in charges within a DNO region

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EDCM charging elements

- EHV connected customers currently face charges based on their impact on the network, which is based on complex power flow modelling
- Charges comprise:
  - Volumetric charge – applies during the "super red" period, which is between 4-7pm from November to February
  - Capacity charge – charges are based on a customer's agreed import or export capacity
  - Exceeded capacity charge – unlike the CDCM, this is not adjusted to remove the customer contribution discount
  - Fixed charge

CDCM charging elements

- Apply across the whole DNO region (non-locational) but vary by customer category

Tariff	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN/day	Capacity charge p/kVA/day	Exceeded capacity charge* p/kVA/day	Reactive power charge p/kVArh
Domestic aggregated	Red	Amber	Green	√			
Domestic aggregated (related MPAN)	Red	Amber	Green				
Non-domestic aggregated	Red	Amber	Green	√			
Non-domestic aggregated (related MPAN)	Red	Amber	Green				
Unmetered supplies	Black	Yellow	Green				
LV site specific	Red	Amber	Green	√	√	√	√
LV Sub site specific	Red	Amber	Green	√	√	√	√
HV site specific	Red	Amber	Green	√	√	√	√
LV gen aggregated	Red	Amber	Green	√			
LV Sub gen aggregated	Red	Amber	Green	√			
LV gen site specific	Red	Amber	Green	√			√
HV gen site specific	Red	Amber	Green	√			√
LV gen site specific no RP	Red	Amber	Green	√			
LV Sub gen site specific no RP	Red	Amber	Green	√			
HV gen site specific no RP	Red	Amber	Green	√			

**This is calculated as the capacity charge without the discount that is applied to reflect the contribution that customers have made through their connection charge*

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Issues with current arrangements

Charges for EHV customers may be to volatile and unpredictable to provide a meaningful signal

This means...

That having a more conceptually sophisticated approach may not, in practice, result in signals that customers can response to

The time and effort required to calculate charges under the EDCM may not be justified or necessary

Users at HV and LV do not receive locational signals about the costs/benefits they drive on the upstream network

This means...

That the charging signal for behavioural change is more locationally muted for these users

This could be a barrier for increased levels of flexibility in response to network charges for those users who are located in constrained areas of the network at lower voltages

There are hard commercial boundaries between the methodologies

This means...

This creates a non-cost reflective 'cliff edge' in charges at the boundaries because the charge for each portion of the network is derived in isolation

Customers can be incentivised to make inefficient decisions about where to locate

We have split our review of DUoS charges into three main areas, which focus on asset-related costs. We are also mindful of the interlinkages between the areas

Network asset costs – based on just forthcoming reinforcement or longer-term view on cost of providing user's network capacity, or a hybrid?

1. What costs are being modelled?

2. On what basis do costs vary by location?

a. Locational variation based on:
- reinforcement proximity
- dominant flows
- asset costs

b. Different options for sizes of charging zones

3. How are modelled costs turned into charges?

Charges based on agreed capacity, usage at certain times or fixed charges (or a combination)

4. Our review is also considering the treatment of operational costs and how they are allocated between customers and charge designs *(this will be covered in a later session)*

Our shortlisting decision said:

Cost model

- At EHV: charges could be based on an incremental or an ultra long-run model, which could be supplemented with a spare capacity discount
- At HV and LV: charges would be based on an ultra long-run model (if we retain an incremental model, this could change over time as network monitoring data increases)
- Charges and credits based on contribution to upstream costs and, where practical, dominant flows
- Locational granularity: for HV and LV customers, DNO regions could be split into zones, based on primaries or groups of primaries while for EHV customers, volatility could be reduced (e.g. by moving to zonal charges)

Charge design

- Charges could be based on agreed capacity only or a hybrid with volumetric charges (but small users would not have agreed capacities)
- Charges could be based on more accurate time bands

In general, respondents:

- Support increasing locational granularity to ensure more efficient network signals but some respondents supported considering simplifying the EDCM
- Prefer an ultra long-run model with a spare capacity indicator over a pure ultra long-run model or an incremental model
- Agree with the decision to not short list a short run margin cost model
- Support a charges and credits regime, based on upstream costs, although some concern about the impact on existing generators and achieving Net Zero
- Mostly supported a decision not to shortlist dynamic charging or charges based on actual capacity, although some stakeholders would prefer these options
- Where options are not being shortlisted, would welcome clarity regarding if they would be considered in the future (e.g. when more network data is available)

Based on responses, we are not proposing to revisit any options we excluded at shortlisting

Overview of our current thinking

EHV connected customers
- Retain **nodal** EDCM
- Move to **zonal** EDCM
- Move to zonal **ULR model**

EHV costs for HV and LV customers

Layered onto HV and LV costs
- Move to **zonal** incremental model
- Move to **zonal** ULR model

All-the-way tariff
- Retain **single zone** ULR model*

HV and LV costs

Level of locational granularity under unrefined ULR model
- Move to basing on **dominant flows**
- Move to basing on **asset mix**
- Retain **generic model across DNO region**

Refinements for zonal ULR model for EHV costs
- Apply a zonal ULR model **with a spare capacity discount** to indicate where there is capacity EHV network
- Apply a zonal ULR model **without spare capacity indicator**, similar to the Transport Model
- Apply **charges and credits**, based on dominant flows at primary substation
- Retain **credits only** for generation export, regardless of dominant flows
- Primary substation
- Bulk supply point
- Grid supply point

Charge design options

Charge design
- Capacity charges only
- Hybrid of capacity and volumetric

Time bands
- Move to **seasonal** time bands for all users*
- Move to time bands that **vary within a DNO region**

***Small users will be considered in our impact assessment, including the extent that increasing granularity should be applied to them**

Overview of our current thinking
Illustrative examples

- We recognise that the interaction between the different elements of the cost model and charge design can be complex and so have set out some simple examples below to illustrate what charges might be for different customers under the following cost model:
    - Ultra long-run model with a spare capacity indicator
    - Locational granularity, based on asset mix and dominant flows
    - Seasonal time bands
    - Layered EHV charges onto HV and LV customers
- Note these are intended to reflect our current thinking and are subject to change as our assessment progresses and we have greater clarity with regards to the detailed application

Situation	EHV related costs	HV related costs	LV related costs
A generator connecting at EHV in a generation dominated location	• Charge for export during the peak period • Outside the peak period would not receive credits or face a charge • Could still receive credits during the winter peak period for offsetting demand	• N/A	• N/A
A demand customer connecting at HV in a generation dominant area	• Credit for usage during the peak period • Outside the peak period would not receive credits or face a charge • Could still face a charge during winter peak period for contribution to peak	• Charge in relation to HV costs, reflecting the average cost across the DNO region *(note: this would be the case if the current assumption that demand drives costs is still applied)*	• N/A
A domestic customer connecting in a demand dominated area	• Charge for usage during the peak period • If there is significant spare capacity, this charge would be discounted to reflect this • Could receive a credit during the summer peak period for offsetting generation *(symmetric application)*	• Charge in relation to HV costs, reflecting the average cost across the DNO region	• Charge in relation to LV costs, reflecting the average cost across the DNO region

1. What costs are being modelled?

Summary of high level options

Ultra long-run
- Stronger more stable ongoing signals
- Does not signal spare capacity

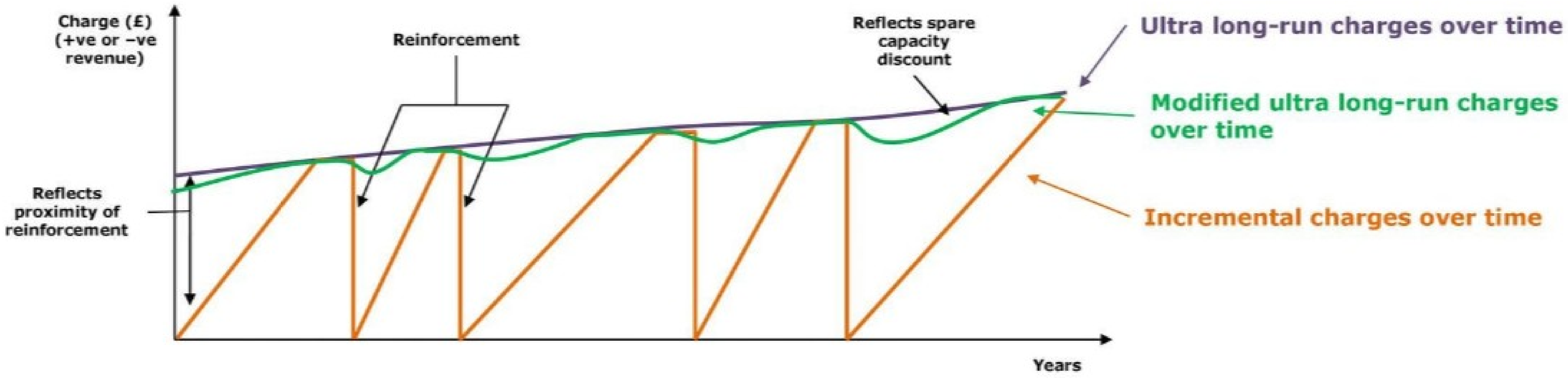
Modified ultra long-run
- Generally stronger ongoing signal, if discount only applied where there is significant spare capacity
- Can ensure stronger signals in locations where reinforcement expected sooner

Incremental
- Signals timing ad location of future reinforcement and spare capacity
- More volatile signals, generally weaker
- Can be bespoke

Lower granularity
More simplicity

Higher granularity
Lower simplicity

- This graph provides a stylised example of how charges in a location could vary over time under each model (note spare capacity could be due to a reduction in usage or when reinforcement has occurred)



For the high level cost model options, one of the key issues we are still working through is with regards to the design and calculation of a spare capacity indicator. We are currently working with the Subgroup to work through a series of options, including:

- How sensitive should the indicator be to changes in spare capacity?
- Should there be a minimum level of spare capacity before a discount applies?
- Should there be a minimum number of years after reinforcement before a discount applies?
- Would applying bands avoid the issues associated with an incremental model?
- What unintended consequences might applying a spare capacity indicator to an ultra long-run model have?

Illustrative example

1. DNO calculates difference between asset rating and peak load to identify the spare capacity
2. The spare capacity percentages for each primary substation are grouped into fixed bands. For example:
    - Less than 20% receives no discount
    - Between 20-40%
    - Between 40-60%
    - More than 60%
3. The discount is applied to the £/kW of forward looking costs, which is applied to capacity and volumetric charges
4. This process is carried out annually

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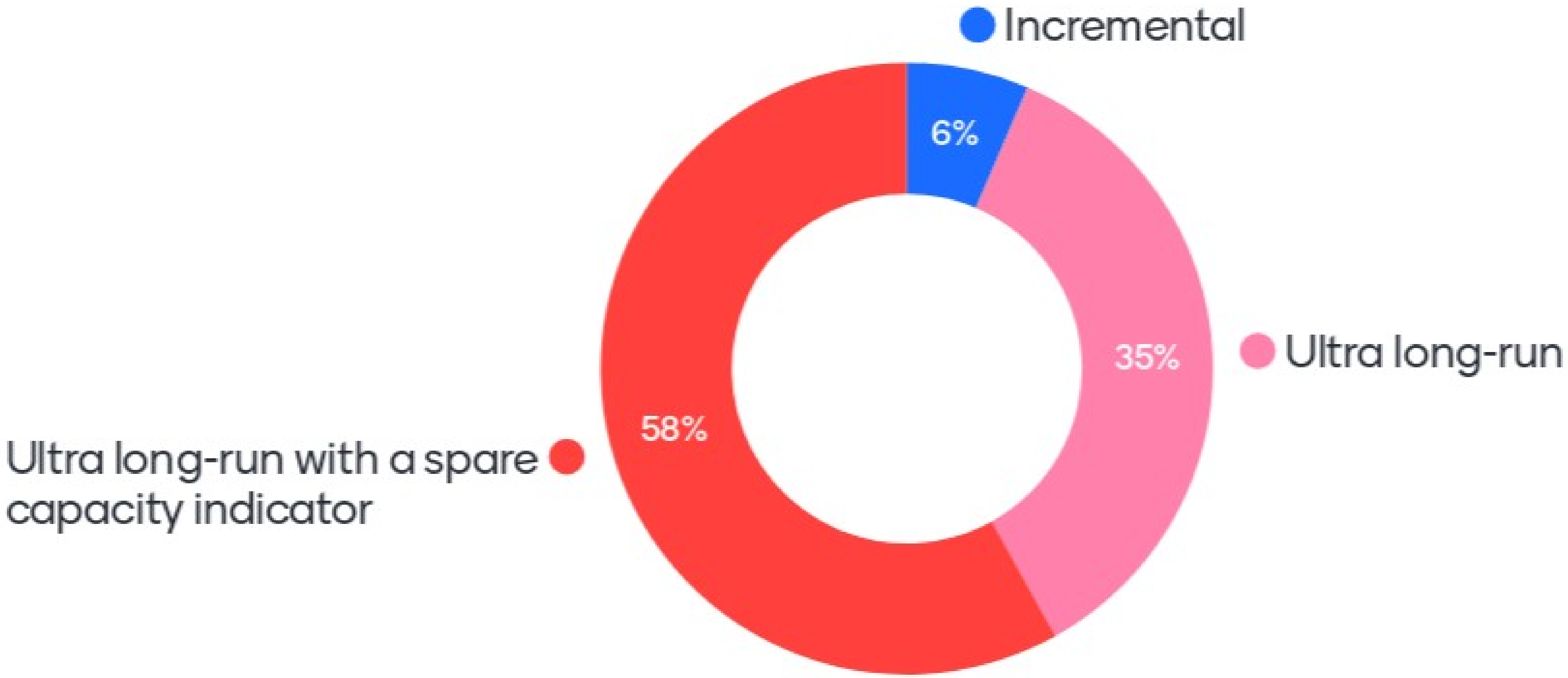
1. What costs are being modelled?

Assessment of high level options

Type of cost model	Principle 1 – arrangements support efficient use and development of system capacity	Principle 2 – arrangements reflect the needs of consumers as appropriate for an essential service	Principle 3 – any changes are practical and proportionate
Incremental	• Signals timing and location of spare capacity, which should incentivise more efficient network usage • It can be too volatile and unpredictable to influence investment decisions • Charges rely on significant forecasting and assumptions • Incremental signal is generally weaker than under an ultra long-run model	• A volatile signal may have a negative impact on investment and operational decisions • If layered onto HV / LV customers, will introduce locational granularity and more volatility to currently simple charging regime	• The model is underpinned by complex load flow modelling and a significant level of forecasts and assumptions • Only possible for EHV related costs, as we have ruled out for HV and LV during shortlisting, due to practicality issues
Ultra long-run	• Does not provide signals about spare capacity on the network resulting in a too strong signal in some locations • Sends a stronger and more stable signal, which users may take into consideration • Locational variation in charges will only reflect differences in the local asset mix	• Easiest to understand charging arrangements • If locational granularity is layered onto HV / LV customers, may face higher charges, based on the asset mix serving them, which they cannot directly influence	• Simple to apply and maintain on an ongoing basis
Modified ultra long-run	• Would provide a signal about spare capacity in the network. However, this would be underpinned by simplifying assumptions, which may not reflect actual network conditions • Sends a stronger and more stable signal, which users may take into consideration • Locational variation in charges will only reflect differences in the local asset mix	• Simpler to understand than the incremental model • Customers will pay a lower charge, where there is a lot of spare capacity • If locational granularity is applied, customers may face higher charges, based on the asset mix serving them, which they cannot directly influence	• Will introduce complexity to the model, which needs to be balanced against improvements in efficient usage • Only possible for EHV related costs, as we have ruled out for HV and LV during shortlisting, due to practicality issues

What is your preferred cost model option?



Please explain your choice of cost model.

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Spare capacity is a relatively 'dumb' measure- contracting flex and tout. Would be more efficient

Price discovery would be helped by including connect and manage combined with financially firm access

Space capacity indicator does not allow proper price discovery

How does the modified ULM signal constrained capacity?

Efficient true ULR signal would be nearer the average of an incremental model signal?

More stable for incentivising investment

Financial firmness 100% necessary for price discovery....

would the spare capacity approach give credit to assets that increase 'spare capacity' ?

Not sure how this would apply to storage?

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Please explain your choice of cost model.

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Incremental too volatile to base investment on. Long run better for investment but doesn't capture true costs at the time.

A new user may not connect because they see no spare capacity .. what if reinforcement could be avoided because the existing users change their behaviour in response to price signals. .... so did the chicken come first or the egg ?

Immediate thoughts are that reflecting spare capacity will make tariffs less predictable (with potential step-changes on reinforcement etc.) and so less likely to change behaviour/investment.

I can only see spare capacity working if you allow an access market

Not clear at all what is meant by "modified" ULR

How long would the spare capacity signal be live? Thinking about lead time to build assets.

Gives best economic signal for people to respond to

Is spare capacity a stranded asset?

Does spare capacity represent inefficient network investment

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Please explain your choice of cost model.

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How might a delay in SCR timetables impact on TCR?

Ultra long run with a spare capacity indicator is best of both worlds. Provides a more stable price signal for a better investment signal. Also avoids perverse incentive such as an expensive price deterring connection despite spare network capacity

Test

Clearly need to be assessed as a package with access reforms.

Is flexibility an asset cost (i.e. a negative asset cost?) or an operational cost?

Need to take into account impact on investment and volatility which will be passed to the market. Reasoning behind impacts on net zero and flexibility/storage would be welcome.

What is an "operational" cost being defined as?

Ultra long run will dampen and smooth out any useful signals for effective use of the network. Spare capacity indicator feels like a very crude and clunky version of a market based signal for capacity.

We agree that the EDCM charges are too volatile to provide meaningful long term signals

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Please explain your choice of cost model.

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Seems a reasonable compromise. If spare capacity discount based on peak, rather than removing the discount when at full capacity could you narrow it to apply only to peak periods to deal with the price discovery point?

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2a. On what basis do cost vary by location?

Summary of high level options

As part of our review, we are considering the right level of locational granularity that should apply to charges. This is influenced by the granularity that it is possible to accurately apply to costs at different voltage levels

Voltage level	Dominant flows	Asset costs	Reinforcement proximity / spare capacity (depending on cost model)
EHV related costs *(For EHV connected customers and able to be layered for HV and LV connected customers)*	• This is already done in the EDCM, although generation credits are floored at zero • Intermittent generators are not eligible for credits (based on F-factors) • Charges could vary for HV and LV customers, based on the dominant flows at the primary substation	• This is already done in the EDCM for EHV connected customers • Charges could vary for HV and LV customers, based on how EHV asset cost vary in different locations	• There is sufficient network data and monitoring to enable load flow modelling / assessment to identify timing of reinforcement under both models • This is inherent in an incremental model, which signals timing and location of future reinforcement • Under an ultra long-run model, a spare capacity discount would have to be applied to the total asset costs
HV related costs	• This might be possible, if based on strong assumptions about the dominant flow at the primary reflecting the dominant flow across the connected HV network • However, the subgroup has indicated this is not a robust assumption • Might be possible in future with greater network monitoring	• Network connectivity data is currently insufficient to enable customers to be assigned to assets • The subgroup considered using network archetypes but decided there was not enough consistency (e.g. all urban areas having similar costs)	• This would require application of very significant assumptions about spare capacity at the primary being reflective of spare capacity on HV assets • Might be possible on a roadmap with greater penetration of monitoring
LV related costs	Significantly more network data would be required and the cost / benefits would need to be assessed: • Cost to implement network monitoring across the whole DNO region (monitoring is currently targeted) • Feasibility of maintaining network models covering millions of LV feeders and customer connectivity • Whether it is acceptable potentially have a large number of different tariffs across the domestic customer group		

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2a. On what basis do costs vary by location?

Assessment of high level options

- As identified in the previous slide, each of these options are already applied in some form to customers connected at EHV under the EDCM and so we would expect that they are generally neutral against our Guiding Principles. One key exception would be if we allowed generation to face charges, where export is driving costs, which we would expect would improve network efficiency under Guiding Principle 1.
- The table below relates is focused on calculating and layering more granular EHV related costs for HV and LV connected customers as both an overarching concept under each of the three options for determining them.

Option	Principle 1 – arrangements support efficient use and development of system capacity	Principle 2 – arrangements reflect the needs of consumers as appropriate for an essential service	Principle 3 – any changes are practical and proportionate
Layering the EHV level granularity to introduce granularity for HV and LV customers	• Would improve efficiency by strengthening the signals faced by HV and LV customers with regards to their impact on the upstream network	We would need to consider the impact on vulnerable customers, as some could face significantly higher costs, due to where they are located	• This would introduce significantly more complexity, as would move from a single charge for HV and LV customer categories
Charges and credits are applied at each location, based on the dominant flow at the primary substation *(Note that this can be applied alongside other granularity)*	• Would improve efficiency by removing incentive for generation to export where it drives costs • Efficiency is reliant on how well the signals reflect the impact of generation vs demand on costs	• Under a layered approach, customers connected at HV and LV could receive a charge or credit, reflecting their EHV costs	• Under the EDCM this approach happens already for generation, although currently credits are floored at zero • Similar network data can be used to determine this under an ultra long-run model for EHV related costs
Differences reflect local asset mix at EHV	• Provides customers with a signal about the relative cost of connecting in one location vs. another, rather than being averaged across a DNO region • However, does not signal when any additional costs are likely to be incurred	• Although variations in the cost of assets may be due to the location (e.g. topography) it may also reflect DNO preferences at the time, which the customer cannot influence • It could significantly increase costs for some users in high cost locations	• Already happens on the EDCM • Similar network data can be used to determine this under an ultra long-run model for EHV related costs
Differences reflect the degree of spare capacity (timing to reinforcement) under an ultra long-run model *(Note that under an incremental model, this is built into the cost of the "increment")*	• Would provide customers with a more accurate signal of the relative cost at different locations • Efficiency of signal is dependent on how well a spare capacity indicator reflects network conditions	• Customers will pay a lower charge, where there is a lot of spare capacity	• Will introduce complexity to the model, which needs to be balanced against improvements in efficient usage

2a. On what basis do costs vary by location?

Determining dominant flows

For the high level locational variation in costs options, one of the key issues we are still working through is with regards to how to identify dominant flows for the purposes of applying charges and credits. Some of the questions we are still working through are:

- If, for example, winter peak demand was expected to trigger the next reinforcement, should generation face charges in summer when it is the dominant flow?
- How should the interaction between this and a spare capacity indicator be treated? In the above example, demand would face a charge, but, if there is spare capacity, then the charge would be discounted. Our current thinking is that the generation credit would also be discounted, to reflect the fact it is not driving the same benefit, as on a constrained network.
- How would charges and credits be applied, if peak loads driven by demand and generation are expected to be similar (i.e. it is uncertain which flow is the dominant flow and could trigger reinforcement first)? Would a "dead band" be appropriate, where neither load pay the load related charge or receive a credit?
- How should charges and credits be applied at HV? Is there sufficient evidence to support continuing the current assumption that generation always provides a benefit when it exports or would it be more cost reflective to turn off both charges and credits in relation to costs in that voltage level? Should the treatment be different at LV?
- Some stakeholders have suggested this could be volatile, as dominant flows can "flip" back and forth. To what degree is this volatility an issue when based on annual peak loads?

What are your views on the discussion of identifying dominant flows and the impact of generation vs demand? Any areas that haven't been considered?

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Assume these would need to be reassessed annually also?

Test

Could the dominant flow be determined by the reason for the last network reinforcement?

how might this take into account various projects and initiatives to reduce peak ?

Dominant flows are not a reliable indicator of usage

If based on a credits vs charges system, how will smaller generators know what is happening at the primary-sub, so know how to respond?

Are dominant flows right. Aren't there different security standards for generation and demand connection? These may drive different levels of investment. Its important that charges are related to costs, not flows

How would storage be treated in these circumstances?

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What are your views on the discussion of identifying dominant flows and the impact of generation vs demand? Any areas that haven't been considered?

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It's a too binary - just a "yes/No" which has risk of flipping in future - not a great investment signal

How do you define that an excess of generation is driving peak flows, tather than insufficient demand. In particular where a large demand site may shut down.

Is this too simplistic a model and we need something more nuanced?

The segmentation of small users from this thinking is restricting the consideration of the impact of these charges on users - small users stand to benefit the most from easy access to flex signals compared to larger users who can access markets

If you want to signal areas where there are generation or demand driven, you will intend to drive these to be on the balance point between both... Therefore the 'flipping' between mechanism should be carefully considered as it may dominate in future

A difficult investment signal that could be volatile and at risk of flipping

Generation and demand peaks may trigger different reinforcement needs.

Charging based on the network context is a good idea for driving optimum behaviour. This needs to be designed in a granular and dynamic way for it to work. Defining a dominant flow for a whole GSP for a whole year defeats the object.

Dominant flows should be measured at peak times as this is what the network is sized for. Peaks will change through time

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What are your views on the discussion of identifying dominant flows and the impact of generation vs demand? Any areas that haven't been considered?

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If a DNO cannot depend on generation being on load at peak, is it fair that generation and demand charges are equal and opposite?

Peak flow analysis should take account of security. This is because managing a constraint by constraining off a generator is much cheaper than cost of "lost load" from unserved demand. So dominant flow does not by itself reflect reinforcement need

If it is uncertain which flow is the dominant flow and could trigger reinforcement first, a "dead band" could work, where load neither pays the load related charge nor receives a credit....

The diversity of flow are an important factor - different usage at different times will influence flow, both imports and exports

simplify charging - treat 132kV in Scotland same as EHV with DUoS

Very concerned about the feasibility challenges outlined - if DNOs are unable to maintain network models, how are we going to deliver an efficient system for NetZero? (e.g. delivering flex markets)

deadband - with soft edges to avoid cliff edge

Thinking about dominant flows is helpful, but the proposals are very static - can more granularity be introduced to enable DNOs the flexibility to use the best information available in the relevant area (i,e. more granular for LMA, less for unconstr

Generation at HV should continue to receive a credit if a non GDA as measured by the dominant flows at the primary- otherwise you will create a distortion between EHV and HV

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What are your views on the discussion of identifying dominant flows and the impact of generation vs demand? Any areas that haven't been considered?

Dead bands make sense to avoid arbitrary flipping

Load flow modelling and network monitoring should be appropriate to need - we should wait for whole network monitoring to deliver value from appropriate signalling in LMA

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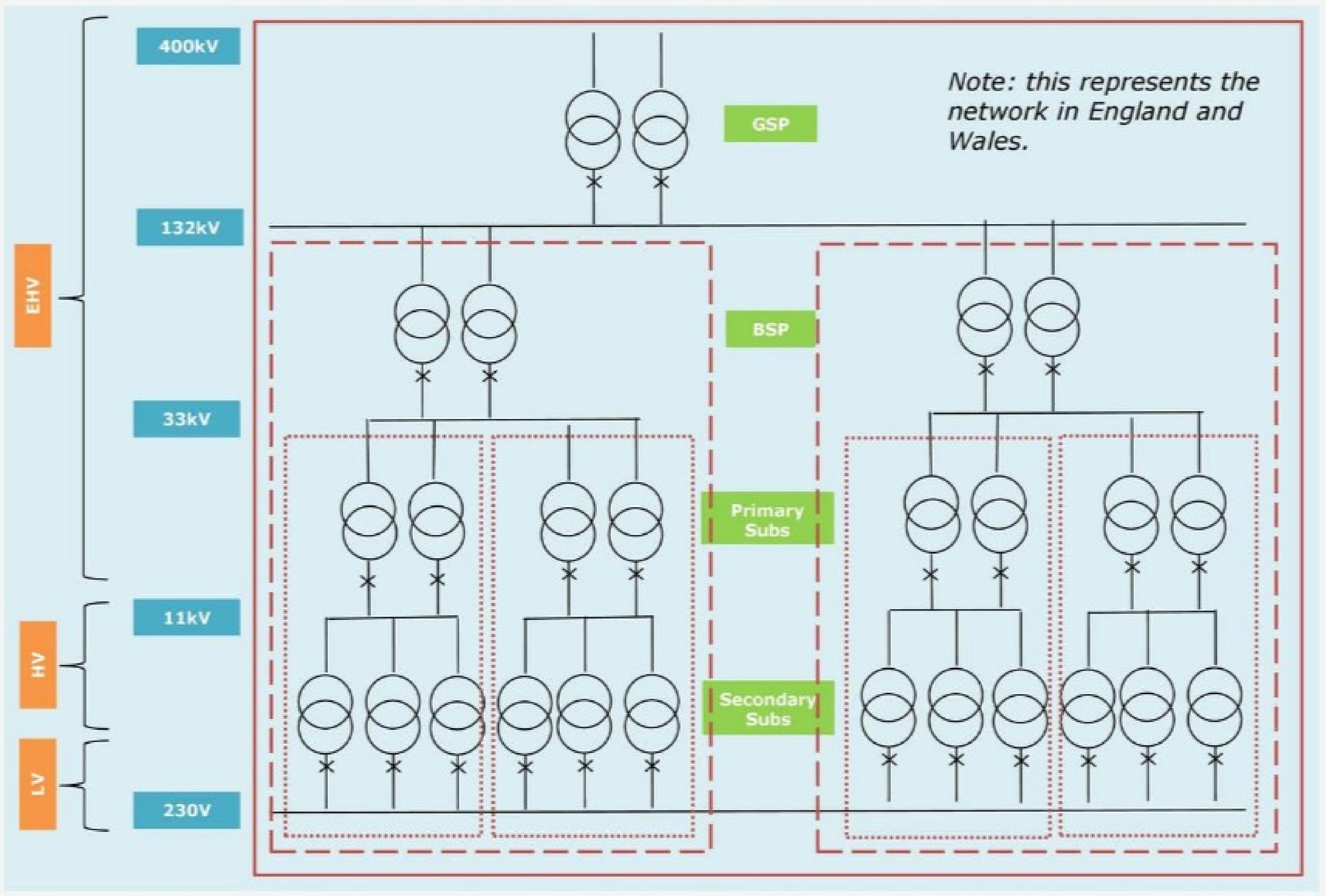
2b. What size should charging zones be?

Summary of high level options



Grid supply point (GSP)
- Main point of supply between the transmission and distribution networks
- There are approximately 145 GSPs across GB

Bulk supply point (BSP)
- Any point where electricity is delivered from the transmission to distribution networks
- There are approximately 820 BSPs across GB

Primary substation
- Transformation level between EHV and LV networks
- There are approximately 5,800 primaries across GB

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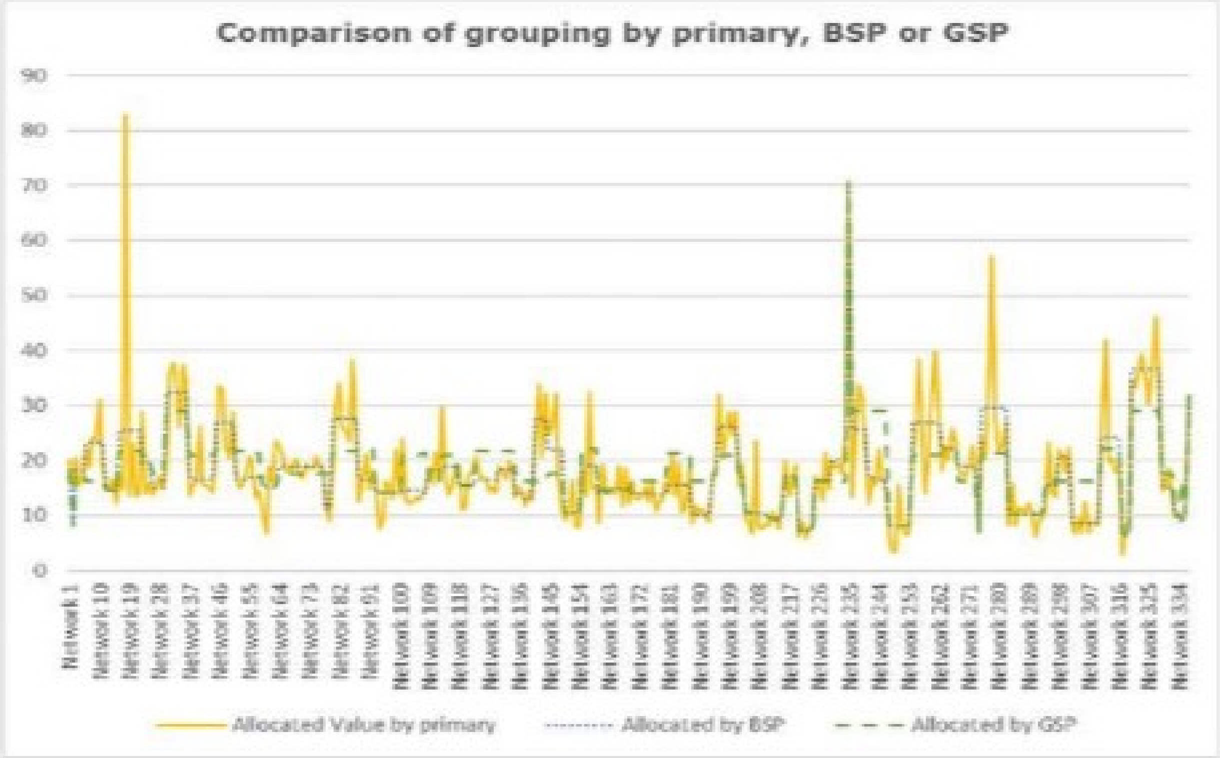
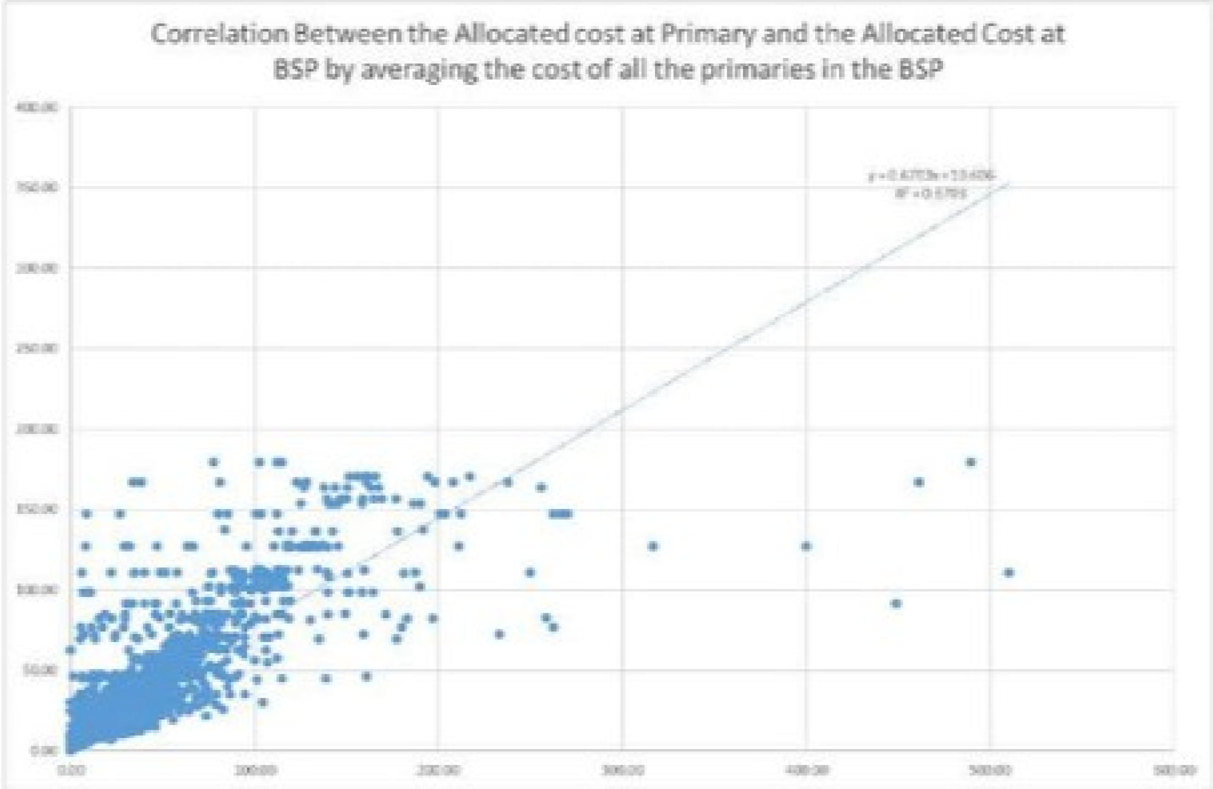
2b. What size should charging zones be?
Assessment of high level options

- There not currently any locational granularity within a DNO region for customers connected at HV and LV, as all costs are reflected in the all-the-way tariff.
- Under the ultra long-run model, the most granular option for setting charges is by primary substation, but this would mean that there would be over 50,000 charges across GB, due to the number of customer categories. This is especially significant for the IDNOs who may have customers in every DNO region.
- The Subgroup has undertaken analysis to identify the impact that grouping customers by BSP or GSP would have on charges
    - The graph illustrates the extent that signals are smoothed when grouped by GSP or BSP in one DNO region, as charges will be averaged across the group (Guiding Principle 1). However, this would reduce the administrative complexity (Guiding Principle 3) and boundaries between primary substations (Guiding Principle 2)
    - The second graph illustrates the correlation between all DNOs' primaries (x-axis) and BSPs (y-axis). The R2 value is 0.67, which indicates a strong positive correlation.
- It appears there is a good correlation between primaries in a group and their and the BSP but there could still be significant smoothing for some primaries. In addition, we expect that the size of the differences in costs between primaries could be even greater under an incremental model.





Do you agree that introducing locational granularity for HV and LV connected customers at a BSP level would result in greater network efficiency?

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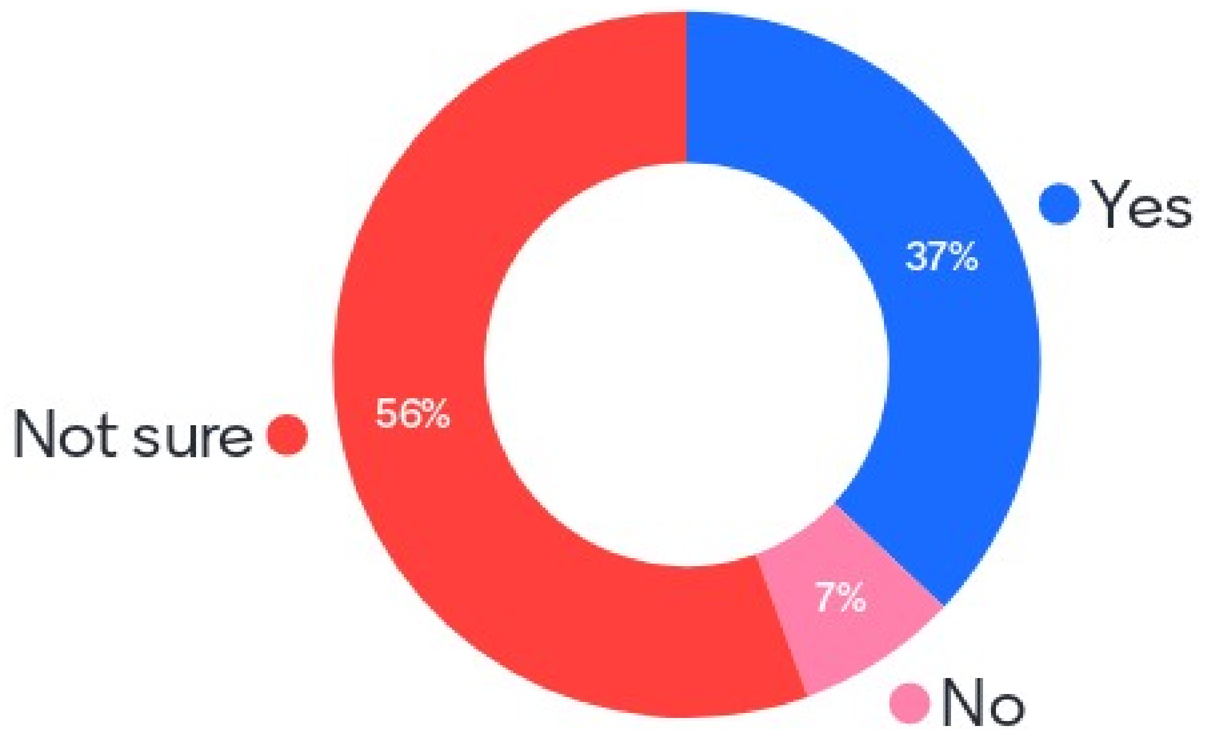

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Do you agree that introducing zonal charging for EHV connected customers at a BSP level would result in greater network efficiency?

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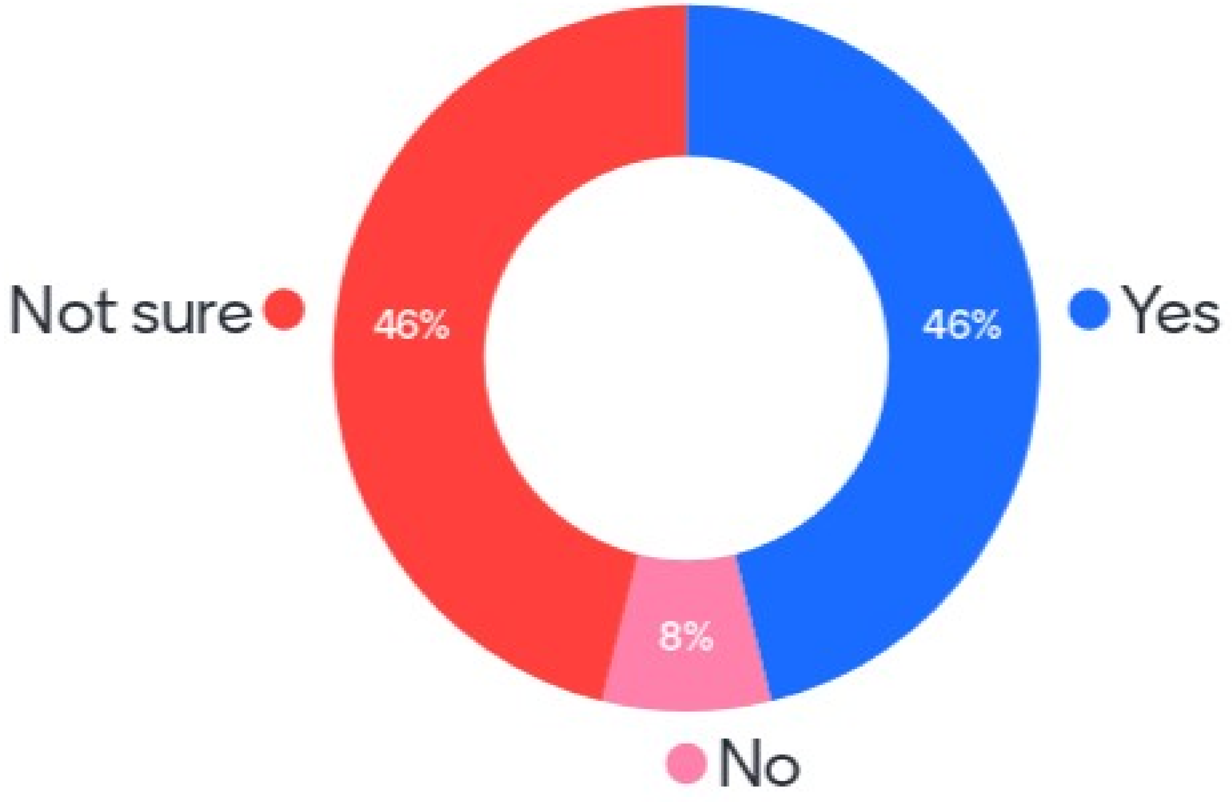

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How might introducing locational granularity in charges for HV/LV or moving from nodal to zonal charges for EHV impact on you and/or your customers?

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Significant numbers of zones would would create a large administrative burden for supplier pricing systems

There should be some reduction in volatility

EHV: would need to see long-term forecast and volatility of the new model. In principle seems to reduce volatility, if so this will assist investment decisions

Can't see how they are supposed to respond to these signals. And therefore how it will help it be more efficient

Customers already input their full 7 digit postcode to uswitch or supplier's own site and they have no idea what locational granularity lies behind that. They're fine so are our systems

The additional stability for ehv would be welcome

We would welcome it as it would create more opportunities for customers to engage in making the system smarter and cheaper

Help to avoid cliff-edge: take Scottish 132kV into DUoS (EHV) and remove these costs from TNUoS -

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How might introducing locational granularity in charges for HV/LV or moving from nodal to zonal charges for EHV impact on you and/or your customers?

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Creating even more of a postcode lottery for domestic would not be appreciated by consumers

Impossible to know without seeing the expected direction and quantum of charges/credits

John Tindal's points in the chat are all very relevant

.

More locational granularity is important in order to avoid subsidisation and inefficient behaviours. Primary substation granularity would not be an issue for us as a large supplier

Fine for systems, fine for customers, doesn't make any difference except, if you want to look up your charge other than on statement from Supplier, bit more complicated for some large customers, fine for domestics (postcode resolves)

Level of complexity for introducing significantly more tariffs needs to be carefully considered. Could lead to significant implementation costs.

EHV: current model is extremely volatile, zonality would improve uncertainty passed on to customers

Have to balance the benefit of better network efficiency with potential additional costs for customers unable to change their consumption.

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How might introducing locational granularity in charges for HV/LV or moving from nodal to zonal charges for EHV impact on you and/or your customers?

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Larger administrative burden for suppliers. Would need plenty of notice to enable suppliers to 1) redesign pricing systems 2) take it into account in producing quotes 3) time to avoid conflicting with signing existing/new fixed price supply contracts

Test

Removing averaging always leads to sharper price signals. However, these have to be passed on to end users. Suppliers will end up having to quote by MPAN (rather than DNO level).

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2b. What size should charging zones be?

Moving to zonal charges under the EDCM

- In addition to the discussion about introducing locational granularity for HV and LV customers through layering their EHV related costs, we are also considering the benefits of reducing the granularity of EDCM charges, which are currently applied on a nodal basis.
- We would expect that the smoothing effect of grouping nodal charges in zones would help to address the volatility, which some stakeholders have indicated is an issue, although charges would generally still be more volatile than under an ultra long-run model. Our current assessment is summarised in the table below.
- Note that this is subject to a decision discussed under Question 1 regarding whether to apply an incremental model or move to some form of ultra long-run model for EHV related costs.

Option	**Principle 1** – arrangements support efficient use and development of system capacity	**Principle 2** – arrangements reflect the needs of consumers as appropriate for an essential service	**Principle 3** – any changes are practical and proportionate
Move to zonal charges under the EDCM	• Charges would no longer be bespoke to each customer, weakening the signals for individuals • This would reduce volatility and improve predictability, enabling customers to better reflect them in decision making	• A volatile signal may have a negative impact on investment and operational decisions	• Would remove a current step in the calculation process where charges are calculated for individual customers

4. How are modelled costs turned into charges?

Summary of high level options

- The current split between capacity and volumetric charges is driven by the assumption that the DNOs take into account agreed capacities at the point of connection and peak loads at higher voltages.
- Based on input from the Subgroup and network planners, this is still consistent with how the DNOs plan their networks:
  - **At the voltage of connection**: the DNOs ensure they are able to meet a customer's agreed capacity needs, even if they are not currently using it
  - **At higher voltages**: diversified demand mean that the network does not need to be sized to accommodate each customer's agreed capacity and their contribution to peak load is the key driver
- Given this, our initial view is that it is still appropriate to apply a hybrid for customers with agreed capacity on the network, as it is reflective of how costs are incurred

Other charge design elements

- In addition to our general assessment of DUoS charges, which are applicable to all users, we are considering two specific issues:
  - Whether to maintain the current treatment of reactive power charges, which apply when a HV or LV connected customer has a power factor of less than 0.95.
  - How to treat unmetered supplies (UMS), which currently face only volumetric charges, based on the assumed usage. This is an important issue, given the expected increase in UMS, as local councils convert their street lights to include electric vehicle charging.

4. How are modelled costs turned into charges?

Key sub-options

For the charge design, there are several important sub-options that we are considering:

- Under a hybrid option there are several refinements we could make to the time bands to help ensure the volumetric signal does not over-incentivise customers to change their behaviour outside of periods of peak network load:
  - Introducing seasonality to charges for HV and LV connected customers
  - Refining the "super red" charges under the EDCM, to enable a summer charge for generation where it is driving costs
  - Enabling time bands to vary within a DNO region to reflect any significant variations in local network peaks
- Although our initial view is that it may be more cost reflective to retain a hybrid option, if we moved to a capacity charges only approach (for relevant customer categories):
  - Whether to apply seasonal backgrounds, reflecting the fact users' network access may not drive costs year round
  - A method for reflecting credits for offsetting dominant flows, which does not incentivise users to over-state their capacity needs to increase the credits they are eligible to receive.
- For customers who do not pay capacity charges, their costs relating to the voltage of connection are recovered through fixed costs. However, it may be more cost reflective for these to be recovered through volumetric charges under an ultra long-run model.
- How to reflect the value that flexible access rights choices could provide the DNO through avoided reinforcement, which is being considered across Subgroups and with support from CEPA TNEI. Issues being considered include how to identify the additional value that certainty provides over and above changes in usage, in response to a volumetric signal.

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4. How are modelled costs turned into charges?

Current assessment of sub-options

Option	Principle 1 – arrangements support efficient use and development of system capacity	Principle 2 – arrangements reflect the needs of consumers as appropriate for an essential service	Principle 3 – any changes are practical and proportionate
Capacity charges only – seasonal profiles	• The network at the voltage of connection is sized to accommodate the capacity customers have agreed with the DNO and so charging on this basis may incentivise customers to release unused capacity • Sharpening the signal further to increase the incentive the release capacity during the period when the network requires it the most • Agreed capacity does not provide a good reflection of how peak usage could vary significantly across customers • Would rely on users choosing flexible access right choices and/or development of liquid DNO flexibility markets, which is uncertain in the short- to medium term	N/A (no small user impact)	• Some system changes will be required • DNOs will need to develop a methodology for calculating charges in the initial years, where a full set of capacity-based seasonal data is not available
Hybrid charges (volumetric for users without an agreed capacity) – refinements to volumetric charges	• Applying some form of volumetric charges is consistent with how the DNOs plan the network and incur costs • Customers are most likely to respond to this signal so, if not cost reflective, could incentivise inefficient changes in behaviour • A stronger capacity charge creates a greater incentive for users to accept flexible access rights, where this will provide network benefits	• Sharpening the signal through refinements such as seasonality will increase charges during winter. We will need to consider the impact of this on small users' charges	• Some system changes will be required • Minor changes to how the models assign costs to time bands, etc. would be required
Hybrid charges - refinements to time bands for volumetric charges (e.g. seasonality)	• Better aligning charges with times when customers' behaviour drives costs on the DNO networks should improve efficient network usage • The sharper signal could create incentives for users to enter into flexible arrangements or invest in technological solutions	• In most areas, introducing seasonal charges will result in much sharper winter charges. We will need to consider the impact on small users	• Some system changes will be required • Allowing time bands to vary within a DNO region would increase the complexity involved in managing a portfolio of customers' usage

What would the implications of retaining a hybrid option be for you and/or your customers as compared to moving to an agreed capacity only approach?

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Not sure. It's really hard to tell for storage right now - it depends...

Volumetric charges can influence decisions made in the energy market by lowering apparent cost of embedded generation

static time bands seems like a historic approach - is that fit for a 2050 facing net zero network? users could be offsetting peak so much that peak occurs at a different slot, or not at all. Note e.g. Covid-19 almost eliminated morning peak.

I struggle with agreed capacity only. I suspect that you end up with an inefficient use of the network as you hold excess capacity "in case"

Prefer hybrid approach to only agreed capacity

An agreed capacity approach does not incentivise customers to make flexibility changes

Straightforward - as explained, reflects the approach to network planning

Hard to say, especially for fixed price contracts

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What would the implications of retaining a hybrid option be for you and/or your customers as compared to moving to an agreed capacity only approach?

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Refining the "super red" charges under the EDCM, to enable a summer charge for generation where it is driving costs, is good

Prefer a hybrid option

volumetric charges are more consistent with changing peaks and can better influence behaviour

Hybrid appears best, capacity only would likely drive more behaviour changes than a hybrid

Peak time of use tariffs distort generator dispatch resulting in higher carbon emissions. For BTMG and DG Need to balance this against simplicity.

Agreed capacity works best with flexibility markets to incentivise dispatch. This is much more efficient than time of use.

Static and locationally harmonised bands are not consistent with a smart responsive energy system

Agreed capacity approach would be a kick in the teeth for early movers on flexibility

If you want to provide locationally granular signals for operational dispatch, this is better achieved using flexibility markets which can be highly targeted. By contrast, TOU is too blunt to efficiently manage operational constraints.

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Next steps

- Your feedback will input into development and assessment of options
- There is a second webinar tomorrow to focus on:
  - Access rights choices
  - Connection boundary
  - Packing of options for impact assessment modelling
- In addition, we intend to set up another short series of webinars towards the end of June – to discuss focused TNUoS reforms and our impact assessment.
- As mentioned earlier, we will continue to engage with the CG over the next few months
- We will be issuing our minded to consultation in late Autumn 2020.
- We are keen to engage. Feel free to contact us directly on FutureChargingandAccess@ofgem.gov.uk

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Are there any other comments you want to provide in relation to the topics covered in this presentation? Please be clear which issue you're addressing

15 questions
23 upvotes

Ask me anything

15 questions
23 upvotes