Draft Final CUSC Modification Report

CMP324 & CMP325

Generation Zones – changes for RIIO-T2 and Rezoning – CMP324 expansion

Overview: The CUSC requires that generation zones, used for Transmission Network Use of System (TNUoS) tariff setting, are reviewed at the start of each price control period. CMP324 and CMP325 seek to change the zones and the underlying methodology used to establish them. CMP325 was raised to widen the defect of CMP324.

Modification process & timetable

1. **Proposal form** – 12 September 2019
2. **Workgroup Consultation** – 26 February 2020 - 18 March 2020
3. **Workgroup Report** – 29 May 2020
4. **Code Administrator Consultation** – 3 June 2020 - 24 June 2020
5. **Draft Final CUSC Modification Report** – 23 July 2020
6. **Final CUSC Modification Report** – 13 August 2020
7. **Implementation** – 01 April 2021

Have 5 minutes? Read our Executive summary
Have 20 minutes? Read the full Draft Final CUSC Modification Report
Have 1 hour? Read the full Draft Final CUSC Modification Report and annexes

Status summary: This Report will be submitted to the CUSC Panel for them to carry out their Recommendation Vote on whether this change should happen.

This modification is expected to have a: high impact	Generator Users liable for generation TNUoS and National Grid ESO
Governance route	This modification has been assessed by a Workgroup and Ofgem will make the decision on whether it should be implemented.

Who can I talk to about the change?

Proposer: Grahame Neale, National Grid ESO

grahame.neale@nationalgrideso.com

07787 261242

Code Administrator Chair: Joseph Henry

joseph.henry2@nationalgrideso.com

07970 673220

Executive Summary

The CUSC requires that generation zones, used for TNUoS tariff setting, are reviewed at the start of each price control period. CMP324 and CMP325 seek to change the zones and the underlying methodology used to establish them. CMP325 was raised to widen the defect of CMP324.

What is the issue?

14.15.37 of CUSC requires that the ESO reviews generation charging zones to be used during each price control period[1]; the next price control period for transmission commences on 1 April 2021.

The current methodology used at the previous price control created 27 generation zones. If the same criteria were applied for 2020/21, the ESO predicts this would create 48 zones. This would change again ahead of the next TO price control period, which is expected to start in 2026/27. This is likely to lead to significant investment uncertainty and tariff disturbances for TNUoS-liable generation.

What is the solution and when will it come into effect?

Proposers solution: Replace the existing rezoning methodology with a statement that demand and generation zones have been determined to be 14 in number and shall be the Grid Supply Point (GSP) Groups.

Proposers solution implementation date: This CMP should be approved no later than mid-October 2020 to be able to be implemented on 1 April 2021. Delayed implementation is not possible without a further CUSC change, an ESO derogation or an extension to price control.

Summary of potential alternative solution(s):

- **RPI (WACM1)** - Inflate the +/- £1/kW used in the current methodology to +/- £2.25/kW (in line with RPI) and index link £2.25/kW for future price controls.
- **Fixed 27 zones (WACM2)** - Use the current 27 TNUoS charging zones within the CUSC and remove the requirement of re-zoning at the start of every Transmission Price Control.
- **Current 27 Zones until delayed implementation, then Original (WACM3)** – Keep the current 27 zones until charging year ending March 2023, then from the next charging period change to the GSP group (14) zones as per the Original.

Workgroup conclusions: The Workgroup by majority agreed that the Original Proposal and WACM1 better facilitated the applicable CUSC objectives than the Baseline.

The Workgroup by majority agreed that the Baseline was better than WACM2 or WACM3.

4 members voted for the Original as the best option, 5 members voted for WACM1, 1 member voted for WACM2 and 1 member voted for WACM3.

[1] CUSC 14.15.37 ‘*Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances.*’

What is the impact if this change is made? (Proposer's View)

Who will it impact?

In the Proposer's view, generators liable for TNUoS are directly affected by CMP324 and CMP325.

Increased stability in zoning should provide better certainty regarding long-term investment signals to generators, potentially improving competition in the wholesale and Contracts for Difference (CfD) markets.

There may be a short-term implementation shock to individual generator's tariffs because zonal tariffs would be averaged across a wider range. There will also be a reduced locational granularity of tariffs.

Interactions

The workgroup is mindful of the interactivity of the RIIO-T2 price control (discussed throughout the report), CUSC modifications CMP315[2], CMP317[3], CMP320[4], and the modifications stemming from Ofgem's Targeted Charging Review direction[5] (CMP327, CMP334 and CMP333)[6], however neither the price control data nor ongoing modifications have been included in the analysis. The RIIO-T2 data was not available at the time of publication, and each modification must be judged against Baseline CUSC.

Workgroup Report

This document is the CMP324/325 **Draft Final CUSC Modification Report.** This document outlines:

- **What is the issue?**
- **What is the solution?**
    - Proposer's solution
    - Workgroup considerations and consultation summary
    - Alternative solutions
    - Legal text
- **What is the impact of this change?**
    - Workgroup vote
    - Code Administrator Consultation summary
- **When will the change take place?**

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[2] CMP315: TNUoS: Review of the expansion constant and the elements of the transmission system charged for

[3] CMP317: Identification and exclusion of Assets Required for Connection when setting Generator Transmission Network Use of System (TNUoS) charges

[4] CMP320: Island MITS Radial Link Security Factor

[5] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment

[6] https://www.ofgem.gov.uk/system/files/docs/2019/12/full_decision_doc_updated.pdf

- **Acronym table and reference material**
- **Annexes**

What is the issue?

Background – what are generation zones and why are they needed?

1.0 All TNUoS tariffs are based on which geographical zone users are connected to.

1.1 The CUSC currently applies different methods for determining generation and demand zones. Demand is zoned using the 14 Grid Supply Point (GSP) Groups on the distribution network geographic boundaries.

1.2 Transmission connected generation is zoned by grouping together nodes which have a total marginal cost of the generation connecting at each node to be within +/-£1/kW (14.15.42[7] of CUSC).

1.2 TNUoS charges give locational signals which show where on the network more investment may be needed. Generation zones are set before each price control period to i) dampen nodal marginal cost fluctuations; ii) provide stability ahead of a price control period in as much as the zones will be fixed for that specific period; and iii) enable a reduction in tariff volatility, whilst maintaining locational price signals.

What is the issue?

1.3 14.15.37 of CUSC requires that the ESO establishes generation charging zones to be used during each price control period; the next price control period for transmission commences on 1 April 2021.

Why is it an issue?

1.4 The current method has created 27 generation zones and, if the same method was applied for 2020/21 ahead of the RIIO T2 price control period, it is predicted this would create 48 zones, which would need to be changed again ahead of the next TO price control period[8], which is expected to start in 2026/7. This is likely to lead to significant investment uncertainty and tariff disturbances for TNUoS-liable generation.

What is the solution?

Proposer's solution - Aligning generation and demand charging zones

2.0 The existing provisions of 14.15.42 - 45 should be removed and replaced with a single paragraph stating that the number of generation zones has been determined as 14, corresponding to the 14 GSP groups as they are currently defined[9]. This wording already exists in 14.14.5 of CUSC. There will be consequential changes to other parts of Section

[7] 14.15.42 - 14.15.45 relate to generation zoning. In practice, zones are set by reference to expansion constant and expansion factors, the security factor and the output of the nodal TNUoS tariff.

[8] The Workgroup's interpretation is that as the ESO and TO price controls are not aligned post legal separation in April 2019. The Workgroup determine that the relevant price control on which generation zones must be reviewed for is the TO price control.

[9] It is the proposer's intention that the original solution would use the current 14 GSP groups and would not necessarily be subject to change if there were any subsequent changes to GSP groups, as defined in the CUSC.

14 solely to the extent that generation zones are referenced – in practice there would cease to be 'demand' or 'generation' zones, instead just 'zones'.

2.1 Using the existing fixed demand zones (the 14 GSP groups) for the purposes of generation charging would resolve the noted defect, namely that the current zoning criteria is no longer fit for purpose, as the output is overly-complex and does not lend itself to long-term investment signals. This is because;

- Whilst generation TNUoS is reflective of a long run marginal cost, the wider tariffs are sensitive to regional generation fuel mix. Regional generation mix is determined by boundaries of zones, as well as the assumed "connectivity map" that forces flows along a single path (i.e. no parallel paths are allowed between zones).
- If both the inputs into the wider zonal tariff methodology, and the boundaries/connectivity of zones are subject to repeated change in the short to medium term, the wider tariff therefore cannot provide a useful long-term capacity investment signal to generators.
- As demand zones are fixed based on GSP Groups, an alignment between zones will lead to greater stability for generator users seeking to connect, as well as for those users already connected.

2.2 It is expected that constant zones will also support generators looking over the longer term at bidding into Contracts for Difference (CfD) auctions, keeping costs lower in line with reduced uncertainty.

2.3 Aligning the demand and generation zones could also facilitate options under consideration by the Significant Code Review (SCR), and as a further potential benefit, increases the ESO's ability to provide locational signals to demand and generation.

2.4 There are multiple drivers for changes to zones, including but not limited to:

- changes in demand and generation output over the long-term;
- changes in network topology, including assets moving between being in scope of local circuit charges to being in scope of the wider tariffs;
- the addition of circuits between Main Interconnected Transmission System (MITS) nodes (for instance, the HVDC lines) and
- the number and size of generation connections within a price control period.

2.5 It can be the case that a single generator connection would, under the current methodology constitute a zone in itself, particularly in lower voltage areas (e.g. Scotland) where the "unit costs" of circuits are high. The ESO is then required to calculate and apply zonal tariffs for that single generator. Whilst this is accepted as being cost-reflective, it is not the most efficient way to ensure cost-reflectivity, and does not send appropriate, or sufficiently stable, investment signals to generators seeking to connect.

2.6 The Proposer believes that locational TNUoS tariffs should reflect the relative Long Run Marginal Cost (LRMC) of the building and maintenance of the transmission system, and that tariffs should therefore provide long-term investment signals to the parties connecting. Whilst tariffs do change year-on-year, it is likely that maintaining the status quo in relation to rezoning will lead to greater volatility in Generator TNUoS than would occur if the methodology underpinning zoning were more likely to lead to fairly static zones over the longer term.

Workgroup Considerations

3.0 The Workgroup convened 7 times between 22 November 2019 and 11 May 2020 to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable CUSC Objectives.

The Workgroup held their Workgroup Consultation from 26 February – 18 March 2020 and received 17 responses. The full responses can be found in Annex 11 **and a summary of responses can be found later in this report**.

Context

3.1 The workgroup discussed the principles on which they will judge potential solutions for determining generation zones. They discussed that the solution should have positive impacts in one or more of the below areas:

- cost reflectivity,
- electrical proximity – as per the electrical boundaries in the Electricity Ten Year Statement (ETYS),
- impact of distributional effects,
- stability,
- practicality, and
- effective competition – i.e. transparent price signals (looked at under sections of the report which concern cost reflectivity, stability and practicality).

3.2 There are a variety of different methods that can be used to determine generation zones. In each method, the total amount recovered via generation TNUoS (across all zones) would remain unchanged. What differs in each method is who pays the charges (i.e. how much of the total is recovered from each zone). The workgroup discussed to what extent each method achieves the above areas. The current method of zoning (outlined in the "***What is the issue*?"** section) is considered to be a flexible method, as zones adapt to changes in nodal prices. A potential solution to increase the current figure used to achieve zones in line with RPI is also seen as a flexible method. It was discussed that the flexible methods had stronger arguments for cost reflectivity as they adapt with nodal prices and expansion of the network. They also have arguments for practicality as there is less requirement for the methodology to be reviewed ahead of each price control period, if an enduring solution is implemented.

3.3 The original solution to CMP324 to fix generation zones to the 14 GSP groups contrasts with more flexible methods of zoning (such as the status quo and adjusting by RPI), as the zones would stay fixed irrespective of any changes in nodal prices or network expansion. Another potential solution was considered to fix the current 27 generation zones. Fixed zones were seen by some workgroup members to have less association with economic drivers or electrical proximity, however can have benefits in that they may create more stability of prices for TNUoS payers and strong arguments for practicality as there is less requirement for the zones to be reviewed.

The below solutions were discounted by the workgroup.

3.4 A zoning method which uses the zones published in the ETYS statement was discussed. This method would have both fixed and flexible aspects, as the zones would change in line with changes to the ETYS zones, which are amended to reflect changes in network. This method has merit in that it is based on electrical proximity, and there is less requirement for zones to be reviewed, however the method is less practical given the number of ETYS zones and methodology required to merge zones. This method was discounted for being too impractical. A considerable amount of discussion was had on this method and so more on this can be found later in this report.

3.5 The present methodology uses a fixed range of +-£1/kW to achieve a number of zones considered to be reasonable in 1992 when the range was set. These were also electrically and geographically proximate. The workgroup considered that the current £1/kW could be increased incrementally by a set amount (e.g. by 10p) until it achieves a fixed number of zones considered to be reasonable today (e.g. 25-30 zones); these zones would then be fixed for the duration of the TO price control. From then on, the range could be inflated in line with RPI or the process repeated to stay within the 25-30 zone range. This solution would have merit in that it flexes without intervention and would provide locationally granular price signals. However, this potential solution was discounted by the workgroup because it was believed not to add any benefits compared with to the other solutions which could deliver a similar result, such as inflating the +-£1 by RPI.

3.6 For completeness, the workgroup discussed Nodal Charging. It was stated that Ofgem's direction of travel on Distribution Use of System Charge (DUoS) is to achieve more granular charges, and that the proposed solution may be against that direction of travel in industry. The workgroup discussed whether it would be possible to charge all generators based on their own node. They agreed that they would need to ensure consistency with the distribution network. This method offered benefits of cost granularity and cost reflectivity. However, the workgroup concluded that this method would not achieve simplicity, stability or practicality.

3.7 In their Workgroup Consultation responses, it was suggested by SSE and Banks Group that there could be a single charging zone for generation. The workgroup is sought further advise from Ofgem in regard to whether the option put forwards by SSE which would see one generation zone overlaps with the ongoing work on Access and Forwards Looking Charges SCR. In their response, Ofgem advised that this would be a significant departure from current charging arrangements and that it would not be appropriate to be considered by this workgroup.

3.8 In their Workgroup Consultation response, HIE suggested that an alternative concerning the treatment of HVDC links should be raised, this is available in full at Annex 11. However, the Workgroup considered that these issues were being dealt with elsewhere in the CUSC modification process, namely CMP303[10], CMP337/8[11] and CMP320[12], with the timeline for the CMP303 modification aligning with CMP324/5. Therefore this was not taken further.

[10] CMP303 - Improving local circuit charge cost-reflectivity

[11] CMP337: Impact of DNO Contributions on Actual Project Costs and Expansion Factors and

CMP338 - Impact of DNO Contributions on Actual Project Costs and Expansion Factors – New Definition of Cost Adjustment

[12] CMP320 - Island MITS Radial Link Security Factor

Considerations and interactivity

3.9 The workgroup is mindful of the interactivity of the RIIOT2 price control, CUSC modifications CMP315[13], CMP317[14], CMP320[15], and the modifications stemming from Ofgem's Targeted Charging Review direction[16] (CMP327, CMP334 and CMP333)[17]. They are also conscious that it would be beneficial if their solution facilitated (or did not hinder) the ability for TNUoS to be charged to embedded generators in a way that is consistent with transmission connected generators, as they are aware that this and other changes may be taken forward as an output of Ofgem's Access and Forward-Looking Charges Significant Code Review[18].

Data in this report

3.10 The intent of the proposer is that any modification to the zonal configuration should be implemented before the next price control. It is expected the RIIOT2 data will be available in October 2020. The workgroup highlights this to readers and state that any tariffs presented as part of this analysis will be subject to change and will be formally presented to industry in October 2020 and January 2021 as per the current charge setting process.

The analysis provided in this report is illustrative and is built upon assumptions about RIIO2. It should not be used to forecast tariffs.

RIIOT2 data

3.11 Several data items in the analysis undertaken by the ESO, for discussion by the workgroup, were based upon the latest RIIO1 data and were not adjusted to predicted RIIOT2 values. This is due to the ESO not having sufficient information available at the time of the analysis to accurately estimate this data. The ESO revenue team have recently published in their March TNUoS forecast[19] indicative generation wider tariffs for 48 zones

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[13] CMP315: TNUoS: Review of the expansion constant and the elements of the transmission system charged for

[14] CMP317: Identification and exclusion of Assets Required for Connection when setting Generator Transmission Network Use of System (TNUoS) charges

[15] CMP320: Island MITS Radial Link Security Factor

[16] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment

[17]https://www.ofgem.gov.uk/system/files/docs/2019/12/full_decision_doc_updated.pdf

[18] Access and Forward Looking Charges – Summer 2019 working paper - https://www.ofgem.gov.uk/system/files/docs/2019/09/000_-_working_paper_-_summer_2019_-_exec_summary_final.pdf

[19] https://www.nationalgrideso.com/document/166761/download (page 36 - indicative generation wider tariffs – 48 zones

https://www.nationalgrideso.com/document/167311/download (Forecast sensitivities - generation zones site/node map) (which is the number of zones that would be in the next price control period if the existing methodology was applied and if the existing parameters stayed the same).

3.12 The main data items that would need to be adjusted for RIIOT2 data are;

- Expansion Constant: This is the indexed cost of 1MWkm of 400kV overhead line and is the base that the Expansion Factor[20] is applied to for all circuits that are not 400kV overhead lines. Changes to the expansion constant will change £/MWkm value of nodes and could increase or decrease these nodal values depending on how they change compared to the current figures.

- Transmission Owner (TO) Annuity Factor and Overhead % rate: The Annuity Factor takes into account of; asset depreciation, regulated rate of return and the overhead rate which reflects TOs' operation and maintenance costs. These figures feed into Expansion Constant (which is the annualised cost of building and maintaining 1km and 1MW of 400kV OHL capacity), and therefore affect the nodal prices and tariffs directly. This is currently set at 5.8% (annuity factor) and 1.8% (overhead factor) respectively[21] and are under review as part of establishing the RIIOT2 price control.

- Expansion Factor: The TNUoS Transport model is designed around calculating the marginal cost of moving 1MW over 1km (see Annex 4 for more information about the Transport Model). The assets that do this with the lowest marginal cost is 400kV Overhead Line. The TNUoS Transport Model therefore assumes that all other assets (voltage level, underground cable or HVDC) are more expensive as a multiple of the 400kV overline cost (this multiple is the Expansion Factor). Changes to these expansion factors will change £/MWkm value of nodes (unless they are connected by 400kV overhead line) and could increase or decrease these nodal values depending on how they change compared to the current figures.

Workgroup consideration of Proposers solution

Proposers solution: Aligning generation zones with demand zones (GSP Groups) – Original Solution

Cost reflectivity

3.13 The Original solution may bring about better alignment between embedded generators and transmission-connected generators. If embedded generators are to pay TNUoS in future, they will have the same zones and the same charge as transmission-connected generators.

3.14 The workgroup discussed whether the Original provided cost reflective signals to generators. It was generally agreed amongst the Workgroup that whilst the Original would provide less granular cost reflective signals compared to the baseline or other alternatives, it would still provide broad locational signals.

3.15 Zoning based on the original proposal is not related to the nodal cost attributed to that transmission generator. It is derived solely on the geographic boundaries of distribution networks.

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[20] The current Expansion Constant can be found here: https://www.nationalgrideso.com/document/162431/download)

[21] Find the latest charging statement here https://www.nationalgrideso.com/document/140751/download

3.16 It could be beneficial to have greater alignment between generation and demand – which is also zoned using GSP groups. The workgroup explored whether demand zoning is appropriate. Some Workgroup members suggested that the demand zoning method is practical, but not as cost-reflective as other zoning solutions.

3.17 It was noted by the Workgroup that this method of zoning does not create equal and opposite signals for demand and generation due to the assumptions used in the ESO's Transport Model (such as using net GSP demand, not gross GSP demand). Moreover, if the generation residual is set to zero, there could be further distortion in signals.

3.18 It was raised that nodal prices are averaged into zonal prices differently for demand as they are for generation, which may create a distortion. However, it was noted that locational investment signals for generators from TNUoS in this solution would potentially be weaker due to there being fewer generation charging zones than the baseline method.

Stability

3.19 The Workgroup discussed that many CUSC parties have said in the past that they value stability and predictability in the forecasting of TNUoS. Charges change year to year, reflecting changes on the transmission network. However, overall tariff stability can be aided by zoning. The proposer argued that by mapping the generation zones to the GSP groups, there would be no need to re-zone at each price control period, and this would tend to increase long-term stability for generation sites. It was also noted that the stability of zones would have a positive benefit on competition.

Practicality

3.20 As mentioned in the previous paragraph, the result of having no need to re-zone at each price control period presents a practicality benefit. Also, GSP zones are a well-defined and understood concept with the industry. It was also noted that the stability of zones would have a positive benefit on competition. Other workgroup members noted that there was no evidence of this. Indeed, the assumption should be that fewer zones with more generators per zone would tend to lead to a larger differential between individual generation nodes in a zone.

Distributional effects

3.21 It was noted that users are currently allocated to zones, and as such will be allocated to different zones resultant of this modification. Some users will see charges go up, whilst others will see a reduction.

3.22 Under the original proposal this would not be a consequence of any individual sites costs increasing or decreasing on the network, rather the impact of moving from a cost reflective method of charging zonally to a purely geographic method of charging not related to cost.

Effect of outliers

3.23 The workgroup considered the effect of an outlier node, such as an island, later connecting to a zone (nodal charges on islands tend to be higher). It was considered that for the original solution this would increase the average zonal price for generators already connected in that zone. Annex 5a includes a tool which can be used to calculate example tariffs for all zones (instructions on how to use the tool can be found in Annex 9, slide 3). Comparably the, this effect in the Original is smaller than the in the Fixed 27 zones alternative because the number of nodes per zone is greater. for the Original. The below table shows the count of relevant nodes per zone between the Original and 27 zones options.

Zone number	Original (GSP Groups)	WACM2 (27 zones)
1	47	23
2	32	2
3	8	8
4	6	1
5	8	5
6	8	2
7	13	5
8	2	2
9	14	1
10	5	14
11	9	13
12	2	4
13	5	7
14	5	4
15	N/A	9
16	N/A	11
17	N/A	5
18	N/A	16
19	N/A	2
20	N/A	1
21	N/A	4
22	N/A	1
23	N/A	1
24	N/A	12
25	N/A	4
26	N/A	5
27	N/A	2
Grand Total	**164**	**164**
Average nodes per Zone	**11.71428571**	**6.074074074**

Electrical and Geographical Proximity

3.24 The workgroup discussed CUSC 14.15.42. ii.) "The nodes within zones should be geographically and electrically proximate". To use GSP groups would indicate the removal of 14.15.42 i) and ii) from CUSC, because geographic and electrical proximity would no longer be criteria used in the zoning methodology.

3.25 The workgroup discussed whether interpretation of "electrical proximity" is material in the proposed change. It was raised that "electrical proximity" takes a judgement from the ESO and this is not defined. It was felt by some Workgroup members that a reasonable geographic spread was not the priority, rather to get a justified basis of zoning. It was discussed that that the method sought would be the one which has the best balance between cost reflectivity, stability and practicality and that the best solution may move away from electrical proximity to some extent. It was also highlighted by the workgroup that GSP Groups are by their nature geographically and electrically proximate.

Modelling

3.26 The ESO's Transport Model was used to understand the impact of the ESO's proposed solution. The Workgroup hypothesised that aligning Demand and Generation zones should help create equal and opposite price signals. The model showed that in most zones this was not the case and generation tariffs were greater in magnitude than demand tariffs. This is because the nodal prices are averaged across the zone, and generally generation is connected in more expensive nodes within the zone. The Workgroup noted that averaging would have the impact of reducing tariff prices in more expensive nodes within a given zone, but making currently cheaper nodes more expensive to connect in.

3.27 It was noted by the Workgroup that this method of zoning does not create equal and opposite signals for demand and generation due to the assumptions used in the ESO's Transport Model (such as using net GSP demand, not gross GSP demand). Moreover, if the generation residual is set to zero, there could be further distortion in signals.

GSP Groups in the TNUoS Transport Model

3.28 The ESO presented how using GSP groups would work in their Transport Model which they use to calculate TNUoS tariffs (see Annex 4 for more information about the Model). The model uses a connectivity map to apply the methodology for zoning. The ESO demonstrated how GSP groups would work on the connectivity map. The map sees zones in a single path, flowing into each other until they reach the demand centre[22]. The model works on a waterfall basis; when an additional MW of energy is added, it is worked out how many flows it goes through before it gets to the demand centre. By using the existing rules in CUSC (14.15.50), the ESO showed how the current network could be simplified to use GSP groups in the Transport Model. See Annex 8 slides 4-9 for illustrations of the connectivity map with GSP groups.

Workgroup consideration other potential solutions

Inflating the range in line with RPI – proposed by Uniper – WACM1

3.29 This solution would set zones for generation TNUoS charges by inflating the +/- £1/kW used in the current methodology to +/- £2.25/kW in line with RPI and thereafter to index the number to an appropriate inflation index when reviewing the zones at the end of each price control period.

Stability

3.30 Compared with the baseline, the number of zones is reduced in line with historic levels, providing a degree of averaging to help protect generators from volatility which may occur in their nodal prices.

3.31 A small minority of generators may face the risk of their zonal price changing as a result of moving from one zone to another, when zones are redefined at a change in price control. However, this is restricted specifically by the plus or minus £2.25/kW limit that zonal charges can differ from nodal charges.

[22] a hypothetical point on the system representing the centre of demand.

Cost Reflectivity

3.32 This solution specifically limits the amount of averaging of nodal prices which can occur when setting the zonal average price. This means price signals are more cost reflective then any of the other solutions. Any cross subsidies between nodes within a zone are limited. Analysis by the ESO confirms that a move to +/-£2.25/kW would create 21 zones (see Annex 9 slides 8-9). It was noted that this approach would retain the cost reflectiveness of the baseline approach of placing nodes together in zones based on the cost of those nodes being similar to each other.

3.33 Another beneficial feature of the RPI method is the facility for zones to flex. For instance, if significant new infrastructure is added to the network the cost reflectivity of the zonal average charges is maintained and the potential for greater cross subsidies to be introduced is restricted. This flexibility has been demonstrated by analysis which calculates the ranges of nodal costs which would occur within each zone (Annex 9). This showed that the other potential solutions could contain a wider range of outcomes, particularly in Scotland where the range between highest and lowest nodal charges in a zone could be around £30/kW. Even if significant new infrastructure is added to the network, as the methodology allows for flexing of the zones, the cost reflectivity of the zonal average charges is maintained and the potential for greater cross subsidies to be introduced is restricted.

3.34 As an illustrative example, the proposer of the RPI alternative calculated that if 600MW of generation were to connect to Spittal substation from Shetland, with £60/kW being added on top of the onshore MWkms cost to account for the island link, this would move the indicative DNO zonal cost provided in the CMP264 consultation by £9.5kW (Annex 5d). However, the RPI cost could not move more than £2.25 (as indexed) from the nodal cost for a particular generator.

3.35 However, it was suggested that there is not yet industry consensus on the most appropriate approach for applying TNUoS zones to Island generators, regarding whether remote islands should have their own zone, or be considered within onshore zones. In particular, how to deal with the issue of potential market distortions which could arise if there were a large miss-match on remote islands between tariffs for generation compared with demand if remote islands had their own zone for generation charging but were considered part of an onshore zone for demand charging. It was suggested the question of zoning for remote islands would be better considered as a separate CUSC modification with appropriate opportunity for industry to fully consider the implications specifically relevant for remote islands.

Practicality

3.36 This is a modest change to the baseline and should need little effort to implement or for Users to understand. It would require the continued recalculation of zones on a change of price control as now, which is the same as the baseline approach. As the RPI option represents a small change to the existing methodology, it was argued that this would be a simple modification to implement and for Users to understand. It was accepted that this would mean that the ESO would need to recalculate zones at each price control, which would not be necessary under fixed approaches, but it was suggested that this might be an efficient use of ESO resources in order to ensure better cost reflectivity and therefore better investment signals to generation Users. The proposer of the RPI Workgroup Alternative did not believe that creating zones containing a single node was problematic and noted that this occurred at present. This Workgroup Alternative therefore does not propose any minimum level of nodes per zone.

Electrical proximity

3.37 As part of setting the 27 zones in RIIO-T1, electrical and geographic proximity were considered as implement on the basis that they were electrically and geographically proximate. As this solution maintains the 27 zones, this is assumed to be the case.

Distributional effects

3.38 The proposer produced a tool to work out the impact of this alternative on their costs. This is available in Annex 5a.

Effect of outliers

3.39 Defining a tighter range of nodal prices within a zone would prevent average prices within the zone from being moved by large cost infrastructure changes. This is because the RPI approach would limit the extent to which a generator's zonal charge could move away from its individual nodal charge. Therefore, such infrastructure changes would most likely result in the creation of a new zone or zones, leaving other nodes less affected than if they were forced to be in the same zone through a fixed approach which was unable to flex.

3.40 Using the example of the introduction of a remote island link this would it limits the impact on the charges of other generators, by restricting the extent to which a generator's zonal charge can differ from its nodal charge. Although this would prevent the cross-subsidising that would happen in the Original and Fixed 27 zones solutions, it would mean that the island zone is likely to have a high average zonal price (as the price of island nodes tend to be high).

3.41 As an illustration, the proposer of the RPI alternative calculated that if 600MW of generation were to connect to Spittal substation from Shetland, with £60/kW being added on top of the onshore MWkms cost to account for the island link, this would move the indicative DNO zonal cost provided in the CMP264 consultation by £9.5kW (Annex 5d). However, the RPI cost could not move more than £2.25 (as indexed) from the nodal cost for a particular generator.

3.42 Following the Workgroup Consultation, the following Workgroup Alternative CUSC Modification was raised. See Annex 16 for the proposal paper.

Solution	Party	Characteristic	Implementation
RPI	Uniper	£2.25 Range	2021

Fix current 27 zones – proposed by SSE – WACM2

3.43 This solution fixes the current 27 TNUoS charging zones, rather than changing to the 14 GSP groups as in the Original solution.

Stability

3.44 Fixing the current 27 zones would avoid a shock change to generator's tariffs created by changing generation charging zones from April 2021. This could therefore be more beneficial than the Original in aiding tariff stability.

3.45 It would also help to deliver long-term stability in a similar way to the Original, because there will be no need to re-zone at the start of each price control period. In creating long-term stability for generators, benefits of reduced costs can be seen by consumers as generators would not have to take into account re-zoning risks into their price margins. Charges would obviously still change year to year, reflecting changes on the transmission network.

Practicality

3.46 Similar to the Original, fixing the current 27 zones avoids the need for generators to carry out modelling and commercial analysis to determine the potential impact of future re-zoning on business cases. It also improves efficiency of tariff setting and publication by allowing the ESO to provide more accurate 5 year forecasts of TNUoS tariffs. Forecasts would not need to account for the risk that generation charging zones could substantially change which would help to make them more accurate.

Cost Reflectivity

3.47 The workgroup discussed whether the 27 zones option provided cost reflective signals to generators. Whilst this approach provided cost reflective signals at the start of the current price control, it was questioned as to whether the 27 zones would accurately reflect the nodal costs in the next price control – which would require 48 zones under the baseline methodology. It was also raised that the cost reflectivity of this option would be diluted over time as the network changes compared to the network at the start of RIIO1 (when the 27 zones were created).

Electrical proximity

3.48 As part of setting the 27 zones in RIIO-T1, electrical and geographic proximity were considered as implement on the basis that they were electrically and geographically proximate. As this solution maintains the 27 zones, this is assumed to be the case.

Distributional effects

3.49 The proposer produced a tool to work out the impact of this alternative on their costs. This is available at Annex 5a.

Effect of outliers

3.50 The workgroup considered the effect of an outlier node, such as an island, later connecting to a zone. It was considered that for this solution this would increase the average zonal price for generators already connected in that zone. Comparably this is more impactful than the Original solution due to the number of nodes per zone being fewer in some zones, which would have a greater effect on generators connected in those zones. See table at paragraph 3.23 for a count of relevant nodes per zone.

3.51 Following the Workgroup Consultation, the following Workgroup Alternative CUSC Modification was raised. See Annex 14 for the Proposal paper.

Solution	Party	Characteristic	Implementation
27 Zones	SSE	27 Zones per Status Quo	2021

Fix current 27 zones until delayed implementation, then Original – proposed by EDF on behalf of Neven Point Wind – WACM3

3.52 This solution fixes the current 27 TNUoS charging zones until 2023 when the GSP group methodology as per the Original solution would be applied. It would ensure that a modification must be raised to create any additional zones – such as for a new remote island connection.

Stability

3.53 The main reason for this solution is to increase certainty for generators. This method would aid short-term stability, as it would reduce the potential for several consecutive changes affecting generation TNUoS; which is argued to be easier for participants to deal with.

3.54 There are several interacting factors which could affect stability:

- The April 2023 implementation coincides with the intended implementation date for any measures taken forward for Ofgem's Forward-Looking Charges Significant Code Review[23]. It is possible that other changes then come in which may include distributed generators being liable for TNUoS charges.
- The final RIIO-T2 data will not be available until later this year; and parties may need a more time to adjust. Additionally, COVID-19 may also cause some disruption which may continue at a level for some time.
- Recently the implementation of CMP332 postponed by Ofgem by 1 year to give affected parties more notice of a change that for some could be material. Delaying implementation aligns with this.

Practicality

3.55 It is argued that fixed zones improve transparency and improve efficiency in TNUoS tariff setting and publication processes, as well as simplifying matters. This adds certainty for multi-site and single site developers, on a long-term basis.

Cost Reflectivity

3.56 As this option is a combination of WACM2 and the Original, the cost reflectivity comments of those respective options would apply this WACM3 option.

Electrical proximity

3.57 As this WACM is a combination of Original and WACM2, please see above points regarding electrical proximity.

[23] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment

Distributional effects

3.58 The proposer produced a tool to work out the impact of this alternative on their costs. This is available in Annex 5a.

Effect of outliers

3.59 The effect of outliers would be the same as the 27 zones alternative until implementation of the Original, then it would have the same effect as the Original.

3.60 This alternative assumes that the Original makes no arrangements for setting up bespoke Island Zones.

3.61 The 27 zones are, under WACM3, viewed as less desirable from when the island generators might get a MITS node as their nodal price, if that came to pass, would be averaged into a small zone (one of 27). This would therefore lift the zonal price more than would be the case under the 14 zone (GSP Group) approach. Moving to 14 (GSP Group) zones from today's 27, after reasonable notice to generators, is then viewed as having the advantage of the original (of having the same charging zones for demand as for generation) whilst removing one source of distortion between Small Distributed Generators (embedded generation of <100 MW) and other generation (>100 MW Distributed Generators, and transmission-connected generation).

3.62 Following the Workgroup Consultation, the following Workgroup Alternative CUSC Modification was raised. See Annex 15 for the proposal paper.

Solution	Party	Characteristic	Implementation
Current 27 Zones until delayed implementation, then Original	EDF on behalf of Neven Point Wind	Delayed implementation to 2023	2023

ETYS Zones – Discounted Option

This solution was discounted by the Workgroup and was not raised as a formal WACM.

3.63 Electricity Ten Year Statement (ETYS) zones[24] are published by the ESO each year. They are used to simplify analysis as part of Future Energy Scenarios work carried out by ESO. The zones are reviewed within the to the System Operator Transmission Owner Code (STC) by the ETYS subgroup. These consist of zones labelled by letters A-T which are then subdivided further to give 96 zones. ETYS zones are reviewed annually and when they are published they are fixed for the year. The zones are driven by engineering judgement and only change significantly if reinforcement works instigate a boundary to change or if levels of generation and demand change significantly. ETYS zones are

[24] https://www.nationalgrideso.com/document/133181/download

currently used to calculate the 'Wider Cancellation Charge' for connections as per CUSC section 15.

Modelling

3.64 A Workgroup member created a model using a version of the ESO Revenue Team's Transport Model[25], which is used to model tariffs. This was used to model what the tariffs would look like using the ETYS zones as their zoning criteria in contrast to the proposer's solution which uses GSP groups. The work showed that for most of the zones in England and Wales, the tariffs were close in price. However, in the North of Scotland, the differential between zones was significant. The zonal difference is larger in Scotland because there are more megawatt kilometres between zones. The model suggested that there should be more zones in Scotland and fewer in England and Wales.

3.65 The ESO undertook additional analysis (Annex 9, slides 6-7) on ETYS zones which showed that this method has a large averaging effect for Scottish zones but for England and Wales the nodal values are used for many zones due to there being only one user connected in some zones.

Stability

3.66 It was considered that the ETYS zones are reviewed annually and so could change every year, as for example, there are regular debates on whether Dumfries-and-Galloway should be a separate zone. To counter this, the Workgroup considered whether zones could be set based on what the ETYS zones were at the start of any given price control period, which would arguably create more stability. However, it was noted that one of the reasons for suggesting the use of ETYS zones was to attain better cost reflectivity, and this could be impacted if the ETYS zones were only used at the start of a specific price control period, which could last several years.

Practicality

3.67 The Workgroup considered how they could reduce the number of the ETYS zones from 96 to make this method simpler and more practical. If the current zoning method was applied for the next price control, the number of zones would rise from 27 to 48 which ESO believe are too many to charge practically. The Workgroup considered that the subgroups within each ETYS zone letter could be merged if they were within a certain £ amount. E.g. if zones C1 – C7 were all within +- £1.50 they could be merged. As part of the analysis undertaken by the ESO, the ESO grouped the ETYS zones in to the major ETYS zones (i.e. by letter).

3.68 It was noted that the TNUoS Transport Model relates to load flow and disregards existing spare network capacity. It was suggested that it would be less cost reflective to define charging zones based on ETYS boundaries which are defined by existing network constraints.

3.69 The Workgroup discounted this as a potential solution due to its creation of a large number of zones which would lead to near-nodal pricing in some parts of the country whilst having a large averaging effect in other parts, and therefore not achieve principles of practicality or simplicity.

[25] Direct Current Load Flow Investment Cost Related Pricing (DCLF ICRP) Transport Model is used by ESO to calculate TNUoS tariffs

Nodal Analysis for each solution

The analysis provided in this report is illustrative and is built upon assumptions about RIIO2. It should not be used to forecast tariffs.

3.70 The ESO modelled the Year Round and Peak nodal process per zone for the Original and Alternatives. This can be found in Annex 5a (updated analysis[26]).

Bus Nam	CatBGen	CatAGen	RPI Index Gen Zon	ETYS Gen Zone	27 Gen Zone	DNO Zon	SelectedZone	YR Nodal Price	PS Nodal Price	YR £ (MW*£/kW)	PS £ (MW*£/kW)
ABHA4A	0.0	0.0	19	18	27	14	14	-5.7	-0.9	0.0	0.0
ABHA4B	0.0	0.0	19	18	27	14	14	-5.7	-0.8	0.0	0.0
ABNE10	0.0	0.0	3	1	5	1	1	27.5	0.7	0.0	0.0
ABTH20	572.3	1186.0	20	11	21	10	10	-5.1	6.7	-2917.2	7985.0
ACHR1R	30.1	0.0	7	1	7	1	1	37.5	4.1	1128.9	0.0

3.71 Additional analysis was undertaken by SSE to illustrate the spread of typical charges which generators would pay in each of the proposed solutions (combining Peak Security, Year Round and ALF) (Annex 5b). This is using generic ALFs for illustrative technologies: Wind and CCGT. The workgroup member used the analysis to demonstrate that in the fixed 27 zones and Original solutions, the spread 'tariff spread' is narrower (when considering effect of Annual Load Factors (especially for Northern zones) than in the nodal spread analysis undertaken by the ESO analysis. For RPI zones the analysis was used to demonstrate that the nodal spread 'tariff spread' is wider than in the ESO's nodal spread analysis due to applying the Peak Security tariff to southern conventional generators. Therefore, the point was made that this end in tariff spreads being similar across all of the alternatives.

3.72 Further analysis was undertaken by Uniper to assess the SSE analysis, by using Actual ALFs in the TNUoS Transport Model for each of the proposed solutions. The workgroup member was concerned that carrying out analysis using ALFs was not appropriate as assumptions on ALFs could skew the data but felt it would be useful to carry out additional analysis to understand how the ranges of charges may be affected by using these ALFs, rather than generic values. The values from the 27 zones methodology were used for this analysis in order to minimise the effect of overestimating sharing for the extreme nodes, as these values have the lowest amount of averaging. The analysis (annex 5c) looks at the effect on the generation included in the Transport Model, at the relevant nodes, using the ALFs contained in the model. This differs from the nodal approach as there are some nodes with multiple generators of different types and load factors. This also uses the 27-zone split between Year Round Shared and Year Round not shared tariffs.

3.73 This Analysis (contained in Annex 5d) adds a new node into the relevant nodes sheet in the original version to represent Shetland. The analysis shows that the fixed zones approaches are still not robust to connection of remote island links as wider infrastructure, even with the dilution caused by applying an ALF. The spreadsheet on this shows a zonal range in GSP group zones of £60.7/kW for wind and of £45.8/kW for CCGTs.

[26] Previous analysis which was shared at the Workgroup Consultation stage showed with GSP group zones, zone 8 (West Midlands) had no transmission connected generators. Two embedded generators are now connected in zone 8 so now all GSP group zones have applicable generators. Annex 5a therefore shows updated tariffs for all zones and that adding these two generators has had a minimal effect on other zones and other options.

3.74 Uniper concluded that ALFs can have a large impact on either reducing or widening the ranges observed in a zone and therefore using ALFs can make it difficult to draw clear conclusions on the amount of cross subsidy being created by averaging in zones. Both sets of analysis by Uniper and SSE conclude that the RPI zones created by NGESO have a relatively large range in zone 20 of around £13/kW on the peak charges, due to the zoning being carried out on the basis of Year Round charges. Uniper felt this range was still relatively narrow compared with the £/kW range in other zones caused under other methodologies.

Other matters discussed in the context of this modification

How often should rezoning happen?

3.75 It is currently a CUSC requirement that re-zoning is carried out before each transmission price control period (14.15.37).

3.76 The ESO highlighted that the costs of building and maintaining the network change between price control periods. Therefore, the allowed revenue that the ESO can recover will also change, which has an impact on the bills that system users would be liable for, and this includes the proportion of TNUoS paid by generators. It was noted that rezoning ahead of each price period ensures that changes are considered.

3.77 The Workgroup discussed that rezoning each price control may achieve more cost reflectivity but create more volatility. There was concern that methodology which creates a temporary fix may lead to volatile prices for some each time that methodology is reviewed. Under the Original Solution, re-zoning would not be required as the zones would be fixed as GSP groups for generation. There was a view that a flexible method of zoning could be more manageable and stable in the long term as it would ensure that zonal charges were closer to the nodal charges within the zone. There was a concern by some members that if a fixed zone approach was adopted, over time the differential of nodal charges within the zone would become so great they become unsustainable and would give inaccurate locational signals for some sites. This would create pressure to revise the zoning methodology again, which would result in generators seeing a greater step change in prices.

3.78 The workgroup discussed that rezoning between price controls may create a 'shock' for generator's whose charges may change significantly due to moving to a new zone between price controls. The workgroup discussed that this can be avoided by either by fixing the zones (as per the proposal) or by rezoning more frequently so the 'shock' is smeared over several years.

Boundary Sharing and Sharing Factors

The ESO shared how boundary sharing works with the current methodology (Annex 7).

3.79 Having discussed the zones, the working group discussed how boundary sharing and sharing factors would be applied. The ESO suggested that an additional method may be to simplify connectivity required to make the TNUoS Transport Model work for zones which have multiple inputs leading to multiple outputs. The Transport Model works on zones having one output for boundary mapping purposes. The ESO put forward a simplified model with each GSP group zone only having one input and one output (Annex 8, slides

4-9). It was agreed that for zones with more than one output, the longest route to the demand centre should be the one that is selected, as per the current methodology. In the simplified model, some zones are combined. Workgroup members advised that if there are two inputs to a combined zone, a weighting methodology may be required. This would be to reflect the proportion of energy flowing through to each of the combined zones.

3.80 The ESO stated that the sharing factor calculations in the current methodology would stay the same under the original solution.

3.81 A Workgroup member questioned whether under the Original solution, the use of sharing factors would still be appropriate in the methodology. This is because they had doubts that boundary sharing factors would not be reflective when the GSP groups do not align with potential constraint boundaries. It was suggested that the model could be applied without the sharing elements. Alternatively, it was asserted that the current +- £1/kW zoning methodology does not reflect connectivity either.

3.82 Some workgroup members conveyed that Boundary Sharing by GSP groups may work well for Scotland, where the largest flows between boundaries are. It was raised that the GSP groups do not work as well for zones which have smaller flows between zones, but that it is also less impactful on these zones.

3.83 The workgroup concluded that the approach to sharing is out of scope of this modification. Within baseline CUSC, any change in the definition of zones at each price control would need to be taken account of within the sharing methodology anyway, so this modification is no different in this regard. The ESO was asked to demonstrate how the sharing methodology would accommodate 14 GSP groups and presented to the workgroup how this can be appropriately applied. The ESO explained how the sharing methodology is driven by connectivity between zones and the mix of generation within a zone (Annex 7). It was noted that with 14 GSP groups, the zonal sharing approach would work best and most clearly where it was most relevant to reflect low carbon generation in northern zones.

Generation Backgrounds

3.84 To work out Year Round charges, ESO takes each circuit on the transmission system and categorises it as either Year Round or Peak, depending on the generation connected to it. The background with the most MWkm is then used to calculate and allocate the nodal prices - this has been the Year Round background historically.

3.85 It was suggested that the ESO should investigate adding both Year-Round and Peak backgrounds together. This is because in Scotland, the Year Round background is dominant, whereas in England and Wales, the Peak dominates. It was suggested that Scotland could be zoned on Year Round and on Peak in England and Wales. ESO responded that the backgrounds are mutually exclusive, and that combining backgrounds would be a significant piece of work which would go into the nodal price calculation, which is out of scope of this modification. Currently the backgrounds are mutually exclusive, as generation is scaled differently in the two backgrounds as per chapter 4 of the SQSS.

Further Analysis undertaken by the Workgroup post-Workgroup Consultation

Intra-zone volatility during RIIO1 and RIIO2

3.86 Analysis was undertaken by ESO on request of the Workgroup to look at intra-zone volatility during RIIO1 and RIIO2. Annex 12 shows RIIO1 tariffs for 'typical' generators. However, it should be noted that only major CUSC changes were considered in the analysis and the CUSC methodology not consistent between years.

Summary of changes within RIIO1:

See full analysis in Annex 12

Total charges (£/kW) for each generator type in each zone	**Biggest Change**	**Average Change**	**Smallest Change**
Conventional LC	£23.76	£10.41	£6.53
Conventional	£23.76	£9.85	£6.54
Intermittent	£21.00	£10.54	£5.44

3.88 ESO modelled what charges could look like for RIIO2. The inputs to the analysis, which can be found in Annex 12 are:

- Includes allowance rate of return and overhead rate which will be included in the calculation of nodal prices.
- TOs might be able to share with ESO an early view of this data in the summer. ESO plan to include these early views into their next 5-year forecast, to be published by end of August.
- ESO expect the finalised data by December this year, which will then feed into final zoning calculation, ahead of final TNUoS tariffs by January 2021.

Baseline discussion

3.89 The workgroup wanted to understand how the current zoning methodology has been applied by the ESO. ESO responded to this by sharing the nodal level information in order to explain how the existing baseline methodology results in 48 zones. Under the current methodology and the current CUSC requirements, the ESO has numerous principles to consider when grouping nodes into zones and connecting these zones together;

- Zones are created using the Year Round background (i.e. using the generation background with the most MWkm of circuit, as per CUSC 14.15.42).
- Wherever possible, ESO starts from existing zones (14.14.53) and applies the +/- £1 criterion on the relevant nodes (i.e. nodes that have generation under the Year Round background). Then, zones are merged if they become too fragmented (14.15.53)
- All nodes within a zone are checked for electrical and geographic proximity (14.15.53);
- If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries (14.15.44).

3.90 Even with these principles, there is still some judgement that the ESO needs to undertake when rezoning;

- Only relevant nodes (i.e. those generation nodes under the relevant background) are checked for the +/-£1 range; therefore, connection of a new generator, or closure of an existing generator, may alter the zoning results. For example, if there were only two relevant nodes within a zone and their nodal price difference was within the £2 range, a new generator connecting (to a non-relevant node within the zone) could create a new relevant node and push the range over £2 (LIMK10 near Dounreay is an example).
- In a geographic area where generators are connected to various voltages (e.g. ETYS Zone L0 where there are 275kV and 400kV connected generators), due to the relatively large difference in nodal marginal prices, separate zones may be created for certain voltage levels.

- The way zones are grouped is also affected by perspective (i.e. where the zoning exercise is started from). With the same nodal prices, different zoning results will be achieved by starting at different locations. This is because the first node determines how all the other nodes relate to the 1st node and the +/- range. For a simple example, 3 nodes in a North (top) to South (bottom) line with the current +/-£1 range is shown in the below table. Depending on where the starting point is, 1 or 2 zones (a yellow zone and a green zone) will be created with different nodes.

Node Name	Nodal £	A Start	B Start	C Start
A	1			
B	2			
C	3			

3.91 A more practical example is Indian Queen substation which can be grouped with Langage (if starting from west and moving to east) or can be put to its own zone (if starting from east and moving to west).

Workgroup Consultation Responses Summary

Question	Responses summary
Do you believe that the CMP324 and CMP325 Original Proposal better facilitates the Applicable CUSC Objectives?	Positive response - 14 Negative responses - 4 **Positive** **Better facilitates competition -** *"Fixed DNO zones in the charging methodology will result in stable and predictable transmission and demand charges. It will facilitate a level playing field between generation connected to the transmission system and the distribution system".* **Helps to achieve carbon targets -** *"they inform future investment decisions for the location of renewable generation. We believe that without the increased stability which arises by*

	decreasing the number of TNUoS charging zones it will not be possible for Island Generators (classed as onshore) to take part in the CfD auction process – the next round of which is due in 2021". **Better alignment -** *"this solution may bring about better alignment between embedded generators and transmission-connected generators via. alignment between generation and demand charges".* *"Yes, HIE agrees that the original proposal better facilitates the applicable CUSC objectives and strongly supports this solution compared to others raised by the Working Group: Retail Price Index (RPI) zones and the Electricity Ten Year Statement (ETYS) zones".* **Negative** **Reduced stability -** *"While the solution itself provides a more stable approach for setting TNUoS zones, the underlying data used for the calculation of tariffs is subject to a significant change before the implementation of this mod, therefore, there will lead to a reduced stability in and predictability of tariffs".* **Other methods more cost reflective -** *"it is unclear why a reduction in the number of zones in and of itself is beneficial. It is however clear that, if reducing the number of zones is beneficial, then that could be accomplished through various methods that are more cost reflective than the original Proposal".* **Flexible zones better than fixed -** *"we agree that something has to be done to prevent an unmanageable number of generation charging zones, we believe that fixing the zones as proposed is not an appropriate way to address the issue. Zones should be allowed to continue to flex in response to changing nodal locational signals, to give the best investment messages to generation plant".*
Do you support the proposed implementation approach?	Positive responses - 14 Negative response - 4 **Positive** **Yes** - *"Yes, the implementation date, 1st April 2021, is in line with the next price control period which is in line with CUSC requirement 14.15.37".*

	Yes - *"We support the implementation of fixed DNO zones from the start of the next RIIO-2 price control period (1st April 2021)".* **Yes** - *"although implementation for April 2021 seems very short notice. …we would nonetheless appreciate the WG's views on any alternative implementations, including for example a later date".* **Negative** **No –** *"We would suggest the Proposer considers updating the proposal such that it maintains the current 27 zones for a suitable implementation period, before moving to the GSP zonal approach. This would allow asset owners to make effective decisions with respect to cancellation charges".* **No –** *"Given the number of parallel and subsequent charging reforms and changes, we do not think it is efficient to be developing and implementing radical changes to TNUoS charging and CUSC in such a short period of time without having final RIIO-2 parameters and decisions on other related charging mods".* **No –** *"We accept the desire for the review to conclude by October to align with the start of the next RIIO2 price control. However the process should not be rushed and modifications should only be implemented if there are positive outcomes across the relevant CUSC objectives. The original proposal does not achieve this. We would urge the ESO to amend its original modification to deliver a cost reflective solution"*.
Do you have any other comments?	Other options more cost reflective - "We believe that there is opportunity for consensus if the ESO alters its original proposal to be based on one of the cost reflective options that have been discussed." "We would suggest, however, that specifically knowing the zone a generator would be in under the proposed methodology does not provide accurate information for investment decisions".

	"The CUSC clauses around the Boundary Sharing Factor (BSF) are outdated and need reviewed". Volatility can be managed in other ways - "Volatility in charges is in part a necessary feature of cost reflectivity, as the cost of reinforcing the network varies depending on how the capacity and location of generation (and demand) varies over time. Volatility can be managed by increasing the predictability of charges by (a) the information provided to users; and (b) updating parameters at price control". "Consideration requires to be given as to how the new charging regime would apply to generators in Orkney connected to the distribution grid through the Orkney RPZ Active Network Management system as they have non-firm connections subject to curtailment. If they were to be subjected to the full impact of the proposed TNUoS charging regime then they would require full access to the UK grid."
Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	Consider using 1 Generation Charging Zone - SSE HVDC Links - Highlands and Islands Enterprise (HIE) "We would suggest that if the Original is taken off the table or modified to leave Islands with their own zones then an alternative which specifies the 14 Zones as Demand going forward to 2024/5 should be raised."- Neven Point Wind
What are your views on the potential solutions discussed in the report? Please provide any evidence or rationale for your preferred solution.	13 responses highlighted a preference for the original CMP324 solution. "All other potential alternatives would seem to result in separate charging zones for each Island group even if they have one node." "the DNO zone solution is preferable in terms of stability and facilitating a level playing field between transmission and distribution connected generators" "At present, the 27-zone model utilised to assess charging could be viewed as being unfairly skewed to favour generators in the south, where generators are effectively paid to use the system. This modification seeks to find a balance".

	"the original proposal (aligning with DNO zones) provides a locational signal which is sufficiently stable and predictable such as to provide a more useful signal". 5 responses indicated a preference for the RPI solution "easy to implement as it is simply the current option adjusted correctly for inflation". "The setting to +/- £2.25 is preferable to the original proposal as it offers a more cost reflective solution. However, it does still reduce the number of zones from 27 to 21 which implies a dilution of the cost reflectivity of the zoning process compared to the status quo". "As noted in the consultation, provision can be made for the RPI indexed zone approach, to have larger adjustments to zone increments as needed in order to sensible limit the number of generation zones". "This method of zoning would provide more cost reflective signals than GSP Groups whilst also limiting the number of zones to a more reasonable amount. However, this method would require review prior to each price control and therefore doesn't provide the key benefit of stable long-term investment signals which is achieved by the original proposal". "SPR's preferred solution based on the information available is to inflate the range with RPI – section 3.3 and 3.31 pages 12/13. The rationale being that the other inputs involved with calculations such as Gross Asset Value, Securities etc. within the overall methodology are inflated annually so therefore this nodal range should be too". Some responses expressed a desire to maintain the current 27 zones "On balance, we are supportive of the Original proposal, although as set out above, we suggest that any option should maintain the current 27 zones for a suitable implementation period."

	"We expect that the ESO should undertake analysis to identify what +/- £ price would lead to the 27 zones that currently exist. This would be a more cost reflective starting point then the original proposal, or the +/- £2.25 method, as it would more accurately reflect the topology of the network". ETYS zones did not receive any support "We do not support the DNO, ETYS or Fix27 approaches because they all have in common fixed zone boundaries and, as stated above, we believe the charging methodology should retain the ability to flex zone boundaries, as the pattern of generation and demand evolves".
What are your views on the distributional effects of the potential solutions outlined? Please provide your rationale.	Some respondents suggested further analysis or refinement of analysis was needed "The distributional effects are difficult to gauge without further analysis. The impact on zones and nodes can be seen, but the present analysis requires stakeholders to calculate the effects on specific stations rather than providing an overall analysis of how parties could be affected. Clearly the impacts can be significant from the limited amount of analysis we have carried out using the Spreadsheet". Wider range of tariffs may be material "We note that the other solutions outlined in the consultation document produce a wider range of tariff outcomes which may be more cost reflective but which will lead to significant and material changes in charges at the extremities of the transmission system. These changes will have material consequences for generation located in these zones". Long term benefits outweigh distributional effects "The distributional effects, as suggested by the modelling provided in the appendices, are justified by the overall long-term benefit of the proposal". Fixing to 14 zones from 27 may see upwards price disturbances, or benefits to parties "Insofar as users are currently allocated to 27 generation charging zones, and under the mod would be allocated to 14

	new, different, generation charging zones, there will be effects: some users will see charges go up, whilst some will see a reduction".

Legal text

3.92 The Legal text can be found in Annex 13.

What is the impact of this change?

Who will it impact?

4.0 Generators liable for TNUoS are directly affected by CMP324 and CMP325.

What are the positive impacts?

4.1 Increased stability in zoning should provide better long-term investment signals to generators, potentially improving competition in the wholesale and Contracts for Difference markets.

Workgroup vote

4.2 The workgroup met on 11 May 2020 to carry out their workgroup vote. The full Workgroup vote can be found in Annex 18. The table below provides a summary of the Workgroup members view on the best option to implement this change.

The applicable CUSC (charging) Objectives are:

(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);

(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;

(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1 *; and

(e) To promote efficiency in the implementation and administration of the CUSC arrangements.

*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

Voting for CMP324 and CMP325

Workgroup Member	Company	BEST Option?	Which objective(s) does the change better facilitate? (if baseline not applicable)
Bill Reed	RWE Supply and Trading GmbH	**Original**	**A**
Paul Mott	EDF Energy	**WACM3**	**A E**
Andrew Enzor	Cornwall Insight	**WACM1**	**A B C**
Simon Lord	ENGIE	**WACM1**	**A B C**
Paul Jones	Uniper	**WACM1**	**A B C**
Paul Youngman	Drax Power Limited	**WACM1**	**A B C**
Grahame Neale	National Grid ESO	**Original**	**A E**
John Tindal	SSE plc	**Original**	**A E**
Simon Swiatek	BayWa RE	**WACM 2**	**A B E**
Joseph Dunn/Chris Coates	Scottish Power	**WACM1**	**A B C**
Graham Pannell	Fred. Olsen Renewables	**Original**	**A E**

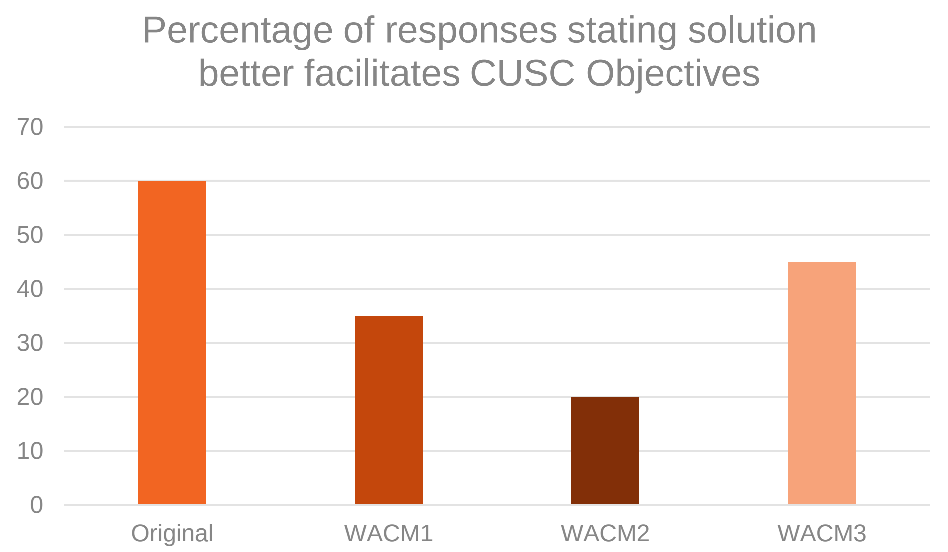
Code Administrator Consultation responses

The Code Administrator Consultation was issued on the 3 June 2020 and closed on 24 June 2020 and received 22 responses including 2 Confidential responses and no late responses. A summary of the responses can be found in the table below. The full responses can be found in Annex 19.

Code Administrator Consultation summary	
Question	
Do you believe that the CMP324/5 Original solution, WACM1, WACM2 or WACM3 better facilitates the	**12 Responses indicated some support for the original solution** “Alignment with demand zones will increase the predictability of the resulting Generator TNUoS signals and will also facilitate greater alignment between Transmission and Distribution connected

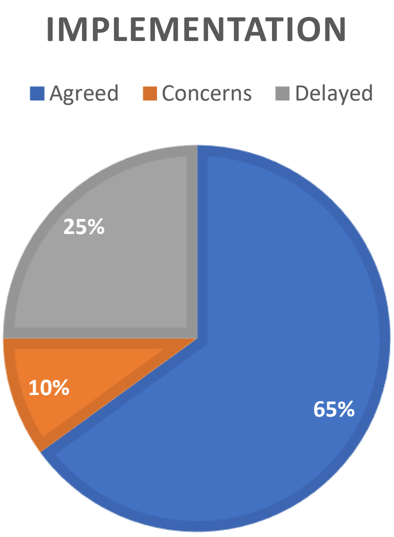
Applicable CUSC Objectives?	generation charging arrangements. Therefore, on an enduring basis the proposal will have a positive impact on competition. However, we also recognise that the short implementation timescales for the original are likely to produce short-term distributional impacts, which could have a negative impact on competition". "By mapping the generation zones to the GSP groups, there would be no need to re-zone the generation zones at each price control period, creating real long-term zonal stability for generation sites". "We consider that the Original would best facilitate the CUSC Applicable Objectives. Specifically, we consider that it would best facilitate applicable objective a) and also applicable objective e). This is due to the improved stability, transparency and simplicity that would be introduced through the proposer's Original. We also consider that it would have a neutral effect on the other Applicable Objectives". **7 Responses indicated some support to the view that WACM1 better facilitated the applicable CUSC objectives** "WACM 1 Better facilitates the Applicable CUSC Objectives compared to the baseline arrangements. It updates and secures the benefits of the current methodology by applying indexation of the +/- £1 differential to +/- £2.25. This maintains a cost reflective basis to zonal charges and ensures that zones are able to flex and adapt on an enduring basis". "WACM1 is the closest to an economic solution, and it allows new zones to be created mid tariff, and the basical zonal allocation can be reviewed mid-tariff". "It is the only solution proposed that retains cost reflective generation charging zones that can vary according to the changing location of generation over time(objective (b)). **4 Responses indicated support for WACM2** "WACM2 offers more charge stability than baseline and than WACM1". "We believe that the Original Solution, WACM2 and WACM3 would best facilitate objective a, by providing a more stable and well-understood long-term charging environment within which generators will be better able to develop competitive projects. They would also facilitate objective e, by removing the industry overhead associated with the System Operator's reassessment of the generation zones at regular intervals".

	9 Responses indicated support for WACM3. “Moreover, April 2023 implementation of the 14 zone solution (with today’s zones stabilised before then) would coincide with the intended implementation date for any measures taken forward for Ofgem’s review of access and forward looking charges, from when it is possible that other changes could come in including a shortlisted option entailing SDG potentially starting to pay generation TNUoS (or similar) - so rather than there being several consecutive changes affecting generation TNUoS, one of which would be the move to 14 zones, some of the changes could come in at the same time, in April 2023; this is more holistic and easier for participants to deal with than a “string” of charging changes, one after another”. “We support WACM3 as the best option as it fully aligns with the Original (moves to a 14 charging zone permanent solution) but allows a period of 2 years for generators to plan for the change, which may be significant for some. It makes sense, also, for the present 27 zones to be fixed in the interim”. “Onshore wind is one of the lowest cost forms of new-build electricity generation in the UK. The unintended consequences of the planned reforms could potentially have a significant negative impact on both existing and planned new onshore wind generation in the north of Scotland and the Scottish islands; adversely affect the move to decarbonise and reduce investment and jobs in these remote rural areas which have limited alternative investment opportunities”. “It is a close call between WACM3 and the Original. WACM3 has a lot of merit because it delivers the same long-term solution as the Original, so has the same long-term benefits versus Baseline as the Original, so is similarly better than Baseline with regards to objective “a” and “e” “ ***Many of the responses indicated support for more than one of the outlined solutions.***



	Responses%
Original	*60*
WACM1	*35*
WACM2	*20*
WACM3	*45*

Do you support the proposed implementation approach?	**13 of the 20 non confidential responses agreed with the outlined implementation approach.** **5 respondents indicated a delayed approach would be preferable – these largely correlated with responses which supported WACM3** **2 respondents expressed concerns with implementation approach.**



	Drax expressed concern in regard to the implementation approach not being clear within the consultation – pointing out paragraph 5.1 of the consultation document being ambiguous. *BayWa Re highlighted that they had concerns with adverse impacts arising from the implantation of any solution that would reduce the number of zones in Southern Scotland.*
Do you have any other comments?	*"We appreciate that there is an argument that the use of demand zones for transmission connected generation could allow embedded generators and transmission generators to be exposed to the same charges. However, the demand locational and generational locational charges are averaged in different ways so this will not be an outcome of CMP324/5 even if the demand zones option were chosen"* **Uniper** *"The Stornoway Trust has been patiently playing the waiting game since local wind generation exceeded the capacity our local grid can accommodate. At little or no cost to either the government or the consumer, unlocking the door to island grid connectivity could hugely boost the nation's net zero target aspirations"* **Stornoway Trust** *"Changes to the charging methodology should lower barriers to entry for remote Island wind and offer an opportunity for the development of marine technologies"* **Northwind** *"WACM 2 has no merit as it simple keeps the existing nodes allocated to fixed zones with no possible change. Whilst the proposal results in stable zones (the nodes in each zone) the price of the zones is far from stable and will fall or rise depending on new connections with peripheral nodes being especially susceptible to price shocks (e.g. should islands links connect into the zone)."* **Engie** *"We are still concerned about the number of concurrent modifications and a lack of holistic view of all changes affecting TNUoS charges. We are keen to see more certain and stable forecasts based on a baseline that includes all changes, including CMP 317/327 , CMP 320 and other relevant modifications. We would also urge NG ESO to alert the industry should the forecast and the baseline analysis provided as part of this consultation change materially before the implementation. "* **ESB** *"The desire for change appears partly driven by the saving of administration costs. We do not believe administrative benefits are so significant to justify either the impact of eroded cost reflectivity*

	under the original proposal, WACM2 or WACM3,or the greater distributional effects arising. In contrast WACM1 has a neutral impact on the administration of the charging methodology and reduces the distributional effects" **NGET** *"Moving to the same 14 Charging Zones for Transmission as the current Demand Zones would serve to remove a source of distortion between Small Embedded Generation (<100MW) and other Generation (>100 MW Distributed Generation and Transmission –connected Generation). "* **Neven Point** *"We have concerns that if remote island connections were to become part of the MITS they would significantly distort cost reflectivity (in zone 1), with generators in North Scotland providing a large subsidy for Island generators' connections. We do not believe this is cost reflective or fair from a competition perspective. We believe the Remote Island connections should be considered local circuits.".* **Statkraft**
Legal text issues raised in the consultation	
None	

When will this change take place?

Implementation date:

5.0 The Proposer stressed the importance of a decision on any solution by mid-October 2020 to be able to be implemented on 1 April 2021, at the start of the RIIO-2 price control period. This would also be beneficial for the publication of applicable tariffs ahead of the 2021/22 Charging Year.

Implementation approach:

5.1 NGESO are still to complete a full impact assessment of the system changes required for this modification. It is foreseen that there may be potential changes to charging and billing systems.

Acronym table and reference material

Acronym	Meaning
ALF	Annual Load Factor
CfD	Contracts for Difference
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DCLF ICRP model	Direct Current Load Flow Investment Cost Related Pricing Model – "Transport Model" for calculating TNUoS tariffs

DNO	Distribution Network Operator
DUoS	Distribution Use of System
ESO	National Grid Electricity System Operator
ETYS	Electricity Ten Year Statement
GSP	Grid Supply Point
HVDC	High Voltage Direct Current
LRMC	Long Running Marginal Cost
MITS	Main Integrated Transmission System
RIIO-T2	Transmission Price Control period
RPI	Retail Price Index
SCR	Significant Code Review
STC	System Operator Transmission Owner Code
TCR	Targeted Charging Review
TNUoS	Transmission Network Use of System
TO	Transmission Owner
WACC	Weighted Average Cost of Capital

Annexes

Annex	Information
Annex 1	CMP324 Proposal Form
Annex 2	CMP325 Proposal Form
Annex 3	Terms of Reference
Annex 4	About the TNUoS Transport Model
Annex 5a	Node Analysis by ESO (updated since Workgroup Consultation)
Annex 5b	Node Analysis by SSE
Annex 5c	Node Analysis by Uniper
Annex 5d	Node Analysis by Uniper plus Shetland
Annex 6	Workgroup 1 Slides
Annex 7	Workgroup 2 Slides
Annex 8	Workgroup 3 Slides
Annex 9	Workgroup 4 Slides
Annex 10	Workgroup 6 Slides
Annex 11	Workgroup Consultation responses

Annex 12	TNUoS RIIO T1 History
Annex 13	Legal text
Annex 14	WACM 2 - SSE Alternative (Fix 27 zones)
Annex 15	WACM 3 - EDF (on behalf of Neven Point Wind) Alternative (Fix to 27, then GSP groups)
Annex 16	WACM1 - Uniper Alternative (RPI)
Annex 17	Nodal Prices for Scenarios with Connectivity Maps
Annex 18	Workgroup Vote
Annex 19	Code Administrator Consultation responses