The Voice of the Networks

Energy Networks Association

Targeted Charging Review Project Initiation Document

December 2019

Energy Networks Association

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Document Control

Authorities

Version	Issue Date	Authorisation	Comments

Related Documents

Reference 1	Targeted Charging Review: Decision and Impact Assessment – Ofgem Publication, 21 November 2019
Reference 2	Direction to Licensees – DCUSA; Direction issued to DNOs in relation to the TCR SCR – Ofgem Publication, 21 November 2019
Reference 3	Direction to Licensees – CUSC; Direction issued to the ESO in relation to the TCR SCR – Ofgem Publication, 21 November 2019
Reference 4	Open Letter: Launch of a second Balancing Services Charges Taskforce – Ofgem Publication, 21 November 2019

Change History

Version	Change Reference	Description
0.1	N/A	Draft for consideration by the DNOs and ESO at workshop to agree structure
0.3	Structure, all sections	Draft shared with ESO, DNOs and iDNO for detailed feedback
0.4	All sections	Updated to reflect feedback from the DNOs and ESO, reissued for review
0.5`	All sections	Updated to reflect feedback from the DNOs and ESO, and Elexon
0.6	Risks, Plan	Updates to Plan on a Page and the Workstream 1 Risk Table
1.0	All sections	V1.0 baseline agreed and shared with Ofgem

Distribution

Electricity Regulation Group Ofgem National Grid Electricity System Operator

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1 Introduction

1.1 Background to the Targeting Charging Review

1.1.1 SCR Decision

On 21 November 2019 Ofgem published the Targeted Charging Review (TCR) Significant Code Review (SCR) Decision and Impact Assessment (the 'TCR Decision')[1]. Alongside this, Ofgem published two directions (the 'TCR Direction'), one to Distribution Network Operators (DNOs) and one separately to the National Grid Electricity System Operator (ESO). The TCR Direction requires the DNOs and ESO to raise one or more modifications to the Distribution Connection and Use of System Agreement (the 'DCUSA') and the Connection and Use of System Code ('CUSC'), with a view to addressing the issues outlined in the TCR decision. The Direction requires the changes to be implemented by 1 April 2021 for transmission and 1 April 2022 for distribution.

1.1.2 TCR guiding principles

As part of the SCR, Ofgem have carried out a principles-led assessment, setting out three guiding principles. The TCR Direction requests licensees to *'have regard to and to the fullest extent practicable comply with'* these principles. They are:

1. Reducing harmful distortions;
2. Fairness; and
3. Proportionality and practical considerations.

In developing this PID, an initial assessment of implementation options has been undertaken, and a proposed solution has been put forward ('the baseline solution'). For the demand residual, other options are considered to require changes to industry registration systems on which there is a moratorium on changes due to the Switching Programme. Without presupposing the development of alternative proposals via open governance arrangements, these other options have been discounted in accordance with principle 3 of these guiding principles; for the purpose of demonstrating to Ofgem that code modifications can be delivered to satisfy the requirements set out in the TCR Directions.

1.2 Purpose of this Project Initiation Document (PID)

The TCR Direction places a requirement on the licensees to present a detailed plan to Ofgem in December 2019 to *'ensure that the proposal(s) is / are capable of implementation'* by 1 April 2021 for transmission and 1 April 2022 for distribution. This plan sets out how the respective DNOs and ESO will work together and collaborate with other relevant industry stakeholders.

The DNOs and ESO, with input from other stakeholders including Elexon and ElectraLink, have produced a joint plan in the form of a PID. This PID outlines the following:

- The initial scope as defined in the TCR Decision;
- Early developed thinking on the potential implementation options
- A high level, indicative timeline, together with plans for engaging with various stakeholders;
- Resourcing approach and proposed governance structure for the project; and
- Key risks, assumptions and dependencies relating to the development and implementation of the proposed modifications, along with possible mitigating actions

[1] https://www.ofgem.gov.uk/system/files/docs/2019/11/tcr_final_decision.pdf

In doing so the PID should:

- Provide confidence to Ofgem that the ESO, DNOs and other key stakeholders are collaborating and have a robust project structure established;
- Ensure that the DNOs and ESO are aligned and in agreement on the scope and indicative timelines for the TCR, before conducting any further work;
- Identify the key dependencies between the changes being proposed by ESO and the DNOs; and
- Set out clearly the baseline solution, with the associated timelines, such that any deviation from this can be managed.

This PID is based on the best view at the time of preparation in December 2019 and will be updated and maintained throughout the project. Each iteration will be shared with the relevant governance bodies (see section3.1) for review and be published on the Charging Futures website.

1.3 Approach to planning

It is important to note that whilst this PID sets out a plan that meets the timeframes set out in the TCR Direction; this is based on a significant number of assumptions. The key assumptions are detailed within the PID and will be monitored throughout the delivery of the project. Any changes to the assumptions are likely to cause a change in the timeframes set out. Additionally, the plan shows the large number of inbound and outbound dependencies between the activities of the ESO, DNOs, Elexon and Ofgem. It is a highly ambitious timeline, with a number of overlapping activities, that poses significant risk. The key risks have been identified and listed in this document. If any of the risks materialise, the impact on the timeline will be assessed and reported to Ofgem.

2 Outline Scope and Delivery Approach

This project has been established to solely deliver the scope as defined in the TCR Decision and the Open Letter published on 21 November 2019. In summary the key scope is:

DCUSA direction: DNOs are required to raise one or more proposals to modify the DCUSA in relation to the way residual charges are allocated and levied.

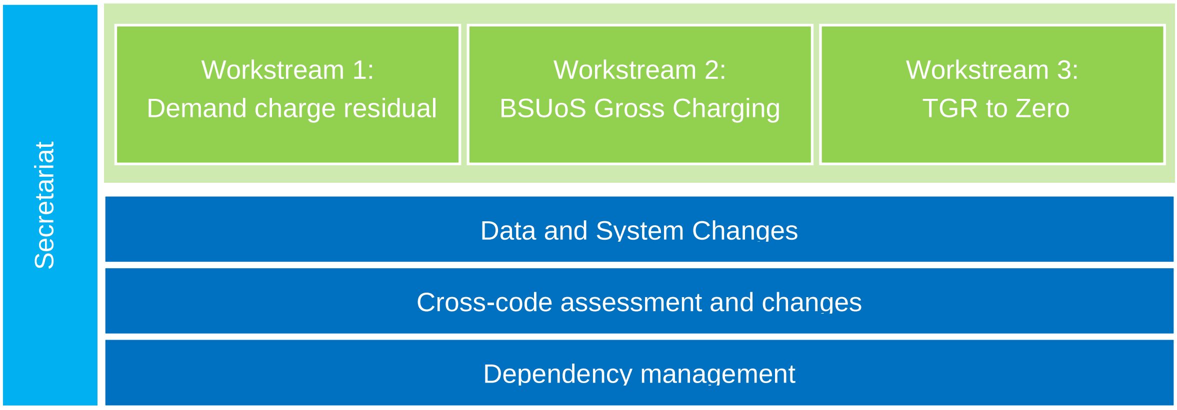
CUSC directions: The ESO is required to bring forward proposals to modify the CUSC a) in relation to the way residual charges are allocated and levied, b) to set the Transmission Network Use of System (TNUoS) Generation Residual (TGR) to zero, and c) to reform the basis on which Balancing Services Use of System (BSUoS) charges are applied to suppliers. A separate Open Letter additionally requires the ESO to establish and chair a Balancing Services Charges taskforce to consider a) who should be liable for balancing services charges and b) how these charges should be recovered. The outputs of this working group will inform the modifications that the ESO will raise to the CUSC.

The purpose of these reforms is to *'ensure that network costs are recovered fairly from network users and to reduce harmful distortions which impact competition and the efficiency of the electricity market'*.

2.1 Workstream Definition

Having assessed the scope of the TCR Directions and undertaken a gap analysis of the two directions (see section 4.3), the project has been structured into three workstreams. The first workstream will cover the 'demand charge residual' elements from the two TCR Directions. The diagram below shows how the workstreams will be structured:

Figure 1: TCR workstream and supporting activities



Workstream 1 - Demand charge residual will deliver requirements contained within the TCR Directions to make changes to the CUSC and the DCUSA resulting in a single fixed transmission residual charge and a set of single distribution residual charges for Final Demand consumers, within each of a number of distribution connected groups and unmetered suppliers. These changes will deliver a set of fixed residual charging bands, based on a consumer's[2] voltage level and net consumption volume or maximum agreed import capacity, for non-domestic metered consumers. There will also be a single fixed residual charge for domestic consumers based on net consumption volume, and at distribution a volumetric residual charge for unmetered consumers based on net consumption or agreed capacity.

[2] For the purpose of this PID, consumer, customer, user, and site are used interchangeably and should be interpreted consistently with the TCR Decision

Workstream 2 - BSUoS Gross Charging will deliver requirements contained within the TCR Direction to the ESO to make changes to the CUSC to charge BSUoS based on gross demand.

Workstream 3 – Transmission Generation Residual (TGR) to Zero will deliver requirements contained within the TCR Direction to the ESO to make changes to the CUSC to set the TGR to zero whilst maintaining compliance with regulation 838/2010.

Each workstream will also include:

- a cross-code assessment to understand which other industry codes require changes as a result of the DCUSA and CUSC modifications. Following an initial assessment, it is expect to include but not limited to the:
    - Balancing and Settlement Code (BSC)
    - Master Registration Agreement (MRA)
    - Data Transfer Catalogue (MRA)
- a detailed assessment of the system and data changes required to enable the implementation of the modifications.

2.2 Out of Scope

The following areas are out of scope of this project:

- Changes to arrangements relating to forward-looking charges. These will be delivered under the Access and Forward-Looking Charges SCR.
- Changes to arrangements relating to Multiple supplier. The outcomes of this TCR project will be delivered prior to the completion of the BSC code modification[3] relating to customers' ability to buy and sell electricity from multiple suppliers.

2.3 Project Phases

The project will be delivered through a series of phases. Each workstream will follow this phased approach although the individual tasks and timelines will vary. The initiation phase is already underway.

Phase 1: Initiation Phase

- Establishing the working groups and reporting structure
- Defining terms and definitions across the three workstreams
- Optioneering and determination of approach
- Engagement with Ofgem
- Draft and submit relevant code modifications
- Further project planning and risk assessment

Phase 2: Development Phase

- Develop modifications through the respective code body
- Formal change process
- Consultation and wider industry stakeholder engagement
- Determine implementation approach
- Formal approval of changes by Ofgem

Phase 3: Implementation Phase

- Implementation of system and data changes to support changes to relevant codes

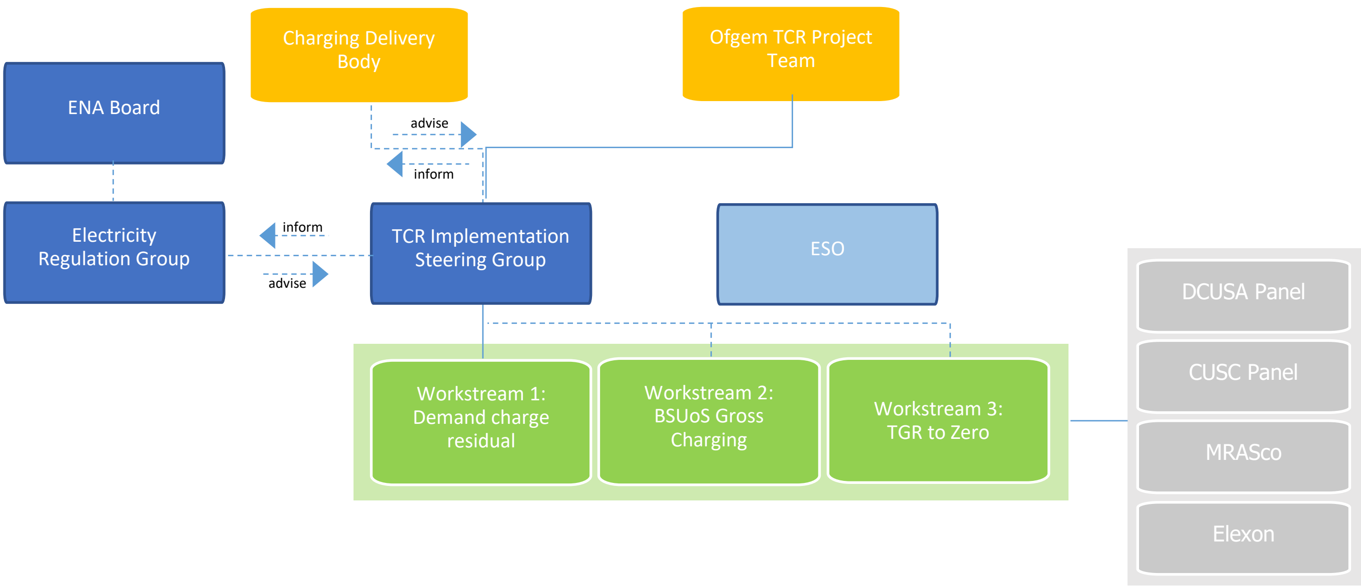
[3] P379 '*Multiple Suppliers through Meter Splitting*'

3 Governance and Stakeholder Engagement

3.1 Project Governance

The project governance structure is as below:

Figure 2: Project governance structure



TCR Implementation Steering Group

The TCR Implementation Steering Group is the key group with responsibility to direct the delivery of the project with regards to the development, submission, resourcing and coordination of the relevant code modifications, and the underpinning PID. Any proposed deviations from the approved PID, which are likely to cause a significant change to the key milestones included within the plan, will be managed by the group and escalated to the Electricity Regulation Group (ERG). Where changes to the PID are necessary as a result, these will be reported formally to the Ofgem TCR Project Team and the Charging Delivery Body (CDB).

This group will ensure the fair allocation of DNO and ESO resources are made available to drive delivery of the code modifications and seek to make the change process operate as efficiently as possible. The Steering Group will also identify and monitor dependencies across the project.

The TCR Steering Group will be a small group formed of (at minimum) a single representative (with alternate) from each of the DNOs and from the ESO as well as (at minimum) a single representative on behalf of the Independent Distribution Network Operators (IDNOs). The group will be chaired by the ENA.

The TCR Implementation Steering Group will represent the networks from a united programme perspective. The groups will work collaboratively to produce outputs that represent the majority view. A single DNO member of the TCR Implementation Steering Group will be responsible for raising each DCUSA modifications on behalf of the group and a member of the ESO will be responsible for raising the CUSC modifications.

In the development of this PID the group have met weekly. On an enduring basis the group will meet twice a month at the ENA offices. Additional meetings will be arranged subject to requirements.

Electricity Regulation Group (the ERG)

The ERG will provide an advisory role to the Project and as such does not have a formal decision-making responsibility. The TCR Implementation Steering Group will report monthly progress to the ERG and ensure they have early sight of imminent risks and dependencies. Issues, if they arise, that are likely to cause significant slippage to the timescales outlined in this PID will be reported to the ERG immediately, and the ERG will provide advice on how to manage these situations, as well as ensuring that appropriate stakeholder engagement is undertaken.

Ofgem TCR Project Team

In line with the TCR Directions, the networks will engage with Ofgem during the development of the modifications and advise of any potential issues arising which could prevent implementation by the deadline (1 April 2021 for transmission and 1 April 2022 for distribution), together with mitigating actions. The timeframes for the project are highly challenging and so decisions need to be made promptly, in line with agreed dates. It is therefore essential that the TCR Implementation Steering Group keep Ofgem engaged throughout the process. The primary route for networks' engagement will be via the Ofgem TCR Project Team ensuring that 'undesired' proposals are either not developed, or are flagged at the earliest opportunity. Ofgem should also actively engage in the code modification working groups. This will allow timely alternative proposals to be developed and to avoid inefficient use of sparse specialist industry resource.

Charging Delivery Body (CDB)[4]

The TCR Implementation Steering Group will have dual reporting requirements for the ERG and the CDB. The TCR Implementation Steering Group will liaise with the CDB as required to provide updates and to take CDB input on the development of the modifications. The purpose of the CDB is to help coordinate the development and implementation of required changes to electricity network charging and access arrangements. The CDB will therefore provide an essential secondary channel for providing updates and gaining early feedback on the proposals under development, providing insight of potential cross-code implementation issues and risks and conflicts with other Ofgem work areas.

Working groups & Resources

Initiation Phase
During the initiation phase each DNO and the ESO will provide, at minimum, a single expert resource to contribute to the project. Within Workstream 1, each DNO will be allocated to a specific code modification (in accordance with sub-section 4.5.1) and will be responsible for the drafting of the modification as well as conducting any stakeholder engagement as required before submitting to the DCUSA Panel. It is expected that the same individual will then join the code modification working groups during the development phase and until the implementation of the modification is complete. The same is true for the ESO, who will raise all CUSC modifications.

Development Phase
During the development phase the DNOs will together provide, at minimum, two expert resources to join the DCUSA modification working groups[5], support the planned stakeholder engagement and contribute to the supporting technical activities relating to data and systems. DNO and ESO working groups representation shall be agreed through the TCR Implementation Steering Group. The code modification working groups are, in addition, expected to be resourced with representatives from

[4] http://www.chargingfutures.com/media/1151/cdb_tor_rvsd_march18.pdf
[5] In addition, at least one representative from a DNO will join the CUSC working groups under Workstream 1

IDNOs, suppliers and Elexon, together with any interested parties e.g. generation or demand customers[6].

Implementation Phase

The implementation of the system and data changes required to support the code modifications will primarily be resourced by the ESO and Elexon due to the significant system changes required at transmission, but will be supported by DNOs.

ENA Secretariat

The ENA will provide a secretariat role to the project. This will be distinct from the wider Charging Futures secretariat role that will continue to be undertaken by the ESO and includes the delivery of the Charging Futures Forum (CFF). The ENA will:

- Be responsible for the management of the TCR Implementation Steering Group meetings including, scheduling, preparing agendas and supporting/other papers and tracking actions and decisions;
- Prepare and maintain the PID and project plan and monitor progress against the plan;
- Provide Ofgem with a single point of contact, as and when appropriate, for communications with the DNOs and ESO; and
- Chair the TCR Implementation Steering Group meetings, and additionally any ad-hoc meetings required to support the delivery of the plan.

The assumption at the time of agreeing this PID, is that this function will be delivered by the existing Access and Forward-looking Charges SCR secretariat team and will not require further recruitment or budget.

3.2 Stakeholder Management and Communications

3.2.1 Stakeholder management to-date

In the development of the PID, the DNOs and ESO have collaborated to develop the proposals and project plan and are committed to continuing to do so through to implementation. In the process of developing the plan, the DNOs and ESO have actively engaged with Elexon and ElectraLink, specifically in relation to the provision of data which will underpin the successful implementation of the TCR Decision in both transmission and distribution.

To further inform consideration of data provision and the implementation options presented DNOs and the ESO have also carried out engagement with a number of wider stakeholders. Such engagement includes via structured forums such as the Distribution Charging Methodologies Development Group (DCMDG), but also bilateral targeted engagement and in response to interest from stakeholders. The parties engaged include:

- a number of electricity suppliers, primarily via the Transmission Charging Methodologies Forum (TCMF) and bilateral engagement, as well as via DCUSA forums such as the DCMDG
- iDNOs via the Competitive Networks Association (CNA) – primarily to gather views on the baseline solution and establish enduring engagement initiatives;
- Ofgem – primarily to ensure that this PID delivers the requirement set out in the TCR Directions to submit a 'detailed plan', and provide assurance that the DNOs and ESO are working together

[6] Any party can attend working group meetings, but only code signatories can vote on proposals.

and with wider stakeholders to deliver the plan which will satisfy all requirements set out in the TCR Directions;

- Frontier Economics – primarily to ensure that information used in Ofgem's published impact assessment aligns to what DNOs and ESO understand is required in the TCR Decision; and
- Generation and demand customers – primarily in response to interest in the potential impact of TCR reform, and to seek views from customers on relevant areas of the baseline solution.

3.2.2 Enduring Stakeholder Engagement

The project licensees will engage with industry using existing channels to keep stakeholders abreast with developments and seek additional input. The DNOs will, as a minimum, engage via the:

- Monthly DCMDG – where focus will primarily be on policy development, but will also cover impact assessment and allow an opportunity for attendees to ask questions; and
- Quarterly DCUSA Schedule 15 'Cost Information Table' presentations, where focus will primarily be on the impact on use of system charges but will also cover policy development and allow an opportunity for attendees to ask questions.
- The DNOs will undertake engagement with electricity suppliers during the initiation phase in early 2020, primarily to discuss the proposed code modifications and data considerations.

The ESO will also engage with industry via:

- Charging Futures – as the secretariat for Charging Futures, the ESO has set up various webinars and forums to engage across industry on the TCR and will continue to provide this role throughout the project; and
- TCMF – where a focus will be on the proposed transmission modifications as set out in the PID. The forum covers policy development, but also cover impact assessment, and allow an opportunity for attendees to ask questions.

DNOs will attend the TCMF as required and similarly, the ESO will attend the DCMDG as required.

All channels have already been used to engage with stakeholders early in the initiation phase. Throughout the project all parties will engage with stakeholders via webinars and the Charging Futures newsletter.

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4 Workstream 1: Demand charge residual

4.1 Introduction

The section below outlines the specific scope of the workstream along with an assessment of the potential implementation options. This chapter sets out the baseline solution upon which the plan and associated risks, assumptions and dependencies have been built. Any changes to this baseline will need to be assessed for impact on the plan.

4.2 Scope

Table 1: DCUSA Direction Scope

Reform area	Requirements
Final Demand	• Define Final Demand as "*electricity which is consumed other than for the purposes of generation or export onto the electricity network*". • Develop an appropriate process to assess and identify, or, where a practical and proportional approach cannot be identified, to robustly estimate Final Demand, for the purposes of residual charging, having regard for paragraph 3.56(2) of the TCR Decision[7]. • Residual fixed charges will only be applied to a 'Single Site' with Final Demand. • Therefore, generation only (including storage) sites will not pay residual charges.
Single Site	• Residual fixed charges are to be applied on a 'Single Site' basis. • Develop an appropriate definition of a 'Single Site', having regard for paragraph 3.55(10) of the TCR Decision[8].
Residual charges	• The value of the residual will be apportioned between the methodologies[9] as they are currently. • The residual will then be apportioned to bands[10] on the basis of aggregated net consumption of all users in that band, relative to total net consumption for all users under the respective charging methodology[11]. • The allocated proportion of the residual value to each charging band will then be divided equally among all Sites within that band, with all Sites in a charging band paying the same level of residual fixed charge (excluding unmetered customers). • A single fixed use of system residual charge for domestic low-voltage (LV) connected customers, per Distribution Services Area.

[7] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.55(2) of the TCR Decision.
[8] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.54(10) of the TCR Decision.
[9] i.e. the Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM).
[10] Domestic customers are in a single 'segment', whereas non-domestic customers are split into different segments, and metered customers then sub-segmented by 'band'. For the purpose of this PID 'band' represents both segments and bands unless specified otherwise.
[11] i.e. CDCM customers will be apportioned the CDCM residual, and EDCM customers the EDCM residual.

	• A single fixed use of system residual charge in each of four fixed charging bands for each of four non-domestic customer segments (except unmetered customers), per Distribution Services Area. • The four non-domestic customer segments are: 1. LV connected, where customers have no agreed capacity as the basis of their current use of system charges; 2. LV connected, where customers have an agreed capacity as the basis of their current use of system charges; 3. High-voltage (HV) connected customers; and 4. Extra-high voltage (EHV) connected customers[12]. • Consideration will be given to the frequency and relevant units of the fixed charge (e.g. p/site/day). • Charges for unmetered customers will be derived considering net consumption or agreed capacity on the basis of its 'profiled' demand and the applicable charging methodology.
Setting non-domestic charging bands	• The four non-domestic charging bands will be set with boundaries based on 40th, 70th, and 85th percentiles of the number of relevant Final Demand Sites, in each segment, and on a GB-wide basis. • The percentiles will be determined by customer numbers on the basis of increasing agreed capacity levels in the LV with an agreed capacity, HV and EHV segments; and increasing net consumption for the LV without an agreed capacity segment. • In setting the charging bands, regard will be given to paragraph 3.55(9) of the TCR Decision relating to redundant connection capacity[13]. • Appropriate arrangements shall be implemented to review the non-domestic charging bands, such that any changes to the bands can be implemented at the same time as the next transmission price control takes effect: regard will be given to paragraph 3.55(11) and 3.58 to 3.59 of the TCR Decision[14]. • Having regard for paragraph 3.57(1) the TCR Decision[15], assess (and develop solutions if needs be) whether there may be circumstances, in particular for EHV customers, where regional differences lead to substantially different distributions of customers in Distribution Service Areas, which may result in a very low number of customers in any given band.

[12] These are Designated EHV Properties (as defined in the electricity distribution licence), being customers connected to a DNO at 22kV and above (i.e. EHV customers) and customers connected directly to a DNO substation between 1kV and 22kV and where the primary voltage of the substation is 22kV or more and where the Metering Point is located at that substation (i.e. HV sub customers).
[13] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.54(9) of the TCR Decision.
[14] The TCR Direction incorrectly refers to the need to have regard for paragraphs 3.54(11) and 3.57 to 3.58 of the TCR Decision.
[15] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.56(1) of the TCR Decision.

Allocating customers to non-domestic charging bands	• Non-domestic customers will be allocated to bands based on agreed capacity where available, or net consumption where not. • The data will relate to, and be averaged over, a period of no less than 24 months prior to the setting of the applicable residual charges: or longer if the requisite data can be made readily available at proportionate cost. • For any new customers, where the appropriate data is not available, a process will be established to allocate that customer based on an assessment of its agreed capacity or net consumption, as applicable, and to best estimate the expected usage of that customer. • In allocating customers to the charging bands, regard will be given to paragraph 3.55(9) of the TCR Decision relating to redundant connection capacity.
Reallocation of customers	• Having regard for paragraph 3.57(3) of the TCR Decision[16], consideration will be given to implementing a process by which customers can move between segments and bands during transmission price controls.
Disputes	• An appropriate process shall be established to manage any disputes relating to a customers' residual charge. • Such a process will consider dispute process already in place, and ensure that the process is efficient and proportionate.
Licensed Distribution Network Operators (LDNOs), private networks, and complex Site arrangements	• Consideration will be given to establishing appropriate and proportionate arrangements for residual charges for customers connected to non-DNO networks and for complex Sites. • The Authority expects that LDNO charging regimes will continue to function as of today.
Data: systems and processes to implement the TCR Decision	• Having regard for paragraph 3.56(4)[17], appropriate arrangements will be developed, where needed, in relation to systems and processes to implement the TCR Decision, and code modifications raised to achieve it. • Consideration will be given to: 1. how existing systems may need to be adapted, and centralised approaches utilised, in establishing banding and allocating customers to bands; and 2. how the bands, and customer allocation to the bands, are to be defined and communicated within systems and processes, including considering the potential to use existing processes such as Line Loss Factor Classes (LLFCs) etc.

[16] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.56(3) of the TCR Decision.
[17] The TCR Direction incorrectly refers to the need to have regard for paragraph 3.55(4) of the TCR Decision.

4.3 Gap analysis between DCUSA and CUSC directions

The DCSUA and CUSC directions both contain requirements relating to the demand charge residual, in order to understand how best to structure the delivery of these requirements, a gap analysis of the two has been undertaken.

The table below sets out where the requirements on modifications to the DCUSA and CUSC differ, as well as providing clarity where the requirements are consistent across both codes. Where a requirement is specific to the CUSC e.g. in relation to the TGR, these have been intentionally omitted from this assessment.

Table 2: Variation in requirements in DCUSA and CUSC Direction

Reform area	Requirements
Final Demand	• Consistent across both codes.
Single Site	• Consistent across both codes.
Residual charges	• A single fixed residual charge for transmission-connected connected customers. • Transmission charges to be consistent across all Distribution Services Areas, therefore no regional differences, unlike the potential for differences in distribution. • Need for a suitable allocation of transmission residual charges between non-half hourly (NHH) and half-hourly (HH) customers.
Setting non-domestic charging bands	• Consideration of the need for more than one band for transmission residual charges for transmission-connected customers (e.g.) in relation to very small customers connected at higher voltages. This should be considered alongside the need for DNOs to consider a different approach to banding EHV distribution-connected customers.
Allocating customers to non-domestic charging bands	• Consistent across both codes.
Reallocation of customers	• Consistent across both codes.
Disputes	• Consistent across both codes.
Licensed Distribution Network Operators (LDNOs), private networks, and complex Site arrangements	• Consistent across both codes.
Data: systems and processes to implement the TCR Decision	• Consistent across both codes.

4.4 Implementation Option Assessment

4.4.1 Baseline solution: Utilise existing data and processes to apply a default binary assessment of residual charging eligibility

High Level Description

A designated party will be provided distribution-connected customer data to determine the non-domestic charging bands early in 2020[18]. The process will be repeated in the regulatory year t-2 prior to the beginning of each electricity transmission price control period; for transmission price controls beginning after RIIO-ET2. The upper and lower thresholds in each band will be consistent across all Distribution Service Areas and the ESO.

For the determination of the indicative band boundaries in 2020, each Meter Point Administration Number (MPAN) shall be considered to be a site except where a DNO knows that the MPAN is an additional MPAN (for example an off-peak supply)[19]. All metered import data shall be considered Final Demand unless demonstrated otherwise. Only imports measured by MPANs which qualify for zero residual charges under DCP341/342[20], albeit extended to cover all generators and not just storage, shall be considered not to be Final Demand. A separate process will be needed for directly connected transmission sites. This could be through an extension of the P383[21] arrangements or some other method.

These assumptions, in relation to the determination of customers which are eligible for residual charges, will be reviewed and revised as appropriate before any customers will be allocated to the bands, and those customers will remain in that band for the duration of that price control period; subject to exceptional circumstances. Customers will be mapped to charging bands using Loss Factor Classes (LLFC). For use of system charge setting purposes, DNOs will forecast customers and gross consumption[22] in each of the relevant bands[23]. DNOs will provide this forecast to the ESO no later than January each year (post implementation), and the ESO may use this information as a basis of its own forecast for the purposes of setting its use of system charges.

DNOs will continue to bill use of system as at present, and no billing system changes will be required other than to recognise the revised tariff structure. The ESO will require that the information provided to the DNOs, for the purpose of billing[24], be aggregated on a national basis by band and by chargeable party (e.g. electricity supplier). In addition, the ESO will require that relevant capacity, volume and site/Final Demand classifications are provided to it for sites directly connected to the Transmission System. If banding is utilised for these sites and where no agreed capacities exist for these within their connection agreement(s) the ESO will propose a process utilising the current Demand Capacity (DC) values as held by Elexon. It is anticipated that this will be done by a 'Residual Charging Agent' (RCA), and the RCA may be Elexon, who currently provide billing information to the ESO. The ESO will require a new billing system to process new data and invoice each chargeable party.

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[18] It is assumed that the ESO will undertake this role and therefore transmission-connected data will not need to be provided, otherwise it will be provided to the designated party

[19] This is in line with current arrangements which prevent multiple fixed charges being levied

[20] DCUSA Change Proposal (DCP) 341 '*Removal of residual charging for storage facilities in the CDCM* and DCP 342 '*Removal of residual charging for storage facilities in the EDCM*

[21] P383 'Enhanced reporting of demand data to the NETSO to facilitate CUSC Modifications CMP280 and CMP281'

[22] In this context, gross consumption is import measured by the Metering System at the Boundary Point, and may therefore be offset by 'behind the meter' generation.

[23] Forecasting assumptions will be determined by each DNO

[24] E.g. per supplier, the number of customers in each band on a daily basis

Each DNO will publish and provide the RCA with mapping information to show which LLFCs are mapped to each residual band. The RCA will aggregate the DNO Supplier Purchase Matrix and any other relevant data flows (e.g. flows for sites connected directly to the transmission system) to produce daily customer counts by supplier by residual band. The ESO will use this data to bill customers on a monthly basis or as otherwise agreed.

System changes will be required to perform the aggregation, and a new or updated dataflow is likely to be needed, and included in the Supplier Volume Allocation (SVA) Data Catalogue.

A customer will be able to dispute the band to which it has been allocated with the DNO via its Supplier[25], and if the dispute is successful will result in the customer being reallocated to a different residual charging band, and which may result in the need for an appropriate rebate/adjustment. The DNO has the right to validate/challenge any request for re-banding.

1 Definition of Final Demand and Eligibility for Zero Residual Charges

All sites with any Final Demand will attract a residual fixed charge. Only standalone generators and storage sites will be deemed to have no Final Demand and hence will be exempt from residual charges. There would be no need for the generator to hold a generation licence. The codes will define Final Demand as "*electricity which is consumed other than for the purposes of generation or export onto the electricity network*".

Determination of whether a site is a standalone generator or a storage facility is expected to follow the approach envisaged in DCP 341/342 albeit extended to cover all generators. A separate process will be needed for directly connected transmission sites. This could be through an extension of the P383 arrangements or some other method.

2 Definition of Single Sites

The definition of Single Site and associated processes will need to be defined in the DCUSA and the CUSC, and possibly be documented in the MRA. The lead/primary MPAN will be allocated to the band based on the sum of consumption across all MPANs, and 'secondary' MPANs assigned to an LLFC with zero residual charge[26].

There may be Single Sites which comprise multiple MPANs. Where a Single Site has multiple MPANs only a single fixed charge is levied; customers will need to demonstrate that all MPANs are part of a Single Site.

No system changes should be required, but robust definitions and processes will be needed.
There may be sites where all the demand on the site is not considered Final Demand. It will be considered whether the banding of such sites should be adjusted in these circumstances and the appropriate metering arrangements that would need to be put in place to separate the site, such that only import which is Final Demand receives a residual fixed charge[27].

[25] Or a different party with relevant authority to act on its behalf.
[26] Currently all MPANs may be allocated the same LLFC as the 'lead' MPAN, but as noted, billing arrangements avoid multiple application of fixed charges.
[27] As a result, the lower consumption would be used to determine allocation to a residual charging band, with the customer potentially reallocated to a different band during a price control period

It will be necessary to create a process under the BSC that will allow the ESO to accurately establish whether there are directly connected sites that should be considered a Single Site.

3 Determination of Charging Bandings

A preliminary determination of the banding boundaries, the number of customers in each band across each DNO, and the average and median consumption will be undertaken at an early stage of the project based on the customers eligible for a residual charge as set out above. It is expected that DNOs will refresh data provided to Ofgem in support of the TCR Decision, and will utilise existing industry processes[28] to obtain the disaggregated data for small non-domestic customers which DNOs do not currently hold (e.g. Profile Class (PC) 3-4 customers). The determination of the actual bands to be used effective from 1 April 2021 will be undertaken when the relevant DCUSA modifications and data sources have been finalised.

The DCUSA and CUSC will be amended to define a process for the future determination of residual bands, which will specify what data is required and when it will be provided. The data provided to the designated party to determine the upper and lower band thresholds will pertain to the most recent held agreed capacities or most recent rolling 12 months' consumption, where an agreed capacity is not available. Where disaggregated data is not readily available to the DNO (e.g. PC3-4 customers) 12 months' consumption is not available.

Regional DNO bands will not be used. Where there are customers in any band, consideration will be given in the tariff methodology as to the costs allocated to customers in that band (e.g.) where a DNO has less than two customers in any band, the charge for that band will be calculated as if those customers were included in the band below it, and if that band is the first band, it will be calculated as if those customers were included in the band above it. This will retain the integrity of the national bands, whilst protecting customers from potentially disproportionately high residual charges.

There are likely to be project costs associated with this exercise including potentially the development of scripts to transfer bulk MPANs to new LLFCs, however it is unlikely to require fundamental changes to systems.

If a banding approach is required for directly connected transmission sites this will require the provision of capacity data to the ESO and a methodology established under the CUSC for establishing a capacity for a site where there is nothing agreed in a relevant connection agreement.

4 Allocation of Customers to Bands

The data used to allocate customers to bands will be based on a rolling 24 month average where available. The data will represent average annual consumption (i.e. an average of the last two years) or average agreed capacity as appropriate.

Where 24 months of data is not available (e.g.) due to a recent connection, it is proposed that the customer will be allocated to a band based on its current agreed capacity where available, or annual consumption where not. Annual consumption will be a minimum of 12 months' data (e.g. for HH customers), and where this data is not available, will be the most recent Estimated Annual Consumption (EAC) for that customer (e.g. for NHH customers), and if not available, will be assumed to be in line

[28] See 'NHHDA Run and Send EAC Data to Distributors Report' in Balancing and Settlement Code Procedure (BSCP) 505 '*Non Half Hourly Data Aggregation for SVA Metering Systems Registered in SMRS*' https://www.elexon.co.uk/documents/bsc-codes/bscps/bscp505/

with the average annual consumption for a typical customer at the same voltage and with no agreed capacity, and based on a simple arithmetic average.

Disaggregated data is currently not available for small non-domestic customers. Although customers may not be 'new', DNOs will utilise existing industry processes to procure EAC data for these customers from NHH Data Aggregators (NHHDAs); therefore such customers will be treated as if 'new' by basing consumption on their EAC, and allocated to the residual charging bands accordingly. Default EACs or average consumption for a typical customer at the same voltage will otherwise be used as noted above.

Suppliers/DNOs may review such customers when 24 months of data becomes available, and considered for reallocation if deemed necessary.

A customer can dispute with the DNO, via its Supplier or other party with the authority to act on its behalf, the residual charging band to which it is allocated, and in doing so must provide supporting connection agreements and/or metered consumption data.

Arrangements are already in place in the DCUSA for the dispute of incorrectly applied use of system charges i.e. the invoice being incorrect due to the incorrect tariff being applied, as opposed to the calculation of the tariff being incorrect. Different resolution arrangements will be required for transmission, but the dispute of the band allocation is a matter to be resolved with the DNO only.

Following a successful dispute, a customer may be reallocated to a different charging band from the next billing period, and may be entitled to a rebate effective from the period on which the Supplier was first billed in the old charging band, and ending on the effective date of the new band, unless that period is greater than six years, in which case it will be six years[29][30].

If relevant, for sites that are directly connected to the transmission system a rolling 24 month data set will be used and where this is not possible the ESO will calculate an estimate of the sites usage and capacity.

5 Calculation of Residual Charges

Residual charges will be levied on a pence per site per day basis. Residual charges for unmetered customers will remain consistent with the current methodologies on a pence per kilowatt hour basis.
In addition to the domestic, unmetered and non-domestic charging bands, there will be a fifth 'band' for each of the segments where no residual charge will be applied, however unit charges, non-residual fixed charges, capacity charges (agreed and excess) and reactive power charges will apply where appropriate. In total there will be a minimum of 32 CDCM tariffs (including generation):

1 Domestic Aggregated
2 Domestic Aggregated (Related MPAN)
3 Non-Domestic Aggregated no residual charge
4 Non-Domestic Aggregated Band 1
5 Non-Domestic Aggregated Band 2
6 Non-Domestic Aggregated Band 3
7 Non-Domestic Aggregated Band 4
8 Non-Domestic Aggregated (Related MPAN)
9 LV Site Specific no residual charge
10 LV Site Specific Band 1

[29] This is not currently the arrangements at Transmission and will be looked at through the modification process
[30] In line with the relevant statutory limitations. A five-year prescription period applies in Scotland.

11 LV Site Specific Band 2
12 LV Site Specific Band 3
13 LV Site Specific Band 4
14 LV Sub Site Specific no residual charge
15 LV Sub Site Specific Band 1
16 LV Sub Site Specific Band 2
17 LV Sub Site Specific Band 3
18 LV Sub Site Specific Band 4
19 HV Site Specific no residual charge
20 HV Site Specific Band 1
21 HV Site Specific Band 2
22 HV Site Specific Band 3
23 HV Site Specific Band 4
24 Unmetered Supplies
25 LV Generation Aggregated
26 LV Sub Generation Aggregated
27 LV Generation Site Specific
28 LV Generation Site Specific no RP Charge
29 LV Sub Generation Site Specific
30 LV Sub Generation Site Specific no RP Charge
31 HV Generation Site Specific
32 HV Generation Site Specific no RP Charge

EHV tariffs will remain site-specific, other than the residual charge which will be one of the four banded charges, or zero.

LDNO charging arrangements will continue as they currently exist, with discounts relative to the voltage of connection applied consistently to each charging band at that voltage level.

Transmission tariffs will follow the same structure for residual charges with 18 as a minimum in the following categories:

1. Domestic Aggregated
2. Non-domestic LV no MIC[31] Band 1
3. Non-domestic LV no MIC Band 2
4. Non-domestic LV no MIC Band 3
5. Non-domestic LV no MIC Band 4
6. Non-domestic LV Band 1
7. Non-domestic LV Band 2
8. Non-domestic LV Band 3
9. Non-domestic LV Band 4
10. Non-domestic HV Band 1
11. Non-domestic HV Band 2
12. Non-domestic HV Band 3
13. Non-domestic HV Band 4
14. Non-domestic EHV Band 1
15. Non-domestic EHV Band 2
16. Non-domestic EHV Band 3
17. Non-domestic EHV Band 4
18. Non-domestic Transmission Connected Bands

[31] Maximum Import Capacity.

In addition, there will need to be 14 NHH and 14 HH locational tariffs calculated to retain the current locational signals. The number of Transmission Connected Bands may vary through the workgroup process.

4.4.2 Alternative option assessment

The baseline solution is intentionally pragmatic; to minimise disruption to existing data, processes and systems, and in doing so seeks to satisfy the requirements set out in the TCR Direction – whilst being particularly cognisant of the implementation date of 1 April 2021 for transmission.

Alternative solutions to certain elements of the baseline solution have been considered. The following is not an exhaustive list, and the code modification working groups may identify additional options to be considered. Consideration as to why the option set out in the baseline solution is preferred is also included.

1 Definition of Final Demand and Eligibility for Zero Residual Charges

The existing code modifications to exempt storage sites from residual charges differ between transmission[32] and distribution[33], and where a key difference is the need for the storage site to hold a generation licence in the transmission proposals. Whilst the baseline solution proposes to align to the DCUSA proposals, the need to hold a generation licence could be considered. However, this could widen the distortion between generators which hold and do not hold a generation licence, e.g. those with a generation licence face no Final Consumption Levies on electricity used for the purpose of generating electricity, whereas those who do not hold a generation licence do. This would serve to create an un-level playing field and widen an existing distortion.

A Final Demand 'threshold' could be considered, where (e.g.) import relative to export consumption (at the boundary)/capacity would need to be a defined percentage, where import in excess of the threshold would result in that site being eligible for a residual fixed charge. However, any approach used to determine a threshold risks introducing artificial boundaries and therefore opportunities for gaming. As result, this could manifest as an inefficient signal to which a user can respond and in doing so avoid costs; which would then be borne by the generality of users who cannot, or do not, respond – this is contrary to the underlying problem the TCR seeks to remedy.

2 Definition of Single Sites

The association of MPANs to determine a Single Site could be determined relative to ownership and distance between Metering Systems. For consideration of code working groups, Ofgem offered the following definition of a Single Site in the TCR Decision: "*One or a collection of buildings, structures or pieces of land in close geographical proximity, owned or occupied by one customer within a defined curtilage on one site, where each building, structure or piece of land serves the other in some necessary or reasonably useful way*". However, any approach which relies upon defining (or rather interpreting) how close e.g. "*close geographical proximity*" is, risks introducing artificial boundaries and therefore opportunities for gaming.

There are already examples in the current methodologies where similar boundaries exist which facilitate distortions; such as eligibility for sole use asset fixed charges in the EDCM, and where the definitions

[32] CUSC Modification Proposal (CMP) 280 '*Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users*' and CMP 281 '*Removal of BSUoS Charges From Energy Taken From the National Grid System by Storage Facilities*'
[33] DCP 341/342

on metering location rely on terms such as "*immediately adjacent*", and create unnecessary ambiguity and increase the risk of errors. As a result, this could recreate the issue the TCR has ultimately sought to address where users can unduly avoid costs which are then borne by others.

3 Determination of Charging Bandings

The data used to determine the charging banding boundaries does not need to be a minimum of a 24 month average, which is a requirement in relation to the data used to allocate customers to the residual bands. However, the data which is used may relate to (e.g.) the most recent held agreed capacities or most recent 12 months' rolling average consumption. The data may need to relate to a specific Settlement Reconciliation Run, whereby (e.g.) Settlement Final (SF) data may be excluded due to the high degree of estimation included.

As noted, DNOs do not currently receive disaggregated small NHH non-domestic customer data (e.g. PC 3-4 customers). The baseline solution relies upon the EAC Data to Distributor Report as set out in BSCP505; whereby a snapshot of EAC data and Metering System details in respect of Metering Systems located at Boundary Points on the relevant DNO network is procured from NHHDAs. This solution builds on existing processes; however, it does comes with associated temporal requirements in terms of initial notice periods and processing. Reliance on additional parties introduces greater risk. However, a solution for DNOs to procure the data on an enduring basis and including historical information is unlikely to be achievable in the required timescales, certainly for data to be used to determine the residual banding boundaries in time for the beginning of RIIO-ET2 on 1 April 2021.

4 Allocation of Customers to Bands

The baseline solution proposes to use a rolling 24 months' data, and avoid extended periods whereby due to limits on data availability, a consistent dataset may not always be feasible. A lack of consistency, where (e.g.) some customers may have more than three years of historic data and some may only have two years, is detrimental to predictability, and inclusion of older data increases the risk of including capacities or consumption which is no longer reflective of the customer's needs/behaviour. As a result, this may increase the reliance on dispute processes, and potentially increase the liability of rebates to be paid by the DNO.

An alternative approach than the baseline solution would be highly reliant on such data being made available to DNOs for small non-domestic customers, where, as noted, the DNO does not receive such customer-specific information; and therefore cannot allocated such customers to residual charging bands based on (e.g.) individual historical consumption data. A solution therefore relies upon data being sourced elsewhere, e.g. the Department for Business, Energy and Industrial Strategy (BEIS) information used by Frontier Economics as part of the impact assessment published in support of TCR Decision, or potentially requires BSC changes which build on the foundations of the BSCP505 provision. It is unlikely that this will be achievable in the timescales required and is arguably not necessary.

Customers will be identifiable to which residual charging band they are allocated by LLFC. Whilst this is not without its issues (which are set out in section 4.11), alternative approaches severely risk delivery of an implementable solution in line with the requirement for 1 April 2021 at transmission. Alternatives include introducing new registration items including a residual banding reference, together with the relevant consumption and capacity information.

It is assumed that there will need to be only a single charging band for sites that are directly connected to the transmission system as per the decision and direction from the Authority, however, it is likely that alternative solutions will be brought forward where multiple bands are introduced for these sites.

5 Calculation of Residual Charges

This is a well-defined area of reform with minimal room for ambiguity. Options which diverge from current treatment of IDNOs and other non-DNO connected customers are out of scope of the TCR.

4.5 Delivery Approach

4.5.1 DCUSA Modifications

Table 3 sets out the assumed DCUSA modification packages which will deliver all areas of scope listed in section 4.2.

In order to fairly distribute the workload, each modification package has been assigned to a single DNO to lead on, with support from those DNOs without a lead role. The lead organisations are responsible for drafting and raising the modification to the DCUSA panel, and to join the DCUSA working group and supporting the development of the change until it is approved by Ofgem.

These modifications will be raised as urgent change proposals, which will speed up the process by which working groups are established. The modifications will likely be classified as authority change proposals, meaning that restrictions can be placed on the timetables to be applied to each stage of the Assessment Process, the duration of the assessment process in totality, and the inability of the proposer to withdraw the modifications without the Authority's consent[34].

A joint DCUSA and CUSC working group will be established to assess and develop the second DCUSA modification package (Customers: who should pay?). Collaborating in this way, ensures the solutions are aligned and delivered in a more efficient way.

Table 3: DCUSA modification packages

DCUSA modification package	Reform areas included	Responsibility[35]
1. Determination of charging bandings	• Setting non-domestic charging bands	Raised by: ENWL Supported by: SSEN
2. Customers: who should pay?	• Final Demand • Single Site	Raised by: NPG
3. Customers: allocation to bands, and interventions	• Allocating customers to non-domestic charging bands • Process for initial allocation to LLFC by DNOs/ IDNOs • Reallocation of customers • Disputes	Raised by: WPD
4. Calculation of charges	• Residual charges • Treatment of bands with low customer numbers	Raised by: SPEN Supported by: UKPN

[34] https://www.dcusa.co.uk/wp-content/uploads/2019/08/Section-1C-v11.2.pdf
[35] Further details, and contact information, for those responsible for development the modifications can be found in Annex 1.

	• LDNOs, private networks, and complex Site arrangements	

4.5.2 CUSC Modifications

The ESO will raise modifications for the CUSC. All of the CUSC modifications will be raised as urgent, to give the ESO the best opportunity to deliver the required changes to systems. As noted above, the second modification will be run as a joint working group with DCUSA.

Table 4: CUSC modification packages

CUSC modification	Reform areas included	Status
• Transmission Demand Residual bandings and allocation (TCR)	• Site and demand inputs • Banding calculation • Residual cost apportionment • NHH locational methodology	CMP332 Raised at December panel as urgent.
• Transmission Demand Residual definitions	• Final Demand • Single Site • DCUSA, BSC inputs • Relevant CUSC definitions	To be raised in early 2020 by the ESO
• Transmission Demand Residual billing and liabilities	• Structural billing and reconciliation changes • Structural liability calculations changes • Associated definitions	To be raised in early 2020 by the ESO

4.6 Wider code changes

During the Initiation Phase, the TCR Implementation Steering Group will assess if changes are required to wider industry codes and raise modifications in similar timescales to the DCUSA and CUSC modifications. It is expected that these wider code change will include:

- BSC changes required to support the new data flows required from Elexon, it is assumed that this could be done through a change proposal;
- MRA changes may be required to align to the definition of Single Site and associated processes defined in CUSC and DCUSA; and
- Changes to the Data Transfer Catalogue (DTC, part of the MRA).

4.7 Data Changes

4.7.1 Changes required to LLFCs

LLFCs have been proposed in this PID as the method to identify the residual charging band to which a site has been allocated. This option was selected as it has the potential to be implemented without requiring significant additional works to industry wide systems or data flows.

The creation or modification of other identifiers through registration systems may also provide equivalent for improved functionality, however the delivery of the Switching Programme has effectively ruled out any modifications to these systems.

The use of LLFCs has evolved in recent years to include the identification of:

- Line Loss Correction Factors
- Tariff ID
- Voltage/point of connection (for embedded networks)

- Load Managed Areas
- Private Networks
- Other purposes

The structure of LLFCs can vary from one network operator (DNO/IDNO) to another and may also include multiple iterations of the above list for each GSP group, particularly where network operators work across different areas.

LLFCs are paired with other Market Domain details such as Profile Class (PC), Standard Settlement Configuration (SSC), Time Pattern Regime (TPR) and Meter Timeswitch Class (MTC) in a series of different arrangements known as 'valid combinations.' The management of valid combinations is controlled via the Market Domain Database (MDD) with different parties responsible for selecting different aspects of an overall combination.

Adding the identification of residual charge bands in to the LLFC adds further complexity and may introduce potential risks. These are included in the risks below. During the development of the code modifications these risks will be fully assessed, and proposals set out to mitigate them.

4.7.2 Process to change LLFCs

The following process is the assumed approach for delivering the required changes to the LLFC. These activities are reflected on the plan on a page (Figure 3**Error! Reference source not found.**).

1) Create appropriate LLFCs
   - DNOs and IDNOs to agree appropriate LLFC structures
   - Each separate company to raise MDD modifications for their respective Distributor IDs
   - **Timings:** It will take one month to confirm LLFC proposals and prepare the MDD submissions. Following this, it will take two months for submission to be enabled, assuming each application passes validation and approvals without any issues arising.
2) Move MPANs to appropriate LLFCs
   - Develop automated approach for updating LLFCs, the detailed methodology will be developed during the project
   - Test and implement process
   - **Timings:** It would take, at minimum, one month to test the script. DNOs would then transfer the MPANs to the new LLFCs by entering limited daily batches onto the Data Transfer Network (DTN).

4.8 IT and System Changes

The impacts of implementing the baseline solution on the ESO IT systems is significant, as the charging and billing system is not currently set up to work on a banded approach. An initial impact assessment from the ESO IT department concluded that the impact on the charging and billing system is very high due to the complex technical modifications being required, an outline of these are below:

- New interface or change in existing interface to bring in sites category distribution
- New complex calculations for up to 40 tariffs within the billing arrangements
- Significant change in the backing sheets outlining charges for customers
- Enhancement of existing reports to display new charges
- Change in interface between finance systems

In addition, there will be changes required to the ESO SAP finance systems. As other systems where data flows will change as a result of the demand residual changes.

The ESO expect that 12 months will be required to deliver the changes outlined above, however it will also need a period of testing to ensure that data flows between organisations work.

It is not anticipated that similar issues will apply to DNO billing systems and therefore this plan is based on the assumption that minimal changes will be required as a result of implementation of the proposed baseline approach. However, DNO processes/tools will be impacted in relation to the allocation of LLFCs to facilitate the bulk transfer of customers to new LLFCs. The current working assumption is that this will be resolved in a timely manner to facilitate implementation in April 2021 for transmission. Any change to this position will be flagged immediately, together with any mitigating actions.

4.9 Indicative timelines

The timeline to which the working group(s) is/are expected to work towards is set out in **Error! Reference source not found.**, and supported by a list of milestones (see **Error! Reference source not found.**). Achieving these milestones is heavily reliant on well-developed proposals being thoroughly considered by the working group(s) as soon as possible, building on this detailed plan, and largely subject to the risks and mitigation actions highlighted in this plan (see 4.11).

4.10 Key Milestones

Table 5: Key milestones in the delivery of the demand charge residual changes

Milestone	Due date	Responsibility
All modifications raised	January 2020	DNOs and ESO
DNOs receive EAC data from NHH Data Aggregators	4 February 2020	NHHDAs – following a request from DNOs
DNOs and Elexon provide ESO with banding data	February 2020	DNOs
Working groups complete development of modifications and submit to Ofgem	May 2020	DNOs and ESO
ESO to produce preliminary cut of bands	April 2020	ESO
CUSC and DCUSA modifications approved by Ofgem	June 2020	Ofgem
Designated party set final bands	July 2020	ESO
TNUoS go-live	April 2021	ESO
DUoS go-live	April 2022	DNOs

The plan (Figure 3) outlines how a 2021 implementation date for transmission and 2022 date for distribution could be met. As highlighted in the Risk table below (see Table 7), this plan has no contingency and has significant risks associated with it. If there is any slippage in the plan, resulting in a delay to key milestones, there will be a significant knock-on impact on the transmission implementation date. This is due to the complexity of the programme and inter-related nature of the component parts across transmission and distribution, including ESO system changes and the necessity to avoid mid-year tariff changes. In this instance the plan would most likely adopt a change that aligns the delivery of the transmission and distribution changes by 1 April 2022, as shown in Figure 4.

Figure 3: Plan on a page for delivery of the demand charge residual changes

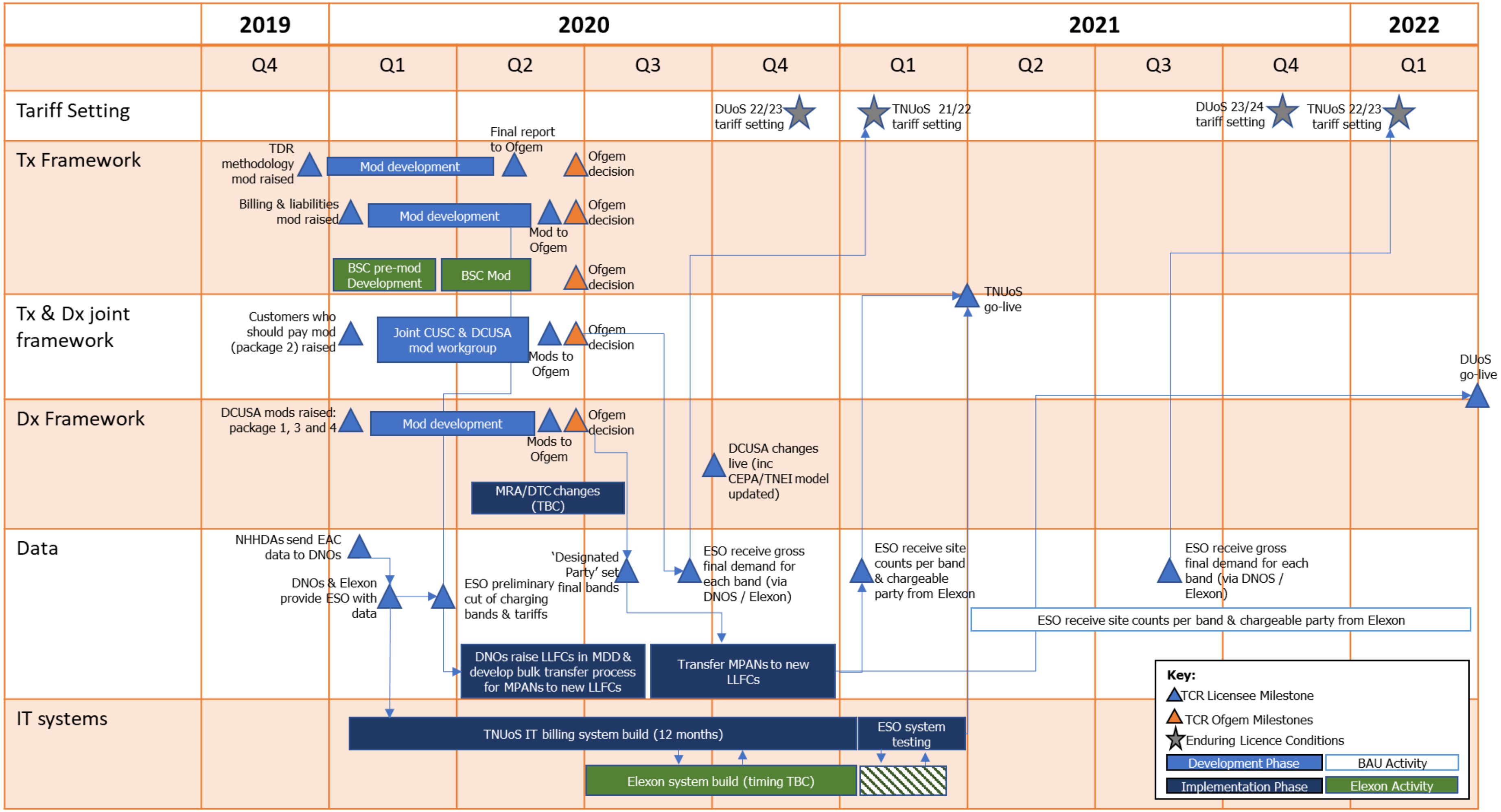
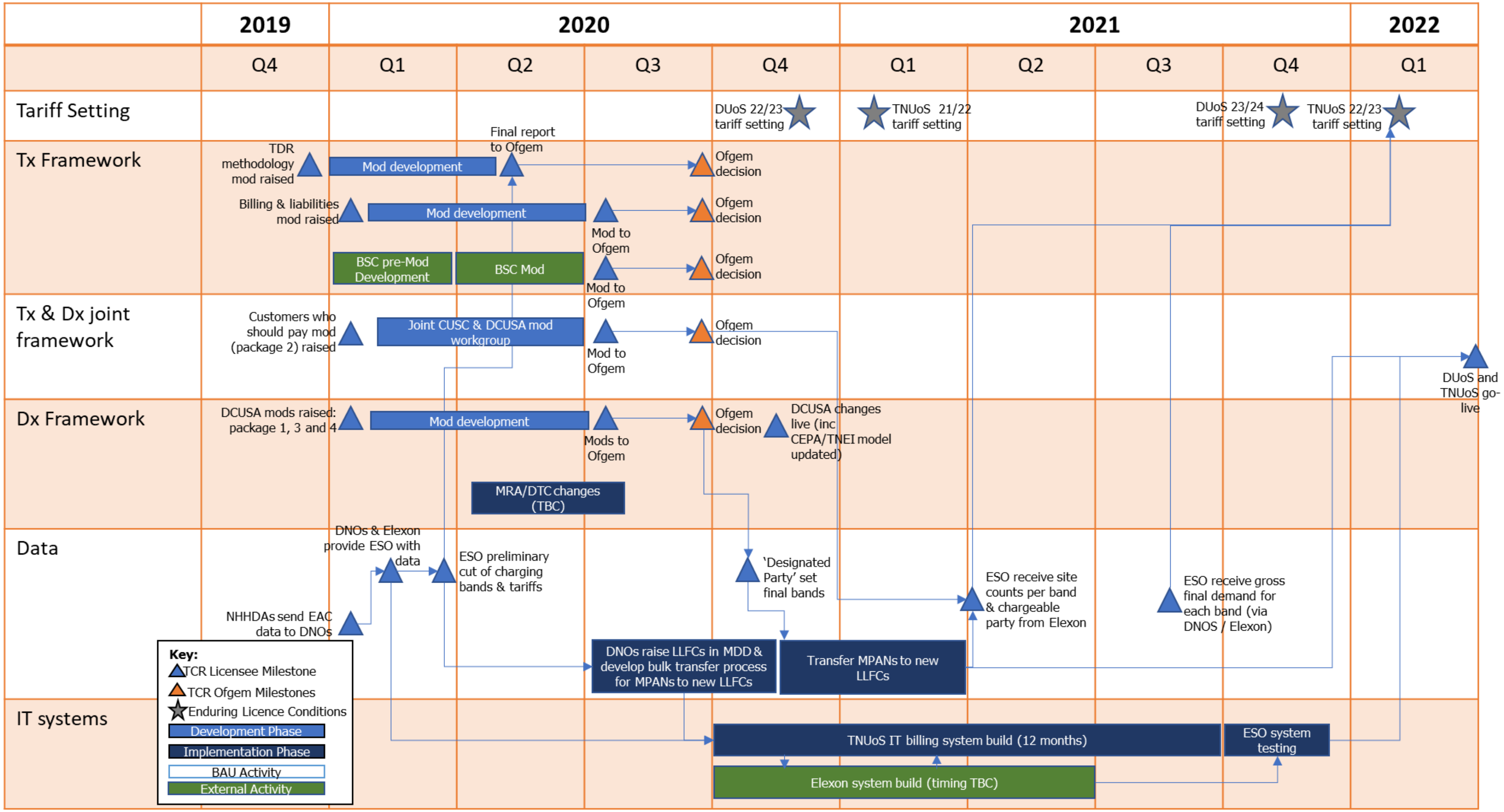


Figure 4: Plan showing delivery of both the transmission and distribution changes by 1 April 2022



4.11 Risks, Assumptions and Dependencies

The following Assumptions, Risks and Dependencies have been identified in relation to the delivery of the scope within the timeframes set out above.

4.11.1 Workstream 1 Assumptions

Table 6: Assumptions within the plan for delivery of the demand charge residual

ID	Assumption Description	Impact Area
A01	The timeline is based on the implementation of the baseline solution as defined in section 4.4 and assumes no changes will be made to this solution within the open governance process which create additional impacts on existing systems	Planning, Scope
A02	The modifications to DCUSA and CUSC can be raised without the licensees receiving formal feedback or approval from Ofgem on the baseline solution or the PID.	Planning
A03	All DCUSA and CUSC working groups will have sufficient membership to be quorate and hold the first meeting within two weeks of the approval being accepted by the respective panel.	Planning
A04	Inflight DCUSA and CUSC modifications, that have not been approved by Ofgem, will not be considered as part of the TCR modification scope or planned for within the baseline solution.	Scope
A05	DNOs can provide the required data for the determination of charging bands to the ESO/designated party, to the timescales set out in the plan.	Planning, Data
A06	For the proposes of setting the bands, DNOs will request disaggregated NHH data from suppliers/NHHDA at least 20 working days prior to 1st February 2020, and the report is received in the week commencing 3 February 2020.	Planning, Data
A07	The determination of the indicative banding boundaries will be undertaken by the ESO.	Roles and Responsibilities
A08	Ofgem approval is not required on the determination of the indicative banding boundaries.	Planning
A09	DNOs together will have sufficient capacity to provide a minimum of two representatives to support the development of the DCUSA modifications.	Resourcing
A10	The implementation of the baseline solution will require no significant change to DNO systems and is therefore not on the critical path of the plan. The only changes required will be those to DNOs billing systems to recognise the revised tariff structure and to facilitate the transfer and allocation of new LLFCs in bulk.	Planning, Scope
A11	MPRS update of LLFCs could be undertaken as required and as scheduled in the plan, and will not be impacted by the moratorium on changes by the Switching Programme.	Planning, Data
A12	The design of the system changes to the LLFCs will be flexible and could accommodate additional banding in future to remove need for expensive changes.	Scope
A13	The process to define and implement changes to LLFC in MDD takes three months	Planning
A14	The process to update MPRS with the LLFCs will take 6 months, based on limited bulk transferred per DNO per day and overall DTN capability.	Planning

A15	The TNUoS IT billing system build, test and go-live will take 12 months.	Planning
A16	Ofgem will review and approve each modification within the timeframes set out in the plan and will approve the modifications on first review, without rework being required.	Planning
A17	The DCUSA panel and the CUSC panel will approve the modifications being raised as urgent change proposals	Planning
A18	That relevant data for directly connected transmission sites can be provided to the ESO or calculated from current data sets.	Planning, Data

4.11.2 Workstream 1 Dependencies

The key dependencies between the project activities have been identified and mapped onto the plan on a page (Figure 3). Delays to any inbound dependencies will have an impact on future activity in the plan. Where any milestone changes the plan will be updated to understand the impact of the change on all dependent activity within the plan. A potential outcome of a delay is a change to the key milestones detailed in Table 5. Any changes that are likely to cause a change to a project milestone will be reported to the Ofgem Project Team, the CDB and the ERG. Workstream 1 Risks.

Table 7: Risks relating to delivery of the demand charge residual changes

ID	Risk Description	Potential Impact	L[36]	S[37]	Mitigation
R01	**Timescales –** As there is no contingency or slack in the plan there is a risk that if one activity is delayed, the implementation deadlines will not be hit.	• Licensees fail to meet obligations set out in the TCR Direction. • Reputational damage for Licensees.	H	H	• Regular engagement between licensees and Ofgem to ensure that Ofgem have a thorough understanding of the changes being proposed and of the dependencies on Ofgem. • Run activities in parallel, such as starting the ESO and Elexon IT changes prior to formal decision on the modifications. • Formal change control, such that any changes to the scope are assessed for their impact on the plan. • The Authority may need to consent to DNO (and LDNOs) not providing the periods of notice described in clause 19.1A of the DCUSA (15 and 14 months' respectively for DNOs and LDNOs).
R02	**Scope –** Due to the fact that the plan is based on an assumed baseline solution, there is a risk that the working groups and/or Ofgem decide to proceed with a different solution that takes longer and/or is more complicated to implement than the assumed scenario.	• Delay to the implementation of the changes, potentially beyond the dates set out in the TCR Directions. • Additional system and data changes that have not been included within the scope of this PID. • Large cost impacts which have not been accounted for by DNOs.	H	H	• Ofgem review the proposed baseline solution within the first week of January 2020 and provide early feedback. • Raise the modifications as urgent and as Authority change proposals. • Engage suppliers early in 2020 to ensure they understand the rational for solution presented.

[36] Likelihood
[37] Severity

		• Increased resource requirements from Licensees.			
R03	**ESO IT system changes -** Due to the fact that the build of the ESO IT systems has to commence in advance of Ofgem's approval of the modifications (to meet the 1 April 2021 date), there is a risk that the build of the IT system will not support the final approved modifications.	• Delay to the completion of the ESO IT system changes, resulting in a delay to the implementation dates of the transmission changes. • Wasted time and cost on developing an IT system that is not fit for purpose.	H	M	• Prioritisation of code modifications to ensure areas which will determine the scope of the ESO system changes are progressed efficiently, and locked down first. • This may require amendments to the scope of inflight TCR modifications. • ESO engagement in all DCUSA modifications. • Ofgem change the transmission implementation date to 1 April 2022, in line with distribution.
R04	**Ofgem engagement -** Due to the areas of uncertainty which working groups must develop (e.g. defining a 'Single Site'), there is a risk that Ofgem will not approve the modifications on first review, or will require rework and changes that are not planned for.	• This will cause a delay to the setting of the final bands, and the subsequent transfer of sites to final LLFCs, resulting in a delay to the go-live of the transmission changes beyond the 1 April 2021 date. • Increases period that the ESO IT build is working at risk. • Unnecessary rework, where problems could be identified early in the project.	M	M	• Regular engagement between licensees and Ofgem to ensure that Ofgem have a thorough understanding of the changes being proposed. • Ofgem to actively engage as part of the working groups, primarily to highlight a need to change direction.
R05	**Data, allocating customers to bands -** Due to the fact that the DNOs and ESO do not currently have access to sufficient data to allocate all non-domestic customers to bands there is a risk that as the process to be used is not properly tried and tested, that there will be delays in establishing the regular provision of the data, and that the data may not be fit for purpose without significant further processing by DNOs/LDNOs before it is usable (including by the designated party that will determine the banding boundaries).	• Without the data the licensees will not be able to successfully implement the TCR Decision. • Additional data processing will be required to collate the data which would likely require changes to data flows and systems which could delay the implementation of the changes by the dates set out in the TCR Directions.	H	H	• Use EAC data via BSCP505 to set the charging boundaries and allocate customers to bands (remove requirement for 24 month historical data for these customers). • Alternatively, a third party could provide the data to DNOs / ESO, but this presents its own risks. • Engage with Elexon early in the project to understand the process for collating EAC data via BSCP505. • May require intervention from Ofgem to use powers under the 'Duty to Cooperate' licence conditions. • Set preliminary bands using data available, without requiring full data set of all customers.
R06	**Data, setting GB-wide bands -** DNOs do not have access to other DNO information, and due to needing GB wide bands and to avoid confidentiality issues there is a risk that a third party is required to be appointed to process the data.	• A third party processing all DNO data could come at additional and as yet unknown cost, but it would alleviate data confidentiality concerns. • Delay to the production of the first cut of the charging bands as DNOs would have to	M	L	• Progress on the assumption that the ESO will undertake the mapping for the purpose of setting the indicative banding. • Raising a code modification to detail the specific process for setting the GB wide bands, including the responsible owner.

		procure a third party to undertake the assessment.			
R07	**Data, setting GB wide bands -** The setting (and reviewing) of GB-wide bands will impact both transmission and distribution, therefore a lack of consistency between the DCUSA and CUSC is a risk depending on how and when modifications are developed.	• The basis on which the residual charging bands are determined differs between transmission and distribution. This could include who does it; the data used to derive the bands; and timelines (in particular as DNOs need to provide 15 months' notice of changes to use of system charges).	M	M	• Raising a separate DCUSA modification to establish this process, in a timeline compatible with CUSC changes, will serve to ensure a consistent approach can be implemented. • DNOs to be involved in discussions as part of the wider CUSC change (CMP332) on demand residual charges.
R08	**Data, defining a mechanism to determine a 'Final Demand Site' -** Determining whether or not a customer should face a residual fixed charge is open to interpretation and so there is a risk that this modification is more complex than anticipated to develop.	• Being open to interpretation risks delaying the development of the modification, in particular as defining these terms/process risks introducing opportunities for gaming and therefore manifesting as the problem the TCR sought to remedy in the first place (i.e. people avoiding costs and others unfairly picking up the difference). • It also risks the development of multiple alternative proposals, or simply one which the Authority is unlikely to accept.	M	M	• Raising modifications for CUSC and DCUSA in the same timescales, which will be run together as a joint workgroup to ensure a consistent approach. • Active engagement from Ofgem throughout the working group phase.
R09	**Data, minimum number of customers per band -** Determining an appropriate solution should the distribution of customers result in a very low number in any given band is open to interpretation and so there is a risk that this modification is more difficult to develop than anticipated and/or that regional banding is required for DNOs.	• Regional DNO bands at any voltage level risks introducing a different banding between distribution and transmission. • Being open to interpretation risks delaying the development of the modification. • It also risks the development of multiple alternative proposals, or simply one which the Authority is unlikely to accept.	M	M	• Develop modifications based on assumption that transmission and distribution will use GB wide bands. • DNOs and the ESO to be involved in the relevant discussions as part of the CUSC and DCUSA working groups respectively.
R10	**Reallocation of customers to a different band -** Determining an appropriate intervention should there (e.g.) be a change of circumstances at a Site is open to interpretation and so there is a risk that this modification is more difficult to develop than anticipated.	• Being open to interpretation risks delaying the development of the modification. • It also risks the development of multiple alternative proposals, or simply one which the Authority is unlikely to accept.			• Active engagement from Ofgem throughout the working group phase should prevent inefficient use of resource.
R11	**Dispute process -** Determining a process for customers to challenge their residual charge is open to interpretation.	• Being open to interpretation risks delaying the development of the modification. • It also risks the development of multiple alternative	M	M	• Active engagement from Ofgem throughout the working group phase should prevent inefficient use of resource.

		proposals, or simply one which the Authority is unlikely to accept.			
R12	**Outstanding Authority decisions** - Industry continues to await a decision on CMP 280/281, and DNOs await updated models and legal text to use as the baseline for raising the TCR modifications.	• Approval of these modifications will result in different base position from which the TCR modifications are developed, as the legal text and models discharging the methodologies will be different. • It may take a month from approval before DNOs are in receipt of revised legal text and models (therefore expected mid-January 2020 at the latest). • Implementation on 1 April 2021 requires DNOs to republish 2021/22 use of system charges and/or request derogations from the Authority (e.g. to potentially leave charges published in December 2019 unchanged and just add the new tariffs). • This risks further delays in the development of the TCR code modifications.	M	H	• The Authority should be very clear of its intention to approve or not these modifications, and do so in a timely manner.
R13	**Resourcing -** DNO and ESO expertise is limited and is currently being stretched due to a number of competing Ofgem priorities, including the SCRs (e.g. TCR, Access, Switching Programme, HH Settlement and code reform), ED2 and other DCUSA modifications (there also remains a potential need to republish 2020/21 use of system charges[38]) creating a risk that there is not enough specialist resource to support the TCR to the level set out in this PID.	• Delay to the drafting and submission of the modifications. • Insufficient resource to support the working groups, and therefore failure for groups to reach quorum. • Prioritisation of resource onto TCR could result in a reduction in people deployed onto the Access and Forward-Looking Charges SCR causing delays and slippage or a loss in quality of outputs.	H	H	• Early visibility of what is on the horizon and pragmatic solutions where possible will ensure the DNOs can plan ahead and deliver within the limited pool of expert resource • Efficient decision making by Ofgem, particularly where outstanding decisions remain in other projects that are impacting on DNO resource • Integrated planning by Ofgem, such that delays in one project are assessed for their impact on resourcing as a whole, across all the activities that require ESO and DNO support.
R14	**Ofgem engagement –** As the code modifications will be drafted in January there is a risk that Ofgem will provide feedback on the PID, seeking significant changes, once the modifications have already been raised, and the build of supporting IT changes kicked-off.	• This may cause delay to the subsequent activities in the plan, and ultimately the implementation of the changes beyond the dates set out in the TCR Directions. • Rework may be required early in the process, or the modifications may need to be put on hold until Ofgem feedback is assessed and agreed.	M	M	• Ofgem review the PID early in 2020 to provide any feedback as early as possible. • Remove dependency between two activities, licensees submit modifications as planned in January and Ofgem participate in the working groups to provide input at an early stage.

[38] https://www.ofgem.gov.uk/system/files/docs/2019/08/duos_derogations_minded_to_approve_letter_v2.pdf

R15	**Legal Challenge -** There is a risk that a party or parties will individually or collectively challenge the final Authority decision.	• Any legal challenge will put at risk the deliverability for April 2021 and April 2022. • Undoing inflight changes if successful may put licences at risk of over or under recovery.	H	H	• Robust code administration activities. • Early decision making by Ofgem to allow challenge windows and action to be brought. • If legal challenge is brought then development could be paused to allow the challenge process to complete.
R16	**Data changes-** It may not be possible for all parties to implement the required banding within the LLFC structures.	• It will not be possible to implement the baseline solution; a different approach is likely to take longer to implement (e.g. adding new data entry in MPRS) as it will require more complex system changes • This may cause delay to the subsequent activities in the plan, and ultimately the implementation of the changes beyond the dates set out in the TCR Directions.	L	M	• Delay implementation date to allow other solutions to be developed.
R17	**Timescales –** Due to the fact that the code modification working groups are formed of a variety of stakeholders who are all set to be impacted by the TCR in differing ways, there is a risk that the working groups may take longer to develop and agree the change modifications than is accounted for in the plan.	• Delay to the subsequent activities in the plan, and ultimately the implementation of the changes beyond the dates set out in the TCR Directions. • Additional resource requirements from licensees to support the additional working group meetings and activities. • Increased likelihood that the solution will be substantially changed from the baseline solution presented in this PID.	M	M	• Raise the code modifications as urgent and authority change proposal such that the timeframe for the change process can be limited from the outset. • Early engagement with suppliers during the implementation phase.
R18	**System testing –** The ESO charging and billing system changes have only two months for testing the system, there is a risk that a significant problem may be found which cannot be fixed before go-live.	• The ESO charging and billing system is unable to go-live for April 2021, therefore the demand residual would need to be delayed until April 2022. • The ESO would require a derogation from its licence to re-calculate tariffs for the 2021/2 charging year under the preceding methodology and an urgent change to the CUSC to undo the changes that would have been applied.	M	H	• Test the system throughout system build. • Ideal mitigation would have longer test period at the end of the build, however this would result in an April 2022 implementation date.
R19	**Elexon system changes** – Due to the fact that the ESO IT system build is dependent on inputs from Elexon, there is a risk that the development of ESO IT systems is delayed as Elexon are unable to start system changes until the modifications are approved.	• The completion of the ESO system build & system testing will be delayed resulting in the transmission go-live in April 2021 being delayed.	M	M	• Elexon engage with Ofgem early in the process to gain assurance that work can start prior to Ofgem decision. • ESO consider using other sources of input data.
R20	**DCUSA Modification Timeline** – Due to the fact that the time in the plan to complete the DCUSA modifications is accelerated (from the timeline provided by ElectraLink) there is a	• Delay to the date that the DCUSA modifications will be sent to the Authority, resulting in slippage in the Ofgem decision and all future dependent milestones.	H	H	• Raise modifications as urgent, as early as possible in 2020. • Early stakeholder engagement in advance of the modification working groups being established.

	risk that the modification process will take longer than accounted for.	• Delays to the TNUoS go-live as this is dependent on the Ofgem decision on the 'Who should pay' modification package.			• Active engagement from Ofgem throughout the working group phase.
R21	**DNO billing system changes** –At this stage of the project, before the LLFC changes are tested, there is an assumption that no significant system/tool changes will be required by DNOs to facilitate the changes, there is therefore a risk that during the implementation of these changes issues arise that take longer to fix than accounted for in the plan.	• Delay to implementation of the TNUoS changes, which are dependent on the transfer of MPANS to new LLFCs. • Additional cost that has not been accounted for within the baseline solution.	M	H	• DNOs begin work on LLFC changes early in the project and raise any anticipated issues as early as possible.

5 Workstream 2: BSUoS Gross Charging

5.1 Introduction

Ofgem's TCR Decision, stated that charges for balancing services, more commonly referred to as BSUoS, should be levied on suppliers on a gross volume basis. The current BSUoS methodology charges suppliers on their net volume.

There are no changes directed to the BSUoS costs paid by Transmission connected generators as part of the TCR Decision, however the TCR Decision did instruct the ESO to run a second BSUoS taskforce. This BSUoS Taskforce will provide analysis and comment to support the further decisions on the future direction of BSUoS charges. The second Taskforce will examine, in particular, who should pay BSUoS and how the charge should be designed. The taskforce detail is covered on the Charging Futures website and is not covered in this PID.

For this reason, Workstream 2 can be referred to as "BSUoS Gross Charging" or "partial BSUoS reform" as there will be further work undertaken in this space after the outcome of the second Taskforce.

5.2 Scope

BSUoS charges to Suppliers to be based on Gross Volumes rather than Net Volumes

- Changes will be required to the CUSC throughout Section 14.30 *Calculation of the Daily Balancing Services Use of System Charge*. These will need to reflect that the proportion of the BM Unit Metered Volume of the total BM Unit Metered Volume for an individual supplier does not include exports in that calculation.
- Minimal change to the BSC to determine the data sharing requirements for the calculation of BSUoS.
- Some changes to ESO billing systems will be required. If it is possible for Elexon to provide volumetric data for each supplier Balancing Mechanism Unit (BMU) in each settlement period on a gross basis rather than net which they currently do today in a separate file, the system changes for ESO will be reduced.

5.3 Initial Option Assessment

To give effect to the Ofgem TCR Direction the ESO will raise a CUSC change proposal to rewrite the BSUoS methodology in Section 14.30 *Calculation of the Daily Balancing Services Use of System Charge*.

Our CUSC change proposal will include legal text which will give effect to the direction and set up the industry codes to charge Suppliers on gross volume whilst also continuing to charge Transmission generators on their net volumes.

5.4 Delivery Approach

The draft delivery approach for the industry frameworks and the taskforce are in the Indicative Timelines section below. This timeline has been developed taking into consideration the resourcing level of the Code Administrator and full consultation periods for the modification and is therefore the "worst-case" timescale. The TCR Decision acknowledges that the reforms made through the industry Code change to give effect to the aim of charging Suppliers for BSUoS on gross volumes basis may be superseded by the work of the Taskforce. The ESO have, however, made the assumption that changes as a result of the Taskforce recommendations will not be implemented before April 2021. The outcomes of the Taskforce's work will not be known until the end of June 2020 and there will be a further period of uncertainty whilst Ofgem determines the preferred direction of reform.

The ESO will begin making the changes required to the billing systems at risk to ensure that Gross volume data can be used to bill Suppliers for BSUoS whilst continuing to bill Transmission connected generators on their net volume.

The current view of the most efficient implementation route, is for Elexon to provide the ESO with a new data file, which will then require smaller scale ESO system changes (in comparison to the demand residual). To do this a change proposal (CP) or modification will be required to the BSC and Elexon will need time to create a new file. This would be required by April 2020, for the ESO to make the required system changes for April 2021.

The ESO is continuing to work to understand the scope of the changes required and have developed an IT impact assessment to fully ascertain the scale of the system change required and some indicative timescales required.

5.5 Indicative timelines

5.5.1 Timeline for changes to industry frameworks

Table 8 and Table 9 detail the timeline for the changes to industry frameworks to enable Supplier BSUoS to be charged on Gross Volumes, based on the latest possible timelines to meet 2021:

Table 8: Workstream 2 BSUoS modifications timeline

Activity	Target Date	Status
Raise BSUoS modification	11th December 2019	Complete
CUSC panel review BSUoS modification	13th December 2019	Complete
WG#1	16th January 2020	
WG#2	23rd January 2020	
Workgroup Consultation	31st January – 21st February	
WG#3	3rd March 2020	
WG#4	10th March 2020	
Workgroup Report	20th March	
Code Administrator Consultation	30th March – 20th April	
DFMR to Panel	21st April 2020	
FMR to Authority	4th May 2020	

Table 9: Workstream 2 BSC modification timeline

Activity	Target Date	Status
Consequential change to the BSC	Could be raised as early as January 2020	
Final Report to the Authority/Panel (if a CP)	May 2020	

Note: This BSC change is expected to be reasonably minor and therefore to progress through the "Change Process (CP)" route rather than the full modification route. The ESO want to mitigate the risk of leaving insufficient time for Elexon to change their own internal processes to produce the new volumes file and consequently intend to run the BSC change process alongside the CUSC modifications process.

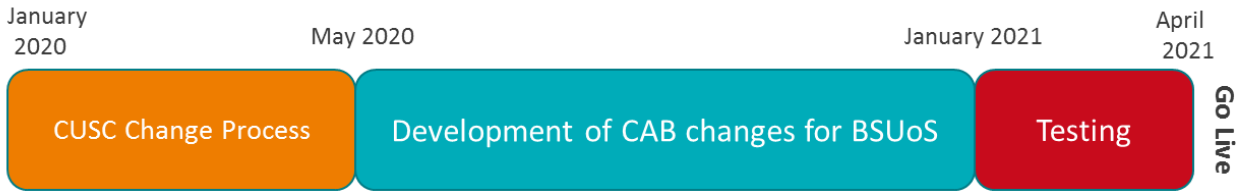
5.5.2 Timeline for system changes

Changes are likely to be required to the Charging and Billing system. An ESO IT impact assessment has been made for two options for delivery of the BSUoS related system changes:

1. Combined delivery with other TCR reforms. This will be the most cost efficient option but creates risk as the deliveries will be dependent on one another. Combined project timescales are 12 months. Delays in the CAB system changes for TNUoS would have a knock-on impact on delivery of BSUoS reforms.
2. Separate IT project to deliver the system changes required to implement BSUoS reform. This is a more expensive option but lower risk. Delivery timescales for the BSUoS only project are 8 months.

Figure 5 below shows the project timescales for the separate BSUoS project option where development starts upon the conclusion of the CUSC modification process. This is expected to be the end of April 2020.

Figure 5: Workstream 2 BSUoS Project Timescales Option



This course of action reduces the risk of rework as any potential alternatives will be known. The ESO is hopeful that an Authority decision on CMP333 will be delivered as quickly as possible to enable the IT project to proceed with confidence.

5.6 Risks, Assumptions and Dependencies

Table 10: Workstream 2 Assumptions

ID	Assumption Description	Impact Area	Date raised
A10	The BSUoS taskforce conclusions will have no impact on the TCR direction to charge suppliers based on gross volume until after 2021.	Scope, potential for rework	Dec-19
A11	Relevant data from other industry parties can be provided in a timely fashion.	Delivery timescales	Dec-19

Table 11: Workstream 2 Risks

ID	Risk Description	Potential Impact	L	S	Mitigation
R1	CAB changes for other TCR reforms	• If the whole CAB project is delayed, due to other elements of the TCR, the BSUoS changes will be delayed as well. • There is also a risk that the system may struggle with implementing various solutions in the same timescales.	H	H	• Assess the potential to run changes separately if delays in one area are impacting others.

R2	The industry workgroup for CMP333 put forward alternatives that require very different system changes and they are approved by Ofgem	• The ESO IT teams may struggle to implement development changes at a late stage which could affect the whole system change project. • If the ESO doesn't work at risk and instead wait for an Authority decision on CMP333 then the timescales to implement change will be unachievable. If the ESO does begin IT development before the CMP333 workgroup have finalised their solution(s) then there is a risk of rework and additional costs.	L	H	• Raise modifications as soon as possible.
R3	BSC Panel indicate that they would like the CP to go through the workgroup route	• The implementation date of April 2021 may be at risk	M	L	• Start the BSC change process as early as possible.
R4	Industry cannot resource the modification workgroups and Taskforce sufficiently leading to delays in the process for industry framework change.	• The timescales given above demand a lot of time from industry colleagues to make these changes quickly. The scale of change in the industry right now may mean that some parties struggle to resource every meeting. The ESO risk losing the input of segments of the industry and slowing the progress of both CMP333 and TF_II.	M	M	• ESO Code Administrator to take a whole industry look over the different changes in flight.
R5	Legal Challenge There is a risk that a party or parties will individually or collectively challenge the final Authority decision.	• Any legal challenge will put at risk the deliverability for April 2021 and April 2022. Undoing inflight changes if successful may put licences at risk of over or under recovery	H	H	• Robust code administration activities, early decision making by Ofgem to allow challenge windows and action to be brought. • If legal challenge is brought then development could be paused to allow the process to complete.

6 Workstream 3: TGR to Zero

6.1 Introduction

Ofgem's TCR Decision, stated the decision to set the Transmission Generation Residual (TGR) to £0/kW. The TGR is currently the means by which the ESO remains compliant with European Regulation 838/2010 which stipulates that generators' transmission network charges must be within the range of €0-2.50/MWh. At present the TGR is negative and was forecasted in the ESO's 2019/20 Five Year Forecast to get increasingly negative in future years[39].

The TCR Decision states in Section 1.17 that the negative TGR acts as a benefit to those who receive the credit (Transmission connected generators and embedded generators larger than 100MW). Setting the TGR to £0/kW will remove any distortion it may have been causing between generation connected at Transmission or Distribution.

From the charging year commencing in April 2021 and from then going forward the TGR needs to be set to £0/kW.

6.2 Scope

Ofgem has stated explicitly in the TCR Decision (Section 4.16) that: "Setting the TGR to zero – this will require:

- The implementation of the correct interpretation of the 'connection exclusion' for 838/2010 and
- Setting the TGR to zero"

This means that the current in-flight CUSC modification proposal (CMP317) which exists to review the transmission assets which are covered by the connection exclusion referred to above must be run concurrently with a new CUSC modification proposal (CMP327) which will set the TGR to £0/kW.

The outcome of these two modifications will determine whether further adjustment is likely to be required to ensure compliance with 838/2010. If a significant cohort of high value transmission assets is found to be excluded from the costs used to calculate compliance with the €0-2.50/MWh range then it may not be necessary to use an 'adjustment factor' to further reduce TNUoS charges faced by generators.

In the event that an adjustment factor is required the method through which this is applied will be devised during the CMP317/327 workgroups.

The "adjustment factor" would be applied during the annual tariff setting process. As more clarity is revealed around the nature of this 'adjustment factor' the ESO will be able to ascertain any process or data impacts and plan for the necessary changes.

There will, however be changes required to the ESO Charging and Billing system to implement a reconciliation process at the close of a charging year to make refunds to generator users (if required) in May and to recover the refunded amounts instead from suppliers in the following month.

6.3 Initial Option Assessment

Ofgem have indicated in their decision that generators should be charged "all applicable charges". In the solutions discussed thus far in CMP317 there have been options which exclude Generator Only Spurs (GOS) from the costs assessing compliance under 838/2010 as they meet the definition of Physical Assets Required for Connection within 838/2010.

[39] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges

Ultimately, Ofgem, as the Authority will approve whichever of the solutions the workgroup and CUSC panel return to them that they feel most appropriately meet the applicable CUSC objectives. Once the outcome of the Authority decision on both CMP317 and CMP327 is known, any further changes to ESO processes and systems will be identified and enacted.

There will also be system change requirements to enable reconciliation through the ESO's Charging and Billing system (CAB). Compliance with 838/2010 is imperative. The ESO's view is currently that it will be necessary to reconcile the amount charged to generators **after** the charging year has concluded and recover any outstanding amount from suppliers in the same timescales.

The process changes required to accommodate this reconciliation are:

- Calculate the €/MWh out-turn by using:
  - total generation TNUoS revenue for the charging year
  - daily €/£ exchange rate
  - total MWh generation for the charging year, weighted by the daily exchange rate
- Adjust each generation TNUoS invoice to bring total recovery back in to permitted range
- Adjust the amount charged to electricity suppliers, at the annual initial demand reconciliation in June, by an amount inverse to the adjustment to generation billing
- Amend backing sheets for both electricity suppliers and generators to include details of the adjustment amount
- Create additional line item(s) in the invoice for adjustment amount
- Reporting throughout the year to provide year to date €/MWh out-turn.

The additional data required to perform the above adjustment is the published Bank of England daily exchange rate data, and the permitted €/MWh range (required once per year). The existing SAAI014 settlement metering file provides the generation volumes and is thought to be adequate.

These will be changes to the ESO business processes and the CAB system to accommodate the new reconciliation process.

6.4 Delivery Approach

The draft delivery approach for the industry frameworks is in the Indicative Timelines section below. This timeline has been developed taking into consideration the resourcing level of the Code Administrator and full consultation periods for the modification and is therefore the "worst-case" timescale.

6.5 Indicative timelines

6.5.1 Timelines for framework changes to enable TGR set to £0

Table 12: Workstream 3 timetable for framework changes

Activity	Target Date	Status
Raise TGR modification	27th November 2019	Complete
CUSC panel review TGR modification and determine priority	29th November 2019	Complete
WG#1	15th January 2020	
WG#2	22nd January 2020	
WG#3	3rd February 2020	
Workgroup Consultation	17th February – 9th March	
WG#4	17th March 2020	
WG#5	25th March 2020	

WG#6	31st March 2020	
Report	17th April	
Code Administrator Consultation	28th April – 19th May	
DFMR	22nd May 2020	
CUSC Panel	29th May 2020	
FMR to Authority	8th June 2020	

6.5.2 Timelines for system changes to enable TGR set to £0

The timelines for the system change required to CAB will be the same as that for TDR reform (see workstream 1). The change is of a smaller scale to enable TGR to £0 but as the changes are in the same area it is most efficient to have a combined project to deliver both changes for April 2021.

The ESO note that due to the high risk to the demand residual element of the project, they will be working on whether an offline process can be in place to support any required "adjustment" if charges are outside of the €0-2.50 range in April 2021, therefore limiting dependence on the CAB system.

6.6 Risks, Assumptions and Dependencies

Table 13: Workstream 3 Risks

ID	Risk Description	Potential Impact	L	S	Mitigation
R1	CAB changes for other TCR reforms	• If the whole CAB project is delayed, due to other elements of the TCR, the TGR changes will be delayed as well. • There is also a risk that the system may struggle with implementing various solutions in the same timescales.	H	M	• Assess the potential to run changes separately if delays in one area are impacting others. • Develop offline process if required.
R2	The industry workgroup for CMP327/17 put forward alternatives that require very different system changes and they are approved by Ofgem	• The ESO IT teams may struggle to implement development changes at a late stage which could affect the whole system change project. • If the ESO doesn't work at risk and instead wait for an Authority decision on CMP317/27 then the timescales to implement change will be very tight. If the ESO does begin IT development before the CMP317/27 workgroup have finalised their solution(s) then there is a risk of rework and additional costs.	M	M	• Develop offline process if required.
R3	Industry cannot sufficiently resource the modification workgroups leading to delays in the process for industry framework change.	• The timescales given above demand a lot of time from industry colleagues to make these changes quickly. The scale of change in the industry right now may mean that some parties struggle to resource every meeting. The ESO risk losing the input of segments of the industry and slowing the progress.	M	M	• ESO Code Administrator to take a whole industry look over the different changes in flight.

R4	**Legal Challenge** There is a risk that a party or parties will individually or collectively challenge the final Authority decision.	• Any legal challenge will put at risk the deliverability for April 2021 and April 2022. Undoing inflight changes if successful may put licences at risk of over or under recovery	H	H	• Robust code administration activities, early decision making by Ofgem to allow challenge windows and action to be brought. • If legal challenge is brought then development could be paused to allow the process to complete.
R5	**Likelihood of Reconciliation** Due to the economic situation of GB vs the EU becoming more volatile as the final Brexit outcomes are known tariff setting may carry more inherent risk.	• There is a greater likelihood of having to reconcile offline without a system solution in place (if charging and billing system changes for TCR are not in place for 2021).	L	H	• Robust tariff setting processes. • Continued usage of an error margin. • Early sight of likely inputs (i.e. TO revenues) to the charging models.

Annex 1: Key Contacts

The tables below are accurate at the time of writing but are subject to change.

TCR Implementation Steering Group

Licensee	Representative	Alternate
ENWL	Tony McEntee	Chris Barker
NPG	Lee Wells	Kara Burke
SPEN	Claire Campbell	Kathryn Evans
SSEN	Nigel Bessant	Donald Preston
UKPN	Chris Ong	Ross Thompson
WPD	Simon Yeo	Dave Wornell
ESO	Grahame Neale	Eleanor Horn
IDNO	Mike Harding	Alex Travell

DCUSA Modifications:

DCUSA Modification Package	Role	Licensee	Contact Details
Determination of banding boundaries	Lead	ENWL	Tony.McEntee@enwl.co.uk
	Support	SSEN	nigel.bessant@sse.com
Customers: who should pay?	Lead	NPG	Lee.Wells@northernpowergrid.com
Customers: allocation to bands, and interventions	Lead	WPD	syeo@westernpower.co.uk
	Support	WPD	dwornell@westernpower.co.uk
Calculation of charges	Lead	SPEN	Claire.Campbell@spenergynetworks.co.uk
	Support	UKPN	chris.ong@ukpowernetworks.co.uk

CUSC Modifications:

CUSC modification	Name	Contact Details
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