Distributed ReStart

Distribution Restoration future commercial structure and industry codes recommendations

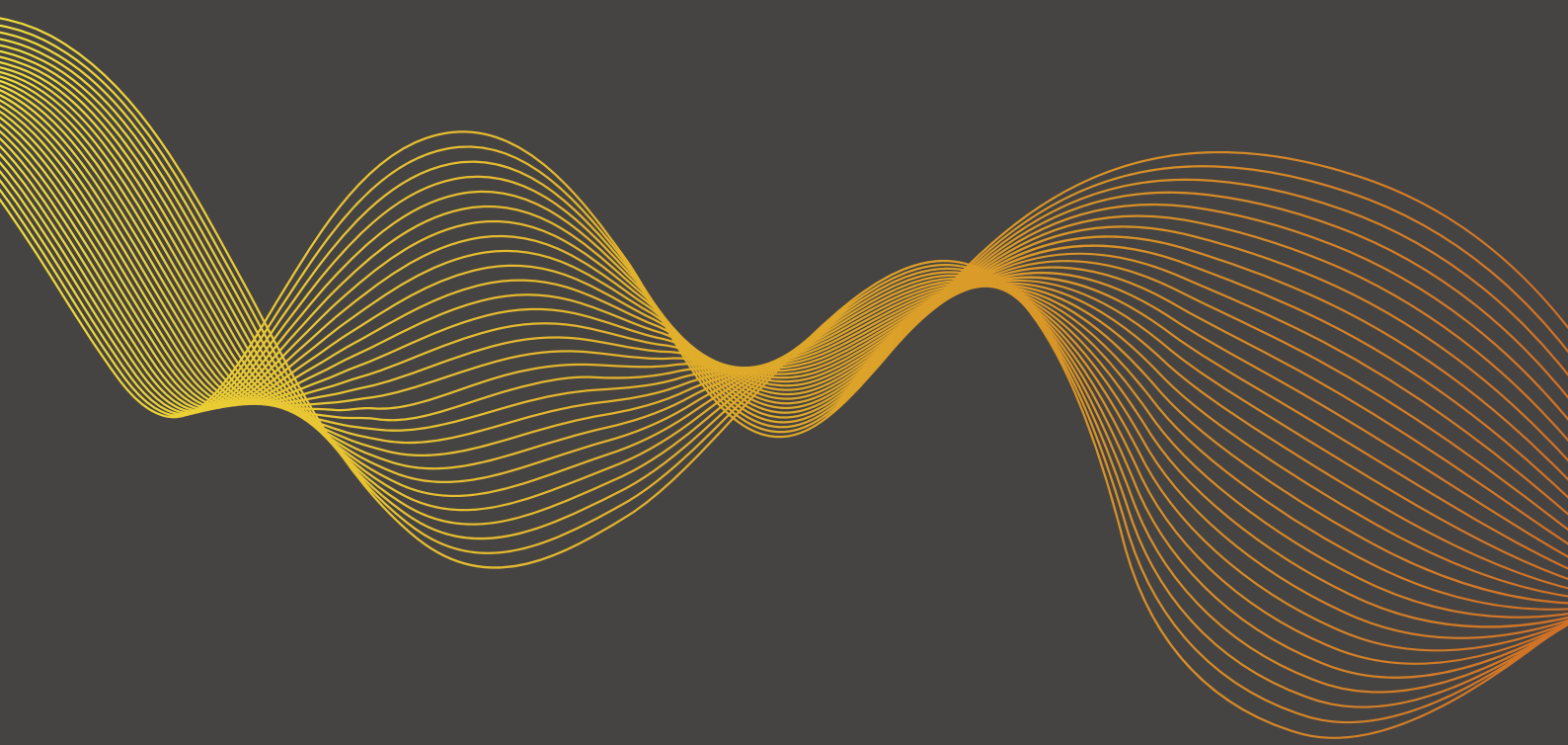
Procurement and Compliance workstream 20 December 2021

In partnership with:

tnei

SP ENERGY NETWORKS

nationalgridESO



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Distributed ReStart

The Distributed ReStart project is a partnership between National Grid Electricity System Operator (NGESO), SP Energy Networks (SPEN) and TNEI (a specialist energy consultancy) that has been awarded £10.3 million of Network Innovation Competition (NIC) funding.

The project is exploring how distributed energy resources (DERs) can be used to restore power in the highly unlikely event of a total or partial shutdown of the National Electricity Transmission System (NETS). Past and current approaches rely on large power stations, but as the UK moves to cleaner and more decentralised energy, new options must be developed. The enormous growth in DERs presents an opportunity to develop a radically different approach to system restoration. Greater diversity in Black Start provision will improve resilience and increase competition, leading to reductions in both cost and carbon emissions. However, there are significant technical, organisational and commercial challenges to address.

The project is tackling these challenges (Jan 2019–June 2022) and aims to develop and demonstrate new approaches, with initial procurement of Black Start service from DERs as part of the next tender round, which commences around April 2022 (with service commencement around 2025 onwards), if deemed feasible and cost-effective. Case studies on the SP Distribution (SPD) and SP Manweb (SPM) networks will be used to explore options then design and test solutions through a combination of detailed off-line analysis, stakeholder engagement and industry consultation, desktop exercises, and real-life trials of the re-energisation process.

Project Description

The project is made up of five workstreams. The Project Direction and Knowledge Dissemination workstreams cover the effective management of the project and ensure stakeholders are considered and communicated with throughout all project deliverables. The other three workstreams cover the wide range of issues to enable Black Start services from DERs:

- The Organisational, Systems and Telecoms (OST) workstream is considering the DER-based restoration process in terms of the different roles, responsibilities and relationships needed across the industry to implement at scale. It is developing requirements for information systems and telecommunications, recognising the need for resilience and the challenges of coordinating Black Start across a large number of parties. Proposed processes and working methods will be created and refined and consulted upon with various stakeholders.
- The Power Engineering and Trials (PET) workstream is concerned with assessing the capability of GB distribution networks and installed DERs to deliver an effective restoration service. It will identify the functional requirements that should apply on an enduring basis. This will be done through detailed analysis of the case studies and progression through multiple stages of review. It will be tested through demonstration of the Black Start from DERs concept in 'live trials' on SPEN networks.
- The Procurement and Compliance (P&C) workstream is addressing the best way to deliver the concept for customers. It explores the options and trade-offs between competitive procurement solutions and mandated elements. It uses a strategic process to develop fit-for-purpose commercial solutions that are open and transparent, stakeholder endorsed and designed end-to-end with the commercial objectives of the project and workstream in mind. It will feed into business as-usual activities to make changes as necessary in codes and regulations.

Keep up to date and find all other project reports here: **nationalgrideso.com/future-energy/projects/distributed-restart/key-documents**

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Executive summary

This report is the third and final deliverable from the Procurement and Compliance (P&C) workstream and should be read in conjunction with and following on from the first two reports – 'Functional Requirements for Procurement & Compliance (FRPC)' and 'A high-level outline of commercial and regulatory arrangements (OCRA)'. It provides the detail and engagement behind the final P&C process designs, what needs to be considered for the transition of Distributed ReStart into business as usual, and the detail behind the code change requirements.

Strategic process

Throughout the three years of developing the Distributed ReStart project's Procurement and Compliance designs, this workstream has used a strategy development process to provide a mechanism and rigour for the required commercial solutions, once all the inputs needed are available. In this final 'Refine' stage of the project, an iteration of this strategic process has been undertaken and as a result, it has been possible to propose final options for the procurement and commercial structures.

Progress at the beginning of 2021

Procurement and commercial designs

The strategy development process was iterated using inputs from the PET and OST workstreams, along with industry feedback. A set of commercial objectives for the service were agreed:

Accelerated restoration times

- Functional route to market for new service.

Financial value to the end consumer

- Increased transparency
- Increased competition
- Reduced barriers to entry.

These were used to inform the designs of proposed procurement approaches. Three procurement approaches were developed with Approach Two recommended to move forward for further development, following stakeholder feedback.

Approach Two enables contracting for each of the required services for a DRZ individually, as necessary, with the parties who provide the best value proposition. It provides the most flexibility for the procuring entity on the specific design of the service, and it also offers the lowest barriers to entry for potential providers.

Codes

A detailed review of industry codes has been undertaken, highlighting that the key codes requiring change were the Grid Code and Distribution Code. Interdependency mapping between the different industry codes was also completed and highlighted the required areas of change across all the industry codes.

Developments in 2021

This year, the focus has been on the development of the proposed end-to-end procurement process which indicates at a high level the roles for Ofgem, NGESO, distribution network operators (DNOs), the lead procurement agent and distributed energy resources (DERs) service providers – both as anchor generator (AG) and top-up service (TUS) providers. As part of this work, the P&C workstream has engaged with various stakeholders to review options and come out with recommendations for:

- The lead procurement agent
- Contracting
- Settlement and funding.

Working closely with the other workstreams, the functional requirements for a distribution restoration service, and the 'rules of play' to help govern the development of distribution restoration zones (DRZs), were also set up. These requirements are still being tested through the other workstreams; any future changes, if required, will be updated by project closure in mid-2022. To future-proof the Distribution Restoration service, the P&C workstream have coordinated the drafting of potential codes changes through a project codes working group of code specialists across NGESO, SPEN, TNEI, the **Energy Networks Association (ENA)** and **Cornwall Insight**.

Stakeholder engagement

Throughout the development of these specifications, the P&C workstream have actively engaged with various stakeholders ranging from a variety of DER providers, aggregators, BEIS, Ofgem and the DNOs via the Open Networks project (ENA), to examine the options and agree the best solution to take forward.
This has been done through:

- P&C progress updates through the Distributed ReStart 'The Live Trials Stage' Podcast

- stakeholder webinars – one for updating DER providers on progress, and two more as part of the P&C Test Procurement Event
- a Test Procurement Event over the summer
- presenting at various industry forums including: NGESO Incentives meeting with Ofgem, ENA's Commercial Operations Group, ENA's Flexibility Services workstream 1A and NGESO's Whole Electricity System Joint Forum
- regular monthly meetings with Ofgem and BEIS through NGESO's Restoration team's tripartite sessions
- bi-lateral meetings with DER providers and DNOs
- regular checkpoint meetings with other teams developing similar DER-based services such as the Regional Development Programmes (RDPs), Power Potential, Resilience as a Service (RaaS)
- conferring on legal matters with contract experts in Shakespeare Martineau and the NGESO's Legal Team, liaising with the NGESO's DSO team
- seeking advice on regulatory matters from RIIO price control leads within SPEN, NGESO and Ofgem through various meetings.

P&C final proposals

Following extensive stakeholder engagement, the P&C workstream has produced a set of final recommendations and service designs, which were approved by the Distributed ReStart Project's Steering Committee. The final proposals are as below.

1. The end-to-end procurement process is the primary deliverable for this report, and following stakeholder input, the AG and TUS processes have been aligned as part of the service designs.
2. As part of the discussions on the proposed procurement process, the lead procurement agent has been agreed to be NGESO until a point in time (probably around 2026), when a review of the process should be held. At this stage, depending on the outcomes of other industry-wide initiatives and following direction from Ofgem, the process can be evolved accordingly.
3. For the settlement and funding aspect of the process, NGESO will cover DER contract costs through its price control and the DNOs should recuperate their network upgrade and automation system costs through their own price control. Ofgem have clarified that provisions in **NGESO RIIO-2** and **DNO ED2** plans can be made as required, especially for any initiatives supporting net zero ambitions.
4. To supplement the changes in codes and to capture roles and obligations effectively, a tripartite contract is recommended which will use the **Standard Agreement produced by the Open Network's WS1A** as the boiler plate detail that underpins the contract. The draft contract that has been developed fulfils the final requirement* from this workstream for the required deliverables of the Distributed ReStart Network Innovation Competition (NIC) project.

*Generic standard terms of contract by which a service for Black Start could be procured reflecting industry engagement. These will include the contracted obligations on each party required in the delivery of the service and the necessary commercial arrangements.

Codes

Following the detailed review of the industry codes completed in the OCRA report, the codes work has progressed to developing legal text draft changes and solutions to enable Distribution Restoration.

Draft legal text has been developed for the Grid Code, Distribution Code and the System Operator Transmission Owner Code (STC). The proposed legal text changes for the Grid Code and Distribution Code will be progressed via the code modification GC0148 Implementation of EU Emergency and Restoration Code Phase II, while Distribution Restoration continues to remain within the scope of the terms of reference for GC0148. The STC legal text changes will be progressed via a code modification for Distribution Restoration, which will be raised early 2022.

A more detailed review of the commercial codes has also been undertaken and solutions proposed to enable Distribution Restoration. The key codes considered are the Connection and Use of System Code (CUSC), Balancing and Settlement Code (BSC) and the Distribution Connection and Use of System Agreement (DCUSA). These changes will be progressed via code modifications and issue groups during late 2021/early 2022 for implementation by 2022/2023.

A summary list of the key discussions that have been held during 2021 to agree the required changes to the codes are as below:

- How to deal with non-CUSC parties participating in restoration services.
- How to capture Distribution Restoration service providers and their obligations in the Grid Code and Distribution Code via the definitions and legal text drafting.
- How to deal with DER providers and fuel compensation payments within the BSC.
- The impacts on the DCUSA with potential increased DNO spending due to a new Distribution Restoration service.

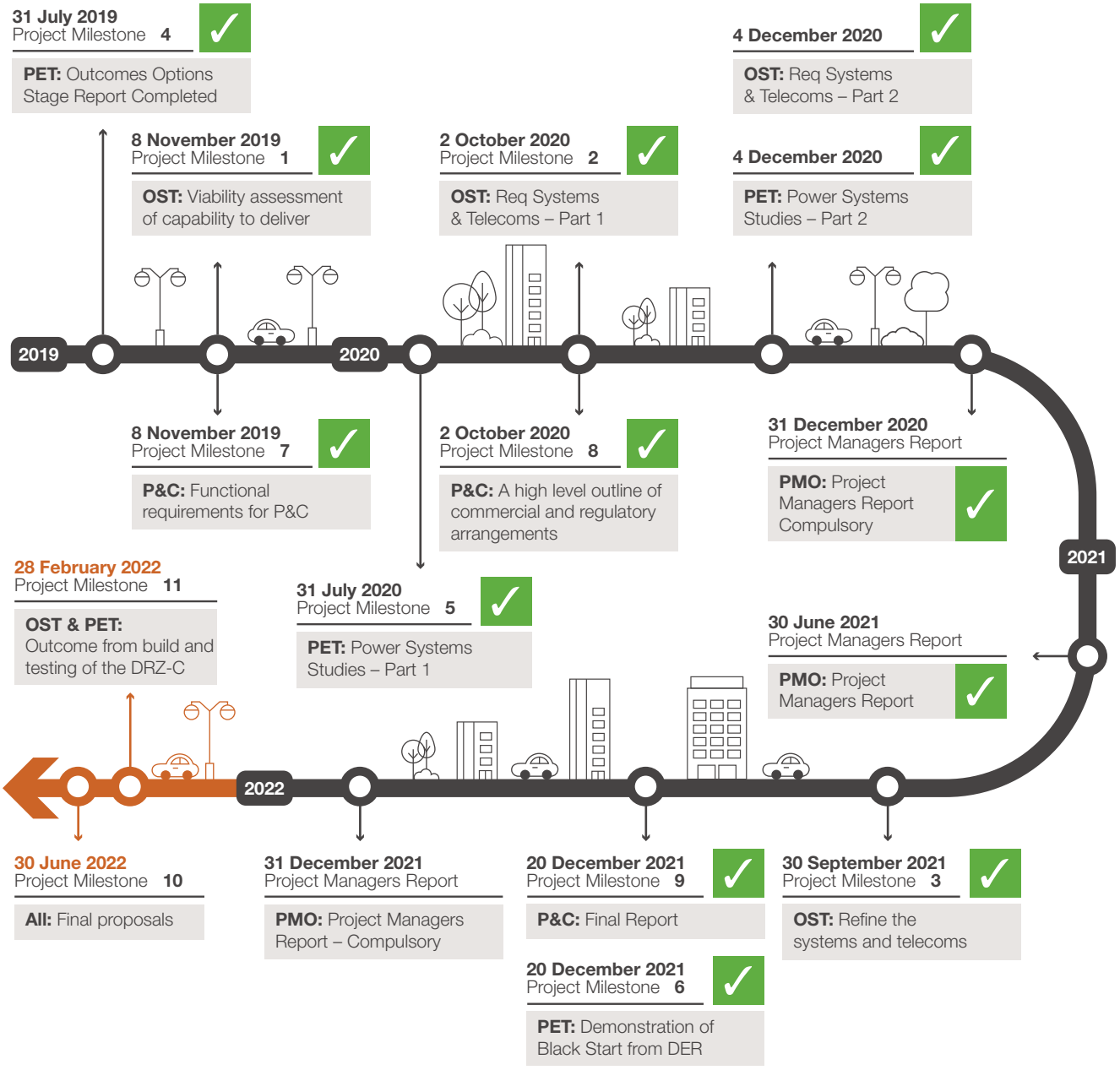
Next steps – the transition to business as usual (BAU)

The outcomes and designs of the P&C workstream will support the next round of Electricity System Restoration (ESR) tenders, the first of which is in the South East (SE) region, commencing in April 2022, with contract delivery from 2025 onwards. It is intended that the two processes – the traditional process and the new Distribution Restoration process – will be run in tandem.

The process designs, draft contract and the mock tender documents that were developed in this project will require further consultation by NGESO's BAU Restoration teams in order to align with their tender plans. Further collaboration with the DNO for the SE region, which is UK Power Networks (UKPN), will also be required.

To fully embed the recommendations into the mainstream ESR process, the outcomes/success/challenges from the pilot in the SE region tender will be needed to evolve the process to suit the industry needs for Distribution Restoration.

Project milestones – Distributed ReStart.



1. Introduction

This report is the third and final deliverable from the Procurement and Compliance (P&C) workstream and should be read in conjunction with and following on from the first two reports – 'Functional Requirements for Procurement & Compliance (FRPC)' published in November 2019 and 'A high-level outline of commercial and regulatory arrangements (OCRA)' published in October 2020.

1.1 Report structure

This report has been split into the following main parts:

- **Introduction** sets the context for this report including workstream background, assumptions and re-caps from the previous reports.
- **Refining the service design** contains most of the material content. It is split up according to the various phases of the procurement process.
- **P&C mock event** contains the outcomes and designs of the Test Procurement Event, along with the stakeholder feedback received.
- **Codes** stands alone to cover the context and details of changes required for the relevant industry codes.
- **Next steps for transition** contains the summary of the final procurement and commercial recommendations and thoughts about what happens next for the project to transition into business-as-usual.
- **Appendices** include details on stakeholder engagement, draft contract and the legal text on code changes.
- **Glossary** contains frequently used terms and acronyms in this report.
- **References** which contain all the links and information against the foot note numbers throughout the report.

1.2 Background

At present, the Electricity System Operator (NGESO) is obliged under the Grid Code (OC9) to maintain the capability to restore the network from a total or partial shutdown. The procedure to perform this recovery is known as **Black Start,** and NGESO procures this capability under Special Condition 4G of its licence to support this procedure through Black Start and/or restoration contracts. Note that the name of this service is changing to Electricity System Restoration (ESR).

The network conditions under a shutdown scenario and the early stages of a restoration are complex and challenging and require a wide span of technical capability to manage. NGESO currently employs a top-down skeletal restoration strategy, whereby a number of contracted Black Start providers re-energise parts of the transmission system, and enable the start-up of non-contracted secondary generation and the restoration of demand. The current **technical requirements,** which are aligned to the top-down restoration approach, are published on NGESO's website and provide the basis on which the current commercial design of the service and procurement mechanism have been established.

Historically, the types of provider who have been able to meet all of the technical requirements for restoration services have been large, conventional generators. The key to providing a Black Start service is the ability to start up without external supplies (power taken directly from transmission/distribution networks). However, as the obligation to provide Black Start capability lies with NGESO, there is a limited case for generators to install this capability in their designs for the plant, so most assets in GB are built without this.

Installing this capability for a large thermal generator can typically require auxiliary generators in the region of 5–25 MW to be installed (depending on the characteristics of the main units), along with retrofitting of control and instrumentation systems to ensure the ability of the plant to control and regulate a power island. These changes contribute a large proportion of the costs of delivering a Black Start service and are central to the commercial framework and procurement mechanism for the service today. In addition, they require a lengthy and complex process from concept to implementation to assess the feasibility of the proposals and provide assurance to NGESO of the capability, and to contract can take (end-to-end) up to four years in some cases.

Although significant changes have been implemented to broaden participation and reduce barriers to entry, such as introducing competitive procurement events, the process for achieving restoration was developed on the basis of a top-down restoration strategy, which is more easily delivered by certain types of providers.

As a number of the stations that historically have had Black Start capability (and may have had it built into the design for the stations) are now coming to the end of their expected life, the energy industry is approaching a period where a larger scale of investment is required to replace this Black Start capability.

Given the rate at which the energy landscape is evolving, it is prudent to ensure that where investment is necessary to ensure capability, Black Start should be future-proofed as far as possible. This should take into account that the number of large thermal generators connected to the transmission system has decreased and is likely to continue to do so.

It is probable that this will require adjustments to the **Black Start Strategy and Procurement Methodology (BSSPM)** in order to deliver new commercial frameworks and procurement mechanisms to access Black Start services from DER utilising a bottom-up approach as well as the current top-down approach, which it may eventually replace. Note that this document will be replaced by an **Assurance Framework** by April 2022, as part of NGESO's new licence condition.

1.3 Report aims and scope

The aim of this report, which should be read in conjunction with the former two reports (FRPC & OCRA), is to finalise a set of proposals for an effective procurement design to access the various technical capabilities required to deliver a Distribution Restoration service.

This year, the P&C workstream focused on the development of the proposed end-to-end procurement process which indicates, at a high level, the roles for Ofgem, NGESO, DNOs, the lead procurement agent and distributed energy resources (DERs) service providers – both as anchor generator (AG) and top-up service (TUS) providers. Additionally, working closely with the PET and OST workstreams, the functional requirements for the Distribution Restoration Service and 'rules of play' to help govern the distribution restoration zones (DRZs) have been drafted. Alongside these designs, potential code changes required to future-proof the Distribution Restoration service have also been developed.

Given the dependency of this workstream on outcomes of the PET and OST workstreams, this report will iterate the strategy development process developed in FRPC, feeding in more detailed base assumptions, and with more emphasis on the 'refine' and 'implement' stages. Note as well that even though this P&C final report will be published in December 2021, the PET and OST workstreams will continue with their work through to June 2022. Given the outputs from the other workstreams, there may be updates to the designs in this report by the project end.

Out of scope for this report are any plans and requirements for the next round of Electricity System Restoration (ESR)/ Black Start services tender roll-out. The section below highlights other industry future initiatives that have a strong bearing on P&C's final recommendations; however, these are not covered in detail within this report.

1.4 Assumptions and caveats

The procurement process and commercial designs have been developed following a number of key assumptions agreed across the project. Most of these have been explained in the previous two P&C reports and also in the previous OST and PET reports.

For this final report, the solutions explored, together with the information from stakeholder engagement, are all based on what is known right now, both from within the Distributed ReStart project and industry-wide. There are several other mainstream initiatives being planned which will undoubtedly have an impact on the future of the Distribution Restoration procurement process. These are:

- The outcome of introducing DER providers in the next ESR tender roll-out planned in the South East region from April 2022 with service commencement in 2025/26.
- The implementation of the new **Electricity System Restoration Standard (ESRS)** in 2026.
- The next **RIIO-ED3** consultation that may commence around 2026.
- The **DSO transition** beginning now and evolving over the years.
- The outcome of the consultation on the energy **Future System Operator (FSO) consultation.**

Based on the outcomes of industry consultations on the initiatives above, it may be that the process recommended now is subject to change. It remains to be seen, possibly around 2026, which party Ofgem decide is best placed to facilitate Distribution Restoration, whether that is the DSO, or potentially remains with NGESO, as part of the outcomes of the FSO consultation.

Note that in this report there are references made to Black Start, Electricity System Restoration (ESR), Distribution Restoration and Distributed ReStart. These have subtle differences. Currently, the Grid Code which governs the requirements for ESR still uses the term Black Start. The industry codes will be updated through the ESRS work. The ESRS consultation has only just started, and it is through this that any references to Black Start will change eventually to ESR. Distribution Restoration refers to the part of ESR that deals with bottom-up restoration. Distributed ReStart simply refers to the work undertaken as part of this project.

These final P&C recommendations have been designed to support the roll-out of the SE tender in 2022. Once there are more firm outputs from all the other programmes listed above, this process can be reviewed and adjusted based on industry and Ofgem direction. This notion was tested with stakeholders, who concurred with this forward thinking.

DER service providers entering this service can be asset owners, operators or aggregators. The criteria for entering this service are listed in Section 4.1. P&C proposals are intended to increase market participation and remove any barriers to entry; nevertheless, a cost-efficiency criterion is applied during the bid assessment to ensure that it is value-adding for the end consumer. DER providers who are supplying other market services will not be hindered on

participation, provided they are able to demonstrate that their assets can still meet the functional requirements and are ready to provide the Distribution Restoration service in the event of a Black Start.

For the codes work, there are two assumptions to highlight. Codes change proposals are dependent on the outcomes from the project; this has underpinned the codes work to date, and any changes proposed have been on the basis of the various design aspects of the technical, organisational and commercial elements. The other assumption is that some of the required changes can be passed through an ongoing Grid Code and Distribution Code modification (GC0148 Emergency and Restoration Code Phase II), as the proposed changes align to GC0148, rather than proposing a code modification solely for Distributed ReStart.

1.5 Method of engagement

Stakeholder engagement has been pivotal throughout the development of this procurement process and its commercial designs. Since the publication of the last report in October 2020 (OCRA), the P&C workstream has continued to conduct focused engagement with stakeholders and industry experts to collect information, seek feedback on the proposals and refine its approach in line with the strategic process. This report builds on the stakeholder feedback and discussions from the previous two P&C workstream reports (FRPC and OCRA).

1.5.1 Approach to engagement

This year, as the P&C specifications were developed:

- Interests of the P&C workstream's stakeholders were upheld in this final stage of the workstream by communicating with them proactively to encourage co-creation of designs.
- Focussed engagement with DNOs on the current designs and work done to date was held to seek their input into the final proposals.
- A 'live test' of the proposed procurement processes was carried out to seek participant feedback and data to stress-test the assessment criteria with.

To do all of this, the P&C workstream used tried-and-tested communication channels to actively engage with stakeholders, ranging from a variety of DERs, aggregators, BEIS, Ofgem and DNOs.

This was done through website and email updates, stakeholder webinars, a Test Procurement Event, presenting at various existing industry forums, regularly contributing at the Electricity System Restoration (ESR – formerly Black Start) team's tripartite sessions with Ofgem and BEIS, and through bi-lateral meetings with DERs and DNO representatives.

Refinement of the P&C workstream procurement designs has also been influenced by dependencies on the OST & PET workstreams. There has also been collaboration with other service development teams within NGESO, conferring on legal matters with contract experts in Shakespeare Martineau and NGESO's Legal Team, liaising with NGESO's DSO Team and seeking advice from price control leads within SPEN and NGESO.

Table 1:
Summary of P&C stakeholder events in 2021

Event	Date	Details
Distributed ReStart 'The Live Trials Stage' Podcast 6 – A new procurement approach for DER-based Black Start	12–16 April 2021	65 downloads. 44 streams.
Distributed ReStart Procurement and Compliance – DER stakeholder engagement webinar	21 May 2021	35 attended out of 55 that signed up to this event.
Bi-lateral meetings with DER stakeholders following the engagement webinar	Multiple dates from 22 May to June 2021	10 separate meetings with various DER representatives.
Distributed ReStart Test Procurement Event	Launch webinar – 28 July 2021 Test event starts – 2 August 2021 Mid-point support webinar – 18 August 2021 Test event deadline – 6 September 2021	13 potential participants attended out of 15 that registered. 5 mock bids received by deadline.
Presentation at the ENA Open Networks WS1A forum	17 August 2021	Presented at the WS1A forum meeting on the P&C current designs with a request for further 1:1 engagement.
Test Procurement Event follow-ups	Various dates in September 2021	Post event feedback sessions with 3 participants; the rest commented via email.
DNO bi-lateral meetings	Various dates in September and early October 2021	6 separate meetings with DNOs.
Codes stakeholder engagements		
Presentation to the GC0148 joint Grid Code and Distribution Code modification workgroup	18 August 2021	Presented on the current designs for the Distributed ReStart project and the proposals for code changes to the Grid Code and the Distribution Code.
Presentation to Elexon's BSC Panel	9 September 2021	Presented on the current designs for the Distributed ReStart project and the proposals for code changes to the BSC.
Presentation at the ENA's Commercial Operations Group (COG)	13 October 2021	Presented on the current designs for the Distributed ReStart project and the proposals for all code changes.

Full details of all the stakeholder engagements conducted can be found in Appendix 1 and is referenced as relevant throughout this report. Section 11 is dedicated to the plans and findings of the Test Procurement Event.

All the engagements planned were conducted virtually due to COVID-19 restrictions. The inability for face-to-face interactions may have impacted on the quantity and quality of outputs from various stakeholders. Timing of the stakeholder events was pushed into spring/summer mainly due to the process and commercial designs being ready to be scrutinised at that point. Participation numbers were challenged by a mixture of remote working arrangements and generally reported busy periods by key stakeholders.

1.6 Re-cap of the previous P&C workstream reports

The project has gone through three NIC governance phases, 'Options', 'Design' and 'Refine'. This has enabled structure for the development of proposals and solutions.

'Functional Requirements for Procurement & Compliance' (FRPC), published in November 2019, was P&C's first deliverable and formed the deliverable for the 'Options' stage of the workstream. The FRPC report proposed a strategy development process that would provide structure and rigour for determining the required commercial solutions for future Restoration services from DER. The report considered and analysed information that was currently available, which included reviewing the current procurement and commercial processes for Restoration services, as well as the outputs from the PET and OST workstreams. An initial high-level review of the industry codes and licences was also conducted to identify and highlight the potential changes required to enable future restoration services from DERs.

'A high-level outline of commercial and regulatory arrangements' (OCRA), published in October 2020, was second deliverable and formed the deliverable for the 'Design' stage of the workstream. This second report iterated and updated the strategic process in FRPC, to further develop options for the commercial solutions and procurement process.

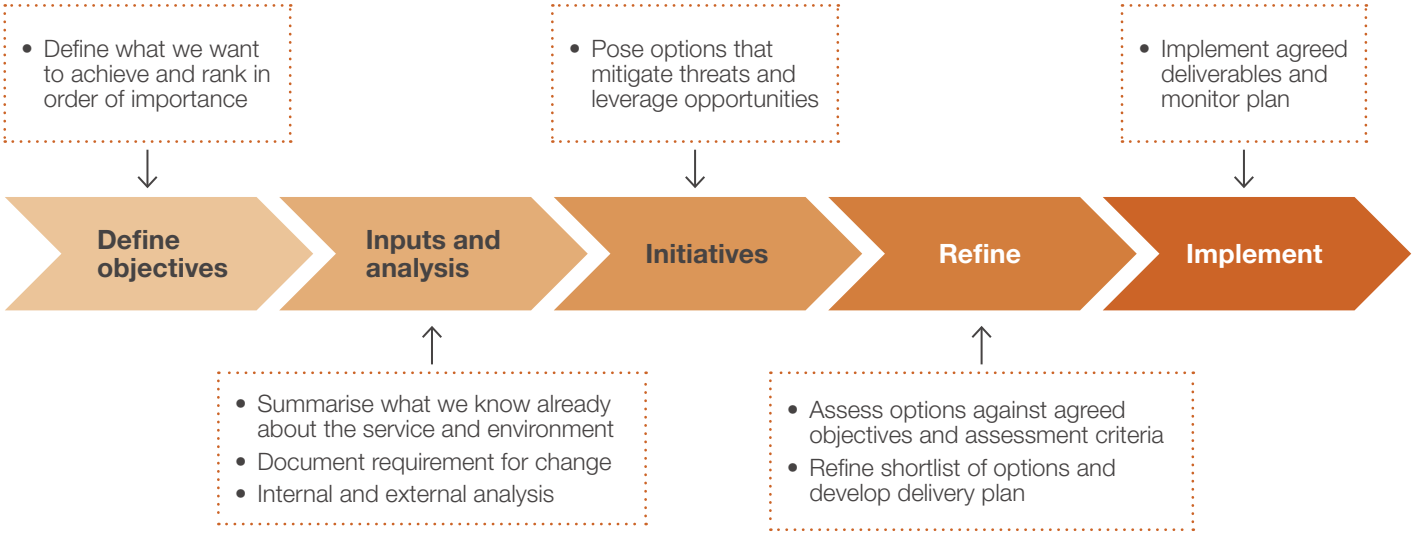
Following updated outputs from PET and OST and wide-ranging stakeholder engagement with industry colleagues, it was possible to develop new, more fitting initiatives and with review from industry ascertain a least-regrets approach to develop further. A more detailed and comprehensive examination of specific industry codes and clauses was carried out, and interdependencies between the codes were mapped.

This is the final report from the P&C workstream, following on from the two previous reports, and forms the outcome from the 'Refine' stage. This section will provide a quick recap of both reports (FRPC and OCRA) to set the context and baseline for this final report, firstly looking at the procurement and commercial elements and then recapping the reviews undertaken of industry codes.

1.6.1 Strategy development process recap

The FRPC report developed a five-stage strategy development process through which Distributed ReStart could design, develop and ascertain the most effective procurement approach and commercial structure for Distribution Restoration, which can be seen in Figure 1 below.

Figure 1:
Five-stage strategy development process – Flow chart of strategic process



Overview
The first step of this strategic process is to define the commercial objectives for a potential future Distribution Restoration service, these can then be used to assess the options developed. The next stage considers the required inputs to the strategy development process and how these inputs can be analysed to provide useful understanding and insight.

The purpose of the initiatives stage is to develop ideas and solutions in an unconstrained way to mitigate any risks or creatively address any of the insights raised during the analysis. These are further developed and honed through the refine stage, where impact versus effort is considered and an options assessment is conducted before the implementation plan is developed in the fifth and final stage.

Objectives
The FRPC report proposed objectives for the commercial outcomes. The aims for procurement mechanisms are typically based on the need to reduce cost and increase value.

In the OCRA report, these objectives were taken forward and reviewed and refined through stakeholder engagement. As a result of the stakeholder feedback, the objectives were proposed to be structured as follows, with four sub-categories of two high-level objectives:

Accelerated restoration times
- Functional route to market for new service.

Financial value to the end consumer
- Increased transparency
- Increased competition
- Reduced barriers to entry.

Inputs and analysis
During the inputs and analysis stage, FRPC considered the current processes and commercial structures, and used various commercial analysis and market analysis tools to draw insight that could be taken forward for consideration. A collated list of these can be found in the appendices of the **FRPC report.**

OCRA summarised the new/additional information which formed an input to the strategic process for consideration while developing initiatives. Key elements of the inputs were the project assumptions, outputs from the OST and PET workstreams and the stakeholder engagement undertaken. These can be found in the **OCRA report.**

In the FRPC report, as it was so early on in the project, there was a much stronger focus on objectives and inputs and analysis, taking in information and processing it, and idea generation. Following the publication of the FRPC report, the focus naturally shifted towards developing initiatives and refinement.

Initiatives
The different routes to market outlined in FRPC were assessed and analysed against their ability to meet the objectives, the benefits and challenges of the routes, and elements required to enable them. More detail on the discussions can be found in the OCRA report. This analysis formed part of the initiatives stage, to support with developing designs and solutions.

From the assessment of the different routes to market and their benefits and challenges, three procurement approaches were developed:

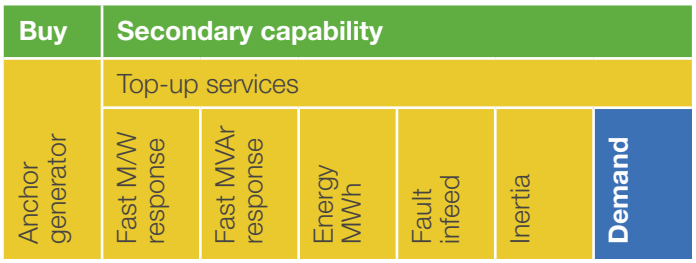
Figure 2:
Structure of approach 1

Approach 1: there is one contract between the party responsible for contracting and a lead service provider for each DRZ, for all required services (both the anchor generator (AG) and top-up services (TUS). The lead service provider is likely to be the owner/operator of the AG and may want to sub-contract for any required TUS.

Figure 3:
Structure of approach 2

Approach 2: the contracting party contracts for all of the required elements of a DRZ, with whichever parties create the best value proposition. They can hold one or multiple contracts per DRZ. The procuring entity would procure the AG and TUS separately (as required). The TUS could be procured in different combinations (individually, all together or a combination of the two).

Figure 4:
Structure of approach 3



Approach 3: while the AG is still contracted for, the proposal is that the top-up elements would be accessed through code mandated capability during market suspension in a Black Start situation, as opposed to contracted for ahead of time.

Following stakeholder engagement, the OCRA report recommended moving forward with the refinement of Approach 2, as it provided the most flexibility for the procuring entity around the specific design of the service and it also offered the lowest barriers to entry for potential providers. The other two approaches were discounted as they did not provide the same lower barriers to entry and value for consumers.

Refine and implement

This final report from the P&C workstream focuses on the refine and implement stages of the strategy development process, taking forward the outputs from both the FRPC report and the OCRA report. Finalising the procurement process and approach, through stakeholder engagement, and developing a final recommendation of the procurement process which can transition into business as usual.

1.6.2 Codes recap

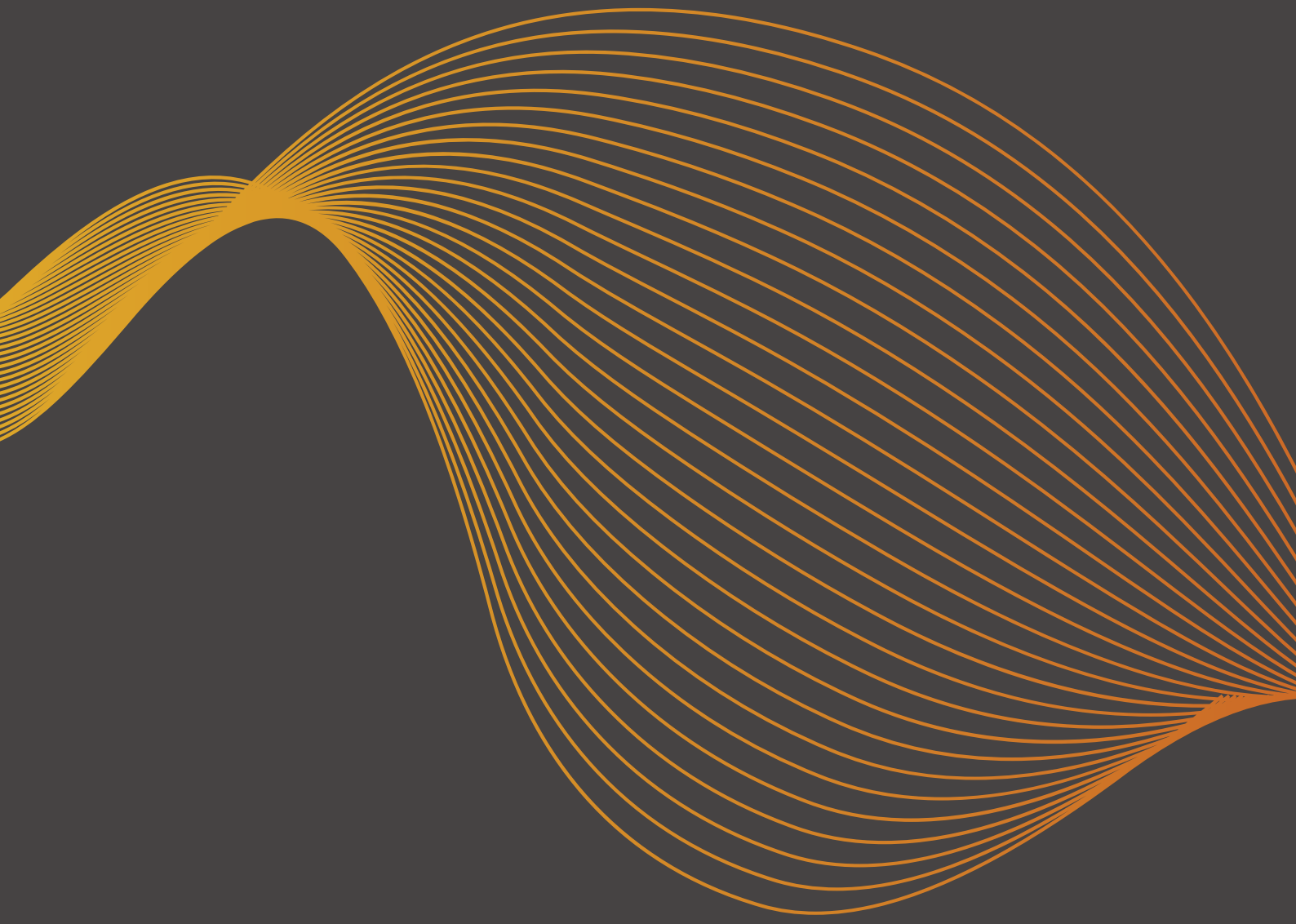
To enable Distribution Restoration, changes will be required within the GB codes and policies which underpin the connection to and operation of the electricity system. These codes have been written and adapted over time, based on the principles that large, conventional generators are the primary providers of traditional Black Start services.

In the FRPC report, an assessment of the gaps and blockers in relevant codes was undertaken to highlight areas where changes need to be made to enable greater participation from DER and distribution network and system operators (DNO/DSOs) in a restoration. More information can be found in the FRPC report.

Following the FRPC report, a more comprehensive and detailed review of key areas of specific code documents, such as Grid Code and Distribution Code, was undertaken. A mapping exercise was also undertaken during the detailed review, to better understand how changes in one industry code would impact others. More information can be found in the OCRA report and a more detailed summary can be found in Section 12.

Distributed ReStart

Refining the service design



2. Procurement process development

The following sections focus on the work undertaken in the refine stage of the strategy development process, looking at the development and refinement of the procurement process and commercial designs. Each of the following sections will explain the options explored, the stakeholder feedback received and the final design recommendations.

The sections in this chapter are:

More detailed evidence of the stakeholder engagements and any materials used in refining the process are all referenced in the Appendices.

A key requirement for the P&C workstream was a proposed end-to-end procurement process. This could only be developed after the technical, organisational and communication requirements for this service were outlined by the PET and OST workstream. As a result, this deliverable was designed and refined in the end stage of this workstream.

As discussed in Section 1.6, approach 2 was recommended to be taken forward for further development and refinement, following the stakeholder engagement outlined in the OCRA report.

Figure 5:
Structure of approach 2

Buy	Buy individually, all together or a combination of the two					
Anchor generator	Top-up services					
	Fast M/W response	Fast MVAr response	Energy MWh	Fault infeed	Inertia	**Demand**

In the design of approach 2, the procuring entity contracts for all of the required elements of a DRZ, with whichever parties create the best value proposition for the end consumer. The procuring entity can hold one or multiple contracts per DRZ. The procuring entity would procure the anchor generator (AG) and top-up services (TUS) separately as required. The TUS could be procured in different combinations (individually, all together or a combination of the two).

The next step to move the development of a procurement and commercial approach forward, once the P&C workstream had recommended to move forward with approach 2, was to develop an end-to-end procurement process. This needed to consider the different parties involved, their roles and the required steps within the process, with the objective to ensure the end result of any future Distribution Restoration procurement event leads to contracts awarded to the market participants who create the best value proposition.

Throughout the development of the procurement process P&C have engaged with different parties to ensure the development of a fit-for-purpose procurement process. The parties engaged with range from various DER, DNOs, internal NGESO teams especially the Restoration teams, and both the OST and PET workstreams. The outputs of this stakeholder engagement can be found in Appendix 1.

Early on in the development process the opportunity was taken to learn from the experiences of NGESO from running two Black Start tender events, plus the experience of running mature procurement processes for other balancing services. The review and analysis of the process and contract was undertaken within the FRPC report, and the insights highlighted were used to underpin the development of the end-to-end procurement process.

The learnings taken from previous NGESO Black Start tender events included updated experience on how long different tender activities took such as the pre-event strategy. Plus, feedback received from providers for example, on the time needed to develop appropriate Black Start service solutions. The benefits of undertaking eligibility checks early on within the expressions of interest step and supplying a contract data form to support efficient completion of the standard contract terms once contracts had been awarded were also realised.

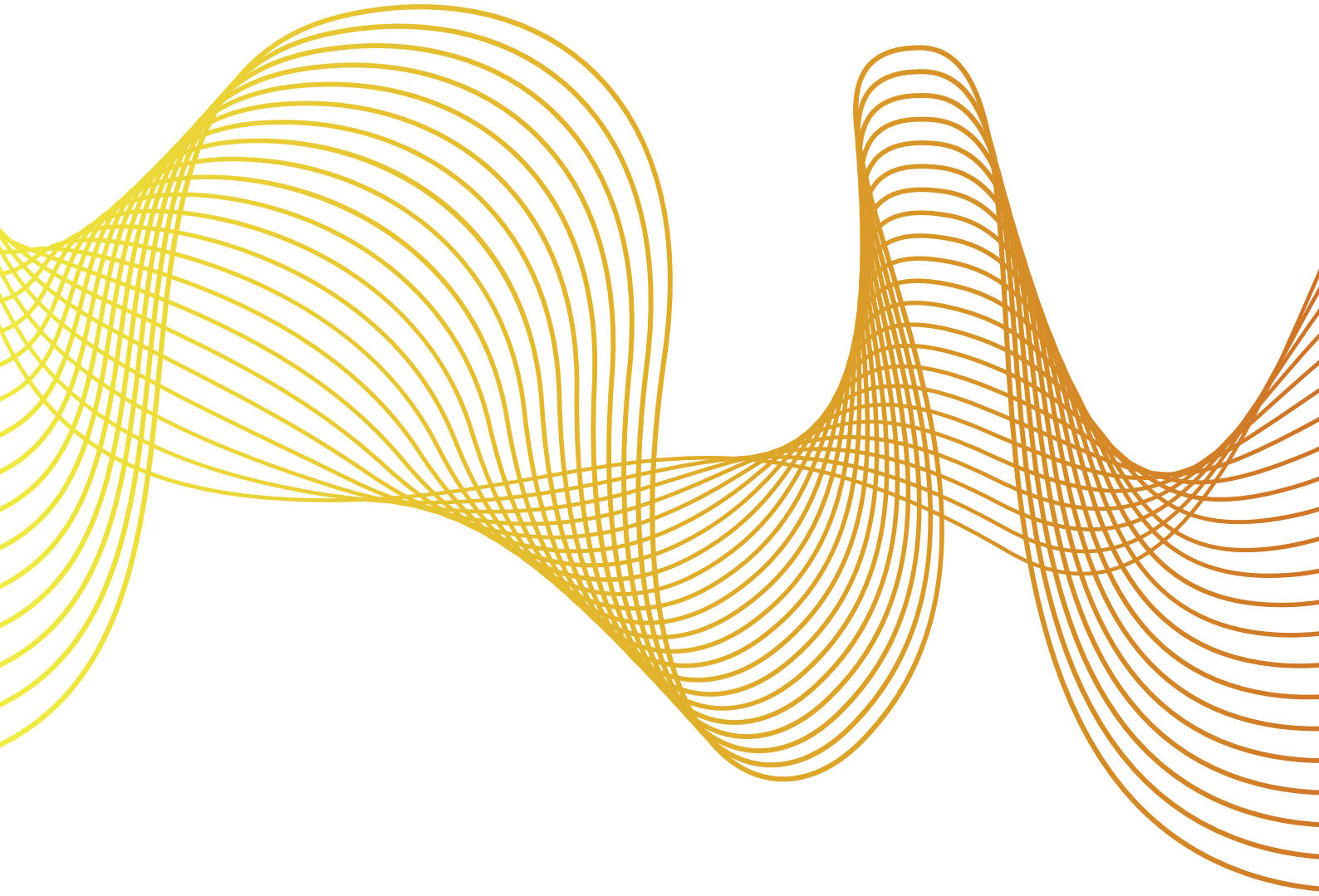
The learnings from other balancing services included understanding how testing and approval of capabilities is undertaken by independent technical experts. This is utilised for **frequency response services;** the approach speeds up the process and allows for providers to assess their own capabilities ahead of entering the tender for the service.

The P&C workstream considered the different high-level phases of procurement processes, such as those mature processes used by NGESO and the newer flexibility service processes used by DNOs. The high-level phases which have been developed for the Distribution Restoration service are national strategy, regional strategy, pre-event, procurement event, construction and commercial operations.

The national and regional strategy phases will set out the needs for running a procurement event. The pre-event phase involves strategising and planning for the procurement event as well as any engagement required. The procurement event phase involves all the elements required to end in contract award, including testing/ feasibility studies, submissions and assessment.

The construction phase will be where any required enabling works for assets happen, and finally, the commercial operation phase is the management of the contract across the duration of the contract length.

Throughout the development of the end-to-end procurement process design P&C have engaged with different industry stakeholders to end with a final fit-for-purpose recommendation. The stakeholder feedback received is outlined in the Appendix 1. Each phase will be discussed in detail in the following sections.



3. Strategy phases of the procurement process

This section covers the two strategy phases, national and regional, it also covers the discussion decision on who is best placed to lead the procurement process.

Crucial to the development of this process was the identification of key stakeholders and understanding the roles they might play.

At a strategic level, the Department for Business, Energy & Industrial Strategy (BEIS), is responsible for the overall requirements of Electricity System Restoration, and discharge obligations on NGESO through its licence condition to maintain Black Start capability. Ofgem is responsible for enforcing this licence condition.

NGESO currently defines the GB strategy for procurement of Black Start services, so it will have a key role in the future of Distribution Restoration services, through supporting the regional strategy, coordinating at a national level, and feeding into the procurement process.

As this is a service aimed at distribution connected parties, the DNOs will need to be involved in the regional strategy as well as the procurement process.

Finally, the providers of a Distribution Restoration service will need to be involved in the procurement process; this includes both anchor generators (AG) and top-up service (TUS) providers. Section 3.3 goes into the detail of the engagement and discussion on who should lead the procurement process. In the table below this role is currently referred to generically as 'lead procurement party'.

Table 2:
Proposed role definitions

Party	Proposed roles
Ofgem/(BEIS)/Local Government	Set and enforce the Electricity System Restoration Standard (ESRS).
NGESO	Run the national strategy and the traditional Black Start tenders, plus feed into the Distribution Restoration service procurement process.
DNOs	Run the regional strategy and feed into the Distribution Restoration service procurement process.
Lead procurement party (NGESO/DNO/Third Party)	Run the Distribution Restoration service procurement process.
AG providers	Participate in the Distribution Restoration service procurement process as an AG provider.
TUS providers	Participate in the Distribution Restoration service procurement process as a TUS provider.

3.1 National strategy

The first element that will feed into the national strategy is the setting of an **ESRS** by BEIS, which will be enforced by Ofgem. During 2021, this Standard was consulted on by BEIS and Ofgem and updated into NGESO's licence on 19 October 2021. NGESO must fully comply with the Standard by 2026; it requires that 60 per cent of regional demand is restored within 24 hours and 100 per cent of national demand restored within five days. This Standard is the starting point for the Distribution Restoration service end-to-end procurement process.

NGESO currently reviews the national strategy every year; the outputs are published to industry via the **Black Start Strategy and Procurement Methodology (BSSPM)**, to be replaced by an **Assurance Framework** as part of the new licence condition. The national strategy involves reviewing and assessing the current and required service provision to identify any future gaps in capability; this is done with a GB-wide lens. The strategy outputs then feed into the procurement methodology which sets out what and how NGESO intends to procure future Restoration services.

The proposal for the Distribution Restoration service process is that NGESO will continue to undertake the national strategy as it has a GB-wide view of required capability, and the licence condition to implement and ensure the Standard is met.

The outputs of the national strategy and any identified future gaps in service provision, which could be filled by DER, will be passed to the next phase, which is the regional strategy.

3.2 Regional strategy

As Distribution Restoration will have a regional element to it, there is need to introduce a regional strategy. The aim of the regional strategy is to assess whether any of the national gaps in service provision could be filled via DERs connected to a distribution network. The regional strategy is proposed to include an assessment of the network and potential restoration capability from DERs; for example, whether the connected DER assets could form feasible DRZs, and whether the potential DRZ could energise all the way to the transmission network.

It is proposed that the relevant regional DNO would undertake the regional strategy as it has the knowledge of its network and connected assets.

A joint decision between NGESO and the relevant DNO would be made as to whether a commercial solution/ procurement event is needed to fill the future gap in ESR service provision, and if DERs can participate.

The next two phases are the pre-event and procurement event; however, before the report moves onto discussing these sections, the P&C workstream reviewed who would lead the procurement process. The next section delves into the options explored and the conclusion reached on who should lead the procurement for Distribution Restoration services.

3.3 Lead role for the procurement process

Pivotal to the proposed procurement process is the role of who should lead the procurement. This role underpins other key aspects of the commercial designs such as settlement and funding, and how contracting might work.

Whoever leads the procurement will be ultimately responsible for:

- planning and running the tender event and the commercial strategy,
- collaborating with NGESO/DNO/DSO for assessing the bids, shortlisting applicants for feasibility studies, final assessments, contract award and contract management – the final decision in any of these phases will remain with the lead procurement agent,
- the settlement of contractual costs with participants through the relevant funding mechanisms,
- leading on the design of the contracts and getting the other relevant parties to agree and sign up to their obligations in this process,
- mitigating risks, issues, successes and challenges throughout the process, having accountability back to Ofgem and BEIS.

Table 3:
List of criteria against which the options for the lead procurement agent were assessed

	The consideration of which party ought to be responsible for contracting the service was underpinned by the following factors:
1	Ability to perform the role as early on as 2022, as part of the next ESR tender round.
2	Lead time for relevant provisions to be updated in licences and code obligations to ensure that the responsible party is incentivised and obligated to carry out this procurement process effectively.
3	Whether the choice of responsible party will keep end consumer costs down through their procurement processes and systems.
4	Whether the responsible party will be able to provide consistency in DER experience across different areas – are they the ideal choice for the service providers?

The end-to-end procurement process was designed with NGESO and DNO roles already considered. However, the role of 'lead procurement party' could easily be taken on by either NGESO, DNOs or a third party, for example a procurement specialist company or even Ofgem. The third party option was explored to accommodate for any decisions by other industry initiatives, such as the **Early Competition project** who considered a third party for its procurement entity, before NGESO was directed by Ofgem to take on this role.

In the future, there is a possibility that DSOs could be involved. At this stage these considerations are affected by maturity of processes, consistency across regions, by when exactly their full role spectrum is established and, the appetite of DNOs/DSOs. It is only plausible to indicate this as a future option to explore.

For the purpose of this report, DNO and DSO are not assumed to be the same.

Table 4:
Benefits and risks for options of who leads the procurement process

Options	Benefits	Risks
National Grid Electricity System Operator (NGESO) to lead	• Holds the licence obligation for ESR and is responsible for meeting the new Electricity System Restoration Standard (ESRS). • Consumer costs are kept down as this service is delivered as cost pass-through – no extra costs included or any future return on investments as the systems and capabilities are already in place. • Has the GB-wide view and experience of running such tenders using mature procurement systems and processes. • Can pick this role up in readiness for April 2022; however, for DNO or DSO, it might be too soon to take on especially given the planning is in tow for ED2. • Can run the procurement events in different regions more consistently, whereas DNO/DSO may choose to vary its approach. DER feedback is more for consistency and parity of approach. • From a perspective of changes required to codes, which can be a long process to implement, NGESO leading the process has the least changes compared to moving the obligations over to DNO or DSO. • The Energy Future System Operator (FSO) consultation could result in more or enhanced whole system roles.	• As part of the DSO transition, NGESO might be eventually required to delegate this role to the DSO to deliver optimised local services for customers. Therefore, all the investments from NGESO may only be for a short-term period. • NGESO could be required to settle some of the costs on behalf of the DNO(s) if they cannot claim through their own price control – this will be complicated (especially if the network upgrades are used for other future flexible services by the DNO) and this will require Ofgem engagement.
DNO/DSOs to lead	• Might be better placed for this role, given DNOs will have a more enhanced role in the procurement and operational processes from the input into the regional strategy through to coordinating the DER provider in the event of a Black Start. • Has detailed knowledge of the relevant network and its connected customers, so its choice and autonomy on how to procure the relevant services. • Has a better understanding of demand restoration service requirements in its 'patch'. • Has experience of procuring flexibility services. • All the associated costs for Distribution Restoration can be remunerated through their own network price control instead of being split with NGESO.	• DNO/DSOs will not be able to pick this up immediately in time for April 2022 – review on their organisation and system readiness will be required beforehand. • Cost and role provisions not included in ED1 or ED2 submissions, and work needs to start from or even before April 2022. • NGESO will still be responsible for procuring transmission ESR services, so it could result in more difficulty introducing standardisation and consistency, as procurement would be run across different corporate entities with different incentives. • Will still need a framework or handover from NGESO, and this requires time and resources. • Part of the licence obligation will need to be passed to the DNO/DSOs to provide the same incentive as NGESO to deliver this restoration service. • Comparably more code and licence changes will be required, and these can take a long time to implement. • There is no firm date by when the DSO role will come into effect and what the role is expected to cover. • If DNO/DSOs are one and the same organisation, conflicts of interest regarding the tendering/reimbursement of these services might occur.
Third party	• Neutral position to procure services from DER for NGESO and DNO/DSO.	• This will drive up consumer costs as the third party aggregation of services is another layer to consider. • Does not make sense in this process as the service is at transmission and distribution levels therefore more pertinent for it to be NGESO or DNO/DSO. • Contracting will be even more complex by including another party (quadripartite). • Extra step to procure the third party ahead of the process will be required thus elongating the procedures to an expense. • Lack of knowledge of existing procurement mechanisms for ESR services.

To inform the decision for this lead role, P&C engaged with DER stakeholders, DNOs, internal NGESO teams, Ofgem and BEIS, to present the above options and to ask for feedback on who should be responsible for coordinating the procurement.

Key stakeholders such as DER providers, DNOs, Ofgem and BEIS were asked to weigh the benefits and risks in Table 4 and the criteria in Table 3, and share their perspectives.

The outcomes from the engagements are summarised below.

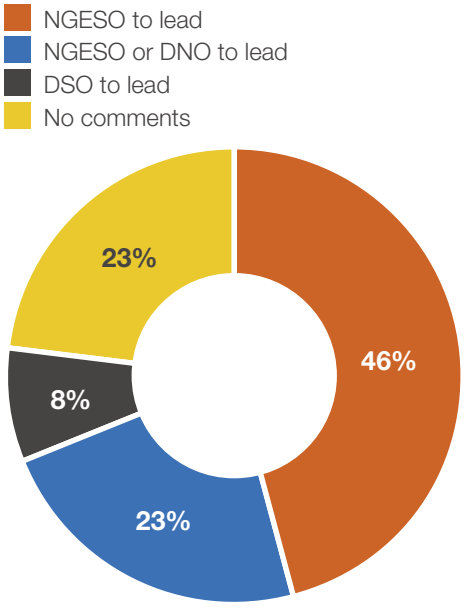
From the DER stakeholder engagements, nearly half were quite clear that NGESO should lead the procurement of the Distribution Restoration service. The three stakeholders who did not have strong opinions about who leads commented that flexibility, transparency and fairness of the procurement process was key to encourage more/new DER providers to join this market. See Figure 6 below, for the breakdown of the DER stakeholder feedback summary.

The Distributed ReStart Stakeholder Advisory Panel suggested that more engagement was required at DNO level about who should lead the procurement process. This was on the premise that even though NGESO might have a GB-wide view and experience of this process, the DNOs would know their network and connected assets better. They also acknowledged the risk that each DNO might do this process differently, and therefore it is important that whoever leads conducts a consistent and transparent process across different regions for the sake of parity for the DER providers.

Ofgem and BEIS felt it made most sense for NGESO to lead the procurement process for the DER providers. Their reasons were centred around the fact that the licence obligation remained firmly with NGESO until a point in time where these obligations are shared or lifted.

Figure 6:
DER stakeholder feedback summary

DER stakeholder feedback on lead procurement agent

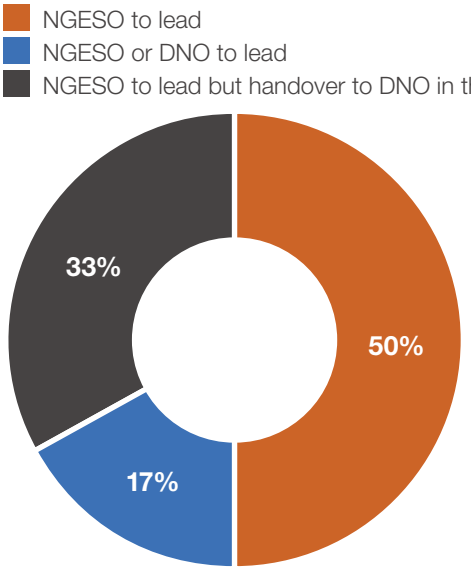


The comments shared by various DNOs were as follows:

- Either option of NGESO or DNO/DSO leading the procurement was fine, provided the process is conducted in a collaborative manner and aligns with the whole electricity system initiatives.
- NGESO is fine to lead this process as the DNOs already have an enhanced role to play in Distribution Restoration.
- NGESO should continue to lead on the national coordination of the ESR process with support from DNOs/DSOs at a distribution level.
- NGESO should remain in control of the overall ESR process; however, it could consider contracting with DNOs to locally procure the service and dispatch the providers.
- This is a role better suited to DSO, and therefore at the right time, NGESO should hand over a framework for procurement at distribution level.
- NGESO is best placed to lead in the interim with a view to delegate or have joint-procurement with DNO/DSOs in future.

Figure 7:
DNO feedback summary

DNO feedback on lead procurement agent



Considering all the feedback provided by stakeholders and DNO colleagues, the final recommendation is that NGESO should lead the procurement of Distribution Restoration services for now until a point in time (probably around 2026) when a review of this process should be conducted.

At this stage, depending on the outcomes of the FSO consultation, DSO transition and the ESRS work, if there is movement and direction from Ofgem to hand over the process to DSO, then provided there is readiness of resources, systems and shift in regulatory matters (code obligations and licence conditions), then NGESO can evolve the procedures accordingly.

NGESO would still stay in control of the overall Restoration process. This aligns with the OST workstreams designs in that NGESO retains full control of a Black Start situation with DNOs operationally managing DRZs in their network areas.

4. Procurement process – pre-event phase

Once the national strategy and regional strategy have been set and a decision has been made to move forward with a tender event for Distribution Restoration, the procurement process moves into the pre-event and tender event phases.

The pre-event phase is where a tender event strategy is developed.

The commercial strategy will involve:

- considering who might participate
- agreeing the assessment criteria
- agreeing the functional requirements
- outlining timelines and the contract strategy
- and creating a tender plan and the tender documents.

Once this has all been decided, there would need to be publication of, and engagement on, the upcoming procurement event to notify industry.

The proposal is for the pre-event phase to be undertaken by the lead procurement party.

A key element of the pre-event phase is the development of tender documents. These need to provide the participants with everything they need to make an informed decision on participation and provision of a Distribution Restoration service.

The documents need to include:

- the timelines and information on the different steps within the procurement event,
- the functional requirements for service provision, the commercial submission requirements and the assessment process
- the standard contract terms and any other information deemed necessary for providers to be able to enter a tender for Distribution Restoration services.

During the Test Procurement Event P&C developed several tender documents; these are discussed in more detail in Section 11.

4.1 Functional requirements

As seen in Figure 5 in Section 2, the design of the Distribution Restoration service allows for one asset to be an anchor generator (AG) and multiple assets to provide supporting top-up services (TUS) in a Distribution Restoration Zone (DRZ).

The DER providers need to understand the functional requirements for each of these services (AG and TUS) and what the required minimum technical capabilities are. These are developed as part of the pre-event phase and contained within the tender documents published. Understanding the functional requirements enables participants to propose technically feasible solutions and to price accurately.

There are multiple options for what a feasible DRZ can do, and these are further explained in Section 2.4 of the OST report **'Operating a Distribution Restoration Zone September 2021',** but a summarised list can be found below:

- option 1: Local network growth only
- option 2: Distribution level network growth
- option 3: Synchronisation of a parallel DRZ
- option 4: Distribution network growth via the transmission network
- option 5: Inclusion of a transmission connected resource within the DRZ
- option 6: Skeleton network growth fed by the DRZ with synchronisation at transmission level.

4.1.1 AG functional requirements

The PET workstream developed functional requirements for the AG, which they explained in their December 2020 report **'Assessment of power engineering aspects of Black Start from DER – Part 2,'** but is summarised as:

Table 5:
Functional requirements for anchor generator (AG) from PET report in December 2020

Requirement	DER minimum requirement
Time to connect	≤8 hours
Service availability	≥90 per cent
Resilience of supply, Black Start service	≥72 hours up to 120 hours
Resilience of supply, Black Start auxiliary units	120 hours
Frequency control	A fast-acting proportional frequency control device is required.
Voltage control	Ability to provide continuous steady state control of the voltage with a set point and slope characteristic.
Block loading size	Estimated ≥ 2MW (site specific depending on distribution restoration zone (DRZ).
Reactive capability	Minimum of 0.95 leading and 0.95 lagging power factor at the point of connection.
Sequential start-ups	≥ 3
Short circuit level	≥ 1 x DER MVA rating
Any DRZ specific functional requirements	To be confirmed based on specific DRZ requirements.

These requirements have been further developed by the project in 2021 through industry engagement, testing in the PET live trials, OST desktop exercises, and the P&C Test Procurement Event. The updates made have been to balance the technical feasibility for the designs and capabilities of DERs within a DRZ, at the same time as ensuring competition is enabled and barriers to entry are reduced.

The below table shows the updated version of the functional requirements for the AG service.

Table 6:
AG functional requirements – updated

Requirement	Minimum	Definition	Rationale
Time to connect	≤ 8 hours	Time taken from instruction from the relevant network operator to start up the asset from shutdown without the use of external to site power supplies and energise to the point of connection to the DNO network. Instruction to start up may be up to 72 hours after a blackout, which means the site will have been without external power supplies all of that time. Once started, you must be able to operate in a condition with no external load for at least four hours.	Capability required in terms of hours. Explanation will be required to explain the relationship if time to connect is related to the time without external power supplies. Confirmation required if a load bank or other additional equipment is needed to enable operation without external load.
Service availability	≥ 90 per cent	The ability to deliver the AG service over 90 per cent of each year (expected availability to be declared).	A Black Start could happen at any time thus a high service availability is required.

Requirement	Minimum	Definition	Rationale
Resilience of supply – availability to start up	≥ 120 hours	The AG must have sufficient access to auxiliary power supplies (in network black-out conditions) for at least 120 hours to: • maintain the generator declared 'time to connect' availability • deliver the full range of AG services as declared in 'Resilience of supply – service delivery'.	It may be several days before an AG is instructed to start up, and then the restoration process may last several days.
Resilience of supply – service delivery	≥ 72 hours	Once instructed to start up, the minimum time the provider will be able to deliver the full range of anchor services.	Full capability will be declared.
Sequential start-ups	≥ 3	Ability to perform at least three separate start-up processes.	Time required between sequential start-ups will be declared.
Voltage control (reactive power capability)	Provide continuous steady state control of the voltage at point of connection Minimum of 0.95 leading and 0.95 lagging power factor at the point of connection	The AG must be 'grid forming' in that it is able to create a voltage source independent of the external network. Voltage control capability as defined in **Engineering Recommendation G99**. As specified in G99, the voltage control should be provided with a set point and droop characteristic. The voltage setpoint should be adjustable by an external control system. The AG must have the ability to absorb MVAr (leading power factor) to energise part of the network while active power export is zero. This may be achieved by using an onsite load bank, or other means to allow a generator to operate at the MW level necessary to give the required MVAr range. Voltage must be controlled within acceptable limits (+/- 10 per cent) during the process of network energisation and addition of demand blocks.	MVAr leading and lagging capability at zero power export to be declared. The anchor generator will need to keep voltage within limits when creating, maintaining, and expanding a DRZ.
Frequency control	Fast-acting proportional frequency control	Frequency control capability as defined in Engineering Recommendation G99. The AG must have fast-acting frequency control capable of being operated in isochronous mode or with a set point and droop setting. Frequency must be controlled within acceptable limits (47.5–52.0 Hz) during the process of network energisation and addition of demand blocks.	During a Black Start event the AG will be the frequency leader for the DRZ.
Block loading size	≥ 2 MW (site specific depending on DRZ)	The AG must have the capacity to accept instantaneous loading of demand blocks and maintain the frequency within the 47.5– 52 Hz range. The AG must be able to supply power to the additional load for at least 10 seconds, giving time for other DER to be adjusted. In the initial stages of restoration, before other DERs are connected to the DRZ, the AG must be able to supply all power required. Any block load may need to be sustained for as long as is required to bring other DERs online. The time required will be specific to the DRZ.	Full capability to be declared.
Short-circuit infeed	≥ 1 x DER MVA rating (at t≥1s)	The AG must be able to inject reactive current during a fault disturbance on the network. The maximum equivalent MVA short-circuit infeed that can be sustained as measured at the DNO point of connection for at least one second.	A minimum level of short circuit infeed is required to ensure network protection can operate safely, including fuses at low voltage.
DRZ specific technical	To be confirmed based on specific DRZ requirements	Technical requirements on an anchor DER specific to a DRZ in order to facilitate the restoration process.	DRZ feasibility study to confirm.

The key changes to the AG service capabilities were updating the definition for service delivery, merging voltage control and reactive capability and tweaking the definition for block loading.

The first change has been to update the definition and name for 'resilience of supply, Black Start service'; the definition in the **PET Dec 2020** report required continuous output at 90 per cent rated capacity, with exact capability to be declared. This potentially rules out the ability for storage to participate as an AG because they may be unable to continue output for ≥ 72 hours at 90 per cent capacity.

The requirement has now been updated to 'resilience of supply – service delivery' with the requirement for continuous output at 90 per cent rated capacity removed from the definition. The definition has been changed to specify the minimum time the provider will be able to deliver the full range of anchor services, which does not include continuous power output beyond what is necessary to deliver the other services. This allows storage technology to be considered as a possible AG because it may be able to meet all the other AG functional requirements.

'Voltage control' and 'reactive capability' were merged as they are closely related. A capability to control voltage is essential for an AG, and this requires an appropriate reactive range. Assessing the MVAr capability allows for differentiation between different DER, all of which are likely to have similar forms of voltage control.

The update P&C have made to the requirement for 'block loading' is to add clarity on what is needed. Originally the requirement only stated a need for the ability to block load at least 2 MW; the addition has been to add a minimum duration of 10 seconds. This still enables storage technology to participate but demonstrates that there is a need to be able to sustain the block load before top-up services in the DRZ are able to respond.

These AG functional requirements may be further developed and updated by the PET workstream as the outputs of the live trials are collated and reviewed, to ensure they fully take into account the feasibility of creating a DRZ and the required technical capabilities of an AG and supporting TUS.

4.1.2 TUS functional requirements

Functional requirements for the different TUS have also been developed and refined following engagement with industry. The TUS functional requirements are structured slightly differently in that the providers do not have to meet all of the functional requirements.

The functional requirements they need to meet will depend on which service they may want to provide, but there are several requirements that will need to be met regardless of which TUS the provider wants to offer; these are related to resilience and communications.

Table 7:
Functional requirements providers of all TUS need to meet

Requirement	Minimum	Definition	Rationale
Resilience of supply – availability of communications	≥ 72 hours	Ability to maintain the availability of the control and communications with the DER site for greater than 72 hours after a blackout before any external supplies (extra high voltage (EHV), high voltage (HV) or low voltage (LV)) are restored.	The main connection to the DER will be restored as soon as practical, but it may be up to 72 hours after a blackout before the connection is restored, and the DER will have to be resilient for this time period in order to then provide the required service.
Resilience of supply – service delivery	≥ 72 hours	When instructed to start up, the service will be available for a minimum duration of 72 hours (exact capability to be declared).	Time for which the top-up service can be provided after the DNO connection has been restored, needs to be declared with indication that this time is dependent upon the length of time after the blackout before the DNO connection is restored.
Service availability	≥ 90 percent	The ability to deliver the contracted service for 90 per cent of each year of the contracted period (expected availability to be declared).	The TUS providers will be required to be available equal to, or above, the availability of the AG.
Time to connect	≤ 4 hours	Time taken from instruction from the relevant network operator to start up the asset once external supplies have been restored. Instruction to start up may be up to 72 hours after a blackout, which means your site will have been without external power supplies all of that time.	Capability to be declared in terms of hours, from the time when external supplies are restored. If time to connect is related to the time without external power supplies, then more explanation is required to understand that relationship.

The table below displays the rest of the functional requirements for the different top-up services. Providers do not need to satisfy all of these; they just need to meet the requirements which correlate to the TUS(s) they want to provide. However, during a procurement process it will be useful to understand the providers' capabilities against each of these requirements, to inform the overall assessment of DRZ feasibility.

Table 8:
Functional requirements for each of the TUS

Requirement	Minimum	Definition	Rationale
Fast MW control (increase)	Ability to increase active power output within 200 ms of receipt of signal and sustain for at least 10 seconds.	Deliver rapid MW response triggered by a local frequency measurement or on receipt of an external control request. The ramp rate to be implemented will be agreed. DER capability will be assessed in terms of the maximum MW change upwards and downwards that can be achieved within 200 ms and sustained for at least 10 seconds. After this period there can be a gradual change back to the prior or preferred operating position.	This response will support the anchor to maintain DRZ frequency in the event that the anchor generator (AG) alone cannot restore frequency within limits. As an example, this response could be required if a DER tripped, or if additional sub second MW control is required to support block loading.
Fast MW control (decrease)	Ability to decrease active power output within 200 ms of receipt of signal and sustain for at least 10 seconds.		
Inertia	There is no minimum requirement for individual generators/resources, but the service provider should state what inertia is available.	The inertial response should be provided by an inherent response without any measurement delays. (For synthetic inertia refer to 'fast MW control'.)	DRZ feasibility study will confirm what (if any) the inertia requirements will be (e.g. this may be required to increase the block load pick up capability within the DRZ).
Frequency control	Provide frequency sensitive control of active power.	Frequency control capability as defined in Engineering Recommendation G99. All frequency response requirements are applicable including LFSM-O, LFSM-U and FSM.	This response will support the AG to maintain the frequency within limits during normal operation.
Voltage control (reactive power capability)	Provide continuous steady state control of the voltage (or reactive power) at point of connection.	Voltage control capability as defined in Engineering Recommendation G99. As specified in G99, the voltage control should be provided with a set point and droop characteristic. The voltage setpoint should be adjustable by an external control system. If voltage control cannot be provided, it may be acceptable to provide a MVAr set point controlled by an external signal. Voltage must be controlled within acceptable limits (+/- 10 per cent) during the process of network energisation and addition of demand blocks.	MVAr leading and lagging capability to be declared. The DER will support the AG to keep voltage within limits when creating, maintaining and expanding a DRZ.
Short-circuit infeed	≥ 1 x DER MVA rating (at t≥1s).	Injection of reactive current during a disturbance. The maximum equivalent MVA short-circuit infeed that can be sustained as measured at the DNO point of connection for at least one second.	To increase DRZ fault level if anchor generator alone does not provide the DRZ minimum acceptable fault level.
Energy MWh	Generate or consume MW on instruction from an external control system; deliver within 10 seconds of request.	During operation the DER will report the maximum and minimum range of MW output which can be delivered if requested. Output will be controlled by a set point (a suitable constraint value will be applied to intermittent sources). Will be assessed in terms of the average power output that can be reliably maintained over a period of 120 hours. This should account for intermittency, fuel supply or other factors that may reduce average power available.	The DER will support the AG to deliver MW to the DRZ and energise more demand.

The TUS functional requirements were shared as part of the Test Procurement Event collateral and can be found on the **Distributed Restart website**.

P&C have since updated these following industry feedback and learnings from the Test Procurement Event; there may be further updates by the PET and OST workstreams following outputs from the live trials and final development of the DRZ-C designs.

The key updates made by the P&C workstream have been to include time to connect as a requirement for all TUS providers and to split fast MW control into two elements: increase and decrease. The time to connect has been added to ensure there is understanding of how quickly a provider can respond following instruction from the relevant DNO. This minimum requirement of four hours may be updated further following industry engagement and learnings from the PET live trials.

The fast MW control requirement has been split into increase and decrease; this is to provide clarity and is from learnings that assets can potentially have different capabilities depending on which way they are providing the service.

A key question raised during the Test Procurement Event was on the state of charge of batteries that are providing TUS(s) and how this would be managed when a Black Start situation arises. Two options were posed by one of the participants of the Test Procurement Event for how they could send in their submission:

- bid in to deliver Distribution Restoration with the battery's full capacity and then state of charge is managed via the anchor generator (AG);
- always withhold some capacity when operating the asset in other services and then bid in for a smaller amount (but will price more expensively as would not be able to achieve full discharge in other services).

The final recommendation on these options is that a TUS provider can expect to be energised from the network before delivering services, and the other DER within the DRZ can be planned to deliver the energy required. Requiring a TUS provider to have stored energy goes against the design of having individual TUS, as well as reducing competition and increasing costs. This would need to be managed against the requirements for the AG service, or full DRZ requirements as there would be a requirement to have enough Energy MWh to meet the demand of the whole DRZ and the connected storage asset.

An understanding of the DER's capabilities against these functional requirements will form part of the EOI step of the procurement process, and as the participant progresses through the procurement event phases increasing detail against these minimum technical capabilities will be required to ensure full understanding of the DER's capability.

5. Procurement process – tender event phase

Once the pre-event phase has been completed, the next phase is the tender event where the Distribution Restoration service is published to the market. An invitation is extended to receive offers of service provision with the aim of getting the best value propositions by assessing technical capabilities and commercial submissions.

Figure 8:
Procurement event process for AG and TUS

Anchor generator and some top-up services tender process

Top-up services tender process

5.1 Expression of interest (EOI)

The purpose of an EOI is to understand the market's ability and appetite to supply the service, and to confirm the eligibility of participants for providing the AG and TUS services.

The P&C workstream proposal is that the EOI will be done as one for both the AG and the TUS. Tender documents will be released detailing the functional requirements. The aim of the EOI will be to understand which services participants are willing to offer (AG and/or TUS), the capabilities of providers against the functional requirements, and whether they may need to make upgrades to assets to meet the requirements.

At this stage there is also the option to check the eligibility and reliability of companies who wish to tender. This will ensure that when contracts are awarded, it is likely the companies will make it through the process and can be relied upon to deliver for the full contract length. This is important for Distribution Restoration, as to have a successful solution, at the end of the procurement process, it is a combination of companies that will form part of a feasible DRZ, so it is necessary to have a firm knowledge that the contract obligations will be met. For example, **NGESO's Stability Pathfinder Phase 3** tender is using a pre-qualification form to review the financial reliability of potential providers; this is something that could be used for Distribution Restoration.

The current view is that no funding will be provided to DERs at this stage of the procurement process. More information on funding can be found in Section 9.

In responding to the EOI, each DER will have to assess their asset against the functional requirements, whether as an AG or TUS provider. Please see Section 4.1 to understand the functional requirements.

The providers may identify a need for upgrades to meet the functional requirements. If there is need for upgrades, they will need to highlight this via their EOI submission.

At this point, the providers would also need to highlight whether they would be aiming to stack this service against other industry services and the implications this may have for delivery of the Distribution Restoration service.

When the EOIs are received from the participants, this is the first step where an assessment and review of submissions will be undertaken. As NGESO will be the lead procurement entity, this will be led via NGESO; however, it will be imperative for the relevant DNO(s) to feed into this process.

This step will review the eligibility of individual providers, as well as the feasibility of potential DRZs, by considering whether there are enough TUS to support the AG and whether the DER assets are in appropriate locations to form a DRZ.

5.1.1 Rules of play

The rules of play will be applied during the assessment of the EOIs, as well as be used during the regional strategy phase undertaken by the DNOs yearly; this is explained in Section 3.2. The rules of play are used to assess whether a feasible DRZ can be assimilated from the available DER options.

There are four rules of play which reflect the essential technical services for a DRZ and give a relatively simple set of key requirements. The rules thereby allow a first-pass or high-level assessment of feasibility, but it will always be necessary to follow up with more detailed analysis.

The rules consider the 'available' level from the DER options and the 'required' level for the DRZ as a whole. The 'available' needs to be greater than the 'required' level for there to be the potential to form a feasible DRZ.

Rule 1: power

This involves comparing the maximum 'reliable' power generation in a given area with the maximum demand, or some other value of demand considered appropriate. Power generation from intermittent sources would be discounted by some factor to determine a 'reliable' value.

The rule should reflect the requirement of the ESRS and point to the possible purpose of the DRZ. This rule encompasses both the power and energy requirements, so no separate rule is required for energy.

Power required = 60 per cent x maximum MW demand in a DRZ

The DNO will provide information on demand in a potential DRZ area.

Power available = anchor MW x energy available factor + ∑ (TUS MW * intermittency factor)

The energy available factor reflects the fuel resource or stored energy available to the AG. For example, a gas turbine with reliable gas supply might be assigned a factor of 90 per cent whereas a battery with very limited stored energy might be assigned a factor of zero, which means the TUS providers will be relied upon to deliver the power required to meet demand. The intermittency factor for TUS providers depend on the technology type. The factors used in the Capacity Market may be appropriate, e.g. 9 per cent for wind, 1.5 per cent for solar. Either a de-rating or load factor may be appropriate.

Power available must exceed power required.

The excess power available will inform an assessment of what the DRZ may be used for, that is whether it can go beyond restoring demand within its own boundary. If the rule is not satisfied there may, in some circumstances, still be interest in development of a DRZ that focuses on transmission restoration or network resilience services only.

Rule 2: block load pick up

This rule focuses on block load pick up (BLPU) capability and thereby encompasses the functional requirements of fast MW control, frequency control and inertia, which are all related. It compares the combined BLPU capability of the AG and potential TUS providers with the block loading requirement within a DRZ. The requirement is set by the largest MW step that will have to be accommodated.

In some cases, it may be possible to avoid restoring some demands to prevent very large BLPU, or it may be possible to install additional switching flexibility to reduce the largest BLPU. The requirement will vary across potential DRZs, although a typical value might be 5 MW. While BLPU capability is a stated requirement for the anchor, the capability provided by TUS providers must be derived from MW ramp rate or other information.

BLPU required = largest necessary MW block load in a DRZ

The DNO will provide information on block loads. This will typically be the feeder or primary substation with the largest demand.

BLPU available = ∑ (DER BLPU capability)

Where DER covers the anchor and TUS providers and including any supplementary resources like controllable load banks, if this is known at the time of assessment, and assuming that a Distribution Restoration Zone Controller (DRZ-C) is used to harness the available capability. BLPU can be estimated where necessary using what information is available on the DER.

BLPU available must exceed BLPU required.

If BLPU available is notably high, then it suggests that the DRZ may be useful in energising other DNO areas, transmission connected demand, or providing start-up power to large power stations or other resources.

If the rule is not satisfied with the resources considered in the initial assessment, then a review might be conducted to identify opportunities for improvement, e.g. the addition of a controllable load bank may enhance the BLPU available sufficiently.

Rule 3: reactive power

MVAr capability of the DER can be compared against the requirement of the DRZ distribution network and, by considering the reactive power range available at the Grid Supply Point (GSP), point to the extent to which the DRZ might support transmission network energisation.

In a first-pass feasibility assessment, this can be done quite simply as a sum of MVAr ranges, discounted by a factor derived from examples. As the assessment proceeds, it might be done in a more sophisticated way assessing the specific capabilities of a given network and its DER. The assessment is focused on the capability of DER to absorb MVAr produced by circuit energisation. Typical values for 33 kV networks will be around 10 MVAr. It is assumed that MVAr capability can be delivered quickly and in a controlled way, as per the functional requirements.

MVAr required = the total MVAr gain of circuits in the DRZ distribution network

The DNO will provide information on MVAr gain, that is the total MVAr absorption capability that will be required.

MVAr available = ∑ (DER MVAr absorb capability) x MVAr range reduction factor

Where the MVAr Available is assessed across all potential participating DERs in the DRZ. The MVAr Range Reduction Factor accounts for the effects of uneven sharing across the DERs and the limitations on MVAr flows and voltage limits across the network. A typical value might be 60 per cent, but this could be refined through more detailed assessment of the DRZ in question.

MVAr available must exceed MVAr required.

The excess MVAr Available will inform an assessment of what the DRZ may be used for, i.e. how far into the transmission network might be energised. If the rule is not satisfied, then the scope for providing additional MVAr capability might be considered, e.g. installation of reactive compensation.

Rule 4: fault level

Fault level must be sufficient to operate protection and to allow other resources, including converters, to connect. In a first-pass feasibility assessment, this can be done quite simply as a sum of fault infeed contributions, discounted by a factor derived from examples. As the assessment proceeds, it might be done in a more sophisticated way assessing the specific capabilities of a given network and its DER. The DNO, with reference to the TO where appropriate, should specify the requirement at the GSP or at another busbar that represents the boundary of the DRZ. A typical value for a 33 kV network could be 50 MVA. Analysis within the project suggests that if fault level is sufficient at 33 kV, then energisation of 132 kV circuits should also be possible, but that energisation to 275 and 400 kV may require additional fault infeed sources.

Fault level required = minimum acceptable fault level at GSP or DRZ boundary

The DNO/TO will provide information on fault level requirements.

Fault level available = ∑ (DER Fault Level Infeed) x fault level reduction factor

Where the Fault Level Infeed is assessed from all potential participating DERs in the DRZ. The Fault Level Reduction Factor accounts for the effects of circuit impedances between the DER connection points and the GSP or DRZ boundary. A typical value might be 80 per cent, but this could be refined through more detailed assessment of the DRZ in question.

Fault level available must exceed fault level required.

The excess Fault Level Available will inform an assessment of what the DRZ may be used, that is how far beyond the DRZ boundary might be energised, and how much additional fault infeed may be necessary to support energisation up to 275/400 kV.

If the rule is not satisfied, then the scope for providing additional fault level might be considered, or means of reducing the requirement might be considered, for example modifying network protection.

Once the rules of play have been applied, it will become clear which DERs can create potential DRZs, and a decision will be taken by NGESO, with support from the relevant DNO(s), on who to move to the next step of the procurement event.

5.2 Assurance of capability

The purpose of the next step of the procurement event is to get assurance of the capabilities of the DER, both AG and TUS providers.

The nature of the AG service design means there is a high likelihood that upgrades will be required to the asset. This would be highlighted initially via the EOI. The next step is to conduct feasibility studies to ascertain the full nature of the upgrades, how much they might cost and how long they may take to implement.

The proposal is that this would follow the design of the traditional ESR tender events, as this has been proven to be successful over many years of NGESO procuring the service.

The participants will be required to undertake a feasibility 1 (F1) study, and alongside the submission of the F1 study would be a proposal of works for a feasibility 2 (F2) study. There will be a stage gate in the process after the submissions of the F1 study and F2 scope of works to assess whether it is beneficial to move forward with the provider on economic and technical grounds.

In the F1 study, the goal is to establish overall feasibility including an initial indication of costs and timeline for any changes required to equipment, supporting services and organisations. As mentioned, the participants would also need to submit a scope of works for an F2 study. This would outline what the participant would undertake, and how much the F2 study will cost.

The F2 scope of works will be used to understand the necessary elements to have a fully costed, detailed solution and the potential works required to be undertaken by the original equipment manufacturer (OEM).

A similar assessment will be conducted by the relevant DNO(s) who may host the DRZs. If the initial studies conclude that the DRZ is not feasible, then the process will terminate for the AG and TUS. If feasibility is confirmed, then NGESO, in collaboration with the relevant DNO(s), will decide who to invite to participate in the next step, which is the F2 study. This review will also consider the benefits of taking forward multiple participants to undertake F2 studies and the value to the end consumer.

P&C's current view is that the F1 study and F2 scope of works would not be funded; providers would need to fund this study themselves. The provider funding the F1 study demonstrates their commitment on offering Distribution Restoration services, and the F1 study is fairly low cost; generally, it is only the DER's cost of the resource required to support the development of a submission.

In the F2 study the aim is to provide a comprehensive and robust technical and commercial evaluation of the AG capabilities.

While the feasibility studies are being undertaken by the AGs, P&C proposed a different process for the TUS. The aim here, as mentioned previously, was to reduce barriers to entry to enable smaller parties to be able to participate in service provision for Distribution Restoration by reducing onerous and rigorous study requirements and associated costs.

The different technical services under the TUS banner are already provided by DERs in other NGESO balancing services, such as frequency control, fast MW control and reserve, so the understanding was that DERs may already have the capabilities for some of the technical services and not need to make upgrades to assets.

Other NGESO services utilise self-certification tests accredited by independent technical experts to prove their capability for the service. This enables the provider to understand their capability and to prepare to enter a service in a timeframe suitable for their business.

The proposed design for the TUS process, following feedback from DNOs for the previous report, was to create a 'pool' of pre-approved TUS providers who could be contracted with shorter contract lengths. This would be via self-certification tests which could be undertaken and approved within shorter timeframes.

In the extreme, contract lengths in days or even hours would enable fuller use of intermittent renewable generation who would have better sight of their service provision closer to real time.

However, learnings following the Test Procurement Event and feedback from DERs and DNOs has demonstrated it may not be as simple or currently technically viable to only utilise self-certification tests for TUS. The feedback received highlighted that there will be elements of the TUS functional requirements which will need to be studied, such as the resilience requirements. The understanding will also need to feed in, alongside the AG feasibility studies, to studies which the relevant DNO(s) will need to undertake.

The proposal now is that the F2 study will encompass feasibility studies from AGs and TUS providers and these will provide a comprehensive and robust technical and commercial evaluation of the proposed DRZ. The relevant DNO(s) will also be required to undertake network studies to understand any required upgrades to enable the DRZ options. Given the multi-party nature of the DRZ restoration process, the detailed studies will require a significant degree of collaborative working between the DNO and DERs.

Outputs of the feasibility studies will need to include an implementation plan and firm commercial offer from each service provider.

The P&C workstream's final procurement process design for the assurance of capabilities still allows for TUS providers to undertake self-certification tests if they are able to, and the output will prove their capability to provide the service.

P&C's current view is that the detailed study work by DERs will be funded with a cap on costs, subject to agreement of scope of work and contracts with the funding party. At the stage gate between the F1 study and the F2 study, there will need to be consideration on funding lots of F2 studies, if there are multiple TUS providers who require F2 studies, against the value for the end consumer.

Once the F2 study has been completed, this would be submitted to NGESO alongside the commercial submission which will include the tender participant's total cost to provide the service.

5.3 Combined assessment and contract award

The final phase of the tender event is where the received submissions are brought together to be assessed, with the aim to decide on contracts to be awarded to DERs within technically feasible and economically viable DRZ solutions.

All tender submissions will be evaluated against the functional requirements and assessment criteria. The assessment criteria has been designed to look at all the variables that need to be considered in assessing potential DRZ designs and options, including capabilities of the tender participants, the requirements of the DRZ area and total costs of the DRZ options.

The aim of the assessment process is to ensure the contracts are awarded to the most appropriate and economic combination of options for the DRZ. Publishing the assessment criteria provides transparency to tender participants on what NGESO values with service provision.

The assessment will look to assess what are the viable technical combinations from the tender submissions, alongside considering the weighted capabilities of the participants and the respective costs for the solutions. As such, there are two elements to the assessment: technical capabilities and commercial, which are brought together into an overall assessment.

The assessment process will consider all possible combinations of tender bids; individual tender submissions will be scored in combination with the other tender submissions. This means that participants will need to rely on the other participants to be successful in securing a contract. This is unusual for a tender design because a participant can usually understand the success criteria and use this for drafting their submission. In a Distribution Restoration service, there is a need for multiple parties to make a successful/feasible DRZ, so when it comes to the assessment this will be done across the multiple parties.

5.3.1 Technical capabilities assessment

The first step is the technical assessment of individual DERs, where the functional requirements will be assessed as pass or fail at the minimum level, with the minimum requirements for the service outlined in the above Section 4.1.

The technical assessment criteria for a DRZ will then be applied, and the capabilities of all participants will be considered alongside the submissions from other participants, to identify viable combinations that could form a feasible DRZ

There are 10 elements to the technical assessment criteria, which reflect both the functional requirements for AG and TUS and the rules of play for a DRZ as a whole. The criteria have specific measures, as described in Table 9.

As part of the design of the assessment criteria, P&C with support from the PET workstream, have weighted the different technical elements. Each technical element is important, but the weighting demonstrates the difference of importance between the capabilities and which are more highly valued. The rationale for the different weightings is also shown. These weightings could be modified as deemed appropriate by whoever is running the tender event.

The total minimum requirements for the DRZ will be calculated using the 'rules of play', as described in Section 5.1. As such, the minimum DRZ requirements will vary for different network areas. The rules of play will have been applied during earlier tender phases (pre-tender and EOI), so the minimum requirements for the DRZ as a whole will already be known.

Table 9:
Assessment criteria: measurement, weightings and rationale for weightings

Assessment criteria	Measure	Weightings	Rationale
Anchor capable	Pass/Fail	Pass/Fail	No weighting as it is a minimum requirement.
Power/energy	Average reliable MW over 120 hours	20 per cent	Most valued as it increases ability to restore demand and meet restoration standard.
Block load pick up	MW step increase capability	10 per cent	Given a medium/low weighting as greater capability gives more flexibility and will help reduce restoration timelines but with lower capability a DRZ may still be feasible. Note that these criteria are all related to frequency control and together assign a significant weighting to this group of capabilities.
Fast MW control	MW decrease in 200 ms	5 per cent	
Fast MW control	MW increase in 200 ms	5 per cent	
Inertia	MW.s	10 per cent	
Reactive capability	MVAr absorb at zero MW	15 per cent	Given a medium/high weighting as these capabilities are essential to establishing a feasible DRZ.
Short circuit level	MVA infeed 1s after fault	15 per cent	
Time to connect	Hours after instruction / energisation	10 per cent	Given a medium/low weighting as it will help to reduce restoration timelines but does not undermine the basic feasibility of a DRZ.
Service availability	Percentage available across the year	10 per cent	Given a medium/low weighting as the minimum requirement already sets a high threshold and greater capability will deliver only marginal improvements. This element has been given a weighting of 10 per cent, but if there are specific DRZ requirements, this may decrease to a 5 per cent weighting.
DRZ specific	Depends on DRZ, assume score out of 10	0 per cent	This element has been given a weighting of 0 per cent, but if there are specific DRZ requirements this may be given a 5 per cent weighting. Given a low weighting as it is not one of the fundamental technical requirements, although may be important in some circumstances.
Technical weightings total		**100 per cent**	

An individual DER provider will be scored more highly if it exceeds the minimum functional requirements and, when combined with other DERs in the assessment, the combinations of which they are a part will be scored more highly. The weightings are used to combine the scores from the different criteria to produce a single overall technical score for each specific combination of DERs. An individual DER is more likely to be part of the highest scoring combination if its own capability is higher for the elements with highest weighting.

5.3.2 Commercial assessment

As part of the assessment, consideration needs to be given to the total cost of the service. This includes understanding costs for service provision, upgrades to assets to meet the required technical elements, upgrades to networks to enable the service, upgrades to communications and other related costs. The various costs that will be involved in a DRZ all need to be considered in the assessment to ensure that the consumer is getting the best value for the service.

A commercial submission will involve a full breakdown of all costs for the DER. There are also costs outside of the DER that may be incurred by the host DNO. These include network upgrade costs (such as protection changes), resilience upgrades including communications and the potential installation of a DRZ-C to support the restoration process. The DNO feasibility studies will outline any costs that require capital investment to upgrade assets or networks.

The proposal for the cost assessment is to understand the total cost for the duration of the DER contract, which can then be used to compare between submissions.

There are a number of elements which make up the DER total costs, such as any capital investment costs, which are for upgrading any assets to meet the functional requirements. These costs are most likely to be more applicable to AG who may need to invest in self-start capability. However, there may be costs for TUS meeting the functional requirements, such as upgrading to meet the resilience requirements.

Alongside the costs for any capital investment is the ongoing annual cost of providing the service. This will be covered via the availability fee. This is made up of the following elements:

- Testing and assurance: any costs which are associated with testing the asset, such as a commissioning assessment or required tests over the duration of the contract. Testing is required every 3 years as mandated by the **Grid Code**.
- Ongoing operating or maintenance costs: these are for the provider to continue to meet the service obligations, such as maintaining the required technical capabilities and personnel resourcing as necessary to provide the required response to a Black Start instruction.
- Finally, there is the service margin; this is what the provider charges to provide the service. It may be broken down into a number of elements, such as their profit or any risks to the provider for providing the service.

The submission from the participant on these costs would be made for the duration of the whole contract. P&C's suggestion is this could be broken down into each year of the contract so it is visible where changes in costs may be expected. For the assessment, the total cost across the duration of the contract would be calculated and used alongside the technical scores to feed into the overall assessment.

Once the contract is awarded, the availability fee would be calculated by dividing the total cost of the contract by the number of settlement periods across the duration, to provide the ability for working out the monthly payments. The availability fee would also be updated for any inflation increases.

5.3.3 Overall assessment

The commercial and technical assessment outcomes will then need to be brought together to provide an overall assessment to ensure the right technical solution at the most economic cost.

Table 10:
To summarise, the steps for the assessment are as follows:

1	Assessment of viable DRZ options against the DRZ minimum total requirements.
2	Weighted individual technical capabilities will be used to calculate a score for each viable DRZ option, which will create a stack of viable DRZ options.
3	Total costs are calculated for the DER and the DRZ options.
4	A combined score is calculated from the technical and commercial assessment which forms the final stack of DRZ options.

For step 4 the combined assessment; the technical and commercial assessments will be brought together and assessed using a weighting for the technical score vs commercial score, this ensures that contracts are given to the options which provide the best value service, considering both technical benefits and lowest cost for the consumers.

During the Test Procurement Event, more detail can be found in Section 11, P&C tested different weightings for the commercial versus technical assessment. The weightings tested were technical 30:70 commercial, technical 50:50 commercial, and technical 70:30 commercial.

The outcomes from the assessment using the data received during the Test Procurement Event were the same for the different weightings, suggesting there was not much material difference. However, this outcome needs to be caveated as there were limitations in the data received from participants. Detailed feasibility studies had not been undertaken, so the technical data and commercial data were high-level estimates and intended only for testing the assessment process.

The proposed process is that NGESO would lead the combined assessment but the relevant DNO(s) will feed in their knowledge and review this process.

In the current ESR service, the technical and commercial weightings are 30:70, respectively. As this is a more mature procurement process and the technical capabilities are well known, it places more weighting on the commercial score as all tender participants will have suitable technical offers.

For Distribution Restoration, P&C's suggestion is that to begin with during an initial roll-out to weight the technical and commercial elements at 30:70, respectively. While all technical offerings from the Distribution Restoration service are suitable, as the process embeds itself some technical offerings may be more worthwhile than others; however, the ambition of Distributed ReStart is to always ensure value for the end consumer.

The output of the technical assessment process will be only technically feasible options, so it makes more sense to put a higher weighting on the commercial element to ensure value for the service. As the industry learns from the technical implementation and abilities of providers, and the process for Distribution Restoration becomes more mature, these weightings for technical vs commercial may evolve. These are recommendations which can be used to feed into the business as usual processes as the project transitions from innovation to implementation.

5.3.4 Competition between DRZ options

Alongside the DER technical and commercial assessment there will need to be an element that considers the wider service costs which are external to DERs, such as DNO upgrade costs. These will need to be taken into account to provide a holistic assessment of the total cost of a DRZ. The assessment spoken about in the previous three sections is solely for comparing DER solutions within one DRZ.

As the service grows and expands, assessment may need to happen across multiple DRZ options. P&C's suggestion is that once the technical, commercial and overall assessment has been completed, a cross-DRZ assessment will need to be undertaken to assess the different DRZ options, and this would look at the total costs for a DRZ.

The total costs for a DRZ will include a total of the costs for each of the DERs within a DRZ option, plus costs for the required upgrades to DNO networks. As mentioned in Section 5.2, as the DERs are undertaking detailed feasibility studies the DNOs will also undertake detailed network studies to understand the full requirements of any upgrades to their networks to enable the DRZ options.

DNO costs could include:

- network upgrades, such as protection changes, installation of circuit breakers, additional earthing, etc
- installation of resilient communications
- potential procurement and installation of a DRZ control system
- expansion of control room and field resources plus additional training
- additional engineering resource required for DRZ analysis and testing.

Once this assessment has been done, the DRZ options would be stacked in merit order, considering the technical capabilities and total costs. Then a cost benefit analysis (CBA) could be done to ensure that the total benefits of the DRZ are considered and not only compared on cost. The benefits could include how much the DRZ aids the restoration timescales and NGESO meeting the ESR Standard, the customers connected at the DNO network, or other benefits.

The cost element of the CBA would consider the total costs of the DRZ, both DER and any DNO costs. The DRZ options could then be re-stacked and contracts would then be awarded down the merit stack against the requirement for how many DRZs may be needed in the relevant DNO(s) area, subject to any budgetary limitations. This requirement will be decided in the national/regional strategy and pre-tender phases.

5.4 Contract award

Once all the assessments have been completed and a decision has been made on which DER will be awarded contracts, the DER will be informed that they have been awarded a contract and what the next steps will need to be.

As part of the P&C workstream's deliverables, the draft contract has been developed, which is discussed in Section 10. This will have been provided to tender participants at the EOI step, possibly along with a contract declaration form, where participants have the opportunity to agree to the standard terms or suggest changes.

DER providers will be required to sign and return the contract within a set time period. The standard terms of the contract will have been published during the EOI stage of the procurement process, so providers will have had sight of the contract ahead of contract award.

Once the contract has been awarded this is the end of the procurement event. Next the procurement process moves into the construction phase of the procurement process, where any enabling works to assets are undertaken.

6. Procurement process – construction and commercial operation phases

There are two final phases of the procurement process: construction and commercial operation. Construction involves implementing any build requirements and upgrades to plant. Commercial operation covers the delivery period of the contract.

6.1 Construction phase

Once the contract has been awarded and signed by all relevant parties, the procurement process moves into the construction phase. The construction phase is for conducting any enabling works to ensure the DRZ service procured can meet the obligations set out in the contract.

These enabling works may need to be undertaken by all parties involved in the procurement process: NGESO, relevant DNO(s), the anchor generator (AG) and top-up service (TUS) provider(s). These works will differ for each party but will have been outlined in and agreed during contract award.

The relevant DNO(s) will need to upgrade the required parts of their network, including potential procurement of a DRZ-C. The specifications for these upgrades will have been outlined and developed through the feasibility study undertaken by the DNO, as explained in section 5.2. The requirements for the development and procurement of a DRZ-C have been designed by the OST and PET workstreams with more developments being finalised early 2022.

The AG provider will most likely need to make enhancements to the asset to ensure that by the service commencement date it can meet all the obligations within the contract. Again, these will have been outlined during the feasibility studies and the plan for implementation will be included within the contract.

The different TUS providers may or may not need to complete any works. If there is a requirement, this will have been highlighted via the feasibility studies or self-certification tests. Any implementation plan for the works will be included within the contract.

NGESO may need to update communication routes with the relevant DNO(s) or DER provider(s); this will be done alongside the other construction works and may be highlighted during the feasibility studies or through discussions with the providers and relevant DNO(s).

Once the works have been completed by providers, a commissioning assessment will need to be organised to prove they have the required capability and can commence service provision. This will be organised in conjunction with NGESO and the relevant DNO. Outputs from the PET and OST workstreams will feed into what the design of a commissioning assessment may need to include. Where a TUS provider has undertaken a self-certification test and they do not require any enabling works, there may be a need to complete a more stringent assurance process to ensure they can meet the requirements of the contract.

Alongside any enabling works will be the development of a Distribution Restoration Zone Plan (DRZP). This is the equivalent to a Local Joint Restoration Plan (LJRP) used in the traditional ESR process. The DRZP will outline the processes to follow when in a Black Start situation. More information can be found in the **OST report.**

Multiple DRZPs can co-exist in the same DNO area but not utilise the same parts of the network and could be invoked simultaneously depending on instructions from NGESO. DRZPs and LJRPs cannot use the same part of transmission network, they are mutually exclusive.

Once all the commissioning assessments have been completed and a DRZP is in place, the service can commence.

6.2 Contract delivery phase

The commercial operation phase begins when the service commences and finishes when the contract ends. This phase involves ensuring that the Distribution Restoration service can be enacted, if needed, in the event of a Black Start.

The providers will need to ensure they maintain their capability to provide the Distribution Restoration service. This could include any maintenance to assets, or training of their staff on the procedures to undertake in the event of a Black Start.

The relevant DNO(s) will also need to ensure they maintain their capability. This could include training on restoration procedures and maintenance on any network assets required for DRZs. **The OST workstream's latest report*** outlines proposals for frequency of training.

During the contracted period, the contract will be managed, and the delivery by DER parties will be monitored. As part of the service requirements there is the need to meet 90 per cent availability on having the capability to provide either the AG service or the relevant TUS. If the availability is not being met, NGESO and relevant DNO(s) may have scope to manage this non-delivery with discussions on how to

*Page 38, section 6.2.

improve and ensure the provider meets the obligations of the contract, or potentially terminate the contract. This is discussed in Section 10. To support with managing the contract, the proposal is to have a 'DRZ operational working group'. This will be made of up representatives from NGESO, relevant DNOs and all DER parties (anchor generator service provider and each top-up service provider), and potentially also representatives from the relevant transmission owner (TO).

The aim of this working group will be to highlight and manage any issues as they appear, to reduce any need for termination of contracts within the DRZ. The working group would also be responsible for organising training for all parties and testing of the DER assets. This working group would be set up straight after contract award to support with managing any works before service commencement. P&C recommend this could be organised on a quarterly basis, or more regularly if necessary.

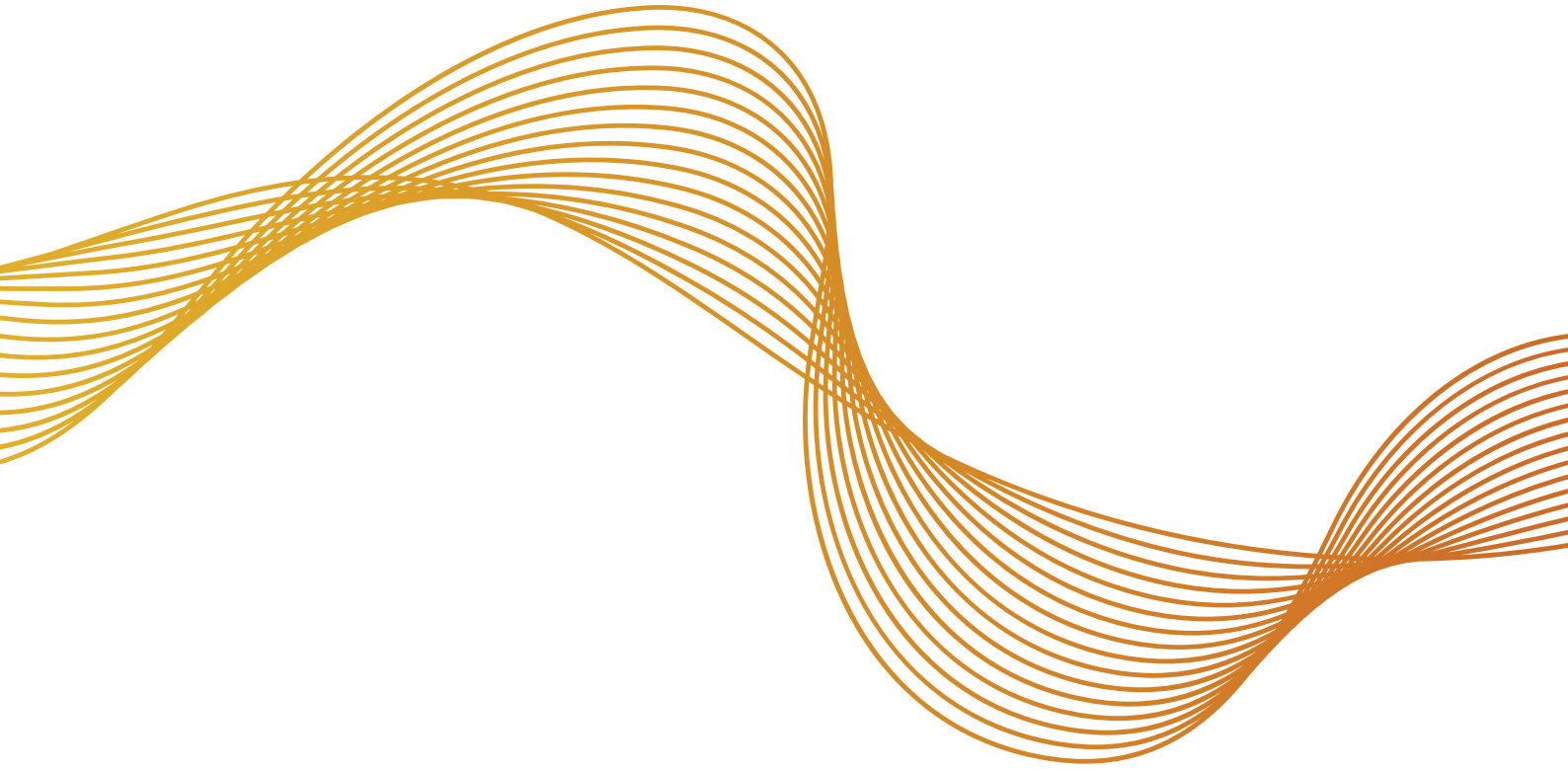
It also recommends that the participants of the DRZ working group sign an equivalent of non-disclosure agreements to enable the free flowing of information between providers.

6.2.1 Performance monitoring

Performance monitoring will be undertaken to assess providers' abilities to meet the required 90 per cent availability of service provision. Each year an assessment of availability will be done, this will exclude times of planned maintenance or other agreed periods of unavailability. The DRZ-C design monitors availability continuously and could feed this data into the yearly availability assessment process. This data will need to feed into the settlement processes and systems so the service can be paid for correctly. More detail on how the data flows between different systems and is used for monitoring is covered in Section 7.

6.2.2 Testing

During the contract delivery phase providers of a Distribution Restoration service will be required to undertake testing of their assets, this is to prove their restoration capabilities. The initial designs for these required tests will be developed by the PET workstream. In the Grid Code and Distribution Code legal text drafting, explored in Section 12, two types of tests have been included Station Tests and Unit Tests.



7. Procurement systems

This section gives consideration to systems required for procurement, what functionality would be needed and where in the process these might need to be developed.

The OST and PET workstreams have developed and discussed the systems required for the operational side of Distribution Restoration and what is needed within a Black Start event; this includes the DRZ-C. More information can be found on the **Distributed ReStart website** in the different OST and PET reports.

As discussed in Section 3.3, P&C's proposal is that NGESO will lead the procurement process, which means that the Distribution Restoration service can use systems which are used or being developed by NGESO. NGESO currently has systems in place for settlement which will be used for Distribution Restoration.

The EOI step, explained in Section 5.1, could benefit from a system to support with registration and pre-qualification for the tender participants. NGESO is currently developing a system called the Single Markets Platform (SMP), which aims to provide seamless access to all NGESO ancillary services markets for a wide range of diverse participants.

The SMP is currently developing its foundational functionality to onboard participants into new day-ahead response and reserve products expected to be launched from March 2022. The SMP could, in the future, include onboarding and registering providers for the Distribution Restoration service. More information can be found on **NGESO's website.**

The development of the SMP is being done in stages and is focused on closer to real-time markets initially; as a result, during an initial roll-out of the Distribution Restoration service it may not be appropriate to use the SMP, but for future tenders there may be the possibility to enable the use of the SMP.

The current ESR service already utilises a system for registering participants and receiving submissions which can also be used for the Distribution Restoration service; the SMP could replace this in the future.

As part of refining the service design, P&C also considered a number of other systems that could be used for the procurement process, such as the systems used by the DNOs for procurement of flexibility services. This includes **Piclo** and **Flexible Power.** Both advertise the flexibility services that the DNOs need to procure and enable parties to upload their assets onto the platforms and tender for services.

The assessment process, outlined in Section 5.3, could also benefit from being supported by a system. Section 11, Test Procurement Event, discusses how a spreadsheet was used to assess the mock tender submissions, which was manageable in the test environment with a small number of inputs.

It would be beneficial to develop a system or a more advanced model to support with assessing the submissions received in actual tender events. It would need to understand the technical elements of each of the submissions and the commercial elements and assimilate the submissions into a feasible DRZ utilising the 'rules of play' discussed in Section 5.1, to produce a merit stack of DRZ options which provide the best value for the end consumer.

Key to the success of a Distribution Restoration service is the integration between the different systems to ensure they work in tandem. The data needs to flow seamlessly between the systems to feed into the different processes, such as from the assessment and contract award into NGESO/DNO operational systems and from NGESO/DNO operational systems into the settlement system.

Once the contract has been awarded, coordination between systems is integral to ensure the Distribution Restoration service can be monitored and maintained. Any procurement platform or procurement team will need to feed through the contract data to the operational systems. This includes the DRZ-C, which will monitor and manage availability of the DER within a DRZ. More information can be found on the **Distributed ReStart website** in the OST report and further information will be released next year.

The DRZ-C collects availability data on the service provision from DER; this will need to flow through into the team that settles the service. They will need to be aware of the availability of DER assets to ensure the DER assets are paid for the correct level of service provision.

Any systems forming part of the Distribution Restoration service will need to communicate with each other, this will ensure the data flows correctly through the processes and systems.

There will be more providers as part of the Distribution Restoration service, which means there will be more data to handle compared to the traditional ESR service. If this data is handled manually there may be more safety and compliance issues with the way the data is managed, so development of suitable systems is beneficial for reducing these risks.

The table below demonstrates what the P&C workstream considered needs to be answered at each phase of the procurement process and the different inputs and outputs between these phases. The outputs from this exercise will help determine the requirements for how data needs to flow between the different systems required at each stage of the procurement process.

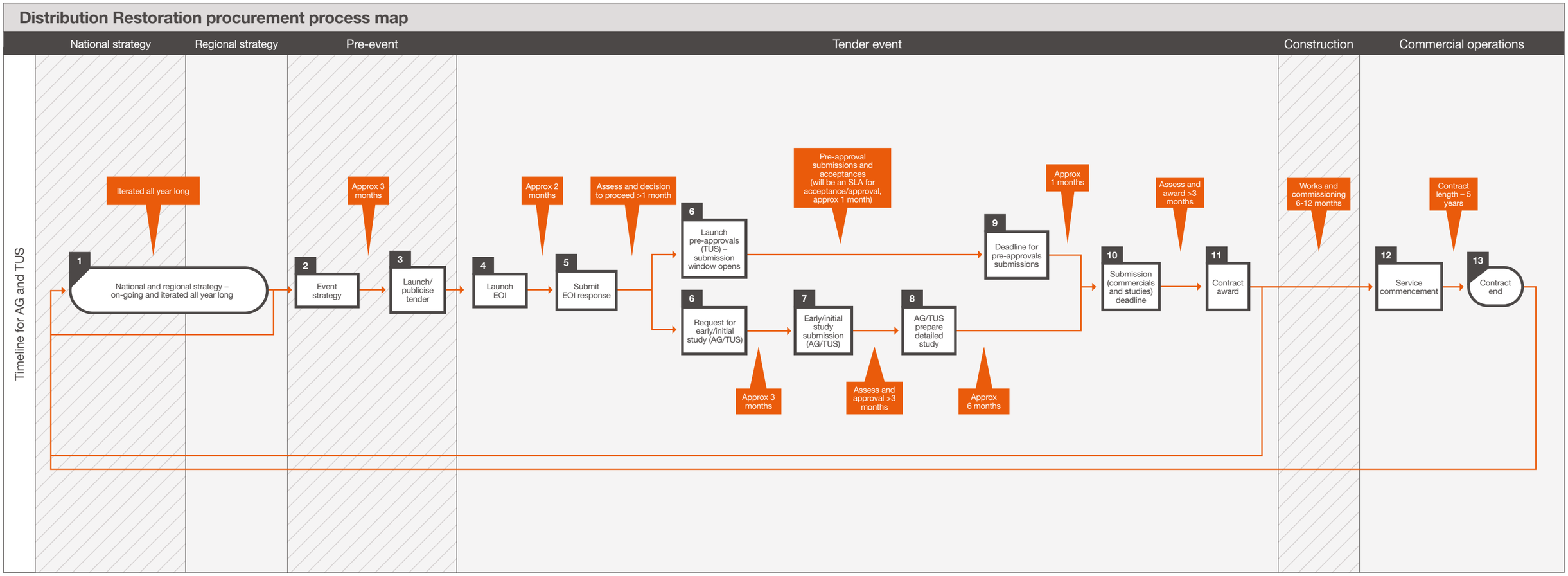
Table 11:
Data flows between procurement process phases

	National strategy	Regional strategy	Pre-event	Tender event	Construction	Commercial operations
What questions need to be answered?	• What is the strategic aim of the service over the short/medium/long term timelines? • What courses of action might be needed to meet the aim? What risks are there to meet the aim? • What capability is there currently (profile of current contracts – when do they end)? Profile of supply pipeline against future service design, e.g. current, built but not involved, future builds? • What is the national service level required? • How much can current capability meet it? How much can future expected capability meet it? Where are the gaps? • Is regional support required to meet national service level? Will the regional capability be sufficient to meet the required regional service level?	• Is there generation connected at the distribution level? Are there feasible DRZs? • Does the network support DRZs? • Can the national gaps be filled by the distribution connected assets/DNO network? • Will the regional support be enough? • Assess methods of accessing services; is a commercial solution optimal?	• What does the commercial strategy need to contain? • Who might participate, what is the event strategy, what are the assessment criteria and technical requirements? • What do the timelines need to be? And what is the contract strategy? • What information do the tender participants need? Geographical area for tender? What systems will be used? • How to align required tenders between traditional ESR process and Distribution Restoration?	• What are the technical capabilities of the providers who have submitted tenders? • Are there enough submissions to meet the required service level? • Are there enough DER submissions to create feasible DRZs? • Which are the most appropriate and economical solutions to award contracts to?	• Are the providers meeting their enabling works progress plans? • Are DNOs progressing their network upgrades, inc automation, resilience? • Have providers met requirements of required commissioning assessments? • Will the service commence on time?	• Are all parties aware and trained on what to do in the event of a Black Start situation using the DRZP? • Are providers meeting their availability level? • Do DERs pass the required tests? • Are DERs meeting the contract obligations?
What data inputs are required?	Restoration model, Future Energy Scenarios (FES), current contracts, 'generation' information (NGESO). Distribution FES (DFES). NGESO's Restoration model, assurance schedule (NGESO). Electricity System Restoration Standard (ESRS) (BEIS/Ofgem).	Outcomes of national strategy, DFES, Distribution Long Term Development Statements (LTDS), DNO network data, distribution 'generation' data, technical requirements of Distribution Restoration service.	Knowledge of number of potential tender participants, outcomes from the strategy phases, requirements for meeting the ESRS, technical requirements for the service.	Initial provider capability data contained within EOI submissions. Data from both feasibility studies (F1 & F2). DNO network study data and outcomes. Commercial submissions. Buying requirements.	Progress updates, contract obligations, testing designs, DRZ-C designs, outputs from feasibility studies.	DER availability (monitoring via the DRZ-C), DNO network availability, design of the DRZP, DRZ operational working group outputs.
Outputs of each phase	A developed national strategy which can be used by the DNOs to underpin their regional strategy.	A developed regional strategy with agreement between NGESO and relevant DNO(s) on appropriate commercial solution.	Design of a tender process for Distribution Restoration along with developed tender documents, inc tender timelines and process, service design and requirements.	Contract award to the most appropriate and economical solutions. Contract data which feeds into the development of the DRZP.	Completed enabling works and successful commissioning tests.	A functional DRZ that can be used within a Black Start situation. A good value Distribution Restoration service delivery.
Who requires the information?	NGESO.	All DNOs with support from NGESO.	NGESO with support from relevant DNO. Potential tender participants.	NGESO, DNO(s), tender participants.	NGESO, DNO(s), successful DRZ participants. DRZ operational working group.	NGESO (Contracts, Settlement, Restoration and Control Room teams) DNO (Control Room team, and a potential Restoration team), DER providers' operational and commercial teams.

8. Procurement process timelines

As part of the development of the Distribution Restoration service procurement process, the P&C workstream have proposed accompanying timelines for each of the phases of the procurement process.

Figure 9:
Procurement process timelines



P&C engaged on the whole process using the process map developed as a visual support, see Appendix 4. The main feedback received was on aligning the AG and TUS processes, which has been discussed in Section 5, and on the proposed timelines. This section will discuss the proposed timelines, feedback and updates.

Section 3 outlines the processes for the national and regional strategy phases. P&C's proposal is that the strategy review for restoration services would be done on a yearly basis, which is currently the case for NGESO's GB national strategy review.

A yearly basis ensures that there is awareness and understanding of current restoration service levels and future requirements. It can also feed into planning for future tender rounds and provide the market with reasonable notice of when tenders for restoration services will be run.

Once a decision has been made to run a restoration tender, the suggestion is for the pre-event planning phase to take around 3 months. This enables time to develop all the required tender documents, as outlined in Section 4, as well as advertise the upcoming tender to the market.

As NGESO will be picking up the lead for the procurement, the timelines for each of these phases will need to be aligned between the tenders for Distribution Restoration and the traditional ESR services. This ensures there is alignment between the procurement on both the requirements for procurement event, which feed through to the pre-event phase, and decisions when it comes to contract award.

The proposed timelines for the steps in the procurement event phase can be seen in Figure 9. These were based on learnings from NGESO on the tenders already run, as well as understanding of the process for Distribution Restoration. The feedback received from industry can be seen in Table 12 below.

Table 12:
Feedback received from the DER webinar and follow-up 1:1s, as well as from the Test Procurement Event on the proposed timelines for the procurement process

Feedback received	Action
The timelines as they stand do not enable new builds.	Consideration will be taken on board as to whether to enable new builds to participate and how long the durations for each phase might need to be to enable a new build to participate.
Tight to turn around a feasibility study in 6 months.	The process will be updated to align with the traditional tender but also allowing time for detailed feasibility studies to be undertaken by all parties (AG, TUS and the relevant DNOs). Outputs from the PET workstream will also feed into any updates made to the time required to complete detailed feasibility studies.
5-year contract is too short to enable new builds. 5-year contract would need flexibility built in to accommodate market changes.	The contract length will be aligned with the traditional tenders, and also the requirements of the Electricity System Restoration Standard. Considerations will be made on how to incentivise new builds with potential longer contract durations.
Differences between timelines for AG and TUS.	P&C updated the proposed process to align the AG and TUS processes, enabling both services to undertake feasibility studies as required.

As this service gets implemented into business as usual, there will be the requirement to review the proposed timelines and update. The learnings will come from further industry engagement, the final outputs from the PET and OST workstreams, and the requirements from the ESR Standard.

The outputs which will feed in from the PET and OST workstreams are the design of the required feasibility studies and how long they might take, the time needed for the required tests, and the development, design and procurement of the DRZ-C.

9. Funding arrangements

This section focuses on the aspects around funding the service and how the costs might be settled. Given the differences between the existing ESR process and the one proposed in this report, the objective here is to have appropriate funding mechanisms that support the obligations and accountabilities between NGESO, DNO/DSO and DER providers.

NGESO is obligated through its **licence special condition 2.2** to make its strategies and methodology around the procurement of ESR transparent. Through these yearly publications the schedule of regional tender rounds and service provision requirements at transmission level is detailed.

All costs associated with running these tenders are recovered through **NGESO's RIIO (Revenue = Incentives + Innovation + Outputs)** price control as cost pass through via **Balancing Services Use of System (BSUoS)** charges.

In NGESO licence the definition of Black Start Costs is "the total costs associated with the provision of Black Start, including procuring, testing, warming, utilising, capital contributions and payments for Feasibility Studies costs."

This means that for NGESO, any Distribution Restoration costs can be deployed within the RIIO-2 price control to recover appropriately, any contractual costs with the parties involved. This is on a cost pass-through basis, although under its regulatory model NGESO is incentivised to be efficient in this procurement through its incentives scheme.

The regulatory models are prescribed via the codes. The Grid Code is the technical governance document which covers the ESR process; the **BSC** and **CUSC** methodologies are used to enable effective settlement via BSUoS. Sections 12 and 13 outline the required changes to industry codes for enabling the new Distribution Restoration process.

Figure 10:
The categories of costs recovered by NGESO for existing ESR/Black Start contracts

9.1 Options for funding arrangements

The P&C workstream liaised with the PET and OST workstreams, as well as with DER providers and DNOs, to compile a list of cost categories, which is outlined below. Once established, expert advice from regulation and price control experts from within NGESO, SPEN and Ofgem was sought to outline options of how the costs could be settled in an interim or more enduring period.

Figure 11:
Summary of costs incurred by the different parties in the Distribution Restoration procurement process

Lead procurement agent (NGESO):	For DER:	For DNOs:
Time and resource for developing the national and regional strategies as well as pre-tender arrangements with DNO or DSO.	Feasibility studies.	Time and resource for developing the regional strategy and pre-tender activities with NGESO or DSO.
Legal costs associated with contract development.	Capital investments, which include resilient communications and upgrades to asset capabilities	Network feasibility studies during the tender process, for the establishment of feasible DRZs.
Audit costs across the process.	Integration with systems, such as the DNO's DRZ-C automation system,	Network upgrades to enable the restoration, including circuit breakers and protection settings.
BAU costs of running the tender event, managing contracts and assurance/testing activities.	or NGESO's procurement or settlements systems.	Procurement of the DRZ-C system that creates the automatic links with the DERs for communication and start-up and management of the DRZ.
Annual training of control room engineers.	Availability fees, which includes the cost for testing the asset capability.	Cost of setting up resilient communications and any extensions out to new DER parties joining the DRZ.
		Testing of network system with DER providers.
		Training resources for the DER on system use and processes.

Key:

Yellow – NGESO RIIO-2 (BSUoS)

Orange – DNO RIIO-ED2 (DUoS)

The three options explored to recover these costs were as below:

1. NGESO leads the procurement and settles all the DER costs; however, all the DNO network, systems and telecommunication upgrade costs are recovered as part of the DNO's own network price control.
2. DNO/DSO lead the procurement and pay for all the DER contract costs plus their own network costs.
3. NGESO leads the procurement and pays for the DER contract costs and any costs incurred by the DNO.

Engagement on these options was conducted in tandem with the procurement process and who leads it, so that it was not influenced by any prior decisions.

Other considerations made were:

- These options should support the decision around who leads the procurement as they would be expected to pay the DER providers.
- The cost recovery needs to work for the various funding frameworks which function differently. The price control and licencing arrangements differ between the DNOs and NGESO which means that their remuneration has different parameters and mechanisms to scrutinise performance, investments and efficiencies/value for end consumers.
- On the assumptions outlined in Section 1.4 which could influence how this process may need to operate immediately and then differently following industry review in future.
- All the necessary code modifications are in place to support the appropriate funding mechanisms.

The three options explored had the following benefits and risks.

Table 13:
Options appraisal for settlement and funding arrangements

Option	Benefits	Risks
NGESO pays for DER costs only	• This is as close to the as-is ESR process and therefore the settlement procedures are tried and tested already and NGESO's price control has provision for remunerating DER service costs through BSUoS and one-off invoices. • Compared to the other two options, relatively few code modifications will be required; these changes are already captured in the codes work to make provision for Distribution Restoration services. See Sections 12 and 13. • For DNO network costs, Ofgem have suggested that DNOs will be able to recover these costs, whether as part of their ED2 submissions or through uncertainty/ reopener mechanisms in ED2 as required. This is mainly because these upgrades have future use beyond Distribution Restoration, DNOs should recover this investment in their own funding model. • This aligns with the position that NGESO should not be required to make settlements to the DNO for upgrades on its network which could add future returns on this investment.	• As this Distribution Restoration process will be used in the next round of ESR tender in South East region from April 2022, the affected DNO will still be in the ED1 price control. Expecting provision for network upgrades might be difficult to arrange with the new ED2 period imminently starting. As a result, a temporary arrangement might need to be agreed with Ofgem to help recuperate these network costs required ahead of 2023. This process could take time, and engagement with Ofgem would need to start immediately.
DNO/DSO pay for everything	• This option makes more sense if the DNO/DSO are leading on the procurement.	• Consultation and further engagement may be required with DER providers, some of whom have expressed a strong preference for contracting with NGESO, on account of being used to dealing with the NGESO rather than the DNOs. • As the PET and OST workstreams are not fully concluded until June 2022, DNOs will not have full scope of what network costs they are required to plan and include in their ED2 business plans. They will most certainly require an uncertainty mechanism or a restoration reopener, similar to what TOs have in their price control plans. • The DSOs may only pick up the requirement for procurement of Distribution Restoration services if obligations are transferred to them via the ESRS work. More code and licence modifications may be required to enable this, which could add time to the implementation.
NGESO pays for everything	• There are familiar models of settlement to use, where NGESO has paid out to the DNO for DER services, like Power Potential.	• As this restoration service differs from RDPs and Power Potential, it makes less sense for the DNOs to get paid by NGESO. In this Distribution Restoration service, there is a direct contract with DER providers and utilising the DNO's network, unlike the other services where the DNO contracts with the providers for use on their network. • The investment on upgrades can be used by DNOs for other DER services, which means they could get a further return on investment in the longer term through their own network price control. If DNO network upgrade costs are passed via NGESO, there is a risk that it will miss the regulatory scrutiny on network investments which ensure the best value for consumers. There would need to be a process in place to ensure consumers are protected which would need to ensure equivalent scrutiny to any other investment. • This is not a preferred option, and if pressed to take forward, consultation with Ofgem will be required upfront to agree the best approach. This will need more time planned in before this process can be transitioned into business as usual (BAU).

To demonstrate the differences against the three options, see Figure 12 to 14 which group the costs at a high level, so that the volumes of payments required can be seen.

Figure 12:
Option 1 – NGESO pays for DER costs only and DNO recover their own network costs

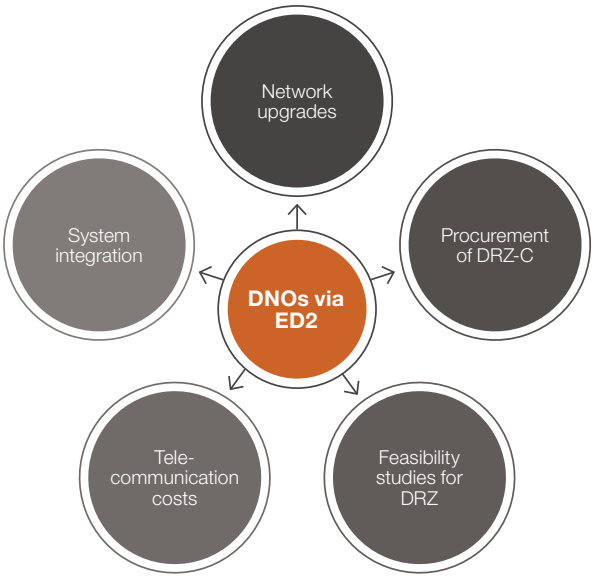
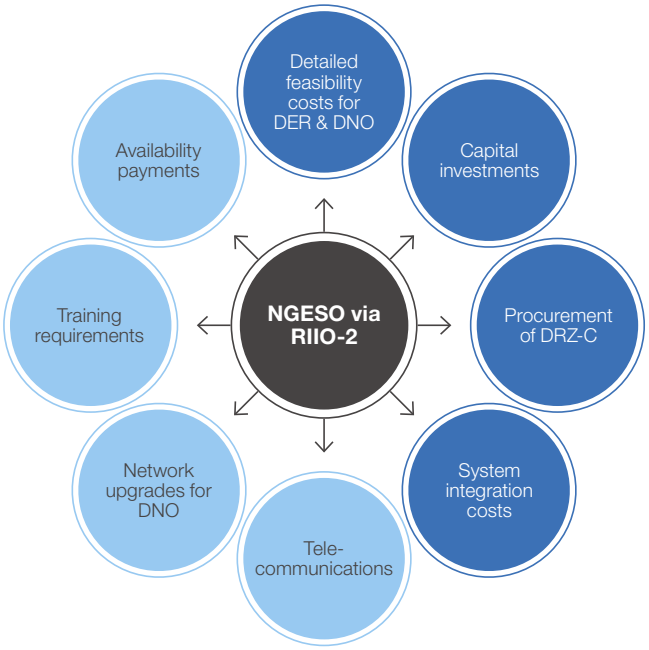


Figure 13:
Option 2 – DNO/DSO pays for all the costs

Figure 14:
Option 3 – NGESO pays for everything



9.2 Stakeholder engagement

The three options above, the consideration points and the benefit analysis were shared with DER stakeholders, the DNOs, regulatory experts, Ofgem and BEIS. The P&C workstream's aim here was to find a method of settling the costs incurred by the various parties, by using the most suitable funding mechanisms that keep the end consumer costs down and scrutinise the performance and incentives for the lead procurement agent, in a fair but regulated manner.

The common feedback from the DER stakeholders was that it made sense that whoever leads the procurement process should set up the service payment structure. The options for the stakeholders was whether they preferred being contracted and paid by NGESO or by the DNO/DSO. Three out of thirteen DER stakeholders did not have any comments to share on this area. Out of the remaining ten, six preferred it if their payments came from NGESO, two of them were happy with either choice and only one felt DSO should lead.

Other recommendations suggested were around:

- possibility of funding provision for the initial feasibility study
- more transparency in how commercial assessment against the breakdown of costs is carried out
- preference to have a payment process based on availability rather than utilisation of this service.

Initial feedback from Ofgem and BEIS was that they both agreed that the current remuneration process for Restoration services using BSUoS worked well. On the question about the costs incurred by DNOs as part of this new process, their collective opinion was that the DNOs should be able to claim for those through their own network price control, whether through their business plans, a reopener or other uncertainty mechanism process especially for initiatives that support Great Britain's net zero ambitions. The BEIS representative echoed the point that the Secretary of State has sanctioned this need; therefore, aspects such as how costs are recuperated through the different price controls should not become a blocker to progress. Between these departments, neither parties could see any reasons DNOs should disapprove of the proposals.

DNO feedback was a bit more mixed:

- Two were most comfortable with each party recovering their respective costs through their own price control mechanisms.
- Two felt that as this is mostly a NGESO obligation, costs on the DNO networks for restoration services should be covered by NGESO.
- Two had no preference as long as mechanisms exist in both price controls for this type of service.

Other comments shared by the DNOs that had an impact on the final recommendation were:

- Despite the diminishing timeframe to incorporate potential DNO network upgrade costs required into ED2 Business Plans, if enough support is gathered from across the DNOs, a formal reopener mechanism can be requested from Ofgem to support the first option.
- There are other settlement models such as the Accelerated Loss of Mains Change programme where NGESO covers DNO costs so that the costs flow through BSUoS, as BSUoS payers benefit from this project in the longer run.
- NGESO could have a future role as a moderator if costs are passed through them, to avoid any regional imbalances. There may be a risk that if DER costs are recovered through Distribution Use of System (DUoS) charges, some parts of the UK could end up paying more for this ESR service than others due to where they are located.
- It might be worth running this process for a while and then evaluating in future to see if the cost benefit analysis of either of the three options might mean that one of them is better value for the end consumer, whether by NGESO or DSO.

To seek further clarity following the DNO engagements, their feedback was raised with Ofgem again to understand if there was a single solution that could be recommended going forward. Ofgem considered the scale of activity ongoing with ED2 business plan submissions and the need to roll out a version of this process quite soon to support the SE tender round in 2022. Their position was that the proposals need to be pragmatic and stakeholder tested. Like the earlier interactions with Ofgem, they are willing to arrange, on a case-by case basis with DNOs, an appropriate funding mechanism that might work best for them in ED2.

9.3 Funding arrangement recommendations

For settlement and funding, the P&C workstream propose for now that NGESO will cover the DER contracted costs through BSUoS, and during the tender the DNOs should recuperate their own costs including network upgrades and the procurement of a DRZ-C through their own price control using DUoS.

Ofgem have clarified that provisions in ED2 will be made as required especially for initiatives supporting net zero ambitions. DNOs should discuss options with Ofgem directly, which could range from including the costs as part of their totex, agreeing cost pass-through arrangements or using uncertainty/reopener mechanisms.

In the long run, if the process changes hands to DNO or DSO, or obligations change as part of the FSO consultation, then the provisions for funding and the relevant charging methodologies will need to change accordingly following direction from Ofgem. As this process gains momentum, it is the P&C recommendation that the remuneration of all the respective costs is carried out as part of business plan totex calculations. Once tenders have been run for Distribution Restoration multiple times, DNOs will have a good idea of how much to budget into their ED3 Business Plans for example. At that point, all code changes to support the evolved process will need to be completed too.

The process for claiming any incurred costs as a result of a Black Start instruction is currently covered within the BSC. Sections 12 and 13 delve into the required code changes to enable Distribution Restoration and the potential claim process for DER.

10. Contract development

This section covers the contracting options explored to support the proposed procurement process for DERs providing the anchor generator service or top-up services. The contract aims to cover the obligations on the three parties involved (NGESO, DNOs and DERs).

In the existing ESR process, NGESO has obligations and responsibilities for consistency across procurement, tendering and testing processes written into its industry codes and licence conditions **(Electricity Transmission licence special condition 4G)**.

In the current ESR process, NGESO will have Commercial Service Agreements (CSAs) on a 1:1 basis with individual providers, who are generally large-scale transmission connected generators.

Interconnectors are a slight exception, where tripartite agreements are utilised. In this case NGESO will have a tripartite agreement with the Interconnector owner and the respective TSO. The agreement will cover the cost of maintaining the asset for the Interconnector owner and will cover the energy required to deliver the service, in the event of a Black Start, with the relevant TSO.

This is a back-to-back contracting arrangement. In this process, NGESO does not need to contract with the TOs or DNOs as their requirements are factored into the Local Joint Restoration Plans (LJRPs) and mandated by the Grid Code and the STC.

In the proposed procurement process, to support the bottom-up restoration strategy, there will be a lot more contracts required (compared to the existing ESR/Black Start process) with various DER providers providing either AG or TUS services.

The biggest change in the proposed Distribution Restoration process is that the DNOs have an enhanced role to play from the very start in the regional strategy and pre-event phases, right through to the end of the contract period. In the event of a Black Start, following instructions from NGESO, they will be responsible for instructing the DERs and coordinating the process right back up to the transmission network – following Distribution Restoration Zone Plans (DRZPs).

In this section, the focus is on what agreements need to be in place for the commercial operations phase of the future Distribution Restoration procurement process.

Note that any requirements for pre-tender arrangements are highlighted but not explored in the same depth as the contract for delivery of the service. This is because further collaboration is still required between NGESO and DNOs to agree how this could work, and this could be informed in the transition to BAU plans.

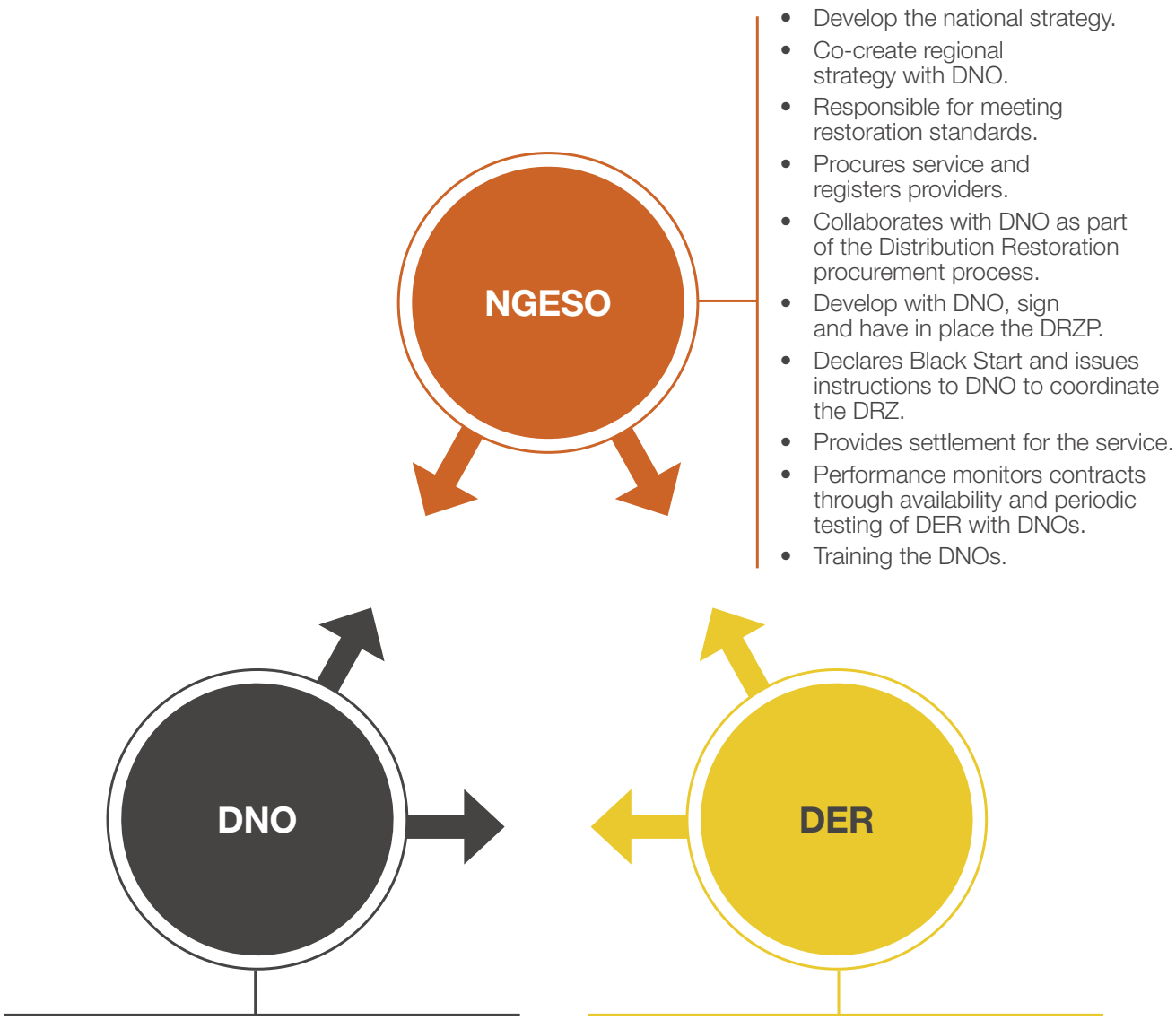
10.1 Development of contracting options

To understand and deduce the best options around contracting for this service, advice was sought from the existing NGESO's Restoration and Contracts Teams, legal experts, ENA representatives and regulation experts from SPEN and NGESO.

In the traditional ESR process, NGESO contracts directly with just one other provider and stipulations are covered in NGESO licence obligation and Grid Code. The difference in the Distribution Restoration proposed process is that NGESO remains with the licence obligation, but with the role of the DNOs increasing this needs to be appropriately captured in contractual arrangements and via industry codes. This in effect needs the Distribution Restoration contract to become a tripartite arrangement between NGESO, DNO and DER providers.

Figure 15 on the following page explains the obligations on each party:

Figure 15:
Capturing the obligations of each party in a transparent way



Initially, depending on who led the proposed procurement process, the options explored were:

1. NGESO leads the procurement and contracts with both the DNO and DERs. This tripartite option with DNOs is untried and may be complex; however, it ticks all the boxes for openness, transparency and clarity around obligations on all parties involved in the process.
2. DNO/DSO leads the procurement and contracts with DERs; however, NGESO's obligations are covered in the licence. There are many example contracts to choose and adapt, and this could be very straightforward in this situation.
3. The second option could also be flipped so that NGESO contracts with the DER, and the DNO's obligations are covered in codes. This may take a longer time on account of changes to codes and the engagement process that precedes the code modifications.
4. NGESO leads the procurement and contracts with DNO who in turn sets up separate contracts with the DERs. This option could provide a degree of autonomy for control for the DNOs. However, there are considerations to be made around how consistently each DNO may wish to contract in their areas; the interface between NGESO and DER is missing, and there is a gap of creating linkages between the two arrangements: NGESO to DNO and DNO to DERs.

Figure 16:
Contracting options

Other key considerations evaluated alongside these options were:

- Feedback from DER providers through the Distributed ReStart project as well as other ongoing initiatives such as the Regional Development Programme (RDP), Power Potential, Resilience as a Service (RaaS).
- Does the proposed length of the contract for five years have any bearing on potential providers? Will a fixed contract be conducive or does a degree of flexibility need to be factored in, on account of economic/market shifts/regulatory drivers?
- The fact that DNOs/DSOs could work quite differently to each other and therefore what needs to happen to ensure parity and consistency for DER providers across the different regions.
- As this is an innovation project, it is a ripe opportunity to trial 'arrangements' with the parties involved that are new and less tried – this could be a pioneering platform for other future multi-party flexibility services.
- What synergies can be forged with other contract developments, such as the **Standard Agreement** designed by the ENA Open Networks?
- What considerations will need to be factored to remove barriers for entry into this market, for example catering for DER providers who are not CUSC parties?

In terms of other mechanisms, the following options were explored:

- Framework agreement – this best works when the parties sign up to provide a service ahead of agreeing the delivery periods and prices. It provides a framework for contracts (including delivery periods & prices) to be agreed against.
- Service level agreements (SLA) – these are mainly useful for monitoring performance and are not strictly a contract arrangement.
- Codes and licence changes – this is probably the best long-term solution to make it a legal/regulatory requirement on whomsoever leads the procurement.

After considering and scrutinising all the options and mechanisms above, and engaging with legal and contract experts, the following three options for contracts were outlined for further engagement with stakeholders. The benefits and risks are highlighted in Table 14 below:

Table 14:
Options appraisal for contracting

Option	Benefits	Risks
Tripartite/multi-party agreement	• This is the most open and transparent approach between all the parties. Everyone can see each other's obligations, and there is a higher degree of trust around conduct and responsibilities in the process. • Legal experts prefer this arrangement as it can capture everyone's requirements in one set of documents, contrary to one-to-one bespoke contracts. • More future-proof changes are easier to assimilate in one set of documents instead of multiple contracts.	• It is not a common arrangement that has been used in other flexibility services, and some DNOs still feel a bit unsure about how this might look like and work in practice. • It can be a very complex contract to pull together and there may still be need for subsidiary arrangements between two parties contrary to the three that are involved.
Bi-lateral/one-to-one contract	• This will work best if the DNO/DSO is procuring DER services. NGESO will not need to be involved as its obligations are covered in the licence and codes. • This is a better fit for longer-term or more complex contracts, in lower liquidity markets. • This is relatively straightforward to set up as there are several examples to choose and adapt from.	• Bi-lateral contracts between different service providers are not open and transparent (unless published publicly). • Each DNO may choose to do this slightly differently unless an open template is developed across all the regions.
Back to back contract – for example: NGESO contracts with DNO; thereafter the DNO contracts with DER for the services	• This is a popular way of contracting for flexibility services, and DNOs feel comfortable with this arrangement. • Presently used in the Interconnector arrangements between NGESO, connecting TSO and the service provider for existing ESR services.	• Not as open and transparent. • Would only work if DNOs were aggregating the DER services for NGESO. The intended procurement approach is not designed to do that.

10.2 Stakeholder engagement

The three contracting options above, the key consideration points, alternative solutions and the options appraisal were shared with DER stakeholders, the DNOs, legal experts and Ofgem. This the only area in the procurement design where the feedback received was quite varied based on the organisation's experiences.

When asked what their preferences were on contracts, most of the DER stakeholders that were engaged through bi-lateral meetings and the Test Procurement Event, commented that they wanted consistency, fairness, transparency and flexibility in the contract. They were mostly comfortable with the suggestion of a multi-party contract, or a one-to-one contract with NGESO rather than the DNOs.

Some of the DER providers suggested contract length to be longer than five years on account of the investments they were prepared to undertake on their assets. There was a strong preference to try to avoid settling on fixed contracts.

DER providers felt that with shifting industry drivers it would be advisable to build in a degree of flexibility into the contract especially if new technology can be added to the DRZ asset base. Another question was around shorter contracts for top-up services in order to permit more providers joining across the overall five-year period. This may be a future design concept, but for the approach recommended, both anchor generator and top-up service providers will remain together for the full length of the contract.

The main comment shared from the Project's Stakeholder Advisory Panel was on mitigation of the risk that each DNO might do this process differently and therefore it is important that whoever leads conducts a consistent and transparent process across different regions for the sake of parity for the DER providers.

In Ofgem's view, the idea of a multi-party contract sounds fair and transparent; their only concern was on how complex this contract might become trying to incorporate the terms of service against the three main parties. Their challenge to the P&C workstream was to try to produce a contract template that is simple and can be adapted for more than just restoration services.

On the question around how DNO obligations to this restoration process can be captured, Ofgem stated that under the **Whole Electricity System Condition 7A Part A,*** the DNOs must coordinate and cooperate with other network licensee holders to provide the benefits for the total system, unless there is a negative financial benefit to them. Provided they can claim the costs incurred (which they can in these recommendations; see Section 9), there should be no reason for the DNOs not to undertake their roles and obligations in this Distribution Restoration service. Furthermore, Ofgem suggested that through the **Flexibility Licence Conditions,** there are requirements on DNOs to coordinate with NGESO on such services and even though restoration services are slightly different, the principles still apply here.

The DNOs yet again had different views based on their experiences from other services, like Power Potential. The more comfortable position for the majority of them was to use back-to-back contracts so that it gave more control over the procurement of restoration services from DERs. A summary of their comments is below:

- Maintain two agreements: NGESO to DNO as a contract for services, and for the DERs, use a framework agreement that they can sign up to.
- Multi-party contracting is fine so long as the commercials are fairly sorted. Trying to keep this as a framework will future-proof the process.
- As NGESO obligations are covered in codes and licences, only a contract between the DNO and DER provider is required to keep things simple.
- Any type of contract will work for the moment; however, in the long run, more obligations should be codified to ensure transparency and consistency in terms.
- Use the Open Networks **Standard Agreement** as the boiler plate for the service/general terms as this has been approved by the DNOs.

All this information was shared with legal experts and the Project's Steering Committee to agree a hybrid solution that would work best with a more collaborative approach given the roles of NGESO (leading the overall process) and the DNOs (coordinating the DRZ requirements).

After evaluating the stakeholder feedback and expert advice from legal representatives and NGESO's Contracts Team on the contracting options, the final recommendation is below.

The challenge the P&C workstream had was to propose a contracting solution that minimised any extra costs incurred in this process through fragmented contracting that was not standardised across different regions.

The procurement design for the Distribution Restoration service is based on de-coupling of the service requirements to allow multiple DERs to bid in, and for NGESO to find the most cost-effective combination of providers to meet the service requirements, and to do all of this in an open, consistent and transparent way. This design is not based on aggregation of services via DNOs; therefore, the option of back-to-back contracts was ruled out.

The final recommendation is to use a tripartite/multi-party contract using the ENA's **Standard Agreement** as a boiler plate template which underpins the whole contract. This will support the process where NGESO leads the procurement, and even in future, if this role changes over to DSO, the same format can be adapted. The next section details more about the specifics included in the draft tripartite contract.

10.3 Draft tripartite contract development

The draft contract outlines for AG and a separate one for TUS can be found in Appendix 2.

Please note that this draft contract template has not been shared for any stakeholder comments as part of this workstream. That will be conducted as part of the transition to business as usual and updated accordingly.

In this section, the design and components of the draft tripartite contract are explored.

1. At the regional strategy/pre-tender phases, NGESO and the relevant DNO(s) will have a framework type of agreement between them that covers their roles during the tender round. The obligations that will be included are featured in Figure 15. This agreement will also contain mitigations of what happens in the event of gross negligence by the DNO.

2. From this point, NGESO and DNO will work together on the key decisions required during the procurement event.
3. For the contract with the DER participants, a tripartite contract will be used. This contract will be between NGESO/relevant DNO and DER providers. Sections will include general terms and service terms specific to the service provision.

*Part A: Whole electricity system coordination.

7A.2 The licensee must coordinate and cooperate with other Electricity Distributors and Transmission Licensees to seek to identify actions and processes that advance the efficient and economical operation of the Total System.

7A.3 The licensee must consider actions proposed by Distribution System Users which seek to advance the efficient and economical operation of its network.

7A.4 The licensee must use all reasonable endeavours to implement actions or processes identified or proposed under paragraphs 7A.2 or 7A.3 of this condition that:

(a) will not negatively impact its network; and

(b) are in the interest of the efficient and economical operation of the Total System.

There will be four versions of this contract, for:

- anchor generators who are CUSC parties
- anchor generators who are not CUSC parties
- top-up service providers who are CUSC parties
- top-up service providers who are not CUSC parties.

NGESO and DNO  **DER parties**

4. Arrangements for the detailed feasibility studies for successful bidders will be covered by a letter agreement outlining the scope and payments for the feasibility studies. Feasibility study payments can be paid either in advance or on receipt of invoice by the bidder. There is usually a maximum amount that is caveated. The cap amount for the Distribution Restoration service has not yet been set as the PET live trails are still ongoing and will provide the basis for this amount.
5. All the representatives in the contract will remain in contact with each other post-tender, through the DRZ operational working group.

The P&C workstream brought in legal expertise for the drafting of a contract outline for the Distribution Restoration service. The basis for this draft contract is the existing traditional **Black Start contract template** and the ENA's **Standard Agreement**. As components of this draft contract were developed, ongoing discussions were had with NGESO Contract and Restoration teams, for their experience and suggestions.

This tripartite contract will support the requirements within a DRZP and cover any service obligations not covered via the relevant codes and licence conditions. The following components are captured in the draft contract:

Table 15:
Components of the draft contract

Component	Contract content:	Applicable to
Service description and required capabilities	Requirements on the anchor generator and top-up services, as well as the specific capabilities of the assets.	DERs
Roles and responsibilities	The accountabilities on each party during the contracted period, plus the requirement on being part of the DRZ operational working group.	NGESO, DNOs and DERs
Communications	Requirement on resilient communications and the necessary data-sharing systems required for operation and monitoring.	DERs and DNOs
Payments and availability	Captures how DER providers will be paid for the service, which is via an availability fee paid monthly, calculated by converting submitted tender costs into a £/Settlement Period (SP) figure. DNO costs will be covered under their own price control.	DERs
Testing	Outlines the tests required prior to service delivery and throughout the duration of the contract.	DERs
Monitoring of capability	Monitoring and inspection schedules to ensure the required capabilities are met and what will happen if they are not, which could involve penalties. It also outlines requirements to notify of maintenance on assets or any absence of capability.	DERs
Events of default	The consequences of not meeting the contract obligations.	DERs and DNOs
Training and DRZP	Requirement to comply with the DRZP on the day in event of a Black Start; it also includes the requirements on training.	NGESO, DNOs and DERs
Provisions of other market services and use of paid assets	Outlines the ability to stack other service provision, for example NGESO balancing services or DNO flexibility services.	DERs
Other standard contract sections	Such as safety, insurance, force majeure, anti-slavery, contract termination, damage to plant and apparatus and no public announcement clause. These will be covered across the ENA **Standard Agreement** and the Distribution Restoration Contract.	DERs and DNOs

For most of the contract requirements above, the amalgamation of text was straightforward; however, for the sections below, options had to be considered and modified so that they support the procurement designs.

Table 16:
Modification of key components of the draft contract

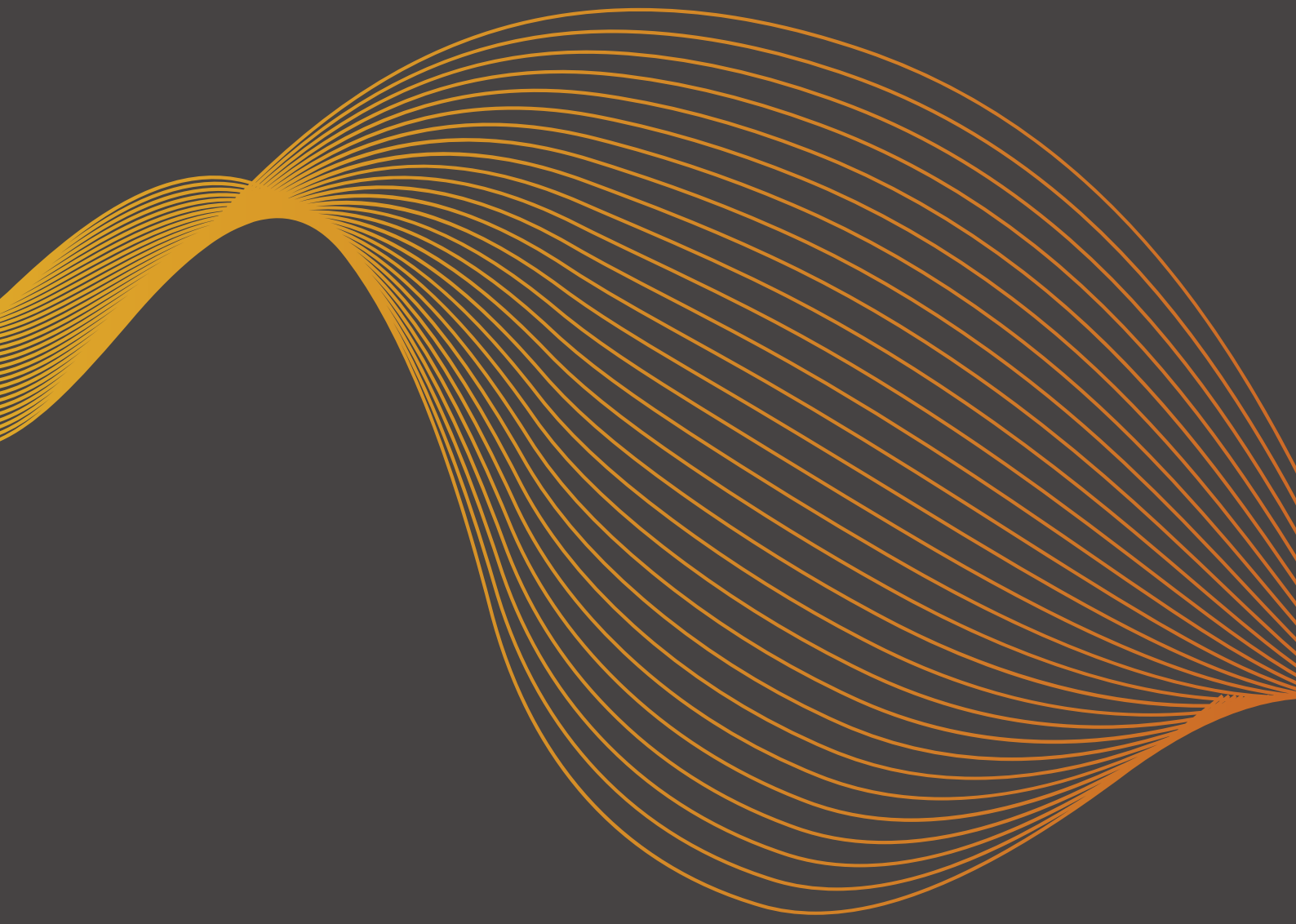
Components	Decisions required	Decisions made
Payments and rebates, including works contribution payments	How to ensure the availability payment is captured correctly and any rebates required if availability falls short.	If a DER provider is unavailable during the course of the contract that is less than the required availability level (90 per cent), NGESO will be able to claw back works contributions or availability payments, as applicable.
Treatment of funded capability	How to manage DERs that have received funding for an uplift in capability but want to provide other services using this capability.	This will be managed during the tender process. Participants will be required to notify NGESO that they wish to provide other services with the funded assets and will agree a suitable reduction in price.
Treatment of unavailability	How the DRZ as a whole is impacted when parts of the services or network become unavailable, when unavailable the DER will not be paid the availability fee.	In the event of the AG becoming unavailable, the whole DRZ along with the TUS providers is declared unavailable. In the event of the DNO network becoming unavailable and the DRZ would not be available in a Black Start situation, the whole DRZ including AG and TUS will be declared unavailable. In the event of any unavailability of TUS providers and this causing the DRZ to be below the minimum DRZ requirements, the whole DRZ including the AG and other TUS providers will be declared unavailable.
Events of default	How to manage DERs who do not meet the required contract obligations.	Decisions on which events of default to apply and how severe the application. The difference for the Distribution Restoration service versus the traditional ESR process is that if a termination of contract happens it can affect other contracts within that DRZ.
Testing	How to capture the requirements for testing assets to ensure capability.	The contract requires three types of test: commissioning, capability assessment and reproving tests. There may be further tests required once the final outputs from the PET workstream are known, such as energisation of the network.
DNO obligations	How to manage the DNOs meeting their obligations.	The DNO obligations of instructing and managing the DRZs are part of the Grid Code, and where there are any issues/damages which are considered Gross Negligence this will be covered via the contract.

The draft contract may be updated further following outputs from the PET and OST workstreams on testing requirements, DRZ-C requirements or other developments.

There will also need to be further engagement with industry on the design and content of the contract to ensure it is fit for purpose for the Distribution Restoration service and the intricacies it brings.

Distributed ReStart

P&C mock event



11. Test Procurement Event

To further test the P&C proposed procurement process, the functional requirements and assessment criteria, a Test Procurement Event was hosted between 5 August and 6 September 2021. This Test Procurement Event was the closest to a live trial for this workstream.

It was designed to create a mock tender environment over a condensed period, to share draft tender documents and receive data to stress-test the proposed assessment criteria.

The aims of the Test Procurement Event were as below:

- to test if the proposed designs work as intended
- to bridge any gaps through DER feedback
- to get good-quality, as close to real, submission data for assessment and to create a potential mock DRZ
- to understand the costs and breakdown required in order to conduct a commercial assessment
- to receive feedback to create technology agnostic services.

For the participants, they got:

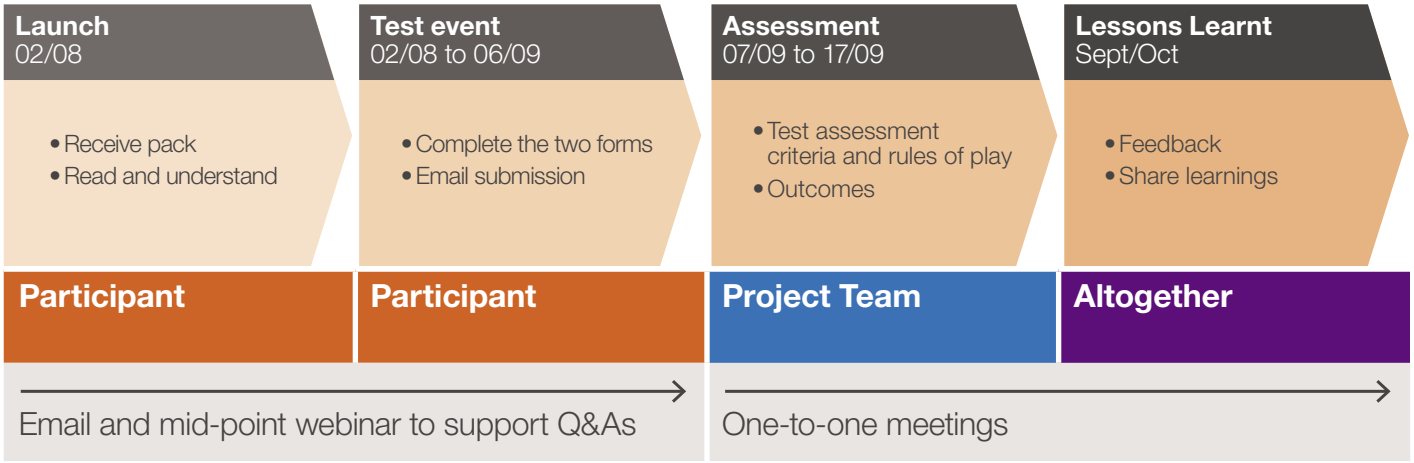
- first-hand trial of a mock tender event for Distribution Restoration
- the opportunity to co-create the design of the future procurement process
- acknowledgement of participation in this world-first innovation project.

The overall purpose behind doing this trial was to update the proposed approach and process in order to meet the restoration principles, which are to provide:

- a clear and transparent service requirement;
- enablement of competition
- a reduction or removal of barriers to market entry.

The plan for the event ran as below:

Figure 17:
Test Procurement Event plan



The P&C workstream had support for this Test Procurement Event from the PET and OST workstreams, who were present during the webinars for questions from the participants and during the mock assessment stage.

11.1 Approach for the Test Procurement Event

For the start of the event on 2 August, P&C hosted a launch webinar on 29 July. Twenty-three individuals signed up, and on the day, thirteen potential participants dialled in. These represented a combination of battery storage, flexibility solutions, fly wheel technology and telecommunication providers.

It was made clear to the participants that by partaking in this test event there was no pre-advantage for any future ESR contracts – at transmission or distribution level. The participants were encouraged to provide ready information and not undertake any paid studies as these would not be reimbursed by the Project.

During the launch webinar, attendees were taken through the types of services required, their functional requirements and the proposed process timelines. Other assumptions and caveats shared with the providers were:

- This is a test exercise – no contract will be awarded at the end.
- These are not the final tender documents.
- Any (commercially sensitive) information will be treated confidentially.
- They could bid for anchor generator, top-up services or both.
- In a Black Start event, there is no power on any systems and the electricity markets are suspended; therefore, participants needed to consider how their assets and communication lines could cope in this circumstance.

To support the Test Procurement Event, the following documents were developed and shared for the start of the event on 2 August:

1. Invite to Test Procurement Event (for background information before starting)
2. Appendix 1 Mock Tender Requirements Document (for vital information before starting)
3. Appendix 2 Mock Tender Submission Template (to be completed)
4. Appendix 3 Event Feedback Form (to be completed).

Copies of these documents can be found on the website:

nationalgrideso.com/future-energy/projects/distributed-restart/events-and-webinars

The deadline for submission of both forms was Monday 6 September.

To design the documents listed above, the basis was a combination of tender documents used in the traditional ESR process but modified for the Distributed ReStart project. As the test event was running over a concise period, the expression of interest, early feasibility studies and commercial submission stage requirements were combined together into the Mock Tender Submission Template.

The Invite to Test Procurement Event document explained the context behind the Test Procurement Event and the documents shared as well as a helpful synopsis of what each of the tender phases in the proposed procurement process included.

Appendix 1 Mock Tender Requirements document outlined the minimum functional requirements expected from a provider against the type of service they wished to bid for. It also included the draft assessment criteria, feasibility assessment process and a snapshot of draft contract principles.

Appendix 2 Mock Tender Submission Template was for the participants to enter the data and estimated costs for providing the service.

Appendix 3 Event Feedback Form was intended to gather comments to supplement the experience of the potential bidders and in summary, understand:

- if the information shared made sense
- if the bidders were able to make an informed decision on what services to tender for.

To further support potential participants, a mid-point webinar was hosted on 18 August as an opportunity to address any initial questions regarding the Test Procurement Event process. Attendance was comparatively low on this session however, a few questions by email were raised during the period.

11.2 Stakeholder engagement

The outcome of the Test Procurement Event resulted in five successful bids being submitted, which had good-quality of data and two providers completed the Event Feedback forms.

A further two DER stakeholders were in contact after the deadline stating that they would have participated but other priorities came up. This was a very positive outcome considering this Test Procurement Event was scheduled over a peak summer period and quite soon after the OST workstream Desktop Exercise live trials.

The bids were submitted by:

- **Flexitricity**
- **Beacon Power**
- **PeakGen**
- **Zenobē**
- **Limejump**

The next steps once the submissions were received were that acknowledgements were sent and a mock assessment was carried out for a set of results, followed by bi-lateral meetings with the participants to share feedback, and lessons learned sessions on the gaps in the P&C workstream's designs.

A summary of the feedback provided by the participants who were able to join us in the follow-up meetings or by email are in Appendix 1 Stakeholder Engagement.

11.3 Outcomes

The data submitted in this Test Procurement Event was treated with a lot of caveats such as:

- The data, even though modelled on assets the providers were familiar with, was not real data – it was approximated in most instances.
- As this information was gathered without detailed feasibility studies, there were gaps in what the providers could complete with confidence.
- As the mock tender documents were shared for the first time, there were areas that needed more clarity and therefore some of the data submitted was incomplete.
- As these mock bids were from different providers based in different regions, the mock DRZ they formed was assessed without the considerations of geography or topography against any real network area as the process would have normally required.
- Costs external to DERs such as the DNO network upgrade costs were not taken into account in this Test Procurement Event.

Nevertheless, the information was compared against the other participants, checked against the assessment criteria and entered into an assessment spreadsheet created for the purpose of the Test Procurement Event.

Four of the five submissions offered either an anchor or top-up service while the fifth submission was for a TUS provider only.

Nine possible DER options means z^9=512 combinations (including a null combination with none of the options selected), but as a DER can be only an anchor or a TUS provider, not both simultaneously, there are only 162 possible combinations. Of these, only 58 were assessed as satisfying the minimum DRZ requirement (as specified for the purposes of the exercise). Applying the weighting factors produced a set of scores ranging between 0.61 and 0.95. Fifteen of the combinations achieved the highest score of 0.95; these combinations used all five DERs. Lower scoring but still viable options included combinations using only three of the DERs.

Thus, the technical assessment identified a range of viable options and some useful guidance on overall capability that could inform a procurement decision.

For the commercial assessment, the information provided was inconsistent with some participants providing a range, others in £ per settlement period and others across the full length of the contract. Learning was taken to improve the instructions for the costs and the level of breakdown required to fully assess DERs in a DRZ.

With the limitations on the figures, levels of aggregations were made in order to complete the necessary totals; however, as a result the commercial rankings were heavily skewed demonstrating a range in cost of service from £55,500 to £1,786,319.

The key takeaways and lessons learned from this exercise are as below:

- Assessment based on the data provided by the participants was possible but not conclusive. A ranking of the providers was possible but not shareable on account of all the other data caveats and commercial sensitivities.
- The scale of resource needed to respond to the Test Procurement Event was greater than envisaged and with being held over August, access to resource was impacted by summer availability.
- The cost and pricing instructions need to be clearer especially around the breakdown of various elements, format of cost and duration. Further clarification required on what are the physical capital costs required ahead of tender versus what they need on the day, and finally their ongoing commercial costs.
- Further clarification required on the functional service requirements, for example:
  - Ensuring MVAr ratings can be consistently measured between different asset types, for example batteries versus diesel-powered generators.
  - Removing self-start as a capability title and changing to anchor capable as a title, as well as, splitting out Fast MW control into increase and decrease in the assessment criteria.
  - Reducing the typical minimum DRZ requirement on Energy MWh, expressed as the average power output that can be reliably maintained over a period of 120 hours, to 25 MW from 50 MW for the purpose of the mock tender assessment.
  - Adding time to connect as a requirement for the TUS functional requirements.
- Updating the service design following feedback, to align AG and TUS processes and timelines in the proposed procurement process so that the studies and assessment period are more consistent.
- Where a new build might be considering entering the service, provide information on what other DER is within a region; this information can be accessed via the relevant DNO's Embedded Capacity Register (ECR).
- While conducting the assessment procedure, P&C workstream realised that submissions from multiple AGs in one DRZ area might be received, where one asset may be right for an anchor generator and the

other would provide more benefits as a TUS. This could also happen the other way, where a TUS submission might be best placed to be an anchor. However, it was decided that this would reduce an ability for informed participation from DER, it may impact DER business investment cases and would complicate the commercial assessment procedure where parties may want to charge different prices for different services.

The conclusion here is that this scenario will be handled in business as usual on a case-by-case basis. The small Test Procurement Event group was not enough to test and conclude the option here.

There was a suggestion to change the P&C workstream service design from AG and then each individual TUS to just having two services – AG and TUS.

The benefits and risks of this were evaluated in the below table. The decision made was to not change the service design because it permits lower price offers and reduces barriers to entry into this market by enabling service providers to make informed choices.

Table 17:
The benefits and risks of the different service design options

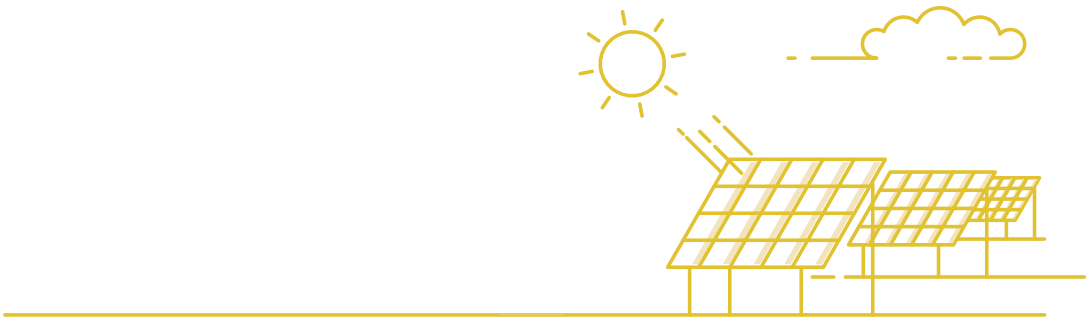
Benefits	Risks
It's a simpler design, with only two services for providers to choose from.	Takes away an informed choice for providers being able to choose between anchor generator and each of the individual top-up services (for example frequency, fast MW, Energy MWh).
Providers can price AG as having self-start and TUS as having other service abilities and not self-start.	Providers may have to make investments to meet all the requirements of a top-up service – or it may be comparing provider prices, but the service offering they are giving is not the same.
Simpler assessment process, providers could give two prices for the services, anchor generator versus top-up service, and then this can be used to assess which they are best for.	Providers may not want to take on the provision of an anchor generator service or vice versa – if they go in for anchor generator may not want to just do top-up services.

The feedback received from participants was both positive and practical for the P&C workstream to take forward and action. Some examples are as below:

"The information provided in the test procurement exercise is clear and the documentation easy to follow. The requirement is clearly specified. As the purpose of this exercise is testing procurement processes, I believe that the aims of this were well met."

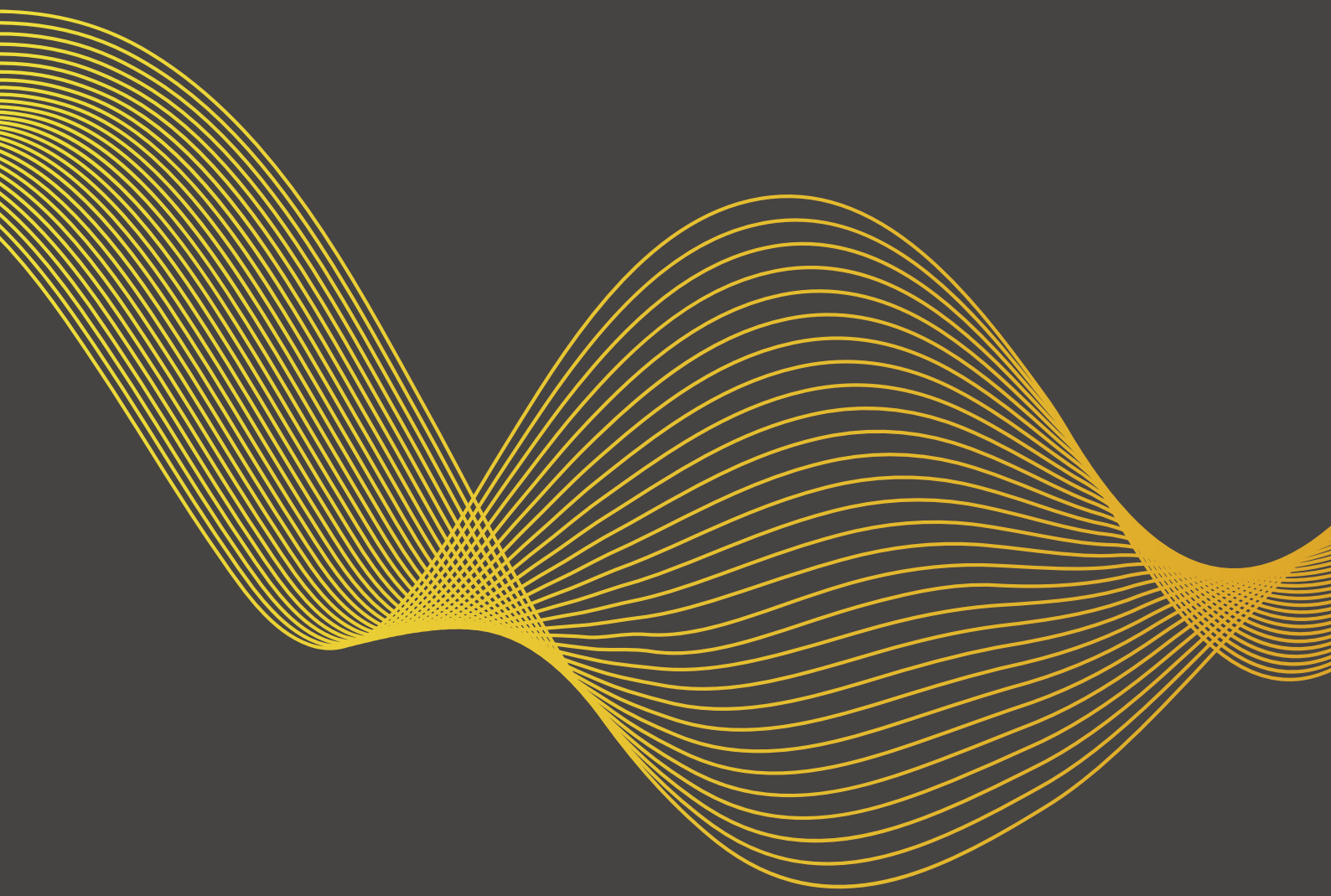
"The requirements were quite clear. The pricing was much less clear. The form was felt to be created for an existing plant which X is not. It wasn't clear whether to include total investment or £/SP."

Overall, the Test Procurement Event was a great success in terms of giving the P&C designs the impetus for further change, which has been taken on board following all the stakeholder engagements in 2021.



Distributed ReStart

Codes



12. Codes overview and review

Building upon the ongoing review and update of industry codes to enable a Distribution Restoration service, significant legal text drafting and development of change proposals has been undertaken for Grid Code, Distribution Code, BSC, CUSC, DCUSA and STC.

12.1 Purpose of this chapter

A review and update of the relevant industry codes has been completed as per the scope of the original Distributed ReStart proposal for the P&C workstream. Proposed changes to the legal text in various codes, and changes to other supporting documents, have been made and are provided in Appendix 3.

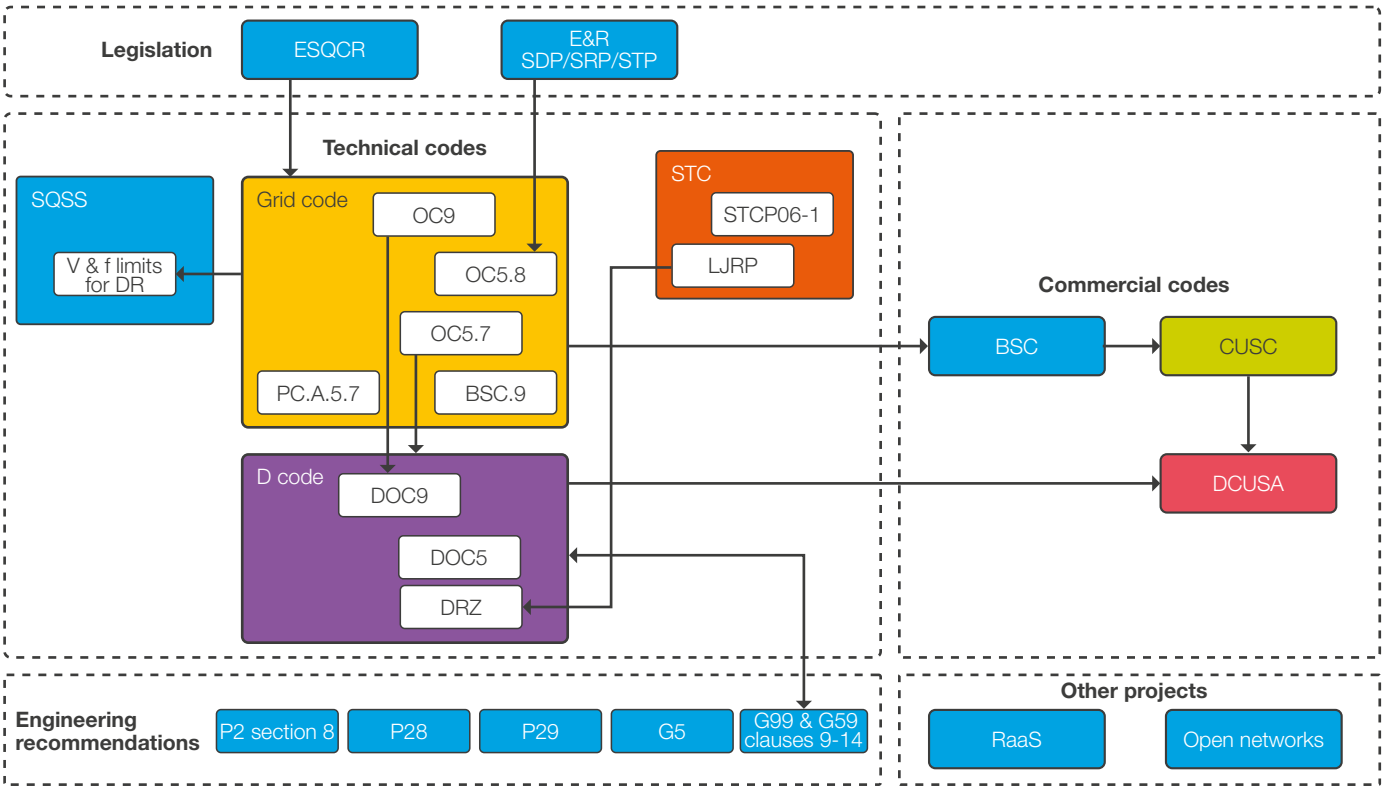
This report is intended to serve as a handover document to the codes expert teams within NGESO and wider industry, such that the necessary changes required can be progressed, and enable Distribution Restoration services to transition into business as usual processes.

12.2 Summary of detailed code review

A review of industry policies, regulations, codes and standards was carried out and presented in the **FRPC report** in November 2019, and this highlighted how some of these may have to be changed and adapted to enable Distribution Restoration. Following this, a more in-depth review was undertaken which focused on the key areas of specific code documents, such as the Grid Code and the Distribution Code, and the outcomes of this review were presented in the **OCRA report** in October 2020.

A mapping exercise was undertaken during the detailed review, to better understand how changes in one industry code would impact the understanding and delivery of others. Figure 18 below shows the interdependencies that were identified at the time.*

Figure 18:
Codes interdependencies map



*Thinking on these interdependencies has evolved over this phase of the project through the drafting of the proposed legal text, which has brought out some nuances in how the various codes are linked.

The detailed review also highlighted some key areas that would require further discussion and investigation, such as:

- definitions, such as Black Start Providers, and whether existing definitions would sufficiently encompass all future restoration participants;
- the requirement of smaller DER sites to meet the necessary technical conditions if they are not CUSC parties;
- findings and outcomes from P&C, PET and OST workstreams, such as an agreed approach to procurement, functional requirements for DER from studies, live trials and roles and responsibilities of NGESO, DNO/DSOs and DER in a DRZ; and
- developments from ongoing Grid Code modifications, for example GC0148 – Implementation of EU Emergency and Restoration Code Phase II, GC0117 – Improving Transparency and Consistency of Access Arrangements across GB by the Creation of a Pan-GB Commonality of Power-Generating Modules Requirements, and the implications for subsequent code modification requirements under the Distributed ReStart project.

The process undertaken in this phase of the codes work to address these discussion points is detailed in the following section.

12.3 Approach to code drafting

The overarching approach taken for this phase of the codes work was to begin drafting legal text, with the outcomes of the detailed review in mind, through a collaborative iteration process. The Distributed ReStart project's codes working group (CWG) engaged in weekly focused workshops to discuss key issues and agree on final wording. The drafting of the Grid Code, and other industry codes, has been written to enable the existing Black Start arrangements to be initiated along with the ability to enact Distribution Restoration in parallel with these well-established processes.

At key intervals, the CWG engaged with the wider project team to stay abreast of outcomes and decisions from the three main workstreams with a view to understanding any code implications. Broader industry engagement was also undertaken, including the involvement of some CWG members in the GC0148 (Implementation of EU Emergency and Restoration Code Phase II) code modification process.

Currently, it is within the mandate of GC0148 to implement Distribution Restoration proposed changes to the Grid and Distribution Codes, although GC0148 does have the option to drop the Distribution Restoration changes if those changes would interfere with the timely delivery of the primary scope of GC0148. The progress on the Distributed Restart project aligns with GC0148's expectations and currently remains as being progressed in GC0148.

As the main industry document pertaining to Black Start at present, the Grid Code has been subject to the most significant changes during this phase, and this is where the majority of debate and decision making was required.

Key sections that have been updated include OC5 (testing) and OC9 (implementation of Black Start and the subsequent restoration phase). In parallel, changes to the Distribution Code were proposed. There has been substantial additional legal text added to the Distribution Code, to reflect the much larger role that distribution networks and DER will play in Distribution Restoration. The structure of the Distribution Code largely mirrors that of the Grid Code, so many changes flowed directly from the Grid Code drafting into the Distribution Code.

A thorough due diligence exercise was undertaken to ensure consistency across these two documents, while also ensuring subtle distinctions were made where appropriate to reflect the slightly different context of the two documents. The roles and responsibilities of different parties were captured appropriately in each.

Proposed changes made to the System Operator Transmission Owner Code (STC), G99 and G59 have also cascaded from the changes made to Grid Code and Distribution Code.

Similarly, with the commercial codes, the CWG started with the Balancing and Settlement Code (BSC) and the Connection and Use of System Code (CUSC), with changes to the Distribution Connection and Use of System Agreement (DCUSA) flowing from this in a similar manner to how the Distribution Code changes followed the Grid Code. Changes to the commercial codes have been influenced heavily by decisions made on the procurement approach, detailed in Sections 3 to 10 previously.

12.4 Codes stakeholder engagement

As part of the codes work, the P&C workstream have undertaken a number of engagements to ensure the proposals are well thought through and have been challenged. The table below displays the engagements undertaken, and the feedback received.

P&C are also proposing several future engagements on the implementation of the proposed code changes into business as usual. These are to kick off the required code modification processes and to inform the relevant code administrator panels.

P&C will present at the STC Panel in January as well as at the Distribution Code Review Panel, in December, to ensure industry is aware of the proposed changes and is able to comment and review.

Alongside these engagements, consideration needs to be made to the ongoing ESRS implementation work, and where possible code modifications will be done in tandem, for example any required changes to the CUSC.

Table 18:
Codes stakeholder engagement

Date	Channel	Feedback & challenges received	Actions taken
18/08/2021	Presentation to the GC0148 joint Grid Code and Distribution Code modification workgroup.	Check that the proposed drafting meets the requirements for the Emergency & Restoration (E&R) Code on resilience requirements for mains independence and voice communications.	The Project and the CWG ensured the project designs and legal text drafting complied with the requirements of E&R on resilience and communication specifications.
09/09/2021	Presentation to Elexon's BSC Panel.	Questions on environmental permits and other uses for DRZs. Present at the ENA Commercial Operations Group (COG) group to ensure full engagement with relevant parties.	• Environmental permits – this would be for the provider to ensure they have the correct permits, and any changes/increase in cost would need to be priced into their submission. • For the moment, DRZs will be used for GB network restoration purposes, but in the future DRZs could be used within DNOs' networks to support network outages.
13/10/2021	Presentation at the ENA's Commercial Operations Group (COG).	• How would independent distribution network operators (IDNOs) be involved in this service? • The impact of active network management (ANM) schemes on availability and how this is measured. • Impact of the Energy Code Reform. • If the DRZ does not work when needed (e.g. the DNO does not give the instruction) – what are the implications?	• For the moment IDNOs have not been considered; there would not be a solution during the project timescales, but in the future, they could be considered on a case-by-case basis. • In a Black Start situation, the ANM schemes would not be running. The measurement of availability will be conducted on whether the DER has the capability to meet the service obligations; an ANM scheme would not impact this. • DRZ non-response/non-compliance needs to be considered and will be managed via the contract design. Engagement with the DNOs will be undertaken to manage any liabilities.

13. Key issues and discussion

The full proposed legal text drafted to enable Distribution Restoration in the Grid Code, Distribution Code, STC, G99 and G59 is provided in Appendix 3. The proposed changes and update process to the BSC, CUSC and DCUSA is reflected below.

As mentioned previously, the approach taken was a collaborative iteration process. Through this process, a number of key points, both from the previous detailed review and those that have arisen during this phase of drafting and refinement, were the subject of focused discussion.

Through the CWG, and engagement with the wider project and industry, agreement was sought on these matters. The sections below outline these key areas and present the rationale for the final decisions made, and the subsequent code drafting proposed.

13.1 Grid Code

Key discussion points	Decision process and outcome
Implementation of Distribution Restoration into Operating Code 9 (OC9) and appropriate inclusion of relevant requirements	Drafting shared with the project team and PET workstream to ensure the Grid Code drafting in OC9 was consistent with the Distribution Restoration Zone design. The drafting was developed to complement the existing Restoration approach using Black Start Service Providers and Local Joint Restoration Plans (LJRPs) with the introduction of Distribution Restoration Zones (DRZs) and Distribution Restoration Zone Plans (DRZPs). This ensures that NGESO can initiate System Restoration using both LJRPs and DRZPs in parallel with the aim of restoring System Demand in the shortest amount of time possible. As part of the project, it is acknowledged that establishing and running a DRZ is slightly more complex than the traditional Black Start arrangements under an LJRP, and therefore some of the text relating to DRZs is more detailed. As part of the drafting, the definitions used for LJRPs and Black Start Service Providers are different to that used for DRZPs and Anchor Plant. This is intentional to ensure there is no risk of confusion between the two. While this makes it explicitly clear that a provider is either part of a LJRP or DRZP, as to which one a Provider is party to is dependent upon the topology and agreement reached between the NGESO, Transmission Licensee, DNO and Restoration Service Provider. This would generally be resolved at the contractual stage. The drafting retains the differentiation in the requirements between those in England and Wales and those in Scotland. To be clear, Transmission Licensees in Scotland can instruct Generators as part of a Black Start process whereas in England and Wales NGESO undertakes these instructions directly. In the case of DRZs, similar principles have been applied, where a Scottish Transmission Licensee can instruct a Scottish DNO to initiate a DRZ whereas in England and Wales the action of instructing DNOs would remain with NGESO. As part of the drafting for the Grid Code, Anchor Plant can be any technology (e.g. Generation, HVDC Systems etc). At the early stages of the solution some concern was expressed that the EU Emergency and Restoration Code requires a TSO to be appointed as a Frequency Leader. Clearly, a DNO is not a TSO, and this resulted in some uncertainty. However, it was clarified by NGESO's legal team that NGESO is managing and coordinating the overall System Frequency during the Restoration Phase and therefore the DNO would only be managing the frequency during the establishment of a specific DRZ and would in essence not be the National Frequency Leader. As part of the drafting, the solution allows for two operating DRZs to be amalgamated in real time, for a DRZ to extend into the Transmission System and for the termination of the DRZP.

Key discussion points	Decision process and outcome
Requirement for DER to be a CUSC party	The initial starting point was to assume DERs, in particular Anchor Plant Owners, would be treated as CUSC parties. It was also noted that there are separate Grid Code modifications in process at the time of drafting (GC0117 for example – Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Station requirements) which could have the impact of requiring Power Stations with a Registered Capacity of 10MW to become 'Large Power Stations' and hence become CUSC parties. It was, however, realised that this work overlaps with other industry initiatives, such as TNUoS charging and work within the ENA Open Networks project, and so more detailed thinking within the GC0117 workgroup was required before changes can be implemented. After some discussion, it was subsequently agreed that compliance with the relevant Grid Code sections can be achieved either through such parties being CUSC parties or through a separate contractual mechanism to oblige them to meet the applicable requirements of the Grid Code. Non-CUSC parties who opt to provide a Restoration Service would automatically be caught by the requirements of the Emergency and Restoration Code, which is an issue being addressed as part of the GC0148 Grid Code modification. In this latter case, a condition of the contract would require them to satisfy the applicable restoration requirements of the Grid Code. Grid Code modification GC0148 provides for the implementation of Phase II of the EU Emergency and Restoration Code requirements, which have an implementation date of December 2022. The EU Codes introduce the concept of Significant Grid Users (SGUs), which would include parties who either are CUSC Parties and fall under the requirements of the Grid Code and Restoration Service Providers who would be required to meet the applicable restoration requirements of the Grid Code through their contractual arrangements.
Restructure of Operating Code 9 (OC9)	With the fundamentals of Distribution Restoration introduced into OC9, the opportunity was taken to re-structure OC9. The purpose of this was to provide a more logical and structured approach to OC9 so that the total restoration process from Black Start through to the resumption of normal system operation is detailed in a sequential and logical way. The revised structure provides separately for LJRPs and DRZPs. The resequencing also improves the logic and flow of the restoration process in the Grid Code from a total shutdown to normal system operation. As part of this revision, further clarity was added to the sections relating to the 'Reconnection of Power Islands' and 'Interconnection of Power Islands'.
Testing – Operating Code 5 (OC5)	OC5, in particular OC5.7, deals with testing for Black Start Service Providers. As part of this work, OC5.7 was updated to include testing for Anchor Plant forming part of a DRZ. The testing, however, is limited to the Anchor Plant itself and the site where that Anchor Plant (i.e. Generators or HVDC Systems or DC Converters) is located rather than testing Restoration Service Providers providing top-up services and the wider DRZ. It is also acknowledged that it is not feasible to routinely test a complete DRZ. This approach is broadly similar to that used for Black Start Service Providers.

Key discussion points	Decision process and outcome
Glossary and Definitions	A number of changes were introduced to the Glossary and Definitions. These can broadly be classified into two areas: i. new definitions such as Anchor Plant, Distribution Restoration Zone, Distribution Restoration Zone Plan, Distribution Restoration Zone Controller etc; and ii. existing definitions which needed to be changed as a consequence of the introduction of the Distribution Restoration Zones such as Block Loading Capability, Local Joint Restoration Plan and Restoration Service Provider etc. As noted above and to ensure clarity to Users, the drafting has been structured to ensure complete segregation between the definitions used for LJRPs and DRZPs. To aid further clarity and distinguish from those Black Start Service Providers contributing to a LJRP, the Generators who provide a restoration service under a Distribution Restoration Zone have been defined as Anchor Plant Owners. This was initially segregated between Generators and HVDC/DC Converter providers but was after some discussion given the common title of Anchor Plant Owners who own and operate Anchor Plant. Anchor Plant Owners and the separate providers of top-up services are collectively defined as Restoration Service Providers. While the text was updated to include testing on Anchor Plant, the opportunity was also taken to clarify that Station Auxiliaries could be made up from any number of technologies other than Gas Turbines or Diesel Engines hence the term 'Auxiliary Energy Supplies' was introduced.
Planning Code (PC)	PC.A.5.7 requires information to be supplied in relation to Large Power Stations during a Black Start event. To be clear, this does not include data from Black Start Service Providers and also excludes those plants who are part of a DRZ. In the case of DRZs, a new section (PC.A.5.8) has been added in respect of the data required from Plant forming part of a DRZ.
Connection Conditions and European Connection Conditions (CC/ECC)	Minor consequential amendments were made to CC6.5.8/ECC.6.5.8 (Black Start) and CC/ECC8.1 (System Ancillary Services). Both of these sections have been updated to include DRZs as they already refer to Black Start.
Balancing Code 2 (BC2)	Consequential changes were made to BC2. These were generally minor in nature with most amendments being made to BC2.9 (Emergency Circumstances) which encompasses Black Start. As a general comment, text within BC2.9 which relates to Black Start or LJRPs has been updated to reflect the arrangements for DRZs. The main areas of text which have been updated are BC2.9.2.2(iv), which simply distinguishes the arrangements between Black Start under an LJRP and Distribution Restoration under a DRZP. Under Balancing Code 2, instructions are issued generally to Users during times of System stress as 'Emergency Instructions', which would be the case at the time of a Black Start condition. In this situation, NGESO would issue Emergency Instructions to DNOs to initiate DRZs. The DNO would then issue appropriate instructions to Restoration Service Providers under the terms of the Distribution Restoration Contract.
Data Registration Code (DRC)	Additions have been made to Schedule 16 and 19 (Black Start Information). These are relevant consequential changes to reflect the additional data required from parties forming part of a DRZ In the case of Schedule 16, the opportunity has been taken the adjust the orientation of the tables.

13.2 Distribution Code

Key discussion points	Decision process and outcome
Addition of new Distribution Restoration text to DOC5 and DOC9	The text is largely a transparent copy of the Grid Code text (incorporating the restructure of OC9 described above) but modified to take account of the slightly different context of the Distribution Code. It has been written to apply to any Restoration Service Provider, irrespective of whether they are an accessory to the CUSC or not. The Distribution Code does not have any reference to HVDC within it, so all the Grid Code provisions for HVDC providers have not been included in the Distribution Code drafting.
Glossary and definitions	A number of new definitions for Anchor Plant and Restoration Service Providers have been added, along with a small number of new terms required by the new processes.
Resilient communications for DER sites – DPC 7.4.8	A new requirement has been added to DPC 7.4.8 for all relevant plant and equipment to have resilient communications capability for up to 72 hours. This is consistent with the resilience of communication and control capabilities for all network equipment that is required to recover from a Black Start. The requirement applies to the equipment at the service providers site; the resilient communication between the DNO's control systems and the service providers site will be provided by the DNO.
Distribution Restoration Zone data and information DPC8.11 and DDRC Schedule 5f	A new section DPC8.11, and a new DDRC schedule 5f, have been included to collect the necessary data from Restoration Service providers.
Black Start Testing DOC5.7	A new section covering the requirements for testing Restoration Service Providers capabilities as required by DRZPs.
Execution of Distribution Restoration Zone Plans DOC9	DOC 9 now includes text to differentiate Black Start restoration between the existing LJRP approach and the new DRZPs. It also includes an addition to DOC9.4.1 to extend the possible suspension of security standards to include power quality standards during a Black Start.

13.3 System Operator Transmission Owner Code (STC)

Key discussion points	Decision process and outcome
General Approach	The STC defines the relationship between NGESO and Transmission Licensees. Since most of the requirements for Distribution Restoration are managed via the DNO and parties who form part of the DRZ, then it is the Grid Code and Distribution Code which have the major updates rather than the STC. That said, there have been a number of consequential changes required to the STC to reflect the introduction of DRZs.
STC	The changes to the STC itself are largely consequential and relate to Section J (Definitions), Section C Part Three, Clause 5 (Black Start) and Schedule 3. In these sections, where the text relates to Black Start or LJRPs, the text has been updated to include references to DRZs and DRZPs
STCP 06-1 (Black Start)	STC Procedure 06 – 1 relates to Black Start. The procedure has been updated extensively to include DRZs and DRZPs. It covers the differences between the arrangements in Scotland and those in England and Wales and mirrors the arrangements defined in the Grid Code and Distribution Code.
STCP 06-2 (De-Synchronised Island Management)	STCP 06-2 relates to De-Synchronised Island Management and covers a specific case where parts of the Total System are operated or are intended to be operated as De-synchronised Islands under specific Outage or contingency conditions. A De-synchronised Island is defined as part of the Total System that is operating Out of Synchronism with the main National Electricity Transmission System, but where there is no Total Shutdown or material Partial Shutdown (as determined by NGESO). The procedure applies only in the north of Scotland to Scottish Hydro Electricity's Transmission Area and as it does not cover a Total or Partial Shutdown or a LJRP, it was agreed by the project team that no changes were necessary to this procedure.
STCP 06-3 (System Incident Management) **STCP 08 – 4 (User Tests)** **STCP 11 – 1 (Outage Planning)**	Following examination, it is thought that no further changes are necessary.
STCP 08-3 (Operational Tests and System Tests)	STCP 08 – 3 relates to Operational Test and System Tests. Amendments have been introduced to this Procedure to ensure tests relating to DRZs, in particular from Anchor Plant, can be facilitated.
STCP 18 – 1 (Connection and Modification Application – section C.5.3.2)	A new section (C.5.3.9) has been added to this procedure to ensure the TO provides the necessary information to a DNO so that the DNO can establish a DRZ. This largely relates to the information available from the TO System so the DNO i) has the correct data inputs to establish a DRZ, ii) has, if a DRZ-C system is employed, the correct data inputs available and iii) can, if the DNO needs to, pass information about the TO System onto a Restoration Service Provider (including an Anchor Plant Owner).
STCP 19 – 3 (Operational Notification and Compliance Testing)	STCP 19-3 comes in two parts. The main part of STCP 19-3 appears as a document in Word format, and this has been updated to include DRZPs. The second part of STCP 19-3 is the compliance checklist in Excel format, which has been updated to ensure consistency with the Word document.

13.4 Balancing and Settlement Code (BSC) and Connection and Use of System Code (CUSC)

	Key discussion points	Decision process and outcome
BSC	Update reporting responsibilities to include DNOs.	All of these points to be discussed as part of a potential BSC Issue Group before inclusion in a BSC modification/terms to be considered for Distribution Restoration contracts with providers.
	Update fuel compensation process to account for VLPs/service providers which don't comprise the entirety of their BM Unit.	
	Consideration of how market suspension drafting applies to potential regional restoration offered by DER.	
	Consideration of updates to ABSVD settlement processes.	
	Update what Black Start Instructions are and who issues them.	
	Relationship of suppliers with DER providing Distribution Restoration.	
CUSC	Clarification of NGESO-specific Black Start costs (relevant if DNOs are incurring costs and recovering via DUoS).	As some legal text changes are required for the ESRS work, NGESO are currently deciding the best approach to take for CUSC while accounting for Distribution Restoration. Current CUSC legal text does not create any issues for Distribution Restoration as the only suggested change is a clarification. This is especially less of a concern as NGESO will be the party procuring contracts with providers and hence incurring the costs to be recovered via BSUoS (which matches the current process).

13.5 Distribution Connection and Use of System Agreement (DCUSA)

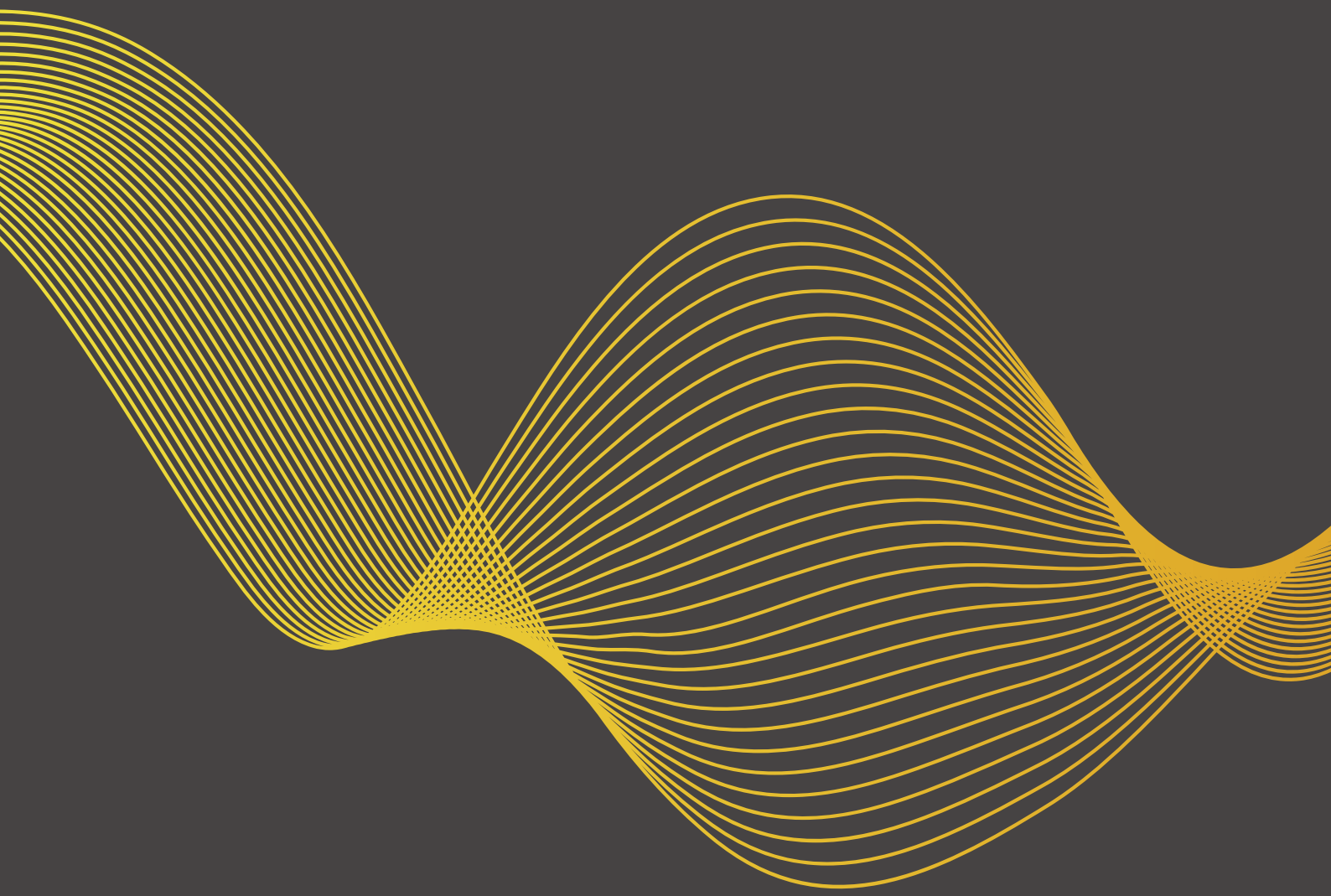
Key discussion points	Decision process and outcome
How to capture DNO cost recovery within DCUSA	There are two main ways the costs could have an explicit 'cost line' in the price control: **1.** In the Price Control Financial Model as part of the build-up of totex feeding into base revenue - No DCUSA changes will be necessary as the charging methodology takes base revenue as an input. **2.** As a separate pass-through line - A DCUSA change will be needed as the charging methodology takes each pass-through line as an input so will effectively need a new input for Restart costs. This would be a minor change to Schedule 15. These are the options for how network investment costs for Distribution Restoration can be captured in DCUSA. Section 9 explains the process for how the DNOs will need to manage the costs. The decision for how the DNO costs will flow through to DUoS will be decided by Ofgem and the DNOs.
How to manage generator DUoS (GDUoS) charges incurred during a Black Start event	There are two potential ways in which these costs could be treated: • Contractually mitigated – the generator party would incur the costs as standard and then would have any incurred costs reimbursed to them under their Distribution Restoration contract to ensure they do not face a cost to supporting system restart. These costs could then be recovered through BSUoS as per other ESR operational costs and paid to the generator. • Mitigated in DCUSA – modifications could be made such that, in the event of a system shutdown and restoration event, distribution charges are not levied on parties acting under Distribution Restoration contracts. Alternatively, the specific charging sections could be modified to set out the specific circumstances in which each charge should not apply in relation to ESR. Impacts of the above options: • Resolving via DCUSA would require complex DCUSA changes specifying the circumstances in which charges would not apply. • Those DCUSA changes would likely then drive a need for distributors to undertake potentially costly upgrades to their billing systems (and likewise supplier validation systems) to correctly 'dis apply' charges following a restoration event. • Contractual arrangements would allow future proofing against future charging changes via a broader clause to make generators 'whole' for distribution charges as opposed to specific drafting required for the Code. • If the changes were to be progressed via DCUSA, a solution could be to design a new section similar to Section G 'Contingencies' in the BSC arrangements; this would be preferable to modifying individual sections and this would minimise the level of code redrafting required, improve understanding by collecting all the arrangements in a single clause and align with the BSC approach. The conclusion is that these would be covered indirectly via the contract, through the providers' availability fees. When submitting the cost submissions, providers are required to price in any elements they need to consider, such as risk, to enable them to provide the service. They would need to consider any extra charges, such as an increase in GDUoS, for their provision of the service. The BSC issue group will consider how DER providing a Distribution Restoration service may be compensated for their fuel used in a Black Start situation.

13.6 Engineering Recommendation (EREC) G99 and EREC G59

Key discussion points	Decision process and outcome
G99 and G59 requirements for earthing	The earthing requirements will need to be engineered on a site-by-site basis. G99 and G59 now contain a statement that this design may differ from the more general assumptions and requirements of G99/G59, but in any case, would be agreed contractually with the DNO for the site in question.
G99 and G59 requirements for interface protection	The interface protection requirements will need to be engineered on a site-by-site basis. G99 and G59 now contain a statement that this design may differ from the more general assumptions and requirements of G99/G59, but in any case, would be agreed contractually with the DNO for the site in question.
Requirements that customers' supplies are in line with other Distribution Code requirements and the ESQCR requirements	A general statement has been included to point out that during a system restoration event it might not be possible to comply fully with all other requirements for all of the time.

Distributed ReStart

Next steps for transition



14. Implementation

This section covers what happens next as part of the plans for the project designs to transition into a business as usual (BAU) process.

As already indicated in the **BSSPM 2021/22,** the plan is to introduce DER providers into the next round of ESR tenders from April 2022 in the South East (SE) region. The Distributed ReStart project itself is not concluding until June 2022 due to delays in some of the PET Live Trials and OST DRZ-C developments. However, the proposals included in this P&C final report could inform the BAU procedures for the SE tender round.

To summarise the proposals in this final report:

- NGESO will continue to lead the procurement for both the traditional ESR tenders and the new Distribution Restoration service. The latter will be done in full collaboration with the relevant DNOs.
- The contract for the Distribution Restoration service will be a tripartite agreement.
- The settlement of costs for DER contract costs and pre-tender support costs from the DNO will be covered under RIIO-2 (BSUoS). However, any network upgrades and procurement of systems by the DNO will be recovered through ED-2 (DUoS).
- Changes in the industry codes will incorporate the requirements of Distribution Restoration services.

The proposed procurement process and all these aspects will need to be agreed by the relevant BAU restoration teams and the DNOs.

14.1 Options for the next steps

In this section, caveats, assumptions, issues and recommendations are covered, along with options for what could be considered as next steps.

The key caveat for consideration is that certain aspects of the commercial solutions are dependent on finalisation of operational and organisational aspects which will not be concluded until 2022. However, for all purposes of planning for the SE tender, discussions about how this will align with the traditional ESR process will need to start imminently.

The other key aspect is around the assurance that the functional requirements from this innovation project all work under tests and therefore the services that will be procured are sufficient for Distribution Restoration. The ball-park cost for DER services and DNO network costs are also key considerations which have not been fully priced out yet. This cost-benefit analysis is underway but not due for completion until project closure in June 2022.

This process is not intended to replace the traditional ESR process. It is meant to be slowly introduced in the areas identified by the DNOs as having good potential. This will mean a tandem process implementation plan, where timescales of the traditional ESR and the proposed Distribution Restoration procurement process need to be aligned and resourced accordingly. The good news is that the proposed process' timelines have already taken learnings from the traditional process; however, the number of additional resources required will depend on the number of interested DER parties. Unfortunately, at this stage it is unknown how many potential DER bids to expect on top of the usual traditional ESR providers in the South East region.

It is also unproven at this point, without a live round of tenders to compare to, whether procuring DER services are much more expensive than before. It is acknowledged that this Distribution Restoration service is paramount in the net zero ambitions for GB; however, it is anticipated that as it is introduced into the mainstream restoration process, the initial costs will be much higher than traditional costs.

However, over a period of time with all the upgrades in situ, these costs should plateau, and cost efficiencies will be more evident at that point. Nevertheless, during assessment of the DER bids against the traditional ESR bids, a potential for implementation is to bring in Ofgem to review and approve the proposed contract award shortlist, a process similar to one proposed by the **Early Competition project,** where Ofgem is the final approver of the bids.

Given the SE tender is in effect lined up almost as a pilot to try out this new procurement process, it'll be advisable that stringent checks are conducted as part of the pre-qualification company checks to ensure that the new DER providers are suitable for the full length of the contract. As a suggestion (this is discussed in Section 5.1), a set of criteria checks for new providers could be used as demonstrated by the **Stability Pathfinder Phase 3** tender.

For the SE tender round, conscious that the DNO in question (UKPN) is still operating in their ED1 price control until 2023, for any provisions required on their network and procurement of DRZ-C, the instruction from Ofgem is that they need to price up these requirements and discuss with them (Ofgem) in order to agree the best way to recuperate these investments ahead of ED2.

14.2 Next steps for stakeholder engagement

Engagement and co-creation of the Distribution Restoration service is key to the success of introducing this service as a tandem process alongside the traditional ESR service. The below outlines what engagement needs to happen as part of the next steps for transitioning the Distribution Restoration service into business-as-usual.

To start this process off, the Distributed ReStart project team has already engaged very early thoughts with Ofgem, UKPN as the DNO that goes first in the deployment of this process and the Project's Steering Committee. These initial conversations don't have a roadmap at this point although planning for the transition of project to BAU is starting within NGESO.

Future engagement required: with the recommendation that NGESO should lead this procurement process as part of the SE tender from April 2022, teams within NGESO need to be informed and onboarded.

The first part of the process is to seek NGESO Executive Team's approval, especially if the recommendations have policy changes for NGESO. Discussions are required imminently with UKPN, who go first with this process.

The recommendation is to follow the steps required as part of the regional strategy and pre-tender phases, agree a 'role framework' (which outlines responsibilities between the parties) and form a team that works jointly between both organisations.

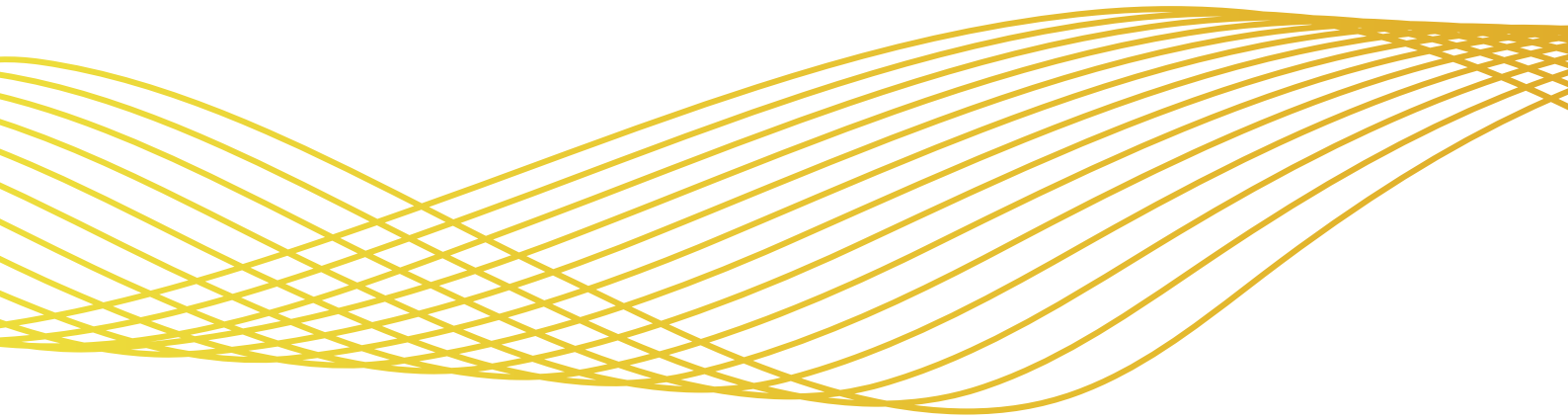
Aside from the procurement role, this DNO is also expected to upgrade their network and communication capabilities to make provision for multiple DER providers to join this service. To enable this, the specifications need to be shared soon so that they can commence their procurement of these components ahead of the tender commencement in April 2022. The OST workstream are already planning their focused engagement with UKPN on this front. For the commercial matters, it will make sense for the BAU restoration teams (both NGESO and UKPN) to join these discussions.

Ofgem will need to be kept in the loop about all the progress of this work. NGESO ESR team already have monthly catch-ups with BEIS and Ofgem where progress against ESR tenders is regularly reported.

It is known that the outcome of this first round of restoration with DER providers is of interest to the other DNOs especially as the Northern region tender is due to commence by 2023. It is important that engagement with the Energy Networks Association (ENA) is maintained, to provide updates, successes and lesson learned as this process embeds itself within the wider restoration plans.

Communication should also be maintained with DER providers across the regions. This is important to keep their interest levels up and demonstrate the success of this first round and encourage more participation for future restoration tender rounds. This can be done by NGESO and in conjunction with UKPN through stakeholder webinars, podcasts, bulletins and word of mouth during various meetings that are planned in BAU.

Finally, with the ESRS implementation planned for 2023, it is important for the ESRS team to stay informed on the progress of the Distributed ReStart project. As NGESO is leading the ESRS consultation, it should be relatively straightforward to provide updates to and from the BAU tender plans.



14.3 Next steps

The next steps for the P&C workstream following the publication of this final report is to support NGESO BAU restoration teams in aligning the two tandem procurement plans, creating a roadmap for delivery that involves UKPN and updating any recommendations in this report by the time OST and PET final reports are published – if required.

The final recommendation for implementation is to keep the proposed process evolving based on stakeholder engagement, industry direction and lessons learnt as it is trialled into BAU. These options are deduced following robust stakeholder input and with a lens of providing cost efficiencies downstream to the consumers. They are not fixed as policy changes but a solid starter for further discussions and development.

Given the positive feedback this workstream has heard already from DER providers and other forums, it is envisioned that these recommendations will soon assimilate into a well-trodden procurement process to help achieve net zero ambitions by increasing the diversity of generation and diminishing the reliance on coal-based power stations.

If done right, it is anticipated an expected benefit of savings around £115 million by 2050 through enhanced competition and potentially saving 810,000 tonnes of CO2 realised by avoiding the warming of conventional generation.

An updated Cost Benefit Analysis was completed for the **Project Progress Report in December 2020;** the updated CBA reaffirmed that Distribution Restoration has potential benefits exceeding £115 million across all the different future energy scenarios and is robust for varying levels of DER cost. The CBA work in 2021 will focus on updating the DER retrofit costs informed by the live trials, as well as updated generation technology redispatch volumes, and will also focus on refining the model to inform investment decisions.

The proposal for implementation of the recommendations from the P&C workstream is that these would be reviewed around 2026 and the proposals/service design updated as necessary from industry developments and learnings from the tenders.

Depending on the industry developments on the DSO roadmap, the outcomes of the FSO consultation and other industry initiatives, it may be that industry direct NGESO to transition procurement of the Distribution Restoration service to the relevant DSOs/DNOs.

14.4 Codes next steps

As discussed in Sections 12 and 13, the required code changes to enable Distribution Restoration are being progressed with industry and further engagement is being undertaken to aid industry understanding.

Grid Code and Distribution Code changes are being progressed via code modification GC0148: Implementation of EU Emergency and Restoration Code Phase II, with this code modification going to consultation in early 2022 for implementation by Dec 2022.

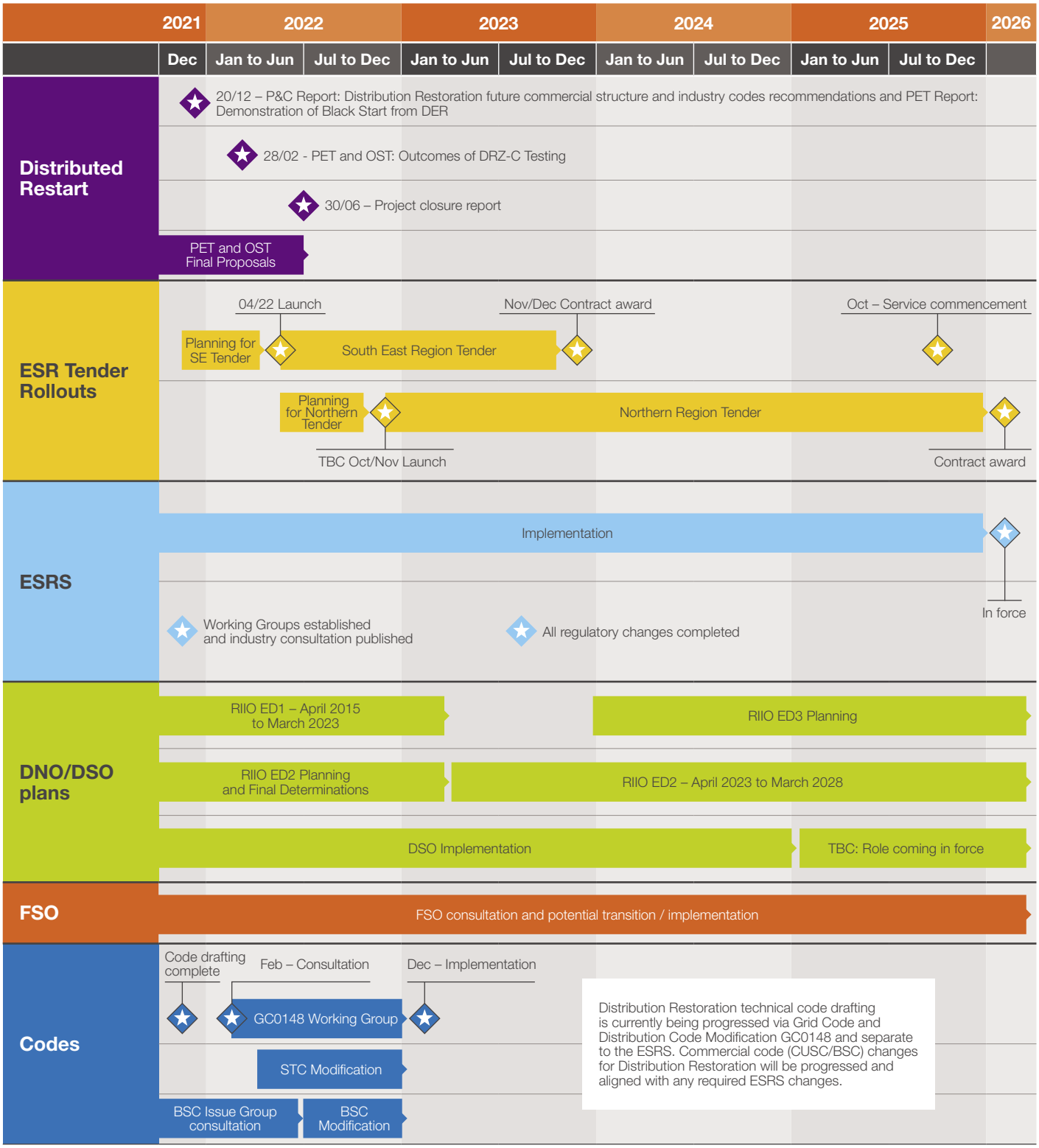
An issue group is going to be raised for the BSC, to work with industry to come to a suitable solution for how best to treat DER who provide a restoration service within the BSC, this will then progress to a code modification mid 2022.

P&C will present to the STC panel in January to highlight the required changes for Distribution Restoration, a code modification will then be raised to the STC.

As the changes to codes progresses for Distribution Restoration, there will be outcomes from the ESRS project on codes changes to enable the ESRS. The NGESO teams working on code changes for Distribution Restoration will ensure there is alignment between the different work packages and where possible efficiencies will be made.

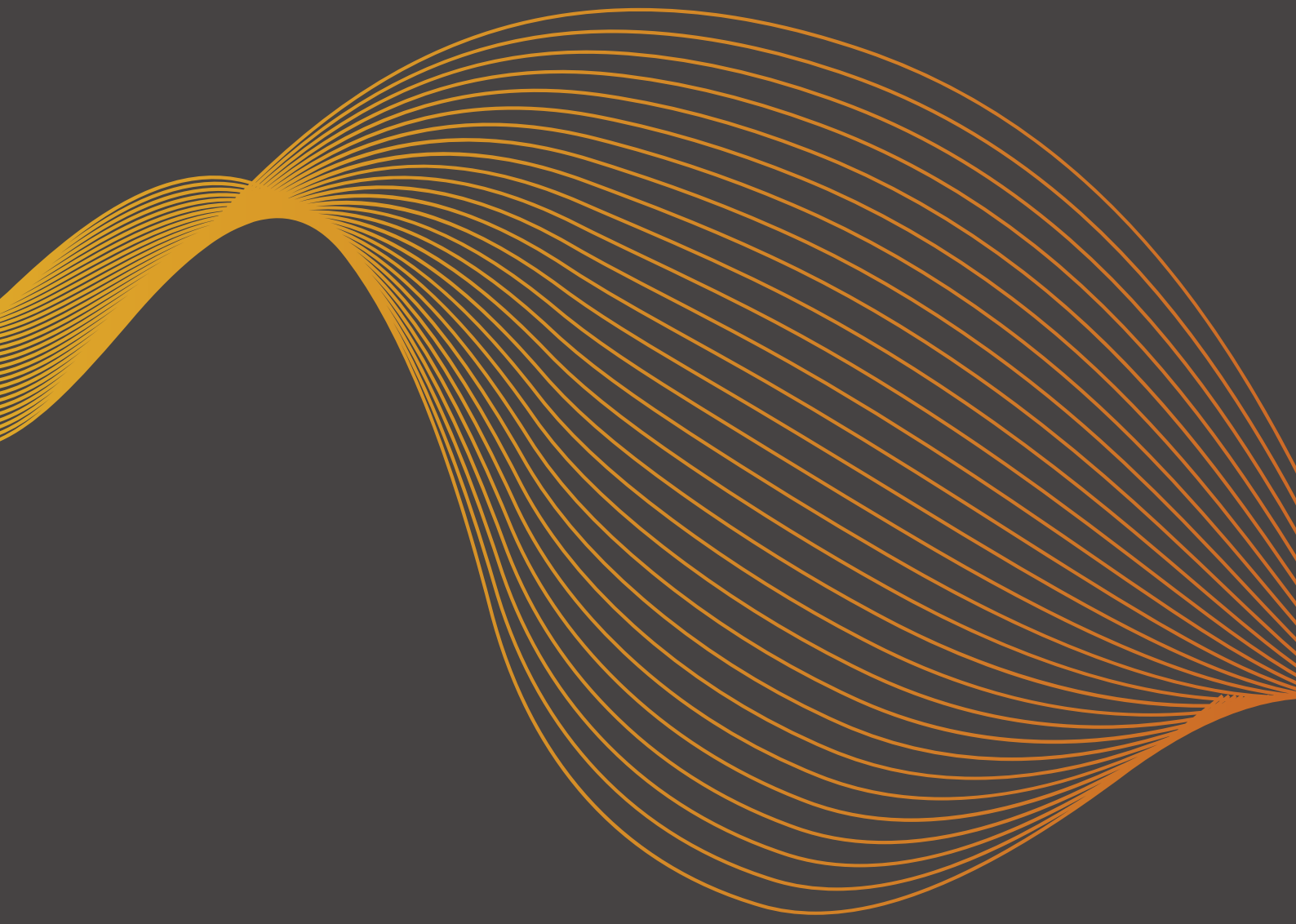
The diagram below demonstrates at a high level how the different industry initiatives and the proposed implementation timelines for the Distributed ReStart project will align together.

Figure 19:
Timelines of different industry initiatives and implementation of Distributed ReStart project



Distributed ReStart

Appendices



Appendices

There are four appendices supporting this report which can all be found here **nationalgrideso.com/future-energy/projects/distributed-restart/key-documents**

Appendix 1 Stakeholder Engagement

This summarises the outcomes of the various stakeholder engagements carried out as part of the Refine stage developments in 2021.

Appendix 2 Draft Distribution Restoration Contracts

There are four draft contract documents included in this appendix.

These are the:

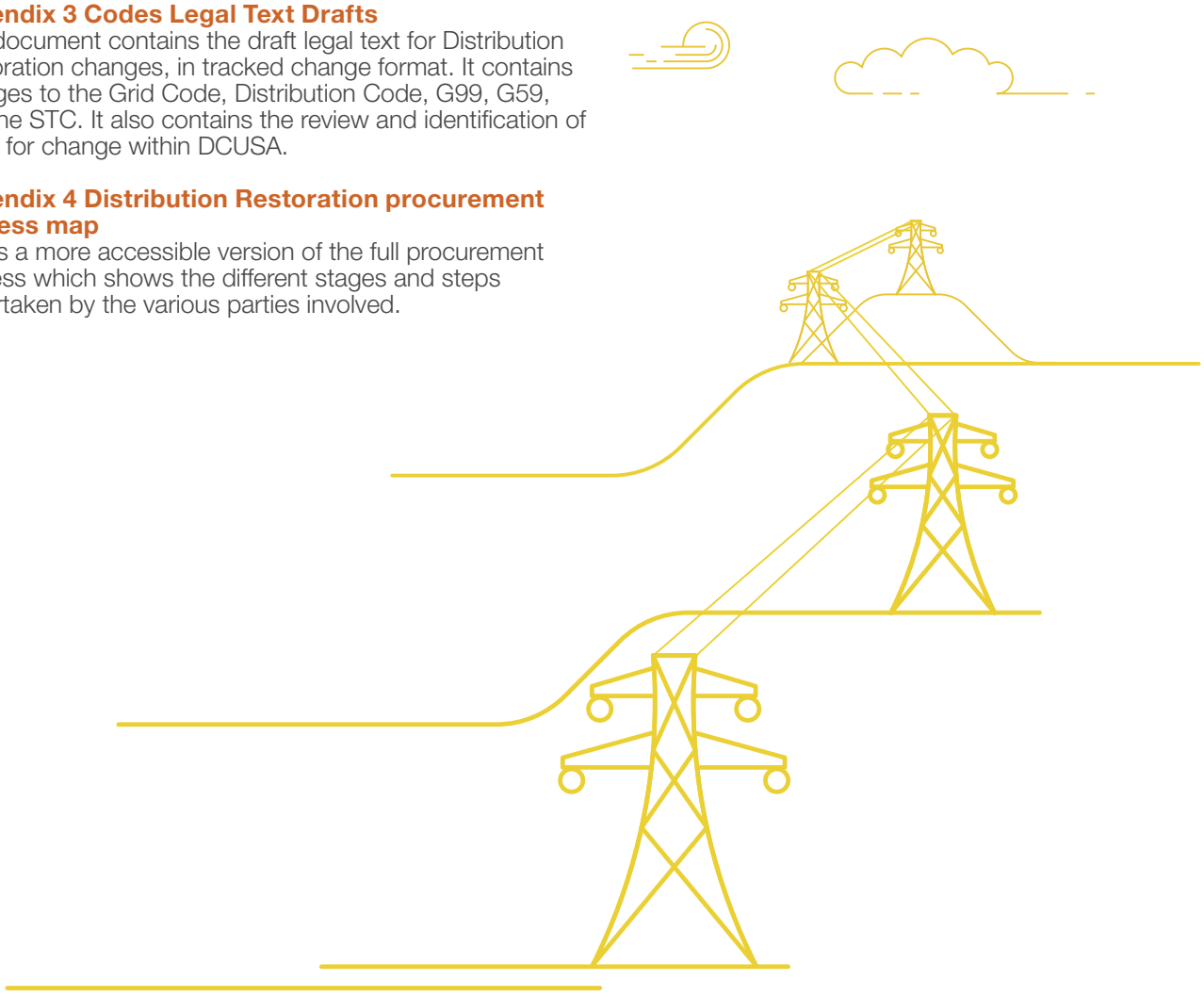
- Distribution Restoration Anchor Generator Service Terms
- Distribution Restoration Anchor Generator Contract Form
- Distribution Restoration Top-up Services Service Terms
- Distribution Restoration Top-up Services Contract Form

Appendix 3 Codes Legal Text Drafts

This document contains the draft legal text for Distribution Restoration changes, in tracked change format. It contains changes to the Grid Code, Distribution Code, G99, G59, and the STC. It also contains the review and identification of areas for change within DCUSA.

Appendix 4 Distribution Restoration procurement process map

This is a more accessible version of the full procurement process which shows the different stages and steps undertaken by the various parties involved.



Glossary

The table below explains some of the definitions and acronyms of terms referred to regularly in this report.

Table 19:
Glossary

Term or acronym	Definition
Anchor Generator (AG)	A generator with the ability to establish an independent voltage source.
BAU	Business as usual.
Black Start	The procedure necessary for a recovery from a total shutdown or partial shutdown of the electricity system.
BSC	Balancing and Settlement Code.
BSSPM	Black Start Strategy and Procurement Methodology.
BSUoS	Balancing Services Use of System.
Cost Benefit Analysis	An options appraisal process by which the quantifiable value of a deliverable is measured by comparing against a business as usual process or design.
CSA	Commercial Service Agreements.
CUSC	Connection and Use of System Code.
DCUSA	Distribution Connection and Use of System Agreement.
Distribution Code	Licensed electricity distribution businesses, or Distribution Network Operators (DNOs) in Great Britain, are obliged under Condition 21 of their licences to maintain a Distribution Code detailing the technical parameters and considerations relating to connection to, and use of, their electrical networks. For more information: **www.dcode.org.uk/**
Distributed Energy Resources (DERs)	DERs are electricity-producing resources or controllable loads that are connected to a local distribution system or to a host facility within the local distribution system.
Distribution Network Operator (DNO)	A company licensed to distribute electricity in the UK.
Distribution Restoration	Part of the Electricity System Restoration process which focuses on the energisation of the electricity system from distribution level up to transmission level.
Distribution Restoration Zone (DRZ)	A power island in the distribution network used for Black Start/Restoration purposes.
Distribution Restoration Zone Controller (DRZ-C)	A system that monitors and controls one or more DRZs.
Distribution Restoration Zone Plan (DRZP)	A plan detailing the agreed method and procedure by which a distribution zone will be energised from start to end of a distribution zone.

Term or acronym	Definition
Distribution Restoration Zone Operational Working Group	This group will contain representation from NGESO, DNO and successfully contracted DER parties both anchor generator and top-up services that are providing service for a single DRZ. The main purpose of this group is to come together regularly, maintain communication, raise any issues/troubleshooting factors and agree mitigations as part of the contract. If there are multiple DRZs in a region, there will be multiple DRZ Operational Working Groups to support each of those zones at GSP level.
Distribution System Operator (DSO)	A future entity responsible for actively operating the distribution network. The Energy Networks Association (ENA) is currently investigating various DSO 'worlds' outlining the division of responsibility and which entity is most appropriate to fulfil this activity.
ENA	Energy Networks Association.
EOI	Expression of interest.
ESR	Electricity System Restoration.
FSO Consultation	The Energy Future System Operator consultation.
FRPC	Functional Requirements for Procurement & Compliance.
Grid Code	The Grid Code details the technical requirements for connecting to and using the National Electricity Transmission System (NETS). Compliance with the Grid Code is one of the requirements of the Connection and Use of System Code (CUSC). For more information: **www.nationalgrideso.com/industry-information/codes/grid-code**
Grid Supply Point (GSP)	This is traditionally the point where power is delivered from the transmission system to either a distribution network or a customer directly connected to the transmission system.
Industry Codes	Industry codes underpin the electricity and gas wholesale and retail markets. Licensees are required to maintain, become party to or comply with the industry codes in accordance with the conditions of their licence. For more information: **www.ofgem.gov.uk/energy-policy-and-regulation/industry-codes-and-standards**
Local Joint Restoration Plan (LJRP)	A plan detailing the agreed method and procedure by which a Genset at a Black Start Station (possibly with other Gensets at that Black Start Station) will energise part of the total system and meet complementary blocks of local demand so as to form a power island. In Scotland, the plan may also cover more than one Black Start Station, include Gensets other than those at a Black Start Station and cover the creation of one or more power islands.
NETS	National Electricity Transmission System.
NGESO	National Grid Electricity System Operator. A company with licence obligation to ensure effective balance of electricity supply and demand, to develop markets, advise on network investments and, in terms of Black Start, develop strategy and ensure that the electricity network is restored in cases of total or partial shutdown.

Term or acronym	Definition
NIC	Network Innovation Competition.
OCRA	A high-level outline of commercial and regulatory arrangements.
OST workstream	Organisational, Systems and Telecoms workstream.
P&C workstream	Procurement and Compliance workstream.
PET workstream	Power Engineering and Trials workstream.
Power Island	A part of the electricity network that is electrically disconnected from the larger grid and operated in an islanded mode.
RaaS	Resilience as a Service project.
RDP	Regional Development Programmes.
RIIO-ED2	The price control set by Ofgem.
SP	Settlement Period.
SPD	SP Distribution.
SPEN	SP Energy Networks.
SPM	SP Manweb.
Strategy Development Process	A standardised approach to strategy development that is divided into five stages: define objectives, inputs and analysis gathering, initiatives (options), refine (options appraisal) and, finally, implement.
STC	System Operator Transmission Owner Code.
TNEI	A specialist energy consultancy.
Top-up Services (TUS)	These are the supplementary services required to fulfil the technical capability of a DRZ such as Energy (MWs), fast MW control, frequency control, voltage control and short circuit level (MVArs).
TSO	Transmission System Operator.
UKPN	UK Power Networks.
CWG	Codes working group.

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