December 2020

Operability Strategy Report 2021

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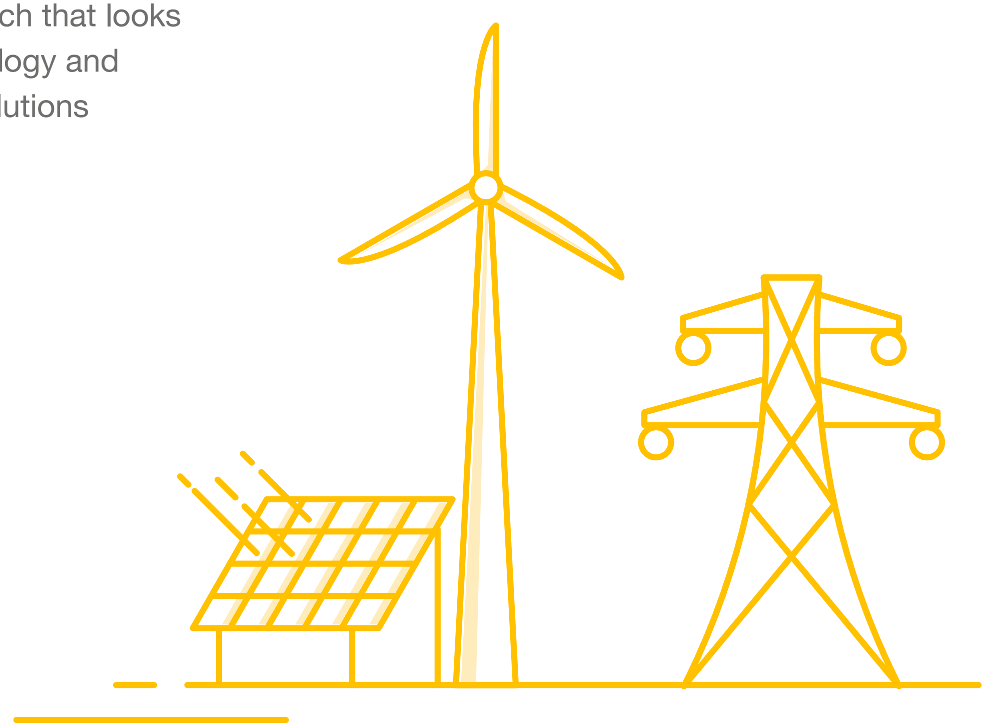
Introduction

Our annual Operability Strategy Report explains the challenges we face in maintaining an operable electricity system and how we are addressing them. Our work is framed by our 2025 ambitions, including 'an electricity system that can operate carbon free', 'competition everywhere', and 'ESO as a trusted partner'.

While the focus of this report is operability and how we will deliver safe, reliable electricity supply today and into the future, the challenges we face in enabling the energy transformation are wide ranging. Across the ESO we continue to work closely with our stakeholders to ensure a holistic approach that looks across systems, markets, policy, technology and innovation as we develop and deliver solutions in response to those challenges.

Collaboration and co-creation are at the heart of our approach. Throughout this report we highlight opportunities for engagement, and signpost where to look for more information.



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Introduction

Context

As the Electricity System Operator for Great Britain, we are in a privileged position. We sit at the heart of the energy system, balancing electricity supply and demand second by second. We keep the lights on and the electricity flowing directly to where it's needed. Electricity underpins our modern lives and National Grid ESO exists to make sure everyone gets access to a safe, reliable and affordable supply.

Decarbonisation, decentralisation and digitalisation are driving significant change across the electricity network, impacting how we operate the system now and into the future. It is our role to support the energy transition, while making sure we can continue to operate the system in a way that delivers the biggest benefits to end consumers.

By 2025, we will have transformed the operation of Great Britain's electricity system and put in place the innovative systems, products and services to make sure that the network is ready to handle 100% zero carbon energy.

This means a fundamental change in how our system is operated – integrating newer technologies right across the system – from large scale off-shore wind, to domestic scale solar panels, to increased demand side participation. This report outlines the work we are doing to meet these challenges – providing an update on our progress and setting out our program of work for 2021 and beyond. We recognise the critical nature of our work – to ensure safety and reliability, to lower consumer bills, reduce environmental damage and increase overall societal benefits and we are committed to delivering in collaboration with industry to unlock this value.

The impacts of COVID-19 presented a challenge for the ESO in maintaining safe, reliable energy supply with the unprecedented low demands in 2020 and as such provided an insight into potential future operability challenges. We shine a **spotlight on 23 May 2020**, setting out the operability challenges and the actions we took to ensure continued safe and secure system operation. In the following pages, we bring together our actions and explain the learning, while the subsequent chapters go into the detail and learnings that we will take into our ongoing operability work.

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Key messages

As in previous editions of this report, we consider operability challenges in 5 key areas of Frequency, Stability, Voltage, Restoration and Thermal. Across each of these areas we provide a brief overview of the challenge, highlights of our progress over the last 12 months and a look ahead to our main areas of focus in 2021 and beyond.

A short summary of our key messages is provided below, with links to the relevant chapters for more detail.

1 Frequency

Our Frequency workstream looks primarily at our operability gap for frequency response and reserve services as we transition from services primarily designed around the thermal characteristics of large synchronous plant, to a decarbonised, distributed and digitised system.

A key focus during 2020 has been the development and soft launch of a new super-fast acting response product called Dynamic Containment (DC) - a significant step forward helping us manage frequency on a system where inertia levels are dropping and there are larger potential losses which require faster frequency response. We have worked closely with providers to bring DC into service and to understand the entry barriers for new market participants.

Looking ahead, with the DC soft launch complete, we are delivering on our plan to improve the day-ahead procurement process as well as launching the high frequency response service.

In 2021 we will work closely with industry to develop a new suite of reserve products, taking the same approach we used for developing DC. Our reserve reform project will build on lessons learnt from the creation of the new optional downward flexibility management (ODFM) service during summer 2020, as well as leveraging the accessibility improvements made through Wider Access to the Balancing Mechanism.

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2 Stability

Our Stability workstream focuses on ensuring that stability capability (which was traditionally available through market dispatch of synchronous generation) is retained to ensure the operation of a safe, secure and economic system. We will achieve this through a combination of updated industry standards to better reflect how we manage low inertia, and by finding new sources of stability capability.

We have made considerable progress since our last report. Working closely with DNOs through the Accelerated Loss of Mains programme, we are seeking to ensure that embedded generation has the appropriate relay settings – improving network security by ensuring that generation on the distribution network will respond appropriately to a change in system conditions. To date we have seen more than 10 GW of generation submitting applications to the program and good progress has been made this summer through strong engagement between ESO, DNOs and generators.

We are reflecting these changing system conditions by changing our operational policies. Security and Quality of Supply Standard (SQSS) modification GSR027 increases the transparency of our actions to secure risks such as these.

Our world first, Network Options Assessment (NOA) stability pathfinder is creating a market for new stability service providers as the existing, traditional stability sources continue to decommission. Phase one procured 12.5GVAs of inertia in January and phase two will open up the service to a broader range of potential service providers, such as wind and battery providers.

Looking ahead we will use the learning from this pathfinder to support the development of a new industry agreed stability specification. We are also investigating if there will be a need for a shorter-term market to sit alongside the long-term contracts.

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3 Voltage

To continue maintaining a secure and operable system, the need for reactive power support continues to grow as the energy system decarbonises and the provision of reactive power support from large synchronous generation decreases. To manage this increase in reactive power need and decrease in reactive support, we need to find new ways of managing the production and absorption of reactive power, further develop how we communicate and contract our requirements, and find new providers of reactive power.

In 2020 we have made good progress through the NOA Mersey pathfinder and Power Potential projects. These projects are leading the way, accessing services from a reactor, a battery and distributed energy resources.

Looking ahead we are using the learning from these projects, to improve future pathfinding projects such as the NOA Pennines pathfinder.

We are also conducting a holistic review of reactive power. Initially we will work with industry to improve our understanding of concerns with the current market. We will then work together to drive efficient market reform. There are three key areas that we will be focussing on: finding new reactive power providers, reviewing existing procurement mechanisms and making sure that by 2025 we can manage reactive power with a zero-carbon generation mix.

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4 Restoration

In the unlikely event that the electricity system fails, and the lights go out, the ESO has a robust plan to restore power to the country as quickly as possible. Our vision for Restoration is that by the mid-2020s, we will be running a fully competitive restoration procurement process with submissions from a wide range of technologies connected at different voltage levels on the network, with Transmission Owners (TO) and Distribution Network Operators (DNO) playing a more active role in the Restoration Approach.

During 2020, we have made significant progress – we will continue to push on all areas through 2021 and beyond.

Our focus for restoration is on running a fully competitive procurement process from a wide range of technologies. In 2020 we awarded six contracts in the South West and Midlands through a competitive procurement exercise and we will be concluding the competitive procurement exercise in the North West, North East and Scotland in 2021.

Through the Distributed ReStart innovation project, we are also working with industry to facilitate the provision of a restoration service from distributed energy resources. The first successful live trial took place in October 2020, when an 11kV generator energised part of the 132kV/33kV network.

Together with Industry, Government and Ofgem, we have been developing a GB restoration standard that will specify the required timescales for restoration from total shutdown.

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5 Thermal

In our role as ESO, we manage the flow of electricity across the high voltage transmission system from where it is generated to where it is consumed. The assets which transport this energy around the network have physical limitations on how much power can be carried. We must prevent these limits being reached or exceeded to prevent loss of supply to areas of the network; we are mindful of the impact of our actions both from a carbon and cost perspective and are proactively focused on seeking innovative solutions to manage these constraints.

Our electricity ten year statement, published in December 2020, shows that thermal constraint costs are likely to increase due to high flows on the transmission system in the next ten years. This increase is driven by significant growth in renewable generation expected to connect in Scotland, Northern England and offshore, and further growth in continental interconnectors in the South.

We have a number of activities underway. We are continuing to work with Distributed Network Operators to increase visibility and control of embedded units through the Regional Development Programmes. This will maximise the opportunities for further efficient deployment of distributed resources and reduce overall system costs for energy consumers.

We are increasing our ability to export power out of constrained areas through the NOA constraint manager pathfinder. We are working with market participants to develop solutions that use existing network capacity more efficiently and increasing access to the system for market participants and are focusing on actions that we can take to reduce the costs of managing constrained boundaries.

Even with these activities, there are still forecast to be significant congestion costs towards the middle to end of the decade. Therefore we will work with industry to bring forward further solutions to minimise the impact of constraint costs on end consumers.

We want to work with you!

Our strategy is ambitious and transformative. It is vital for making sure we can continue to operate a safe, secure and reliable electricity system, and deliver against our zero carbon by 2025 ambition while maximising benefits for the end consumer and your input and support is critical.

Throughout the main body of our report you will find links to specific opportunities to get involved in all key areas of our work. We would also welcome to your comments and feedback on our overall approach to our operability challenges. Please get in touch by emailing us at SOF@nationalgridESO.com

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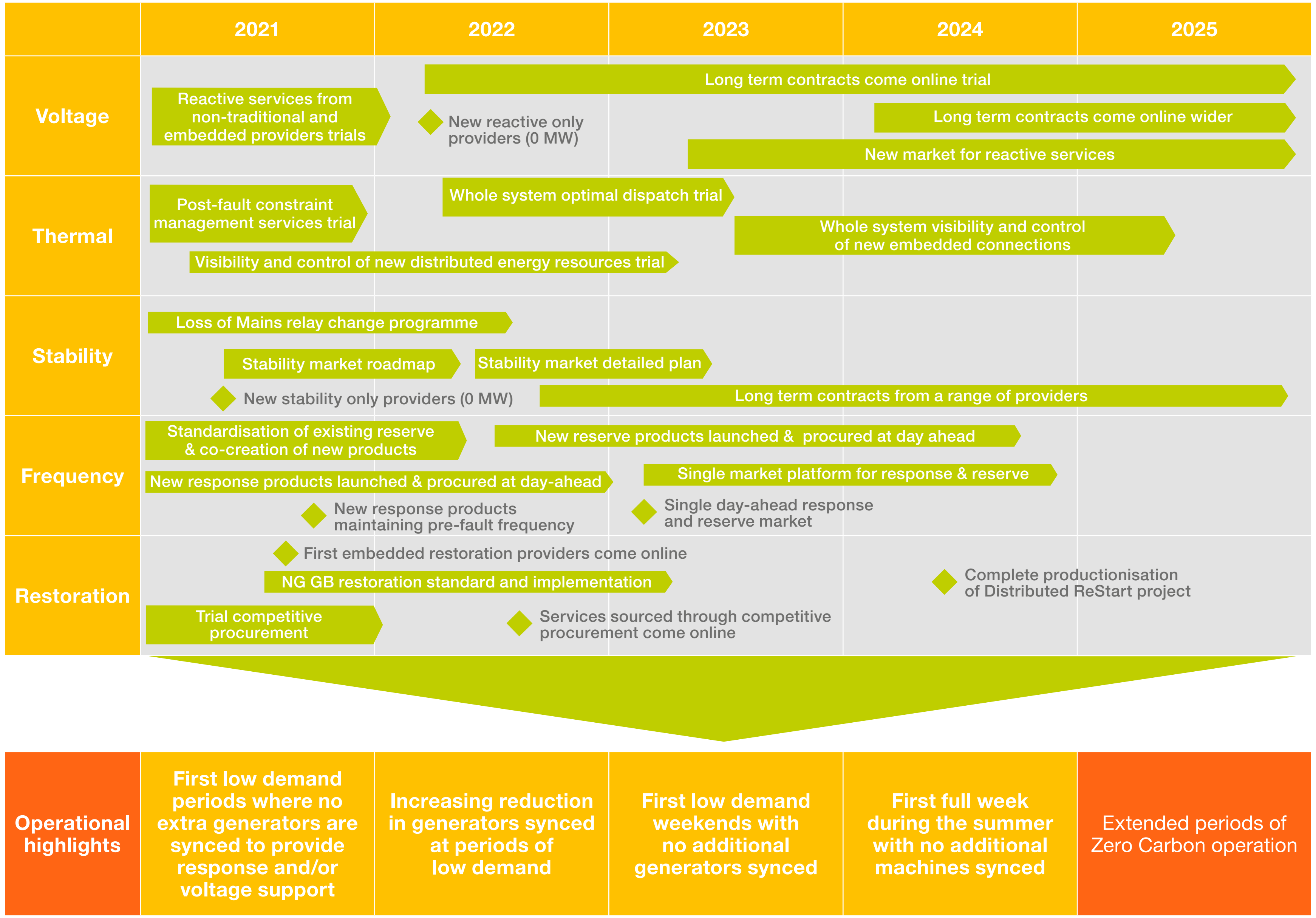
Operability Milestones

Framed by our zero carbon 2025 ambition, our operability milestones overview the key outcomes in each of the security areas. Commonly deliverables are viewed through project plans and timelines. This is an alternative lens by looking at the timeline against the outcomes we are seeking. For example, our voltage pathfinders are investigating alternative service providers from non-traditional and embedded sources. Initially this was in Mersey. Next year it will be expanded to Pennines, with the end goal being to deliver GB wide. The underpinning detail of this view is contained in the following security chapters.



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Case Study

Saturday 23 May 2020

Case study

Saturday 23 May 2020

During 2020, the operability challenges we experienced were the same ones that we usually manage: maintaining frequency, managing voltages, making sure the system is stable, resolving thermal constraints and making sure that we can restore the system.

However, this year the impact of COVID-19 provided a glimpse into how those operability challenges will evolve and change in future. Exceptionally low demands due to the impact of COVID-19 resulted in a significantly changed generation mix, with zero carbon sources such as renewable and non-synchronous providers, making up their largest ever share of generation on the system. This resulted in the lowest carbon intensity for electricity generation of 46 gCO_2/kWh that we have seen to date. The characteristics of this generation mix (low inertia, largely inflexible) meant that our control room had to make more operational interventions than ever before to maintain safe, reliable supply.

Our Future Energy Scenarios suggest that as we move forward, reduced demand periods with high levels of zero carbon generation will be normal during the summer and even extend into the spring and autumn. While this summer was exceptional in many respects, it also gave insight into what a future zero carbon electricity system could look like. It showed that we can operate a low carbon grid and keep the lights on. However, this required a disproportionate level of operational intervention, that our Operability Strategy aims to reduce.

To help explain our operational needs, we investigated 23 May 2020 and have used it as a case study in this report. Saturday 23 May was over the bank holiday weekend and demand was unusually low at 23GW due to the combined impact of COVID-19 and the normal bank holiday demand suppression. It was sunny and windy which meant there was a high renewable generation output.

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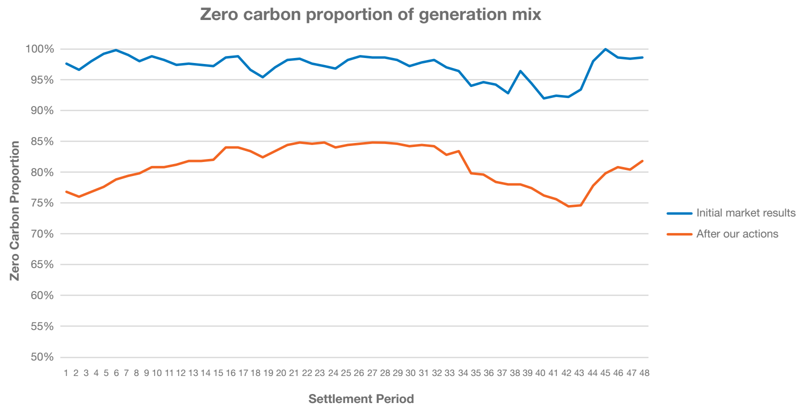
Case study

Saturday 23 May 2020

On 23 May 2020 the market provided close to 100% zero carbon generation for some periods. However, for operational reasons, our control room had to take actions to pull back wind and hydro to put on carbon generation (gas and biomass). These interventions were needed as only some generation types provide the system services we need to operate the electricity system safely and securely. The graphs below show the market provided solution and the impact of our operational actions. These actions reduced the zero carbon proportion of the generation mix to ~80% over the day.



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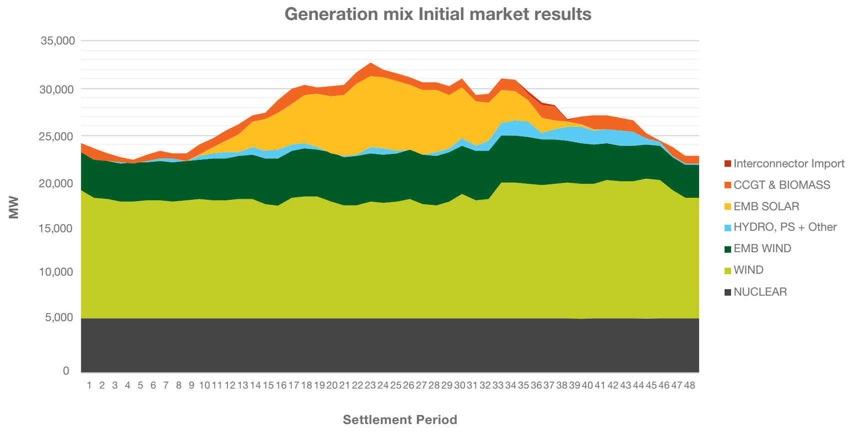

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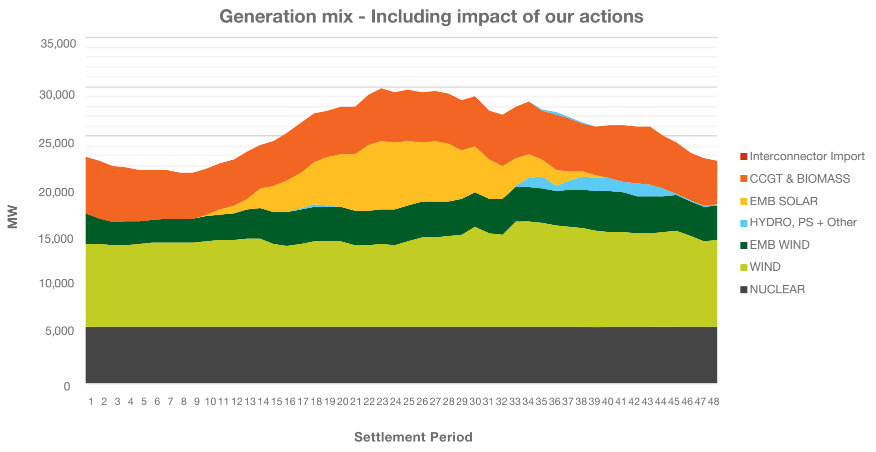

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Some key operational learnings

Some key operational learnings are clear from our experience on 23 May:

- To help manage **frequency** over the summer, we created a new temporary downward flexibility service called ODFM (Optional Downward Flexibility Management). ODFM was created to give us access to downward flexibility when demands are low. On Saturday 23 May we used the service to instruct mainly embedded wind and solar providers to reduce their output. This action was taken to make sure that our requirement for negative reserve (footroom) could be met, as there was insufficient volume available through our normal reserve and balancing services. Going forwards, our reserve product reform program will look to incorporate these new providers into an enduring solution. This will enable providers to continue to offer us flexibility services and help support system operation.

Stability

- As can be seen from the graphs, on 23 May we had to replace on average ~4GW of zero carbon plant, with an equivalent amount of **stability** providing synchronous plant. This was required to manage the risk of disconnecting embedded generation, some of which has over sensitive protection. We have a programme to fix this (the Accelerated Loss of Mains Change Programme) and have already changed the protection settings at over 3,000 sites. This means that the next time we experience similar system conditions, we will have to take less operational interventions and once all the susceptible relays have been changed, we will no longer need to take actions for this purpose. The stability providers that we source from the NOA stability pathfinder, will further reduce our need for operational interventions by attracting solutions which can provide stability without generating, such as synchronous compensators, as well as non-synchronous generators which can be adapted to offer grid forming capability. For example, stability pathfinder phase 1 will provide the equivalent inertia of around 5 coal fired power units.

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Case study

Voltage

- Managing **voltage** levels must be done locally as reactive power cannot travel great distances. On 23 May we had large power flows out of Scotland and Northern England to meet a low demand level. This meant there was not enough reactive support across the rest of the network. We needed to instruct 11 synchronous generators onto the system to provide reactive power, displacing up to 2.5GW of renewable generation. Our Mersey voltage pathfinder is already demonstrating its value. On 23 May it negated the need to run fossil fuelled generation, reducing costs and our carbon impact. Our next NOA pathfinder will focus on the Pennines and Northern England region which required 900MW of fossil fuelled generation to be synchronised on 23 May. This will have an even bigger impact than Mersey as the requirement in Pennines is significantly larger.

Restoration

- On 23 May, we didn't have to take additional actions to make sure there were stations available to provide a **restoration** service. This was because they were already available to meet our other operational requirements. Our strategy of diversifying the range of technology types that can supply this service is critical to reducing our reliance on synchronous plant.

Thermal

- On 23 May, there were **thermal** constraints that limited the amount of power we could transfer out of Scotland and the North of England. Resolving these constraints required up to ~5GW of actions to reduce the zero carbon generation in this area. We replaced this energy with mostly carbon emitting plant. Through the work we are doing on the NOA constraint management pathfinder, we are looking to find commercial solutions that will help increase the amount of power that can be exported from this area. This will help to reduce constraints and the control room will need to take fewer interventions to balance the system, reducing costs for the end consumer.

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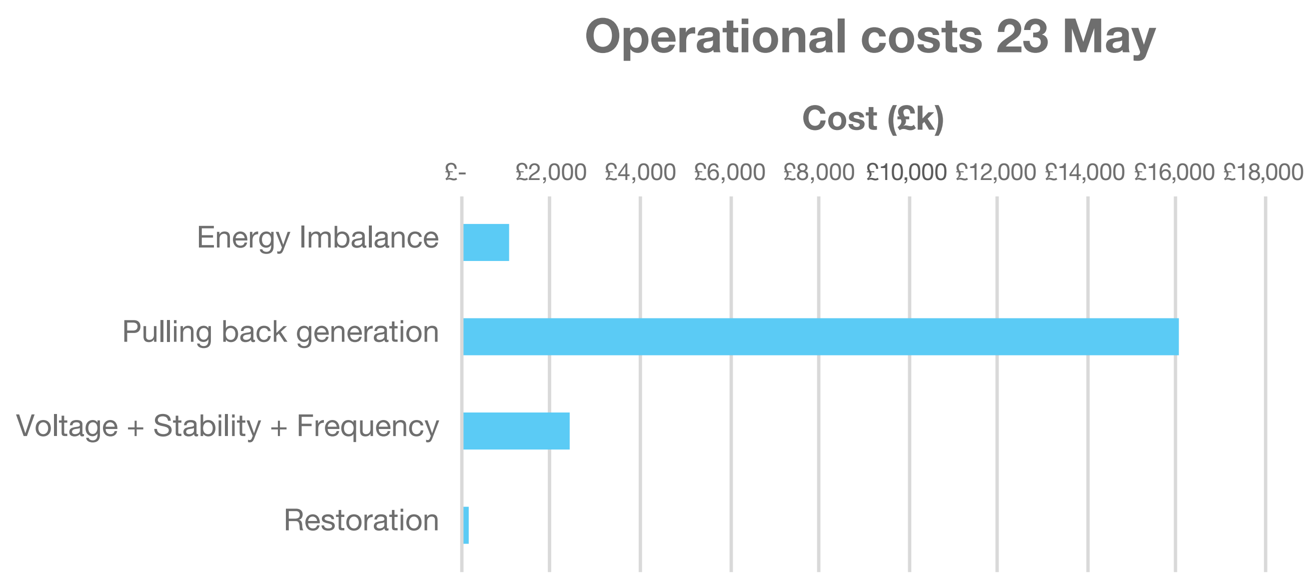
Case study



Looking at all of the actions taken by the control room to balance the system, the total operational spend for 23 May was £19.7m. The energy imbalance spend was because the market was short and we had to schedule extra generation to meet the physical demand. Further we pulled back ~140GWh of generation to make space to bring on the generation we needed to resolve our voltage and stability issues. This cost ~£16m. The remaining costs are broken down by security workstream. What the plot doesn't show is that there can be trade-offs when operational actions are taken. This is because a single action can help (or hinder) multiple constraints.

For example, removing wind to make space to bring on generation to solve our stability and voltage issues, can also help resolve our thermal constraints. In such a case, the cost of pulling back wind would be tagged as thermal, despite being required to help stability or voltage as well. For stability we needed to increase the inertia on the system, whereas for voltage we needed to replace wind generation with service providers that would support the volts in specific locations.

In the following chapters we explain our operational strategy to facilitate zero carbon operation, with reference to how it would have addressed the challenges we faced during the case study day. We will continue to use the learnings from this summer to inform the development of our future operability strategy.

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OSR 2021: Get involved

Get involved

System operability framework

Get involved

1 Frequency

- All information about and opportunities to get involved with **dynamic containment** can be found on our dedicated webpage
- To find out more about our **reserve services** and sign up to be involved in co-creation workshops please visit our reserve services webpage

2 Stability

- To participate in the **Accelerated Loss of Mains Change Programme** (ALoMCP) please visit the Electricity Network Association website
- To find out more about our **SQSS modification proposal GSR027** please consult the review documentation on our website
- The window for expressions of interest in NOA Stability pathfinder phase 2 are open until 8 January 2021 website
- To get involved in **GC0137 the specification of grid forming capability** please review the modification proposal on our website

3 Voltage

- Lessons learned from the **NOA Mersey voltage pathfinder** can be viewed in a report published on our website
- We will be publishing our next steps for the NOA Pennine voltage pathfinder in the new year on our website
- To find out more information about how we are pushing forward with the future of reactive power, please visit our website

4 Restoration

- Information on our **strategy for restoration and our current methodology for procuring services** to support restoration, can be found on the black start page of our website
- To find out more about our **Distributed ReStart** project please visit our website

5 Thermal

- Updates to the **NOA Constraints Pathfinder** are available on our website; we will also publish the tender information here which we expect to be in Q1 2021/22
- We welcome industry views on the improvements made to the **probabilistic methodology** in the Electricity Ten Year Statement (ETYS) 2020 and on the inclusion of the methodology in the Network Options Assessment – contact transmission.etys@nationalgrideso.com

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System operability framework

What can I expect this year?

Throughout the year, we will be releasing further publications about upcoming operability challenges.

How can I get involved?

We are keen to hear your comments and feedback on our approach to these operability challenges.

You can get in touch with us at SOF@nationalgridESO.com

All our past publications, plus the option to sign up to our mailing list can be found on our webpage.

Reports	Overview	When to expect
National Trends and Insights	A comprehensive analysis of the latest FES data and its impact on system operability and potential solutions.	Feb 2021
Risk Analysis on Multiple Fault Ride-Through Protection in Wind Generation	Assessment of the risk associated with multiple fault ride-through protection employed by wind generation on the system.	Mar 2021
Power Quality in Electrical Transmission Network	Assessment of how the changes in the system (particularly reduction in synchronous generation) impact the power quality parameters (voltage imbalance, harmonics and voltage flicker) over time.	May 2021

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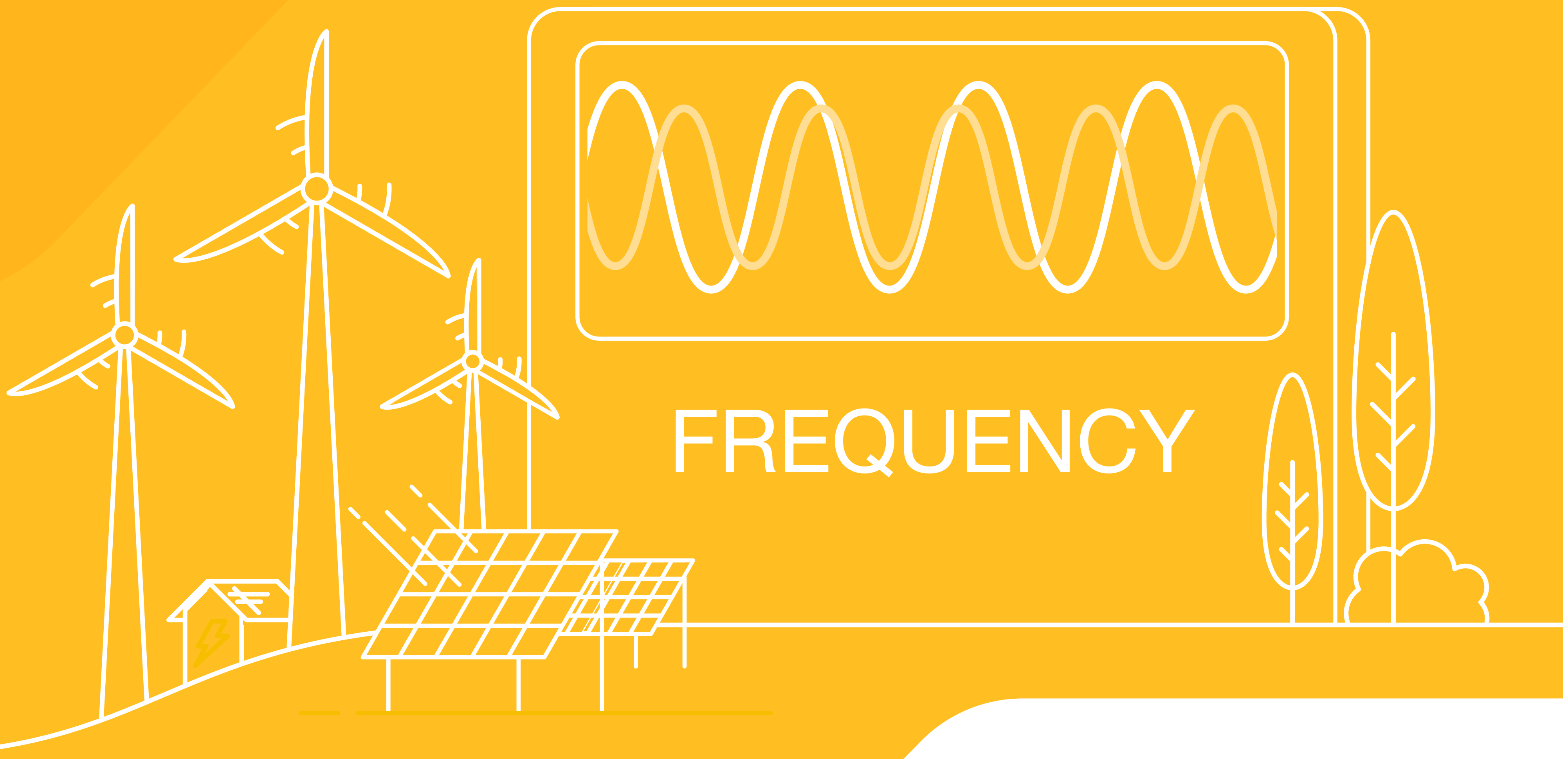
Frequency

Insight into the future energy mix

Dynamic containment

Reserve product reform



Frequency

As part of our operability strategy the Frequency workstream looks primarily at our operability gap for frequency response and reserve services. Both response and reserve can be described as access to a change in delivered power, either up or down.

Response services are activated automatically using a measurement of frequency to determine action. Reserve is dispatched manually by a control room operator following an observed system event or proactively in anticipation of a system need.

As we look to facilitate zero carbon operation by 2025 our operability gap indicates that we need to reform both our response and reserve services, in this report we highlight the latest developments to this aim.

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Frequency

What we saw over 2020

Typical low demands over summer were exaggerated by the behavioural effects of the national lockdown. On some days national demands were up to 18% lower than expected before the pandemic hit.

These low demands influenced the generation mix provided by the market with much lower quantities of inertia providing plant scheduled to run as almost all the demand could be met by renewables and imports across interconnectors. This reduction in system inertia also increases our requirement for frequency response to catch any change before it exceeds limits.

Our faster acting response services, starting with dynamic containment, are much more efficient in securing losses and managing frequency on low inertia systems. Compared to existing, traditional frequency response services we will require much lower quantities of our new faster services to meet the expected operability challenge.

In the first section we look in detail at dynamic containment and how it has been designed to manage the type of system conditions that we were exposed to in the summer.

Frequency / Insight into the future energy mix 24

The conditions of summer 2020 will not be unique by 2025, they will be normal. So the summer has given us a helpful insight into the future needs of the system and the actions we may need to take to operate securely. As detailed in the case study, on 23 May we needed access to additional sources of negative reserve and met this via the ODFM service.

The service was created and utilised because all our normal routes to accessing negative reserve (the balancing mechanism, interconnector and bilateral trades) were expected to be fully utilised. The conditions on that Saturday of low demand, high renewable output and high interventions for voltage, stability, thermal constraints and frequency response meant that ODFM was required to supplement and support our normal operational actions.

In the second section of this chapter the strategy for reserve product reform is outlined. As part of a wider review of reserve services this project will look at if and how the ODFM service can be developed. We are very keen to continue to engage with all the new providers that signed up for ODFM, to ensure that we retain access to their valuable flexibility and also to increase competition in our balancing services.

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Frequency

In October 2020 we launched a new frequency response service, dynamic containment (DC). As the name implies the purpose of the service is to contain frequency within our statutory limit of 50Hz +/- 0.5Hz.

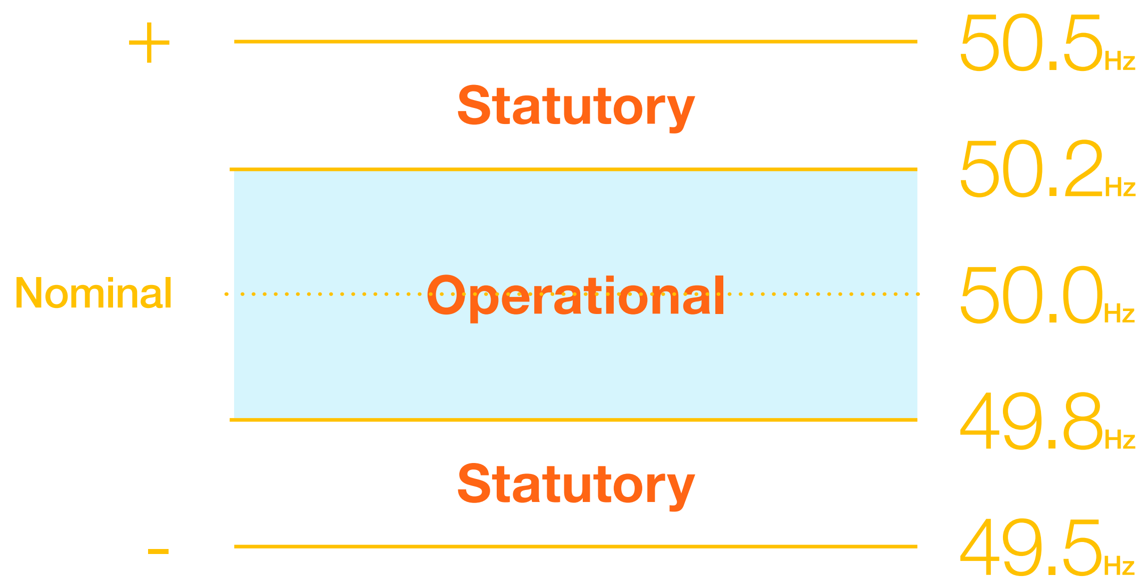

Figure 1: Frequency limits

The key features of DC are:

Fast

Providers must deliver a change in active power within one second of a change in frequency

Dynamic

The amount of power delivered is proportional to the frequency deviation; the further frequency is away from 50Hz the more power that must be delivered

High and low

There is no obligation for providers to deliver high & low response capability at the same time

Day-ahead

The service is contracted at day-ahead for a period of 24 hours

You can find out much more about Dynamic containment here and how to participate in the service here.

Frequency / Dynamic containment 26

Fast

Faster acting response services, of which DC is the first, are required because we increasingly experience system conditions defined by low inertia.

Inertia helps to resist and slow down changes in the system frequency. Having low inertia means that frequency moves more quickly in the immediate moments after a large imbalance (e.g. the instantaneous loss of 1GW of demand or generation). A rapidly changing system frequency requires equally fast frequency response services, like dynamic containment.

Our existing services are at risk of delivering their power too slowly (see **Figure 3**) to contain frequency before operational, statutory and automatic disconnection limits are met. The lower the system inertia falls the greater the required quantity of these response services to secure losses. It soon becomes impossible to source, buy and use such high quantities of existing frequency response services.

In terms of securing losses, dynamic containment is much more efficient per MW bought. It delivers 100% of its power within one second, and starts responding between 0.25s and 0.5s.

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Frequency

Dynamic containment

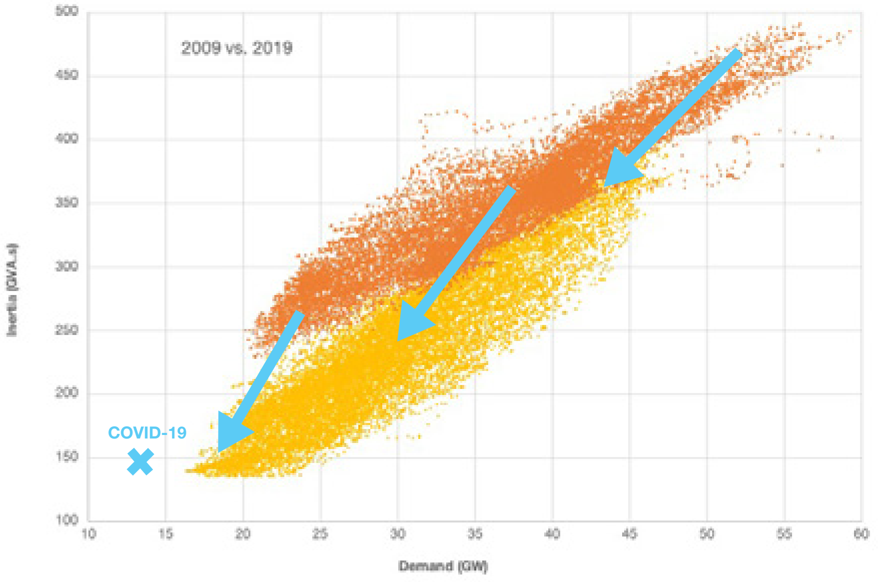

Figure 2: Inertia vs. Demand, 2009 and 2019

The figure left plots demand against inertia for each settlement period of 2009 (orange) and 2019 (yellow). In both cases lower demands are strongly associated with lower inertia. There is also a clear trend (blue arrows) between 2009 to 2019 of a shift downwards and to the left – i.e. we more frequently see lower demands and lower levels of inertia. The blue "x" identifies the conditions we experienced during the COVID-19 lockdown of summer 2020.

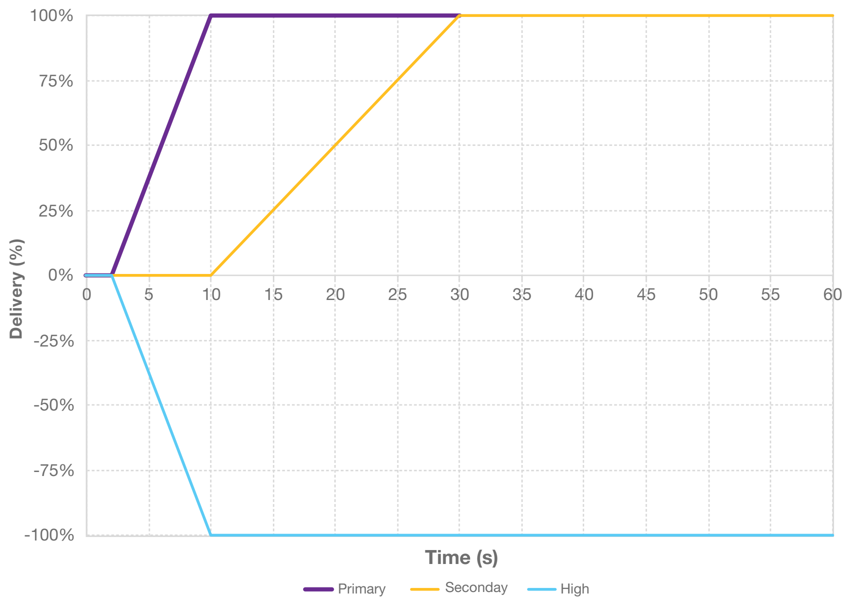

Figure 3: Frequency response delivery profiles for Primary, Secondary and High frequency response

Click to jump to enlarged diagram

Most of our existing frequency response services are too slow to contain a rapidly falling or rising frequency in low inertia conditions. Services like mandatory frequency response, (primary, secondary and high) firm frequency response, dynamic low-high, all have a response time of around 10 seconds.

Click to jump to enlarged diagram

Frequency / Dynamic containment 28

Dynamic

Speed of response is crucial, but so too is proportionality of delivery. A very fast service that delivers either too much power or not enough power can make frequency control more difficult.

A dynamic service is one that changes its delivery of power proportionally to system frequency. A static service will deliver a fixed quantity of power once a system frequency reaches a pre-determined threshold. And the static service will continue to deliver, even if frequency returns to a normal range.

We chose to make DC dynamic because this is the most efficient way of securing a range of loss sizes on what we generally now experience as a low inertia system.

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High & low

Our needs for high frequency response (HF) are often different from our needs for low frequency response (LF), so it makes sense to buy these services separately. Generally, we need more LF than HF; generation losses tend to be larger than demand losses.

Dynamic containment is actually two services; DC-low and DC-high. This benefits the ESO; we can buy exactly the quantity we need without paying for a symmetrical amount that we may not require. It also benefits providers that may not be able to or may not wish to deliver symmetrically.

We see this as a positive for wind and solar, which may prefer to deliver HF only and also demand-side, which may be naturally suited to LF only. It is also our intention to allow providers to bid for, and win, contracts for both LF and HF simultaneously.

Dynamic containment high and low

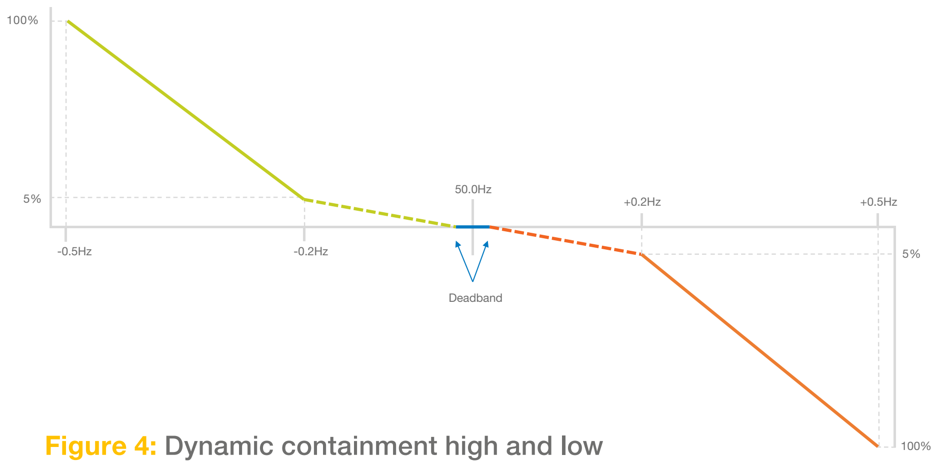


Figure 4: Dynamic containment high and low

Click to jump to enlarged diagram

The figure above illustrates how dynamic containment is delivered (y-axis) against the system frequency (x-axis). Low frequency response (DC-LF) is represented by the orange line and high frequency response (DC-HF) is represented by the green line.

Frequency / Dynamic containment 30

Day-ahead

The market for dynamic containment sees contracts being agreed at the day ahead stage, for a duration of 24hrs.

As system operator we often see big changes in the overall system conditions from day to day. These changes can be driven by the weather which has a material impact on the generation mix that the market provides.

Given the changing needs of the system we are evolving the mix of contracts, moving away from long term contracts towards close to real time procurement that is reflective of near term system needs.

Our requirement for DC might be very high on a windy, sunny day with low inertia and high interconnector exports. The next day might be precisely the opposite, with high inertia and smaller losses meaning that we require much less DC. The generation mix will clearly be different on each of these days, and so will be their capability to deliver DC and the cost at which providers are willing to offer the service.

Procurement closer to real time, in this case at day-ahead, allows us to capture these efficiencies. Ultimately, provided that the market functions effectively, with transparency and fairness this approach will drive down costs for consumers.

What we have learned

We have learned that success like the launch of dynamic containment is possible when the ESO co-creates with stakeholders.

The advantages of this approach are that it ensures that the service design meets the ESO needs but also accommodates the requirements of a diverse range of providers. This approach allowed us to spot that some providers could not immediately meet some of the service requirements for DC, meaning they would not be able to participate from the beginning.

As a consequence we introduced transitional arrangements which allow providers to participate from day 1 even if they cannot meet the full service requirements. We heard from providers that they were very keen to join the market, but our own deadlines to deliver the service did not give them all the time they needed to make some upgrades to systems, controllers or communications. The transitional arrangements are therefore time-limited, allowing both providers and the ESO to make necessary developments while the DC market continues to grow.

Co-creation will continue to guide us as we move from the soft-launch phase of DC into the enduring market. It will also serve as a best practice for work required before we launch subsequent response and reserve services.

Frequency / Dynamic containment 31

Upcoming developments

Our priority is to continue to grow the DC-LF market and resolve some of the barriers and factors that limit participation. In the short term there is an opportunity for the ESO to learn from and consolidate some of the processes and systems that were created for the soft launch. In 2021 the transitional arrangements will come to an end and we will be actively supporting providers as this happens. We intend to introduce procurement of DC-HF in addition to DC-LF in 2021.

Following on from the DC engagement we have been running throughout 2020, we have identified some topic areas to investigate and co-create with industry. We will host workshops and other engagement events to develop these aspects of the service design. Three examples of the topics we will look to co-create are outlined on the following page.

Frequency / Dynamic containment 32

Co-creation topics

Baselines

We use these for validating service delivery, they are an important part of the performance monitoring process. But we also use them for visibility of behaviour (baselines in the form of physical notifications) and we have some special rules relating to their use for state of energy management. This multiple use of baselines has created some compromises, in some cases these can limit participation. We have already had some excellent feedback from stakeholders on how we might lessen the impact of these compromises.

Aggregation and location

We will be looking at opportunities to further open DC and subsequent services to aggregators. As ESO we are responsible for maintaining frequency but we also have license conditions that require us to consider and manage localised constraints. Increasingly we need to collaborate with DNOs and ensure that the whole system is considered before taking actions or buying services. Its for these reasons that we find it very helpful to know the location of a balancing service provider but we also acknowledge the huge potential for aggregation of services across regions and grid zones.

Stacking

Stacking means the same asset providing several services at the same time. This can result in increased competition in markets and lower costs for consumers. Our frequency response suite (dynamic containment, dynamic moderation and dynamic regulation) has been designed to consider and allow stacking opportunities. We will be testing these ideas and options as part of our co-creation process with stakeholders.

All information about and opportunities to get involved with dynamic containment can be found on our dedicated webpage.

Frequency / Dynamic containment 33

Reserve product reform in context

There are several simultaneous and related challenges that necessitate our requirement to review what we buy, how we buy it and how we use it.

Operational need

The need for faster acting reserve services springs from many of the same considerations outlined earlier in this report for faster acting response services. Just as we need to rapidly contain frequency (using response) we also need to quickly restore frequency to 50Hz (using reserve). Reserve is instructed manually so 'faster acting' means both quick and easy access to the service for our control room engineers and also relatively fast reaction and delivery times from providers (for example power being delivered in less than 5 minutes from the receipt of instruction).

European standard products

The TERRE project and the MARI project, which aim to deliver pan-European standard products RR (replacement reserve) and mFRR (manual frequency restoration reserve) respectively will, once implemented, significantly change how the ESO can access balancing resources as well as massively expanding the market for providers of these services.

Frequency / Reserve product reform 34

European codes, directives and regulations

The standard products noted previous are just one component of a large number of regulations designed to shape the European energy market. In particular the Regulation on the Internal Market for Electricity has resulted in obligations on system operators around the type, design, procurement and use of reserve services.

Opening up the balancing mechanism and zero carbon operation

Our programme to increase participation in the BM via Wider Access and the API (application programming interface) has already brought new providers into our most significant balancing market. We expect that the attractiveness of this route to deliver further growth in both the number and type of balancing service providers.

Our ambition to be ready to operate a zero carbon grid in 2025 means we need to provide balancing services access to zero carbon forms of generation (including demand-side services). A practical example of work in this area is our move to closer to real time procurement which will better facilitate provision of reserve from intermittent generation sources.

Frequency / Reserve product reform 35

Frequency

Upcoming developments

The aim of reserve product reform is to deliver a suite of upward and downward reserve products that work holistically with new frequency response products and reserve replacement products (mFRR from MARI and RR from TERRE) and can be procured at day ahead through an auction held on the Single Market Platform. The ESO committed in RIIO-2 to start procurement of the new reserve products at day ahead by the end of March 2022.

Taking learning from dynamic containment we will use co-creation with stakeholders, industry and our regulator to drive the development of new services. In practice this means that the ESO will articulate the operational challenges and needs as well as any regulatory boundaries. Stakeholders will be asked to provide input and insight to product design including: payment/settlement, transparency, performance monitoring, pre-qualification and dispatch/operation. The aim is to produce reserve services that meet the needs of the ESO while maximising opportunity for providers and lowering costs for end consumers.

In parallel with this project we will be working to ensure that our existing reserve services are compliant with all relevant regulation. Most significantly this means moving procurement of STOR (short term operating reserve) to day-ahead from April 2021.

To find out more about our reserve services and sign up to be involved in co-creation workshops please visit our reserve services webpage.

Frequency / Reserve product reform 36

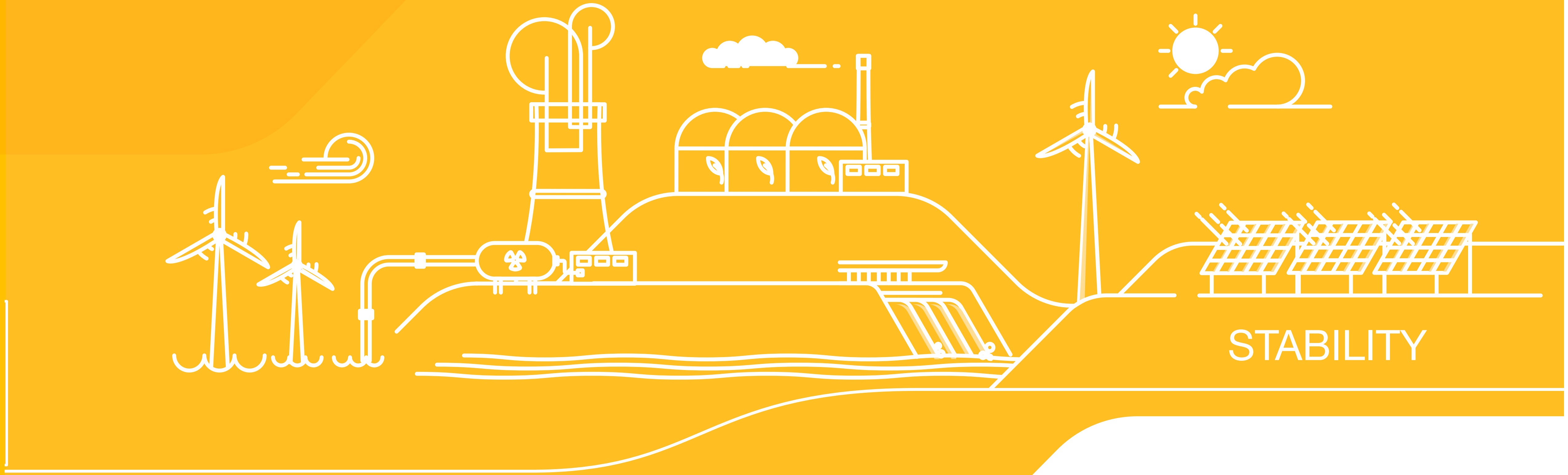
Stability

Insight into the future energy mix

Loss of Mains (LoM) protection management

NOA Stability pathfinder

New technologies



Stability

The electricity system is designed around a stability capability which has inherently been provided by large amounts of synchronous generation operating on the network. We are transitioning to a system with a significantly lower proportion of synchronous generation and we need to ensure that the system remains secure under these new conditions.

As such, in the transition to a low carbon system and the technology this embraces, it is important that the stability capability which was traditionally available through market dispatch, are retained to ensure the operation of a safe, secure and economic system.

To manage this transition, we need to update industry standards to ensure they are appropriate for a system with less synchronous generation. Loss of Mains protection management and updating the Security and Quality of Supply Standards (SQSS) to better reflect how we manage low inertia, are two ways we are doing this. We also need to find new sources of stability capability and we are doing this by improving our understanding of new technologies. We are taking the first steps in introducing a new market to procure this capability by: developing an industry agreed specification for GB Grid Forming technologies, and the Network Options Assessment (NOA) Stability Pathfinder project.

Stability / Overview 38

What we saw over 2020

The low demands we have experienced this year have given us a unique insight into the challenges of operating the network with a higher proportion of non-synchronous generation.

Throughout 2020 we have experienced many days where low system demand, brought about by changes in behaviours from COVID-19 restrictions, resulted in a reduced number of synchronous generators. The combination of a low system inertia and high outputs from embedded generation with LoM relays caused a system constraint. We had to increase system inertia to ensure a transmission fault did not cause a loss of generation with vector shift protection which would then cause a loss of generation with Rate of Change of Frequency (RoCoF) protection.

To increase the system inertia, our only option was to add synchronous units to the network. Some units were already synchronised for voltage support however, this didn't fully meet the inertia requirement. These units have a minimum operating level so the service we needed, inertia, also came with energy that we didn't need. This increase in energy onto the system had to be balanced by taking actions on non-synchronous, primarily wind and hydro units to reduce output. This caused cost. The projects described in this section will reduce the need for these types of actions.

Stability / Insight into the future energy mix 39

Stability

What has changed now and will change in the future

- Going into this summer our peak vector shift loss forecast was 1,000 MW, this drove the large inertia requirement.
- ALoMCP has already delivered protection changes across more than 3,000 sites. This has resulted in a decrease of inertia requirements. Presented with the same energy mix we saw in 2020 we would not have to take the same number of actions again.
- The NOA Stability Pathfinder will reduce the requirement to add energy to the system as we are inviting solutions which do not need to generate MW to provide stability or can provide stability by investing in changes to non-synchronous generation. The events of 2020 demonstrate how important this capability is.
- This year we procured services through NOA Stability Pathfinder Phase 1 which will provide stability services at 0MW output. This will reduce the amount of time we have to constrain non-synchronous generation and allow a greater proportion of zero carbon generation. On 23 May, we added synchronous plant providing 60 GVAs of additional inertia. In comparison Phase 1 procured 12.5GVAs without additional MWs. If this additional inertia from Phase 1 had been available on 23 May and had negated the need to run some of these additional machines, the proportion of zero carbon generation would have been increased by 2-3%.
- Being able to optimise our actions is critical, real time inertia monitoring will enable our control room to do this. The capability to monitor real time inertia is coming on line in summer 21.

Stability / Insight into the future energy mix 40

Stability

Loss of Mains (LoM) protection management

One of the key operability risks on the system is the disconnection of embedded generation due to over sensitive loss of mains protection. Loss of mains protection disconnects generation to prevent damage to equipment however historic standards for this type of protection is no longer suitable for a system with increasing levels of non-synchronous generation.

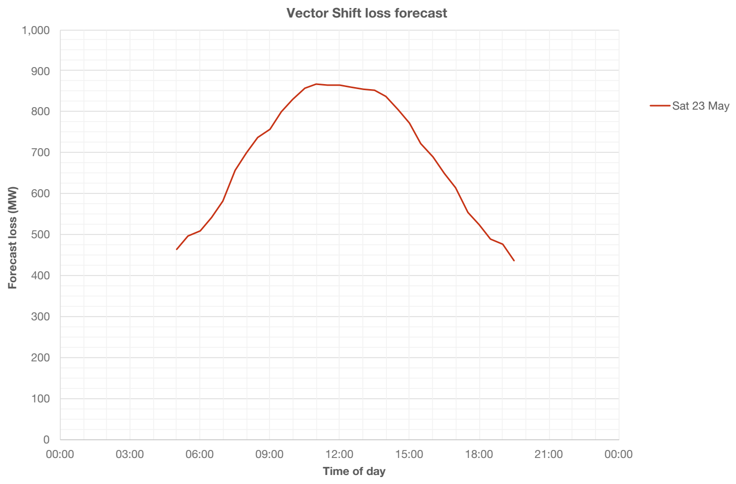
Reducing the number of generators with inappropriate loss of mains protection settings will reduce the volume of generation at risk of disconnecting in response to a large loss (and subsequent high rate of change of frequency) or electrical fault (and subsequent vector shift) on the system. This change will alleviate the RoCoF and vector shift constraints, which are now the dominant factor when managing system inertia, and reduce the cost of balancing the system. This will also allow us to operate the system with lower levels of inertia which is a key step to enable operation with zero carbon in 2025.

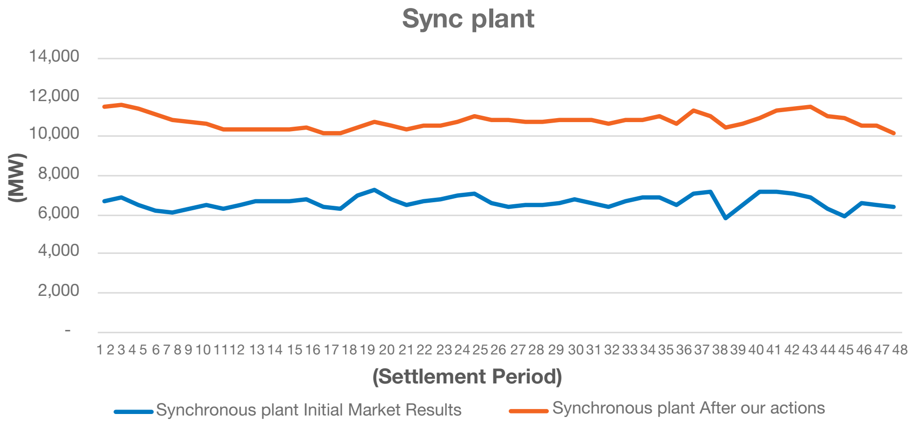
On 23 May there was a forecast maximum of approximately 875MW of export from generation with vector shift relays which could disconnect following a fault on the network. As we do not have the capability to curtail the embedded vector shift generation as they are small embedded sites, we had to maintain the inertia on the system at a level which would prevent an extreme frequency deviation if this fault occurred. An extreme frequency deviation could also lead to the loss of generation with RoCoF protection. Maintaining this level of inertia required us to instruct synchronous generation to run out of merit and over the course of the day we replaced upto ~4GW of wind and hydro units with an equivalent amount of synchronous generation. We also pulled back the interconnectors throughout the day to reduce the largest loss. However in future after the vector shift protection has been removed through the Accelerated Loss of Mains Change Programme, this will no longer be a limiting constraint, reducing the amount of operational actions that we need to take.

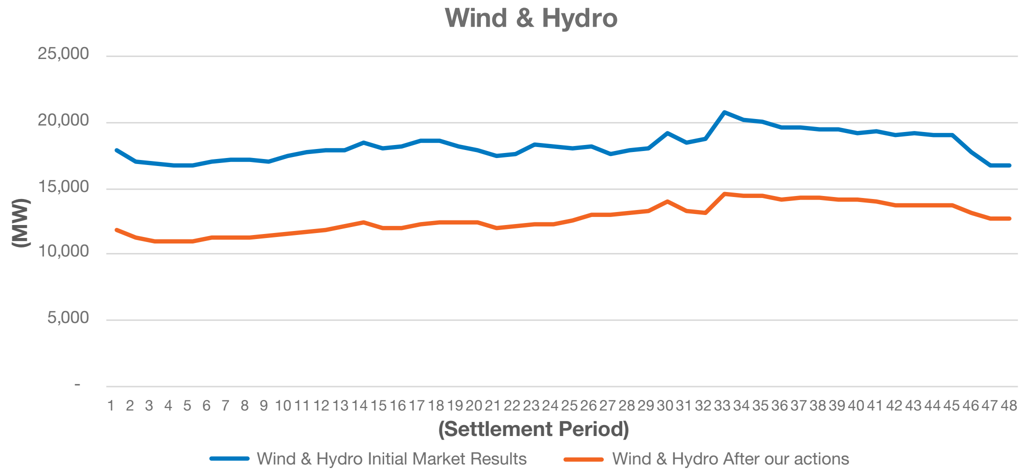
Stability / Loss of Mains (LoM) protection management 41

Stability

Loss of Mains (LoM) protection management







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Stability / Loss of Mains (LoM) protection management 42

Loss of Mains (LoM) protection management

Accelerated Loss of Mains Change Programme (ALoMCP)

The ALoMCP is an industry led project to accelerate compliance with the new Loss of Mains (LoM) protection requirements in the Distribution Code. It is delivered by National Grid ESO (NGESO), Distribution Network Operators (DNOs), independent distribution network operators (IDNOs) and the Energy Networks Association (ENA). Compliance with new protection requirements must be delivered by September 2022. The ALoMCP allows generators to receive a payment for making these changes sooner as, the sooner the changes are made, the sooner we can reduce system risks and operational spend.

In the past year the cumulative total of approved applications is 5,594 sites, for a capacity of 10,700MW at a cost of £20.2m in payments to distributed generation owners. 3,630 sites have declared completion of works at sites with a combined capacity of 6,643MW. DNOs have validated completion of site works for 2,771 sites (4,839MW). These numbers are updated on a quarterly basis after each application window and can be found in the ALoMCP Window Reports.

The completion of the works is reducing the sites at risk of inadvertent tripping. This reduction in risk is now considered when operating the system. The reduction of Vector Shift (VS) risk is delivering a small but growing value. The reduction of Rate of Change of Frequency (RoCoF) risk is not yet enough to reduce operational costs.

Stability / Loss of Mains (LoM) protection management 43

Loss of Mains (LoM) protection management

As the volume at risk decreases we will be able to use the new Dynamic Containment service to secure the system for this risk rather than needing to curtail large losses or synchronise generators to provide inertia.

Working with the DNOs, further engagement with affected sites is being undertaken in autumn and winter 2020-2021. This seeks to:

- Encourage more applications to the programme;
- Identify and accelerate applications from sites with RoCoF settings up to and including 0.2 Hz/second; and
- Identify sites that have achieved compliance outside of the programme so that they can be removed from the calculations of the remaining capacity at risk.

If you would like to participate in the programme more information can be found on the Electricity Network association website.

Applications for payment for making the protection changes will remain open until Spring 2022. The size of the payment will reduce as we get closer to the compliance deadline in September 2022. A fast track scheme offering additional payment for sites with relays set up to 0.2Hz/s will remain open until March 2021.

Stability / Loss of Mains (LoM) protection management 44

Loss of Mains (LoM) protection management

Operation Policy

During the unplanned power outage on the 9 of August 2019, ~500MW of embedded generation disconnected due to the operation of loss of mains protection. We apply an economic and risk-based assessment of potential faults in considering the impacts of distributed generation when securing the system. The SQSS does not explicitly describe how such losses should be considered.

Following the review of the unplanned power outage on 9 August 2019, Ofgem and Energy Emergencies Executive Committee (E3C) made a number of recommendations. One recommendation was that the SQSS should be reviewed periodically to reflect changing system security risks and requirements but also that the process to do this should be open, transparent and engaged. At the SQSS panel in April we raised SQSS modification proposal GSR027 to achieve this. Through the workgroup process this has been developed further and following industry consultation was approved by Ofgem in December.

The modification introduces a Frequency Risk and Control Methodology which will outline the approach we use to identify risks and determine the appropriate policy to manage them. Once the methodology is approved, we would perform analysis and set out any changes to the policy for managing frequency risks in a Frequency Risk and Control Report. Both the methodology and report will be consulted on and approval sought from the SQSS panel. Any amendment to policy due to the report will also be subject to its approval by Ofgem. Both can also be updated periodically as required – for the report it is envisaged that this will take place at least annually.

The first iteration of the Frequency Risk and Control Methodology and Frequency Risk and Control Report will be consulted on in early 2021. By allowing periodic and transparent amendment of policy this will help manage the changes in the electricity system up to 2025 and beyond and to provide value for money to consumers.

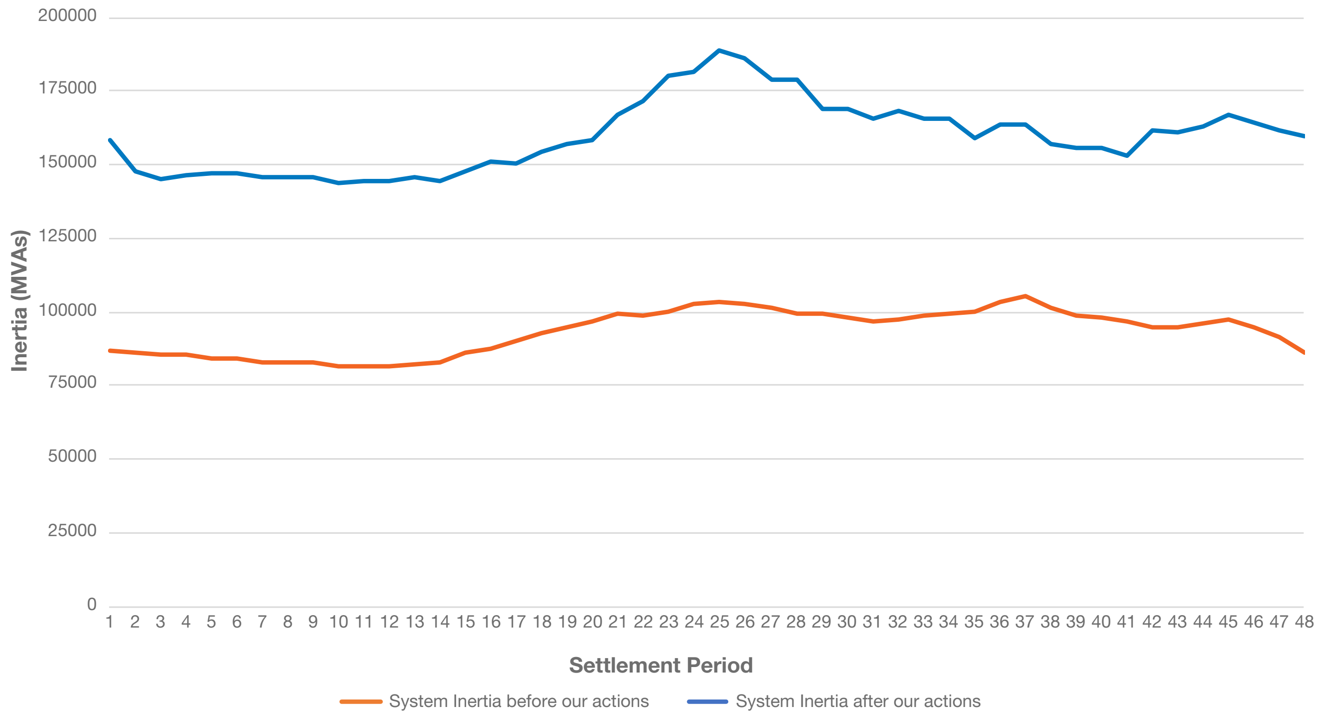
Stability / Loss of Mains (LoM) protection management 45

Stability

Currently, our main route to access any additional stability capability we require on the system is to instruct out of merit synchronous generation to run via payments through the balancing mechanism. We are developing approaches which aim to access stability capability in a more economic and sustainable way.

On 23 May we instructed ~30 synchronous carbon producing generation assets to run. It can be challenging at times of low demand on the system to run enough synchronous generation as generators need to output at minimum level which requires actions on other units to create the 'space'. Much of this synchronous generation is powered by fossil fuels so we need to move away from this approach to meet our zero-carbon ambition. Through the stability pathfinder we expect to be able to attract solutions which can provide stability without generating, such as synchronous compensators, as well as non-synchronous generators which can be adapted to offer grid forming capability.

The Network Development Roadmap is looking at including a wider range of requirements and solutions in our Network Options Assessment (NOA) methodology. One of the requirements we are investigating is stability, including inertia, short circuit level and dynamic voltage support. We are using the pathfinder projects to enable us to learn how we can include our stability requirements into NOA. This will allow us to compare network and market solutions alongside one another to get the best value for end consumers.



Click to jump to enlarged diagram

NOA Stability Pathfinder Phase 1

Stability Pathfinder Phase 1 was our first tender for a stability service. The tender was a short procurement exercise to see if any economic stability solutions could be delivered quickly across GB.

In January 2020 we awarded 12 tenders to 5 providers across 7 sites, securing 12.5GVAs of inertia until 31 March 2026. With a total contract exposure of £328m, NGESO expects to save consumers between £52m to £128m over this period as a result of having to take less actions in the Balancing Mechanism to address system stability.

Phase 1 also highlighted a number of areas where we could improve the process during phase two such as allowing for more time to agree the contract terms ahead of the tender, publishing local effectiveness in a more quantitative manner and clarifying terminology in the technical specification.

NOA Stability Pathfinder Phase 2

Phase 2 is being undertaken over longer timescale than Phase 1 to allow a broader range of technologies to tender in. The feasibility study stage allows us to consider technology types which we have not used before and the later start date gives a longer lead time for solutions which need more development time. Phase 2 is procuring solutions in Scotland as this area has been prioritised based on system requirement.

The invitation for expressions of interest is currently open until 8 January 2021 with a tender to follow in the summer.

Further development of markets for stability

The pathfinders are allowing us to learn more about procuring stability services. In the future we would like to explore how stability requirements can be better coordinated with other requirements like static voltage. Using the learnings from phase 2 and analysis of the requirement in England and Wales, we plan to expand our procurement to other areas. The pathfinders are looking at multi-year contracts to encourage investment, but we would also like to investigate whether a shorter-term market could be appropriate in the future.

Stability / NOA Stability pathfinder 47

Stability

GB Grid Forming Capability

GB Grid Forming Capability (covered under the heading of Virtual Synchronous Machines (VSM) in previous Operability Strategy Reports) enables non-synchronous plant (eg. wind generation, batteries, HVDC) connected to the system via power electronic converters to behave and have similar properties to that of a synchronous machine.

With this technology, non-synchronous plants are able to deliver stabilising qualities which we require on the system. You can read more about the potential operability benefits of VSM and related technologies in the System Operability Framework document we published on this subject earlier in the year.

A specification for grid forming capability is being developed through Grid Code modification GC0137. The specification will enable parties using power electronic converter technologies (e.g. Wind farms, HVDC interconnectors etc) to offer additional grid stability. This will mean that as the proportion of synchronous generation decreases on the system, the capability of other sources of stability will have been defined and standardised. This will ensure that parties understand the capabilities required as we design new markets for stability.

This modification is currently at the workgroup stage. Learning has been taken from the VSM Expert Group and the VSM innovation projects to develop a specification which has formed the basis of workgroup discussions. This work has been invaluable both in terms of the knowledge gained, the technical research and papers published, and the demonstration projects developed to a point where Grid Forming has moved from a concept to an achievable proposition with very significant system benefits.

The workgroup process will include a consultation which will allow us to incorporate views from the wider industry. The final modification proposal will be sent to Ofgem and if approved included in the Grid Code in 2021. We are also very grateful to external developers such as Scottish Power Renewables who have trialled Grid Forming and Black Start at their Dersalloch Wind Farm. This work has very much been instrumental in demonstrating proof of concept.

Stability / New technologies 48

Stability

Phoenix

We are a partner with Scottish Power in the Phoenix innovation project. This project is looking at the potential for Hybrid Synchronous Compensators(H-SC) (combining Synchronous Condensers and Static Compensator with an innovative control system) to help maintain system stability. This type of solution can provide grid stability without generating electricity so will assist as synchronous generation is replaced by non-synchronous power sources. Modelling has indicated that it could improve system stability and hence increase the boundary transfer limit between Scotland and England.

The H-SC is now energised and connected to the GB system. We are now assessing its benefits in the real world (rather than modelling) to better understand its potential to provide reactive power, increase short circuit level and system inertia.

Stability / New technologies 49

Inertia measurement service

Implementing novel tools to measure system inertia in real-time will significantly improve the accuracy of measurement and optimise our real-time operation. A more accurate monitoring system should reduce balancing costs (due to less reserve and response being held), and improved system security and reliability.

On 23 May we needed to maintain inertia to secure against losses on the system. Having an inertia measurement system will allow us to be more confident about the level of inertia on the system and the impact of the actions we take on the inertia of the system.

We have signed contracts with both GE and Reactive Technologies to provide real-time inertia monitoring of the GB system inertia. We are the first System Operator to adopt either of these systems as both are first of their kind systems that will measures the combined inertia-like effects of conventional synchronous generation, power electronic converted generation (such as wind and solar) and passive load responses.

The GE system is non-intrusive, continuously monitoring boundary activity and using machine learning to forecast the inertia up to 24 hours ahead. The real-time metering software is established and awaiting live Transmission Owner phasor data to enable the inertia for the first GB region (Scotland) to be obtained in real-time. Raw data is expected from December enabling comparisons with existing techniques and allowing the forecasting model to be trained. Additional regions will be added as the Transmission Owners increase the phasor monitors within their system.

The Reactive Technologies solution includes one of the world's largest supercapacitors which will be used to 'inject power' into the grid, while Reactive Technologies' measurement units directly measure the response, enabling the full system inertia to be established. Following delays tendering for the supercapacitor, in part due to COVID-19, the contract is signed and work on the design and build has started with the aim of installing the supercapacitor on site in spring 2021 and the service starting in summer 2021.

Once each system is online, tested and proven over a period of time we will be able to use the data provided to improve our operational policies.

Stability / New technologies 50

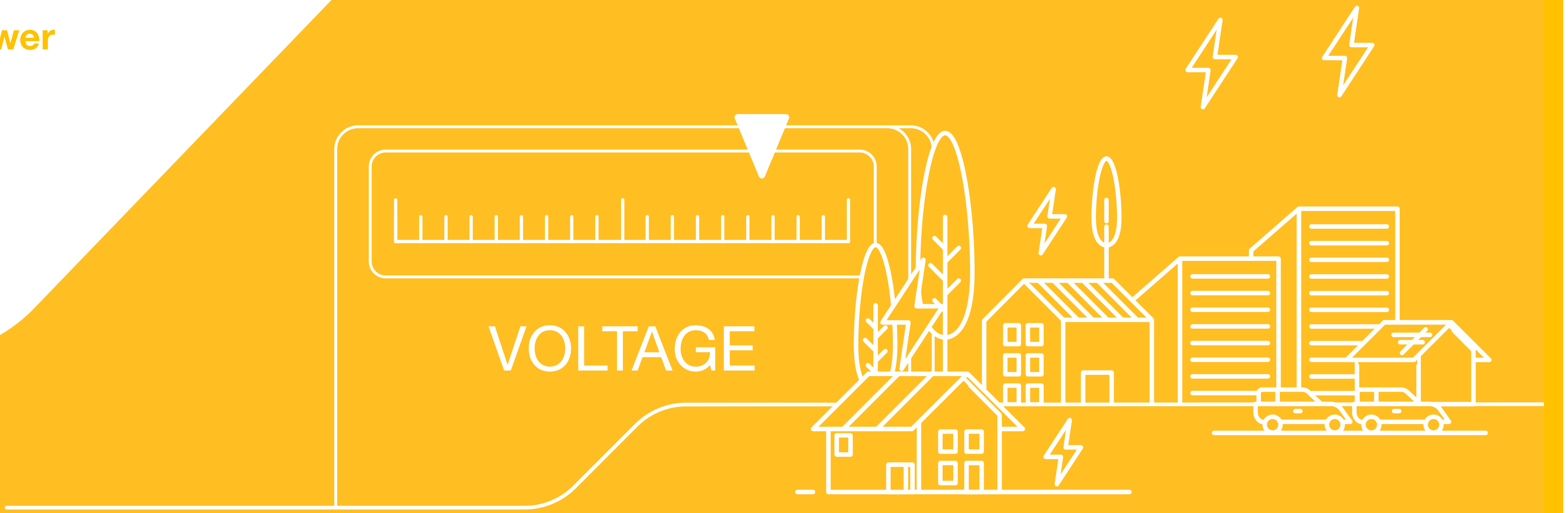
Voltage

Insight into the future energy mix

Strategy for future of Reactive Power

NOA voltage pathfinders

Power Potential



Voltage

Reactive power enables the transmission of electricity across the network, helping power get from where it's generated to where it's consumed. Managing reactive power keeps voltage within safe limits and prevents damage to equipment and blackouts. To continue maintaining a secure and operable system, the need for reactive power support continues to grow as the energy system decarbonises and the provision of reactive power support from large synchronous generation decreases.

To manage this increase in reactive power need and decrease in reactive support, we must find new ways of managing the production and absorption of reactive power, further develop how we communicate and contract our requirements, and find new providers of reactive power. To achieve this, we're developing a strategy for the future of reactive power, trialling dynamic reactive power on distribution networks and running tenders through our pathfinder program.

Voltage / Overview 52

What we saw over 2020

This last year has given us a unique insight into the challenges of operating the transmission system with a higher proportion of non-synchronous generation; something we didn't expect to see until the mid 2020's.

Throughout 2020, we experienced many days where demand on the system was low. This low demand was a result of changes to consumer behaviour, caused by the restrictions put in place due to COVID-19.

This increased the requirement for reactive power support on the transmission network. Maintaining a secure network requires management of voltage levels both before and after a fault on the system – this is often done by holding reactive reserves to ensure enough capability. To achieve this in many areas of the network, we had to add synchronous machines to the system. These units have a minimum output level to deliver their reactive capability – on 23 May this was 11 units delivering 2500MW costing up to £150k per hour. We often don't need this energy and must reduce generation elsewhere to balance, or it has a negative impact on other areas of operability – such as positive and negative reserve – which incurs additional costs. Occasionally reducing output from non-synchronous units, for example wind, is the only option.

During the lowest demand points we needed to increase inertia as well as ensuring enough reactive capability. The amount of energy from adding these synchronous units was too large to ensure we had enough flexibility to reduce generation. This created a requirement for a new service, Optional Downward Flexibility Management (ODFM) to increase flexible plant and create additional energy reserves.

More information on the ODFM service and its use over the summer can be found in our 'Low Demand – Operability Challenges from COVID-19' SOF document.

Voltage / Insight into the future energy mix 53

What has changed now and will change in the future

In previous years the only option to manage voltage in the Mersey region was to add a synchronous machine. This year, the Mersey short-term pathfinder solution at Inovyn has been used on 76% of overnight periods (April to mid-November), including a period of 57 consecutive nights. This reduced our requirement for additional synchronous machines. Having the Inovyn option available on 23 May reduced the need to add a synchronous machine and increased the proportion of zero carbon generation by just under 1%.

The next NOA pathfinder is meeting a need in the Pennine and Northern England region. It will continue to enable solutions reducing the need to add synchronous machines for reactive power support. We added four machines on 23 May for the region, delivering 900MW – if the next pathfinder can negate the need to run these additional machines it would have increased the proportion of zero carbon generation for 23 May by just under 4%.

Voltage / Insight into the future energy mix 54

Voltage

Over the last couple of years since we published our Product Roadmap for Reactive Power, we have been focussed on delivering Power Potential, the NOA voltage pathfinders and working with distribution networks on efficient transfer of reactive power between distribution and transmission networks, amongst other projects. These projects have been exploring new ways of managing reactive power on the transmission system and meeting the new operability challenges.

We are now developing an approach to review reactive power in a holistic way with stakeholder input and build a solid foundation for potential reform of reactive power. Our approach is to co-create this strategy with industry through six key stages.

Voltage / Strategy for future of Reactive Power 55

Six key stages

1 Problem statement

Articulate what the current key problems with reactive power are – to better understand provider experiences of our existing reactive power markets as well as internal analysis.

2 Problem analysis

Analyse problems and identify what the main issues contributing to these problems are.

3 Future vision of reactive power

Articulate what the future of reactive power will look like.

4 Outputs from current projects

Review the output from current projects to understand how their solutions could address the problems identified. We have already shared the lessons learnt from the NOA Mersey voltage pathfinder project and others will follow.

We will be publishing our first document related to this piece of work in early 2021, which will cover the four areas shown above.

Our expected next steps following the publication of this document include:

5 Gap analysis

Our work in the above areas will have identified gaps where existing reactive power projects are not adequately mitigating the problems. We will then analyse what other activities could be required to close the gaps and achieve our future vision.

6 Develop the roadmap and rollout strategy

The final piece of work for the Strategy for the Future of Reactive Power is to agree the timescales for either development or implementation of solutions and a plan for these activities. This will form a roadmap and rollout strategy.

Voltage / Strategy for future of Reactive Power 56

Three identified areas

From our initial work, we have identified three key areas which we anticipate appearing in the problem analysis:

1 The decline in reactive power provision/support

Traditional providers of reactive power are closing or dispatching less and wind turbines do not need to provide reactive power when below 20% active power output.

2 How we procure reactive power services across all timescales

Pathfinders are exploring how we might procure long-term reactive power services, otherwise we use reactive capability from mandated providers and where this isn't possible, we contract for services. The enhanced reactive power service has not been used and has had no market interest since 2011.

3 The ability to operate the system carbon free by 2025

Many parts of the network require thermal synchronous generation (coal/gas) to manage reactive power. We will need to reduce our reliance on these units to meet our 2025 ambition.

Voltage / Strategy for future of Reactive Power 57

Voltage

Our ability to manage reactive power on the network broadly falls into two categories; use of network owner assets such as voltage control circuits or reactive assets, and the use of reactive power capability from large generation. Often there is not enough capability on the system to reduce voltage levels so we dispatch out of merit synchronous generation via trades or the balancing mechanism. We are developing approaches which aim to access reactive capability in a more economic and sustainable way.

The 23 May is a good example of the issues faced by the electricity control room to maintain voltage levels within limits. We needed to dispatch 11 synchronous generators so that there was enough reactive capability spread across the GB transmission network. When demand is reduced – typically in the summer and more so overnight – it can be challenging to get enough reactive capability across the network as synchronous generators need to be dispatched to a minimum active power level. Often this additional MW volume causes other operability challenges and is delivered by generation powered by fossil fuels. To meet our zero carbon ambition in 2025 we need to find new sources and providers of reactive power such as commercially provided compensation equipment, synchronous compensators and embedded providers. The NOA voltage pathfinders are attempting to do this by offering long-term contracts to meet future system requirements and provide opportunities to existing and new build technologies.

The Network Development Roadmap is looking at including a wider range of requirements and solutions in our Network Options Assessment (NOA) methodology. We are using pathfinder projects so we can learn more about how we can include requirements in the NOA and consider network and market solutions alongside one another. We published our first voltage screening report in June 2020 which highlights areas of the network with future potential voltage issues. This report indicates potential future pathfinder regions.

Voltage / NOA voltage pathfinders 58

NOA Mersey Voltage Pathfinder

This was the first time we tendered for a reactive power service to include distributed energy resources (DER). We ran two tenders so we could continue to operate the region securely following the closure of Fiddlers Ferry power station – a reactive power provider – in March 2020. We awarded two contracts, one to an embedded provider. The first tender was for a short-term service covering 2020-21. The second was for a longer term service from April 2022. We received 76 solutions from 14 companies and awarded contracts in May 2020 to two solutions, securing 240MVArs of absorption from a reactor and a battery. Historically we would have sought a solution from the network owner National Grid Electricity Transmission (NGET).

After running this tender and awarding to a commercial provider, we expect to save the consumer ~£2m over the nine-year contract term. We are currently running a procurement exercise to meet the requirement for April 2021 – April 2022.

Following the tender process, we conducted a lessons learnt exercise with the tender participants and have published a report on our website. We have committed to numerous changes for the next pathfinder tender such as providing more information at the start of the tender, extending the length of the tender window and being clearer on assessment criteria and assumptions.

Voltage / NOA voltage pathfinders 59

NOA voltage pathfinders

NOA Pennine Voltage Pathfinder

The next NOA voltage pathfinder is meeting a need in the Pennine and Northern England region from April 2024. It will largely following the same tender process as for Mersey; however, the timescales have been extended to reflect the scale and complexity of the region and the tender assessment.

We announced in November that the pathfinder tender had been delayed to allow additional time to qualify requirements for a complex region. We are also seeking to simplify the tender process, provide additional site-specific information and clarify some wider strategic challenges identified by the pathfinder 'learn by doing' approach.

Pathfinder Lessons

The pathfinders are helping us learn more about procuring reactive power services. We would like to explore how reactive and stability requirements can be better coordinated and procured in the future. Following conclusion of the Pennine tender we will revisit the voltage screening report to determine the next region to focus on and tender for. The pathfinders have been offering multi-year contracts to encourage investment, but we would also like to investigate whether a shorter-term market could be appropriate in the future. This will be part of the future of reactive power work.

Voltage / NOA voltage pathfinders 60

Voltage

Power Potential

Power Potential is a Network Innovation Competition project being conducted jointly with National Grid Electricity System Operator (NGESO) and UK Power Networks (UKPN). This is a world first project looking to create a new reactive power market for dynamic voltage support to the transmission network from distributed energy resources (DER).

Partnering with UK Power Networks the Power Potential project is identifying more new and flexible sources of dynamic reactive power to meet an increasing requirement. This is underpinned by the vision to create a whole electricity system that procures more effectively, adapts to a changing environment and works together with other market participants to deliver value for the consumer.

The live trials for the project started on 14 October 2020 with end-to-end wave 1 technical trials to run for eight weeks followed by wave 2 commercial trials to run until 28 March 2021. The National Grid Electricity National Control Centre (ENCC) has been actively engaged in dispatching the service via the Platform for Ancillary Services (PAS) interface with UKPN. Some corrections and changes have been made to this interface to improve data exchange and monitoring functionality. As with any challenging technical service we continue to work with the participating DERs to achieve the performance necessary from the system.

As of mid-November we have seen reliable dispatch performance from one DER. We are investigating a few issues, in summary, periods of unstable system behaviour associated with dispatch of one DER and periods of un-instructed reactive power from another DER.

We are continuing to learn while monitoring the service performance. On the end-to-end service to system operator, we are still looking into how to align the instruction from super grid, via data historian to DER end results. Further details on the trial outcome will be available on the Power Potential website.

We are committed to working with UKPN to explore how the results of a successful trial could influence and provide alignment on how the reactive power markets develop, within the transmission and distribution spaces.

Voltage / NOA voltage pathfinders 61

Restoration

Insight into the future energy mix

Competitive procurement

Maintaining our restoration capability

Innovation - Distributed ReStart

Restoration standard

Restoration

In the unlikely event that the lights go out, the ESO has a robust plan to restore power to the country as quickly as possible.

Our vision for Restoration is that by the mid-2020s, we will be running a fully competitive Black Start procurement process with submissions from a wide range of technologies connected at different voltage levels on the network, with Transmission Owners (TO) and Distribution Network Operators (DNO) playing a more active role in the Restoration Approach.

Our Restoration vision is integral to meeting the ESO's zero carbon 2025 ambition; as we move towards a zero carbon system the number of large, transmission connected fossil fuel generators will necessarily decline. Maintaining the capability to restore the electricity system at all times is a priority and therefore enabling a more diverse range of technology types, connected not just at the transmission level is essential.

In our Forward Plan for 2020-21 we explained how we would deliver on the commitments we made in the Restoration product roadmap by:

- Delivering a competitively tendered Black Start service to increase competition and encourage wide participation in service procurement
- Explicitly documenting the technical requirements for Black Start service providers and enabling a diverse range of technology types to participate in the service

Further information on our strategy for restoration and our current methodology for procuring services to support restoration, can be found on the black start page of our website. ESO's role during a restoration event is key; we provide coordination between generators, to re-energise networks and export power, and network owners, to ensure energy reaches homes and businesses who need their power supply restored.

Restoration / Overview 63

Restoration

During the low demands this summer we were able to maintain Black Start capability. We have a seasonal readiness strategy that considers the demand on the system when establishing the capability required.

Some fossil fuel generators need to be warm to maintain a suitable readiness level to ensure they can respond to a Black Start. This may require the station to have run recently. Despite the low demands the number of actions required to ensure stations are warm did not increase this summer. In some cases, this may be because stations were instructed to run to fulfil other operational requirements.

Diversifying the range of technology types which can support restoration and provide Black Start services will ensure we can continue to maintain the capability to restore the system on the path to our zero carbon ambition.

Restoration / Insight into the future energy mix 64

Restoration

We are developing competitive procurement approaches for Black Start services. In the past, Black Start services were procured bilaterally from large fossil fuel generators. Our ambition is that by the mid 2020s we will be running fully competitive Black Start procurement processes.

Competitive procurement will enable a wider range of participants to offer services which will help to diversify our capability. Having a more diverse portfolio of services will help us to operate a carbon free network which has environmental benefits and contributes to the security of the electricity system which is beneficial to society as a whole. Competitive procurement will place downward pressure on prices ensuring services are delivered economically whilst offering greater certainty and service dependability.

Development work is happening through competitive procurement process being trialled in different regions based on our service requirements:

- **South West** and **Midlands** - In November 2020, we awarded six contracts for five years commencing from July 2022 from multiple technology types, following our first competitive procurement exercise. We were delighted with the 31 Expressions of Interest response we received; of the 12 providers that participated in the final tender round, 11 were new and we attracted new technologies and types of providers.
- **North West, North East** and **Scotland** (Norther Tender) – This is our second competitive procurement event with a deadline for the submission of the detailed technical feasibility studies and commercial proposals for existing participants being 29 January 2021 with contract award due in April 2021.

The ESO has learnt much from these processes and will feed in any learning to future procurement activities. One such learning is providing more time between final commercial submissions and contract award date, as such we have delayed when we shall announce results for the Northern Tender until the end of April 2021 from the published March 2021 date.

Restoration / Future restoration providers via competitive procurement 65

What next?

- We aim to publish an Expression of Interest in the South East region in Q2 2021 for the procurement of Black Start services from the end of 2022.
- The output from the Distributed Re-start will be known from Q2 2022 and the concept of using Distributed Energy Resources will be considered in any future tender events for Black Start procurement.
- The high-level plan for future tenders is identified in the Black Start Strategy and Procurement Methodology published in July 2020 and updated on an annual basis.

Restoration / Future restoration providers via competitive procurement 66

Restoration

Maintaining our restoration capability

Over the past year we have established two new Black Start contracts which have been successfully procured and tested and now form part of the standard Black Start portfolio. We have an ongoing role to ensure that at any point in time – we are able to restore the electricity system and these new contracts have increased our resilience in certain areas. Furthermore, the seasonal readiness strategy has been used to assess and economically maintain the operational level of Black Start service.

Ongoing assurance monitoring

Despite COVID-19 restrictions we have been able to consistently deliver on the vast majority of activities:

1. BS Training: we have designed a fit-for-purpose Training Package and delivered online sessions to all ESO/ENCC shift teams;
2. Assurance Visits & Local Joint Restoration Plans: highly impacted by travel restrictions across GB. We have been pushing for online sessions with all key Stakeholders and expecting to deliver >50% against our pre-COVID 19 Assurance Plan for 2020.
3. Capability Assessments (BS Tests): also highly impacted by travel restrictions across GB. We have been working closely with Restoration service providers and pursuing more agile approaches, namely considering self-assessment options or special circumstances in which tests can actually be witnessed. Five capability assessments progressed in 2020, three of which witnessed by the ESO. Eight tests in this year's plan.
4. As per the plan, availability of Restoration service providers monitored daily & monthly, resilience of Communications (Optel), Control Centres and CNI Systems monitored on a monthly basis.

Restoration / Maintaining our restoration capability 67

Restoration

Innovation - Distributed ReStart

Distributed ReStart is a world-first initiative. The project explores how distributed energy resources (DER) such as solar, wind and hydro, can be used to restore power to the GB electricity networks in the unlikely event of a blackout.

DER provide a cleaner and greener alternative to large fossil fuel generators. Although the scale of production for DER is typically smaller, their enormous growth on distribution networks presents an opportunity to co-ordinate a black start using renewables. The key challenge for the project is how to bring the organisational coordination, the commercial and regulatory frameworks, and the power engineering solutions together to achieve black start from DER.

The three-year Distributed ReStart project reached its halfway point in June 2020 and is currently in the Design & Refine phase. This involves designing the technical, commercial, organisational, systems and telecommunications solutions to take forward in to the final Demonstration phase (2021).

The next annual Distributed ReStart conference will be in March 2021 and will cover the final phase of the project, the Demonstration phase. This will include desktop exercises, live trials, dummy procurement event, development and testing of automation and developing a route for integration into business as usual processes. The first live trial took place in October 2020 when a 132/33kV network corridor on the Scottish Power Distribution system was successfully energised by a Glenlee hydro generator (connected at 11kV).

You can find out more about the project and subscribe for updates by visiting the Distributed Restart webpage.

Restoration / Innovation - Distributed ReStart 68

Restoration

We've continued to work on the development of a GB restoration standard alongside the industry, regulators and government. This standard will specify required timescales for a restoration from a total shutdown for the country. Once agreed by the Secretary of State, Ofgem will carry out industry consultations for a new licence obligation on us in order to implement this standard.

A successful restoration requires wider engagement and the whole industry to be aware and responsible for their part, and as such we'll look to cascade requirements for restoration through industry code updates and potentially using commercial solutions. We see this as an enhancement on the existing system restoration plan which will be amended to reflect these changes once in place.

In our last Operability report we anticipated that we would be carrying out consultations on industry requirements and necessary changes to implement a standard. As the standard has not been agreed at this point, these consultations will be carried out during 2021, with a more detailed timeline provided to flag key milestones and ensure industry awareness of these.

Once a restoration standard is in place, it is important that it can be monitored and measured. It will be measured using the probabilistic modelling tool we have developed with inputs validated by the Electricity Task Group and industry forum discussions. This year we have introduced the concept of an annual model to ensure we have established and understood baselines from which to benchmark restoration changes. Annual periodicity is thought appropriate at this stage to monitor broad performance trajectory changes in response to year-on-year market changes.

Subject to the specifics of the new licence condition, it is likely that the monitoring framework will become an additional document alongside our current Black Start strategy and procurement methodology. This assurance framework is currently being developed and trialled with a small industry review panel who have identified monitoring areas and principles which will ultimately be consulted on more widely.

Over the final quarter of this year, ESO will be working closely with Ofgem and BEIS to further develop the required processes and documentation in order to support a restoration standard. This will enable us to move quickly to implementation, and to articulate the requirements for other industry parties to be met.

Restoration / Restoration standard 69

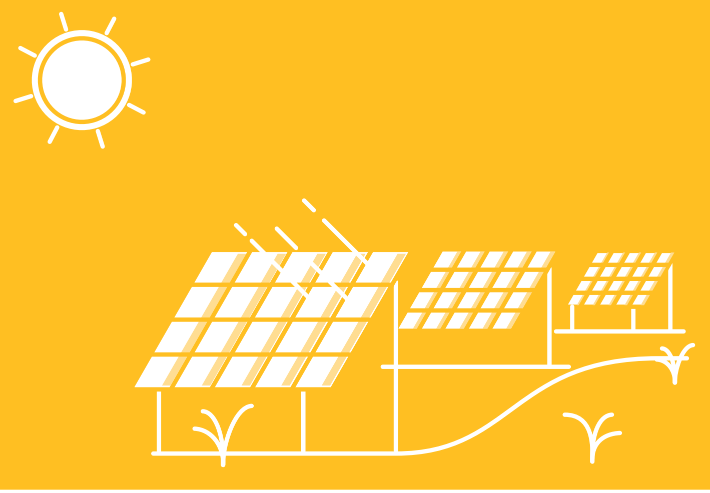
Thermal

Insight into the future energy mix

Regional Development Programmes

NOA Constraint Management pathfinder

Probabilistic Methodology



Thermal

In our role as ESO, we manage the flow of electricity across the high voltage transmission system from where it's generated to where it's consumed. The assets which transport this energy around the network have physical limitations on how much power can be carried.

We must prevent these limits being reached or exceeded to prevent loss of supply to areas of the network. One way we do this is by instructing generation to increase or decrease their output. Often this reduces output from wind turbines and other renewable technologies which hinders our zero carbon ambition for 2025.

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What we saw over 2020

This last year has given us a unique insight into the challenges of operating the transmission system with lower levels of demand and higher North to South power flows; something we didn't expect to see until the mid 2020's.

We have seen throughout 2020 many days where low demand levels have coincided with high output from zero carbon generation, resulting in high power flows across the transmission system. This causes system constraints and requires the ESO to increase or decrease generation to manage the network constraints. We are mostly constrained by network regions where local generation exceeds local demand but can't export enough power out of the region. We mostly resolve these constraints by instructing generation in the region to decrease output. The volume of energy we reduced to resolve these types of constraints in summer 2020 (Apr-Sep) was 50% higher than the same period in 2019. In May and June, when demands were at their lowest, the volume of energy reduced was more than three times higher than in 2019.

We are mindful of the impact of our actions both from a carbon and cost perspective and are proactively focused on seeking innovative solutions to manage these constraints.

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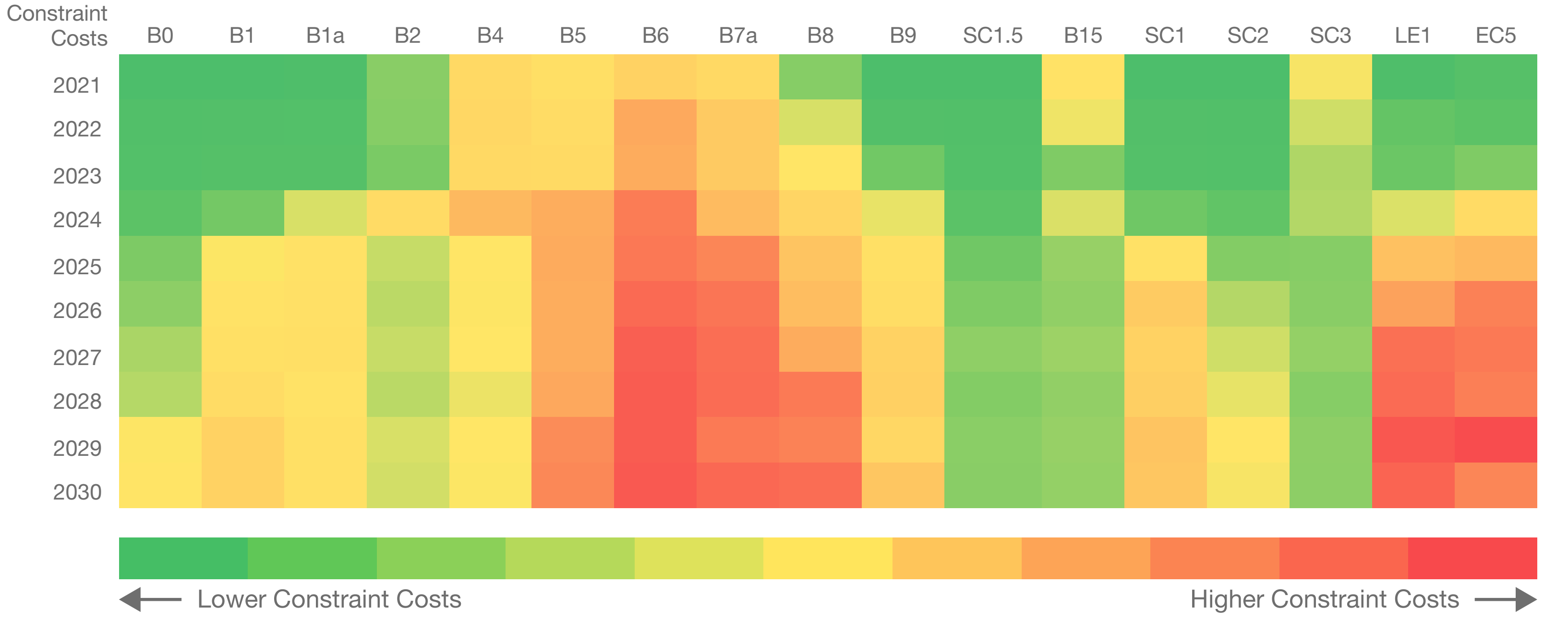
What has changed now and will change in the future

These experiences are a taste of we can expect to see in future years as the energy system decentralises and decarbonises.

As this happens, energy is increasingly generated on distribution networks and at the extremities of the transmission network. This results in an increasing need to manage the flow of energy around the network. This management comes at a cost - we have highlighted in this year's Electricity Ten Year Statement (ETYS) that constraint costs are expected to increase in the next ten years. This is driven by significant volumes of renewable generation connecting in Scotland, Northern England and offshore, as well as increased interconnection to the near continent.

This new generation is needed to allow GB to achieve net zero by 2050 as highlighted in Future Energy Scenarios 2020. Typically, connecting generation is faster than any investment needed in the transmission system to safely and reliably transmit that electricity. To help manage the increase in power flows on the network, and lessen the increased costs, we are improving how we identify future needs by moving to a probabilistic network assessment, increasing visibility and control of embedded generation, and reducing the need to curtail generation through our NOA pathfinder programme.



The heatmap is from ETYS 2020 and represents the boundaries which will incur significant costs without reinforcements.

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Thermal

Regional Development Programmes (RDPs) are strategic pieces of work, carried out jointly by the ESO with network organisations, to assess current and future transmission and distribution needs in given areas.

To date, the primary system need that RDPs have identified lies largely around the ability to manage more localised transmission thermal constraints as a result of the continued connection of Distributed Energy Resources (DER). Initial RDP analysis evaluates a variety of options to address the identified network needs including; network build projects, operational solutions and market-based solutions. Much in the same way as other processes carried out by the ESO, once network needs have been identified and options proposed, a cost benefit analysis is then carried out to provide a recommended way forward.

To-date, RDPs have been developing new business processes, implementing new IT systems and co-creating new market arrangements to support the delivery of visibility and controllability of DER. This work is progressing in line with recommendations from the Energy Networks Association (ENA) – Open Networks project, whilst also providing learning that is shared and used to inform future policy developments.

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N-3 Intertrips

The N-3 intertrip project is a joint endeavour between NGESO and Distribution Network Owners (DNOs) - UK Power Networks (UKPN), Western Power Distribution (WPD) and Scottish and Southern Electricity Networks (SSEN). The system need was identified as part of the early RDP analysis work. The main focus of the project is to ensure regional demand security is maintained under certain combinations of planned outages and faults on the transmission network (known as an 'N-3' scenario). Working with partner DNOs, the ESO is developing the necessary business processes and IT systems to ensure constraints on the transmission system can be managed under these scenarios This is then enabling more DER to connect in the specified regions of southern England and the ESO can continue to operate the system in an economic and efficient manner.

After successful completion of the testing phase, the ESO and UKPN went 'live' with the first N-3 capability in mid-November. As the first partner area to 'go-live', both UKPN and NGESO have learnt valuable lessons throughout the course of the N-3 project design, development and testing work, all of which will be shared with other DNO partners and implemented across future RDP projects. The project has worked through several technical hurdles throughout the testing phase, with lessons learnt now being applied to the capability roll-out with other DNO partners. One such improvement will involve ensuring that third party providers are readily available to help diagnose and fix issues during the testing phase of the project.

Following a successful 'go-live' with UKPN, the ESO will now focus on replicating this capability with both WPD and SSEN into 2021. We will also continue to work closely with National Grid Electricity Transmission (NGET) in relation to the required system outages to deliver the N-3 project and, following successful delivery across the three DNO areas, the project will then focus on how the new capability can be improved in-line with any developments across industry.

MW Dispatch

In addition to the N-3 project, the ESO is also jointly working with WPD and UKPN on the development of a dispatch solution for DER across the south coast of England. Whilst the N-3 functionality will only be used during certain outage scenarios on the transmission network, the MW Dispatch project aims to deliver the processes and systems necessary to manually dispatch DER on a more routine basis. This will enhance the range of thermal constraint management options available to the ESO and continuing to allow more DER to connect to the respective distribution networks.

This project is currently in the development phase and NGESO are working closely with partner DNOs to develop a consistent approach to thermal constraint management across DNO licenced areas - IT requirement gathering will commence early in 2021. We are also currently working on a joint publication with DNOs which will detail more about the commercial arrangements that will supplement delivery of the relevant IT systems.

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Thermal

Storage

Complimenting the MW Dispatch project, work is also underway between NGESO and WPD to assess the impact of flexible demand at Grid Supply Points and the wider transmission system. Whilst the MW Dispatch project is focusing on the ability to manage excess embedded generation, the focus of the storage project is aimed at managing the 'flexible demand' elements that are looking to connect to the distribution network – examples of such projects include battery energy storage (BES), however, the principles could be applied to any asset that is able to act in both a demand and generation direction.

Work to-date has focused primarily on understanding the differences between 'flexible demand' provided by technologies such as BES and traditional 'consumer demand'. As a result, improvements to the connection process have been agreed between the ESO, NGET and WPD. The project is now focused on monitoring the needs case at identified sites and, should the need arise to progress a transmission solution, a whole system analysis process will be applied to identify the most appropriate way forward.

Heysham GSP (Grid Supply Point) – Phase 1

The ESO has been working in collaboration with both NGET and Electricity North West (ENWL) to identify the most economic 'whole system' solution for Heysham Grid Supply Point. As a result of an increase in DER wishing to connect in the local area, several operational challenges presented themselves after initial study work. Following an initial appraisal, the decision was taken to split the analysis into two phases. The first phase is considering the impact of two new generators at Heysham GSP, the second phase will consider a scenario-based assessment of future system needs at the site.

For Phase 1, the study work and an agreement with NGET on the most appropriate solution has been completed. The key issues identified include the need to ensure fault levels are appropriately managed at the site, along with the ability to curtail embedded generation under certain supergrid transformer outage and fault combinations. Our analysis identified that the most economical way to manage the site following these connections would involve an extension to an existing intertrip arrangement at Heysham (extension of the Heysham Overload Protection Scheme) and the commissioning of an auto-close scheme on existing assets. This will allow the connection of additional DER and ensure the site remains secure under certain outage scenarios. In addition, the ESO is also developing appropriate commercial arrangements to compliment the new intertrip arrangements.

Following successful completion of the design work associated with Phase 1, discussions are now underway between NGESO, NGET and ENWL to scope and define the needs case for Phase 2. This work will continue for the remainder of 2020 and into RIIO 2.

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GEMS
(Generation Export Management Scheme)

GEMS is a joint project between the ESO and transmission owner Scottish Power Transmission (SPT). The development of this new operational tool was born out of the original Strategic Wider Works Assessment which recommended that operationally managing the south west Scotland transmission network is likely to be more economic than the equivalent transmission build solution. The GEMS program aims to take the latest Active Network Management (ANM) technology and apply these principles to the dispatch of generators on the transmission system, thereby allowing faster, more automated dispatch of Balancing Mechanism (BM) units. In doing so, GEMS will enable the ESO to operate the network closer to asset capabilities as the response times of the newly implemented systems will be much quicker than the BM processes that exist today.

In addition to developing ANM technology on the transmission network, the ESO is also working with the DNO Scottish Power Distribution (SPD) to deliver a 'whole system' solution for this part of the transmission and distribution network. Utilising the capability of the new distribution ANM, the overall deployment of a joint transmission and distribution dispatch solution will allow participation by a greater number of parties connected at the distribution level.

After the recent completion of initial design work, we will now begin supporting SPT through the procurement stage of the GEMS project and will begin detailed design work early in 2021. In addition, we are working closely with SPD to conclude discussions on the market arrangements for smaller DER in this area, whilst also evaluating any additional ANM requirements on both a transmission and distribution level. The first of a series of phases for GEMS is aimed to begin rolling out in late 2022.

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ANM Coordination

Active Network Management systems are typically installed for the purposes of managing localised constraints for distribution or transmission needs. Control systems monitor local system conditions and manage the generation and demand connected to the ANM to prevent assets being overloaded or constraint limits being exceeded. This means that potential service providers with ANM connections are unable to offer certain balancing services due to their flexible connection to the distribution network. This is because, at certain times, their ability to export will be constrained by local restrictions. For example, if a provider was instructed to reduce their output the ANM could release the capacity to another provider – resulting in a net zero effect to the ESO. Alternatively, a provider might not be able to increase their output due to the ANM being at its limit.

We have been progressing a project funded by the Network Innovation Allowance with WPD and WSP to understand the potential benefits of better co-ordination between balancing services and ANM connections. Initial conclusions have suggested the possibility of significant potential benefits per annum from improved co-ordination. In addition, we are also including feedback from the recent deployment of the Optional Downward Flexibility Management (ODFM) service to help shape work in this area.

Going forwards we will be using the conclusions of these work areas to inform two co-ordinated channels;

- Development of ANM / service co-ordination policy within the 2021 ENA (Energy Networks Association) Open Networks project
- Facilitating improved access for ANM connected parties to balancing service markets

Thermal / Regional Development Programme 78

Thermal

NOA Constraint Management pathfinder

This year we experienced the lowest transmission demand ever. This was caused by a combination of a lack of industrial and commercial demand during the summer months due to the lock down measures taken to reduce the transfer of COVID-19. During these periods of low demand, we can see a greater transfer of power flows between regions of the network. The network isn't always able to accommodate these increased flows and the ESO must reduce generation or increase demand in one region to prevent damage to network assets.

On 23 May 2020 we were required to reduce generation by up to 5GW to solve thermal constraints in Scotland and the North of England, costing the consumer ~£12M. These actions were issued entirely to zero carbon generation and most were for wind farms. Not only are we having to decrease the volume of energy generated by zero carbon sources to solve the network constraint, we are also having to increase generation from fossil-based fuels, like gas, to balance the amount of energy. This day is just one example of high volumes of actions to reduce generation for constraint reasons. Without new solutions or asset investment in certain areas of the network this issue will only get more challenging to manage as more renewable generation connects to the system.

The annual Network Options Assessment (NOA) delivers a set of recommendations for asset investment by transmission owners to increase the capacity of the network. Alternatively, commercial solutions are recommended when they are more economical than asset investment, or delivery of asset investment is not feasible.

The NOA constraint management pathfinder is seeking commercial solutions to deliver additional consumer savings, supporting benefits identified by the NOA recommendations. It is looking to reduce operational costs, than would otherwise be the case, across the B6 boundary between Scotland and England as more generation connects in the region, ahead of the delivery of the Eastern HVDC link which will increase the capacity of the B6 boundary.

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Thermal

Typically, we manage thermal constraints by reducing generation output pre-fault in congested regions to ensure security of the system post-fault. This allows the power flows to be redistributed within the reduced capacity post fault without overloading the assets. This results in assets not being utilised to their maximum capability. The pathfinder is seeking solutions which automatically reduces generation output post fault. In doing so, the constraint is resolved post-fault, we only need to arm generation pre-fault to reduce their output when a fault occurs. With this, we can then operate the assets to a higher rating/capability pre-fault, reducing the volume of actions and operational cost.

We had 77 responses to the request for information (RFI) published at the end of February 2020 with over 22 different technological solutions. From these responses we believe there is consumer benefit to tender for a service. Based on the learnings from the RFI, we decided to initially proceed with a simpler service design which is quick to implement and will deliver consumer savings earlier and one that we can determine its requirements annually. This decision was included in the Network Development Roadmap September newsletter. We expect to tender for a service in Q1 2021/22 and more details of the service will be announced in early January 2021. We are still looking at whether long-term contracts are beneficial for this area of the network but will be prioritising the short-term solution and using the learnings from that to determine additional needs.

Thermal / NOA Constraint Management pathfinder 80

What is probabilistic methodology and why are we moving to it?

The probabilistic methodology uses historical data as inputs to a Monte-Carlo process (a mathematical technique widely used to model risk and uncertainty) that samples those inputs and uses the operational behaviour of generation and demand to produce realistic outputs of wind farms, solar panels, hydro units, generation units' availability and demand. We use these dispatch scenarios to estimate the likely power flow on individual transmission circuits or a group of circuits.

The method produces hourly snapshots of generation and demand for each sample year. We then use economic dispatch to find out the probable dispatches of energy resources assuming an ideal electricity market. The results are evaluated by power system analysis based on direct current power flow for a set of credible contingencies. Pre and post-fault actions are applied, when applicable, to relieve boundary congestion and increase the transfer capability. The results from the power flow analysis helps us understand the impact on the GB National Electricity Transmission System.

We recognise that the most challenging system needs are no longer just at the winter peak demand background. This is mainly due to ever increasing level of interconnection and renewable energy resources which bring greater variability and intermittency to generation and demand patterns. We have started to develop tools and techniques to do year-round probabilistic assessment and identify network needs across the year.

A year-round probabilistic methodology enables us to move from single snapshot to year-round analysis and address the possible impacts of uncertain and wide-ranging outputs from energy resources across the year. We can capture requirements across different times of the year to complement the peak requirements we identify from our deterministic analysis. This allows us to assess the effectiveness of many different solutions, from both third parties and network owners, as either complementary or alternatively competing solutions. We also intend to identify ESO-led solutions that can be further developed through our pathfinder process.

We published our latest probabilistic chapter in this year's Electricity Ten Year Statement (ETYS) 2020 publication.

Thermal / Probabilistic Methodology 81

Lessons learnt

In ETYS 2019 we demonstrated the probabilistic approach and how it can provide further information and insights on the transmission network capability.

In ETYS 2020, we have extended our probabilistic approach and tool capabilities to include power flow control devices such as Quadrature-boosters (QB) and optimisation techniques for optimal setting of these devices for both pre-fault and post-fault conditions (preventive and corrective actions). We have also improved upon our statistical analysis capabilities, and by implementing data mining tools, we can better understand year-round requirements, drivers and opportunities.

We have shown that the traditional single-snapshot boundary capability approach dispatches generation and demand differently when compared to a more comprehensive probabilistic based analysis. Also, when the different dispatches are applied to understand network requirements, the different outcomes between the traditional and probabilistic approaches means that the network could be exposed to previously unforeseen risk. This is partly because there are conditions in which the network could both be secure and unsecure at the same boundary flow level, due to the different dispatch patterns, which are missed under the scaling-based approach. We have shown that year-round probabilistic approach can capture these uncertainties and give a better view of the overall network needs.

We have successfully used our probabilistic tool for the Ten-Year Network Development Plan (TYNDP) that European Network of Transmission System Operators - Electricity (ENTSO-E) publish every two years (TYNDP 2020). The tool has enabled us to do year-round network losses assessments and CO2 computation and for the first time meet the ENTSO-E standards.

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Way forward

We are continually working to extend our tools' functionalities. Our probabilistic work is one of our pathfinder projects, where we are learning by doing and are shaping our thinking as we apply our new tools to real data.

We are investigating various techniques to integrate year-round probabilistic analysis into our planning process and further details on these techniques is going to be published in ETYS 2020. The details on how we're considering alternative ways of measuring probabilistic boundary capability will be published in a University of Melbourne report prepared for National Grid Electricity System Operator titled "study of advanced modelling for network planning under uncertainty".

We are also going to focus on developing a joint market and network module for our probabilistic tool and compare the total constraint cost with the current approach (boundary capability vs detailed network model).

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nationalgridESO