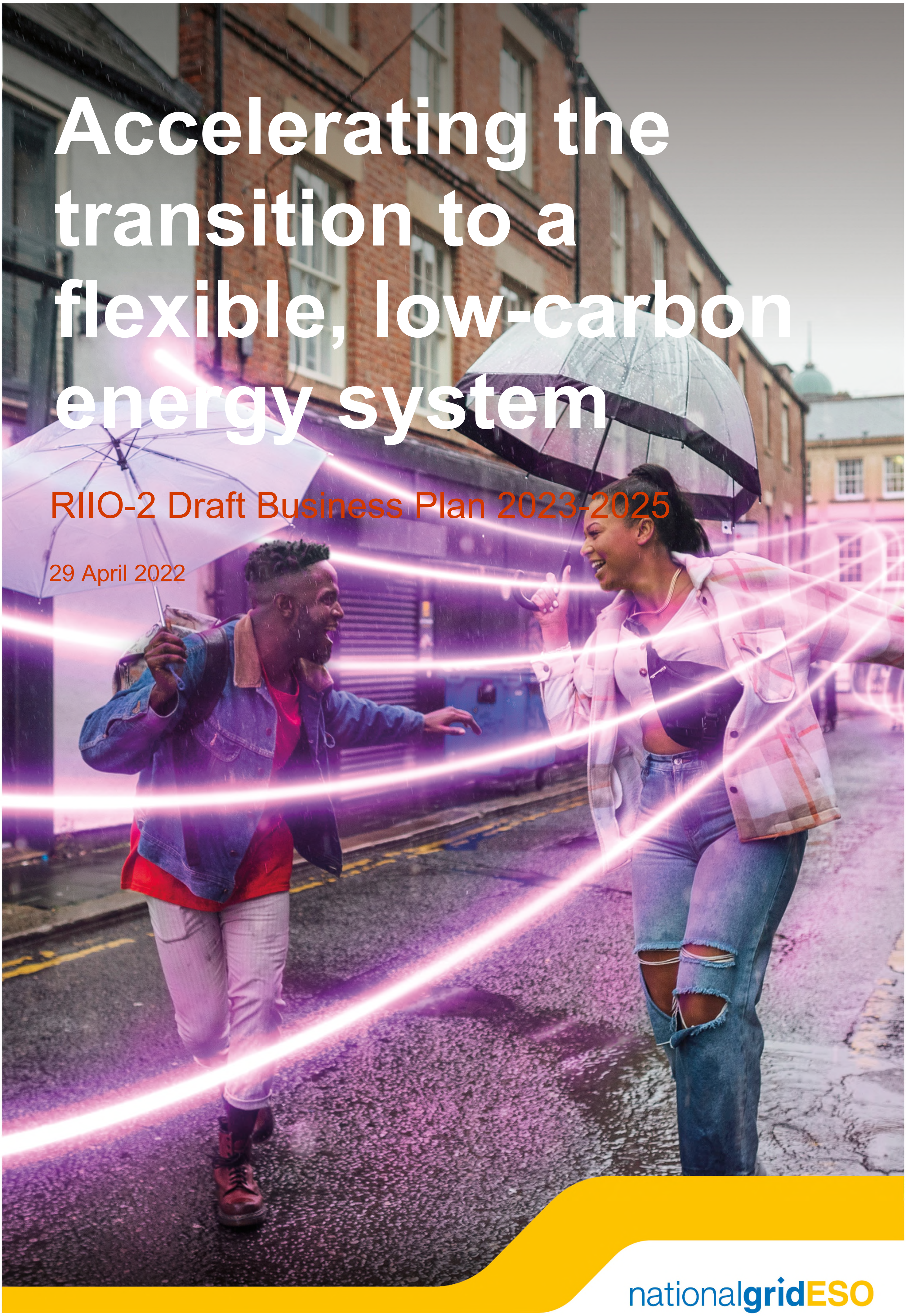
Accelerating the transition to a flexible, low-carbon energy system

RIIO-2 Draft Business Plan 2023-2025

29 April 2022



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1. Foreword

Welcome to our draft RIIO-2 second Business Plan (BP2), which we are inviting you to share your views on before we submit our final plan at the end of August.

The need to tackle climate change and deliver net zero grows ever more pressing and the UK Government has set an ambitious new target - to achieve a fully decarbonised electricity system by 2035. This goal means that now, more than ever, we must go further and faster in pursuit of a decarbonised electricity system.

Our mission is to drive the transformation to a fully decarbonised electricity system by 2035 which is reliable, affordable and fair for all. We believe that the activities outlined in this plan support this mission and deliver value for customers and consumers, providing net benefits of around £2.6 billion.

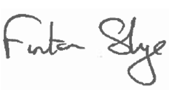
The RIIO-2 framework was designed to help us to be flexible and agile to the changing external environment. In light of this, you'll notice that we've added a number of new activities to our plans since BP1 and we also have a number of materially changed activities across all three roles.

We are excited by the announcement in April 2022 by the Department for Business, Energy and Industrial Strategy (BEIS) and the Office of Gas and Electricity Markets (Ofgem) that they intend to proceed with the creation of a future system operator (Future System Operator). This organisation, which will build on the existing skills and expertise of the ESO with additional roles and responsibilities, will be key to unlocking additional value for consumers and driving towards to net zero.

Prior to this announcement, and as part of our BP2 submission, Ofgem asked to see an indicative plan for the transformational activities we would have to undertake to respond to changes in our governance arrangements. Annex 5 – Future System Operator sets out the key activities, with associated dates, timeframes and indicative costs, of transitioning to a Future System Operator. We will continue working closely with all parties involved in the coming weeks and months to build on these plans and enable a smooth and successful transition.

Delivering the Government's net zero target is a cross industry goal, and we are committed to working with our stakeholders as we design and deliver our activity. This plan has been drafted using the feedback from extensive engagement on our proposals. We encourage you to review, challenge us and provide further feedback as we refine our proposals, before submitting the final version of BP2 in August 2022.

I look forward to continuing to work with you as we accelerate the transition to a sustainable, secure and affordable electricity system for the future.



Fintan Slye

ESO Executive Director

2. Executive summary

2.1. Driving the transformation to a fully decarbonised electricity system

As the Electricity System Operator (ESO) for Great Britain, we operate one of the fastest decarbonising and most reliable electricity systems in the world. We manage the electricity system second-by-second, balancing supply and demand by shifting power across the country and identifying where investment is needed to support the energy transition. We are on track to ensure that the electricity system can support 100% zero carbon power as soon as 2025.

The need to tackle climate change and deliver net zero grows ever more pressing and the UK Government has set an ambitious new target - to achieve a fully decarbonised electricity system by 2035. This goal means that now, more than ever, we must go further and faster in pursuit of a decarbonised electricity system.

The cost of energy continues to be an important consideration for everyone in our industry and for society at large. Our Business Plan therefore maintains a strong focus on driving cost effectiveness and efficiency into our own activities. Many of these activities will open energy markets to low cost, low carbon generation and other new participants, that will help to bear down on overall energy costs

Our Business Plan sets out ambitious outputs that will drive the transformation to a fully decarbonised electricity system. We estimate that these proposed activities will generate benefits of around £2.6 billion for consumers over the five-year RIIO-2 period.

We plan to deliver this transformation to a fully decarbonised electricity system while ensuring security of supply, now and in the future.

2.2 Our second Business Plan

We published our RIIO-2 Business Plan in 2019 and in it we set out ambitious goals for the five-year period 2021 – 2026. To allow us to be flexible in responding to the unprecedented level of change in the energy sector, this five-year period is broken down into shorter planning cycles. Our first plan, BP1, covered the period 2021 – 2023 in detail. This plan, BP2, is a full refresh and sets out detailed proposals for the years 2023 – 2025.

Our bespoke regulatory framework is designed to give us the agility to amend deliverables and take on new activities between formal planning cycles, where these are in the best interests of consumers and delivery of net zero. We have already made use of the framework to start new activities not included in BP1.

We want our Business Plan to deliver the best value it can for our customers and consumers. Our engagement objective for the second Business Plan remains unchanged from the first – we are committed to working with our customers and stakeholders to help shape the future of the energy market and understand how we can deliver better value to energy consumers. We have tested the proposals in this plan with stakeholders and we have demonstrated how feedback has shaped our proposals.

2.3. The pace of change is accelerating, and the scale is growing

In October 2021 the UK Government confirmed its ambition to fully decarbonise the electricity system by 2035. This acceleration of the decarbonisation timeline is something we are excited about and the momentum behind it, across the energy industry and beyond, is something we are proud to be a part of. This pace of change is an underlying theme to some of the proposed new and changed activities in our Business Plan.

Linked to the accelerating decarbonisation of the energy system is the rapid development and deployment of new technologies. Low-carbon technologies, such as battery storage, wind and solar, are changing the way energy is generated and, in turn, the way we operate the electricity system. This has also led to a significant increase in the number of parties wishing to access energy markets and interact with us. As the electricity system changes, so must the markets that support it, including the wholesale and balancing services markets.

Whole system coordination is something that is often discussed alongside decarbonisation. Whole system is often referred to as the link between transmission and distribution or the link across fuel types e.g., gas and electricity. We believe the emphasis on whole system should go much further than this. Whole system coordination means joining the gaps between energy production and consumption, putting the consumer at the heart of our thinking and addressing challenges in a joined-up manner across the entire energy system.

Many of the smaller energy providers, who participate in national wholesale energy and services markets, are connecting at distribution-level voltages. This requires an increased focus by us on how we engage with these smaller participants, alongside helping ensure a smooth and successful transition of Distribution Network Operators (DNOs) to Distribution System Operators (DSOs). This, in turn, means we need to step-up cross industry collaboration and work with partners and colleagues across the sector.

The combination of a rapidly changing electricity system, a large number of new market entrants and markets operating closer to real time, has led to an exponential rise in the volume of information needed to operate and balance the system. This means we are undertaking a thorough review of the systems used in the control room and adopting a flexible and agile approach to future systems architecture.

2.4. A refreshed ESO mission and ambitions

We have refreshed our mission and ambition statements. A key update is that our mission is now strongly aligned to the UK Government mandate to achieve a fully decarbonised power system by 2035.

Our refreshed mission is:

To drive the transformation to a fully decarbonised electricity system by 2035 which is reliable, affordable and fair for all.

Our revised set of ambition statements are now more clearly action-oriented and highlight the importance of both people and technology in achieving our mission. They provide the context for our Business Plan, with all activities now aligned with at least one of our ambitions.

Ensuring the electricity system can operate carbon-free by 2025

Driving competition for the benefit of consumers

Engaging as a trusted partner

New! Being the net zero employer of choice

New! Being innovative, digital and data driven

2.5. Focus for BP2

Against this background of change in the energy industry, we have a key role to play in driving the transition to net zero. Our proposed deliverables reflect stakeholder feedback and begin to address challenges needed to deliver a fully decarbonised electricity system by 2035. Our key areas of focus are:

- **Improved engagement, transparency, and customer service:** Our customers and stakeholders are key to shaping the future of the energy system and understanding how best we can deliver value. It is also important that we are able to react quickly to changing stakeholder and consumer needs so we will continue to engage extensively on our activities and reflect the changes taking place in the industry. We believe that making the data that we hold open and accessible and enhancing the transparency of our decision-making processes will deliver significant industry and consumer benefit.
- **Building organisational capability and flexibility:** We want to be the net zero employer of choice. People are at the heart of what we do and a skilled and engaged workforce is critical to our success. This becomes more important in the context of the pace of change within the energy industry and our role driving the energy transition.
- **Transforming to a digital and data business:** The sheer complexity of the whole energy system in 2035, with smart appliances in homes responding to price signals, millions of electric vehicles (EVs) and heat pumps, and thousands of decentralised assets taking part in wholesale and balancing markets, means that the digitalisation of processes and systems is vital. Increased data sharing and innovation will be needed to provide digital systems with the information needed to optimise markets and to enable timely control room decision making.

- **Keeping the lights on:** We will continue to operate a reliable electricity network and help to ensure security of supply into the future by making it easier to connect to the system and access markets. Our proposed market reforms will provide the services we need to operate a rapidly changing system.
- **Minimising system costs:** We will maintain strict control over the cost of our own operations and continue to focus on the management of balancing costs, minimising those costs we can control and ensuring that all our balancing cost actions are transparent to our stakeholders. We will maximise access to our markets and the system to increase competition and enable more low-cost, low-carbon generation to connect the system.
- **Delivering the capability for zero carbon operation by 2025:** We will invest to refresh the tools and systems we use to operate and balance the electricity system and allow more participants to access the system. We will deliver the new Network Control tool, which will transform the situational awareness capabilities of our Control Centre. We will also begin building our new simulation capability. This will further enhance the suite of automated and flexible training options being developed for our Control Centre.
- **Whole system coordination:** The expanding role of DSOs, the increasing volume of Distributed Energy Resources (DER) and the change in mindset around whole system means we need to think differently to deliver value and enable consumers to interact with the energy they need. We are considering how our processes, systems and operating environment, through real-time operations and longer-term planning, can support the DSO transition and the increase in DER.
- **Reform of energy, flexibility and service markets:** We must continue to explore how electricity markets need to change to deliver net zero efficiently. The work we have done during BP1 shows that the current market arrangement will not deliver net zero cost effectively. Our proposals will create greater opportunities for consumers to access low-cost, low-carbon electricity by stimulating investment in new technologies and enabling greater flexibility for market participants.
- **Strategic planning for delivery of networks and commercial services:** Many of our activities ensure that the future network remains reliable and operable in light of the changing generation and demand mix required to support net zero. To achieve this, planning and network development need to happen in sufficient time to not be a barrier to decarbonisation. This requires robust and transparent identification of the needs of the system and the triggering of solutions with enough time that they can be procured, designed and delivered.
- **Establishing the pathway to a fully decarbonised electricity system by 2035:** The 2035 target represents a paradigm shift in the make-up and characteristics of the energy system. The scale of the challenge to get there is significant and, in the world of planning and delivering large-scale infrastructure, 2035 is just around the corner. Many activities across our plan and in the wider industry are needed to meet the 2035 challenge. We will work to ensure the right network investment is made, taking holistic regional views of electricity requirements.

We continually strive to maximise consumer benefit and deliver at lower cost. Since publishing BP1 we have developed a greater understanding of the scale and complexity of some of our activities, notably the Balancing Programme. We have decided to undertake a strategic review of the existing plans, requirements and approach. Our plans must be compatible with continuing to operate the electricity system in a safe, secure and economic way, while also building the flexible capability needed in the future to help us meet potential changes in market design. Therefore, this draft Business Plan does not present plans, or narrative for the Future of Balancing or closely associated IT investments and the costs are included as a range. We began our engagement with industry with the publication of an open letter in March. Over the coming months we will be engaging further on the Future of Balancing and will present an updated proposal and costing in our August submission.

2.6. Summary financials

We need to invest in new technology and in people with the right skills and expertise to tackle the challenges set out in BP2. Our proposed investments are measured against the benefits they provide to consumers.

Our proposed investment for the RIIO-2 period is an average of £309 million per year over five years.

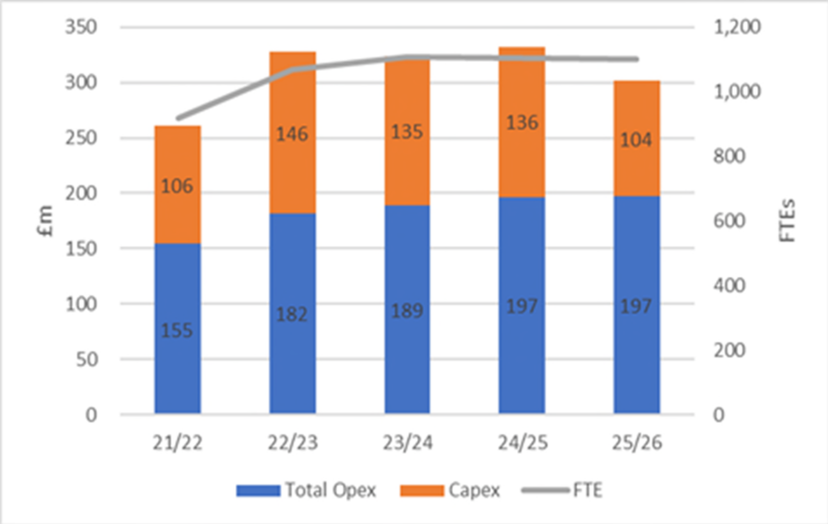


Figure 1: Total opex, capex and FTE over the RIIO-2 period

The cost of our activities in RIIO-2 is around £2.10 on a consumer's annual energy bill. Our proposed new and transformational outputs will save consumers around £5.50 per year, resulting in a net reduction of around £3.40 from the level it would have been without the ESO's actions. Our core ongoing role also delivers consumer savings that have not been quantified, so this figure is likely to be an underestimate.

The Net Present Value (NPV) of the RIIO-2 activities is £2.6 billion over the five-year RIIO-2 period. This is a positive increase of £0.8 billion since our first Business Plan.

As part of this Business Planning process, we are also able to reopen some of our regulatory finance parameters. Assuming our roles and responsibilities remain unchanged, we do not propose any changes to the calculation methodologies for annual capitalisation rates, Additional Funding levels, or the disallowance cap. However, we propose future discussions on adjustments to our Additional Funding if there are changes to our activities.

2.7. A plan for a future system operator

We welcomed the announcement from BEIS and Ofgem in April 2022 to proceed with the creation of a Future System Operator. This organisation, which will build on the existing skills and expertise of the ESO with additional roles and responsibilities, will be key to unlocking additional value for consumers and driving towards net zero. Prior to this, and as part of our BP2 submission, Ofgem asked to see an indicative plan for the transformational activities we would have to undertake to respond to changes in our governance arrangements. The indicative plan, Annex 5 of the BP2 submission, sets out the key ESO activities, with associated dates, timeframes and indicative costs, of transitioning to a Future System Operator.

It is important to note that any costs linked to the Future System Operator are not contained in the BP2 base case numbers and only apply to the ESO activities and costs. For the avoidance of doubt, the plan and costs do not include the likely activities and costs that will be borne by National Grid plc.

Our goal for the Future System Operator is a world leading organisation at the heart of Great Britain's energy system and the delivery of net zero. An organisation that ensures security of supply and resilience and provides a whole energy system view to support optimised decision-making and action in the decarbonisation of power, heat and transport. The Future System Operator will also leverage digital technology to engage openly and transparently across industry and society and act as a trusted partner and advisor to governments, regulators and industry, with deep engineering, data and technology expertise at its core. We are excited to submit our credible, deliverable and affordable plan to realise this goal.

2.8. Creating an ESO for a sustainable, secure and affordable future

Since the start of RIIO-2 in April 2021, we have been evolving to meet the changing needs of the energy industry. And we are on track to make sure that the electricity system can support 100% zero carbon power as soon as 2025.

We are using the skills and expertise of our people to drive this transformation at pace. As we respond to the rapidly changing external environment our plans have evolved too. Our BP2 plan includes five new activities and twelve new sub-activities to accelerate the transition to net zero.

Our mission is to drive the transformation to a fully decarbonised electricity system by 2035 which is reliable, affordable and fair for all. We believe that the activities outlined in our plan support this mission and deliver value for customers and consumers, providing net benefits of around £2.6 billion.

2.8.1 Help us to further shape our plans

We've already tested our activities with stakeholders and shaped our proposals in line with the feedback. Now we want to hear your views on our draft plan. We encourage you to review, challenge us and provide your feedback as we refine our proposals, before submitting the final version of BP2 in August 2022.

Our BP2 consultation is open from **29 April until 10 June 2022**. We will be running a mix of events and providing a range of ways for you to feedback across the entire plan. To get involved visit our RIIO-2 pages of the ESO website.

We look forward to continuing to work with you as we deliver a sustainable, secure and affordable electricity system for the future.

3. How to use this document

This document (BP2) comprises a full refresh of our RIIO-2 plans; and sets out detailed proposals for years three and four of the original five-year RIIO-2 framework, i.e. 2023 -2025. The content is divided into three sections:

1. **Pages 11 - 25**: Outlines our business background, the context for our plan including our refreshed mission and ambitions, the assumptions underpinning our proposals, and how stakeholders have helped develop them.
2. **Pages 28 - 161**: Sets out our planned outputs against our three Roles. In each Role chapter, you will find information about the benefits, costs and NPV of our proposed new activities, as well as stakeholder views on our proposals. We have also included, in each of the Role chapters, our five-year strategy and details of what activities have materially changed or are new.
3. **Pages 163 - 197**: Provides more detail on the parts of our business that underpin everything we deliver, including our IT strategy, our approach to innovation, the crosscutting teams and shared services that support us to deliver value for consumers and how we will invest in people and capability.

Throughout this document you will see reference numbers e.g. A1, A1.1 and D1.1.1. These references identify specific proposed activities, sub-activities and deliverables, and help link them together. A full list can be found in the Annex 1 - Supporting information.

Supporting this Business Plan is a variety of additional information, which provides more detail to support the Business Plan content. This information should be reviewed alongside the relevant sections and includes:

- **Annex 1** - Supporting information, which includes delivery roadmaps, an updated activity and sub-activity list and further information on our new activity A22 Offshore Coordination and Network Planning Review.
- **Annex 2** - Cost-benefit analysis (CBA) report, which details how we calculated the NPVs used in this Business Plan and determined which proposals to take forward. This report also includes our cost summary tables, which you can review as you read through the relevant chapters.
- **Annex 3** – Stakeholder engagement, which highlights the feedback we have received through our extensive stakeholder engagement programme and how we have used it to develop our plan.
- **Annex 4** - Technology investment report, which supplements this document's chapter 10 Technology. It sets out the IT investment references and includes benchmarking information. **Please note that this annex will be published on 16 May 2022.**
- **Annex 5** - Sets out our indicative plan for a Future System Operator.
- **Annex 6** - Glossary, which has definitions of the terms used within this Business Plan.
- **Consultation Questions** – this document contains a list of all of our consultation questions.

Additionally, we have published a shorter Executive Summary document to provide a brief overview of our plan.

Other things to note include:

- The benefits and costs in this document are all in 2018/19 prices.
- We have calculated the NPV of our activities in line with Ofgem's guidance for cost-benefit analyses. More detail can be found in Annex 2 - CBA.
- The costs and full time equivalent (FTE) employee numbers presented in this plan have been rounded to the nearest one hundred thousand pounds and nearest whole FTE.
- In this plan we have submitted updated direct opex, direct capex, property and IT opex costs. The BP1 comparators relate to costs submitted in our first RIIO-2 plan.
- We reference individual IT investments throughout this plan. The detail behind each of these investments can be found in Annex 4 – Technology investment. Where specific IT investments are referenced in the plan, we have included a specific reference number to enable stakeholders to locate the relevant investment within Annex 4 - Technology investment. Please note that this annex will be published on 16 May 2022.

Section 1 - About our Business Plan

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4. Introduction and context

4.1. At the heart of the energy transition

We operate one of the fastest decarbonising and most reliable electricity systems in the world. We manage the system second-by-second, balancing supply and demand by shifting power across the country. We are on track to ensure that the electricity system has the capability to support 100% zero carbon power as early as 2025.

The need to tackle climate change grows ever more pressing and, following COP26, we have a new target – to achieve a fully decarbonised electricity system by 2035. This second Business Plan in the RIIO-2 period recommits us to the ambitious targets in our original plan. It will allow us and the industry to go further and faster to decarbonise the electricity system and, ultimately, help achieve a net zero economy.

4.2. Planning flexibly for a reliable, decarbonised energy system

Our 2019 RIIO-2 Business Plan set out ambitious goals for the five-year period 2021 – 2026; and focused on how to meet the challenges of the changing energy landscape and maximise benefits of the energy transition for consumers. The five-year period is designed with two-year planning cycles, recognising that the energy sector is experiencing an unprecedented level of change and that our plans need to remain flexible and agile in the face of substantial uncertainty.

The 2019 plan (Business Plan 1, or BP1) is now due to be updated. This document (Business Plan 2, or BP2) comprises a full refresh of our RIIO-2 plans; and sets out detailed proposals for years three and four of the original five-year framework, i.e. 2023 -2025.

Our regulatory framework allows frequent changes to our plans, given the difficulty of predicting the pace and scale of change during the energy transition. Even between Business Planning cycles, we can use a 'pass-through' mechanism to respond to more immediate changes and opportunities as the industry decarbonises. This has already allowed us to undertake initial work on potential additional roles not contemplated in BP1, such as our work on early competition and offshore coordination.

So, while the core of activity in this new plan remains unchanged, the extent of new and materially changed activities in this BP2 plan is quite substantial. This reflects the quickening pace of the energy transition, as momentum builds towards delivering net zero.

4.3. Drivers for change to our BP2 plans

There are several drivers that have led to changes in our BP2 plans, some of which were totally unknown to us at the time of submitting BP1 in 2019:

- **An accelerated drive towards zero carbon operation** – in October 2021, the UK Government unveiled an ambition to fully decarbonise the electricity system by 2035, a dramatic acceleration of the decarbonisation timescale requiring a comparable acceleration in the pace and scale of our activities.
- **Challenging operating conditions during the COVID-19 pandemic** – high levels of renewables and very low demand during the COVID-19 pandemic required innovative products and services to be delivered at pace to keep the system stable. We've included what we learnt from this experience in our BP2 activities.
- **An energy cost crisis** – as energy prices continue to rise, it is critical to focus on driving cost efficiency in our own operations, cost transparency in markets and cost effectiveness in new or enhanced activities. Overall, the value of consumer benefits in BP2 has increased over BP1; and we are taking on more responsibility to help mitigate energy costs for customers, such as through our new Market Monitoring function.

Other drivers have either increased in pace and scale, or we now understand more about their impact on our business, again resulting in changes to our plans:

- **Rapid development of new technologies** – advances in low carbon technologies, such as battery storage, wind and solar, are reducing costs and barriers to entry, changing the way energy is generated and consumed. This has led to a massive increase in requests to access the energy market and to connect to the distribution and transmission networks. Therefore, increasing their interactions with us across the board, driving a huge increase in workload.

- **The transformation of markets** – as the electricity system changes, so must the markets that support it, including the wholesale market, ancillary services markets, the balancing mechanism and the capacity market. We are identifying the market reforms needed to support the transition to net zero and will rapidly implement our findings during BP2. Future systems investment will be tested against potential market reform outcomes.
- **An increased need for Whole Electricity System coordination** – the advent of smaller, more targeted energy service providers, often connected at distribution-level voltages, means that DNOs must become DSOs. This means we need to step up coordination across all three of Ofgem's roles for DSOs (development, markets and operations). In addition, as flexibility will be essential for success in a renewables-dominated and decentralised energy landscape we need to enable energy providers and consumers to access markets directly.
- **Regulatory changes** - delivering net zero will require new regulations. These changes will ensure markets benefit from new entrants bringing new technologies and allow market participants to compete on a level playing field. The amount of regulatory change in BP1 has already been far greater than we had anticipated and we expect this pace of change to quicken during BP2.
- **Brexit** – when we set out our original RIIO-2 plans, the UK was still part of the European Union. We've focused our BP2 activity on understanding our changing relationship with the EU and how we adapt to reflect new EU Trade Cooperation Agreements (TCA).
- **Changing ESO roles and responsibilities** – our position at the heart of the electricity system results in us being awarded new roles and responsibilities as part of the industry transition. During BP1, we have already taken on additional work in areas such as offshore coordination, creating models for network competition and overseeing an update to restoration standards. This trend will accelerate in BP2, particularly as proposals to create a Future System Operator move forward.
- **A proliferation in the volume of data and information** – a large number of new market entrants and new markets operating closer to real time has led to an exponential rise in the volume of information needed to operate and balance the system. This necessitates a wholesale review of our Control Room systems and a flexible approach to future systems architecture. As part of this, we have started a strategic review of our Future Balancing Programme in advance of including final proposals in August's final Business Plan. Our final plan will also include an independent, external review of our systems investment.

4.4. Impact of external factors on operating the system

Many of the drivers described above relate to the '4Ds' of the energy transition – decarbonisation, decentralisation, digitalisation and democratisation. These trends are impacting the whole energy sector, as we drive towards net zero. We believe these changes will lead to greater innovation, improved market access and participation and, ultimately, lower prices for consumers. They will also involve fundamental changes in the way the electricity system and the whole energy system is operated. One consequence of these trends, however, is an inevitable increase in the complexity of operating the system:

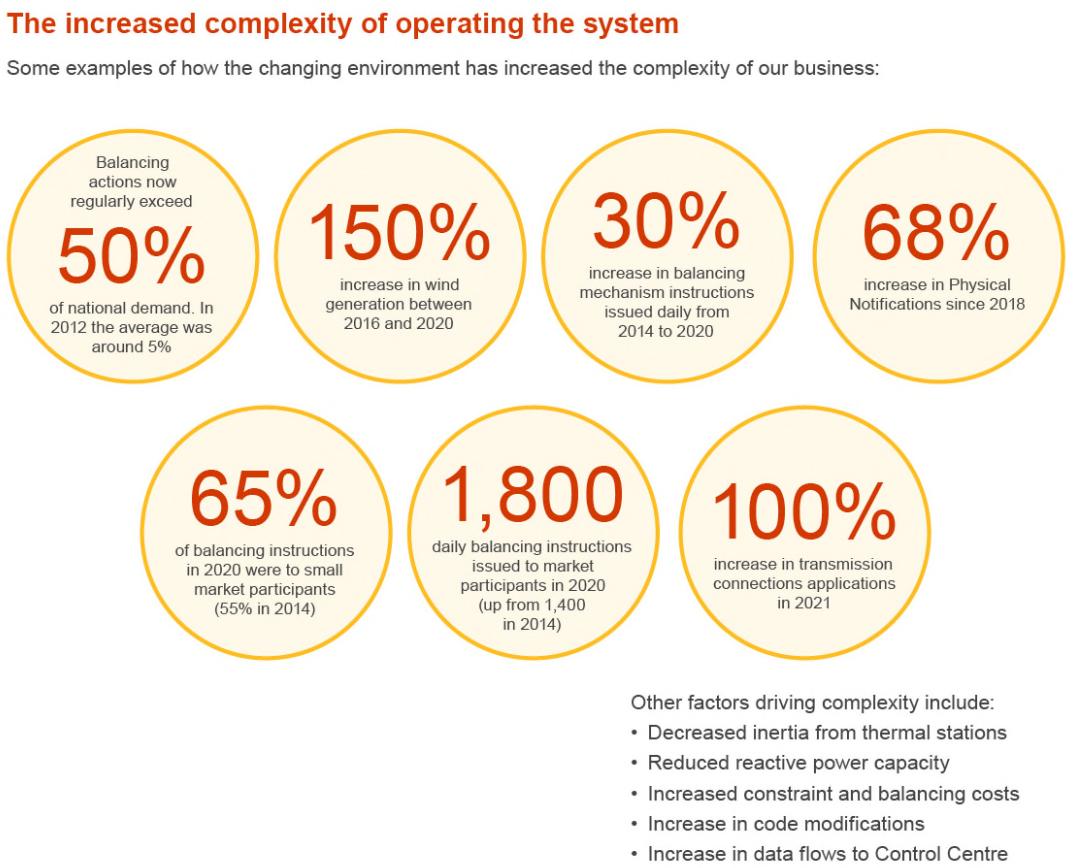

Figure 2: System Complexity

As a result of this complexity, we are now connecting and managing the effects of a vast number of different types of generation, from enormous offshore windfarms down to domestic solar panels, at a variety of different locations and voltages. At the same time, some of the traditional large-scale thermal and nuclear plants are being retired, which has implications for the operability of the system (e.g. the loss of inertia). And this revolution is not just happening on the supply side; we are witnessing increasing numbers of active end-consumers harnessing demand side flexibility to help balance the system.

This increase in complexity inevitably impacts our operations, from the modelling of future system reliability to the volume and variety of balancing actions in real time. We are proud to be in the vanguard, globally, of power system decarbonisation. This results in first-of-a-kind challenges and opportunities to integrate volumes of intermittent, renewable power while keeping the system stable. This increased complexity as we accelerate towards net zero is another driver of changes to our BP2 plan.

4.5. Refreshing our ESO mission and ambitions

The sheer volume and magnitude of the changes described above has prompted a review of the mission and ambitions we set out just a few years ago. We have found that much of what we set out in our 2019 plan remained fit for purpose, but our mission and ambition statements needed refreshing to bring a sharper focus to our BP2 plans. We tested our thinking with the ESO RIIO-2 Stakeholder Group (ERSG) to make sure that we have the right focus for our refreshed ambitions.

Our mission is now strongly aligned to the UK Government mandate for a fully decarbonised power system by 2035. The increased impact of climate change is also a key factor in our refreshed mission, better aligned to the Government's goal of creating a 'single national rhetoric' which can be easily heard and understood by everyone. Specifically, it recognises the imperative of a 'just transition' and the need to deliver benefits across the whole of society, being 'fair for all'.

Our refreshed mission is:

To drive the transformation to a fully decarbonised electricity system by 2035 which is reliable, affordable, and fair for all.

Our revised set of five ambition statements highlight the importance of both people and technology in achieving our mission. They provide the context for our Business Plan, with all activities now aligned with at least one of our ambitions. Our refreshed ambitions are:

- **Ensuring the electricity system can operate carbon-free by 2025** - This ambition remains our 'headline' focus – a clear and ambitious goal that we set ourselves in 2019 which is unchanged in its intent, and against which we are making good progress.
- **Engaging as a trusted partner** - This ambition remains largely unchanged, recognising that whilst we are at the heart of the energy transition, we must work in partnership with all our customers and stakeholders, leading efforts on many of the industry's most difficult challenges. We remain committed to building on our thought leadership and insight activities across the industry, demonstrated through publications such as the 'Future Energy Scenarios' (FES) and 'Network Options Assessment' (NOA). We will be reliable in our approach, credible in our expertise, and use our impartial position to build on our established and trusted role as a key partner to others in the industry.
- **Driving competition for the benefit of consumers** - This ambition is essentially unchanged, highlighting our core mindset to maximise innovation and consumer benefit by driving value through competition in current and emerging markets. By bringing insight and encouraging collaboration, we will drive the transformation of markets, so they are fit for the future.
- **Being the net zero employer of choice** - Achieving our mission requires building a talented and diverse workforce to overcome challenges on the path to net zero. Through this new ambition, we have committed ourselves to becoming the employer of choice for all present and future employees who want to be part of achieving a net zero future. It recognises the need to attract, retain and develop a purpose-driven, innovative and delivery focused workforce if we are to achieve our mission.
- **Being innovative, digital and data driven** - The use of IT and data are already fundamental to our core role of operating the electricity system but will have even greater importance as the complexity of the system multiplies. This is reflected in this new ambition, where successful digitalisation of products, services and applications will be key to unlocking greater innovation, flexibility, and transparency across the whole electricity system. Additionally, the sheer volume of data and information underlying the future energy system means that using machine learning (ML), artificial intelligence (AI), and data driven situational awareness will become increasingly important across all our activities, including forecasting, network planning and operation.

5. Overview of BP2

5.1. Focus for BP2

Against the background of change in the energy industry, we have a key role to play in driving the transition to net zero. Our proposed deliverables reflect stakeholder feedback and begin to address the challenges needed to deliver a fully decarbonised electricity system by 2035. Our areas of focus for the BP2 plan are:

- **Improved engagement, transparency, and customer service:** Our customers and stakeholders are key to shaping the future of the energy system and understanding how we can best deliver value. It is also important that we can react quickly to changing stakeholder and consumer needs so we will continue to engage extensively on our activities and reflect the changes taking place in the industry. For example, we will continue to drive for efficiencies and benefits in the connections process as we manage the complexities of decarbonisation and the increasing number of smaller parties wishing to connect to the electricity network. We also remain committed to providing the highest level of transparency possible. We believe that making the data that we hold open and accessible, and enhancing the transparency of our decision-making processes, will deliver significant industry and consumer benefit.
- **Building organisational capability and flexibility:** We want to be the net zero employer of choice. People are at the heart of what we do and a skilled and engaged workforce is critical to our success. This becomes more important in the context of the pace of change within the energy industry and our role driving the energy transition. We will upscale our resources in line with the growing scope of activities and, in doing so, we want to ensure we are pulling in the best talent from all available sources within a competitive job market. At the same time, we want to grow, develop and retain our existing people so they can help solve the new challenges thrown up by the energy transition.
- **Transforming to a digital and data business:** The sheer complexity of the whole energy system in 2035, with smart appliances in homes responding to price signals and millions of EVs and heat pumps taking part in wholesale and balancing markets, means that the digitalisation of processes and systems is vital. Increased data sharing will be needed to provide digital systems with the information needed to optimise markets and to enable timely Control Room decision making. A major digital transformation is required, not just for us but for the entire industry, and it must be coordinated across different voltage levels, vectors and sectors. For example, increased visibility of distributed generation and demand will be crucial to balancing the future electricity system. Innovation is a key component of our transformation, and we will continue to build our capability in this area, for example through developing a Virtual Energy System and investigating advanced ML techniques and automation.
- **Keeping the lights on:** We will continue to operate a reliable electricity network and help to ensure security of supply into the future by making it easier to connect to the system and access markets. Our proposed market reforms will provide the services we need to operate a rapidly changing system. Implementing the new Electricity System Restoration Standard, and making use of DER, will strengthen our capabilities. We will also continue to improve security of supply modelling through use of enhanced modelling tools and more granular data sets.
- **Minimising system costs:** We will maintain strict control over the cost of our own operations and continue to focus on the management of balancing costs, minimising those costs we can control and ensuring that all our balancing cost actions are transparent to our stakeholders. We will maximise access to our markets, increase competition and enable more low-cost, low-carbon generation to connect the system. Introducing automation into our system modelling process will increase our ability to run system studies and reduce constraint costs.
- **Delivering the capability for zero carbon operation by 2025:** We will invest to refresh the tools and systems we use to operate and balance the electricity system and allow more participants to access the system. We will deliver the new Network Control tool, which will transform the situational awareness capabilities of our Control Centre. We will also begin building our new simulation capability to further enhance the suite of automated and flexible training options being developed for our Control Centre and complement an increase in the number of people in our Control Centre to manage the huge increase in data and workload.
- **Whole system coordination:** The expanding role of DSOs, the increasing volume of DER and the change in mindset around what whole system means all create a change in our activities. In BP2, there will be an increased focus on unlocking flexibility right across the electricity value chain, such as allowing consumers and their suppliers to participate in markets. We are also considering how our processes,

systems and operating environment, through real-time operations and longer-term planning, can support the DSO transition and the increase in DER. We are helping DSOs grow their flexibility markets, as well as removing barriers for aggregators and suppliers to access these markets. We know we need to think differently to deliver value and enable consumers to become more flexible in their energy needs.

- **Reform of energy, flexibility and service markets:** We must continue to explore how electricity markets need to change to deliver net zero efficiently. The work we have done during BP1 shows that the current market arrangement will not deliver net zero cost effectively. Our proposals will create greater opportunities for consumers to access low-cost, low-carbon electricity by stimulating investment in new technologies and enabling greater flexibility for market participants.
- **Strategic planning for delivery of networks and commercial services:** Many of our activities ensure that the future network remains reliable and operable against the backdrop of the changing generation and demand mix required to support net zero. To achieve this, planning and network development need to happen in sufficient time to not be a barrier to decarbonisation. This requires robust and transparent identification of the needs of the system and the triggering of solutions with enough time that they can be procured, designed and delivered. BEIS's Offshore Transmission Network Review (OTNR) and Ofgem's Electricity Transmission Network Planning Review (ETNPR) have further cemented the importance of strategic network planning. We have also included enduring roles to implement and run Early Competition for onshore transmission assets.
- **Establishing the pathway to a fully decarbonised electricity system by 2035:** The 2035 target represents a paradigm shift in the make-up and characteristics of the energy system. The scale of the challenge to get there is significant and, in the world of planning and delivering large-scale infrastructure, 2035 is just around the corner. Many activities across our plan and in the wider industry are needed to meet the 2035 challenge. We will work to make sure the right network investment is made, taking holistic regional views of electricity requirements.

This document sets out the detail of all our BP2 activities, with a greater focus on those that have materially changed or are new. For details of the progress we've made in BP1, please read our End of Year incentives report (published May 2022) which can be found on our ESO website[1].

5.2. How have our activities changed for BP2?

For BP2, our three RIIO-2 roles haven't changed. However, the four themes that sat underneath the roles in BP1 have now been removed, although the intention behind them remains. Our three roles, as defined in Ofgem's roles guidance document are:

[1] https://www.nationalgrideso.com/our-strategy/riio/how-were-performing-under-riio-2

Figure 3: ESO three roles defined by Ofgem

The five-year strategies for all three roles are largely unchanged but, during BP1, we've developed a deeper understanding of the scale and complexity of our goals in each area. This has led to a significant number of new and changed activities for each Role, as summarised in the chart below. In addition, we have started a strategic review of the transformation plans for our Balancing Capability to make sure we are focusing on the right areas and have a robust and cost-effective delivery plan. See our Role 1 chapter for more information.

Across our three Roles in BP2 we have:

- 5 new activities
- 12 new sub-activities
- Material changes to 31% of existing sub-activities

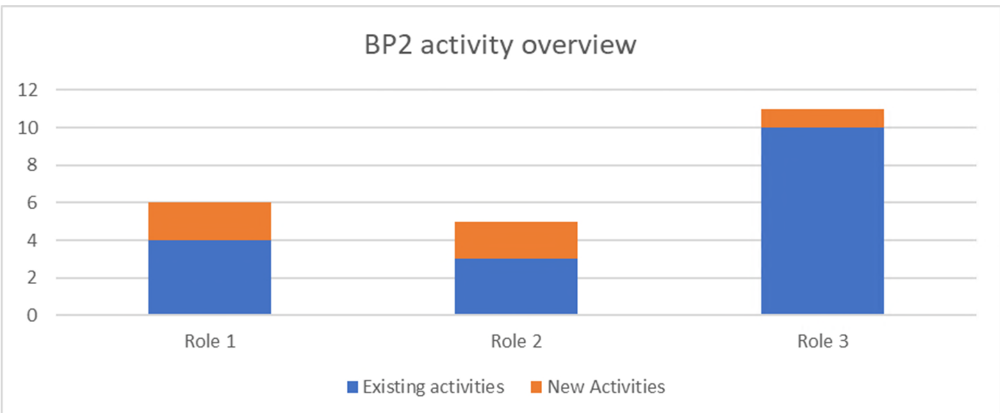

Figure 4: Changes to our BP2 activity

New activities
Role 1 • A18 – Market Monitoring • A19 – Data and analytics operating model **Role 2** • A20 – Net zero market reform • A21 – Role in Europe **Role 3** • A22 – Offshore coordination/network planning review

Around two thirds of our original BP1 sub-activities have little or no change for the BP2 period. However, new and materially changed activities represent a significant shift in what we will be delivering in our evolving role. More information on each of these activities are contained in the Role chapters of this plan.

5.3. How have stakeholders informed our plan so far?

As in BP1, we are committed to working with our customers and stakeholders to help shape the future of the energy market and understand how we can best deliver value. Our priorities were created from extensive engagement as part of our RIIO-2 BP1 plan and remain unchanged. These are shown in Figure 5 on the right.

Throughout the development of BP2, we have continued to listen and take on board feedback from stakeholders. To ensure we have sufficient feedback to inform our commitments we have been:

- Testing with stakeholders that our proposals are well justified, particularly those undergoing significant change from BP1, using existing events where possible to minimise stakeholder fatigue.
- Clearly communicating our proposals and demonstrating how these have been shaped by stakeholder feedback.
- Continuing to run the ERSG - which provides feedback on our BP2 proposals and scrutinises our stakeholder engagement and delivery capabilities.

Figure 5: Stakeholder Priorities

5.3.1. Evolution of the first RIIO-2 Business Plan stakeholder engagement approach

Engaging with a broad range of stakeholders helped us to develop and refine our original RIIO-2 Business Plan. During BP1 we have evolved our engagement strategy, using BAU engagement where possible to develop our BP2 proposals rather than adding additional engagement activities.

A key part of our engagement is gathering meaningful insights that help us to improve on the customer experience. We take feedback through a variety of mechanisms such as user groups, customer and stakeholder surveys, webinars, consultations and interactions logged in our customer relationship management (CRM) tools. These are a ‘dip-check’ to help us understand whether we’re meeting the needs of our stakeholders and where we might need to change. Feedback from these engagements is broad because of their wide coverage and is specific to each part of the plan. Accordingly, how stakeholder feedback has shaped our plan is a theme that runs throughout this document. More details are also available in Annex 3 – Stakeholder engagement.

During the BP1 period, engagement highlights include:

- Two Markets Forums, to update customers and stakeholders on how we are developing markets – e.g. in June 2021 we brought together over 200 participants from across the industry covering topics including Net Zero Market Design, Pathfinders, Strategic Code Change and the development of a Single Markets Platform.
- Launch of the Operational Transparency Forum. This was originally set up at the onset of COVID-19, to provide industry stakeholders with guidance on our operational decisions through this period of uncertainty and low demand. As a result of feedback from stakeholders, this developed into an ongoing weekly event, with typically over 150 stakeholders attending.
- Engagement programmes in specific areas of interest to stakeholders. For example, the Virtual Energy System (VirtualES) is a new programme we initiated for energy system stakeholders to create an ecosystem of connected 'digital twins' for the entire energy system of Great Britain. The VirtualES will be built around stakeholder engagement, with advisory groups ensuring this is led collaboratively.

5.3.2. How stakeholder engagement has shaped BP2

Drivers for new and changed activities from BP1 are varied and include evolving internal processes, change triggered by Government policy or in partnership with Ofgem and BEIS and change in response to stakeholder feedback.

To minimise stakeholder fatigue, we use the many forums and touchpoints we already have in place with stakeholders to test and fine tune proposals once we've established a change is needed.

We are also running activities requiring significant stakeholder input outside of the Business Planning process. Examples include:

- DSO transition work
- Early Competition project
- Offshore Coordination covering the Holistic Network Design (HND) and the OTNR
- Network Planning Review,
- Energy insights activities including FES
- Net zero market reform.

Information from these engagement processes has been extremely valuable in the development of BP2.

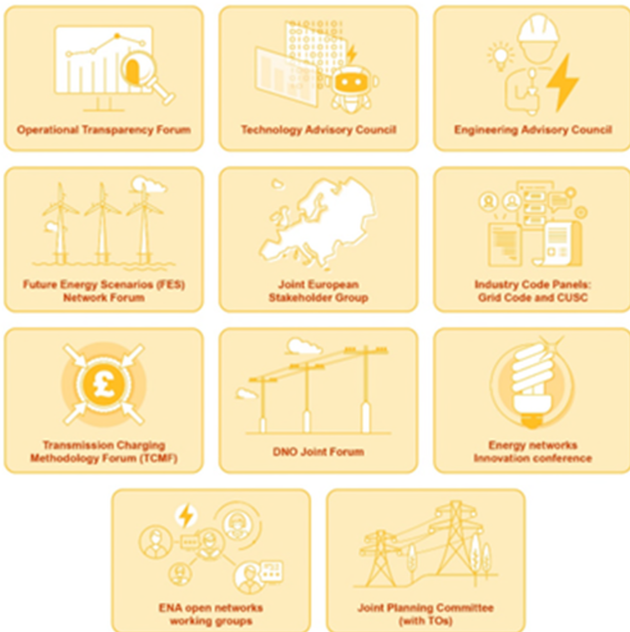

Figure 6: Stakeholder Channels

5.3.3. ESO RIIO-2 Stakeholder Group (ERSG)

ERSG is a group of senior leaders from across our business and the wider industry who challenge and scrutinise our Business Plans. Members are selected for their expertise across a broad range of energy issues. The ERSG has continued to scrutinise our approach to engagement during BP2 and challenge whether we have considered stakeholder and consumer priorities in our proposals. The ERSG focuses on:

- Our stakeholder and consumer approach
- Changes from BP1
- The strategic context and ambition for BP2
- Our ability to deliver BP2

The ERSG have made challenges which we have incorporated into our BP2 proposals. You can find more information about this in Annex 3 – Stakeholder engagement. The ERSG will also publish a report alongside our final BP2 submission at the end of August 2022.

5.3.4. BP2 specific engagement

We started to engage specifically on our BP2 proposals more broadly through a webinar series held in January and February 2022, ensuring all stakeholders had the opportunity to engage and give feedback ahead of the formal consultation period at the end of April 2022.

The webinar series was called “Enabling the transformation to a sustainable energy system – looking ahead to 2023 and beyond” and was aimed at stakeholders with less knowledge of our activities. The webinars signposted what was new or materially changed since BP1. Feedback has been included throughout the BP2 plan and in Annex 3 – Stakeholder engagement as appropriate.

We will undertake further specific BP2 engagement during consultation on our draft BP2 and information on the outcome of the consultation will be available in the final draft in August 2022.

5.4. ESO financials overview

We need to invest in new technology and in people with the right skills and expertise to tackle the challenges set out in our BP2. Our proposed spending for the five-year period reflects the longer-term nature of many of our proposed outputs.

Our proposed investment for the RIIO-2 period is an average of £309 million per year over five years. This compares to £259m on average per year in our first Business Plan, considering the new and materially changed activities. The NPV of the RIIO-2 activities is £2.6 billion over the five-year RIIO-2 period. This is a positive increase of £0.8 billion since our first Business Plan. The cost-benefit analysis and data tables also cover five years.

We have updated our Business Plan, which reflects our latest forecast for FY22 and FY23, and our proposals for the rest of BP2. This has resulted in an increased investment over the five-year RIIO-2 period of £179m capex and £74m opex compared to our original RIIO-2 Business Plan. For the two years of BP2, this is an increase of £88m capex, £42m opex and an increase of 307 FTEs (in FY24).

The BP2 increase in opex is partly reflective of the cost of a number of new activities and sub-activities which we intend to deliver over the period, (opex includes the costs of FTE and non-FTE), including (cost over two years, FTEs FY24):

- Offshore Coordination & Network Planning Review (£7m opex, 48 FTEs)
- Early Competition (£3m opex, 11 FTEs)
- Market Monitoring (£1m opex, 7 FTEs)
- Net Zero Market Reform (£1m opex, 6 FTEs)
- DSO Coordination (£3m opex, 22 FTEs)
- Virtual Energy System (£3m opex, 12 FTEs)

IT investments are a key enabler to delivering the RIIO-2 plan. Over the BP1 period we have mobilised all key enabling investments to support the RIIO-2 plan and ensure we can meet our deliverables. Our IT investment now ranges between £433m and £574m over the five-year RIIO-2 period, compared to £407m in our original Business Plan. This capex range is reflective of some remaining uncertainty regarding solution decisions and will be firmed up in our final Business Plan in August 2022. Our IT running opex costs have also increased by £30m to £80m, from £50m over the five-year RIIO-2 period, mainly due to the increase in IT capex investments being proposed in BP2.

The BP2 capital expenditure increase principally relates to a relatively small number of IT programmes, including the Balancing Programme, Network Control and our Settlements Systems. For the Balancing Programme, our understanding of the complexity and scale of the transition from existing to future balancing capability has developed greatly since we submitted our first RIIO-2 Business Plan and has prompted a strategic review of our plans. We have invited industry stakeholders to participate in this strategic review and published an open letter on 31 March 2022 to start this process. Our IT chapter and annex provide further detail on all our IT investments.

The core roles of the ESO continue to produce efficiencies worth £8 million per year compared to RIIO-1, with BP2 also including 1% efficiency on core activities and a 3% employee attrition assumption. Wherever possible, transformational activities will leverage existing resources, rather than adding headcount and cost. Shared service costs have not materially changed and therefore have not been updated, except for IT and property capex.

The cost of our activities in RIIO-2 is around £2.10 on a consumer's annual energy bill. However, our proposed outputs will save consumers around £5.50 per annum, resulting in a net reduction of around £3.40 per annum from the level it would have been without our actions. This is an increase in savings for consumers of approximately £0.40 in comparison to BP1. We also deliver consumer savings that have not been quantified, so this is likely to be an underestimate.

Figure 7 and Table 1 below represent the revised financial summary for the RIIO-2 five-year Business Plan, and compare the original submission to our updated proposals (in 18/19 prices).

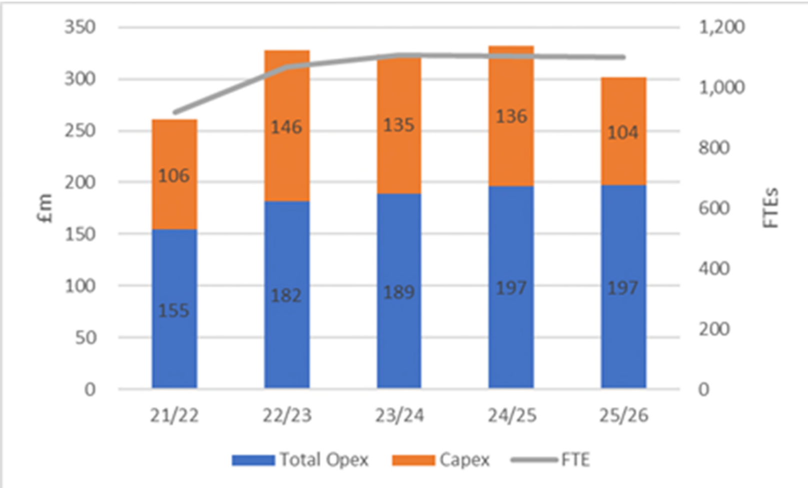

Figure 7: Graph of total RIIO-2 ESO costs and FTE

		Five-Year strategy				
		Forecast		BP2		BP3
Total ESO		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	106.1	145.7	134.9	135.8	104.3
	BP1	96.1	90.2	94.9	88.3	78.3
	Variance	**9.9**	**55.5**	**40.1**	**47.6**	**26.0**
Opex (£m)	BP2	154.6	182.0	188.6	196.5	197.1
	BP1	163.0	164.8	169.9	173.0	174.0
	Variance	**(8.4)**	**17.2**	**18.7**	**23.5**	**23.1**
FTE	BP2	917	1,070	1,108	1,106	1,101
	BP1	746	777	801	804	793
	Variance	**171**	**293**	**307**	**301**	**308**

Table 1: Total RIIO-2 ESO costs and FTE

5.4.1. Financing arrangements in BP2

As indicated in the Ofgem Business Plan Guidance, four factors relating to the ESO's financing arrangements were to be reviewed for BP2. We summarise our proposals below and provide further details and justification in the Innovation chapter (for Network Innovation Allowance (NIA)) and Regulatory Finance chapter (for Additional Funding, DIWE cap, and capitalisation rates) located towards the end of this document.

	Area	Decision for BP1 in RIIO-2 FDs	Our proposal for BP2
1.	**DIWE Cap**	2.5% of RAV	2.5% of RAV
2.	**Additional Funding**		
	2a. Revenue Collection Role: Equity	£3.3m nominal, pa	£3.3m nominal, pa with the current BSUoS arrangements; £7.7m nominal, pa if the fixed BSUoS tariffs are approved and the ESO increases the capital employed by another £300m to cover the increased liquidity/cash flow risk
	2b. Revenue Collection role: debt *(i.e. cost of procuring and maintaining a Working Capital Facility)*	£0.8m nominal, pa	£0.8m nominal, pa
	2c. Risk Asymmetry *(assuming the DIWE cap remains at 2.5% of RAV)*	£1.5m nominal, pa	£1.5m nominal, pa
3.	**Capitalisation rates**	Set annually based on the share of capex / opex investments	Set annually based on the share of capex / opex investments
4.	**Network Innovation Allowance (before 10% contribution funded through totex passthrough costs)**	£20.7m (ESO's projected requirement for the first two years of RIIO-2 which Ofgem considered more developed)	Additional £24.3m (totalling £45m for RIIO-2)

Table 2: Proposed financing arrangements

Given the short time frame of experience in the new ESO price control regime, we propose to keep the **disallowance cap,** and thus the annual level of **additional funding for risk asymmetry,** the same as in BP1. We also propose that annual capitalisation rates are calculated based on the corresponding capex/opex split in our BP2 plan as was done for BP1.

Regarding **additional funding for the revenue collection role** (i.e. both the return on equity employed and costs of procuring and managing the working capital facility (WCF)), for current unchanged responsibilities, we propose to keep the same annual level of funding.

If BSUoS charging reform (fixed BSUoS) is implemented, our equity employed will be higher (primarily due to the increase in cash flow and liquidity risk) and thus we propose a proportional increase to the return on equity component of the funding, following Ofgem's methodology for BP1.

If our risks and costs increase further because we are officially assigned new roles (e.g. Early Competition or Offshore Transmission Coordination), we propose future discussions with Ofgem to increase our additional funding to remunerate any new costs and risks.

Lastly, Ofgem previously allowed only the NIA we had projected to use for the BP1 period and indicated that we can seek further NIA funding once our BP2 plans have crystallised further. In our Innovation chapter, we set out our current plans for NIA projects and why we are requesting additional NIA funding for the balance of the RIIO-2 period.

5.5. Cost-Benefit Analysis overview

The original RIIO-2 cost-benefit analysis (CBA) annex submitted alongside our first Business Plan in 2019 set out the consumer benefit we expected our activities to deliver over the five-year RIIO-2 period.

For BP2, we have updated the CBAs in the areas of material change to our RIIO-2 activities. By a material change we mean a significant difference in the timescales, scope or costs of an activity between our BP1 and BP2 plans. The CBA Annex (Annex 2 – CBA) contains the criteria we have used for identifying material change.

BP1 Total 5-year NPV (£m)	BP2 Total 5-year NPV (£m)	Change (£m)
1,754*	2,581	+827

Table 3: Updated NPV

The updated estimate for the Net Present Value[2] (NPV) of our transformational RIIO-2 proposals is £2.6bn over the five-year RIIO-2 period. All our transformational RIIO-2 activities, subject to a CBA, now have a positive five-year NPV. The positive increase of £827m in our five-year NPV has three main drivers:

1. **Increase to our cost of carbon assumption** – the financial benefits of our activities which limit carbon emissions and reduce environmental damage have increased, due to an updated assumption for the cost of carbon which is based on the marginal abatement cost rather than on the short-term traded value of carbon used for BP1. The update to this assumption is recommended by BEIS[3].
2. **Increase to our constraint costs forecasts** – the financial benefits of our activities which reduce constraint costs have increased because forecasts for constraint costs have increased by £721m over the RIIO-2 period, since BP1.
3. **New deliverables providing greater consumer benefit** – by including more deliverables than in our first Business Plan we will unlock more value and provide greater benefits for consumers.

The breakdown of our five-year NPV by role is presented in the table below.

Role	BP1 5-year NPV (£m)	BP2 5-year NPV (£m)	Change (£m)
1	8*	19	+11
2	411	227	-184
3	1,335	2,336	+1,001

Table 4: Breakdown of five-year NPV change

- The increase in NPV for Role 1 is driven by the increase in the cost of carbon assumption. Our estimated benefits for low carbon DER playing a greater part in restoration services are higher than at BP1.
- The reduction in NPV for Role 2 is due to an improved methodology for estimating the benefits of Balancing Services Use of System (BSUoS) charges reform. Our BP1 methodology was based on the best information available at the time, but there is now better evidence available for the benefits of BSUoS reform.
- The increase in NPV for Role 3 is mainly driven by an increased estimate for constraint cost savings relating to whole-system operability assessments.

[2] Net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows over a given period. NPV is used in budgeting and investment planning to analyse profitability, it accounts for the time value of money and can be used to compare similar investment alternatives.
[3] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal

The updated five-year NPV total excludes Activity **A1** – Control Centre architecture and systems. This has not been updated due to the ongoing Balancing Capability Strategic Review (described in the Role 1 chapter), but it will be updated for our Final Business Plan submission in August 2022. The **A1** NPV is expected to be positive and in the range of £200-£650m.

5.6. Being the net zero employer of choice

Our people are at the heart of our success, and this is reflected in a new ambition to be the net zero employer of choice. To successfully deliver a whole energy system strategy that supports net zero by 2050 requires the right people with the right capabilities. We want to attract, retain, develop, motivate and engage our people to successfully tackle the challenges and maximise the opportunities presented by the energy transition. At the same time, we will further develop the culture of our organisation to be ever more purpose driven, where our people relate to our goals and are passionate about achieving them because they align with their own beliefs and aspirations for a clean energy future.

We are also considering setting up small offices in Scotland and Wales. These offices would give us access to a wider talent pool and bring us closer to customers including, for example, developers of Scottish and Celtic Sea offshore wind projects. It will support engagement with devolved governments.

Our People, Culture and Capability chapter sets our approach to being the net zero employer of choice.

5.7. Data and Technology

5.7.1. Transparency, data and analytics

Our five-year strategy for Transparency, Data and Analytics has not changed since BP1. We remain committed to our ambition of providing the highest level of transparency possible. We believe that making the data that we hold open and accessible, and enhancing the transparency of our decision-making processes, will deliver significant industry and consumer benefit. At the same time, we will ensure that we actively manage the risk of inadvertent over-sharing of data.

We are committed to becoming a fully data enabled system operator, putting data at the heart of every decision, be it operational, strategic, or tactical. Our recent strategy refresh includes a new ambition to be innovative, digital, and data-driven, reflecting the importance of data to achieving the ESO's mission. We will achieve this ambition through:

- Our technology
- Our way of working
- Our people

Good progress has been made with respect to our BP1 plans for Open Data and Transparency. For the BP2 period and beyond, we know that we must:

- Make our data discoverable and accessible
- Continue to develop our analytical capability
- Enable continual improvement to real time decisions through improved data and better day ahead information
- Continue to upskill our people and drive data culture
- Continue to engage with our stakeholders to better understand their requirements and deliver the data services and products they need.

These actions will also allow us to fulfil the recommendations of the recent Energy Digitalisation Taskforce report on "Delivering a Digitalised Energy System".

5.7.2. Technology

A strong IT capability that contains the right blend of technology, knowledge and skills will be a major enabler for us to carry out our functions. Our IT investments comprise a large proportion of our overall Business Plan proposals over the RIIO-2 period and we are committed to ensuring that these will effectively and efficiently enable the delivery of this plan.

Over the course of 2021 and 2022, we have engaged extensively with Ofgem and we are committed to continuing to work together to provide the information they require to enable their assessment of our proposed IT investments for BP2. In addition, we have committed to a full independent review of our IT expenditure, and a firming up of the ranges of IT investment given in this plan, before our Final Business Plan submission in August 2022.

Our '10. Technology' section and Annex 4 – Technology investment summarises our technology landscape, our underlying technology architecture, the technology capabilities we are seeking to deliver over the course of BP2, our underlying governance framework that assures and monitors this delivery, and our portfolio level risks that we are striving to mitigate.

5.8. Innovation

Innovation is critical to us achieving our net zero goals and, as our understanding of the complexities of the electricity system develops, our innovation activities must adapt and refocus. Our innovation capabilities have developed significantly over the first year of RIIO-2. With increased funding and a growing team, we have initiated a series of very ambitious innovation programmes aimed at tackling the challenges of the energy system transition. Our increased capacity has allowed us to set up activities with new partners and suppliers that are larger and more impactful. We aim to continue building on this momentum into BP2 and beyond.

For the first two years of RIIO-2 we were awarded innovation funding by Ofgem of £20.7m of NIA plus a required 10% contribution funded through totex pass-through costs, totalling an overall allowance of £23m. Ofgem agreed that we could seek additional funding for years three to five of RIIO-2 by providing more details of planned innovation activity and evidence of how these activities will build upon the activities in our wider Business Plan.

In our Innovation chapter we provide this detail, outlining how we plan to build on progress made in BP1 on NIA funded projects like the Virtual Energy System, the Future of Reactive Power and Stability Market Design. In BP2, the innovation team will also support our thinking around constraint management and carry out extensive studies on whole energy system challenges.

Each year, we continue to refresh our strategic priorities for innovation based on stakeholder feedback (internal and external), our understanding of the evolving challenges of our industry and the level of funding and number of projects already in train. We believe our innovation activities for years three to five of the BP2 period require minimum additional NIA funding of £24.3m.

6. ESO wider governance proposals (Future System Operator)

Climate change is the challenge of a generation and decarbonisation of the energy system is integral to meeting it. While significant progress has been made in the energy transition so far, there is still more to be done. Delivering a 'net zero ready' energy system requires an entity capable of addressing challenges from a whole energy system perspective. There is a need for coordination across the energy system, and an organisation that can translate decarbonisation policy into immediate strategy and action.

It is against this backdrop that in summer 2021 BEIS and Ofgem consulted on the establishment of an expert, independent Future System Operator with responsibilities across both the electricity and gas systems to start with, and the ability to expand its remit to additional energy vectors when needed. This organisation will be able to drive progress towards net zero, deliver value for consumers by enabling potential cost reductions of up to £3 billion through improved whole energy system decision-making[4], and support energy security. We welcomed the opportunity to respond to the consultation, agreeing that a Future System Operator, with the right roles and capabilities to take a truly whole energy system perspective and an organisational design with the appropriate governance to enable agility and innovation, will play a vital role in the energy system's drive to net zero.

Government and Ofgem have since published their decision document[5] on 6 April 2022. In it, they committed to proceed (subject to legislation) with the creation of a new, independent Future System Operator will be established as a public corporation, with operational independence from government. It will continue to be licensed and regulated by Ofgem and funded by consumers through price control arrangements. The organisation will be founded on the existing roles and capabilities of the ESO, along with strategic gas roles currently undertaken by National Grid Gas. This will require transactions between government and National Grid plc and any other relevant parties.

As part of BP2, Ofgem asked to see an indicative plan for the transformational activities the ESO would have to undertake should there be a decision to change its governance arrangements. This plan should include the key activities, with associated dates, timeframes and indicative costs, of transitioning to a Future System Operator. Our submission set out in Annex 5 - Future System Operator, responds to this request.

In developing our submission, we have used the decisions set out in the joint BEIS and Ofgem consultation response as the basis of our work. We have planned and costed for new and enhanced industry roles where we have reasonable clarity on the likely scope; specifically, whole energy system solutions, coordinated system planning and network development, driving competition in energy networks, energy markets and the advisory role. We have also planned and costed our proposal for an Office of Energy Resilience and Emergency Management, which we believe could be a core element of the new organisation.

Alongside this, we have also designed the appropriate back-office functions to support these new and existing areas of responsibility, while providing flexibility for the Future System Operator to evolve and grow. This will be a significant area of transformation from a cost and planning perspective, as we stand up the people, process and system capability needed to run a new standalone organisation outside of National Grid Group.

Our submission focuses only on the ESO activities and costs of transitioning to a Future System Operator. It does not include the likely activities and cost borne by National Grid plc. Separation of the ESO cannot be achieved without the support of National Grid plc and further work will be required to provide a complete view of the activities and associated costs required to deliver the Future System Operator.

In the next phase, the ESO will need to undertake more detailed design work to further refine our assumptions and indicative transformation plan. The creation of the Future System Operator will require legislation, new and updated licensing arrangements, and amendments to industry codes. We will continue to work collaboratively with BEIS, Ofgem and National Grid plc on next steps and ways of working going forward.

[4] Source: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003944/fso-impact-assessment.pdf

[5] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1066720/future-system-operator-consultation-govt-response.pdf

Section 2 - BP2 Delivery Plans

nationalgridESO

7. Outputs: Delivery plans

7.1. Role 1 Control Centre operations

We keep the lights on and get electricity to people whenever and wherever they need it. In a fast-changing energy landscape that is rapidly decarbonising, decentralising and digitalising, this means we need to develop flexibility and agility in how we operate the electricity system.

7.1.1. Key drivers of change in Role 1

The ability to anticipate and respond to change while also managing operational risk is not new for us. However, through the first year of our Business Plan, the rate of change in the energy industry has surpassed even our expectations. Examples of this trend include:

- **An accelerated drive to net zero** - through the COVID-19 pandemic, we have seen periods of lower than anticipated demand combined with high levels of renewable generation. At the same time, increased challenges with operability and system complexity continue as the system transitions. For example, fault levels and inertia are declining due to a rapid reduction in traditional generation sources (coal and nuclear) and an equally rapid increase in new market participants and renewable generation. To meet this accelerated drive to zero-carbon operation, we have developed a range of new competitive market services which will support operational needs.
- **Transforming markets and changes in technology** - The increase in balancing market participation expands the diversity of technology delivering market services. This breadth of technology brings new opportunities for delivering services as part of our portfolio of Control Centre tools. There is a significant increase in the volume of data used to inform our operational decisions as residual balancer for the electricity market.
- **Regulatory change** - Changes to the regulatory landscape, such as Grid Code modification GC0117 with the increase of minimum unit registration size, can change data volumes and processing requirements for our systems. In the coming years, additional complexity and increased data requirements may arise from the transition to DSOs and further integration of DER assets.
- **Expectations of our stakeholders and consumers** - Stakeholder expectations of us, and of Role 1 in particular, are high when it comes to the transparency of our operational decisions. This, coupled with increasing energy costs, is driving an even a greater focus on the efficiency of our operations and cost effectiveness of our decision making. Understanding how important transparency is for our stakeholders, we have focused on giving clear and concise justifications of our actions, such as through the weekly Operational Transparency Forum. We are also sharing technical findings from system incidents to further inform all parties.

7.1.2. Five-year strategy

Our five-year strategy for Role 1 remains focused on the safe, reliable and economical operation of today's electricity system whilst building the skills, systems and capabilities required for the operation of a carbon free system from 2025.

The scale of change in the external environment will bring more complexity, making it increasingly difficult to continue reliable operation of the electricity system and making our residual balancing role more challenging. This can be seen when reviewing Balancing Mechanism activity (the number of balancing instructions issued daily) over the past decade. In 2014, 1400 instructions were issued per day to market participants, as opposed to around 1800 in 2020. Since 2018, we have also observed a 68% increase in the changes to users' energy profiles submitted as Physical Notifications (PNs).

These increases in balancing mechanism activities and data are a result of increased competition and engagement in current and emerging markets which has led to a growing number of market participants. During 2014, 55% of all issued instructions were for small market participants (under 100 megawatt (MW)) – compared to 65% in 2020. We anticipate continued growth in the number of market participants and the number and volume of instructions and data.

Integral to delivering our Role 1 activities is our data strategy and the IT systems we use to forecast, provide situational awareness, support decision-making and carry out operational decisions. As the complexity of operating the electricity system grows, these systems increasingly become a critical component of decision making and therefore ensuring we have the right capability and tools in place becomes key. So we remain committed to our digital transformation, where the greater use of automation, ML and AI forms a fundamental part of how we will handle ever increasing amounts of incoming data to the Control Centre.

What does this mean for BP2?

Updates to our existing activities

During the BP2 period, we know that to maintain our system operations in a reliable, safe and economic manner Role 1 will need to:

- Maintain our focus on the management of balancing costs, driving efficiency in the costs we can control and ensuring that all our balancing cost actions are transparent to our stakeholders
- Enable continuous improvement, through better data provision, management of change and better forecast information
- Maintain our legacy systems to support the rapidly changing market environment
- Monitor Balancing Services market activity through our Market Monitoring function
- Deliver the requirements of the new Electricity System Restoration Standard (ESRS), in line with our licence obligation, and integrate the Distributed Restart project's recommendations for using DER for system restoration
- Continue to use data to improve our customer digital experience and provide transparency of operational decision-making (this activity falls under **A17 Open Data and Transparency**)
- Focus on how our processes, systems and operating environment can support distributed flexibility and growth in connections from smaller providers, including developing increased visibility of how DER impacts and supports whole system balancing and security actions.
- Drive performance improvements so we can manage the increased number of system investigations and customer queries into the Control Centre

The accelerated drive to zero carbon operation, stakeholder feedback, regulatory changes and the rapidly evolving external environment have brought greater insight into what is required to deliver our ambitions. We have therefore introduced some new sub-activities within Role 1 and updated other existing sub-activities, which now have changed scope or costs.

Increased workloads in Control Centre operations and support

The higher volume of operational data received through the balancing mechanism, as well as the increased complexity of system operation, is set against a background of introducing new products and market changes into Control Centre systems and processes. This means Control Centre engineers and support teams are managing a degree of change and complexity which significantly adds to their workloads.

Over the first year of BP1, we have introduced efficiencies into our core operations, delivering more than originally planned. The recent implementation of the Frequency Risk and Control Report (FRCR) process, where we have saved £176m of Rate of Change of Frequency (RoCoF) costs, is an example of this. Other examples are the execution of a greater number of residual balancing actions and interaction with an increased number of industry participants.

Ensuring that any new products and market changes are fully understood and embedded within our Control Centres and supporting teams requires a considerable increase in workload which was underestimated in our first RIIO-2 Business Plan. Many of these changes require detailed technical input from the Control Centre and supporting teams to make sure they are integrated and deployed effectively. We, of course, need to ensure the Control Centre is well placed to accommodate these product and market changes going forward as the energy transition continues to gather pace.

Balancing Capability Strategic Review

The transformational plans for our balancing capability are critical to achieving our zero carbon operation ambitions. Since our first RIIO-2 Business Plan, we have developed a greater understanding of the scale and complexity of this required capability transition and we have decided to undertake a strategic review of our existing plans, requirements, and approach. This will make sure our plans are cost-effective and adaptable to change. They must be compatible with continuing to operate the electricity system in a safe, secure, and economic way, while also building flexible capability needed to meet potential changes in market design.

As a result, this draft Business Plan does not present plans, costs, or narrative for the RIIO-2 deliverable **D1.2.1 Future of Balancing** or related IT investments. The relevant IT investment references are below and can be found in Annex 4 – Technology investment.

- **180** Enhanced Balancing Capability,
- **210** Balancing Asset Health,
- **260** Forecasting Enhancements,
- **480** Ancillary Services Dispatch.

This strategic review is described in more detail under **A1.2 Enhanced Balancing Capability.** The future balancing capability that emerges from this review will allow full competition in our balancing markets and support innovation in the energy industry to meet net zero emissions goals. Our proposals in this area will be updated for our final Business Plan submission.

Materially changed sub-activities

Our ongoing activities in **A1 Control Centre Architecture and Systems** have changed in scope and costs due to a variety of drivers, including:

- Increased system complexity as fault levels and inertia decline and there is an increase in smaller market participants who are more distributed
- Increased external expectations relating to transparency of operational decision-making and system investigations
- Changes in our European operations due to Great Britain's exit from the European Union
- Evolving cyber security requirements, an improved delivery approach, and adoption of an enhanced IT architecture has significantly increased the costs of the transformational sub-activity **A1.3 Transform Network Control**.

Finally, under A3 Restoration, additional requirements for sub-activity **A3.2 Restoration Standard** have been identified in order to implement the ESRS, following changes to our licence in October 2021.

Additional activities in BP2

A18 Market Monitoring describes a new ESO function, established to monitor activity in balancing services markets to meet our new licence obligation.

A1.5 Operational coordination with DER and DSO is a new sub-activity included in our Role 1 plans to support the DSO transition and DER visibility. This will allow us to implement, in real-time, the enhanced whole electricity system coordination proposed under Role 3.

Figure 8 illustrates the level of change, within Role 1 activities, in comparison to our original Business Plan submission.

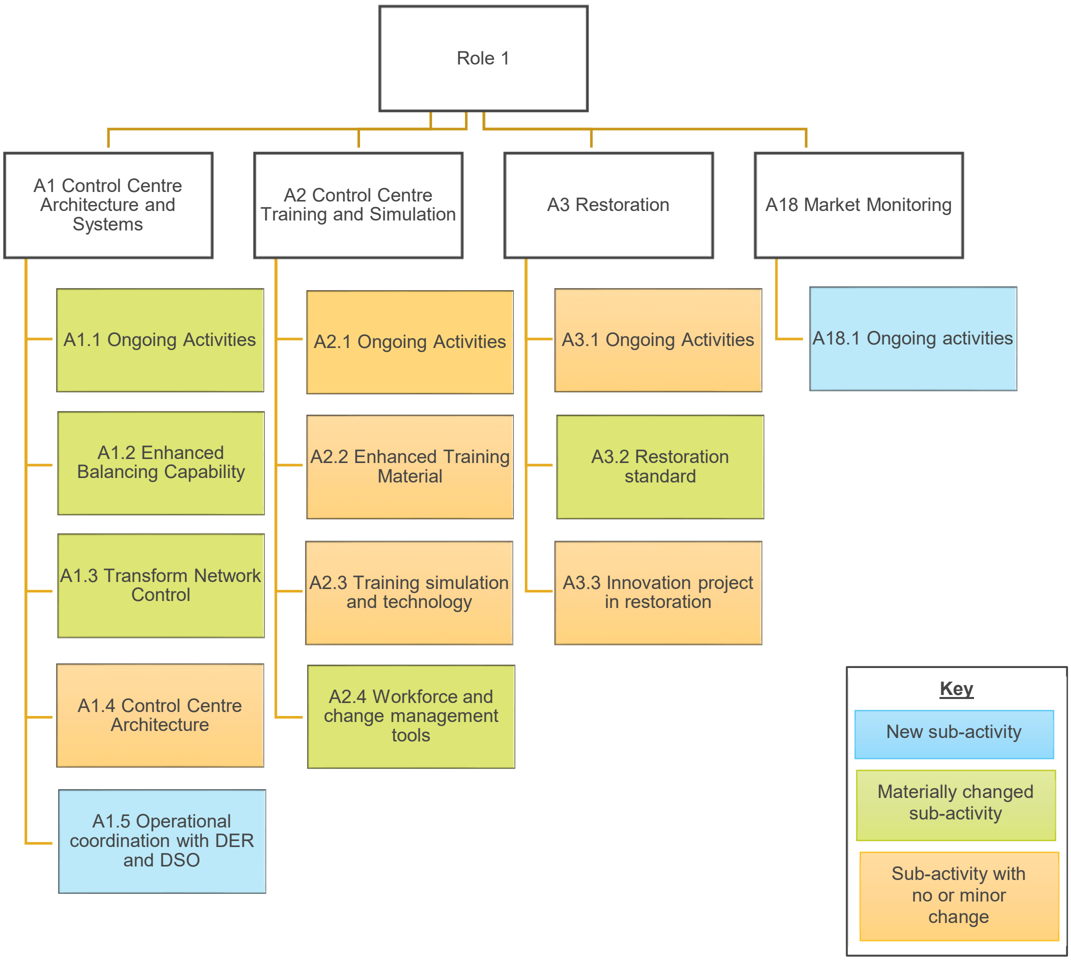

Figure 8: Role 1 activity level of change

7.1.3. Role 1 costs overview

The graph and table below cover the five-year RIIO-2 Business Plan period, comparing the original submission to our updated BP2 proposals (in 18/19 prices). These represent Role 1 costs before support functions and cross-cutting activities are overlaid. The forecasts for the opex, capex and FTEs needed to support Role 1 activities in BP2 have all significantly increased since our first Business Plan submission, driven by much greater complexity in the control environment together with some entirely new activities.

Most of these increases will occur ahead of BP2, as the business plans and supports changes to the Control Centre resulting from IT investments, market reform products and the requirement for whole system operation.

These changes are principally driven by the following activities.

- **A1 Control centre architecture and systems** – an increase of £55m capex, £14m opex and 76 FTE (FY25). Please note that IT investment costs included within these totals are subject to change following the Balancing Capability Strategic Review.
- **A2 Control Training and Simulation** – no change to capex, a reduction of £2m opex and a reduction of 9 FTE (FY25) which have been transferred to **A1**.
- **A18 Market monitoring** – this is a new activity with £1m opex and 7 FTE (FY25).

- **A17/A19 Transparency, data and analytics** – an increase of £3m capex, no change to opex or FTE

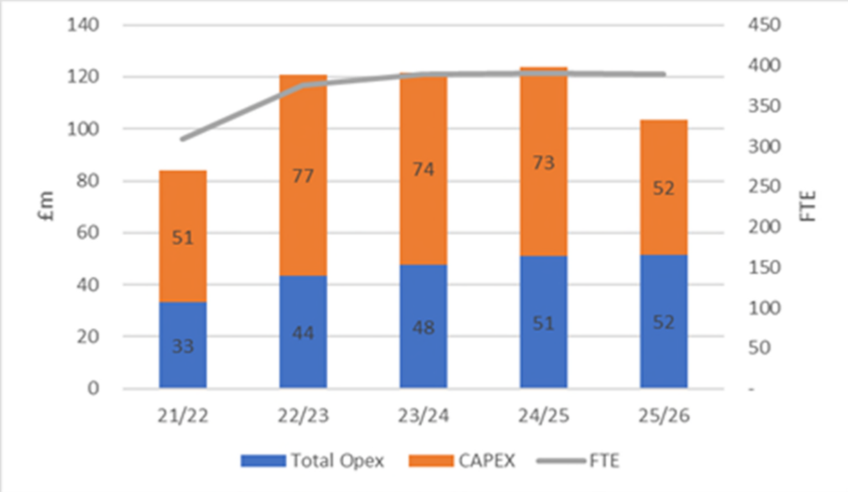

Figure 9: graph of Role 1 RIIO-2 costs and FTE

The graph above presents the updated Role 1 costs for the RIIO-2 period in a 2018/19 price base.

		Five-Year strategy				
		Forecast		BP2		BP3
	Role 1	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	50.5	77.3	74.1	72.7	51.7
	BP1	25.4	38.1	46.9	41.6	31.6
	Variance	**25.1**	**39.1**	**27.2**	**31.2**	**20.2**
Opex (£m)	BP2	33.4	43.6	47.7	50.9	51.7
	BP1	36.3	39.7	42.5	42.9	44.4
	Variance	**(2.9)**	**3.9**	**5.2**	**8.0**	**7.3**
FTE	BP2	309	376	388	390	388
	BP1	294	312	322	318	311
	Variance	**15**	**64**	**66**	**72**	**78**

Table 5: Role 1 RIIO-2 costs and FTE. NB This table includes A17 and A19 which are part of Role 1 but has its own section within this plan (pages 153 – 161)

More details on the drivers of these cost and headcount increases can be found within the relevant activity descriptions below.

7.1.4. Key capabilities required

In the People, Capability and Culture chapter we discuss the capabilities the ESO needs in order to deliver on our RIIO-2 commitments, and how we will build and enhance them across our workforce. For Role 1, we need to continue to build capabilities in the following areas:

- **power system engineering:** application of technical knowledge to understand and operate the GB electricity system, utilising the new tools to manage the increasing complexity of the system
- **ESO technology:** ensuring we have sufficient support in place to deliver the level of IT investments required
- **analytics:** increased use of advanced modelling techniques and ML to improve forecasting of system requirements and real-time situational awareness.
- **data management:** ensuring provision of trusted data, fully integrated with data products and services

- **commerciality:** utilising the full range of market options to ensure delivery of maximum consumer value; identifying and investigating risks of market manipulation

7.1.5. Role benefits

We have updated the RIIO-2 CBAs for the transformational activities in **A2** and **A3**. The CBA for **A1** has not been updated due to the ongoing Balancing Capability Strategic Review, described under sub-activity **A1.2**. However, it will be updated for our final Business Plan submission in August 2022. The **A1** NPV is expected to be in the range of £200-£650m. The activity **A18 Market Monitoring** covers ongoing activities in the BP1 period and does not require a CBA, since it is neither new to BP2 or transformational.

Activity	Name	NPV BP1 (£m)	NPV BP2 (£m)	Change (£m)
A1	Control Centre architecture and systems	Under strategic review		
A2	Control Centre training and simulation	16	16	-
A3	Restoration	-8	2	+10
A18	Market Monitoring	No analysis required		
	Total	**8**	**19***	**+11***

Table 6: Role 1 NPV change

* *Totals may appear incorrect due to rounding*

7.1.6. Balancing Costs Focus

The ESO incurs Balancing Costs as a necessary part of its activities to secure and balance the electricity system. We have seen that Balancing Costs have risen significantly over the last two years from £1.3bn in 2019-20 to £3.1bn in 2021-22. We forecast that these costs will continue to increase as the electricity system transitions towards zero carbon operation.

The main drivers of the increased costs in 2021-22 are:

- The high cost of gas feeding through to electricity prices, meaning that most ESO actions are significantly more expensive than previous years
- Gas and coal generator market strategies e.g., Coal generators setting the marginal price at £4000/MWh, coupled with some scarcity pricing leading to high costs on low margin days
- Constraint costs, mainly the cost of constraining wind in Scotland and the North of England coupled with the high cost of the replacement energy

We understand that higher Balancing Costs has an impact on our customers, their businesses and ultimately to end consumers, particularly given the energy cost crisis. This has created a critical need to move faster to mitigate these costs as far as possible. We will further increase our focus on driving operational efficiency in our actions, cost transparency in markets and cost effectiveness in new or enhanced activities.

An initial internal review of our Balancing Cost management has been initiated focussing on three main areas:

- Short-, medium- and long-term improvement activities that will have a positive and enduring impact on Balancing costs
- A thorough end-to-end review of the processes that impact Balancing Costs and implementation of improvements in activities that span multiple teams
- Improved monitoring and measurement of our actions in all timescales to ensure that improvement activities are tracked, and benefits measured

These activities will take place during the BP1 period and it is anticipated that they will identify actions and deliverables that we will commit to over the BP2 period. These BP2 deliverables will be included in our final Business Plan submission in August 2022. As we develop our focus in these areas we will continue engage with stakeholders externally, for example through existing interfaces such as the Operational Transparency Forum.

Role 1 delivery plan detail

7.1.7. (Materially changed) A1 Control Centre architecture and systems

This activity describes the ongoing work in our Control Centre to improve its tools and systems so that we can meet our Business Plan objectives and achieve the country's net zero ambitions.

The transformational investments proposed in our first Business Plan were:

- Enhancing our balancing capability to deal with greater decentralisation of service providers and to accommodate closer to real-time markets
- Transforming our network control tools to give Control Centre engineers a high degree of situational awareness and to manage an increasing amount of network data
- Building a data and analytics platform as a 'single version of the truth' for all our data
- Establishing a Technology Advisory Council (TAC) (formerly called the Design Authority), to give stakeholders a say in the design of new systems, delivering a step change in transparency and accountability.

We continue to deliver the ongoing investments described in our first Business Plan submission. However, the scope and costs of several have changed significantly. This is due to the greater operational workload caused by increasing system complexity and the requirement to plan and support changes to the Control Centre introduced by IT investment, market reform products and the requirement for whole system operation.

We have included two additions to the **A1** RIIO-2 delivery schedule to ensure we are equipped to support and manage changes in the Control Centre over the BP2 period:

- More investment in National Control support to facilitate distributed flexibility, the DSO transition and DER visibility through the new transformational sub-activity **A1.5 Operational coordination with DSO and DER**
- There will be a greater focus on the provision of day-ahead information into the Control Centre, improving the coordination of day-ahead planning and making it easier to economically balance the system. We will support greater transparency of operational decision-making and drive consistency across our five shift teams; this work is described by the new ongoing deliverable **D1.1.9 Upstream Technical Co-ordination.**

Narrative and plans for the deliverable **D1.2.1 Future of Balancing** are not included in our draft Business Plan submission. However, the benefits of the ongoing Balancing Capability Strategic Review are further detailed under the sub-activity **A1.2 Enhanced Balancing Capability.**

Our ambition for the greater use of automation, ML and AI in the operation of a net zero power system is supported by the work of the ESO Labs. This is embedded within our Innovation function, and its purpose is to consider how we can exploit new and emerging technologies, feeding ideas into innovation processes and assisting our teams with adoption. The ESO Labs resources are accounted for under **A1.** Please see the Innovation chapter for a more detailed description of this team.

A1 sub-activities and deliverables

7.1.7.1. (Materially Changed) A1.1 Ongoing activities

Changes to Control Centre operations

Since our first RIIO-2 Business Plan, our understanding of the complexity of managing the electricity system has increased, as fault levels and inertia decline, and intermittent and distributed generation grow. The rapid pace of change has resulted in our Control Centre workloads increasing substantially ahead of the deployment of our transformed network control and balancing capabilities. To date, this increased workload has been absorbed by our Control Centre staff.

It is critically important to our net zero ambitions that our Control Centre engineers have the capacity to manage this increased activity and can contribute to critical market reform projects. These projects need a dedicated focus to ensure the effective implementation of market reforms into real-time operations, processes, and systems.

Changes to Control Centre support

As detailed below, the scope of our support to the Control Centre has evolved since BP1. However, only the changes to the deliverable **D1.1.5** and to the Market Requirements team are drivers of additional costs.

European Operations (D1.1.4)

Since the BP1 delivery schedule was published in October 2020, the Trade and Cooperation Agreement (TCA) has been finalised, defining the extent to which the UK can participate in European projects and initiatives. The ESO is no longer a member of the European Network of Transmission System Operators for Electricity (ENTSO-E). However, we will support development of new methodologies for interconnector capacity calculations under the TCA, and continue to support European cooperation, including with ENTSO-E, based on the outcome of the Memorandum of Understanding with ENTSO.

Our membership of Coreso continues, based on agreement with EU National Regulatory Authorities, and we value the provision of daily security analysis to our Control Centre.

Following the publication of the Memorandum of Understanding, we will continue to participate in key projects and services relating to cross border capacity calculations, security analysis and situational awareness, along with associated reporting. We are continuing the business-as-usual activities of submitting individual grid models for the Common Grid Model project and Coreso security studies. Activities for intra-day capacity calculations and management of interconnector ramp rates are at the discussion stage with stakeholders. For more information about our role in European electricity transmission activities, see the activity **A21 Role in Europe**.

Maintenance and Upgrades to Legacy Systems (D1.1.5)

The deliverable **D1.1.5** ensures investment in our current Control Centre tools whilst we develop an enhanced balancing capability and a new network control tool. We need to maintain and upgrade our legacy systems to continue operating the electricity system safely and economically. We will remove defects, improve system performance and stability, and introduce new functionality for the Control Centre to better manage the system in the short-term.

We must create the necessary changes and additions to tools driven by Role 2 and 3 deliverables. For example, the Pathfinder projects will introduce new provider types and or services which will need to be reflected in our systems and capabilities. We need additional resource to ensure these changes are tested and implemented in the systems.

We also anticipate that we will need to incorporate new services into our legacy systems to meet our stakeholders' needs, given the anticipated increases in the number and complexity of new market participants in the RIIO-2 period. Over 500 balancing mechanism units have been registered in our systems since 2020, with an anticipated increase of at least 10% per year and potentially higher volumes as a result of Grid Code modification GC0117. We will support the offline network modelling and provision of regular, collated network updates to transmission operators.

Our aim is to maintain our current systems and update them as necessary to deliver transformational capability as market and regulatory changes arise. These must be funded to ensure resource is not diverted away from asset maintenance when externally driven requirements arise. opex and FTEs previously assigned to **A2** in our BP1 plan have been reallocated to **A1** to enable us to achieve this aim. We are also forecasting an increase in associated IT capex costs related to this deliverable as described in the **'A1 finances and headcount' section**.

Operability Strategy Report (D1.1.6)

The Operability Strategy Report (OSR) has been refocused to cover the operational requirements and our future system needs. This makes a clear difference between this report and the Markets Roadmap, which explains how our markets are evolving to meet these future needs in the most efficient way. The reference to Control Centre management plans has been dropped from the **D1.1.6** deliverable description as the focus is on system needs and our operability requirements as set out in our five security workstreams.

The OSR will continue to evolve according to the needs of stakeholders. For example, we anticipate its scope will expand to consider constraints at the transmission-distribution interface, to ensure a whole electricity system view is taken to lowering the constraint costs that impact consumer bills.

In line with sub-activity **A15.9 Net-Zero Operability**, we plan to expand the scope of the Operability Strategy Report to bring in two new areas (flexibility and capacity adequacy) which will set out requirements to further enable decarbonisation. The definition of flexibility will align with the Smart Systems and Flexibility Plan[6] developed by the government and Ofgem to include storage, interconnection, and smart systems.

Forecasting for demand and generation (D.1.1.7)

The scope of this deliverable is unchanged. However, we see additional requirements to support data transparency, develop automation of forecasting-related processes and meet increasing regulatory reporting obligations. We currently envisage being able to absorb these requirements within the current Role 1 business areas and will use the cost pass-through model if additional requirements increase substantially during the BP2 period.

Trading solutions (D1.1.8)

Trading activity reduces balancing costs. Greater automation of trading processes mitigates against the risk of errors and makes sure we continue to meet demand for trading, particularly with interconnector counterparties. As expected, new interconnection capacity has increased the volumes of both preparatory and operational trading activities. Work on new processes and systems to achieve automation must be prioritised to future-proof our trading capability.

In 2019, we introduced the current trading processes for transacting with interconnector counterparties. In its first year, we estimate it saved £22.3m on balancing costs, as well as increasing counterparty participation. Increasing automation of trading processes and moving to an auction platform will ensure we continue to trade reliably, economically, and efficiently as Great Britain's interconnection with Europe increases over the coming years. Our planned IT investments for trading are described in the subsection 'Key investments for this sub-activity'.

Market Requirements

We have increased our Market Requirements team to improve our demand forecasting and Balancing Services Use of System (BSUoS) costs forecasting capabilities. This is part of our five-point plan to manage constraints on the system. A detailed description of these forecasting activities is contained in the 'What are our updated RIIO-2 plans?' section of the sub-activity **A4.1 Manage existing balancing services** markets**.** Some resources in the Market Requirements team are now accounted for under Role 1 due to an internal restructure of our Markets function; this is offset by a decrease in Role 2.

New Control Centre support

Upstream technical coordination (D1.1.9)

In BP1, we have seen an increase in the complexity of Control Centre operations and in activities upstream of the Control Centre that inform day-ahead planning. From July 2022, we will make improvements in the following five areas:

1. Delivering the Winter/Summer Operability Liaison Meeting to improve the engagement with stakeholders and customers, and to provide greater transparency
2. Managing critical operational periods, such as the winter peak demand and the summer low demand (including preparation, output, and industry liaison)
3. Managing the week-ahead strategy plan to reduce system operational risk before the day and to provide additional support to the Control Centre real-time operations
4. Closer working with Network Access Planning, Market Requirements and the broader ESO to ensure timely, accurate, and complete handover of critical information to improve Control Centre activities, before the day and on the day
5. Developing effective processes to support operability management, by continually reviewing, improving, and sharing best practice.

[6] www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

Additional FTEs are required to make these improvements. We believe investment in upstream technical coordination will provide greater operational transparency to industry, contribute to our overall net zero ambitions and reduce Control Centre risk in managing system security and balancing.

Key investments for this sub-activity

Sub-activity **A1.1** needs several key IT investments to maintain and enhance Control Centre tools and systems. The BP2 plans for each are summarised below; more detail can be found in Annex 4 – Technology investment.

For maintenance and upgrades to legacy systems (D1.1.5)

The table below provides an overview of the activities under each IT investment line and how they align to our transformational deliverables. The detail behind these investments can be found in Annex 4 – Technology investment.

IT investment line	Summary of BP2 activities	Link with transformational deliverables
170 Frequency Visibility	Decommission legacy Frequency and Time Error (FATE) system Enhancements to the Wide Area Monitoring System (WAMS) applications to improve stability monitoring	This investment line incorporates transformational activities for updating and expanding the existing WAMS applications, dependent on the transformational network control investment described in sub-activity **A1.3**
240 Electricity National Control Centre (ENCC) Asset Health	Maintenance updates to legacy tools other than those covered by IT investments **170** and **210**	Maintenance updates to systems being replaced are closely monitored to avoid regret spend

Table 7: IT Investments and links

Our updated plans for the IT investment **210** Balancing Asset Health, which links with the transformational deliverable **D1.2.1 Future of Balancing**, will be provided in our final Business Plan submission, due to the ongoing Balancing Capability Strategic Review.

For forecasting demand and generation (D.1.1.7)

The key IT investment for this deliverable is **260** Forecasting Enhancements and is included in Annex 4 – Technology investment**.** Forecasting products under this investment deliver consumer benefits through improved accuracy, frequency, granularity, and transparency. Updated timelines and costs are not presented in this draft Business Plan submission due to the ongoing Balancing Capability Strategic Review but will be included in our final Business Plan.

For trading solutions (D1.1.8)

Greater automation of our trading processes is supported by two IT investments. Firstly, a business continuity solution, required for critical trading systems used for trade capture and trade notification, will be delivered under **240** ENCC Asset Health in BP1. A loss of the systems used for logging and storing all trade details and for subsequent notification of energy contract volumes to Elexon would result in the team being unable to capture trades, publish information externally and notify Elexon of traded volumes. Trading by the ESO would be suspended. Between April 2021 and March 2022, the trading team saved on average £540,000 per day in balancing costs and a robust business continuity solution is required for their systems.

We also plan to deliver a new interconnector auction platform during BP1 and BP2. Interconnectors are not required to submit Bid Offer Acceptances in line with the Grid Code. For this reason, interconnectors are not accessible to the Control Centre in the balancing mechanism. To manage flows on interconnectors we trade with counterparties to acquire capacity on those interconnectors ahead of time. The current interconnector trading processes will be moved onto an auction platform, to provide greater automation, improved reliability, and a better counterparty experience. This will reduce the risk of human error, which is present in the current system since it relies on emails and spreadsheet-based tools. Costs and plans for the IT investment to deliver the auction platform will be presented in our final Business Plan in August 2022.

7.1.7.2. (Materially changed) A1.2 Enhanced balancing capability

This sub-activity covers the significant investment needed in our balancing systems to deal with decentralisation of providers and to accommodate closer-to-real-time Great Britain and European markets.

Balancing Capability Strategic Review

Our balancing capability unlocks the benefits of many other RIIO-2 deliverables. It must:

- Provide the robust and flexible tools we need to ensure the end-to-end balancing process continues to deliver safe, secure, and economic operation
- Enable greater numbers of market participants to connect, increasing competition to drive value for consumers
- Allow new technologies and services to access balancing markets, adapting to the significant change needed to transition to a zero-carbon future.

Our existing balancing capability will not be able to meet all future challenges. Investment is required to develop new capabilities and associated platforms to ensure we have the flexibility to facilitate expected and emerging changes in the industry.

There are RIIO-2 deliverables across all three roles that are dependent on an enhanced balancing capability. The transition to the new balancing capability needs precise planning, which must also be flexible and adaptable to the evolving needs of our customers.

Our understanding of the complexity and scale of the transition from existing to future balancing capability has developed greatly since we submitted our first RIIO-2 Business Plan, so we are carrying out a strategic review of our plans. This will ensure delivery of this critical capability is supported by a cost-efficient and robust schedule. We are unaware of any equivalent industry example of implementing a capability transition of this scale and complexity, whilst maintaining business as usual reliability. We will be engaging on this with stakeholders and will validate our strategy with the TAC.

The challenges our strategic review will address include:

- Assessing the ongoing costs and the viability of maintaining existing systems
- Determining the correct balance of investment between maintaining existing balancing capability and developing future capability
- Understanding the transition between existing and future balancing tools
- Scoping the requirements and timescales for integrating future balancing tools into IT systems and Control Centre processes
- Prioritising the integration of new data feeds and features to deliver benefits from other RIIO-2 deliverables
- Scheduling the releases of new balancing capabilities to align with other RIIO-2 plans.

We have invited stakeholders to engage with this strategic review[7] and to collaborate with us on these challenges, in an open letter published on 31 March 2022.

In the rest of this section, we provide updates for **D1.2.2** and **D1.2.3** only. Full plans, costs and narrative for **D1.2.1 Future of Balancing** will be provided in the final Business Plan.

What are our updated RIIO-2 plans?

We will develop new tools during RIIO-2 to address emerging technology and system management issues, as highlighted in future Operability Strategy Reports. New milestones for the deliverable **D1.2.2 Inertia forecasting, emergent technology, and system management** will likely arise as issues are identified and solutions proposed from the reports. The requirements of this deliverable are also driven by industry provisions, for example services offered under the Pathfinder consultations, and evolving technologies. So our plans must remain flexible and adaptable to these external influences. See **A8 Enable all solution types to compete to meet transmission needs** for more details on the roll-out of Pathfinders.

[7] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-programme/strategic-capability-review

In our first Business Plan we committed to consider how innovation funding can support greater use of automation, ML and AI in the Control Centre. These became a key driver for our innovation priority 'Digital Transformation', as described in our 2020/21 Innovation Strategy, and projects have already been proposed to address Digital Transformation in the Control Centre within BP2. Given that the funding mechanisms for these will be through the NIA and the Strategic Innovation Fund, we are removing deliverable **D1.2.3** from the RIIO-2 schedule. However, increased use of automation, ML and AI remains a key part of our strategy for **A1 Control Centre Systems and Architecture**, and this will also be realised through the capability developed in **D1.2.1 Future of Balancing** and **A1.3 Transform Network Control**, and through the work of ESO Labs, described in the Innovation chapter.

The name of the deliverable **D1.2.1** has been updated in BP2 to **'Future of Balancing'.** This avoids confusion with deliverable **D1.1.5 Maintenance and upgrades to legacy tools**.

Key investments for this sub-activity

This sub-activity is aligned to the IT investments **180** Enhanced Balancing Capability and **480** Ancillary Services Dispatch. The Balancing Capability Strategic Review also includes IT investments **210** Balancing Asset Health and **260** Forecasting Enhancements, as described under the sub-activity **A1.1 Ongoing Activities**. The detail behind these investments can be found in Annex 4 – Technology investment.

7.1.7.3. (Materially changed) A1.3 Transform network control

This sub-activity covers the investment to enhance the situational awareness of our Control Centre engineers. In our first Business Plan we committed to replace our current real-time situational awareness tool, the Integrated Energy Management System (IEMS), with our new Network Control Management System (NCMS). By the end of RIIO-2 we will deliver a fully operational NCMS suite into the Control Centre, integrated into our new Critical National Infrastructure (CNI) Data Centres, and will transition away from the IEMS tool which is shared with National Grid Electricity Transmission (NGET).

What are our updated RIIO-2 plans?

Our milestones for deliverables **D1.3.1, D1.3.2** and **D1.3.3** remain on track and unchanged from our original Business Plan. However, our scope of work has increased in the following areas.

- **Evolving Cyber requirements:** As part of our commitment to replace our IEMS, we have reviewed our design against the latest cyber security intelligence for CNI. This area is rapidly developing, and we have identified new resilience options to maximise the security in the design of the new NCMS tools. [redacted][8].
- **Enhanced IT architecture:** For our new NCMS product, we propose a more modern virtualisation of our architecture, in collaboration with our remaining supplier submissions. This will be deployed in our new CNI Data Centres and offer improved cyber security, performance, and better maintenance options. Owing to higher costs for hardware due to the ongoing semiconductor shortage, we are proposing a higher level of investment to ensure we deliver the most suitable foundations for future operation. This will also benefit future developments such as the Virtual Energy System programme described in the Innovation chapter.
- **Improved delivery approach:** The Programme team is moving to a 'TechOps' way of working, with an agile delivery model. Where we had previously allocated resource to remain in other business areas and provide expertise into the product team, we are now bringing this expertise into the Programme team. This is in response to stakeholder feedback (such as from the TAC).

The continuous deliverable **D1.3.4 Increased operational liaison with DNOs** has been removed from this sub-activity. It's associated milestones and benefits will now be delivered under the sub-activity **A1.5.**

The evolution of our plans within this sub-activity have increased costs in this area (please see **A1 Finances and Headcount** for further information). A14.3

[8] It has been necessary to redact this section from our Business Plan because it contains operationally sensitive information.

Dependencies and assumptions

Requirements for enhanced cyber security measures will evolve and could continue to impact the future costs and schedule for this sub-activity. Cyber security is an area of increasing importance, and we will invest to ensure security and resilience. We will make sure the approach to solution security is mapped to the IT Global Control Set, is compliant with the directive on security of network and information systems, meets and complies with our baseline security requirements and the Security and Compliance Schedule.

Our plans must remain adaptable to meeting the current and evolving needs of the Control Centre end-users. For example, where legacy solutions such as video walls are causing issues, it may be efficient for the Network Control programme to reprioritise and reorder the sub-activity milestones.

Key investments for this sub-activity

This sub-activity is aligned to IT investment lines: **110** Network Control**, 150** Operational Awareness & Decision Support and **140** ENCC Operator Console. These will eventually integrate with the **220** Data and analytics platform, and the investment **200** Future training simulator is dependent on its delivery. The detail behind these investments can be found in Annex 4 – Technology investment.

7.1.7.4. A1.4 Control Centre architecture

This sub-activity covers architecture, capabilities and governance to make changes to our Control Centre systems quicker and smarter.

What are our updated RIIO-2 plans?

Data and Analytics Platform (D1.4.1)

The scope and milestones for this IT investment in the BP2 period are unchanged. Our ambitions, strategy and capability plan for data and analytics are now described in **A19 Data and Analytics Operating Model** to give clarity and focus on the important role these will play in transforming our whole business.

Technology Advisory Council (**TAC) (D1.4.2)**

The TAC is a valuable engagement route for many of our RIIO-2 deliverables, allowing us to obtain stakeholder input into the design, development, and testing phases of IT solutions. The BP2 milestones for TAC engagement have been removed from the delivery schedules of other RIIO-2 deliverables to ensure that we can take an agile approach to using the TAC. Instead of prescribing an engagement schedule months or years in advance, the agendas for TAC meetings will flex with the progress of the transformational activities, the changing role of the ESO and the evolving needs of stakeholders.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **220** Data and Analytics Platform. The TAC is also expected to give significant feedback and direction to **180** Enhanced Balancing Capability, **110** Network Control, **220** Data and Analytics Platform, **250** Digital Engagement Platform, **400** Single Markets Platform and **500** Zero Carbon Operability. The detail behind these investments can be found in Annex 4 – Technology investment.

7.1.7.5. (New) A1.5 Operational coordination with DSO and DER

This is a new sub-activity to address the impact of the interface between ESO, DSO and DER on our real-time operations. Due to the direct interdependencies of their transition activities, detail and ambitions for this sub-activity are found in the Facilitating Distributed Flexibility section of the cross-role activities chapter.

7.1.7.6. A1 Stakeholder feedback

(A1.1 - A1.4)
We have shared plans relating to our Balancing and Network control programmes with the TAC. This included the current technology suite, our goals for 2025, and the five-year delivery roadmaps. Their feedback has shaped how we have worked in BP1 and will continue to deliver in BP2.

The top areas of feedback (as voted by the TAC) are shown below.

- **Technology and operations collaboration** – the TAC told us that having technology and operations teams collaborate very closely leads to continuous improvement as well as an understanding of each other's challenges.
- **Collaborative transformation** – the TAC told us that transformations in other sectors has highlighted the need to fully involve all operational teams from the start to get buy in.

In response, the ESO Ways of Working (WoW) initiative will implement a new way of working and create TechOps (technology and business operations) teams focused on the customer. We are also embracing the Scaled Agile Framework (SAFe) approach to ensure that the delivery of products is exactly in line with the customer's expectations through constant feedback.

See Annex 3 – Stakeholder engagement for more in-depth detail on TAC feedback in these areas.

We still have a lot of stakeholder engagement to do in this area ahead of our final Business Plan submission and beyond. On 31 March 2022 we launched our external engagement activities for the Balancing Capability Strategic Review with an open letter[9]. We welcomed industry to join our review and collaborate with us, to ensure our plans and delivery roadmaps meet our RIIO-2 strategic objectives, minimise balancing costs, deliver consumer benefits and create a foundation for future market changes and reform. A series of virtual and in-person workshops will be held in April and May 2022 to facilitate the engagement.

(A1.5) See section Role 3 Cross-Role Activities – Facilitating distributed flexibility, for stakeholder feedback on DSO related activities.

7.1.7.7. A1 Finances and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A1 - Control Centre Architecture and Systems		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	49.4	72.5	62.4	60.2	41.1
	BP1	23.2	34.6	37.0	30.5	23.0
	Variance	**26.2**	**37.9**	**25.5**	**29.7**	**18.2**
Opex (£m)	BP2	30.8	39.5	40.8	42.4	42.0
	BP1	31.7	33.8	35.2	34.1	34.9
	Variance	**(0.9)**	**5.7**	**5.6**	**8.3**	**7.2**
FTE	BP2	283	333	339	341	340
	BP1	251	262	267	265	261
	Variance	**32**	**71**	**72**	**76**	**79**

Table 8: RIIO-2 costs and FTE for A1

The forecasts for the opex, capex and FTEs needed to support **A1** activities in BP2 have all significantly increased since our first Business Plan submission. Most of these increases will occur ahead of BP2, as we plan and support changes to the Control Centre introduced by IT investments, market reform products and the requirement for whole system operation.

An additional 72 FTEs in FY24, increasing to 76 FTEs in FY25, are required compared to BP1. These are to support the increased IT investment and additional operational deliverables described in this chapter. The main drivers of the increase are:

- £55m capex, £7m project opex and 28 FTEs (FY25) for IT investments. The increase in capex is mainly driven by the IT investments:
    - **210** Balancing Asset Health and **180** Enhanced Balancing Capability – £16m and £13m additional capex respectively was forecasted ahead of our 2021-22 Mid-Year Report[10]. These costs are under review in the Balancing Capability Strategic Review.

[10] https://www.nationalgrideso.com/document/215871/download

- **110** Network Control - £12m additional capex is due to evolving cyber security requirements, an improved delivery approach and adoption of an enhanced IT architecture, as described in sub-activity **A1.3 Transform network control.**
- The costs of the additional 28 FTEs are accounted for in the increase to capex and are to support those capex projects.
- The additional £7m opex is driven by increases in IT project opex and 'run the business' expenditure. These FTE and opex costs are under review in the Balancing Capability Strategic Review. Further information about our **A1** IT investments and their costs, including the remaining capex variances, can be found in Annex 4 – Technology investment.

- £7m opex and 48 FTEs (FY25) for operational deliverables including:
  - 6 FTEs to support the greater use of automation, ML and AI through the work of the ESO Labs, described in the Innovation chapter.
  - 7 FTEs for our market requirements team, to improve our demand and BSuoS costs forecasting capabilities and due to an internal restructure in Role 2, as described in sub-activities **A1.1 Ongoing activities** and **A4.1 Manage balancing services and markets**.
  - 15 FTEs for the Control Centre and its supporting teams in their work described by sub-activity **A1.1 Ongoing activities**.
  - 6 FTEs to cover evolving cyber requirements, enhanced IT architecture and improved delivery approach in sub-activity **A1.3 Transform network control**.
  - 5 FTEs for the new transformational sub-activity **A1.5 Operational coordination with DSO and DER.**
  - 9 FTEs were moved from **A2** to **A1** due to an internal restructure in Role 1. This restructure reallocated resources to the maintenance and upgrades of our legacy Control Centre systems described by deliverable **D1.1.5** in **A1.1 Ongoing activities.** Therefore, these cost increases are offset by corresponding decreases in FTEs and opex for the BP2 period in **A2**.
  - The additional £7m opex is driven by the increase in FTEs explained in the preceding bullets.

7.1.7.8. A1 Cost-benefit analysis

Due to the ongoing Balancing Capability Strategic Review, the **A1** CBA has not been updated for this submission. We will provide an updated **A1** CBA in the final Business Plan submission in August 2022. The **A1** NPV is expected to be positive and in the range of £200-£650m. Further information can be found in Annex 2 - CBA.

7.1.8. A2 Control Centre training and simulation

In the first RIIO-2 Business Plan, this activity described our resource planning and training, incident analysis and investigation, monitoring system performance and guidance on operational policy for the Control Centre.

It also contained transformational sub-activities to ensure our Control Centre engineers have the right training to operate the energy system of the future. The specific deliverables included:

- Enhanced training material through partnerships with academic institutions and through training collaborations with DNOs, as they look to develop their own capabilities in system operation
- Developing a new training simulator and additional online or e-learning options to reflect the changing energy landscape
- Greater automation in document management and personalised training plans, to provide an environment that supports the wellbeing and continued development of our Control Centre engineers.

The delivery of greater automation in document management for Control Centre shift rotas (**D2.4.1**) is currently 12 months behind schedule, due to unforeseen issues with the provider of the new system.

However, we expect to recover this delay by the end of BP1 and to deliver on our BP2 commitments on time. The delivery of the five other transformational deliverables in this activity is on track.

This chapter also contains an update on our ambitions for the use of Digital Twin technology in our Role 1 delivery plans. This update sits alongside the deliverable **D2.3.1 New Simulation Capability** because a new simulator is our first “use-case” for a Digital Twin of our Control Centre IT estate.

A2 sub-activities and deliverables

7.1.8.1. A2.1 Ongoing activities

This sub-activity covers ongoing work in resourcing the control centre, monitoring its performance, investigating incidents, and ensuring operational policy is adopted.

What are our updated RIIO-2 plans?

Control Centre strategic resource planning, scheduling, and training (D2.1.1)

The strategic workforce plan continues to be reviewed and updated to reflect current knowledge of our Control Centre workforce requirements given industry and market factors, process and technology change, process complexity and transaction volumes. Our approach remains adaptable and flexible, however we still need significant lead times for recruitment.

Incident analysis and investigation of abnormal events (D2.1.2)

To fulfil our commitment to being more proactive in sharing lessons learnt, we have been sharing details of system events and reviews through the Operational Transparency Forum and the Grid Code Review Panel. Whilst broader engagement and communications does add to the complexity of incident investigations, it also allows us to fully deliver on our commitment for proactive sharing of system event outcomes.

We have seen an increase in the complexity and number of incidents, driven by emerging power transmission technologies such as wind farms’ and batteries’ controllers, new Flexible Alternating Current Transmission System (FACTS) devices and High Voltage Direct Current (HVDC) links interacting with the transmission network. These new connections, which include “non-standard” connections, increase the volume and technical complexity of system or asset incidents and the resulting investigation process. Weather-related investigations and incidents have also increased. We are not forecasting higher FTE numbers for this additional workload; it will be absorbed by existing teams.

We aim to be more proactive in sharing learnings across the industry. This will enable us to highlight any potential operational risks and lead on new operational policy development and implementation.

Monitor and report on system performance to regulatory bodies (D2.1.3)

The EU System Operation Guideline became UK law in January 2021. As a result, we are directly responsible for the Operational Security Indicators and the annual load-frequency control reporting requirements. The ENTSO-E report compares Great Britain’s TSO performance against other EU countries. Post Brexit, Great Britain is not part of ENTSO-E and some of the content of the report becomes invalid without this comparison analysis.

During BP1 we also committed to additional reporting, including an annual report on Clean Energy Package Article 13 re-dispatching, relaunching the GC0105 System Incident Report in response to industry demand and reporting to comply with GC0151: Grid Code Compliance with Fault Ride Through Requirements. The GC0151 modification has needed monthly meetings with the Transmission Owners (TOs) to coordinate data collection for faults information, increasing the workload of our reporting team. To address this increased workload and increasing numbers of system incidents, our system monitoring solutions and tools may need investment in the RIIO-2 period, which would be carried out under IT investment references **210** ENCC Asset Health or **170** Frequency Visibility.

Dependencies and assumptions

Effective future system monitoring and reporting of system performance relies on the IT investments in **210** ENCC Asset Health and **170** Frequency Visibility.

7.1.8.2. A2.2 Enhanced training material

This sub-activity covers investment in training materials for universities and industry to ensure we have access to a pool of talented people. Our aim is to encourage more students to join us though a better understanding of what we do and how we contribute to society.

We experienced some initial delays during the first year of BP1 due to COVID-19 restrictions, however we still expect to deliver the benefits stated within BP1. Otherwise, the scope, costs and timescales of the sub-activity are unchanged from our BP1 plans.

What are our updated RIIO-2 plans?

We have partnered with two universities to influence course content (**D2.2.1**) to include an understanding of the role of the System Operator now and in the future. We will continue to work with several other engineering and technology universities to influence the talent pipeline. Future training material may include understanding the role of the DSOs and how the data supplied to us is used to make informed decisions.

Our ambition is to train ESO and DNO staff on whole system operation (**D2.2.2**); however, this needs to be agreed as the correct solution with DNOs and broader stakeholders.

Dependencies and assumptions

Excellent simulation tools (as proposed in **A2.3**) are key to the successful delivery of this sub-activity. We have assumed that we will have resource available to support building relationships with universities and that other educational facilities that will champion us as a favoured employer.

We have also assumed DNOs will develop their own simulation capability through their RIIO-2 ED2 plans.

7.1.8.3 A2.3 Training simulation and technology

This sub-activity covers the investment in simulation and e-learning technologies to provide training for control centre engineers that accurately reflects the changing energy landscape. This includes use of Digital Twin technology.

Digital Twin Technology

In our first RIIO-2 Business Plan, we set out our ambitions for using Digital Twin technology to create offline replicas of our Control Centre IT estate fed by real-time data to simulate both markets and the operation of the transmission system. Our ambitions were guided by the recommendations of the N (NIC) and the Energy Data Taskforce for effective management of infrastructure using Digital Twin concepts.

Our first use-case for a Digital Twin in Role 1 is the development of a new training simulator to accurately reflect the changing energy landscape. This will be used to train Control Centre engineers on a range of scenarios, including using real-time and recent system scenario data as opposed to the ‘snapshot’ data we use today.

The key benefit is to enable training on new systems, using real-time or recent data, in a safe offline environment. Presently, offline training can only use snapshot data and live training is done via shadowing. The new simulation capability will also allow us to train staff under varying operational scenarios and could allow testing hypotheses about the effectiveness of new balancing processes or services.

Currently, training for Control Centre engineers is delivered on two disparate systems; our ambition is to link these to deliver a true end-to-end training experience. Beyond the RIIO-2 period, we can explore opportunities to enhance our new simulation capability through interactions with the Virtual Energy System (VirtualES) programme, led by our Innovation team. Through the VirtualES programme, we could investigate the benefits of introducing external live data feeds into our training simulator, explore the trade-offs with more layers of data collection, and design new use-cases for our Digital Twin technology (for example, supporting planning at the transmission-distribution interface).

What are our updated RIIO-2 plans?

New simulation capability (D2.3.1)

Upgrades to the current simulators will be minor and only made to extend their life until the new simulation capabilities are ready. The new simulation capabilities are being developed as part of the **D1.2.1 Future of Balancing** and **D1.3.1 Transform Network Control** deliverables.

The new capability will bring together new Network Control and Balancing simulator tools. This is a large undertaking as we will need to coordinate scenarios, processes and data between systems.

Development of the new simulator depends on delivery of the transformational Network Control and Balancing systems. Due to the ongoing Balancing Capability Strategic Review, the costs, milestones, and scope of this deliverable may be different in our final Business Plan.

In the first Business Plan, our external engagement on simulation technology was based on collaboration with DNOs. We are extending that scope to include the wider industry, to help further our understanding of whole system simulation. To date, most of our external engagement has been with TOs and we can see potential in collaborating with aggregators and generators too.

Engagement with DNOs on simulators supports our whole system operation aims and we will discuss using their SCADA tools and technologies in the year preceding BP2.

Additional training options (D2.3.2)

The new balancing and network control tools must be sufficiently mature before we roll out training to our Control Centre engineers. The other RIIO-2 milestones for enhanced e-training delivery not linked to the balancing and network control investments are unchanged.

Dependencies and assumptions

The key dependencies for this sub-activity are on the delivery of sub-activities **A1.2 Enhanced Balancing Capability** and **A1.3 Transform Network Control**.

Key investments for this activity

The deliverable **D2.3.1 New simulation capability** will be delivered by the IT investment **200** Future Training Simulator and Tools. Further information can be found in Annex 4 – Technology investment.

7.1.8.4. (Materially Changed) A2.4 Workforce and change management tools

This sub-activity covers investment in greater automation to produce personalised training packages for career development and enhancement (**D2.4.1**). Our ambition for 2026 is to create a training repository system which will automatically draw training options into personalised training plans.

What are our updated RIIO-2 plans?

Our plans remain as set out in our first RIIO-2 Business Plan. However, there has been a delay to the delivery of **D2.4.1** (currently thought to be 12 months) due to the technical challenges introduced by the complexities of our rota and a change in ownership of the company we are working with. The mobile application we were intending to procure is no longer supported and an alternative is being launched, which will suit our needs better.

This delay only impacts timing of deliverables within our BP1 plan, and we still expect to deliver our milestones by the end of the BP1 period. We remain on track for our BP2 milestones as originally set out.

Key investments for this activity

This sub-activity is aligned to IT investment line **190** Workforce and Change Management Tools. The detail behind this investment can be found in Annex 4 – Technology investment.

7.1.8.5. A2 Stakeholder Feedback

(A2.1) We are committed to being proactive in sharing learnings across the industry on incident analysis and investigation of abnormal events.

During BP1, we have been using the Operational Transparency Forum and other relevant forums, such as the Grid Code Review Panel and the DNO Operability Forum, for stakeholder feedback in this area. An example relates to a major incident around Heysham on 22nd July 2021. We shared details of our investigation with the Operational Transparency Forum at the beginning of August 2021 and at the DNO Operability forum in mid-October.

(A2.2-A2.4) We have not received any stakeholder feedback that have resulted in significant changes to BAU activities.

7.1.8.6. A2 Finances and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A2 - Control Training and Simulation		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	0.0	0.2	1.2	2.3	2.3
	BP1	-	-	1.2	2.3	2.3
	Variance	**0.0**	**0.2**	**-**	**-**	**-**
Opex (£m)	BP2	1.6	1.5	2.2	3.0	3.5
	BP1	2.1	2.6	3.2	3.8	4.2
	Variance	**(0.5)**	**(1.1)**	**(1.0)**	**(0.9)**	**(0.7)**
FTE	BP2	20	17	16	16	16
	BP1	25	26	27	25	24
	Variance	**(5)**	**(9)**	**(11)**	**(9)**	**(9)**

Table 9: RIIO-2 costs and FTE for A2

The forecast for the opex and FTEs needed to support **A2** activities in BP2 has decreased since our first Business Plan submission, whilst capex remains flat. The reduction in FTEs and opex is due to an internal restructure which reallocated resources to the maintenance and upgrades of our legacy Control Centre systems described by deliverable **D1.1.5** in **A1.1 Ongoing activities**. Therefore, these cost decreases are offset by corresponding increases in FTEs and opex for the BP2 period in **A1**.

7.1.8.7. A2 Cost-benefit analysis

The updated CBA for **A2** gives a NPV of £16 million over the RIIO-2 period, and £41 million over 10 years. The NPV over the RIIO-2 period has not changed. Further information can be found in Annex 2 - CBA.

7.1.9. (Materially changed) A3 Restoration

In BP2, we will continue to open restoration services to more technologies and implement the ESRS which came into effect on 19 October 2021. This will allow quicker restoration and compliance with the agreed restoration times of the ESRS.

Our work with stakeholders has identified additional requirements to deliver the changes needed to comply with the agreed restoration time. Stakeholders have identified a need to deliver code changes earlier than expected, to ensure we can meet these accelerated timescales.

We had anticipated a need for additional resource to support ESRS compliance which would be provided by junior engineers/apprentices building their knowledge and experience over the duration of ESRS implementation. However, accelerated timescales requires more experienced and/or knowledgeable engineers in the initial stages of ESRS implementation.

We will work with the relevant DNOs and industry stakeholders to incorporate recommendations from the Distributed ReStart project into our restoration tenders in 2022 for the South-East and Northern regions. This is earlier than anticipated in BP1 and requires a significant increase in stakeholder engagement, resulting in bringing forward an increase in resource from 2023/24 to 2022/23.

Our Business Continuity team provides support for National Control and was resourced based on plans that were not fully tested. During the COVID-19 pandemic, this team also provided support and expertise to our wider business to implement pandemic response plans to minimise disruption to our critical processes and coordinate reporting, as well as sharing best practice with external stakeholders. This has underlined an increasing need for additional resources to support a coordinated approach to emergency planning with both internal and external stakeholders.

We have removed the term ‘Black Start’ from the description of this activity and its deliverables as this term is no longer used by industry.

A3 Sub-activities and deliverables

7.1.9.1. A3.1 Ongoing activities

This sub-activity covers the ongoing activities ensuring we have the right procedures to economically restore the system within acceptable timescales.

During BP1, we have implemented business continuity plans to mitigate risk and ensure appropriate resourcing levels during the COVID-19 pandemic. We have also delivered multiple incident management and disaster recovery exercises annually.

Restoration plans have been reviewed and updated and the Black Start Strategy and Procurement Methodology 2021/22 was published. Finally, the new Assurance Framework document was consulted on in late 2021 and is due to be published in spring 2022.

What are our updated RIIO-2 plans?

Our Business Continuity team ensures that business continuity plans are agreed for the Electricity National Control Centre and teams within National Control. They also develop exercises with internal and external stakeholders to test our incident management and disaster recovery processes. We intend to expand the remit of this team to include oversight and coordination of business continuity plans across our whole business.

We will work with the relevant DNOs and industry stakeholders to incorporate recommendations from the Distributed ReStart project into our Restoration tenders in 2022 for the South-East and Northern regions. This will allow distribution-level connected generation to participate, increasing competition and enabling compliance with the ESRS by 2026.

Our Business Continuity team will share its knowledge and experience across our business to introduce best practice in all departments. This, combined with the increasing need for co-ordinated approaches with both internal and external stakeholders, drives the need for additional headcount to be brought forward to BP1.

This will provide:

- Business continuity expertise and a coordinated approach across our business rather than just for National Control
- Improved alignment and coordination of business continuity and emergency plans with external stakeholders

As a result of the Distributed ReStart recommendations, the South-East tender for restoration services is expected to involve more stakeholder engagement earlier. Additional work is needed to understand the interaction of generation and demand at both transmission and distribution level as well as revision of the restoration approach

This will include working closely with UK Power Networks (UKPN) and prospective restoration service providers connected to their distribution network. We had anticipated a need for additional resource to support implementation of recommendations of Distributed ReStart in 2023/24 but we can incorporate the project’s findings into our restoration tenders in 2022, which will support compliance with the ESRS in these regions by the end of 2026.

7.1.9.2. (Materially changed) A3.2 Restoration standard

This sub-activity covers the investment to implement the ESRS using an evidence-based methodology, including socio-economic impacts and the likelihood of a shut-down event.

The ESRS was implemented on 19 October 2021, and we were directed by the BEIS Secretary of State to maintain an electricity restoration capability and appropriate restoration timeframe. In accordance with Special Condition 2.2 of the ESO Transmission Licence, the timeframes defined in the ESRS are:

- 60% of electricity demand restored within 24 hours in all regions[11]
- 100% of electricity demand restored within five days nationally

We must be fully compliant with this standard by no later than 31 December 2026. By April 2023, we expect to have:

- Concluded industry engagement to develop regulatory solutions.
- Updated the regulatory frameworks to allow TOs, DNOs and restoration service providers to start network upgrades/investments for efficient network restoration in a Partial or Total Network Power Outage.
- Progressed development of the restoration decision support tool incorporating requirements from across the industry to provide us with oversight and control of the restoration process.
- Published the Annual Assurance Framework. The first will be published in spring 2022.
- Incorporated findings from the Distributed ReStart project (described in **A3.3 Innovation project in Restoration**) into the implementation plans.

What are our updated RIIO-2 plans?

Our original timescales, set out in the first delivery schedule, were based on the new Restoration Standard going live in April 2021. On 19 October 2021, BEIS issued the ESRS Direction confirming the new implementation deadline, which our new delivery schedule meets.

At the time of writing our first RIIO-2 Business Plan we also did not have a full understanding of the scope of work needed for the ESRS. Industry stakeholders have identified a need to deliver code changes earlier than expected (by 31 December 2022) to ensure sufficient time to implement the system changes to meet the restoration times set out in the ESRS. We will work closely with industry to produce the technical requirements to ensure compliance and develop the necessary code changes. To achieve this, we will need to bring forward expected headcount increase in 2023/24 to 2022/23

Dependencies and assumptions

Compliance with the timescales set out in the ESRS is dependent on industry stakeholders delivering changes to their systems and processes. Key to this is ensuring appropriate funding is in place for all network operators, through their individual price controls, and for other restoration providers. We have set up working groups to engage key industry stakeholders and a cross-industry steering committee to ensure work is prioritised and timescales met. We are also regularly updating industry forums on progress and risks.

Compliance with the ESRS is dependent on delivery of the Restoration Decision Support Tool (IT investment **510**) which gives real-time visibility of the time expected to restore the network. This project is expected to start as planned in Q1 2022/23. We are working with key internal stakeholders to ensure delivery of this IT project is coordinated with that of other National Control tools.

Key investments for this activity

This sub-activity is aligned to IT investment line **510** Restoration Decision Support Tool. This will support the decision-making of control centre engineers in a national power outage scenario. Further information can be found in the Annex 4 – Technology investment.

[11] The ESO will define the regions in relation to regional electricity demand in the Electricity Restoration Strategy.

7.1.9.3. A3.3 Innovation project in restoration

This sub-activity covers potential investments to implement the findings of the Network Innovation Competition project 'Distributed ReStart', which will conclude by the end of 2022 (**D3.3.1**).

What are our updated RIIO-2 plans?

The scope of **D3.3.2 Implement Distributed ReStart findings** is unchanged, but we can refine milestones for BP2 now the Distributed ReStart project is in its final stages.

Most of the automation and control systems recommendations are for DNOs. However, we may need visibility of the information they hold, and new communications infrastructure is proposed to feed data from the new DNO control systems to the ENCC. Only one DNO is currently linked in this way.

The Distributed ReStart project recommendations are in pre-publication and stakeholders may decide against adopting them. Therefore, we need to retain flexibility in our plans and we will modify the milestones and IT investment for this deliverable as necessary to meet the needs of stakeholders.

Key investments for this activity

If the ESO adopts recommendations of the Distributed ReStart project, any associated IT investments will be made via **460** Restoration. The detail behind this investment can be found in Annex 4 – Technology investment.

7.1.9.4. A3 Stakeholder feedback

(A3.1-3) We have undertaken significant engagement in the last six months regarding implementing the ESRS. This includes hosting several webinars, formation of new industry working groups and establishment of a Coordination Committee and a Steering Committee. Feedback has fed into our development approach for ESRS.

We also consulted on several areas of ESRS implementation, including how codes and/or licence obligations will need to be changed, suggestions for how industry could demonstrate its capability to meet the ESRS and how we can continue to deliver a secure and resilient communication infrastructure across the industry.

There were seven responses from stakeholder groups, which are being fed through to the relevant working group meetings.

Further details of the consultation feedback can be found in Annex 3 – Stakeholder engagement.

7.1.9.5. A3 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
	A3 - Restoration	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	2.3	7.7	8.1	6.3
	BP1	0.9	2.3	7.7	8.1	6.3
	Variance	**(0.9)**	**0.0**	**-**	**-**	**-**
Opex (£m)	BP2	0.5	1.3	2.2	3.1	3.6
	BP1	0.8	1.4	2.3	3.3	4.0
	Variance	**(0.2)**	**(0.1)**	**(0.1)**	**(0.3)**	**(0.4)**
FTE	BP2	6	19	18	18	18
	BP1	9	14	19	19	18
	Variance	**(3)**	**5**	**(1)**	**(1)**	**1**

Table 10: RIIO-2 costs and FTE for A3

The forecast for the opex and FTEs needed to support **A3** activities in BP2 remains broadly flat. We have brought forward resource increases in FY23 to meet the revised scope of the Electricity System Restoration

Standard. This will enable us to deliver code changes earlier than expected and to implement the recommendations of the Distributed ReStart project in 2022 restoration tenders.

7.1.9.6. A3 Cost-benefit analysis

The updated CBA for **A3** gives an NPV of £2 million over RIIO-2 and £25 million over 10 years. We see an increase of £10m in total NPV compared with our first Business Plan. This is driven by the increase in our cost of carbon assumption. Further information can be found in Annex 2 - CBA.

7.1.10. (New) A18 Market monitoring

This is a new activity for our RIIO-2 Business Plan, created to fulfil a new ESO licence obligation.

In April 2021, Ofgem introduced a new Licence obligation for us to monitor activity in Balancing Services markets. This results from the EU Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), under which we are a Person Professionally Arranging Transactions (PPAT).

We will monitor Balancing Services markets for potential breaches of the Grid Code, investigating where necessary and raising concerns to Ofgem where appropriate. We must also comply with our obligations as a PPAT. This will prevent market manipulation and minimise energy prices for consumers.

A18 sub-activites and deliverables

7.1.10.1. (New) A18.1 Ongoing activities

What are our updated RIIO-2 plans?

In BP1, we have set up the Market Monitoring team to focus on developing tools and processes to fulfil our obligation. By the end of BP1 we expect to be able to monitor all product groups, including Ancillary Services and bi-lateral and interconnector trades. This will be supported by governance processes and training to ensure we have the expertise to carry out these obligations.

The continuous deliverables of the Market Monitoring team in BP2 are:

- **D18.1.1 Daily analysis of Market activity and transaction data** – a process for analysing data in a timely manner, to identify any suspicious behaviour both internally and externally
- **D18.1.2 Detection of suspicious behaviour and submission of Suspicious Transaction Report (STR) to Ofgem** – forming evidence-based cases where suspicious activity is detected and submitting these to Ofgem via an STR in a timely manner
- **D18.1.3 Undertake independent review of our Market Monitoring compliance activities against our PPAT and licence obligations alongside emerging market services** – this includes a review of the original risk assessment and additional risk assessments of new market products and services. The review is planned to begin in April 2023. We have not included a cost forecast in this draft submission, but we will aim to provide one in the final BP2 submission.

There are also several areas where we could expand our Market Monitoring activities. Further investments will be subject to cost-benefit analyses and funded via the pass-through mechanism if they will create value for consumers. One area of expansion is in future tool development. As the market continues to evolve, we will need to develop tools to safeguard the consumer against rising costs through manipulative behaviours.

Dependencies and assumptions

Our BP2 plans will adapt and flex as new legal requirements arise, and to address evolving market behaviours.

7.1.10.2. A18 Stakeholder feedback

(A18.1) We have carried out initial engagement with stakeholders via the Operational Transparency Forum. Attendees wanted to know more about this new role, and our mechanisms for reporting to Ofgem.

In December 2021, we held an open workshop with market participants to support the setting up of the Market Monitoring Team. We spoke with stakeholders about how they would submit data. We also described our processes and answered concerns. Stakeholders told us they support the creation of this function and felt it was appropriate given our position in the market.

7.1.10.3. A18 Finances and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A18 - Market Monitoring		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	-	0.7	0.7	0.7	0.7
	BP1	-	-	-	-	-
	Variance	**-**	**0.7**	**0.7**	**0.7**	**0.7**
FTE	BP2	-	7	7	7	7
	BP1	-	-	-	-	-
	Variance	**-**	**7**	**7**	**7**	**7**

Table 11: RIIO-2 costs and FTE for A18

This new activity requires 7 FTE and £0.7m opex to deliver the new market monitoring deliverables, which are already in progress today.

7.2. Role 2 Market development and transactions

To facilitate the decarbonisation of the electricity system by 2035, we are transforming markets to be smart and sustainable. Our Role 2 activities focus on making markets more efficient and accessible to all participants, digitalising industry codes, and transforming charging frameworks. We are also adding two new deliverables - net zero market reform and understanding our role in Europe. These will help achieve security of supply and operability in a net zero world, while keeping costs as low as possible.

7.2.1. Key drivers of change in Role 2

There are several factors that have resulted in changes to our Role 2 plans for BP2:

- **An accelerated drive to net zero** - The generation mix continues to rapidly evolve, accelerating towards zero carbon operation by 2035. As the types of generation and demand on the system change, we have differing operability requirements, which necessitate an overhaul of the services that we procure. With new technologies we can create markets that deliver the efficient investment and efficient dispatch needed and, importantly, do so while creating value for money for consumers. We also coordinate on a whole electricity system basis optimising the use of assets no matter where they are connected to the network.
- **Post Brexit relationship** - We will continue to shape our post Brexit relationship with Europe through the TCA, ensuring seamless transfers of electricity across borders.
- **Responding to regulatory and technology changes** - The energy industry is governed by multiple codes and regulations. These will need to evolve to keep pace with technological change, allowing access for all potential market participants. We need to make sure that the right investment signals are made available to the market, either through the Capacity Market (CM) and Contracts for Difference (CfD) auctions or targeted changes to charging methodologies or other codes. In addition, we are mindful of the need to respond to the conclusions of Ofgem's and BEIS's work on Energy Code Reform and the changes this will bring to how market participants engage with us and our frameworks.

  Over the last year, we have responded to 69% more consultations than the previous year and facilitated a 22% increase in the volume of code modifications, as the pace of change quickens.

Our BP2 plans reflect the increased operational complexity in managing vital processes on behalf of the industry in a cost-efficient way. For example, during the first year of BP1, with the introduction of day ahead procurement, we have moved from running three Short Term Operating Reserve (STOR) tender rounds a year, to running them 365 days a year. While this adds greater complexity, it allows us to provide more commercial opportunities to market participants and optimise our procurement strategies for the benefit of consumers.

7.2.2. Five-year strategy

The five-year strategy for Role 2 in our original five-year RIIO-2 Business Plan remains broadly unchanged and continues to support our wider mission and ambitions. We will enable the transition to net zero by:

- Developing markets which enable zero carbon operability from 2025 - which remove barriers to entry and promote participation from a wide range of technologies, such as demand side flexibility and renewable generation. Stakeholder engagement and innovation (including developing the world's first stability market) are key to this
- Engaging with our stakeholders to deliver industry code and charging reform, removing barriers to entry and charging distortions which may result in inefficiencies. We are improving our Code Administration services to industry and will continue to listen to stakeholder feedback to drive continuous improvement.

What does this mean for BP2?

We've already made good progress on our code change processes in BP1. However, we need to flex our plans in line with our changing external environment and continue to deliver value while unlocking a net zero future.

Updates to our existing activities

We have updated our activities within BP2 where necessary:

A4: Build the future balancing service markets – we aim to embed and continuously improve the markets we delivered in BP1 and drive further significant market reform in BP2 by:

- Delivering a new frequency management strategy to identify future system needs out to 2030.
- Overcoming barriers to flexibility markets via greater data transparency and innovative design.
- Delivering an integrated day-ahead response and reserve market and continued development of the single market platform (SMP).
- Responding to the growth of flexibility markets by embedding processes and systems to coordinate DER services. We will make sure ESO markets are interoperable with DNO markets and that they facilitate access well for smaller providers.
- Reforming each of our market categories and driving new reforms.

A5: Transform access to the capacity market and contracts for difference (CfD)

- Supporting the development of policy and rules for the CM and enable the transition to annual CfD auctions, helping deliver 50 gigawatts (GW) of offshore wind by 2030.
- Exploring options for the capacity mix to deliver adequacy through the 2030s. This will support policy development and longer-term decision-making needed to meet net zero.

A6: Develop code and charging arrangements fit for the future

- Modifying industry codes to support major net zero programmes e.g. offshore coordination, Early Competition, system restoration and stability market participation.
- Evolving charging and billing processes to meet the needs of our customers. This includes transformation of codes and charging systems to allow for half hourly charging.
- Leading charging reform through a Transmission Network Use of System (TNUoS) Task Force, working collaboratively with the industry to define future changes to the methodology that will drive consumer value through more efficient utilisation of and investment in the network.
- Working with stakeholders to continue removing barriers to entry and simplifying code governance – increasing market participation.
- Digitalising the Grid Code, to make interaction easier for all parties.
- Building on our capability for Balancing Services Use of System (BSUoS) forecasting and deliver fixed BSUoS tariffs – providing certainty of costs to the industry.
- Recommending the best structure for whole electricity system frameworks so Great Britain can reach its net zero goals.

Additional activities in BP2

We have included two additional activities in our submission. We have already begun shaping future market reform that will be integral to unlocking a net zero future. Also, now that we have greater visibility of what a post-Brexit world looks like, we will redefine our relationship with Europe to deliver value for the end consumer.

A20: Deliver Net Zero Market Reform

- Work in collaboration with Ofgem/BEIS and industry stakeholders to deliver net zero market reform. This includes detailed recommendations for market options and working with the new Markets Advisory Council (MAC) to set the strategic direction for reform.

A21: Define and build our new role in Europe

- Plan for the vital role of interconnectors in a flexible and secure future electricity system. This includes a cross-border strategy for interconnectors which will focus on operability, adequacy, system planning, flexibility and balancing.
- Meet the obligations of the UK- EU TCA to continue operating an efficient exchange of energy with Europe.
- Build on our relationships with EU stakeholders to maintain our level of influence in Europe.

The diagram below illustrates the level of change, within Role 2 activities, in comparison to our original Business Plan submission.

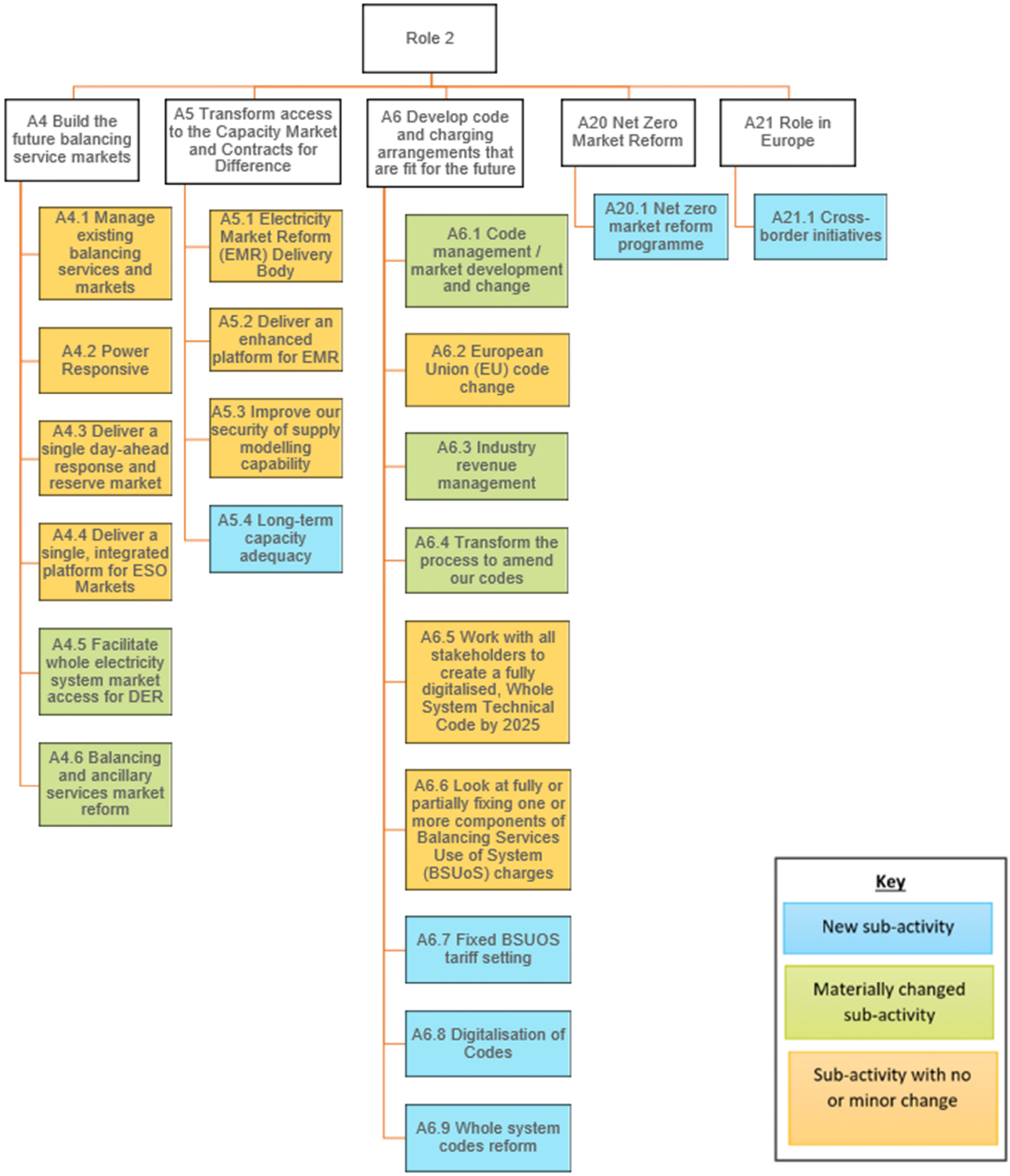

Figure 10: Role 2 activity level of change

7.2.3. Role 2 Costs Overview

During BP1, we used the cost pass through regulatory model to increase headcount in areas where we can drive consumer value. Our increasing ambition will require us to continue to invest in skills and resources and, by the end of the BP2 period, we will have increased headcount by 50 (168 up to 217 at the start of BP2) compared to the original RIIO-2 numbers.

Our delivery plan for the remainder of the RIIO-2 period requires increased investment. However, we continue to absorb extra operational cost where possible. For example, our IT investments are allowing automation of processes, helping minimise FTE requirements. In other areas we are already delivering more with the same headcount and continue to absorb activities such as managing a doubling of CfD auctions.

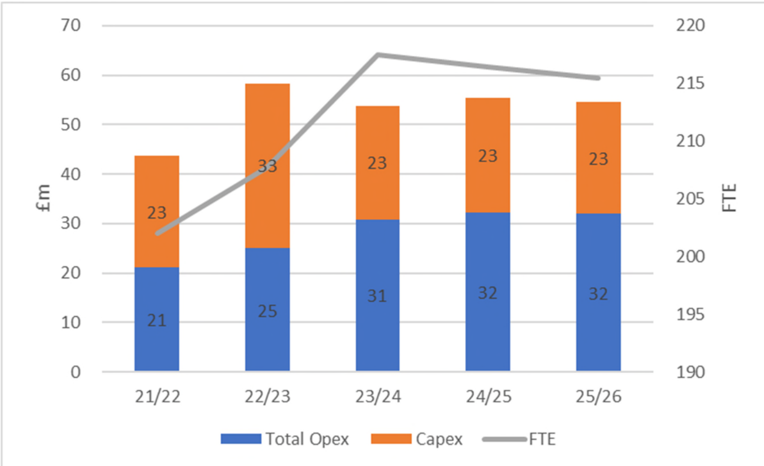

Figure 11: Graph of Role 2 RIIO-2 cost and FTE

		Five-Year strategy				
		Forecast		BP2		BP3
	Role 2	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	22.7	33.2	22.9	23.2	22.6
	BP1	22.0	14.9	14.2	14.2	15.0
	Variance	**0.7**	**18.2**	**8.7**	**9.0**	**7.6**
Opex (£m)	BP2	21.1	25.1	30.9	32.2	31.9
	BP1	29.2	27.5	29.8	29.5	27.6
	Variance	**(8.1)**	**(2.4)**	**1.1**	**2.7**	**4.3**
FTE	BP2	202	208	217	216	215
	BP1	164	164	168	170	168
	Variance	**38**	**44**	**50**	**47**	**47**

Table 12: Role 2 RIIO-2 cost and FTE

The graph and table above represent the five-year Business Plan comparing the original submission to our updated proposals in 18/19 prices These represent Role 2 costs before support functions and cross cutting activities are overlaid. The forecasts for the opex, capex and FTEs needed to support Role 2 activities in BP2 have increased since our first Business Plan submission.

The majority of these increases have occurred ahead of BP2, as the business has adapted to the scale of regulatory change, exponential growth in market participants and the need to overhaul markets sooner than planned due to the acceleration to net zero.

An additional 50 FTEs in FY24 decreasing to 47 FTEs in FY25, are required compared to BP1. These are to support increased IT investments of £18m and £4m of operational deliverables over the BP2 period. The main drivers of the increase are:

- **A4 Build the future balancing service and wholesale markets** – increase of £12m capex, no change to opex and an increase of 9 FTE (FY25)

- **A5 Transform Access to the Capacity Market and Contracts for Difference**– increase of £5m capex, £2m opex and 19 FTE (FY25)
- **A6 Develop code and charging arrangements that are fit for the future** – no change to capex, increase of £1m opex and 12 FTE (FY25)
- **A20 Net Zero Market Reform** – this is a new activity with an increase of £1m opex (FY25) and the continuation of 6 FTE that were recruited in BP1

More details on the drivers of these cost and headcount increases can be found within the relevant activity descriptions below.

7.2.4. Key capabilities required

In the People, Capability and Culture chapter we discuss the capabilities the ESO needs in order to deliver on our RIIO-2 commitments, and how we will build and enhance them across our workforce. In particular, for Role 2 we need to build capability in the following areas:

- **Customer- and stakeholder-facing capabilities:** ability to provide effective support for new and existing market participants and to engage all stakeholders with the design and implementation of new and improved markets.
- **Innovation:** collaborating with industry and academic innovators, in Great Britain and abroad, to identify, develop and implement radically new market designs and solutions that facilitate access for innovative new technologies to ESO markets, driving costs down for consumers.
- **Economic analysis and modelling:** informing design and predicting impact of new markets, providing insights into future market behaviours as a result of increasing participation and a changing technology mix to support net zero market reform.
- **Data and predictive analytics**: deploying an increasingly wide range of analysis techniques, including ML, to fully utilise granular datasets with enhanced models to provide longer term modelling.

7.2.5. Role Benefits

We have updated the RIIO-2 CBAs for transformational activities in **A4, A5, A6.5** and **A6.6.**

A4 has two analyses: a break-even analysis for **A4.1, A4.2** and **A4.5** and a CBA for **A4.3, A4.4** and **A4.6**. The reason for separation is due to the differing nature of the work, combining the **A4** analyses would not provide the best view of costs and benefits to the consumer.

For the new activities **A6.9, A20** and **A21**, we have included break-even analyses in Annex 2 - CBA.

Activity	Analysis name	NPV BP1 (£m)	NPV BP2 (£m)	Change (£m)
A4	Lead a review of wholesale, balancing and capacity markets	Break-even analysis		
A4	Build the future balancing service markets	67	68	+1
A5	Transform access to the Capacity Market	62	59	-3
A6.4	Transform the process to amend our codes	Break-even analysis		
A6.5 & 6.8	A6.5 Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 & A6.8 Digitalisation of Codes	4	32	+28

A6.6 & 6.7	A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) & A6.7 Fixed BSUoS tariff setting	278	68	-210
A6.9	Whole system codes reform	New break-even analysis		
A20	Net Zero Market Reform	New break-even analysis		
A21	Role in Europe	New break-even analysis		
	Total	**411**	**227**	**-184***

Table 13: Role 2 NPV change

**Totals may appear incorrect due to rounding*

Role 2 delivery plan detail

7.2.6. (Materially changed) A4 Building the future balancing services markets

For Great Britain to achieve a fully decarbonised power system by 2035, it is vital that ESO balancing and ancillary services markets are fit for purpose. This means we need to build on the reforms delivered in BP1 by further improving the functionality of these markets, increasing accessibility for market participants and improving the efficiency of our procurement across services. We also must continue to reform and develop the right portfolio of markets to facilitate a smooth transition to net zero.

A4 sub-activities and deliverables

7.2.6.1. A4.1 Manage balancing services and markets

We will continue to evolve our approach to managing balancing and ancillary service markets during RIIO-2 and will introduce an end-to-end process to ensure procured balancing services deliver system stability at lowest cost to consumers (**D4.1**).

We have reformed our frequency and reserve products and continued to drive greater competition to procure our requirements. Through the development of regional competitive tenders for our restoration requirements, we have reduced the cost of procuring these services by £4.5m per annum, while also increasing the diversity of service providers. We also have large aggregated active units in the BM and have evolved the pre-qualification process to enable market participants to complete large scale applications through BP1. Over the nine months since implementing the recommendations of the FRCR[12], RoCoF costs have been £176m lower than last year, although this is partly offset by an increase in response costs due to the new Dynamic Containment (DC) service.

The BP1 period coincided with increasing system challenges which led to the development of new services and procurement approaches through Pathfinders, to efficiently meet our system security needs.

What are our updated RIIO-2 plans?

We will enhance these new services and procurement approaches to ensure providers receive an engaging experience, and our requirements are met efficiently. New licence obligations have introduced the FRCR that increases our baseline activities to ensure quality delivery.

We will continue to listen to market participants, developing our abilities to optimise across services through our buy order methodologies, backed by clear communication on our system needs. We will continue to work with industry to facilitate competitive markets. To manage this additional workload, including an increased

[12] GSR027 was approved by Ofgem in 2020 introducing a new obligation for the ESO to produce a Frequency Risk and Control Report (FRCR) on at least an annual basis

level and complexity of modelling expertise and the need to run processes on a daily basis, we have increased our overall headcount in BP2.

We will continue to widen access to the BM and make the process quicker and easier to complete.

(New) D4.1.1 Frequency management strategy

FRCR - The implementation of our FRCR proposals is already generating consumer value by decreasing operational costs. The proposed new Frequency Management Strategy increases our modelling capability that underpins the FRCR process and allows greater consumer value by expanding the time horizon the modelling assesses. This will help identify future system needs out to 2030.

This is a critical period because, as the system decarbonises, it drives larger and more numerous loss risks connecting to the network while inertia continues to reduce. Growing the modelling capability of FRCR will be critical to identify a frequency policy to accommodate this. It will also maximise consumer value by assessing the risks that may result in unacceptable frequency conditions and proposing the optimal mitigation controls.

We are proposing a new deliverable to look further ahead than a year. This would be a step change in our frequency strategy and deliver significant savings.

Pathfinders - Role 2 provides project lead activities for the implementation of each Pathfinder project and the units that have secured contracts. This ensures projects are progressed, providing commercial support for each project, through the tender process and through to contract award. We also provide implementation support for each successful project, bringing the contracted units into operation by working with SMEs in our different teams. This includes establishing the end-to-end delivery process, so that the units can be dispatched in real time ready for go-live. Implementation needs coordination with business and IT teams as well as confirmation of changes needed for internal systems. More information about our Pathfinder approach can be found in Activity **A8 - Enable all solution types to compete to meet transmission needs**.

Forecasting - Our five-point plan to manage constraints on the system included the need for clearer forecasts of Balancing Services Use of System (BSUoS) costs. These are a tariff on network users (for example generators and suppliers) to recover the costs we incur balancing the system. The proposals to fix BSUoS from April 2023 also require more accurate forecasting.

We have been publishing more detailed BSUoS cost forecasts in recent years but need a new approach with even greater transparency and insight that would be of even greater value to industry – particularly around costs incurred for managing flows on the network.

To support this, we have expanded our team to develop the complex models required, so we can move from central forecasts to providing a range of constraint costs. Also, the increasing volume of renewables, growing number of interconnectors, and uncertainty brought about by the COVID-19 pandemic, has meant demand forecasting has become increasingly complex, and our forecasting models and capability have evolved to meet these challenges.

Accordingly, we have expanded our team to support with Interconnector forecasting, wind and solar capacity tracking and modelling, and demand forecast modelling. Due to an internal restructure, this increase will sit in Role 1 under **A1 Control Centre Architecture and Systems**.

Dependencies and assumptions

Alongside our frequency strategy, we have successfully delivered other operability strategies such as the implementation of DC, the Accelerated Loss of Mains Change Programme (ALoMCP) and Pathfinder programmes. These are interlinked with our FRCR modelling, as FRCR recommendations release additional value by adjusting our operational frequency policies to cater for the new asset capabilities connecting to the system.

7.2.6.2. A4.2 Power Responsive

Power Responsive will continue to play an important role in developing demand side flexibility and its provision of balancing services. In BP2, we will continue to deliver an annual report every April, building on the work delivered under our continuous deliverable **D4.2.1**. This looks at publishing regular and specific metrics for flexibility markets, including DSO markets, through the Power Responsive Annual Report.

In BP1 we delivered a guide to ESO markets for demand side response (DSR) providers in conjunction with the Major Energy Users Council (MEUC). In 2020 we published a new-look Annual Report with our partners, Everoze, which included greater coverage of DNO markets and insights from industry experts.

The Steering Group has met on a regular basis, with topics ranging from the delivery of net zero and carbon intensity in ESO markets, to upcoming code modifications and proposals for new balancing services. We continued to support innovation projects such as e4futures and the BEIS FleX competition winners.

What are our updated RIIO-2 plans?

We will undertake engagement activities such as surveys and focus groups with the demand side community to identify the outstanding barriers to participation. We will focus particularly on industrial and commercial parties who may have participated in balancing services in the past, to learn and implement from their feedback.

We will also work more closely with Open Networks so the voice of the demand side community is heard in the development of DNO markets, specifically around regional development programmes (RDPs), standardisation of contracts and market arrangements and service stacking.

We will also support access for smaller scale flexibility including EVs and domestic consumers. We will focus on DSR projects, which could include removal of barriers or bringing in new participants.

One of the biggest blockers to DSR entering our markets is that our metering requirements were designed for big power generators, not demand-side flexibility. We want to encourage supplier aggregation in the Balancing Mechanism and have committed to reforming our operational metering requirements to unlock these new forms of flexibility. Using probabilistic analysis and techniques, such as asynchronous polling, we think that suppliers will be able to provide appropriate aggregated real time signals to the ESO and meet regulatory requirements. This will enable suppliers to innovate and bring their customers into the market.

7.2.6.3. A4.3 Deliver a single day-ahead response and reserve market

Enhancing our procurement process for our reformed ancillary services markets is crucial to unlocking maximum value for ourselves and the end consumer. In BP1 we introduced two platforms to improve the procurement experience of parties participating in our markets, moving these closer to real time by procuring STOR on the cloud-based Salesforce software and DC on the EPEX platform. Procuring these services much closer to real time, and operating supporting business activities at day-ahead via auctions, has provided greater flexibility for participants and allowed us to be more dynamic in our procurement strategies. We have gained valuable information from this to support activities for both the procurement of our new response and reserve services and the enduring auction tender work.

We started developing the Single Markets Platform (SMP) (refer to **A4.4** for greater detail) in the first year of BP1. The first release went live during Q4 2021/22 in support of the onboarding process for day-ahead Frequency Response Markets, DC, Dynamic Regulation (DR) and Dynamic Moderation (DM). Following its launch, we developed the DC service, launching DC high frequency and permitting stacking with the Balancing Market (BM). The other two new services will see both low and high frequency products and stacking with the BM available to providers from day one.

We are also running a procurement event to select a partner for our Enduring Auction Capability (EAC). Whilst work to implement EAC is being taken forward, we will continue to procure our new services via day ahead auctions and make improvements to continue to realise the benefits of closer to real time procurement.

What are our updated RIIO-2 plans?

D4.3.3 New reserve products development and introduction of a new suite of products to provide reserve to the Control Room.

The design and delivery of new services is of significant interest to customers as revenue is impacted by changes to services. As we move past implementation, our focus will move onto improving and refining services. Engaging with stakeholders on future changes will ensure we continue to improve them.

Implementing a structure around our 'day 2'[13] activities will allow issues to be identified, provide visibility on progression and set out a timetable on delivery. We will have delivered provisional service designs for quick

[13] Day 2 refers to the features of a new service that are not included when this is launched but will be added to the service in the next planned update/release.

and slow reserve services by the end of BP1. In BP2, we will deliver these new services, integrated on SMP EAP with a prioritised product backlog for future development.

D4.3.4 Delivering an efficient frequency market

We are exploring solutions to deliver an efficient frequency market. Part of this is creating a longer-term procurement strategy which spans response and reserve, looking at how the products interact operationally and commercially, and with the wider market. For example, in BP2 we will be looking at the order in which we buy services through auction. Deciphering how these services interact, and how the market rules/algorithms ensure maximum co-optimisation will be a key output.

D4.3.5 Auction Capability

The auction project will move into the delivery stage in BP2. This will be a phased approach and see the transition of new services from BP1 onto the platform. As we move all these new markets, we will be in a position to start introducing features such as procuring by settlement period, and thus the capability to unlock additional value.

These benefits will include improved user experience, enhanced automation and system integration with the SMP and allow us to procure services more flexibly, either through enhanced granularity, requirement setting or a streamlined route to market for future designed services.

Whilst the ESO also runs auctions in EMR (CfD/CM), we consider these to be sufficiently different and stand-alone to not include them in our IT development of EAC.

(New) D4.3.6 - Future developments to frequency response services

After successfully delivering the new suite of frequency response products (DC, DM and DR) and procuring frequency response in day-ahead timescales in BP1, BP2 will focus on improving the user experience and maximising participation. We will create a product backlog with suggestions for new features and changes to parameters of the product or service design proposal. These changes will be impact-assessed and the list of developments, and the order in which they will be delivered, will be shared with our stakeholders.

We will implement a standardised consultation process with engagement throughout the year. Feedback on changes will be fed into the product backlog. Also, IT upgrades will improve visibility and control of response volume in the Control Room (see **A1.4 Control Centre architecture**, **A4.4 Single Market Platform** and **D4.3.5 Auction Capability**) and streamline processes from prequalification through to procurement. This will reduce the volume of manual work for stakeholders for auction and data transfer and improve the experience for response providers.

Dependencies and assumptions

Key dependencies include RDPs, market participation and volume, primacy[14] and facilitating distributed flexibility.

Key investments for this activity

This sub-activity is aligned to IT investment line **400** Single Markets Platform and **420** Auction Capability. The detail behind these investments can be found in Annex 4 – Technology investment.

7.2.6.4. A4.4 Deliver a single, integrated platform for ESO markets

The digital SMP will be an important enabler of decarbonisation. It will provide frictionless access to our markets and is part of a wider strategy to digitise the way we work (further details can be found in Annex 4 – Technology investment “**400** Single Markets Platform” investment line) and make it easier to do business with us. The SMP will also align and interact with wider DSO/flexibility markets, and allow us to enact change more quickly, as well as adapt to new markets (**D4.4.2**).

During February 2022, the SMP team launched the foundational functionality to facilitate the onboarding of day ahead frequency response products (DC, DR and DM). This followed a strategic definition project that set the ambitions for the platform before moving into the initial design and development of the foundational release.

[14] Primacy rules are intended to provide transparent tools for the avoidance, and where applicable, resolution of conflicts to maintain system and network integrity as well as avoiding unnecessary system costs and carbon impacts.

We engaged with interested participants through our 'Show and Listen' industry working group events to ensure we were always focused on delivering the most value from the platform. This approach will continue as we further develop the SMP in line with the agile product development model, to enhance user functionality, integrate with upstream and downstream systems, and apply to further ancillary services.

What are our updated RIIO-2 plans?

D4.4.1 A platform enabling market players to participate in balancing markets.

As we move through RIIO-2, we will develop the SMP in the following areas:

- Extend SMP interaction downstream of the onboarding process. For ancillary services this includes interaction with the auction capability, performance reporting and settlement data.
- Integrate with the upstream Connections Platform (investment "**380** Connections Platform") to promote the seamless transition of a user from connections into ancillary services. The data will be available in the SMP system once an asset is connected, visible and active on SMP for the user to assign it to a unit and specific service.
- Deliver enhanced functionality to improve the user experience.
- Integrate the design system being developed within the '**250** Digital Engagement Platform' project to all our systems.
- Apply SMP to cover other ancillary services.
- Support the ongoing development and evolution of DSO/Flexibility markets (**D4.4.2**).
- Integrate more closely with the EMR Portal when and where possible. However, this will rely on standardisation of the CM and CfD data structures with other market services and products.

This work will continue throughout BP2 in line with the move to a 'product model', where the SMP will be developed with regular releases of additional functionality. This allows us flexibility and the freedom to modify our approach in response to any change in the background or feedback from the industry.

We will continue to engage with our users and stakeholders to identify development priorities. This may result in a different delivery timetable than initially proposed.

D4.4.2 Common standards, including interoperable systems, a common data model and shared minimum specifications between ESO and other flexibility platforms as well as at the distribution level.

While the current focus is on optimising the foundational functionality across our markets, greater interaction with wider DSO markets through RIIO-2 will require a convergence in distribution and transmission market requirements. Industry platforms will integrate more closely to ensure visibility across ESO and DSO/flexibility markets to facilitate real time transparency of what assets are participating in which markets.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **400** Single Markets Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.2.6.5. (Materially Changed and name changed) A4.5 Facilitate whole electricity system market access for distributed energy resources

This activity's name has been changed from "Alignment of ESO-DSO flexibility markets". Due to the direct interdependencies of facilitating distributed flexibility activities, detailed deliverables for this sub-activity are found in the Cross-role section of Role 3 Facilitating distributed flexibility section. This section includes a resource increase to support the DSO flexibility markets referenced here. More Information can be found in **A4 Financials and Headcount**.

7.2.6.6. (Materially changed) A4.6 - Balancing and ancillary services market reform

As the electricity system transitions from one dominated by a few large, synchronous generators to one characterised by millions of distributed inverter-connected assets, the fundamental balancing and operability requirements of the system are dramatically changing. Our markets must evolve to meet those requirements.

We launched our first annual Markets Roadmap in March 2020, and our second edition was published in March 2022. Its aim is to provide a view of how and why we are reforming our balancing code and ancillary services markets. It outlines our market design principles and any potential future reforms to ensure they are delivering the optimal outcome for consumers.

The Markets Roadmap also sets out the drivers for change – not only operability requirements set out in our Operability Strategy Report within Role 1, but by the rapidly-changing technologies and business models of providers, as well as the evolving wider market context. For each market category, the roadmap sets out our medium-term (out to 2030) strategy.

What are our updated RIIO-2 plans?

D4.6.1 Development of competitive approaches to procurement of stability.

Traditionally, synchronous generation has provided stability requirements (inertia, short circuit level and dynamic voltage support) as a natural by-product. As more non-synchronous generation displaces synchronous plant, the ESO needs to replace that lost stability, and manage short-term fluctuations in stability due to dynamic changes in the generation and demand mix.

The Stability Pathfinder approach was launched in 2019 as a competitive way to procure shortfalls in long-term stability requirements. In the BP2 period, we plan to continue with a long-term procurement approach, establishing requirements and launching procurement events with long enough lead times to deliver strong investment signals for the development of new capacity. However, the ad-hoc nature of current Pathfinders may not be delivering the most efficient investment signals.

The ESO relies on the dispatch of synchronous generation in the Balancing Mechanism (BM) to manage short-term fluctuations in stability. However, redispatch in the BM could be seen as inefficient in terms of cost (paying to turn up synchronous plant, as well as potentially paying to turn down non-synchronous plant) and carbon (turning up synchronous plant invariably burns fossil fuel). A dedicated short-term market for stability could therefore result in significant cost and carbon savings.

The current innovation project (Stability Market Design) is exploring an enduring design of stability procurement, exploring different “straw man” designs and recommending the preferred option. Phase 1 of the innovation project found that a combination of short- and long-term procurement is the best option, with the potential of delivering benefits of up to £50m each year by 2030. However, more detailed analysis needs to be done with industry stakeholders to understand the preferred design and implementation of this potential new approach.

We will continue this development work over the second year of BP1. Reform activities in BP2 will depend on whether we can demonstrate benefits for consumers for this potential new design.

D4.6.2 Development of competitive approaches to procurement of reactive power.

To maintain a secure and operable system, the need for reactive power support continues to grow as the energy system decarbonises, leading to increasing reactive power requirements and decreasing sources of reactive power. Reactive power requirements are highly locational, meaning reactive power providers need to be electrically/geographically close to where the need exists.

The Voltage Pathfinder approach was launched in 2019 as a competitive way to procure shortfalls in long-term reactive power requirements. In the BP2 period, we plan to continue with long-term procurement approach, establishing requirements and launching procurement events with long enough lead times to deliver strong investment signals for development of new capacity as well as keeping existing capacity operational when needed.

We access reactive power through four routes which include Transmission Owner (TO) network assets, Obligatory Reactive Power Service (ORPS) providers, voltage contracts and contracted Pathfinder projects. The primary route to market for large generators is through ORPS which requires units to be running to provide this service. Many of these larger power stations have closed and existing ones are running less frequently, meaning that the cost of redispatch in the BM could be seen as inefficient in terms of cost. A dedicated short-term market for reactive power could result in significant cost and carbon savings by providing a route from additional providers to participate, thereby bringing competition and greater innovation to the market. Furthermore, the ad-hoc nature of Pathfinders may not be delivering the most efficient investment signals.

The current innovation project (Reactive Market Design) is exploring an enduring design of reactive power procurement. Phase 1 of the innovation project found that a combination of short- and long-term procurement is the best option (similar to findings in the Stability Market Design project), with the potential of delivering benefits of up to ~£65m each year by 2025. However, more detailed analysis needs to be done with industry stakeholders to understand the details of the market design and implementation of this potential new approach.

We will continue this development work over the second year of BP1. Reform activities in BP2 will depend on whether we can demonstrate benefits for consumers for this potential new design.

(New) D4.6.3 Interconnectors in Dynamic Containment reform

We will create services that meet our changing system needs, and in which all technologies can compete on a level playing field. The Smart Systems and Flexibility Plan[15] seeks interconnector participation in ancillary and balancing services to facilitate efficient and flexible access to cross-border markets. During BP1, we hosted information sharing sessions with interconnector parties to identify the barriers to cross border participation in DC. The next step is to launch an innovation project on how current and future interconnectors can meet the technical specification for interconnector participation in DC.

In BP2 we will work with the industry to implement the changes needed to facilitate participation through a trial interconnector participation in DC.

(New) D4.6.4 Local Constraints Market reform

Ahead of longer-term considerations of Regional Development Programme (RDP) functionality across Scotland, there is a growing need for a solution DER to manage rising constraint costs. The Anglo-Scottish (B6) boundary currently has the highest constraints of any boundary across Great Britain, and these are set to increase.

This work will establish a local constraint management service (Local Constraint Market, or LCM) to specifically target B6 constraint costs. The LCM will offer a day-ahead competitive alternative to Balancing Mechanism actions at the Anglo-Scottish boundary via generation turndown/demand turn-up. It mirrors the simple construct of the ODFM service (recognising its manual processes). The LCM will also investigate a light touch system to facilitate an accelerated DER market for targeted constraint management in Scotland, potentially using third-party platform software.

Our approach is to deliver a day-ahead constraint management service through a platform from a vendor with significant experience and expertise of delivering software-as-a-service (SaaS) solutions to network operators. During BP1 we will award the contract and have the platform operational. This will be in operation throughout BP2, and then closed once the enduring RDP has been implemented.

7.2.6.7. A4 Stakeholder Feedback

(A4.1-A4.2) We have not received any feedback in these areas that have resulted in significant changes to BAU activities.

(D4.3.3) Technical workshops were held which focused on reserve products. Their aim was to co-create with industry design elements for the new reserve products. We set out our ‘red lines’ for service criteria and invited industry proposals. Stakeholders agreed with some of our proposals and asked us to consider the impact on technology types of particular criteria (e.g., ramping limits and service duration). We will build on this as we implement new reserve products.

(D4.3.6) Webinars were held which focused on co-creating product design for frequency response. We shared our proposed design and gathered feedback. Stakeholders had concerns around bundling procurement of the services and Grid Supply Point (GSP) vs. GSP group aggregation for services. We now plan to launch with an

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[15] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003778/smart-systems-and-flexibility-plan-2021.pdf#page=37&zoom=100,57,94

unbundled service at GSP group level. Stakeholders also requested the ability to stack the services and optimise procurement. This will be considered as part of the EAC.[16]

(D4.6.1) - Since the Stability Market Design innovation project commenced in September 2021, we have engaged with industry. Gathering feedback from stakeholders has been critical to shape the case for change and inform decisions on key market design choices. Some of the stakeholder feedback, and how we have used it, is described below:

- Stakeholders expressed a preference for a hybrid market timeframe (long- and short-term). This aligns with our recommendation of developing a combination of both long- and short-term markets for stability.
- Stakeholders highlighted some barriers in the current Pathfinder approach, such as favouring investment in new-build assets over existing providers. We have reviewed the eligibility criteria and our proposed market approach has different eligibility criteria across timeframes. In particular, the new proposed short-term market could be more attractive for existing providers (global eligibility).
- Prospective providers highlighted unpredictable costs (opportunity costs, variable costs and maintenance costs) leading to long-term price risk. In our recommendation, the short-term market would be accessible for those unable to manage long term risk. We also recommend a variable compensation mechanism for long term contracts (e.g., through utilisation payments).

(D4.6.2) Since the reactive power market project started in October 2021, we have received feedback from providers, particularly on the key market design element. Some of this is described below:

- Both long-term and short-term markets are needed as is a balance between short-term and long-term procurement processes. We propose a hybrid short-term and long-term approach.
- We should hedge a proportion of our reactive requirement sufficiently ahead of delivery. In the current design, we are aiming to send clearer requirement signals at different procurement stages, such as four years ahead, year ahead, and day ahead.
- T-3 lead time is not long enough. We confirmed that we are now proposing T-4.

(A4.4) Throughout the latest phases of the SMP development, we have engaged with participants through our 2/3 weekly 'Show and Listen' industry working group events to facilitate genuine co-creation and focus on delivering optimal value. Based on feedback, we have changed the platform design.

We have also taken on board feedback on our plans for SMP at the TAC on specific points relating to our digital design principles.

(A4.5) See section Role 3 Cross-Role Activities – Facilitating distributed flexibility, for stakeholder feedback on DSO related activities.

(A4.6) In June 2021, we approached stakeholders for feedback on our Markets Roadmap 2025. A summary of some of the feedback and our actions is described below:

- Stakeholders want to see more data for service providers/participants, market value and market interactions. We will have a larger focus across all areas, drawing out benefits to providers, more detailed analysis around market insights and what our reforms may mean for wider market interactions.
- Stakeholders want us to provide clear market value signals and volume of products. We have published this data as it currently is in 2022 and set out how this will evolve. We will use the outputs from the Operability Strategy Report (OSR) in terms of volumes in each product market and the growth and change in providers to estimate the impact on market prices for those products where possible.

See Annex 3 – Stakeholder engagement for more in-depth details of stakeholder feedback across **A4**.

[16] https://www.nationalgrideso.com/document/198266/download

7.2.6.8. A4 Financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A4 - Build the future balancing service and wholesale markets		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	9.2	12.0	8.1	7.5	7.4
	BP1	5.2	3.3	2.4	1.4	1.5
	Variance	**4.0**	**8.7**	**5.7**	**6.1**	**5.9**
Opex (£m)	BP2	5.2	6.9	10.4	10.5	10.4
	BP1	11.8	9.7	11.1	10.3	8.4
	Variance	**(6.6)**	**(2.8)**	**(0.7)**	**0.2**	**2.0**
FTE	BP2	55	56	66	66	66
	BP1	56	54	56	57	56
	Variance	**(1)**	**2**	**10**	**9**	**10**

Table 14: RIIO-2 cost and FTE for A4

The forecasts for the opex, capex and FTEs needed to support **A4** activities in BP2 have increased since our first Business Plan submission. The main drivers of the increase over the two years are:

- £12m increase to capex predominantly driven by increases in IT investment **400** Single Markets Platform
- £0.5m opex reduction and 9 FTEs increase in FY25, to support a number of areas across the activity including:
- Six FTEs to support DSO flexibility markets. More information can be found in our Facilitating distributed flexibility section.
- Three FTEs to support Pathfinders and enabling our frequency management strategy to look further ahead and to expand the time horizon that the modelling considers.

This FTE increase has been offset by a decrease in consultancy support.

7.2.6.9. A4 Cost-Benefit Analysis

Activity **A4** has two analyses in Annex 2 - CBA. Sub-activities **A4.1, A4.2** and **A4.5** are subject to a break-even analysis and the other **A4** sub-activities are considered in the **A4** CBA. The NPV of these activities is £68 million over the RIIO-2 period and £159 million over ten years. Sensitivity analysis suggests an NPV range of £8 million to £112 million over the RIIO-2 period depending on delivery factors. The lowest NPV estimate is based on a one-year delay to delivery. Further information can be found in the Annex 2 - CBA.

7.2.7. (Materially changed) A5 Transform access to the Capacity Market and Contracts for Difference

As the Electricity Market Reform (EMR) Delivery Body, we manage the end-to-end process for all Capacity Market (CM) participants, supporting them through prequalification and multiple annual auctions, to the issuing and management of capacity agreements. Through our security of supply modelling, we advise the Secretary of State on the volume of capacity to be procured. We are also responsible for running the qualification and allocation processes for CfD, which is the Government’s main mechanism for supporting low-carbon electricity generation.

We use our expertise and the insights we gain from our customers and stakeholders to advise BEIS on their strategic reviews of the Capacity Market and CfD regimes, to ensure capacity adequacy and to drive the transition to net zero. Working with BEIS, Ofgem and other EMR delivery partners, we shape the policy and rules for the CM and CfD mechanisms to make processes efficient and effective. During BP2, we will continue to improve our processes and systems to enhance the customer experience as well as co-create guidance and effective support.

We will also continue to improve security of supply through use of enhanced modelling and more granular data sets and explore options for the capacity mix that could deliver capacity adequacy through the 2030s to support policy development and longer-term decision-making to meet net zero.

A5 sub-activities and deliverables

7.2.7.1. A5.1 - Electricity Market Reform (EMR) Delivery Body

During RIIO-1 we were the Government's EMR Delivery Body, including core EMR activities for the Capacity Market and the qualification and allocation processes for CfDs. We proposed improvements to our systems, processes and guidance to enhance our service to customers. As part of a funding reopener for EMR in 2019, we had proposed replacing the EMR portal by the end of the RIIO-1 period. The new portal was to allow for the automation of operational processes prior to the start of RIIO-2. Our plans assumed a period of minimal policy and rule changes so we could replace the portal during RIIO-1.

However, the replacement was moved into RIIO-2 as we were required to deliver a large volume of mandatory policy and rule changes, as well as customer and process improvements towards the end of RIIO-1.

We delivered the annual Capacity Market pre-qualification and auctions which secured capacity one and four years ahead of the relevant delivery year and supported customers in discharging their obligations under Capacity Market agreements. We also delivered the fourth allocation round for CfDs, which saw the largest target volume of new low-carbon generation since the start of EMR. As part of the above, we implemented a significant number of policy and rule amendments, including a series of commitments by the UK Government as part of the renewed State Aid approval of the Capacity Market. Several rule and process changes requested by Ofgem have been implemented, as well as improvements to our portal and operational processes in response to customer feedback[17].

We have also worked closely with BEIS, Ofgem and other EMR delivery partners and provided advice on the development of Capacity Market and CfD mechanisms. This included the impacts of proposed policy and rule changes, prioritising the rule change backlog and delivering rule changes into our systems and processes.

What are our updated RIIO-2 plans?

As a result, the efficiencies and headcount reductions anticipated in our first RIIO-2 Business Plan have not yet materialised. For the first two years of RIIO-2, the EMR Delivery Body has maintained a larger team plus additional short-term resource to cover assessment of applications during peak periods. This greater level of resource has been required to cover the revised implementation date of the new EMR portal in RIIO-2 and the implementation of regulatory change across Capacity Market and CfD regimes.

The EMR team have responded to feedback from our customers, the Performance Panel and Ofgem and dedicated resource to improve customer service. We have prioritised customer journey and speed of change implementation ahead of any internal opex efficiency.

We will continue to play a critical role in developing policy and rules for the Capacity Market and CfDs. We expect to deliver key inputs into Ofgem's new Capacity Market Advisory Group (CMAG) to be established later in 2022. We will develop rule change proposals and prepare impact assessments to ensure changes are transparent, effective and efficient for our customers. Alongside supporting BEIS's Ten Year Review of the Capacity Market, we will play a key role in delivering the Government's ambition regarding CfDs. Following BEIS's announcement in February 2022, we now expect to run CfD auctions annually and support an even broader range of technologies and customers to enter the auctions.

D5.1 Continuation of EMR delivery body obligations

We will continue to deliver Capacity Market auctions in annual cycles and support customers in achieving agreement milestones. We are working closely with BEIS to move to annual CfD auctions and will continue to support participants in the pre-qualification process to maximise the number of projects that enter the Capacity Market and CfD auctions. We will continue to enhance the agreement management and delivery assurance processes, in terms of operational performance as well as policy and rule development. Finding

[17] The ESO has been working with Ofgem to explain and consider these changes to our delivery plan during the RIIO-1 period and associated changed to our spend profile through the RIIO-1 Close Out process. Further information on this process is available at: https://www.ofgem.gov.uk/publications/consultation-riio-1-close-out-methodologies-electricity-system-operator

new ways to enhance customer experience will run through everything we do, and we will use our new EMR platform to improve operational processes and customer service.

7.2.7.2. A5.2 Deliver an enhanced platform for EMR

In our first RIIO-2 Business Plan we proposed to build on the new EMR platform to provide a more flexible and adaptable solution that would also significantly improve the user experience. We assumed that the EMR portal would be replaced in the RIIO-1 period and that investment in RIIO-2 would be for maintenance and further gradual enhancements in response to customer requirements and regulatory changes. We proposed to deliver this through an agile process, with the implementation of key functionality in line with the annual operational process. We also proposed to ensure that our EMR systems remained compliant with changes in the regulations and rules governing the Capacity Market and CfDs.

As described under sub-activity A5.1, the replacement of the EMR portal had to be moved into the RIIO-2 period to deliver mandatory policy and rule changes as well as customer and process improvements in the legacy portal during RIIO-1.

We have been building a new platform for the Capacity Market in the first two years of RIIO-2. As we moved the portal replacement (and associated spend) into RIIO-2 and firmed up our forecast based on the selected solution, our cost forecast for BP1 has increased (please see Annex 4 – Technology investment, IT investment line **320** EMR Portal Improvements for more information). This reflects a better understanding of the requirements for the new portal expressed by our customers. (Refer to the A5 stakeholder engagement section to understand how we engaged with customers and took account of their feedback).

What are our updated RIIO-2 plans?

In BP2, we will add functionality to the EMR platform in response to customer feedback and ensure it remains compliant with regulatory changes. The greater automation and operational efficiencies will also enable us to focus on high value-adding activities and further strengthen our efforts to support customers.

D5.2 Developing the EMR platform

We will continue to develop the EMR portal in response to user feedback and to implement policy and rule changes, as well as delivering continuous improvements for the CM and CfD processes. We will work towards the integration of the EMR platform into our Digital Engagement Platform and harmonise processes to find greater efficiencies across our markets. We will implement a new reporting tool, using Power BI, to give greater analytics capability for external users to self-service and generating insightful reports to better inform business decisions and the operation of EMR processes.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **320** EMR Portal Improvements. This will enable us to continue to advance the user experience optimisation, and deliver regulatory changes in the new, Salesforce-based EMR portal and Power BI reporting capability, following its implementation in BP1. The detail behind this investment can be found in Annex 4 – Technology investment.

7.2.7.3. A5.3 Improve our security of supply modelling capability

In BP1 we proposed to improve our security of supply modelling that underpins our Capacity Market recommendations in the Electricity Capacity Report. These improvements are agreed with BEIS, Ofgem and BEIS's Panel of Technical Experts (PTE). The projects harness new data sources and/or improve the modelling methodologies. The work is scrutinised by BEIS's PTE, which produce an annual report.

We delivered the 2021 Electricity Capacity Report to BEIS by 1 June 2021 and published it in July 2021. We have since agreed and carried out a set of development projects in 2021/22 that will be reported in the 2022 Electricity Capacity Report in line with the established process.

What are our updated RIIO-2 plans?

D5.3 Use of enhanced modelling and more granular data sets to improve security of supply modelling

We will continue to develop new data sets, so our modelling approach better reflects the evolving power system. We expect improvements in modelling on intermittent sources, duration-limited technologies and pan-European modelling for interconnectors.

It is also likely we'll need to improve modelling on reduced dependency of thermal generation as we transition to net zero, embedded generation and supporting BEIS's Ten-Year Review of the Capacity Market, which is due by 2024. It is difficult, at this stage, to specify which modelling enhancements will be taken forward in BP2. These are agreed annually through an established prioritisation process with BEIS, Ofgem and BEIS's PTE. Details of our modelling improvements, including the prioritisation process, are reported in the Electricity Capacity Report each year.

We now expect to deliver enhanced modelling quicker than set out in our previous RIIO-2 Business Plan as the net zero transition gathers pace. We also need to improve our modelling on delivery assurance that wasn't previously included. This is particularly important during the mid-late 2020s, when large thermal plant is expected to be replaced by new capacity. To deliver this, we need to expand our team to deliver modelling enhancements sooner and improve modelling on delivery assurance.

7.2.7.4. (New) A5.4 Long-term capacity adequacy

The capacity mix required to meet net zero will present new challenges in ensuring system adequacy (the way in which the power system can match the evolution in electricity demand). The power system is targeted to be fully decarbonised by 2035; this will mean much higher penetration of weather-dependent generation and flexible technologies. Delivery timelines mean that we need to start assessing this now.

What are our updated RIIO-2 plans?

(New) D5.4 Building our capability studies

We are intending to begin this new work in BP1 with support from consultants. We will use the BP2 period to build our capability, undertake detailed studies and publish a report every two years from 2022. These studies will:

- identify options for the capacity mix needed to deliver adequacy in the 2030s
- assess their strengths and weaknesses to deal with the potential adequacy risks
- assess their economic viability

We will work collaboratively with stakeholders to deliver incremental modelling improvements and potentially undertake shorter follow-up studies exploring aspects of interest arising from the main study.

We estimate an initial increase in BP2 (see **A5** financials and headcount). These roles are unfunded in BP1 but given the importance, we have decided to absorb these roles within our existing BP1 budget so that we can start this work earlier in 2022/23. They will then be applied in each subsequent year until 2025/26 as part of BP2.

7.2.7.5. A5 Stakeholder feedback

(A5.1) In delivering our activities for **A5.1**, we have implemented improvements to our processes and systems. We have involved customers in co-creating guidance material and other new supporting material such as 'how to' videos. We also ran events providing information on how to participate in the Capacity Market and CfD schemes. This was supported by a dedicated website for CfD Allocation Round 4 through which we and other delivery partners provided vital information and guidance.

Examples of customer feedback and the changes we made were:

- Our customers wanted more support in meeting deadlines, so we have sought to deliver more direct communication and increasingly notified our customers ahead of key milestones.
- Customers wanted queries answered where possible at first point of contact and we have provided further training and support to our customer-facing teams.

- Customers wanted us to play a wider role in simplifying and clarifying the Capacity Market and CfD rules and we have captured, developed and promoted improvements ideas.

(A5.2) Based on customer feedback, our overarching objectives for the new EMR portal are to deliver a step change in user experience faster and more efficiently.

The new portal was designed around customer feedback. For example:

- Our customers wanted more guidance when preparing applications, so we integrated helper text in our portal.
- Customers wanted more targeted communication from us, and this was reflected in the portal design.
- Customers want to be able to reuse information they have previously provided. We have worked with Ofgem to amend the Capacity Market rules and improved the portal to facilitate this.

(A5.3) We believe the feedback presented in BEIS's PTE Reports supports continuation of the modelling work and so have not proposed significant changes to BAU activities.

(A5.4) We have received several questions on this theme from our stakeholders, for example through the published Frequently Asked Questions on the FES.

7.2.7.6. A5 Financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A5 - Transform access to the Capacity Market		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	5.6	5.5	4.1	3.1	3.1
	BP1	1.2	0.9	0.9	0.9	0.9
	Variance	**4.3**	**4.6**	**3.2**	**2.2**	**2.2**
Opex (£m)	BP2	3.6	4.7	4.4	5.0	4.9
	BP1	4.2	3.9	3.9	3.6	3.6
	Variance	**(0.6)**	**0.9**	**0.5**	**1.4**	**1.3**
FTE	BP2	52	58	53	52	51
	BP1	37	35	35	32	32
	Variance	**15**	**23**	**17**	**19**	**18**

Table 15: RIIO-2 cost and FTE for A5

The forecasts for the opex, capex and FTEs needed to support **A5** activities in BP2 have increased since our first Business Plan submission. The main drivers of the increase over the two years are:

- £5m increase to capex has been driven by increases in IT investment **320** EMR Portal Improvements
- £2m opex and 19 FTEs in FY25 will support a number of areas:
    - 13 FTEs to support the delivery of EMR auctions, delivering regulatory change and to cover the revised implementation date of the EMR portal and process automation **(A5.1).**
    - One additional FTE to support the 2030's modelling capability which includes delivery of modelling enhancements earlier and to improve modelling on delivery assurance **(A5.3).**
    - Five FTEs to support the new sub-activity **A5.4**, to build our capability studies under, deliver incremental modelling improvements and potentially undertake shorter follow-up studies.

7.2.7.7. A5 Cost-benefit analysis

The updated CBA for **A5** has an NPV of £59m over RIIO-2, and £117m over 10 years, which is a £3m and £11m reduction in the 5- and 10-year NPV respectively. This reduction is driven by an increase in costs for the IT investment **320** EMR Portal Improvements that reflects our improved understanding of the requirements for the portal and its integration with the Data and Analytics Platform (DAP) and the Digital Engagement Platform (DEP). The benefits for **A5** are relatively unchanged, so the NPV estimate has decreased. For further information see Annex 2 - CBA.

7.2.8. (Materially Changed) A6 Develop code and charging arrangements that are fit for the future

It is crucial that we continue to reform the codes and frameworks that govern our market. These arrangements establish the commercial and technical parameters within which market participants operate. We will also continue to develop and deliver sustainable improvement in our relationship with Europe through the requirements of the TCA, which will now be covered under the new cross-role activity Role in Europe.

We will develop new tools and processes to ensure we continue to recover transmission system costs and adapt to the demands of the changing market and wider industry reforms. Following the conclusion of the BSUoS reform code modifications, we will set and bill the new BSUoS tariffs to realise the consumer benefits identified by Ofgem to 2040. We will remove complexity and barriers to participation in the code change process and a new team will be established to consider frameworks in a more holistic manner changes to take account of new markets and new participants.

In the first year of BP1, we engaged with stakeholders on the benefits of consolidating the technical codes. As a result, we are going to alter the focus to more fully consider the opportunities presented by alignment and digitalisation of the codes while we determine the details of what the outcome of BEIS and Ofgem's Energy Code Reform work means for the ESO.

A6 sub-activities and deliverables

7.2.8.1. (Materially changed) A6.1 Code management/market development and change

We have progressed a world-first specification for ‘grid-forming’ (also known as virtual synchronous machine) functionality in the Grid Code. This is a vital way of converter connected technologies (interconnectors, renewable generators) contributing to net zero by providing stability products. For the development of offshore coordination and early competition, work on codes has comprised a detailed mapping of requirements. In addition, we have facilitated industry engagement and participation in the HND determining the optimal offshore network and the codified rules required to facilitate it.

Some code modifications are still in progress, including modifications to implement the Transmission Demand Residual, a fundamental change to the charging methodology which has been approved for implementation in April 2023. Several urgent BSUoS modifications have introduced price caps on the overall BSUoS charge to support industry through a period of unforeseen BSUoS costs, while work has taken place on the first stages of the ESRS implementation and modifications to enable our Distributed Restart Project. This gives an indication of the team’s work across the BP1 period.

We are leading an expert group, including manufacturers and developers, progressing a Grid Code modification (GC0137). We are continuing to engage with stakeholders and producing more detailed guidance.

What are our updated RIIO-2 plans?

We have a key role to play in supporting the transition to net zero, enabling sustainable transformation of the energy system and ensuring the delivery of reliable and affordable energy for consumers. Stakeholders have raised concerns about the unpredictability and volatility of TNUoS charges and the suitability of the underlying principles in light of changes to the energy landscape. Ofgem has asked us to lead task forces to formally review the TNUoS methodology in the short- to medium-term. There will also be a longer-term review of TNUoS alongside wider market reform.

It is important that TNUoS methodology aligns with energy transition goals and is coordinated with other work such as the development of onshore and offshore competition, and future market design. We will consider the wider interactions with markets, network capacity and constraints, BSUoS charges, and the enduring solution for market wide half hourly settlement to capture whole systems interactions, costs and benefits.

(New) D6.1.1 Enable major net zero programmes - Offshore Coordination

Enabling the connection of 50GW of offshore wind by 2030 is a key priority to facilitate net zero. Changes to industry codes and frameworks, including the Security and Quality of Supply Standard (SQSS), the System

Operator-Transmission Owner Code (STC), the Connection and Use of System Code (CUSC) and the Grid Code will be required to underpin the design of the offshore transmission network, and the arrangements that will be needed between industry parties.

We expect a high number of changes to enable coordinated offshore networks will need to be made rapidly to support the offshore regime work in Role 3 (more information can be found in Role 3 under Early Opportunities and Pathway to 2030 - Enduring Offshore Regime section). These changes will require additional resources.

To fulfil this, we will increase our resource in the first year of BP2. They would then take forward the code and standard changes for the Enduring Regime in the second year of BP2. Additional resources may be required once we know the extent of the code changes for the Central Strategic Network Plan (CSNP) contemplated by Ofgem's ETNPR.

The scale and complexity of the framework changes, and the resources required to deliver them, have been identified in BP1 and has influenced the need for a separate deliverable to help track delivery in BP2. We are working with stakeholders across the industry to define and design areas for change.

(New) D6.1.2 Enable major net zero programmes – Onshore Competition

Within BP2, we will deliver the code change to facilitate onshore competition, which will benefit consumers by driving innovative solutions and efficient delivery.

This is being progressed with identification of the necessary changes to codes through mapping the requirements. Once the legislative solutions are more apparent, the modifications will be progressed using the standard industry governance arrangements.

(New) D6.1.3 Enable zero carbon operation - System Restoration

Our compliance with the Restoration Standard is required by the end of 2026 due to a licence made by BEIS in October 2021. Facilitating the Distributed Restart project while it has no legislative driver, is closely associated with this as both require code modifications.

The Electricity Supply Restoration Standard and Distributed Restart programme require are key code change to ensure that these initiatives are successful. This will enable compliance with the Restoration Standard and sourcing of restoration services. This will safeguard our ability to restore the system and contribute to our goal of operating a carbon free system. Delivery of the code modifications has started in BP1 and will continue into BP2, along with implementation and stakeholder engagement.

(New) D6.1.4 Enable zero carbon operation – stability

Developing technical specifications for equipment to participate in stability markets is a key enabler for net zero, particularly as an enabler of new technologies in our markets as per **D4.6.1**.

We are aiming to deliver code modifications and guidance to set the specification for equipment to provide stability support to the system and to participate in any markets that will be set up for this. Delivery of an initial Grid Code modification (GC0137) was progressed in BP1. Work continues to engage with stakeholders on this and to produce more detailed guidance.

(New) D6.1.5 Support Charging Reform

We will lead TNUoS task forces to review the current methodology, working closely with industry to define any future changes. This will deliver benefits for consumers and lead to more efficient utilisation of and investment in the network.

D6.1.5, Support Charging Reform, also covers the support the revenue team will provide to sub-activity A6.3 TNUoS reform, covering the code change element and defining what the future TNUoS charging methodology will look like, and their impacts on all parties. We are expecting more detail on next steps from Ofgem in early April; this will define the detail of what this deliverable will look like. As this is close to the publication date for this draft plan, more information will be provided in our August 2022 final plan.

(New) D6.1.6 Support Market Wide Half Hourly Settlement

The Market-Wide Half Hourly Settlement (MHHS) Programme is part of Ofgem's Electricity Settlement Reform Significant Code Review, with the code changes taking place throughout BP2. We have a key role to ensure the modifications and legal text will deliver Ofgem's expected outcomes, given MHHS is a key enabler of the move to a more flexible energy system. This will enable us to deliver code modifications which implement Ofgem's ambition for Market Wide Half Hourly Settlement within the CUSC and BSC.

Industry groups have been established during BP1 to work through the detailed solution for MHHS and we are attending all relevant meetings for development of the detailed design, as well as the industry Programme Steering Group. The feedback from the industry group can be found in the **A6 Stakeholder Feedback section**.

Our data flows will need to change as will the TNUoS methodology, but at this stage no additional FTEs, within the Code Management team, are required to support the code modification process. Ofgem's final decision to proceed with MHHS was supported by a Full Business Case and Final Impact Assessment, published in April 2021.

Dependencies and assumptions

We have assumed progress is made within key externally led programmes such as Market Wide Half Hourly Settlement, and a decision about the future of TNUoS reform through the Taskforces that allow change to be progressed within BP2. Other dependencies include interaction with the onshore and offshore coordination activities, the Competitive Appointed Transmission Owner (CATO) regime and the OTNR, as these may impact the timeline of framework changes in BP2.

This activity will take account of interactions with other areas such as the net zero market reform project. A high-level description of reforms is expected by April 2022 which may lead to further changes to our forward-looking code modification plans.

Progression of the BEIS/Ofgem led Energy Code Reforms (ECR), and the Future System Operator work both have the potential to substantially impact code changes, especially the consolidation of codes that form part of the ECR project. There is likely to be particular interaction with the Whole System Digitalised Technical Code deliverable.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **280** GB regulations and **610** STAR. The detail behind these investments can be found in Annex 4 – Technology investment.

7.2.8.2. (Name changed) A6.2 European Union (EU) code change

In our first plan we outlined the need for efficient progression of EU exit arrangements and changes to codes to support these, as directed by Ofgem and BEIS. We also identified a need for IT system changes in our business, and with industry participants, to ensure that code changes are embedded into BAU with minimal disruption. Under the European Union Code Change deliverable, our goals from BP1 were affected by our exit from Europe, meaning deliverables were replaced by the deliverables set out in the TCA. Deliverables withdrawn after the EU Exit include the planned Trans-European Reserves Replacement Exchange (TERRE) post-go live changes and the delivery of the Manually Activated Reserves Initiative (MARI).

Before the introduction of the TCA with the European Union, we focused on the implementation of the European Network Codes and associated legislation. We are still legally required to manage elements of these codes and legislation following the UK's exit from the EU, but we have also needed to focus on implementation of the TCA. To do this, we have increased resource in this area which we recruited in the BP1 period. We have also completed the submission of data files for Short Term Adequacy (STA), Clean Energy Package changes for Short Term Operating Reserve (STOR) ready for new auctions and Grid Code and BSC change for Emergency and Restoration standard compliance.

We are currently working on Clean Energy Package development and testing, requiring more involvement as we work with all UK TSOs and agree a UK position before engaging with the EU TSOs, and seeking input from Ofgem and BEIS. This work now covers developing technical procedures for capacity calculation at multiple timescales, developing cross-border balancing products and working on re-dispatching and counter-trading, as well as other areas not referenced in the TCA but that will likely require further work. The FTE will continue to focus on this as part of the new **Role in Europe activity (A22).**

What are our updated RIIO-2 plans?

D6.2.1 Implementation of the TCA

Following the UK's exit from the European Union, a new TCA was agreed between the UK and the EU. BEIS then set out a number of technical procedures, created by UK TSOs, needing agreement to facilitate continued efficient energy trades with Europe. We envisage high levels of future uncertainty relating to the TCA implementation due to the timelines not being agreed with the EU. This means the solutions are subject to change. This deliverable is strongly linked to the new activity **A21 Roles in Europe**, and there will be high levels of coordination and collaboration between the two.

TCA technical elements to be delivered include:

1. Developing and delivering, with other UK TSOs (interconnectors), the TCA technical procedures in the areas below; we will also have to strike agreements with other EU TSOs on all these technical procedures:
   - Cross-border Balancing interim solution
   - Cross-border Balancing enduring solution
   - Intra Day Capacity calculation
   - Long-term Capacity calculation
   - Day-Ahead Capacity calculation
   - Coordinated process for remedial actions including redispatch and countertrading (RD CT)
2. Developing short-term market framework changes for interconnectors while long-term initiatives are implemented. We will review the arrangements for interconnectors connected to the GB system. We will develop a clear, fair and transparent set of operational and commercial arrangements that will ensure we can manage the system safely, whilst also ensuring competition and value for money for consumers.
3. Implementing Grid Code modification (GC154) on interconnector ramping limits.
4. Finalising Inter-TSO compensation (ITC) mechanism arrangements.
5. Defining new TCA-related publications; monitoring and preparing the new operational reporting required.
6. Assessing TCA recommendations presented by the Specialised Committee on Energy (SCE).

We foresee elevated levels of uncertainty around the TCA implementation to Role 1 activities (under deliverable **D1.1.4**) leading to the following:

- Supporting the development of new methodologies for interconnector capacity calculations under the TCA
- Continuing to participate in key projects relating to cross border capacity calculations, security analysis and situational awareness
- Continuing business-as-usual activities of submitting individual grid models for the Common Grid Model project and Coreso security studies.

Dependencies and Assumptions

There is a clear understanding of what needs to be delivered through the TCA in the immediate term. However, there are wider, external political factors that may impact the timescales for the delivery and implementation of these TCA obligations, both in the immediate and long-term. These external factors may lead to TCA-related projects significantly changing through BP2. However, these factors and are not within the control of the ESO or UK TSOs.

These external factors may impact the cost, time and resource requirements for delivery. Therefore, we require a more agile approach that recognises both the effort required to implement the various elements of the TCA and the ever-changing landscape that our new relationship entails.

7.2.8.3. (Materially changed) A6.3 Industry revenue management

We must make sure the charging and billing processes meet the needs of our customers while we manage, collect, and disburse charges involving the operation of the transmission system (D6.3.1). Over the RIIO-2 period, we will focus on transforming the experience of customers, whilst also ensuring we run our processes as efficiently as possible, including delivering new charging tools and processes.

During the first part of the RIIO-2 period, we have been acutely aware of the impact of the COVID-19 pandemic and, latterly, the ensuing energy cost crisis. As a result, we have spent a large amount of time focusing on the provision of short-term financial relief, helping soften the impacts on the industry. We have also delivered material framework changes such as the outcome of Targeted Charging Review (TCR) BSUoS and the transfer of the K factor risk to the TOs to deliver the directions given by Ofgem under the TCR Significant Code Review (SCR). Also, to develop a solution following the conclusion of the second BSUoS taskforce to deliver a fixed BSUoS price charged to suppliers only and to transfer the TNUoS cashflow risk to the onshore TOs. We have continued to enhance our tariff setting processes that help dictate the likely ramifications to charges dependent on the outcome of events shaping the regulatory charging framework.

We have begun to re-platform both our charging and settlement systems, details of which can be found here in Annex 4 – Technology investment.

What are our updated RIIO-2 plans?

As the frameworks that underpin industry charging evolve, we will continue to update our systems, modelling and processes, while continuing to transform the experience of our customer base. In A6.1 we describe some of the changes and how these are progressing through the code change process. During the BP2 period we have also created new deliverables to embed these changes into our activities.

(New) D6.3.1 Market-wide half-hourly settlement

Market-wide half-hourly settlement (MHHS) plays a significant role in the transition to net zero and is a part of Ofgem's Electricity Settlement Reform Significant Code Review. **D6.1.6** describes the programme and the code changes required in this area.

Current TNUoS charging is based on non-half-hourly and half-hourly metering and both TNUoS and BSUoS charges are levied in line with the industry settlement timetable. The change to settle all electricity metering on a half hourly basis is mandatory and migration to half-hourly settlement is expected to be complete by October 2025, as directed by Ofgem, with a reduction in settlement timescales immediately after. The programme timelines may change depending on how the industry-led development and resulting code modifications progress, so the plan will need to be flexible.

(New) D6.3.2 TNUoS reform

As discussed in **D6.1.5**, Ofgem, has asked us to lead task forces to review the transmission charging methodology. Code modifications are likely to be required for any changes and we will then be in a better position to identify the resources required to support the delivery of any reform into our charging systems and processes, and the potential timescales.

The charging methodology continues to be updated to recognise the changing landscape and we will continue to adapt our core processes and system capability as needed.

Key investments for this sub-activity

Flexible systems are core to rapidly change the Charging and Settlements landscape, aligning to IT investment line **290** Charging and Billing Asset Health. Through this investment, we will create a more reliable system that can keep pace with change and deliver a higher quality and more efficient service to our customers through greater automation. The detail behind this investment can be found in Annex 4 – Technology investment.

7.2.8.4. (Materially changed) A6.4 Transform the process to amend our codes

During the RIIO-2 period, stakeholder feedback via the Code Administrators' Code of Practice Survey suggests that the process to change a code is too cumbersome and slow. However, by 2025, our codes and governance will be seen as an enabler of change, not a barrier. The codes we administer will be accessible and relevant to all users. Code modification will work for hundreds of market participants, rather than the tens of participants for which the current process was devised. Following the outcome of the Energy Code Review consultation, we will create a no regrets action plan that outlines how we will make the changes required today to make these changes happen. We will work with others to ensure commercial, technical and regulatory arrangements across transmission and distribution will be far more joined up.

The ESO Code Administrator created an incremental improvement plan that makes it easier for stakeholders to drive consumer benefit. An example is the successful series of onboarding workshops for new or smaller parties which helped them navigate the complexity of the governance process. Another is improvements made to the Critical Friend role, which has seen stakeholders' feedback on better quality reports and understanding. We have also taken the necessary steps of recruiting dedicated legal support for our codes on our journey to become a Code Manager.

A more strategic plan exploring licence changes will continue following the outcome of the Energy Code Review consultation. During the RIIO2 period, we have also worked with stakeholders to understand their views on Digitalisation of the Grid Code and to help shape an early view of what the platform might look like.

What are our updated RIIO-2 plans?

As the decision for the Energy Codes Review (ECR) has only recently been published, we have delayed this deliverable in BP1 and it will likely continue into BP2. We have, however, progressed some other deliverables; examples include recruiting more people within the code administrator, securing dedicated legal resource for our codes and improving our 'critical friend' process. We now know the outcome of the consultation, therefore we will create a no regrets action plan around how we will transition from a code administrator to a code manager.

It has and will continue to be important that we listen to what our stakeholders tell us. The 2021 Ofgem-led survey has so far validated that, in BP1, we are making great progress in our improvements to the process, with significantly improved scores across all of our codes.

(New) D6.4.1 Implement no regret actions from the ECR

Following the recent decision published on ECR, we will implement a transparent no regrets action plan. To set ourselves up best to be a Code Manager of the future (**D6.4**), we will continue to consult our stakeholders and make changes to the process where we are can. Likely actions include continued evidence demonstrating code manager capability, such as providing insight into cross code impacts, building expertise within the team, finding ways to enable smaller parties to contribute to code change and to support and inform BEIS and Ofgem with larger scale reform.

We need to show how we will deliver large-scale reforms following the outcome of the ECR. This will impact all stakeholders, not only for our codes, but for all codes. We will set out a clear plan that provides confidence to Ofgem and industry that we can make these changes within the parameters of the timescales provided in the ECR.

Without demonstrating how, when and why changes are being made, there is a real risk that we will not provide enough transparency to stakeholders, nor be able to demonstrate the benefits of the changes.

Dependencies and Assumptions

The timing and the outcome of the Energy Code Review is a key driver in determining the milestones within the no regrets action plan. As the decision has only recently been published, we have not been able to reflect its impact on this draft plan but will do for our final August 2022 plan. Given the consultation is seeking to make fundamental reform across industry, our plan will also need to reflect any interactions with other codes. The changes will require working with stakeholders and Government so we will need to take into account their own timescales.

Another dependency is around the Future System Operator and where the Code Administrator sits within that new space. We aim to become a Code Manager and will continue to work on these deliverables to ensure we are set up best for that future.

7.2.8.5. A6.5 Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 (Whole System Technical Code side)

Our main focus in our first Business Plan was on the Whole System Technical code, as we envisioned this would be the first approach for digitalisation. Further work around a code consolidation solution is required, so a new sub-activity **A6.8 Digitalisation of codes** has been created to look at digital solutions.

In the second year of BP1 the project team, in conjunction with the steering group, will define the scope and objectives of the two workstreams. Since its instigation, the steering group has proposed separate 'go /no go' decisions for each of the workstreams, (digitalisation and consolidation) once scope is defined. This is a deviation from our original plan to decide on both items by 31 March 2022. The project team engaged with stakeholders to seek their views on scope, objectives, and approach, which formed the basis of the consultation issued in September 2021. See **Activity 6 stakeholder engagement** section for further information.

What are our updated RIIO-2 plans?

D6.5 The Grid code combines transmission and distribution codes in an IT system with AI-enabled navigation and document and workflow management tools.

In BP2, we will continue to align technical code consolidation in line with any proposed ECR or other reforms mandated by Ofgem. We will have de-prioritised the consolidation element at the end of the first year of the BP1 period due to significant stakeholder feedback and the potential for interactions with ECR.

We agree with the Whole System Technical Code Steering Group that awaiting further detail from the outcome of ECR and progressing digitalisation and alignment where possible will result in a more successful process. We will consider this further during BP2, when these interactions will be more clearly understood.

Dependencies and Assumptions

Stakeholders are reluctant to deliver work for this activity, which could be negated by the outcome of the ECR. Our proposal is to define the scope of work in BP1 and delay delivery in BP2 until we fully understand the ECR outcome.

We assume industry can resource subject matter experts (SMEs) for required workgroups, e.g. in the proposed governance structure to raise and deliver code modifications. However, due to the great deal of change currently ongoing in the industry, suitable resource may not be available.

See sub-activity **A6.8** for more detail on digitalisation.

7.2.8.6. (Completed) A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

In RIIO-2 we set out our plans to continue to modify industry codes to allow for BSUoS to be fixed, which includes industry engagement, project implementation and ESO financing arrangements. We have worked with industry to deliver a programme of BSUoS reform which will result in code modifications and a change to our licence.

D6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

The first code modification, which changes the BSUoS charging base to be demand only (CUSC modification CMP308), is complete from our perspective. Ofgem has published a minded-to decision and an impact assessment consultation which has since closed. This aligns with the conclusion of the second BSUoS taskforce (and Ofgem's wider policy) on placing residual costs solely onto final consumers to remove market distortions. Ofgem is also minded-to implement this change for 1 April 2023, in line with the second BSUoS taskforce's recommendations.

The second code modification, to deliver a fixed BSUoS price (CMP361), was sent to Ofgem in February 2022. Like CMP308, this also has a planned implementation date of 1 April 2023. Based on analysis conducted by Ofgem's independent consultant, Frontier Economics, BSUoS Reform could see consumer benefits of around £320m by 2040 (in a net zero compliant scenario), reduction in GB energy system costs of around £400m and reduced CO2 emissions due to changes in interconnector flows and generation investment.

We will continue to engage with the consultations for each CUSC modification, as well as the licence consultation to implement BSUoS Reform. We are also developing a new end-to-end BSUoS process, including updated forecasting methodology, to be best prepared for this regulatory change. We will engage with industry on our BSUoS forecasting methodology and provide information on tariff setting as agreed in the CMP361 workgroup.

We expect all this activity to be completed before the start of the BP2 period. A new sub-activity **A6.7** has now been created to look at the long-term delivery of the recommendation from the BSUoS taskforce.

Dependencies and assumptions

Delivery of the changes to the BSUoS methodology rely on the approval of the associated modifications and the delivery of the associated system functionality within our new IT system, **290** The Charging and Billing (CAB) System.

7.2.8.7. (New) A6.7 Fixed BSUOS tariff setting

During BP1, the scope of the changes to the BSUoS charging framework have become more advanced as the associated code modifications within sub-activity **A6.6** also progressed. In advance of being able to fix BSUoS charges for our customers, we have been focusing on improving our BSUoS forecasting capabilities, so that these can be factored into decision making.

This new sub-activity will continue to iterate our associated modelling capability for better forecasts and focus on providing the market with transparency of how we will make incremental improvements long-term. As we react to ever changing market conditions, we will continue to invest resources into improving the accuracy of our forecasts as well as increase resource in BP2. These improvements will also form the basis as to how we set fixed BSUoS tariffs from April 2023 onwards.

What are our updated RIIO-2 plans?

D6.7 Enhanced delivery of the recommendation from the BSUoS taskforce around reducing the volatility of BSUoS forecasting.

Once the code modifications have been implemented, we will need to run the forecasting model and continually improve and refine it to reflect market changes long-term. This will realise the value of fixing BSUoS by providing certainty and visibility up front of the associated costs to our customers of balancing the system.

To do this, we will continue to invest in our forecasting capability and helping the market understand our methodology. This activity builds on our capability for BSUoS forecasting. However, it is more complex than our current approach and the output is fundamentally different to the current tariff setting process. As a result, we are looking to increase headcount to enhance our ability to forecast and then set BSUoS tariffs.

7.2.8.8. (New) A6.8 Digitalisation of codes

Originally when sub-activity **A6.5** (Work with all stakeholders to create a fully digitalised Whole System Technical Code by 2025) was created, we envisaged the Whole System Technical code would happen first and then it would be digitalised. Current industry feedback tells us there is much more work to do around code consolidation, so we continue to look at digital solutions that drive consumer benefit no matter which code they are applied to. Given the industry support for digitalisation, and that this can be progressed on a no regrets basis, we will look to place greater focus on the digitalisation element.

What are our updated RIIO-2 plans?

In BP2, we have split the Digitalisation of Codes element from the original **A6.5** delivery, creating a new standalone sub-activity. This will provide more clarity so we can track both elements more precisely. Stakeholders want to progress the digitalisation element more quickly as they have noted the benefits.

We also want to progress this area and, while it directly links with **A6.5**, it should not be bound by the same time frame. Digitalisation is one way of making code change more efficient and easier to interact with and, to align with future ambition of becoming a Code Manager, is a solution that can also be applied to other codes.

(New) D6.8 Implementation of digital solutions

In BP2, the project will use feedback from the first stakeholder consultations to implement a digital solution for easier interaction with the Grid Code for all parties. The solution will consider the nuances and requirements specifically for the Grid Code but will also be flexible enough for the digitalisation of other codes across the industry. We have undertaken early engagement with other code managers who have undergone similar digitalisation projects to discover best practice.

Benefits that we and our stakeholders have identified so far are:

- Allows users to navigate more efficiently whilst minimising risks of missing 'relevant information'
- Would deliver value to new users who may not be fully aware of all obligations relevant to them
- Automated version control would reduce risk of using old documents
- Supports more efficient customer journey, encouraging new entrants
- Greater clarity on relevant sections of code if it is signposted by meta data/tagging
- A potential to reduce the level of industry resource used to propose changes, as the solution could reduce the amount of analysis required.

Any benefits from the Digitalisation of the Grid Code project will be considered for any other code digitalisation as we move forward into the RIIO-3 period.

Dependencies and assumptions

This activity is dependent on the following transformational activity: **A6.4 Transform the process to amend our codes**, allowing us to manage codes more efficiently while prioritising change and maximising synergies across all ESO managed codes.

We will create engagement channels to encourage a broad range of user requirements, testing user experience. We aim to gain a diverse and inclusive population through this approach, maximising the chance of user acceptance of the published solution.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **330** Digitalised Code Management. The detail behind this investment can be found in Annex 4 – Technology investment.

7.2.8.9. (New) A6.9 Whole system codes reform

We have seen developments in non-traditional players, such as through our Pathfinder programmes, which cause interactions across all frameworks that govern our electricity market. Although we have clear duties to review our codes and ensure that they are fit for purpose, the issues we have observed often have impacts across other areas of governance. This new activity will allow us to take a broader view and assess the likely impacts in other, less well understood areas.

What are our updated RIIO-2 plans?

The differences in the structure of frameworks between parties connected to, and operating at, transmission and distribution levels of the electricity system are no longer fit for purpose.

We envisage a no regrets activity to establish a new whole electricity system market policy team to identify solutions for cross-cutting issues. For further details on related DSO activities, see the Role 3 cross-role activity, Facilitating distributed flexibility. This team within Role 2 will suggest solutions for:

- Changes to licenses, regulations, and codes on behalf of ourselves and other electricity market bodies
- Consideration of 0MW markets within the codes, licences and market frameworks and the implication for costs and efficient economic signals
- Consideration of the effects of future non-network solutions on the electricity frameworks
- Consideration of changes to electricity market frameworks to facilitate DSO and whole system outcomes between ourselves and the DNOs.

By the end of the BP2 period, we will have made recommendations on the appropriate structure of electricity market frameworks and developed a case for change to ensure these facilitate the net zero transition, increase value to consumers and enable efficient participation for all participants.

D6.9 Whole electricity system framework assessment (new)

The new whole electricity system market policy team will assess the relevant frameworks and create a workplan of the areas for delivery. This will include stakeholder engagement to agree areas of priority.

We will then complete a full assessment of delivery areas, reviewing the consumer benefits of changes, working with key stakeholders to ensure they are aligned to wider policy goals and net zero. These will need to be considered in light of other whole system programmes such as CATO, HND, Pathfinders, Open Networks and DSO development.

The team will either take forward code changes where these are within our control or recommend areas of development. This activity will deliver benefits through amendments to the industry frameworks. It will then transition to a period of change and review, coupled with stakeholder engagement. The industry landscape will not remain static for the BP2 period so ongoing assessment and prioritisation will be necessary.

Creating this new team will help us develop a holistic view of the electricity frameworks and how they need to adapt to a fundamentally different set of markets than were envisaged when they were originally established. Through our CATO, Early Competition, offshore and Pathfinder projects, as well as our involvement in Open Networks and the requirements of the Smart Systems and Flexibility plan, we have observed that a more holistic view of the electricity frameworks is required for GB to reach net zero. Without this deliverable, any change to the frameworks for new types of market participant or connection would not be managed efficiently.

Dependencies and assumptions

These deliverables will look to other initiatives such as Early Competition, Pathfinders and the Open Networks programme, as well as wider market development to inform its work.

As markets continue to develop, we will face continuing pressure to adapt and carry out continued amendments to, and improvement of, the electricity market frameworks.

7.2.8.10. A6 Stakeholder feedback

(D6.1.4) Stakeholders say that GC0137 has unlocked their ability to design compliant equipment but they now want further information on how future stability markets will operate as we are progressing through the Pathfinder initiatives.

(D6.1.6) Stakeholders have told us that market-wide half hourly settlement is key, but it is only one element of change in the electricity industry, with the same resource also supporting other reforms. So, we will consider this throughout BP2, particularly when providing our views on modification prioritisation/planning.

(A6.3) Change in this area is not predominantly driven by stakeholder feedback.

(A6.4) The ESO Code Administrator has recently evidenced in the 2021 Code Administrators Code of Practice (CACoP) survey, run by Ofgem, that the provision of service across all codes has significantly improved. Some of the scores were the highest ever received by the ESO Code Administrator. However, the need for larger scale reform to governance processes for all industry codes continues to be important.

With regard to the ECR, stakeholders agree with us it is preferable to wait for the outcome before starting work on consolidation, to ensure it is aligned, so this will continue into BP2. However, stakeholders feel that code alignment, simplification and rationalisation are ‘no-regrets’ and should proceed independently of the ECR project.

(A6.5) The approach proposed by stakeholders was the creation of a steering group comprising broad industry representation to provide overall oversight, strategic direction and decision-making. The group will report to the Grid Code Review Panel (GCRP) and Distribution Code Review Panel (DCRP). It has met monthly since December 2021.

The group has proposed separate 'go/no go' decisions for each of the workstreams, (digitalisation and consolidation) once scope of work is defined. This is a deviation from our original plan which was to decide on both items by 31 March 2022.

Stakeholders proposed solutions to resolve some of the challenges with the technical codes. The group gave a 'go' decision for 21 of the 25 solutions proposed. We have grouped these under seven workstreams for further development as part of the digitalised WSTC scope.

For further information see Annex 3 – Stakeholder engagement.

(A6.7) In January 2022, we presented an overview of BSUoS at the Operational Transparency Forum (OTF). This topic was revisited at stakeholders' request at the OTF to cover additional detail around the new forecasting methodology.

(A6.8) We have received support from the Whole System Technical Code steering group for our digitalisation plans and consideration of the ECR work before wider consolidation.

(A6.9) From the Transmission Charging Methodology Forum (TCMF), stakeholders have told us that they see the benefits in this work, although concern was expressed over whether we are the right body to carry this out. They also said that the ESO should focus on the electricity system if it was to carry out this type of activity.

7.2.8.11. A6 Financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A6 - Develop code and charging arrangements that are fit for the future		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	7.9	15.7	10.7	12.6	12.1
	BP1	15.5	10.8	11.0	11.9	12.6
	Variance	**(7.6)**	**4.9**	**(0.3)**	**0.7**	**(0.6)**
Opex (£m)	BP2	12.3	13.5	15.6	16.2	16.2
	BP1	13.2	14.0	14.8	15.6	15.6
	Variance	**(0.8)**	**(0.5)**	**0.8**	**0.5**	**0.6**
FTE	BP2	96	94	93	93	93
	BP1	72	75	77	81	80
	Variance	**24**	**19**	**16**	**12**	**13**

Table 16: RIIO-2 cost and FTE for A6

The forecasts for the opex, capex have stayed relatively in line with our BP2 forecasts. FTEs needed to support A6 activities in BP2 have increased since our first Business Plan submission. These changes are driven by:

- No overall increase to capex as the changes on the investments net off with each other.
- 4 FTEs recruited during BP1 to enable a dedicated focus on implementation of the TCA under **A6.2**.
- £1m increase to opex supported by an additional 16 FTEs in FY24 reducing to 12 FTEs in FY25.The decrease between FY24 and FY25 is due to us remaining flat at a total of 93 FTE across both years BP2 compared to BP1. The main drivers of the increase in FTE from BP1 are:
    - 3 FTEs to enable the Offshore Coordination programme by implementing code and standard changes to enable offshore networks (**A6.1**)
    - 2 FTEs deliver the recommendations of the BSUoS taskforce, enhancing our ability to forecast and set BSUoS tariffs (**A6.7**)
    - 4 FTEs to develop a holistic view of electricity frameworks and how they need to adapt (**A6.9**)

- 6 FTEs to support our new activity **A21** Roles in Europe. We will develop a cross-border interconnector strategy, work on enhancing engagement with the EU and enhancing interconnector operations.

7.2.8.12. A6 Cost-Benefit Analysis

Annex 2 - CBA contains four analyses for **A6** - two break-even analyses for **A6.4** and **A6.9**, and two CBAs covering other sub-activities. The analyses were separated due to the differing nature of the work described by these sub-activities.

A6.5 and A6.8

The NPV of the updated **A6.5** and **A6.8** CBA is £32m over RIIO-2 and £138m over 10 years. The 5- and 10-year NPV has increased by £28m and £121m respectively, due to the increase in total benefits. These are directly proportional to the total number of connection applications.

In the original CBA we quoted 400 connection applications per year, but we are now forecasting an average of 1,381. We are observing a rising and sustained number of connection applications and any benefit associated with improving efficiency during grid connections will also increase.

A6.6 and A6.7

The NPV of the updated **A6.6** and **A6.7** CBA is £68 million over the RIIO-2 period and £167 million over ten years. This five-year NPV has reduced by £210 million since BP1. This is due to:

- Starting BSUoS reform in 2023 – this start date is aligned with the outcomes of the BSUoS Task Force but it is one year later than was set out in our BP1 CBA.
- The use of an improved benefits methodology for BP2 - our BP1 CBA was created in 2019, well before the final report of the Second Balancing Services Task Force was published in September 2020 and therefore before the proposed changes to BSUoS were known.

For further information see Annex 2 - CBA.

Cross-role activities

Through building the content for BP2, it became clear that a number of activities affect more than one, or all three of our Roles. To ensure a consistent approach on how we tackle these activities, we have created a category of cross-role activities. These are defined as activities that impact more than one ESO Role and require ownership across multiple Roles via independent sub-activities. The following content sets out the cross-role activities identified for Role 2.

7.2.9. (New) A20 Net Zero Market Reform

Our markets do not operate in a vacuum. The links to wider markets (e.g. wholesale, capacity market) and policies (CfD, carbon pricing) are of ever-growing significance as the system transitions to net zero. It is also becoming clear that the framework of Great Britain's markets and policies for electricity are not fit for purpose to deliver net zero in the most efficient way. These markets and policies need to deliver across four key categories:

Investment: we will need unprecedented scale and pace of investment in new generation and flexibility capacity, including new and emerging technology, such as hydrogen electrolysers and bioenergy with carbon capture and storage (BECCS). These will need support to reach commercial scale. This investment is needed in a world of decreasing average wholesale power prices, driven by low marginal cost renewables, as well as wholesale and ancillary service price volatility.

Flexibility: A future world of much more dramatic imbalance in supply and demand will need lots of flexible zero carbon technologies to always meet demand and to avoid significant curtailment of renewable energy. We will rely heavily on flexibility, including large-scale, long-duration storage and hydrogen technologies, yet to be proven at scale. We also need to unlock GWs of flexibility on the demand side, including from consumer EVs and electric heat. The challenges are of investment, but also of markets sending the right real-time whole-system dispatch signals.

Location: Substantial additional generation will connect at the periphery of the network to exploit the locations with the greatest renewable resources. This will cause far greater levels of network congestion, triggering more investment in onshore and offshore transmission infrastructure. Under current arrangements, generators have no incentive to dispatch in a more locationally efficient way. Reform of market design for both generation and demand can greatly reduce whole system costs. Locational granularity could be introduced into wholesale markets via either zonal or nodal pricing. However, this would require a dramatic shift away from the status quo of a national, self-dispatching wholesale market.

Operability: As Great Britain's power system decarbonises and becomes inherently less stable, the challenges to maintain an operable system will become ever greater. Not only will we need to procure much greater amounts of operability services, but how we procure them will need to adapt to potentially significant reforms in the wider electricity markets to deliver the right investment, flexibility and locational signals.

We will tackle these challenges through our new net zero market reform (NZMR) activity. We identified this need two years ago and invested to deliver this activity from January 2021, when we hired the NZMR team. This team was funded under our existing budget through efficiencies found elsewhere in Role 2.

A20 sub-activities and deliverables

7.2.9.1. (New) A20.1 Net Zero Market Reform programme

The net zero market reform (NZMR) programme kicked off in January 2021 and has completed three phases:

- **Phase one: Scoping and stakeholder landscape.** We undertook a high-level analysis of the market landscape; developed case studies of international markets that have adopted innovative market designs (including Texas, California and Australia); interviewed 25 markets stakeholders and experts; and defined the scope of the next two phases.
- **Phase two: Defining the case for change and developing the options assessment framework:**
  - For the case for change, we looked at the challenges facing electricity markets, and the impact of not reforming them. This involved an extensive modelling exercise, where we modelled the three net zero compliant scenarios from our FES and identified what the system would look like if the existing market arrangements remained in place. Secondly, we conducted engagement across the industry including small and large-scale workshops
  - The 'Market Design Options Assessment Framework' covers the criteria we used to judge which options to take forward for further consideration in phase three.
- **Phase three**: Assessment of shortlisted options. We assessed the shortlisted market design options against the criteria developed in phase two. Our analysis in Phase 3 focused predominantly on the operational (location and dispatch) market design elements. We found that locational wholesale pricing signals, through a nodal wholesale market with central dispatch, would be the most enduring and effective solution to build a holistic package of reforms for net zero.

What are our updated RIIO-2 plans?

Our case for change analysis has shown that, while current market arrangements have been effective in delivering the first phase of decarbonisation, they are unlikely to deliver the next phase in a way that secures supply and at least cost.

Evidence indicates that current market design is: (1) already giving rise to negative outcomes and (2) is not well-positioned to solve future challenges. We have identified effective packages of market reform to facilitate the necessary changes. We will work with BEIS, Ofgem and industry stakeholders to develop, de-risk, trial and implement appropriate changes.

Our conclusions from Phase 3 are:

- The status quo will not deliver net zero cost effectively, as current market design creates inefficient behaviours, particularly in dispatch, resulting in dramatic and rising costs for consumers. The most efficient solution to this is real-time dynamic locational signals, and our assessment of the three locational market design options finds that neither national nor zonal pricing can deliver these effectively.

- A nodal pricing market with central dispatch has the potential to deliver significant consumer benefits through facilitating efficient dispatch of generation, demand and flexible assets, and optimising siting decisions across the whole electricity system. It creates the opportunity for consumers and industry to access low-cost, low-carbon electricity when and where it is abundant.

We think it is credible to implement nodal pricing and central dispatch within 5 years. There are some key questions that need to be answered, such as what additional market reforms are required to complement nodal pricing, and to what extent should consumers be exposed to locational price signals.

The responsibility for these decisions lies with BEIS and Ofgem – our role is to provide the insight and analysis that helps them make the best decision. If we do not provide them with the tools to make the best decisions, reforms might be delayed, or the wrong decisions made. This would risk GB not meeting its net zero goals and could result in additional billions of pounds paid by consumers.

(New) D20.1 NZMR programme

Ensuring the right market reforms to achieve net zero efficiently is a hugely complex challenge, with many interdependencies and a raft of future uncertainties. There are also a wide range of market participants that will stand to benefit or lose from any reforms. We are uniquely positioned at the heart of the energy system to lead the debate on what the right packages of reforms are to maximise value for consumers.

We will deliver this work through:

- **Analysis and trials** – phase three of our NZMR project found that a nodal pricing market with central dispatch has the potential to deliver significant consumer benefits through facilitating efficient dispatch of generation, demand and flexible assets, and optimising siting decisions across the whole electricity system. These findings will be developed in much more detail, before being designed, tested and de-risked. Technical and economic impact assessments will be needed.
- **Stakeholder engagement** – there is a vast amount of knowledge, experience and innovation across the industry, both in GB and internationally. Over the course of phases one to three, we have engaged with over 1,000 stakeholders through around 15 workshops and events, and dozens of in-depth bilateral meetings with market players, academics, think tanks and trade associations. We only expect this level of engagement to increase over BP2 as our work increases and our stakeholder community grows.
- We will also be working closely with our new MAC to set the strategic direction for NZMR; to embed stakeholder perspectives and international best practice; to provide transparency, certainty and confidence to stakeholders around our decision making; and to provide input on our strategic priorities and plans.
- **Working alongside BEIS and Ofgem** – we have worked closely with BEIS and Ofgem over the first three phases of NZMR and we expect this to increase over FY22/23 and BP2. We are currently supporting BEIS in their understanding of how our balancing and ancillary services should be reformed in a net zero world, and we are supporting Ofgem in their technical feasibility study of nodal wholesale markets.

Dependencies and assumptions

This activity is based on current expectations of the urgent market reform needed to reach net zero. This urgency is expected to pick up pace, due to failures in the current markets. If this happens, we may need to further grow the size of the Market Strategy team.

Key investments for this sub-activity

Depending on which market reforms are recommended, there may be impacts on our systems and processes. These investments could be initiated in BP2 and we may need to develop prototype/simulation capability to test these new market models. If so, we believe the NIA funding route could be appropriate.

7.2.9.2. A20 Stakeholder feedback

The broad scope of the project, and the fact that net zero market reform covers all GB electricity markets, not just ours, means we have organised stakeholder feedback into multiple categories. One of those is market reform and our role:

Market reform and our role

The more high-level stakeholder feedback can be split into three themes:

1. Our role – leading on discussions around GB electricity market reform is a new role for us with the establishment of NZMR and the market strategy team. Although some feedback has questioned why we are leading on this work; this has been significantly outweighed by positive feedback.

2. The interaction with BEIS and Ofgem – BEIS and Ofgem will be the ultimate decision-makers for any market reform. We have kept both well informed and given visibility of our work throughout. At our Markets Forum in June, Ofgem and BEIS took part in a panel discussion with us. This received great feedback from stakeholders, appreciating the fact that Ofgem, BEIS and ourselves are discussing the issue of market reform together.

3. The level and type of reform needed – across all stakeholder engagement there has been strong consensus about the overall need for market reform, however less so on specific options/solutions. Figure 12 shows the consensus on a set of statements on market reform from our phase 1 interviews.

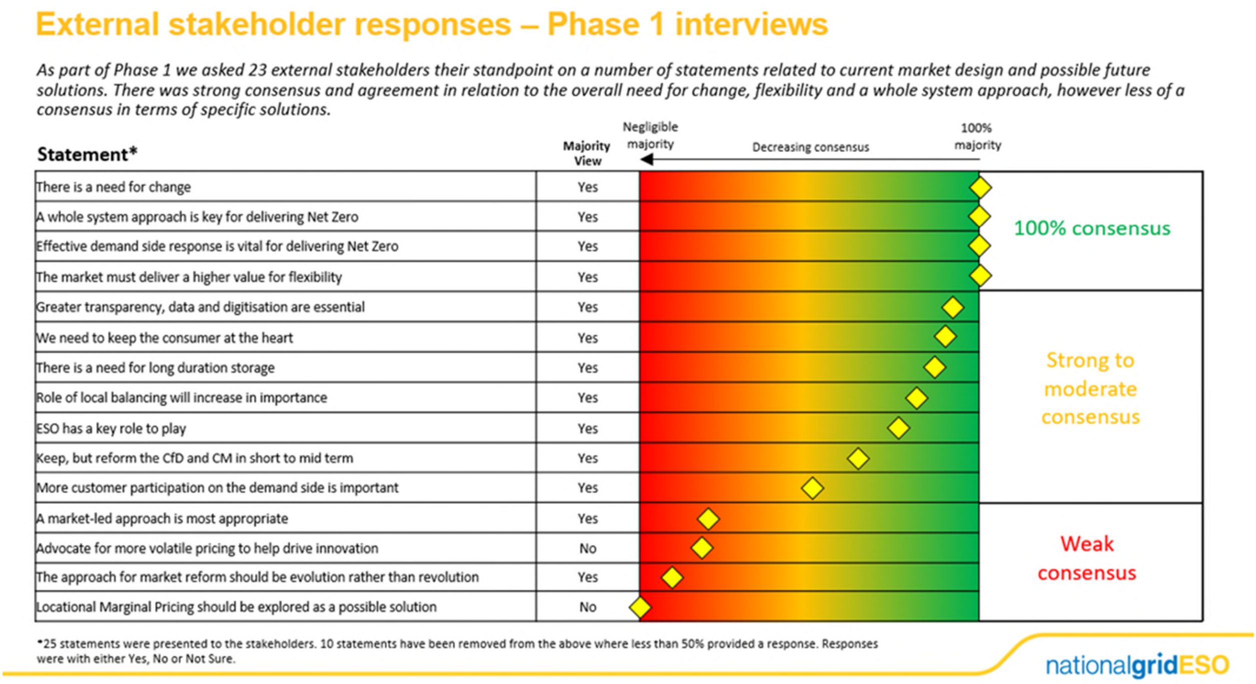

Figure 12: A set of statements on market reform from our Phase 1 interviews, and the stakeholder consensus for each.

For details of the stakeholder feedback grouped under the other categories, including co-creation and engagement – see the Annex 3 – Stakeholder engagement.

7.2.9.3. A20 Financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A20 - Net Zero Market reform		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	-	-	0.5	0.5	0.5
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**0.5**	**0.5**	**0.5**
FTE	BP2	-	-	6	6	6
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**6**	**6**	**6**

Table 17: RIIO-2 cost and FTE for A20

This new activity will be carried out by six FTEs which make up the NZMR team. This team started in April 2021 and were not part of our original BP1 requirements. The costs of the additional headcount are being managed through efficiencies elsewhere in Role 2, and we are not asking for additional funding for these in BP2. There are no figures reflected in our BP1 columns within the table to show that this is a new activity for BP2. The six FTEs referenced will not be additional but a continuation of the team that started in April 2021. We are maintaining the same cost baseline in BP2.

7.2.9.4. A20 Cost-benefit analysis

Annex 2 - CBA presents a break-even analysis for **A20**. A CBA was not created for **A20** as this does not deliver consumer benefit by itself. It is the implementation of its recommendations that provide consumer benefit, and we cannot say at this stage what these are. Further information can be found in Annex 2 - CBA, which lists benefits for **A20**.

7.2.10. (New) A21 Role in Europe

By 2035, our FES forecast between 17 and 27 GW of connected interconnector capacity, up from today's 7GW. Interconnectors will play a central role in a flexible and secure net zero electricity system for Great Britain. We will consider their role in the following areas:

- **Flexibility and balancing** – transitioning to a net zero system means increased fluctuations of supply and demand. This will involve an oversupply of renewables, but also periods of excess residual demand (when there is prolonged low wind). Interconnectors will be crucial to maintaining energy balance at these times.
- **Operability –** interconnectors can provide many ancillary services, so we must remove barriers to their participation. Conversely, without strategic coordination with cross-border parties, interconnectors could have an adverse impact on operability of Great Britain's system.
- **Adequacy -** interconnection will allow Great Britain and neighbouring system operators to support each other during times of system stress.

Now that the UK has left the European Union (EU), our relationship with our European counterparts has fundamentally changed. While some work has progressed on understanding the changes to our co-operation with EU stakeholders, the complexities of the future relationship between UK and EU stakeholders are still being understood.

This new cross-role activity, role in Europe, has been created for BP2 to ensure all activities in the cross-border and interconnector space are working towards the same purpose – not just those within Role 2 but also those in Role 1 (e.g., developing an improved interconnector trading solution (**D1.1.8**), and Role 3 (e.g., the treatment of Multi-Purpose Interconnectors (MPIs), under **A22** Offshore Coordination).

7.2.10.1. (New) A21.1 Cross-border initiatives

Our cross-border activities have been growing in importance in the last few years, not only because of the increasing number of interconnections, but also because of the European transition towards a more integrated energy market. This has led to several additional activities starting during BP1, and others triggered following the official exit of the UK from the EU. We have started developing a 2035 cross-border strategy for interconnectors and MPIs looking at the impact of cross-border infrastructure on flexibility, operability and adequacy in a net zero system; and at how we can support the transition to this future, ensuring GB consumers get maximum value from our interconnectedness with Europe.

We continued our pre-Brexit engagement with European counterparts, while designing new arrangements that will be used to frame European relationships from 2022. In BP1, we have focused on the implementation of the future GB/ EU working arrangements with ENTSO-E, which will also involve the coordination of UK TSOs and cooperation with ENTSO-E. The Offshore Coordination team has been contributing to policy development (OTNR), while engaging with North Seas Energy Cooperation (NSEC) and sharing information and best practices with EU partners.

Work has started on the delivery of the technical elements of the TCA, including engagement on a cross-border balancing interim solution and day ahead capacity calculation technical procedures (see section **A6.2** for more detail). Activities have also focused on enhancing interconnector operations and access to Great Britain markets.

What are our updated RIIO-2 plans?

While the long-term end-state of some technical and commercial arrangements is still uncertain, we are progressing amendments to achieve value and mitigate risk in the interim, which are described in **D21.3**:

This new activity has been necessary since the start of BP1 and is driven by the changes in our role in Europe, following Brexit, and the increasingly active role interconnectors will take under a net zero scenario. Furthermore, sub-activity **A6.2** European Union (EU) code change will lead on the implementation of the TCA and maintaining European relationships.

(New) D21.1 Cross-border strategy

We will work with key stakeholders including BEIS, Ofgem, UK TSOs and European TSOs to deliver a cross-border strategy for interconnectors. This will focus on operability, adequacy, system planning, and flexibility and balancing.

The conclusions of the 2035 cross-border strategy will form a roadmap for how we work with our key stakeholders to maximise the benefits of interconnection and minimise the risks for GB consumers. The key levers for this are still to be confirmed but are expected to be:

- Cross-border relationships: arrangements with European industry bodies and counterparts such as ENTSO-E, TSOs, etc.
- Commercial and market arrangements: for interconnector participation in our balancing and ancillary services markets
- Systems, data, and processes: IT tools, processes and data management systems we need to operate securely, efficiently, and effectively
- Regulation and frameworks: our role in shaping rules and regulations impacting interconnection

Without a single long-term vision, we risk a patchwork of conflicting mitigations being put in place, resulting in cross border flows becoming a fundamental blocker to zero carbon operation.

(New) D21.1.1 Strategic engagement with EU

Our relationship with our European counterparts has fundamentally changed. To maintain our level of influence, we will need to deepen bilateral relationships with stakeholders like EU TSOs, as well as developing additional relationships. We will need to ensure that we establish appropriate networks, so the sharing of data, insights, analysis, and information occurs across borders.

To achieve this, we will:

- Carry on implementation of TCA working arrangements agreement with ENTSO-E, started in 2022, by setting up processes for coordination with ENTSO-E, and coordinating UK TSOs' input into this process.
- Share information on security of supply risks, disruptions, events and sharing best practices regarding short-term and seasonal adequacy
- Cooperate with ENTSO-E on network development plans and pan-European market modelling
- Establish networks and maintain influence with:
    - Cross-border industry groups
    - Our European counterparts; the European Commission, ENTSO-E, EU TSOs, EU trade associations, etc.
- Identify significant EU legislative measures and consultations and respond accordingly.

(New) D21.1.2 Enhancing interconnector operations and access to Great Britain markets

Historically, interconnector arrangements have been developed on a bespoke, bilateral basis which may not achieve the maximum value for consumers and could cause unintended issues in the wider market. While the long-term end-state of some technical and commercial arrangements are still uncertain, we are progressing several amendments to mitigate risk in the interim; this will also align interconnectors more closely with other technologies:

- Work is underway to agree with EU TSOs and Ofgem how cross-border flows will be managed in the interim prior to Capacity Calculation implementation
- Grid Code modifications have been raised to facilitate the operation of a more interconnected system, one relating to ramp rate limits of interconnectors and another to interconnector participation in ancillary services (Grid Forming code modification)
- Analysis has been undertaken and published on current barriers preventing interconnectors participating in the DC market (as described in D4.6.3 Interconnectors in dynamic containment)
- Interconnection is being specifically considered within the net zero market reform project (as described in the new activity **A20 Net Zero Market Reform**) as well as in ESO balancing and ancillary services market reform activities (this is described in A4.6 Balancing and ancillary services market reform).

There are also activities relating to interconnectors in Roles 1 & 3:

Role 1 activities:

- Expand the scope of the Operability Strategy Report to bring in two new key areas, capacity adequacy and flexibility, in line with sub-activity **A15.9 Net-Zero Operability**
- Increase automation of trading processes and move to an auction platform to ensure we can continue to trade reliably, economically, and efficiently as Great Britain's interconnection with Europe increases.

Role 3 activities:

- Continue the development of FES and NOA reports on cross border flows
- Long-term operability and adequacy modelling, including cross role activity net zero operability and undertaking a capacity adequacy study
- Contribute to Ofgem's Strategic Network Planning for interconnection
- Produce a report for Ofgem on system operability impacts of hypothetical combinations of interconnectors between GB and our neighbours
- Finalise Centralised Strategic Network Planning (CSNP); Ofgem envisages a central scenario sufficiently robust to support network planning, both onshore and offshore.

Dependencies and assumptions

These deliverables are dependent on several key factors:

European policy developments

The evolution of European energy and climate legislation will have a direct impact on cross-border activities, given the interdependency of the UK and European energy systems. The progress made in the implementation of the TCA and the development of our European relationships will also depend on other external factors, such as the availability of resources from our UK and European counterparts or the priority they give to these activities. Geopolitical developments may impact the implementation process of the arrangements to ensure a coordinated design and operation of cross-border connections.

UK policy developments

The level of interconnection we will need to manage will depend on the level of interconnection approved by the UK Government. Ofgem intends to open a third cap and floor application window in mid- 2022 for cross-border projects. This will be for any interconnectors or MPIs able to connect by 2030. More interconnection is expected in line with the Government's targets, and we are already taking this into consideration in our activities geared towards enhancing interconnector operations and access to Great Britain markets.

The result of the UK Government's OTNR (see activity **A22**) will provide direction on the future operation of MPIs. Our Offshore Coordination project is working closely with BEIS and Ofgem to ensure we prepare in advance for any future requirements. More information is included in **A22 Offshore Coordination**.

Key investments for this sub-activity

IT or system investments may be required, for example for the development of operational tools to manage interconnectors and MPIs. Where known, the requirements and costs have been included in the respective sections of this plan.

7.2.10.2. A21 Stakeholder Feedback

(D21.1) Cross-border Strategy - Both BEIS and Ofgem have been consulted in detail on the anticipated scope for the cross-border strategy. This deliverable was highly supported by both parties. Ofgem has requested a holistic view of the combined system operator challenges associated with greater interconnection, and how interconnectors will be managed and optimised whilst GB transitions to net zero. We will be engaging deeply with wider industry stakeholders over the second year of BP1.

(D21.1.1) Cross-border Engagement Channels - UK TSOs have welcomed the leadership taken by NGESO to develop enduring engagement routes with ENTSO-E, in order to implement and maintain the TCA.

Long Term System Planning - Several interactions have taken place with BEIS and industry through the OTNR, focused on reducing the cost of deployment as offshore renewable is developed at scale. We are also involved in the debate between ENTSO-E, the European Commission and ACER on the EU Green Deal and the Offshore Renewable Energy Strategy. In this context, we have been engaging through ENTSO-E around different market design concepts for future MPI projects to develop our knowledge and understand which could be best suited to both reducing cost to consumers and providing the right support mechanisms for investors.

7.2.10.3. A21 Financials and headcount

The increased need to manage European and cross border issues was confirmed after the Trade and Cooperation Agreement was finalised, when we began additional recruitment into the Cross Border and EU team. This team was created in March 2020 and consisted of three FTEs; however, BP1 funding allowed the recruitment of three additional FTE in October 2021.

We propose the same headcount in BP2 as in BP1 (six FTEs) to manage our European interactions. This headcount is currently shown in the **A6 financials and headcount table**.

7.2.10.4. A21 Cost-benefit analysis

Annex 2 - CBA presents a break-even analysis for **A21**. We have not created a CBA because this activity does not deliver consumer benefit by itself. It is the implementation of its recommendations that provide consumer benefit, and we cannot quantify these at this stage. Further information can be found in Annex 2 – CBA.

7.3. Role 3 System insight, planning and network development

As the electricity system evolves to meet net zero, we must continue to deliver a reliable supply of electricity. From advances in technology to a changing generation mix, our Role 3 activities of system insights, planning, and network development focus on making sure the network is always ready for the demands placed on it. We use our unique position in the industry to optimise the connection of offshore wind farms, introduce competition to onshore transmission, and advise Ofgem and BEIS on the evolution of the network planning regime.

7.3.1. Key drivers of change in Role 3

Several factors have contributed to the changes described for Role 3:

- **An accelerated drive to net zero** - The focused effort by the UK Government to decarbonise the electricity system is driving accelerated activity across transmission and distribution. In turn, this is putting pressure on industry processes and frameworks to deliver in the timescales.

  This has driven a massive increase in connection applications across transmission (100% increase in 2021) and distribution. Many of these new applications are bringing forward new technologies and innovative solutions that don't fit neatly within the existing frameworks. So, our ability to gain data to model and analyse this rapidly changing network is paramount. We need to develop tools at an ever-increasing pace as we manage the effects of intermittency and inverter-based resource connections at a scale well ahead of what we previously expected.

- **Markets transformation** – Storage is part of the solution to get to net zero. The role of storage in the market and connecting it to the system continues to be a key focus. This has been clearly demonstrated through the 'flexibility first' approach in the DNO networks. This is where a market is created to avoid or delay asset investment, and storage is a key asset that can support this. We are continuing to work with the DNOs and TOs to understand how we can develop connection agreements that support the deployment of storage but don't put the system or consumer costs at risk.

- **Facilitating distributed flexibility** - Our markets are opening to increasing amounts of DER. Delivering a smarter energy system will mean more efficient flexibility markets and a more coordinated approach to network planning and operation. To do this, we need to ensure we have the appropriate tools and processes available to us, particularly in our control room. We will be working with stakeholders to ensure we have the appropriate operational visibility; key to this will be our relationship with the emerging DSOs, ensuring markets are developed in a manner which is interoperable, and which allows for coordinated system operation.

- **Learning from operating the system during the pandemic** - The real-time effects of decarbonising the electricity network were first felt during summer 2020 as a result of the pandemic. Demands on the system, and how it was operating, was an opportunity to learn what the future electricity system will look like. The Grid Code modifications made following 9 August 2019 give us greater access to information from the new technologies connecting to the system. By enhancing our tools and ability to model these new technologies we will be able to predict operability issues and put solutions in place.

- **Responding to increased complexity and the changing nature of the network** - In network access planning, the ability to grant our customers access for maintenance and construction at the most secure and least cost time slot is becoming increasingly challenging due to the variable nature of renewable generation. More system access than ever is needed to replace assets on an ageing network and respond to unprecedented levels of system development. In some areas, access to the network is now dependent on favourable weather conditions, where in the past it was more likely to be dependent on the time of year or season. This means optimisation of the power system is now more important, challenging and complex than ever. We are working closely with the TOs to find flexibility in their outage plans or ways to enhance network capability. We need to invest in our close to real-time tools and provide automation so that more outage scenarios can be considered to find the optimum solution.

- **Responding to regulatory changes** - In the RIIO-T2 framework for the TOs, the threshold to follow the Strategic Wider Works (SWW) process changed from projects with a projected cost greater than £500 million to over £100 million. Any projects over £100 million now need to follow the new Large Onshore Transmission Investment (LOTI) process. As the thresholds for LOTI projects are lower than for SWW, significantly more projects require our independent analysis to support TOs' business cases, creating additional workload.

7.3.2. Five-year strategy

Our five-year strategy is to use competition to support the development of a network that is always ready for the demands placed on it and can operate securely as we transition to a zero carbon system. For Role 3, the foundations for meeting our ambition to have the capability to operate a zero carbon network by 2025 are complete. Post 2025, we will prepare the network to enable 100% carbon free operation by 2035, in line with the new government target for the full decarbonisation of the electricity system.

To achieve this ambition, we must:

- Extend and enhance competition across network development.
- Create a strategic network planning process as a blueprint for the future, with anticipatory investments identified.
- Design a coordinated offshore network to connect 50GW Offshore wind by 2030.
- Invest in capabilities to operate a carbon free network in 2025.
- Create frameworks and ways of working across the whole electricity system that enables the transition to carbon free operation.
- Create a connections process that enables the transition.

While our strategy for Role 3 hasn't changed since the publication of BP1, we have greater clarity on the likely impact of BEIS's OTNR. We've also seen the launch of Ofgem's ETNPR, with its focus on more strategic network planning. We've already delivered significant additional activities within Role 3, establishing our position as a trusted partner for Ofgem, BEIS and the industry. These activities include Early Competition, Offshore Coordination, and supporting the ETNPR.

What does this mean for BP2?

Updates to our existing activities

For our Role 3 BP2 activities, we must continue to deliver against our original Business Plan. The key highlights are:

- **Evolve and enhance our network planning** - Expand the scope of our Electricity Ten Year Statement (ETYS). Evolve how we store and access data to support our new thermal modelling tool (Pouya) and develop better data sharing between us and the TOs. Enhance stability modelling for long term planning (as part of our NIA project with energy consultants TNEI), this builds the outcomes of the NIA project into our business.
- **Build on our system insights** - Deliver deeper operational insights alongside the national FES projections, considering more local factors which impact on national scenarios. Improve integration with other networks to develop regional FES.
- **Improve customer connections** – We need to drive the benefits of the connection process as we manage the complexities of decarbonisation and an increasing number of smaller parties connecting. This includes leading an industry-wide review of the connections process and delivering phase two of our customer connections portal work.
- **Develop networks fit for the future and improve network access**:
  - Improve the quality of system data and models used to analyse future network needs and operability solutions.
  - Continue delivering RDPs to identify key regional areas of the network for development.
  - Deliver a monitoring and control system (MCS) to provide fast and coordinated frequency response for a low inertia system.
  - Engage with stakeholders on the technologies required for effective zero carbon operation, including automation of network access planning to maintain system stability.

    - Bring forward plans to manage system access on a much more heavily constrained network with clarity of long-term network access requirements.
    - Incorporate whole electricity system planning into the NAP process.
- **Facilitate distributed flexibility** - We have already laid the groundwork to facilitate distributed flexibility providing services to the ESO. In BP2 we will accelerate this transition, making sure that our requirements work for smaller providers. We will also develop the tools to ensure continued system operability with greater volumes of distributed flexibility, including operational visibility and service co-ordination systems.

Our activities across Role 3 span a range of topics, and more potential areas of work will likely emerge during the BP2 period. We will continue to lead new areas of work where it is in the consumer interest, making use of the pass through model and flexible regulatory framework as appropriate.

Additional activity in BP2

During the first year of BP1, we have worked with Ofgem and BEIS on the following new Role 3 activities, which are now included within our BP2 plan:

- Ofgem has requested we support the new cap and floor window for Interconnectors by assessing potential connection zones and forecasting the operational costs of connecting interconnectors. This will allow us and Ofgem to ensure any new interconnectors are sited in the least cost/ most benefit zones.
- Ofgem has asked us to continue developing a regime in which transmission assets that meet the necessary criteria can be subjected to a competitive delivery process. We are therefore continuing to develop the roles and processes for carrying out the assessment and tender process for Early Competition.
- BEIS and Ofgem have asked us to lead on developing network design for the connection of 50GW of offshore wind by 2030. This will compare the counterfactual of point-to-point radial connections with an integrated and coordinated design. The resulting designs will compare costs, environmental and community impacts and propose a network design optimised across these criteria.
- Recognising that the current network planning approach is no longer fit for purpose, we have commenced work with Ofgem to design a new long-term approach for making strategic decisions on what network to build and when, or what markets or whole system solutions could be available. This work is being developed in the ETNPR project.

The diagrams overleaf illustrate the level of change, within Role 3 activities, in comparison to our original Business Plan submission.

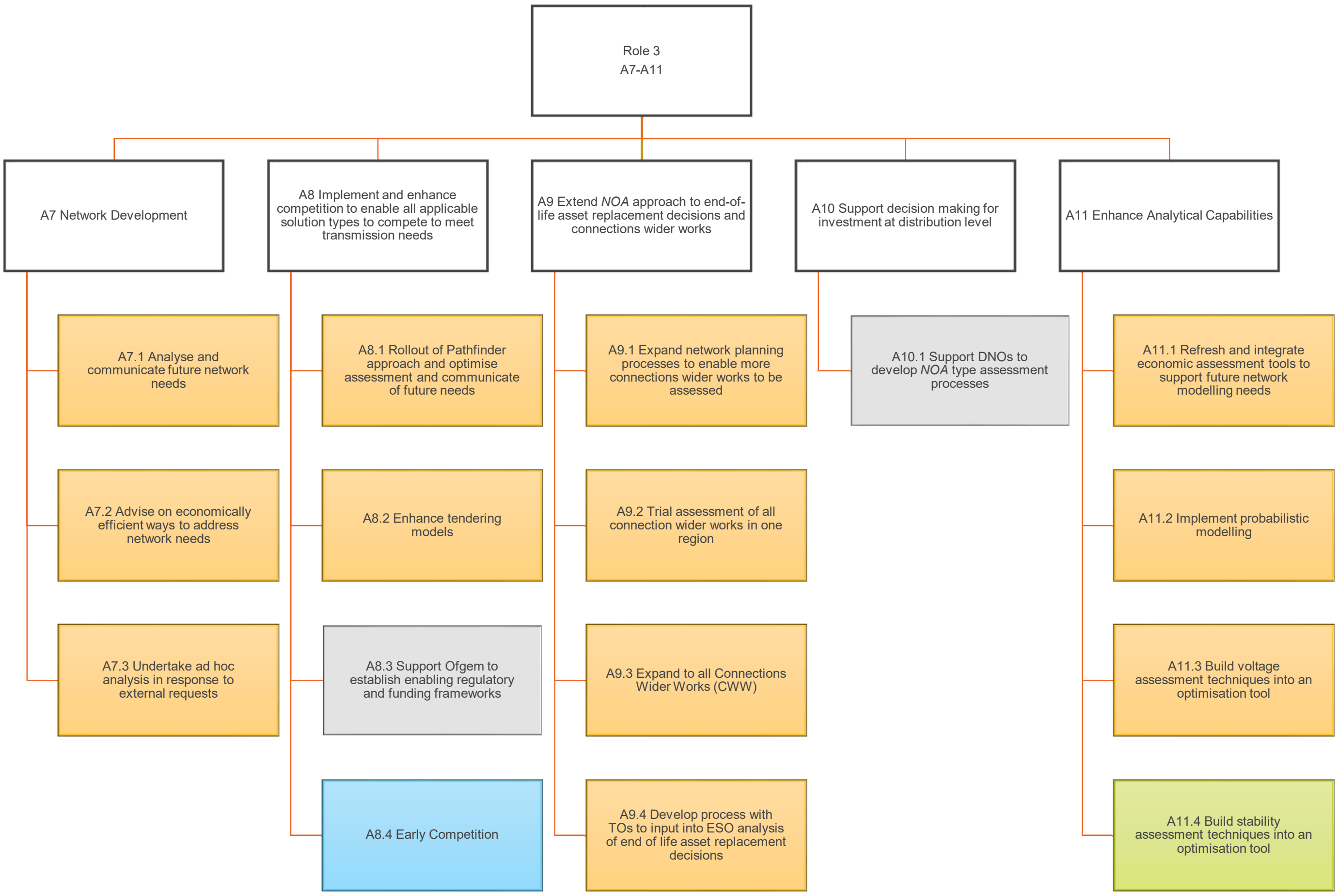

Figure 13: Role 3 activities 7-11 level of change

Key

New sub-activity

Materially changed sub-activity

Sub-activity with no or minor change

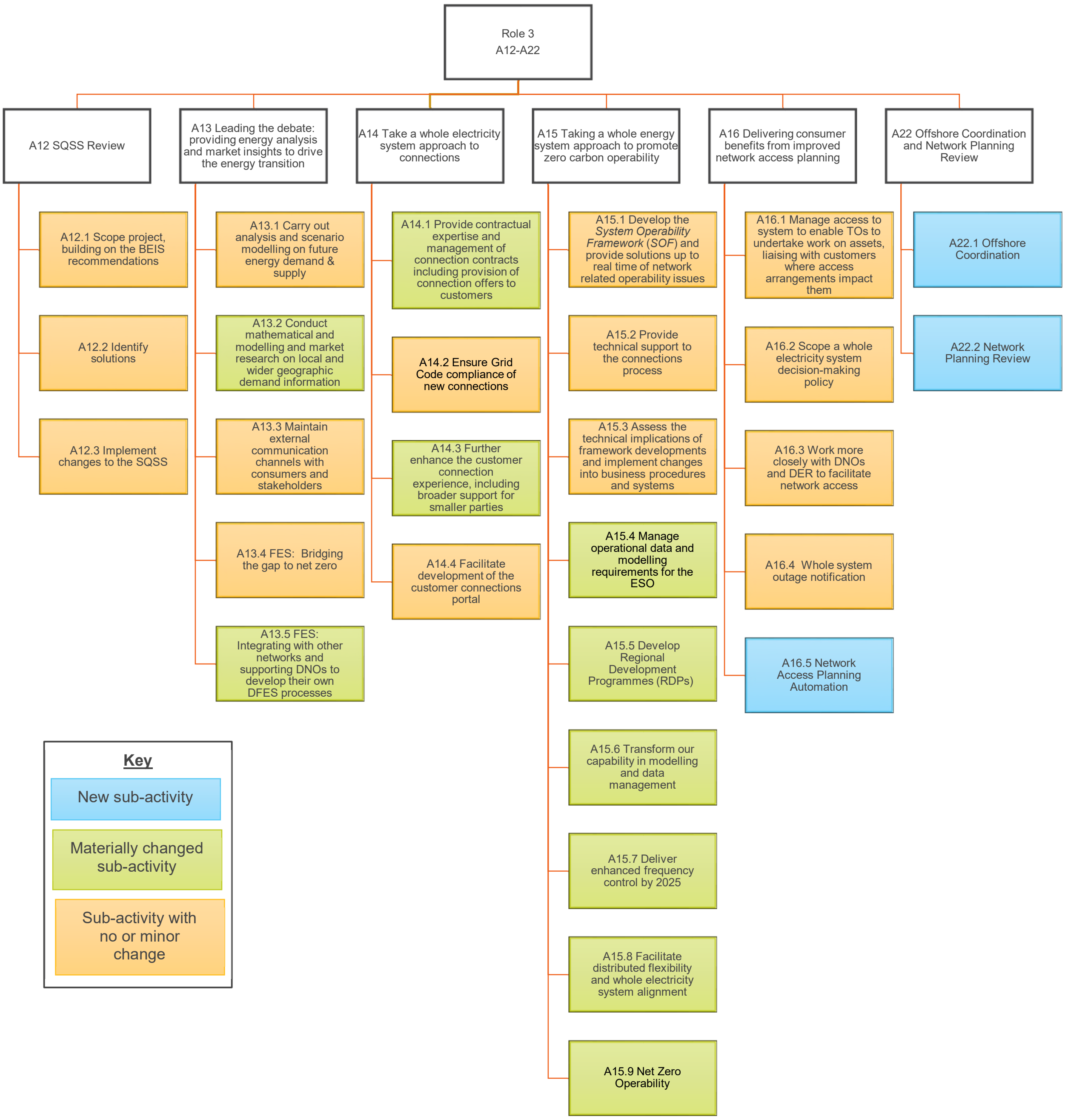

Figure 14: Role 3 activities 12-16 level of change

7.3.3. Role 3 costs overview

The graph and table below represent the five-year RIIO-2 Business Plan period, comparing the original submission to our updated proposals (in 18/19 prices). These represent Role 3 costs before support functions and cross cutting activities are overlaid.

The forecasts for the opex, capex and FTEs needed to support Role 3 activities in BP2 have increased significantly since our first Business Plan submission. The majority of these increases have occurred ahead of BP2, as the business has adapted to meet the greater operational workload caused by the accelerated drive to net zero. We have begun facilitating distributed flexibility, implemented learnings from the pandemic within our tools and models, and made numerous regulatory changes in support of the changing nature of the network.

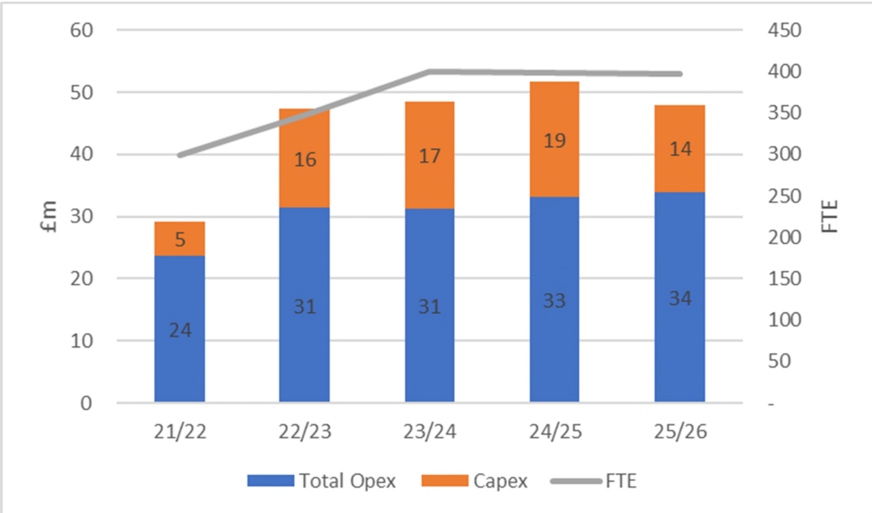

Figure 15: graph of Role 3 RIIO-2 costs and FTE

		Five-Year strategy				
		Forecast		**BP2**		**BP3**
	Role 3	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	5.5	16.0	17.3	18.5	14.0
	BP1	12.2	13.3	15.6	14.4	15.6
	Variance	**(6.8)**	**2.7**	**1.7**	**4.1**	**(1.7)**
Opex (£m)	BP2	23.8	31.4	31.2	33.1	34.0
	BP1	21.5	23.2	25.2	26.8	27.4
	Variance	**2.2**	**8.2**	**5.9**	**6.3**	**6.6**
FTE	BP2	299	348	392	390	387
	BP1	225	236	247	253	251
	Variance	**74**	**111**	**146**	**137**	**136**

Table 18: Role 3 RIIO-2 costs and FTE

Specifically compared to BP1 there is an additional 146 FTEs in FY24, decreasing to 137 FTEs in FY25. These are to support increased IT investment of £6m capex and £12m of additional operational deliverables.

These increases are predominantly driven by:

- **A7-A11** (excluding A8.4) Network Development – no change to capex, an increase of £1m opex and four FTEs (FY25)
- **A8.4** Early Competition – this is a new activity with £3m of opex, and 11 FTEs (FY24), note this reduces to three FTEs in FY25
- **A12** SQSS review – no change to capex and opex, with an increase of two FTEs (FY25)

- **A13** Lead the Debate – no change to capex and opex, with an increase of nine FTEs (FY25)
- **A14** Whole system approach to connections – no change to capex, a decrease of £2m to opex and an increase of 27 FTEs (FY25)
- **A15** Whole electricity system approach to promote zero carbon operability – an increase of £6m capex, £2m opex and 34 FTEs (FY25)
- **A16** Delivering consumer benefits from improved network access – no change to capex, an increase of £2m opex and 11 FTEs (FY25)
- **A22** Offshore Coordination / Network Planning Review – this is a new activity with £7m of opex across BP2 and 47 FTEs (FY25)

More details on the drivers of these cost and headcount increases can be found within the relevant activity descriptions below.

7.3.4. Key capabilities required

In the People, Capability and Culture chapter we discuss the capabilities the ESO needs in order to deliver on our RIIO-2 commitments, and how we will build and enhance them across our workforce. For Role 3 we need to develop additional capabilities in:

- **power systems engineering:** application of technical knowledge to network development and technical compliance of both onshore and offshore power systems and technologies.
- **economic analysis and modelling:** application of sophisticated tools and models to test economic efficiency of various network development scenarios.
- **data management:** ensuring quality and consistency of data collated from ESO, TOs and external sources to provide trusted data which can be integrated.
- **data analysis and programming capabilities:** enhancing models to provide understanding of longer-term outcomes and increasing sensitivity of models to present alternate views. Including the deployment of automation and AI; and developing specific skillsets necessary to complete electromagnetic transients and power quality analysis.
- **customer- and stakeholder-facing capabilities:** ability to provide effective support for new and existing customers, recognising differing needs, and to engage the full range of stakeholders in the development of new processes and services.
- **leading the debate:** facilitating industry collaboration and encouraging consumer participation to reach net zero targets.

7.3.5. Role Benefits

We have updated the RIIO-2 CBAs for transformational activities in **A7-A11** (formerly the CBA for **A8-A11**), **A14**, **A15** and **A16**. The new activity **A22** has a break-even analysis in the Annex 2 - CBA.

Activity	Name	NPV BP1 (£m)	NPV BP2 (£m)	Change (£m)
A7	Network Development	663	820	+157
A8	Enable all solution types to compete to meet transmission needs			
A9	Extend NOA approach to end-of-life asset replacement decisions and connections wider works			

A10	Support decision making for investment at distribution level			
A11	Enhance analytical capabilities			
A12	SQSS Review	Break-even analysis		
A13	Leading the Debate	Break-even analysis		
A14	Take a whole electricity system approach to connections	2	16	+14
A15	Taking a whole energy system approach to promote zero carbon operability	466	1246	+780
A16	Delivering consumer benefits from improved network access planning	204	254	+50
A22	Offshore Coordination/Network Planning Review	New break-even analysis		
	Total	**1335**	**2336**	**+1001**

Table 19: Role 3 NPV change

Annex 2 - CBA presents **A7, A8, A9, A10** and **A11** in a single CBA because there are very large dependencies between these activities. Creating separate CBAs would likely lead to double counting of costs and/or benefits. A summary of the findings of this CBA is presented under activity **A11**.

Break-even analyses were presented for **A12** and **A13** in our BP1 submission. These analyses were not updated for this second Business Plan for reasons detailed in Annex 2 - CBA.

Role 3 delivery plan detail

7.3.6. A7 Network development

Through our network planning processes, we identify which network reinforcements are needed and when, and advise the TOs on which investments will deliver the greatest benefit for consumers.

From January 2022, the ESO has a new role to analyse system operability implications of further interconnection (including impact on thermal, voltage and stability). The analysis will be reported to Ofgem ahead of the third cap-and-floor application window in mid-2022. Ofgem also anticipates an enhanced role for us in an interconnector strategic network planning process, although this work is yet to be fully defined.

We have now developed an improved understanding of the scope and number of projects covered by the Large Onshore Transmission Investment (LOTI) process (which replaces the Strategic Wider Works (SWW) process) and its requirements set out in the RIIO-2 Final Determinations. As the thresholds for LOTI are lower than those for SWW, significantly more projects require our independent analysis to support the TO’s business case. We also expect the complexity and scope of Pathfinder projects to continue to increase as network operability requirements become more challenging on the path to net zero.

While there are no material changes to the deliverables in this activity, we do anticipate additional workload to support increased analysis and complexity of Pathfinders as described above.

A7 sub-activities and deliverables

7.3.6.1. A7.1 Analyse and communicate future network needs

Our BP1 deliverables focused on improving our annual ETYS to engage a broader range of participants. During BP1, we have made our documents easier to engage with, improved our communication of bulk power system needs, and improved our system requirements form.

By the start of BP2, we will have reviewed whether additional system needs can be signalled through the ETYS document. Our improvements to ETYS going into BP2 will rely on the NOA enhanced tools we are developing within **A11**.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2. However, operating the power system is becoming more complex – for example, due to the evolving generation mix - additional analysis is required to assess its needs. We need to expand the scope of the ETYS to consider thermal needs on a year-round basis and include voltage and stability needs. Our team is growing to account for this additional work.

The NOA enhancement tools (**A11**) are a key enabler to communicate increased system needs. Their development is complex and will continue into BP2. The tools will result in more scenarios and analyses, which will require additional resources.

Dependencies and assumptions

Delivery of enhancements to ETYS relies on the enhanced NOA tools being developed to improve our view of year-round system needs. For example, if the Pouya thermal modelling tool (**D11.2**) is delayed, ETYS enhancements will be delayed as a result.

7.3.6.2. A7.2 Advise on efficient ways to address networks needs

We publish the annual NOA report (**D7.2**), advising on the requirement for TOs to build new transmission assets, and where non-network solutions such as intertrips can deliver additional network capacity. We also assess the optimal level of interconnection for the Great Britain (GB) market, which helps developers assess the value of investments.

Since the start of RIIO-2, we have:

- Extended the 'least worst regret' approach to 'least worst weighted regret' to explore sensitivities to the different FES scenarios.
- Made recommendations for non-network solutions, identifying potential for significant consumer benefit such as congestion management services on the Scotland/England boundary via the Constraint Management Pathfinder.
- Started work on the East Anglia boundary to mitigate the rising cost of constraints due to new wind connections ahead of reinforcements.
- Carried out more economic assessment than expected as part of the Pathfinder projects. We expect the volume, complexity and scope of the Pathfinder projects to increase, and so our team has grown to support delivery.
- Reviewed the output from the offshore wider works (OWW) assessment in NOA 2020/21 and are fully evaluating the benefit of OWW options in line with the *Offshore Coordination Project.*

Ofgem has asked us to produce a report in April 2022 covering the system operability impacts of hypothetical combinations of interconnectors between GB and our neighbours (ahead of the third cap-and-floor application window). Our team has grown to undertake this activity.

What are our updated RIIO-2 plans?

Ofgem's December 2021 decision[18] in relation to its Interconnector Policy Review, created a new role for us in carrying out analysis of system operability implications of further interconnection. In the BP2 timeframe, Ofgem also foresees an enhanced role for us in interconnector strategic network planning processes, building on the work we will have done in 2022/23. We will work with Ofgem, BEIS and other stakeholders to develop the end state. Once we have more clarity, we may define additional BP2 deliverables.

Other than the additional work described above, there are no material changes to the ambitions of this sub-activity for BP2.

[18] https://www.ofgem.gov.uk/sites/default/files/2021-12/ICPR%20Decision%20Paper.pdf

Dependencies and assumptions

The future work required by us on interconnector strategic network planning in BP2 is still work in progress, following Ofgem's Interconnector Policy Review. For the first analysis, we are assessing 36 potential interconnector sites in GB. We expect our analysis to be presented by Ofgem at a more regional level in their report. We expect the complexity and scale of future analysis to likely increase, based on a scale of ambition for interconnectors identified by the Government and in the FES.

Delivery relies on NOA tools, so this activity will benefit from improvements from IT investments for related enhancements.

7.3.6.3. A7.3 Undertake ad hoc analysis in response to external requests

In BP1, we envisaged work in three key areas in this sub-activity:

- Strategic wider works (SWW) projects (now the LOTI process)
- Boundary studies for the Connections and Infrastructure Options Note (CION) process covering offshore connections
- Cost-benefit Analysis (CBAs) for small schemes (ad hoc assessments for localised network issues).

So far in BP1 we have undertaken analysis for LOTI projects and several CBAs for small schemes to support TO decision-making.

The SWW re-opener process was replaced in RIIO-T2 by the LOTI re-opener process, which provides TOs with a route to apply for funding for large network investments that were not funded at the time of setting the price control due to insufficient certainty. We undertake analysis in line with Ofgem's Large Onshore Transmission Investments (LOTI) Reopener Guidance[19]. The threshold for LOTI projects is £100m, compared to £500m for SWW projects, so significantly more projects are requiring LOTI assessment than in RIIO-1. We have not undertaken any work for the CION process covering offshore connections, due to this being temporarily subsumed into the Offshore Coordination Project[20], but we continue to provide insight and expertise.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

The volume of projects requiring our analysis as part of the LOTI process had to be estimated at the time of writing the first RIIO-2 five-year plan. The TO price controls have subsequently been finalised, and the workload for LOTI projects is at least double that required for SWW projects due to the change in threshold. Each LOTI project requires cost benefit analysis for both the initial and final needs cases. In FY22, we have completed five assessments for TOs. We are currently working on two more and expect at least a further seven in FY23. The NOA 2021/22 identified a further 14 projects requiring LOTIs (meaning 28 CBAs) in the coming years. We also expect further TO schemes requiring LOTIs.

Despite the increase in volume of work, we have not increased our resource as we envisage being able to absorb any additional requirements within the current Role 3 business areas. We will use the cost-pass through model if additional requirements increase substantially during the BP2 period.

Dependencies and assumptions

We have assumed the number of LOTI projects, and the assessments we undertake, remains broadly stable.

The medium sized investment project (MSIP) reopener in the TO' price control framework can require the ESO to undertake analyses, but our experience from 2021/22 is that, so far, no additional analysis has been required on standalone load-related (thermal constraints) investments. We assume this stays the same in the BP2 period, however this could change.

[19] https://www.ofgem.gov.uk/publications/large-onshore-transmission-investments-loti-re-opener-guidance
[20] See Activity 22

Key investments for this sub-activity

Once implemented, this sub-activity will benefit from improvements resulting from IT investments for NOA enhancements.

7.3.6.4. A7 Stakeholder Feedback

This area does not contain any new or materially changed activities, and stakeholder feedback in this area is limited.

(A7.1) We shared our 'communicating future system needs' proposals with stakeholders in February 2022, who were broadly supportive. Some fed back specifically that having more insight on year-round requirements would be very helpful and others wanted further clarity on the value case. We explained the increasing importance of identifying periods when there are additional thermal constraint management needs on the system. This is so we can communicate these needs to market parties to enable solutions through the Early Competition process.

(A7.2) With regard to the Interconnector Policy Review, most of the work has been focused on engagement with Ofgem. However, we expect our engagement to be expanded going forward and stakeholders will have an opportunity to provide feedback on any of the supporting work we do for Ofgem's Cap and Floor Window 3 once it is released by Ofgem.

(A7.3) We have received some positive feedback from stakeholders, including that the CBA support for LOTI has been very good. Stakeholders believe it is essential we are well resourced, so we have included this in our plan. Stakeholders also mentioned other benefits such as early sight of potential commercial solutions helping TOs in planning, which we are considering.

7.3.6.5. A7 Financials and Headcount

See combined table in **A11.**

7.3.7. (Materially Changed) A8 Enable all solution types to compete to meet transmission needs

The Pathfinder approach allows us to solve issues and find innovative ways of operating the electricity system as it decarbonises while keeping costs down for consumers. It is a pioneering procurement exercise that adopts a 'learning by doing' approach to ensure we continue to attract competitive and innovative service proposals.

Initially, this meant incentivising investment in new, or repurposed stability and voltage service capability to meet the expected shortfall and/or to avoid the significant costs of conventional carbon plant slipping down the merit order or closing completely. The Pathfinders have been very successful in showing how future procurement should evolve. Accordingly, we are currently reviewing how best to take the Pathfinders programme forward and expect to provide more clarity on this in our August final Business Plan submission.

We have also created new sub-activity A8.4 to continue our work on Early Competition, in response to Ofgem's instruction that we produce an *Early Competition Plan*, and in the expectation that Ofgem would ask us to progress this work to the next stage (this decision was made by Ofgem in March 2022 and we will review our proposals against this for our final August Plan).

A8 sub-activities and deliverables

7.3.7.1. A8.1 Rollout of Pathfinder approach and optimise assessment and communication of future needs

This sub-activity establishes a competitive approach to the procurement of transmission system services, to evaluate both TO and commercial 3rd party solutions. From those initial procurement projects, we will improve the process and the identification of future needs to the market.

There are six separate Pathfinder projects, with a seventh project currently being assessed:

- Mersey Voltage
- Stability Phase 1
- Constraint Management B6
- Stability Phase 2
- Pennines Voltage
- Stability Phase 3.

This is in line with our original proposal of doubling the number of Pathfinders carried out in RIIO-1. These projects have led to consumer cost savings[21], enabled increased renewable output from the market as well as supporting system compliance.

The BP1 period coincided with increasing system challenges. In response, we developed new services and procurement approaches to meet our system security needs and net zero ambitions in the most efficient way for the end consumer. This innovative approach, coupled with a code, regulatory and business process landscape that is still catching up, meant we have been experimenting with the best approach to meet these aims. This programme of work was placed under the banner of “Pathfinders”.

What are our updated RIIO-2 plans?

We intend to continue to engage solution providers regarding how best to improve tender processes for long-term contracts.

There is currently no immediate change to our plans for this sub-activity in the BP2 period, although this may be updated for the August final Business Plan.

We have maintained our resource level in this area, based on experience of running and refining the original projects. It is crucial to retain the appropriate market, procurement, and implementation resources to deliver these projects going forward.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **130** Emergent Technology and System Management. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.7.2. A8.2 Enhance tendering models

What was in our first RIIO-2 Business Plan?

This sub-activity examines how we can develop tendering models to drive value for the end consumer. This includes reducing barriers to entry, through adopting technology agnostic requirements, utilising clear and transparent processes and ensuring a level playing field for bidders.

What have we carried out to date?

We initiated the first Pathfinder in 2019 and, during the six projects since then, we have constantly sought feedback from stakeholders. We have incorporated new thinking and improvements into each subsequent tender. These have principally focused on providing clearer and more timely information for potential bidders to allow them to make more informed business decisions, as well as amending codes to remove barriers to entry, reduce tender cost risks and improve equity and transparency. For example, we have undertaken the following:

- Trial of a bay reservation approach to manage connection queue issues. Pathfinders don’t require bidders to have a connection offer, or to have made a connection application at the point of tender. However, speculative connection applications have created some challenges for the Pathfinders process, such as restricting availability and increasing the workload on connection teams.

[21] https://www.nationalgrideso.com/news/voltage-pathfinder-results-consumer-savings

- Standardised the procurement approach utilising the ARIBA platform. This provides an improved process for managing the significant volume of tender documentation.
- Improved information on where parties can connect solutions. Feedback from stakeholders identified the cost uncertainty of connecting to the network, such as land costs, groundworks and perimetry needs. By giving greater visibility to site conditions, including site visits as well as flagging availability of operational land, parties could make better decisions.

What are our updated RIIO-2 plans?

There are currently no new deliverables planned for the BP2 period. The existing delivery of improved tender approaches allowing more participants to enter the market (**D8.2.3**) completes in the first year of BP2.

There is on-going work regarding the future of procurement, so the outcomes of this work may impact this activity. We aim to provide more detail on this in our final Business Plan.

7.3.7.3. A8.3 Support Ofgem to establish regulatory and funding frameworks

In BP1 we identified that regulatory and funding frameworks supported a regime whereby longer-term network needs were addressed by the relevant TO, with funding allocated through their price controls. As the Pathfinders were developing an evolving approach to the procurement of system requirements, it was important to evaluate and potentially amend the supporting frameworks to ensure the appropriate funding was available for all possible solutions.

The Pathfinder programme has identified limitations with the current regulatory arrangements when developing new procurement approaches to meet transmission services. This has included questions regarding the appropriateness of the categorisation of connection types and the connections queue rules when we are procuring service solutions at specific transmission locations.

We have worked with Ofgem and stakeholders to develop solutions to these issues. The lead time to change the codes is significant so we have developed faster temporary solutions with a commitment to develop enduring solutions within BP2.

What are our updated RIIO-2 plans?

The BP1 deliverables for this sub-activity are complete. A Connection and Use of System Code (CUSC)[22] modification has been approved and an equivalent Distribution Connection and Use of System Agreement (DCUSA)[23] modification is in development to remove the voltage Pathfinder projects from the Transmission Network Use of System (TNUoS)[24] demand residual.

We developed a more efficient approach to the allocation of connections for stability and voltage locational procurement projects. Ofgem has since launched its ETNPR, focusing on a more strategic approach. This could potentially impact this sub-activity during the BP2 period. Further detail can be seen in **A22 Offshore Coordination/Network Planning Review**.

7.3.7.4. (New) A8.4 Early Competition

Electricity transmission has a central role to play in delivering reliable and affordable greener power for consumers. Introducing competition in the delivery of new investment has a key role. Ofgem has been developing competition policy for onshore electricity transmission for a number of years. As part of this, Ofgem identified there is likely to be millions of pounds worth of consumer benefit associated with increasing competition.[25]

As part of the RIIO-2 Business Planning process, Ofgem asked us to plan how a competition to design, build and own onshore transmission assets could be run in the early stages of the project lifecycle. This could deliver the most benefit for consumers as it allows innovation across the whole project lifecycle. Our Early

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[22] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc
[23] https://www.dcusa.co.uk/
[24] https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges
[25] https://www.ofgem.gov.uk/sites/default/files/2021-08/Transmission_Early_Competition_IA_Final.pdf

Competition Plan (ECP) was published in April 2021.[26] It included high levels of input from stakeholders, through 33 webinar discussions and two formal consultations.

Since submission of our ECP, we have been progressing with 'low regrets' activity to maintain the momentum towards implementing Early Competition. Ofgem published their decision on Early Competition in March stating that it is in the interest of consumers for the ESO to complete its development of an Early Competition model. From April 2022 we have entered into an implementation phase where we are designing detailed processes of the end-to-end tender process and supporting documentation, and the complex commercial model for Early Competition. We are working with Ofgem, BEIS and industry to progress the required framework changes.

To support the first tender, we will be identifying a suitable project and embedding an ongoing identification process incorporating any changes to planning processes as outlined in **A22** Offshore Coordination/Network Planning Review. We are also enhancing our procurement processes through our NOA Pathfinders to align processes to the Early Competition model.

We are planning new roles and responsibilities to deliver Early Competition. This includes scoping the requirements for a Procurement body, roles and responsibilities in the ongoing management of the winning bidder and activities required from other parties, such as TOs.

We are seeking stakeholder input throughout, balancing the needs of stakeholders with a commercial interest with the needs of the consumer.

What are our RIIO-2 plans?

In the BP2 plan, we have included the activities required to complete implementation of Early Competition, and for the roles that will sit with the ESO on an enduring basis.

In Q1 and Q2 of 2023/24 we will be continuing to conduct Early Competition planning and aim for pre-tender engagement to begin during Q3 2023/24 and for the first tender event to be launched in Q3 2024/25, subject to Ofgem approval.

In their Early Competition decision document Ofgem broadly agree on the proposals for roles and responsibilities set out by the ESO in our ECP. This would see the ESO taking on the roles of Network Planning body, Procurement body, Contract counterparty and Payment counterparty roles. The ESO would however only take on the role of Procurement body once it becomes the Future System Operator and is appointed into the role by the Secretary of State. As the Procurement body role is linked to Future System Operator details for this are included in the Annex 5 - Future System Operator. For other roles we expect our deliverables to be:

- By Quarter 3 2024/25, we will have provided the required technical input to enable the procurement body to specify the network need in the tender document and supported pre-tender engagement with potential bidders.
- By Quarter 3 2024/25, we will have produced a bespoke network model to enable bidders to test their solutions.
- By Quarter 3 2024/25, we will have fed in contractual requirements to the procurement body as part of setting up the tender and supported pre-tender engagement with potential bidders.

During BP1, we are increasing headcount for Early Competition (as outlined in A8.4 Financials and Headcount below) to continue the detailed planning to allow the Early Competition model to be implemented.

We assume technical input will also be made available by TOs to support the tender process, and the procurement body will contain technical resource to evaluate the suitability of technologies and the deliverability of proposals.

Dependencies and assumptions

Completing implementation of Early Competition, and the launch of an actual tender, is dependent on legislation being put in place by BEIS. Current working assumptions are that this will be in place by end Q2 2023.

[26] https://www.nationalgrideso.com/future-energy/projects/early-competition-plan/project-documents

The Future System Operator decision affects whether it is appropriate for us to become the procurement body for Early Competition. This role is considered further in Annex 5 - Future System Operator. For Business Planning, we assume there will be a procurement body in place by Q3 2023.

There is also an interaction with the Network Planning Review, which is developing new network planning processes. We have assumed a project suitable for Early Competition will become available, whether through NOA, strategic planning, connections or asset replacement planning processes.

There is a further interaction with offshore network planning and the use of competition as a delivery method. However, Early Competition onshore is not specifically dependent on this. We assume offshore competition models will evolve from the onshore model.

Key investments for this sub-activity

The cost of IT changes for the Network Planning body role and payment counterparty role during BP2 is expected to be minimal and will not require specific IT investment. Further IT costs are expected to be incurred after BP2 once the competition has concluded. These will be required to integrate a new TO and network solution into our IT systems.

IT investment associated with the Procurement body is not included here.

7.3.7.5. A8.4 Financials and Headcount

The table below covers **A8.4** only. Financials and Headcount data for activities **A8.1-A8.3** are contained within the combined table in **A11**.

		Five-Year strategy				
		Forecast		BP2		BP3
A8.4 - Early Competition		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	1.1	3.2	1.6	1.0	1.0
	BP1	-	-	-	-	-
	Variance	**1.1**	**3.2**	**1.6**	**1.0**	**1.0**
FTE	BP2	4	20	11	3	3
	BP1	-	-	-	-	-
	Variance	**4**	**20**	**11**	**3**	**3**

Table 20: RIIO-2 costs and FTE for A8.4

Financials and headcount data for this sub-activity **A8.4** is included separately as it is a new activity and part of the broader network planning ambitions. Resource peaks during the planning and implementation stage (second year of BP1, 20 FTEs) are forecast to reduce to three FTEs during BP2 to manage the network planning and contract counterparty roles.

This will include developing the detailed tender processes, supporting legislative and framework changes, and engaging the market and other stakeholders. This will continue until Q3 2023/24. Consultancy support will cover major infrastructure procurement skills gaps in our business. Details on the level of support required in this area will be updated for the final Business Plan.

Specific resource requirements for running Early Competition are subject to revision as the detail and split of responsibilities becomes clearer. However, currently we expect that between Q3 2023/24 and Q3 2024/25, we will require three FTEs to perform the Network Planning and Contract counterparty roles.

7.3.7.6. A8 Stakeholder feedback

(A8.1-A8.2) Pathfinder projects are based on 'learning by doing' and stakeholder feedback is an inherent part of this process. Whilst we have not significantly changed the scope of our BP2 activities as a direct result of stakeholder feedback. We will continue to improve BP2 Pathfinder projects by engaging with stakeholders.

(A8.3) We have not received any specific feedback in BP1 that has resulted in significant changes to these areas.

(A8.4) During the creation of the Early Competition Plan (ECP) we received many strong and often opposing views. The ENSG (Electricity Networks Stakeholder Group) was formed to ensure we responded to input. ENSG confirmed its support for our stakeholder engagement during development of the ECP in its final report. Full documentation is available on the early competition page of our website.

Many stakeholders have a strong commercial interest in Early Competition. We sought to balance these views and develop proposals that we felt would achieve the best value for consumers. This included seeking feedback from Citizen's Advice.

Other areas of focus for stakeholder concerns were; whether competition will deliver value for consumers, the ESO independence when running tender processes, implementation timescales and whether the TOs should have a role in network planning. Further information and how we have responded can be found in Annex 3 – Stakeholder engagement.

7.3.8. A9 Extend NOA approach to end-of-life asset replacement decisions and connections wider works

Activity **A9** focuses primarily on expanding network planning processes to look at end-of-life replacement decisions for large assets, making recommendations through the NOA and enhancing processes to assess all connections wider works.

The deliverables within sub-activities **A9.1-A9.4** remain on track, with no plans to extend or enhance them beyond the existing commitments.

A9 sub-activities and deliverables

7.3.8.1. A9.1 – A9.4 (Combined Narrative)

This is a combined narrative for: **A9.1 - Expand network planning processes to assess more connections wider works; A9.2 - Trial assessment of all connection wider works in one region; A9.3 - Expand to all connections wider works (CWW); A9.4 - Develop processes with TOs to input into our analysis of end-of-life asset replacement decisions.**

We have committed to enhancing the NOA by expanding our network planning processes to address end-of-life asset replacement decisions for large assets, with the first recommendations being made in NOA 2024/25. Part of this process is working with TOs to input our analysis into their own decision-making; our access to vital economic and operational data means we can make recommendations on matters such as the most appropriate times to upgrade certain assets.

We also proposed to extend our assessments to encompass all connections wider works, to make sure the NOA accounts for all areas of the network which may need enhancements. The timeline for this begins with assessing a trial region in 2022/23 and expanding to all wider works by NOA 2025/26.

What are our updated RIIO-2 plans?

We are delayed against the Q3 2021/22 milestone due to supporting network design work. We are however working closely with TOs to develop a concept alongside NOA 2022/23, and the final deliverable remains on track.

Dependencies and Assumptions

TO data on connection/asset replacement schemes.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **390** NOA Enhancements. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.8.2. A9 Stakeholder feedback

(A9.1-9.4) We regularly engage with industry stakeholders around our NOA methodology. For example, in May 2021 we consulted with over 1500 industry partners on our NOA 2021-22 methodology. We received five responses, three of which were from TOs. We responded to each consultation with a personalised letter addressing the comments made. We also set up sessions with stakeholders to see where feedback could be actioned for this year's and next year's methodology. We will continue with this approach throughout BP2. More information can be found in Annex 3 – Stakeholder engagement.

7.3.8.3. A9 Financials and Headcount

See combined table in **A11**.

7.3.9. (Completed) A10 Support decision making for investment at distribution level

We assess investment decisions for Great Britain's (GB) transmission network through our NOA processes. These include options, analysis, and recommendations on the 400 kV and 275 kV networks across GB and 132 kV in Scotland.

Building on our expertise of investment decision-making on the transmission network, the key deliverable is to provide expertise to the DNOs throughout the BP1 period, to enable them to develop their own NOA-type processes for their lower voltage networks. This should support DNOs in developing their own approaches for their networks.

A10 sub-activities and deliverables

7.3.9.1. (Completed) A10.1 Support DNOs to develop NOA type assessment processes

During BP1 we have worked closely with DNOs through the Energy Networks Association (ENA) Open Networks project, and bilaterally, to share our learning and experience and we publish our NOA methodology annually.

We have worked on a number of ENA workstreams on the common evaluation methodology, a tool used by the DNOs to evaluate flexibility services and traditional intervention options for an identified network need. This aligns closely with our work on the NOA and has enabled us to share the benefits of our experience. We have also met bilaterally with individual DNOs to share experience from the NOA and our CBA process.

After BP1 we expect our ongoing engagement activity with DNOs to form part of our ongoing activities, captured in **A7**. This activity will include work through the ENA on topics relating to network investment decision-making.

What are our updated RIIO-2 plans?

The current deliverables are on track, and do not extend into BP2. There are no current plans to expand this sub-activity's scope, although we may continue to provide some ad-hoc support to DNOs in BP2.

7.3.10. (Materially Changed) A11 Enhance analytical capabilities

Our modelling capabilities underpin what we intend to deliver in Role 3, enabling us to unlock significant benefits and maintain a secure and operable network. We need to be able to manage the rising number of scenarios and increased modelling complexity driven by the growing interaction between different network needs, such as voltage and stability. The better we understand likely needs, the better we can identify where and when to efficiently invest.

Our current analytical tools focus on thermal needs and some voltage issues, so we need to expand our tools to cover all energy-related network issues. Work is already under way to develop our capabilities. To deliver these tools we expanded our team from the start of RIIO-2, focusing on data pipeline development and the stability workstream. The innovative techniques being explored will need to be implemented during the remaining RIIO-2 period and we expect further consumer benefits as we build on these techniques. For example, greater integration between the different modelling tools will allow us to better understand the interactions between different network needs and optimise our economic decision-making.

A11 sub-activities and deliverables

7.3.10.1. A11.1 Refresh and integrate economic assessment tools to support future network modelling needs

We have been using an economic assessment tool, BID3, since 2016 and committed to review its use against other options in the market and the expansion of requirements that we now have. Our plan was to undertake a tender exercise after having internally reviewed our business needs. Those requirements were then to be tendered to the market, including the incumbent supplier, to confirm we have the most appropriate model for making investment recommendations.

We are currently running a tender process for the economic assessment tool between AFRY's BID3 model[27] (the incumbent) and Energy Exemplar's Plexos. This will conclude in Spring 2022, but implementation will continue until April 2023 while replacement or upgrades go live.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

Dependencies and Assumptions

Network Development is working with the other two key user groups: Energy Insights (the FES team) and EMR Modelling. The Data and Analytics Platform (DAP) project is a key dependency and will also need to integrate with our tool.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **390** NOA Enhancements and 220 Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.10.2. A11.2 Implement probabilistic modelling

Our ambition is to build a model capable of year-round thermal modelling to complete analysis of network flows and other system conditions. This will allow for planning to consider how often and under what prevailing conditions circuit overloads are expected. This is especially important for assessing low probability events or those events that will not occur under winter-peak conditions as currently studied.

This model was to be in a proof-of-concept stage and then progressed into production to be used within the NOA and ETYS processes by the end of BP1. Part of this is the integration with our current modelling suite as well as the update to the economic modelling as per **A11.1**.

We have been developing our in-house tool, Pouya, to complete these thermal modelling requirements. This proof-of-concept includes both the development along with the need to develop business processes and methodologies (for example, ETYS, NOA) to use the insights. Development is on track but has highlighted our data and structures will not support a production version of the tool. This will need more attention during BP2, and so resource will grow to meet this need.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2, but we will need to evolve how we store and access network data alongside providing high-quality versions for use within Pouya (and/or other

[27] BID3 is AFRY's power market dispatch model BID3: AFRY's Power Market Modelling Suite | AFRY

tools). We will work more closely with the TOs to share network data, for example new schemes studied for the NOA. More effective sharing between the ESO and the TOs would elevate the value.

Key investments for this activity

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.10.3. A11.3 Build voltage assessment techniques into an optimisation tool

In collaboration with the University of Strathclyde, we committed to undertaking an innovation project to establish modelling techniques for enhanced voltage-optimisation. If successful, we will produce a full proof-of-concept and integrate with our other year-round modelling tools to have a production tool ready by the end of 2023/24.

We have completed the NIA project for a proof-of-concept of enhanced voltage-assessment. This will need scaling up and testing on our full GB models and as part of our wider ETYS processes. Development support from IT will be needed.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.10.4. (Materially Changed) A11.4 Build stability assessment techniques into an optimisation tool

We committed to completing an NIA project with energy consultants TNEI to investigate the potential to use screening techniques to label unstable network conditions for further analysis. This project would then be used to identify where a more complete stability assessments would be undertaken by identifying generation dispatches and network states. This could allow for year-round stability assessment before building further tools.

In Spring 2022, the NIA project[28] to build a ML tool for labelling stable and unstable conditions will conclude. This innovation project has demonstrated the capability for such a tool to be built but has highlighted the following difficulties in implementing it with our current models, data and systems:

- Challenge in convergence of ETYS model for year-round conditions
- Dynamic data quality challenges.

This has prevented the project from completing its aims of training a tool to run on the full GB system, and investigation of how to implement such a tool into our current processes. Considering this, we will be working to evolve our plans with respect to this stability workstream in the coming months, which will set our detailed ambitions as part of BP2. To use cutting edge techniques, our data needs to be available and fully functioning. We will provide further detail in our final Business Plan.

What are our updated RIIO-2 plans?

We will continue to review how to enhance our stability modelling for long-term planning. This project needs more research and development. This includes the need for enhancing our modelling data with respect to Power Factory and dynamic convergence. Whilst the NIA project has provided a conceptual model, the challenge has been to implement it on our current ETYS models which lack the data for many of the models, due in part to these models being developed for winter peak studies on SQSS backgrounds. Our team will

[28] https://smarter.energynetworks.org/projects/nia_ngso0036/

need to focus on this workstream and bring any new techniques into working tools that can be implemented in business processes.

We will also need to develop our data to allow for more scenarios to be studied within Power Factory to be able to baseline any innovative tools. This will include data pipelines being developed, providing our tools with the necessary detailed network information which currently is only provided for winter peak ETYS models.

Dependencies and assumptions

The main dependency is Power Factory models (as discussed above).

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.10.5. A11 Stakeholder feedback

(A11.1-A11.4) We continue to update our stakeholders on progress with our tools in ad-hoc meetings. When holding our BP2 engagement webinars in February 2022, several stakeholders such as TOs were interested whether the tools we are developing would be available to them. Currently, the proof-of-concepts of the tools are exclusive to us, but we are keen to work with the TOs in the first instance to make sure that we can collaborate and benefit across analysis. This feedback will be retained to ensure we call on insight from other organisations as this work progresses.

7.3.10.6. A7-A11 (excluding A8.4) Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A7 - A11 (Minus A8.4) - Network Development		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	(0.1)	3.2	3.2	1.6	1.2
	BP1	3.0	3.0	3.2	1.6	1.2
	Variance	**(3.1)**	**0.2**	**0.0**	**0.0**	**0.0**
Opex (£m)	BP2	3.4	4.7	4.2	4.1	4.0
	BP1	3.4	3.7	3.9	3.6	3.5
	Variance	**0.0**	**0.9**	**0.3**	**0.5**	**0.5**
FTE	BP2	37	40	40	40	40
	BP1	33	37	37	36	34
	Variance	**3**	**3**	**3**	**4**	**6**

Table 21: RIIO-2 costs and FTE for A7-11 (excluding A8.4)

This table contains the financial and resource data for all network development activities across activities **A7-A11**, except for **A8.4** (Early Competition) which can be found further along in this section. This table covers multiple activities as they all represent our on-going activities and to keep consistency with BP1.

Our resourcing remains largely as outlined in our five-year plan, with minor uplift of four FTEs in FY25. They will support the following activities:

- Two FTEs to support expansion of ETYS scope (**A7.1**)
- Two FTEs to undertake the expanded role covering system operability impacts of combinations of further interconnection (**A7.2**)
- **A8.4**: For Early Competition, the narrative is covered separately within the **A8.4 Financials and Headcount** section as this is a substantial new sub-activity
- All other sections of **A7-A11** do not have significant cost or FTE increases.

7.3.10.7. A7-A11 Cost-benefit analysis

A CBA for activities **A8, A9, A10** and **A11** was submitted alongside our first RIIO-2 Business Plan. This CBA has been updated for our BP2 submission and now includes **A7**. The net-present value of the updated **A7 - A11** CBA is £820m over the RIIO-2 period and £2,191m over 10 years. The NPV has increased by approximately £157m and £886m over five and 10 years respectively. This is driven by an increase in benefits to two main areas:

- **Annual NOA:** A new benefits case accounting for undertaking the NOA every year (activity **A7**) has total benefits of £69m over the RIIO-2 period
- **Facilitate competition by embedding Pathfinder projects into the NOA**: While these benefits are delayed by two years, the volume of benefit in the RIIO-2 period is now approximately £130m larger than at BP1. This is driven by a change in our assumptions for commercial solutions.

Further information can be found in Annex 2 - CBA.

7.3.11. A12 SQSS Review

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) sets the standards that TOs must apply to develop and maintain their transmission system, and that we must apply to operate that system. The electricity industry has changed significantly since the NETS SQSS was first introduced. As we move towards the net zero energy system, the relevant codes and standards must adapt to this significant change. Our first RIIO-2 Business Plan proposed a review of the NETS SQSS to enhance some areas, where issues have been raised constantly by stakeholders.

Our original plans remain on track. Based on the scoping work undertaken within **A12.1 Scope project, building on the BEIS recommendations**, greater levels of complexity are outlined below. While some quick wins have been identified, other areas like the treatment of storage, NOA and chapter 4 of the NETS SQSS review (design of the main interconnected transmission system) are more complex. As a result, in BP2 we will need to engage effectively with industry and to successfully implement the changes.

A12 sub-activities and deliverables

7.3.11.1. A12.1 – A12.3 (Combined narrative)

This is a combined narrative for **A12.1 – Scope project, building on the BEIS recommendations; A12.1 – Identify solutions; A12.3 – Implement changes to the NETS SQSS**

A targeted NETS SQSS review was proposed in BP1 to ensure the standard will enable the decarbonisation of the electricity system. Areas of the NETS SQSS where improvements can be made have been scoped through stakeholder engagement in 2021/22. This will be followed by content changes and potential solution developments in 2022/23.

We have been engaging with the electricity industry on a wide range of issues within the NETS SQSS. These include the review of the offshore transmission section, aligning NETS SQSS chapter 3 with distribution network planning standard P2/7 and assessment of the linkage between NOA and NETS SQSS chapter 4. Key stakeholders reviewed these topics on a one-to-one basis and updated in various forums regularly, including the SQSS Review Panel, Grid Code Development Forum and ENA Open Networks WS1B meeting. Stakeholders have validated that our proposed topics are in line with the interests of the industry and the delivery of the changes will shape the NETS SQSS to reflect the current energy landscape.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this activity for BP2. Based on the findings of sub-activity **A12.1**, to facilitate the implementation of changes (**D12.3**), we expect the resource profile will remain aligned with the final determinations. However, after we conclude the industry consultation in 2022/23, stakeholder feedback may identify the need for further development and research to ensure any change in NETS SQSS are fully verified.

7.3.11.2. A12 stakeholder feedback

(A12.1-A12.3) We have held one-to-one discussions with key stakeholders including TOs, DNOs, generators and representatives from academia. We have also presented the list of potential issues for NETS SQSS review to various forums including SQSS Review Panel, Open Networks Working Stream 1B (WS1B) meeting and Grid Code Development Forum. We have been confirming our understanding of the top priority areas with our stakeholders to develop within the SQSS.

We have also recently consulted on our SQSS Review Plan, which contains suggested priority areas, and have sought further feedback from stakeholders on these. The priority topics include reviewing the limit to loss of power infeed risk of offshore DC converters, revising the design criteria in Section 4 with NOA interaction and aligning demand connection criteria with the engineering recommendation. We will report on this in the final Business Plan in August 2022.

Stakeholders' primary concerns were around the significant amount of effort from both ESO and industry required to facilitate the changes. They asked how the workload would be managed to ensure the project remains on track. We reconfirmed the prioritisation of the proposed changes would mean the most urgent and important needs of the industry will be satisfied in the early stages, and then more comprehensive review will take place with carefully defined terms of reference. The workgroups will be focused to tackle the problems.

7.3.11.3. A12 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A12 - SQSS Review		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	0.2	0.2	0.4	0.4	0.4
	BP1	0.2	0.3	0.3	0.2	0.1
	Variance	**0.0**	**(0.0)**	**0.1**	**0.2**	**0.3**
FTE	BP2	3	3	4	4	4
	BP1	2	3	3	2	1
	Variance	**1**	**0**	**1**	**2**	**3**

Table 22: RIIO-2 costs and FTE for A12

The forecast for opex for **A12** remains broadly in line with BP1. There is a small increase of 2 FTEs (FY25) during BP2. This resource will lead the SQSS change, engage industry and use industry working group to develop the specific proposal for those changes, then go through a SQSS change governance process.

7.3.12. (Materially changed) A13 Leading the debate

As the system operator, we are uniquely positioned to lead the conversation around the challenges and opportunities we face in energy. In our FES, we outline the ways in which GB may generate and use energy between now and 2050. The unprecedented scale and pace of change in the energy industry is only going to grow and get faster. We also see greater interest and scrutiny from consumers and their elected representatives - motivated by greater awareness of the impacts of climate change and by significant increases in the cost of energy alike.

For the past decade, FES has enabled network planning, informed policy and helped people to understand the energy industry. FES continues to be our main way of providing this insight, but we are increasingly challenging ourselves to make it even more relevant to the end consumer, and more actionable by industry. Going forward, that will mean more commentary on things such as the long-term impacts of global events, details of what makes business cases work for a given solution and representation of stakeholder views from different sides of the debate. Using FES as a starting point, Bridging the Gap, the ETYS and NOA will clearly explain what policy gaps need to be filled and what network development actions need to be taken. On top of this, we will take on new deliverables for greater regional engagement and insight, a stakeholder-led process for agile modelling improvement and a new whole energy demand model. We have spent BP1 growing our team's capacity and capability to deliver these and are excited to be in a position to add more value to industry stakeholders during into BP2.

Regional insight

A single solution won't work for the whole country. We will continue to develop our regional modelling, for example through our new heat model[29] as explained in **A13.2**. By working more closely with distribution companies, local authorities and other regional stakeholders, we will be able to understand what FES outputs mean at a more local level and how options and constraints vary by region. We will work with local and/or devolved governments to help them use FES in their own planning activity.

Adapting to change while maintaining a whole system perspective

We have a robust process to ensure that we are prepared for the challenges of tomorrow. We monitor emerging developments for a wide range of technologies and options and then include them in our scenarios based on their commercial and technological readiness levels. Examples include green hydrogen production, carbon capture, use and storage, hydrogen and natural gas mixes, and long-duration storage. We consider the best solutions in each sector and geographical area, for a variety of conditions, like periods of low solar and low wind generation.

We are continuing to develop our data and digitisation capability and integrating new modelling into our work. This includes an assessment of options for our pan-European economic dispatch tool, which is used to simulate the electricity market across GB and Europe. This ongoing assessment will ensure we have the right modelling capability to deliver consumer value over the next five years. The strategic review of FES and our ongoing stakeholder engagement will help us to prioritise effectively and be flexible in the face of a changing environment.

Our new deliverable in **A13.5**, reflects our commitment to continually evolve and develop a new demand model in line with the needs of a decarbonised energy system.

We have grown our resource by more than was outlined our original RIIO-2 plan. This additional resource covers a range of outputs including:

- Enhanced regional engagement and insight (**A13.2**)
- Retention of gas knowledge and experience within the ESO. Doing so allowed us to embed a whole system perspective into FES, conduct specific gas/hydrogen stakeholder engagements and deliver gas services to National Grid Gas Transmission[30].
- Greater monitoring of the external environment and an increase in the number of strategic initiatives as electricity becomes more intertwined with other industry sectors.

We have also incorporated resource for business architecture (moved from business change) to ensure that we remain effectively structured to deliver against our ambitions as the external environment evolves.

A13 sub-activities and deliverables

7.3.12.1. A13.1 Carry out analysis and scenario modelling on future energy demand and supply

We are committed to publishing the FES, Winter Outlook, Winter Review and Consultation, Summer Outlook and other reports detailing our future demand analyses and scenario modelling. This process includes engaging closely with stakeholders to understand key focus areas and needs.

Following the introduction of net zero policies, we have expanded our scenarios over the BP1 period. We no longer just model the energy sector, but now factor in other sectors and their relative emissions. This ensures we understand our role in decarbonisation and GB's progress against the net zero targets. We have improved

[29] https://www.nationalgrideso.com/document/190471/download
[30] Gas services between National Grid Gas Transmission and National Grid ESO are delivered under a General Services Agreement, GSA.

visibility of assumptions and modelling in our documents and through our engagement. We have also improved the accessibility of our data by using the Data Portal.

We have introduced further European scenario modelling to understand the impact of net zero on our European neighbours. This will help us understand the impact on interconnector flows, such as how much we may be relying on imported energy at key times, and when we might need to curtail other generation.

We have improved data sharing and coordination across the scenarios between the different network companies. This helps us to target our analysis in the areas with the greatest impact.

What are our updated RIIO-2 plans?

As data volumes and model complexity increase in the BP2 period, we will need to invest in people, systems, and infrastructure to ensure that we can maximise the value of the insights and help other people understand our results. Key to this will be delivery of the Data and Analytics Platform within Role 1 (**D1.4.1**) which will provide a pathway to utilise additional cloud computing resources for advanced analytics and the application of ML, external data sharing, and opportunities for enhanced data visualisation (such as heat maps) and exploration tools. Gaining access to the additional data to facilitate our analysis may also require additional licencing costs, where we may use other people's models or purchase their data or for new models to enhance our scenario analysis.

There are no material changes to the ambitions of this sub-activity for BP2.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **220** Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.12.2. (Materially changed) A13.2 Conduct mathematical modelling and market research on local and wider geographic demand information

In BP1, we outlined our intentions to conduct electricity and energy mathematical modelling and market research, such as analysis on pan-European models and geographical demand information, to understand how the operational landscape could change. This has allowed us to complete updated pan-European and country-level electricity and energy demand analysis. We also highlighted our intention of enhancing our modelling to allow a more regional approach to understand, for example, the locational impact of heat decarbonisation.

We have worked with other networks to improve data sharing and coordination across the scenarios developed between the different network companies, including discussion of the development of regional scenarios. We have run public focus groups and workshops and polled the public to gain more insights on how they view the UK's climate change agenda and how they can get involved in the energy transition. We have also worked with local authorities and consumer organisations to understand how communities can be supported in climate action and the energy transition and sought feedback looking back at FES 2021 and then input for FES 2022.

A thought piece was published in December 2021 to outline our approach to heat decarbonisation modelling. It introduced our new regional heat model, with inputs to be reflected in FES 2022.

We have been working with DNOs to ensure embedded capacity registers can be used as the main input data to our embedded generation forecast within the FES. This will ensure we are aligned with the networks and their DFES publications.

What are our updated RIIO-2 plans?

We will work closely with local authorities to develop a feedback loop between the national FES, regional scenario projections of gas and electricity companies and local area energy plans.

Through a new deliverable **(D13.2.1) Provide Whole System Regional Insights**, by the end of 2023/34 we will have started work agreeing how the feedback loop between the ESO, DNOs, GDNs and local authorities should look. We will agree with industry the level of granularity needed in FES for hydrogen and natural gas and include regional system insights within FES 2023. By the end of 2024/25, the feedback loop will be functional, with regional insights in FES 2024 following stakeholder feedback. This will then become part of our business-as-usual approach, with continual improvement of the process.

This will provide a deeper level of insights alongside the national FES projections, considering more local factors which impact on the national scenarios. It will provide greater clarity, supporting policy makers and other stakeholders in their decisions, as well as improving whole system planning processes and investment. This will produce more robust analysis and more consistent whole system scenarios, ensuring consumer and industry input is fed into future modelling.

We will also begin innovation projects, such as developing consumer archetypes to display where consumers are on the network, how they use energy, and how they behave with respect to net zero.

Our work to date in understanding the value our stakeholders get from a whole system view of FES has led us to expand our analysis to understand cross-vector impacts. With the shift toward hydrogen and the importance of technologies like CCUS, our ambition is to provide insights and data to the same level of depth across the whole system, working closely with network companies and other regional stakeholders to understand what level of granularity will be required and how it can be used by our customers.

Dependencies and assumptions

Due to the reliance on modelling enhancement, providing deeper whole system regional insights will be dependent on development of our energy demand modelling and obtaining the data inputs we need.

We are dependent on the success of innovation projects to make some of the enhancements for our regional scenario modelling.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **220** Data and Analytics Platform. The detail behind this investment can be found in Annex 4 – Technology investment. The new deliverable (**D13.2.1**) will be solution assessed ahead of the final Business Plan.

7.3.12.3. A13.3 Maintain external communication channels with consumers and stakeholders

Each year our FES team reviews changes to Government policy and engages with stakeholders to ensure FES reflects the latest developments in the energy sector. Stakeholder engagement has become an increasingly important part of the FES process since 2012, when over 150 stakeholders were consulted, to 2021 where we received feedback from over 1200 different stakeholders.

We have continued to engage with our external stakeholders over BP1. Due to the COVID-19 pandemic, much of our engagement has been virtual. We have continued with the FES Network Forum through 2021 and published podcasts on topics like heat, EVs, and hydrogen.

We also made it easier for stakeholders to read and absorb the content on our website. As a result of these improvements, we have seen a significant increase in the number of stakeholder visits. We will continue this for 2022, improving the navigation, data visualisation and accessibility – for example, with configurable data tables.

We have added FES data to our portal, which is a dedicated platform for customers and stakeholders to access information.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

7.3.12.4. A13.4 FES: Bridging the gap to net zero

This sub-activity was introduced in the first RIIO-2 Business Plan. The intention is to work with the energy industry to examine areas of uncertainty in the FES, suggest actions to remove this uncertainty and ultimately progress towards net zero. By talking to stakeholders from across industry and beyond, the project explores the whole energy system challenges that are inherent in meeting the net zero ambition.

Since its introduction in BP1, we have run two successful iterations of the Bridging the Gap project. Each has looked at the near-term challenges relating to achieving net zero and how whole energy system solutions can help. The 2021/22 project looked specifically at achieving a fully decarbonised electricity system by 2035. The 2035 target had been recently introduced, and while it had been modelled in FES before, the implications for taking decisions and actions now had not been widely discussed. Bridging the Gap provided the perfect opportunity to assess the implications of this target on today's actions. The recommendations contained within the report were designed to inform policy and regulatory decisions as well as communicate the need to take action to achieve the 2035 target. Further details and ongoing updates can be followed on our website.[31]

This project builds on FES key messages and insights from the in-depth modelling of future energy demand and generation capacity, undertaken each year.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

7.3.12.5. (Materially changed) A13.5 FES: Integrating with other networks

In our five-year RIIO-2 plan, we outlined the benefits of replacing the electricity demand model (**D13.5.1**) and developing a new energy demand model (**D13.5.2**) to enable greater access to data, analysis and insights to further aid development of regional FES. The new energy model will incorporate the electricity demand model, and these will be delivered as one item.

Delivery of the energy demand model is on track, and we have enhanced our electricity demand models to make them more efficient for the FES 2022 publication – for example, through automation. We have also built on the spatial heat demand and hydrogen supply modelling used in FES 2021 to ensure the common components of each are fully integrated and aligned for FES 2022.

We have utilised our framework agreement with consultants to review the data, processes, and current models across the FES scenarios. We engaged with internal and external stakeholders in 'Voice of the Customer' sessions to understand their needs. We included questions on our current modelling and available data in our 'Call for Evidence' which is sent to over 6000 individuals and organisations to gather their views on the FES. This has provided us with a good view of the requirements of stakeholders with regard to our modelling, along with where improvements can be made to how we handle the data associated with the models.

What are our updated RIIO-2 plans?

The BP2 period will see a new ongoing deliverable (**D13.5.3**) reflecting our commitment to ongoing development of the new energy demand model, with a development plan to be in place by the end of 2023/24. The constant evolution of requirements (such as hydrogen strategy) and challenges across the GB network means we need to stay up to date with model functionality to ensure our analysis and FES is as robust as possible.

These future enhancements will be based on customer and stakeholder feedback along with changes in the industry and society as we advance towards a net zero future. These enhancements are expected to include extending the use of large datasets, such as the Electralink Data Transfer Service or smart meter data captured through the 'Market-wide half hourly settlement' programme (**D6.7**), to facilitate more effective modelling and to better reflect consumer behaviour and choices.

We can also work with GDNs to explore a more granular view of gas scenario projections that can be shared with industry to help understand actions needed to decarbonise the gas network. This includes considering how the co-creation of an agreed set of common building blocks can assist scenario development on the gas side, as it has on the electricity side.

7.3.12.6. A13 stakeholder feedback

(A13.1-A13.5) Stakeholder feedback has influenced areas across **A13**, such as different ways to define regions and fuel interactions, having a whole system focus, and learning lessons from cross-fuel collaboration.

In FES 2022 we asked our stakeholders to provide their views on what aspects of the whole energy system would benefit from a more bottom-up regional modelling approach. Areas included the deployment of hydrogen across the whole energy system, electricity generation topics including how technologies alter over time, more information on distribution-connected technologies and consumer engagement.

[31] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/bridging-the-gap-to-net-zero

We are exploring improvements to our regional heat, road transport and distributed generation modelling. We will also be broadening our engagement to bring in perspectives such as local authorities. We are working closely with the network companies through the ENA to simplify and optimise the interface with the more bottom-up scenarios currently developed by gas and electricity network companies, such as the DFES.

(A13.5) Stakeholders also identified a need to ensure scenario creation is coordinated to avoid a duplication of effort. There also needs to be transparency of the assumptions driving the regionalisation of the FES, and potential for feedback loops with stakeholders to sense-check outputs. There is broad support for closer collaboration on the creation of more granular scenarios. More interactive tools can make it easier to use FES outputs to generate insights and more visibility of upcoming changes can help manage downstream impact. Feedback has provided us with the requirements of stakeholders, and where improvements can be made to how we handle the data when delivering against this activity.

For further information see Annex 3 – Stakeholder engagement.

7.3.12.7. A13 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A13 - Leading the debate		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	3.5	3.8	3.7	3.9	3.6
	BP1	3.7	3.8	3.8	3.9	3.6
	Variance	**(0.2)**	**0.0**	**(0.1)**	**0.0**	**0.0**
FTE	BP2	40	47	43	44	41
	BP1	31	33	34	35	32
	Variance	**9**	**13**	**9**	**9**	**9**

Table 23: RIIO-2 costs and FTE for A13

The forecast for opex remains on track for BP2. The FTEs needed to support **A13** activities has changed over the BP1 period and is forecast to change further for BP2. The main drivers for these changes are:

- During the two years of BP1, the split from undertaking joint SO activities with National Grid Gas Transmission resulted in the requirement for three additional FTEs to support gas specific activities.
- 10 FTEs in response to increased support for strategic projects, increased volume and complexity and modelling.

This gives a total of 13 FTEs for the end of BP1. However, the start of BP2 shows a reduction of four FTEs (13 FTEs to nine FTEs) from BP1. This is due to recognition that with a growth of headcount across the whole ESO, there will be opportunities to flex resource as required. At the time of our draft submission, we are assessing the future needs of the team and so the forecast costs for this activity may change for our final Business Plan in August.

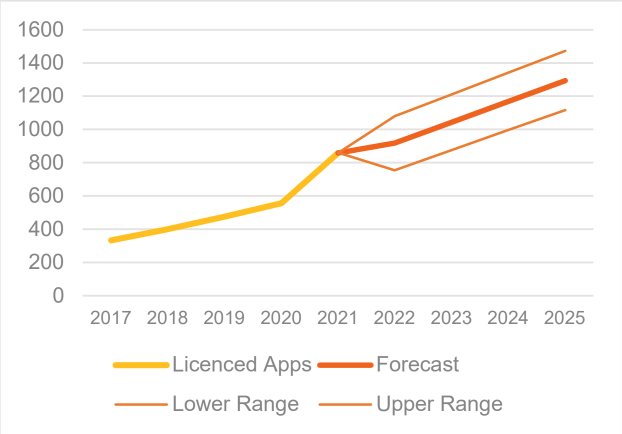
7.3.13. A14 Take a whole electricity system approach to connections

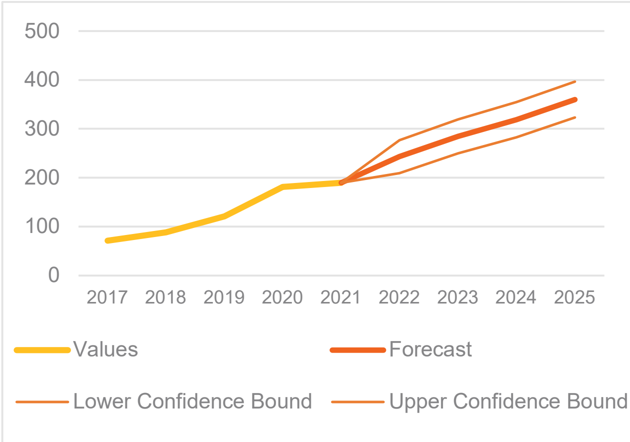
The customer connections team manages connection contracts and provides connection offers to new customers, an activity which has increased significantly in volume and complexity in recent years. The team also ensures that new connections are compliant with Grid Code requirements and is developing a customer connections portal. The team is undertaking a range of initiatives to enhance the customer experience. This is particularly relevant as the current connections process was designed for a small number of large connections, whereas in recent years we have seen an increasing number of connection applications from smaller parties, and this trend is set to continue, as shown in Figures 16 and 17. This is the result of growth in low-carbon technology to meet Government targets.

Connection applications are also increasing in complexity, with Figure 18 showing the wide range of technologies now wishing to connect to the system. These are driving a fundamental change in the technical characteristics of the system.

Increased volume and complexity also result from interactions with projects such as the OTNR, Pathfinder projects and RDPs.

The efficient management of connection processes is important to our customers and stakeholders, and a key enabler for the connection of low carbon technologies to meet the UK's net zero targets. These changes have led us to propose improvements for BP2, including reviewing the connections process, taking a more proactive approach to ensuring compliance with the Grid Code, and making better use of data and systems. Our proposals, although requiring additional resource in the short term, will drive efficiencies in the longer term.





Figures 16 and 17. Connections Licensed Applications and Unlicensed Offers - Current and Forecast

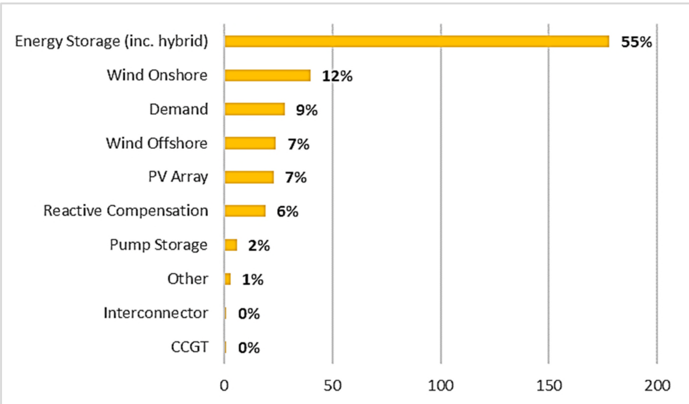


Figure 18: New Applications Technology Type Split 2021/22

A14 sub-activities and deliverables

7.3.13.1. (Materially changed) A14.1 Provide contractual expertise and management of connection contracts including provision of connection offers to customers

In BP1, we set out how we would manage connection contracts and provide connection offers to an increasing number of customers by tailoring our contract management service to assist less experienced customers and work closely with TOs to improve our processes.

So far during the BP1 period, we have managed an increasing number of connections (with a 49% increase in connection applications alone in 2021/22 compared with 2020/21), which are also becoming increasingly varied in terms of technology type. We have also continued to manage contracts associated with connection agreements.

We have achieved this by enhancing our team capabilities, standardising and automating our processes, and recruiting additional resources through BP1. This resource increase addresses changes to the ECC team structure, inclusive of creation of new Policy and Change Management team. It reflects the continued increase in workload, which has so far been managed by existing resource, and enables more focused engagement with customers, and better allocation of tasks, including management of connection contracts.

What are our updated RIIO-2 plans?

For the remainder of the RIIO-2 period, we anticipate the number of connection applications will continue to increase, as more smaller parties seek to connect to the system.

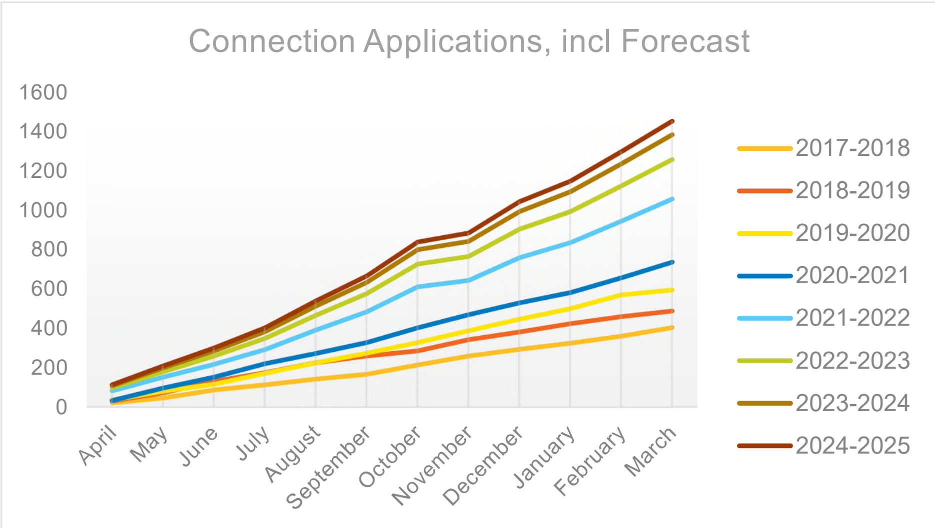


Figure 19: Connections applications forecast up to 2025

We will continue deliverables **D14.1.1 Managing an increasing volume of connection offers for customers** and **D14.1.2 Contract management of connection agreements**, which are continuous activities we started in the BP1 period. However, due to the increasing volumes, we will need additional resources beyond the numbers set out in our original RIIO-2 plans.

The requirement for an increased number of FTEs associated with the management of new connection applications and management of connection contracts has been determined based on data available from time-sheeting records.

Our increase in resource needs takes into account increasing workload volumes, but also efficiencies created by improvement activities (which are described under **A14.3**) and introduction of the Customer Portal. The Portal brings automation to some manual and time-consuming activities. In BP2, this will enable CCMs to focus on shifting from primarily being in the 'Application to offer' process, to other areas where they can add value. This, in turn, will enable the following efficiencies and benefits:

- Improved support to connections projects that require continuous increased engagement and support from the Connections Team to deliver key electricity infrastructure for the targets of 2025, 2030 and 2035
- Improvement of support and customer journey experience
- Management of the connection contracts programmes to secure delivery of connections to planned timescales, ensuring TOs deliver on their programme for enabling connections or conducting reinforcement works, and starting to enforce queue management milestones.

It is important to note that customers' application fees fund up to 60% of the costs of the Customer Connections Team's activities.

Dependencies and assumptions

We have assumed that the number of connection applications increases shown in the graphs above, and the improvement activities described (in particular the introduction of the new Customer Portal) lead to more efficient use of resource and a much-improved customer experience.

No allowance has been made for the potential increase in workload driven by ongoing code changes such as:

- CMP328 - Connections Triggering Distribution Impact Assessment
- CMP379 - Determining TNUoS demand zones for transmission - connected demand at sites with multiple DNOs
- CMP376 – Inclusion of Queue Management process within the CUSC
- GC0117 – Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Stations requirements

All the above listed Code Changes will impact:

- Requirement to review, change and introduce revised processes, which will impact BAU and customer and stakeholder engagement requirements
- Requirement to introduce new processes, which will impact BAU and customer and stakeholder engagement
- Introduction of new activities to be fulfilled by the ECC team, which is currently not accounted for in headcount and workload forecasts.

As an example of the workload changes and FTE requirements that could result from some of the above code changes:

- CMP328: Increase of GB Demand team workload by approx. 50% for 24 months, to accommodate the expectations of new deliverables on the ECC team
- GC0117: Connections Contract Manager (CCM) headcount increase of up to extra 28 FTEs based on approximately 4000 schemes of embedded contracted generation which would have to be processed and managed
- CMP379 and CMP376: Although likely, increase in headcount requirement on administrative and customer contract management not clear until processes are fully developed with customers and TOs

7.3.13.2. (Materially changed) A14.2 Ensure Grid Code compliance of new connections

In BP1, we agreed we would enhance our compliance monitoring to keep ahead of the new technologies connecting to the network and provide sufficient support to our customers while ensuring that new technologies are compliant with the Grid Code.

The requirement to assess the compliance of connection offers has increased both in number and complexity. The connection of new technologies has led to new challenges, for example the addition of storage facilities, which creates new connection configurations which the current industry codes are not designed to accommodate. The characteristics of the system are also changing, with reducing fault levels and system inertia.

This has increased the complexity of the compliance process, requiring us to work closely with our stakeholders to understand these new engineering challenges, including engagement with developers and manufacturers of new technologies. This has led us to publish updated guidance on our website, and to engage with industry on Grid Code modifications for new types of connections. We have also implemented internal process improvements, including standard operating procedures and a renewed focus on training and development.

What are our updated RIIO-2 plans?

For the remainder of the RIIO-2 period, we will continue to assess the compliance of connection offers, which have increased in volume and complexity.

We will continue deliverable **D14.2.1 Compliance monitoring of new connections in accordance with Grid Code provisions**, which is a continuous activity started in BP1. However, due to the increases in volume of connections projects and complexity of new connections, we will need additional resource beyond the numbers set out in our original RIIO-2 plans for 2023/24.

Dependencies and assumptions

The FTE requirements assume connection applications continue to increase in volume and complexity. However, they do not account for the increased workload which could result from potential upcoming code changes. Several Grid Code modifications are ongoing that could change the number of projects going through the compliance process. For example, there is a proposal for a periodic compliance process (GC0141) for existing users, and another proposal to re-define the threshold for large and small generators across GB (GC0117). These modifications, if implemented, could vastly impact the resource requirements of the Compliance team.

Sub-activity **A14.3** sets out improvement activities for customer connections. We expect our improvement activities, in particular the introduction of the new Customer Portal, to lead to more efficient use of resource.

7.3.13.3. (Materially changed) A14.3 Further enhance the customer connection experience, including broader support for smaller parties

We are committed to stepping up the level of support to help smaller parties to navigate the complex connection processes. This includes dedicated account management and extending our customer connections seminars to take a whole electricity system view (including DNO as well as TO input).

We have focused on supporting customers who are new to the industry, particularly those whose requirements are more complex due to technologies and intricate connection arrangements. We have met regularly with these customers, acting on their feedback, which has led to improved customer survey results.

We have also worked closely with DNOs to identify requirements arising from the connection of significant volumes of DER. In some cases, the volume of DER connections has led to wider network reinforcements, leading to interactions with the FES, NOA and wider reinforcements identified by the TOs to meet SQSS requirements.

What are our updated RIIO-2 plans?

We are proposing additional deliverables which will bring significant value to our customers and the end consumer. This includes improving our systems and data further, streamlining our internal processes, improvements to policies and the Grid Code, and leading an industry-wide review of the connections process. These will be actioned by a new Policy and Change Management team.

Improving systems and data (**D14.3.4**): We will make our systems more informative, user friendly and interactive. Improvements to data management will enhance the management and reporting of connections projects milestones, provide better data quality on the Transmission Entry Capacity (TEC) register[32], and unique reference numbers for each contract or connection. We may also introduce the concept of 'Demand Capacity' to connection contracts, leading to the capture of improved data which could be included in a new demand register. These changes will improve transparency and give our stakeholders access to data relevant to their assessments and future planning.

Improving our internal processes (**D14.3.5**): Taking account of the changing nature of connection applications, we will improve our internal processes for managing connection applications and assessing compliance. We expect this to lead to a reduced resource requirement to assess each connection application.

Proposing policy and code improvements (**D14.3.6**): We will review the legal documents used in the connection application and offer processes, driving improvements via the industry codes process. We will work closely with leading industry experts, manufacturers and customers to identify requirements for Grid Code modifications and develop new policies for the timely connection of technology required for zero carbon operation.

Leading an industry-wide review of the connection process (**D14.3.7**): Current regulatory requirements mandating the format and timescales of the customer connection process do not take account of the increasing complexity and volume of connection applications. We have already begun discussions with

[32] https://data.nationalgrideso.com/connection-registers/transmission-entry-capacity-tec-register

Ofgem, leading to them granting us an extension for several applications. We intend to lead an industry-wide review of the connections process which may lead to amendments to the relevant legislation.

We will continue to work closely with DNOs and TOs to establish a view of changes to capacity and network constraints, and upcoming challenges. This will enable us to develop requirements for regional plans to address localised constraints, leading to improved management of DER. This deliverable (**D14.3.1**) has been delayed slightly into BP2 as it is more complex than originally anticipated.

The new Policy and Change Management team will be set up during 2022/23 and will deliver some of these activities during the BP1 period. The team will realise benefits such as:

- Implementation of change that reduces re-work and enable better management of queries from stakeholders and customers
- Improvement of response to the changes in the market, customer expectations, policy and external factors that demand changes within customer connections
- Delivery of transmission connections process reform to ensure suitability to meet the needs of the future energy system
- Support for national policy development and code changes that enable projects such as Pathfinders, HND to transition to business as usual.

Across 2023/24 and 2024/25, we need additional resource (compared with our original plan) to contribute to Pathfinder projects and support the connections and network planning reviews and creation of a new internal connections process. This will enable its alignment with other teams and establish a strategy for periodic reviews and reporting on the process.

FTE requirements for BP2 have been based on assumptions which increase workload due to activities such as:

- Supporting the development of new Pathfinder projects, supporting Ofgem derogation requests for connections process and code changes
- Supporting the Connections Process Review based on the detailed activity schedule for this deliverable (which could change based on policy changes driven by Ofgem)
- Supporting the SQSS review, construction planning assumptions policy, and code driving changes that impact customer connections - in particular DNO and RDPs

Dependencies and assumptions

The improvements to our systems depend on the feasibility of making these changes, legal review of contract and code changes to introduce the new demand capacity concept, and user feedback on the current systems.

Our proposed policy and code improvements are dependent on recruitment of the required resources and capabilities, and the timings and outcomes of code modifications (subject to a prioritisation process alongside other changes to industry codes). This work may also be influenced by the changing nature of connection applications due to technological evolution, and the willingness of equipment manufacturers and other stakeholders to engage with the process.

The review of the connections process is dependent on engagement with wider industry and Ofgem.

Key investments for this sub-activity

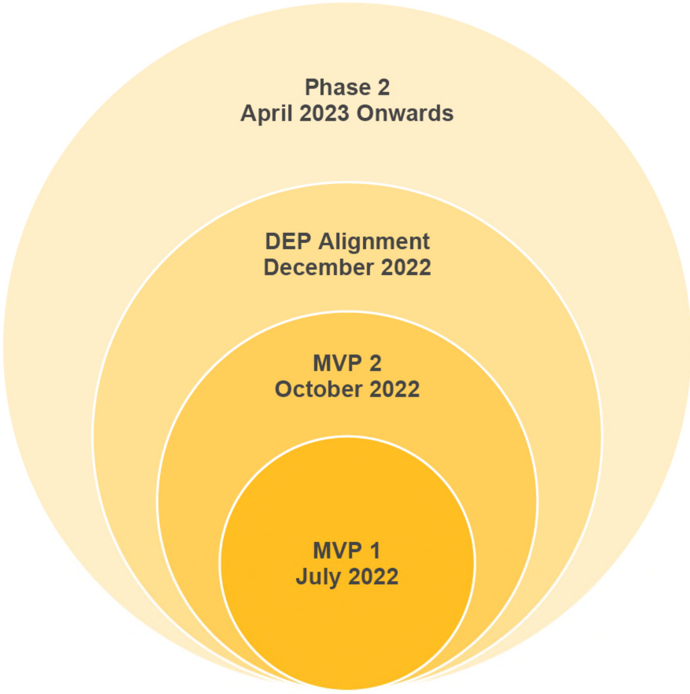
Some IT investment will be needed to for the improvements to our systems, for example to update our CRM database to accommodate new processes. This will be scoped out following the implementation of the Customer Portal.

This sub-activity is aligned to IT investment line **380:** Connections Platform. The detail behind this investment can be found in Annex 4 – Technology investment. Full assessment of the cost of IT changes will be included in the final Business Plan.

7.3.13.4. A14.4 (Name changed) Facilitate development of the customer connections portal

We committed to work with other network organisations to develop a connections hub (now known as the Customer Connections Portal), providing a seamless experience for electricity customers and leading to improved decision making.

We have taken an iterative approach, starting with a minimum viable product (MVP) to be released in July 2022, with an additional release planned for early BP2 due to a slight delay (which completes phase 1). Phase 1 will focus on digitising the connection application process. Incremental improvements will be added in subsequent releases, including process efficiencies and automation before the start of BP2.



Phase 2
- Development of contract storage
- Automation / self serve contracts
- Data submission functionality for customers / Network Companies
- Active milestone/contract management
- Securities functionality
- Integration with other industry platforms

DEP Alignment
- User interface review
- Alignment with Digital Engagement Platform
- Minor functionality updates only

MVP 2
- Query management
- ESO / TO document exchange
- Digital signing of agreements
- Compliance process integration

MVP 1
- Account registration
- Pre-application requests
- Digitised application submission
- Application fee calculator
- Application tracking
- Portfolio overview

Figure 20: ESO Customer Portal early phasing

What are our updated RIIO-2 plans?

Phase 1 of the Customer Connections Portal (**D14.4.1**) has been delayed slightly, with its delivery not fully completed until early within the BP2 period. The current project delivery plan allows for a period where, based on customer feedback, changes and fixes to functionality can be addressed. This will give us the opportunity to optimise the customer experience and improve usability.

We will explore extra functionality for phase 2 of the portal (**D14.4.2**) during the BP2 period, to be delivered in BP3. As more time will be needed to develop extra functionality, this will lead to a change from the original dates. However, this will ultimately bring increased automation and interactivity which will:

- Enable the customer to provide feedback and updates

- Enable uploading of documentation for the new application process during delivery and commissioning
- Enable links and automated processes between ourselves and TO platforms to facilitate sharing of information without the need to move data between systems or use email
- Facilitate links between updates to appendix J and Q (milestones) and the TEC register.

Delivering these commitments will also facilitate a range of improvements to the connection process associated with automation, streamlining of processes and time savings. It will also mitigate the risk of developing a Customer Connections Portal which may become obsolete in a short period of time.

Dependencies and Assumptions

The Customer Connections Portal work is dependent on IT investment **380** as shown below. Detailed development work associated with phase 2 will take place later in 2022, which will determine deliverability.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **380:** Connections Platform. The detail behind this investment can be found in Annex 4 – Technology investment.

A full assessment of the costs of these improvements will be included in the final Business Plan.

7.3.13.5. A14 Stakeholder feedback

(A14.1-A14.4) In conducting surveys and engagement over the RIIO-2 period, we have drawn out some key themes. Much of this feedback is driving the change in this area, so below we set out how feedback themes have impacted our proposals.

We need to be more pro-active: We are creating a Policy and Change Management team. This team will work alongside the Process and Solution team as well as other teams, BEIS, ENA, OFGEM to ensure we can manage change whilst also ensuring communication to customers is timely and as clear as possible.

A greater level of time and engagement needs to be available for each project: The Connections Compliance team is particularly busy, and our response is not always as timely as we would like. We are proposing to increase resources to enable increased volumes of connection applications and projects to be managed with increased quality of engagement.

We should take a lead role in developing a customer connections portal, with feedback informing the scoping of the minimum viable product: Customers also felt the applications process is complex and outdated. The portal will address these points by digitising the process and making it more transparent, guiding the customer through each of the steps.

During engagement specific to our BP2 ambitions, we ran a poll where 75% of respondents thought we should be moving more quickly to issue proposals in BP2. As a result, we are looking to bring in resource ahead of the BP2 timeline.

For further information see Annex 3 – Stakeholder engagement.

7.3.13.6. A14 Financials and Headcount

A14 - Whole system approach to connections		Forecast 2021/22	Forecast 2022/23	BP2 2023/24	BP2 2024/25	BP3 2025/26
Capex (£m)	BP2	0.9	1.6	0.2	0.1	0.1
	BP1	0.7	0.7	0.2	0.1	0.1
	Variance	**0.2**	**0.8**	**-**	**-**	**-**
Opex (£m)	BP2	2.2	2.2	3.0	3.2	3.2
	BP1	4.4	4.4	4.1	4.1	4.1
	Variance	**(2.2)**	**(2.2)**	**(1.0)**	**(0.9)**	**(0.9)**
FTE	BP2	52	60	75	78	78
	BP1	48	48	49	51	51
	Variance	**4**	**12**	**26**	**27**	**27**

Five-Year strategy

Table 24: RIIO-2 costs and FTE for A14.

The forecast for capex is unchanged, and opex has reduced by £2m. The FTEs needed to support **A14** activities in BP2 has increased by 27 (FY25) since our first Business Plan submission. The main drivers of the increase are:

- Nine FTEs (FY25) to support enhancements to the customer connections experience, managing the increasing volume of connection offers and the resulting contracts for the connection agreements
- Nine FTEs (FY25) for compliance monitoring and assessment of compliance connection offers, which have grown in volume and complexity due in part to new technologies
- Four additional FTEs (FY25) to contribute to Pathfinder projects, to support connection and network planning reviews, for the creation of a new internal connections process and for driving necessary code change.
- Five FTEs (FY25) will form the new Policy and Change Management Team.
- Opex decrease from BP1 relates to a rise in recharges to connection applicants. The rise in volume of new applications has driven a parallel rise in team cost recharges to applicants, for which we do not apply the cost pass-through mechanism.

7.3.13.7. A14 Cost-benefit analysis

The NPV of the updated **A14** CBA is £16m over the RIIO-2 period and £36m over 10 years. This represents a £14m increase in both five- and 10-year NPV, driven by greater benefits in two areas:

- **Efficiency Savings:** These benefits are directly proportional to the number of connection applications; for example, if we create process efficiencies which reduce the FTE work required per application, the benefits are realised more significantly as the volume of applications increases. In the original CBA we used a figure of 400 per year but now we are forecasting an average of 1,381. We are observing a rising and sustained number of connection applications and any benefit associated with improving efficiency during grid connections will also increase.
- **Customer Service Improvement:** This is a new benefits case to account for the material changes to sub-activity A14.3. It contributes £1m of benefit in the last year of the RIIO-2 period.

For further information see Annex 2 - CBA.

7.3.14. (Materially changed) A15 Taking a whole energy system approach to promote zero carbon operability

In this area we use our engineering expertise to ensure the electricity system remains operable, and appropriate market solutions are developed to deliver net zero in a timely manner. Much of this work is already focusing on future zero carbon operation, including assessing the technical requirements for new generation connections, implementing technical code and framework changes, and managing our operational data and modelling requirements. An example is the new modelling tools being used to help us understand the performance of a net zero network, including electromagnetic transients (EMT) modelling and power quality analysis.

We will also be looking to understand what we need to do to meet Great Britain's 2035 decarbonisation target. This work is critical to ensure the electricity system remains operable and able to accommodate the changing technologies that the market is connecting. Through our work within activity **A15.9**, we will be building our understanding of the tools needed to manage a net zero electricity system and put plans in place to facilitate the transition.

The drive towards 2035 has created a shift in the energy industry, with huge volumes of zero carbon technologies seeking connection to distribution networks. These challenges need to be managed as a whole system through defining the roles of Distribution System Operation (DSO) and how the technical and market solutions will work across the whole electricity system. We will be accelerating our work compared with our originally intended ambitions, through embedding coordination activities such as primacy rules (ESO and DSO service coordination) and ensuring visibility of distribution-connected energy resources needed to operate a highly decentralised electricity grid.

In BP2, we will be embedding some of the significant new ways of working into the business. These include the technical input into new market solutions for system needs through matured Pathfinder processes, and our RDPs, co-ordinating ESO-DSO flexibility markets now being delivered into Control Room environments.

A15 sub-activities and deliverables

7.3.14.1. A15.1 Develop the system operability framework (SOF) and provide solutions up to real time of network-related operability issues

We regularly publish the system operability framework (SOF). It identifies system operability requirements to accommodate the changing energy landscape. In our first RIIO-2 Business Plan, the SOF commitment is to identify and quantify operability needs in both long and short-term planning timescales, encouraging market-based solutions wherever possible. This will be presented within SOF documentation (**D15.1.1**) and may include the use of external innovation funding, such as the NIA (**D15.1.2**).

Through extensive industry interaction, we have identified several key SOF topic areas in power quality, short circuit level management strategy and new technology impacts on operability. We have published the operability strategy report, national trends and insights and short circuit level data to outline the operability challenges and how we will work with industry to address those challenges.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

The operability needs for a zero carbon system are expected to be significantly different to those of today. The ongoing shift from fossil fuels to renewable generation sources will present new challenges in operating the grid safely and securely, such as how to measure system strength, and how the standard could be defined and implemented. We will continue working in line with our RIIO-2 five-year plan to ensure the new operability needs are identified and addressed.

7.3.14.2. A15.2 Provide technical support to the connections process

We provide vital technical input into the connection process. This includes setting appropriate planning assumptions, identifying future operability requirements for each connection, and ensuring designs from TOs meet future operational needs by specifying the right technical performance requirements and operational restrictions in the connection agreement. In the five-year plan period, we will continue to provide updates to customer offers and agreements, offering technical support and assessing connection offers to determine future operability needs.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2. However, we have experienced a significant increase in the number of connection applications in recent years (49% in FY22 alone) and are expecting continuous growth throughout the BP2 period and beyond. Connection applications are also becoming increasingly varied in terms of technology and complexity - such as zero megawatt connections which provide only reactive power, grid forming technologies and innovative offshore connections with integrated solutions.

Consequently, to be able to continue to support the connection application process and the commissioning of new connections, our team has grown and will grow further into BP2.

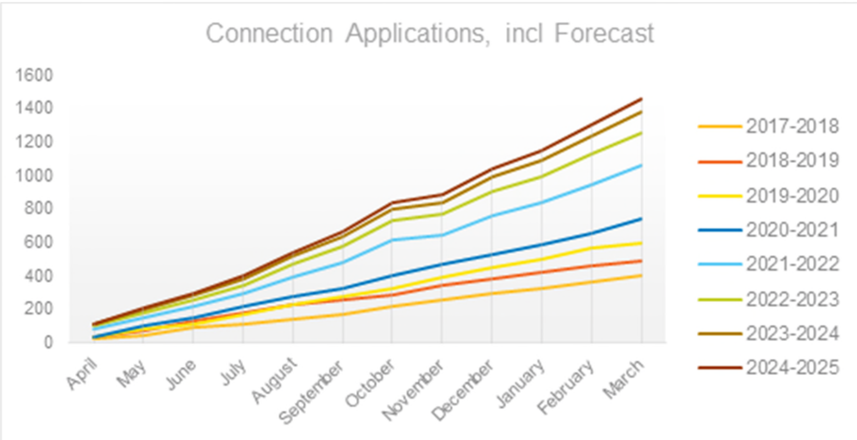


Figure 21: Connection applications forecast up to 2025.

Providing additional technical policy support and ensuring the correct technical requirements are captured in users' connection agreements is key. The ever-evolving nature of connecting technologies means we must ensure flexibility and remain agile, and there could also be the need to access further resource during the BP2 period.

Failure to deliver consistently and effectively could risk the safe and secure operation of the network and could delay new connections from coming online.

7.3.14.3. A15.3 Assess the technical implications of framework developments and implement changes into business procedures and systems

The technical input we provide into codes and standards development mainly includes assessing the technical implications of framework developments, providing technical expertise and implementing changes into business procedures and systems to ensure the new technical requirements are compliant. (**D15.3.1**).

We lead the accelerated loss of mains change programme (**D15.3.2**), which completes during BP1. We have also provided technical inputs into Grid Code modifications GC0137, GC0138 and GC0151, and supported the implementation of FRCR resulting from SQSS modification GSR027.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2.

The current commitments will continue through BP2, carrying out regular operability needs assessments to ensure we can safely achieve zero carbon operation. This includes the continuous support to ongoing Grid Code modifications GC0141, GC0146 and GC0155 in the key operability areas of fault ride through, and control interaction studies. We are also leading the development of industry best practice on grid forming technology.

7.3.14.4. (Materially changed) A15.4 Manage our operational data and modelling requirements

In the five-year plan, we are committed to managing our operational data and modelling capabilities to underpin all our offline network analysis. This enables us to support data transfers between network organisations and technical modelling.

During BP1, all ETYS/NOA datasets were delivered on time with improved data quality by working closely with our stakeholders. Additional ETYS datasets were made available to enable the delivery of other business initiatives and obligations. Data transfers occurred in accordance with Grid Code and STC provisions and we managed the operational and planning data flows across network companies to underpin our offline network analysis.

What are our updated RIIO-2 plans?

During BP2, we will improve the quality of system data and models used to analyse future network needs and operability solutions by moving to an automated approach of data and model maintenance. A new deliverable (**D15.4.3**) sets out the timeline for implementation of this technical data automation. Our team will grow to support this.

Multiple new modelling scenarios will be required, resulting from Grid Code modification GC0139 (Enhanced planning-data exchange to facilitate whole system planning). The implementation will see us and all DNOs migrate to a common information model (CIM) standard, requiring close collaboration and agreement between all parties on the design and functionality in advance. The move to CIM standard was not known when the original plan was written, so the new deliverable will also set the requirements for us to prepare for this change.

As the implementation will not be prior to 2024, we will continue to engage with DNOs to explore other potential methods for developing the data exchange in the interim.

Key investments for this activity

This sub-activity is aligned to IT investment line **350:** Planning and outage data exchange. More details are contained in Annex 4 – Technology investment. A full cost assessment will be included in the final Business Plan.

7.3.14.5. (Materially changed) A15.5 Regional development programmes (RDPs)

RDPs look across the whole electricity system landscape to resolve problems in key regional areas of the network in need of development. RDPs can unlock network capacity, reduce constraints and lead to new revenue streams for market participants. In our first RIIO-2 Business Plan, we committed to undertaking six RDPs over the five-year period. This was subject to system need and may vary. This commitment was in addition to the continuation of the Generation Export Management Scheme (GEMS) and the completion of our work under the N-3 Intertripping requirements with UK Power Networks (UKPN), Scottish and Southern Energy Networks (SSEN) and Western Power Distribution (WPD).

Over the course of BP1, we have made significant progress in the delivery of RDP projects with our partners, key achievements include:

- Under our MW dispatch project (covering RDPs 1 & 2) we have co-created a new transmission constraint management service and gathered feedback from DER via webinars and associated updates. We have held workshops with partner DNOs to capture and refine project requirements throughout the delivery process.
- The delivery of the agreed MW dispatch minimum viable product (MVP) functionality is progressing through development with our internal IT teams, and we have now captured a list of potential enhancements, prioritised for delivery through further engagement events with DER.
- We have also shifted our overall project delivery philosophy towards an agile approach, defining a roadmap for the implementation of a MVP, followed by customer-focused enhancements with WPD and are agreeing a similar MVP scope with UKPN.

- In addition, we have produced a detailed technical specification for the GEMS project, which has been taken forward into the SPT procurement activity.
- We have shared project updates and learnings with all GB DNOs through the new Whole Electricity System Joint Forum monthly meeting to ensure consistent approaches across GB.
- We have formed an RDP Strategy team for new non-network solutions for system needs at the transmission – distribution interface working with DNOs on five potential new regional projects.

During the remainder of the BP1 period, the RDP Strategy team will also be developing a roadmap for a broader roll-out of RDP functionality and learnings. Part of this work will then be progressed through new activities on DER visibility and primacy rules as outlined in **A15.8**. We anticipate this will highlight the need for a proactive process in BP2 that will allow us to identify future local needs for non-network solutions. This will then allow the RDP development programme to transition to a full BAU process.

What are our updated RIIO-2 plans?

We will continue to use our in-flight RDP projects and the roll-out of RDP functionality with partner DNOs. This will ensure solutions that are quickly scalable to other areas, whilst enabling enhancements across existing functionality. This will include participation from other market routes including learnings from our work to develop a local constraint market (LCM) in Scotland. There are currently two RDPs in delivery, two in development, and a further three at an earlier stage of development.

BP2 will see a more flexible approach to delivery. In BP1 we said we would commence an RDP with WPD in the Midlands in Q1 2022/23. However, on further discussion with WPD it was agreed that the operability need case was not as pressing as originally anticipated. In addition, we have commenced new discussions with UKPN on the challenges of connecting large volumes of DER in East Anglia. From these discussions we have determined that the functionality required in the Midlands (RDP3) for storage is also likely to be of value for East Anglia (RDP4). So, the timescales for RDP3 have been reassessed and aligned with RDP4 based on operability need and to facilitate more immediate development discussions on other potential RDPs with other DNOs.

Work with WPD in the Midlands and UKPN in East Anglia will now enter delivery phase at the start of BP2. Whilst we expect this optimisation to deliver requirements more quickly, BP1 has demonstrated that a dedicated team is required to drive the necessary changes to BAU processes and systems, and the collaborative work with our partner DNOs. This approach has also reduced IT costs by approximately £1m.

The RDP strategy team was initially formed from resource within the Network Operability team and will reach its full complement of three FTEs by FY24. This is in addition to our original plan. It will develop needs cases for new RDPs; market-based non-network alternatives to traditional investment needs driven by distribution connection applications, building on the early RDP findings. In BP1, the team has been working with DNOs in response to system needs to co-create potential solutions. In BP2, our strategic ambitions will see needs identified more proactively in future. This work is new and is required to move RDP development into a BAU process for regional constraint market development for transmission system needs. The team is also finding that newer RDPs such as East Anglia and South Wales are either becoming more complex (e.g., nested system needs, or interactivity with transmission offers) or larger in geographic scope, which has also led to increasing resource requirements. We will seek to use the cost-pass through model if additional requirements increase substantially during the BP2 period.

Additionally, we anticipate delivering IT infrastructure to support the connection of new DER at Heysham and will continue developmental works with both WPD in South Wales and SSE-N in the north of Scotland. All three projects will decide whether a market-based solution is needed and trigger IT delivery works. We anticipate that this will result in the need for two IT projects (RDP 5 and RDP 6) as per our original Business Plan, with a possible seventh. This volume of development works and parallel processing of activities (including in RDP 3 and 4) is over and above our expectations set in our original Business Plan, and the team is growing through BP1 and into BP2 for RDP delivery. The costs of related FTEs are incorporated within the relevant project IT budgets.

The GEMS programme dates have been pushed out in discussion with our project partner, SPEN. Whilst this creates overall efficiencies, it means the programme completes by Q4 of 2024/25 and requires additional resource, covered by the project’s IT budget.

Dependencies and assumptions

With the delivery of such complex projects, there is an ongoing risk of change to the overall delivery plan as a result of unforeseen factors such as dependencies on third party actions.

We have provided a 'best view' forecast of RDP development and delivery, but we recognise system requirements can change and the number of active RDPs in the BP2 period is subject to variation.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **340** RDP Implementation and Extension - this investment will provide the ESO with greater visibility and control of parties connected to distribution networks. The detail behind this investment can be found in Annex 4 – Technology investment.

Our baseline plan is to continue with the delivery of six RDPs in the BP2 period. Whilst these projects remain broadly in line with previous forecasts, we have incorporated learnings from our current RDP rollouts. For instance, we expect to make changes into our core registration, planning, scheduling, dispatch and settlement systems to enable successful delivery of a whole end-to-end RDP process.

7.3.14.6. (Materially changed) A15.6 Transform our capability in modelling and data management

In the RIIO-2 five-year plan, we are committed to transforming our capability in modelling and data management, which includes:

- Delivery of major upgrades to our offline modelling tools, allowing us to model a more complex system. This will include establishing offline modelling capability to facilitate operation of a zero carbon system
- Modelling and data expertise to scope planning data requirements for the data & analytics platform. This will provide the foundational architecture to enable the development of an interchangeable suite of tools with a common data set, and seamless exchange of data between tools.
- Enabling higher volumes of network data, regional models, and outage planning data to be exchanged, used and shared by network companies for deeper outage planning.

During BP1, a combined hardware and software upgrade to allow us to undertake more complex modelling was approved. Offline modelling hardware and software upgrades are in progress (**D15.6.6**) and are expected during BP1, with further enhancements during BP2. The software upgrade work will provide our capability to carry out short circuit calculation, which is one of the key operability challenges of our electrical grid.

We have also completed upgrades to our reference database (RDB) system, and rating management systems (RMS) upgrading work is in progress. This implementation will enhance data integrity, capability, automation, and efficiency of the RDB & RMS systems.

The project team is progressing phase 1 data management scoping work to feed into creation of the data and analytics platform (**D15.6.1**).

What are our updated RIIO-2 plans?

With declining traditional synchronous generation levels and increasing converter-based generators, phenomenon such as control interactions between different converter-based generations, system oscillation issues and power quality issues need to be analysed. These require electromagnetic transient (EMT) simulation, to analyse the power system electromagnetic transients in the range of microseconds to seconds, rather than purely root mean square (RMS) simulation. EMT simulation provides greater granularity to analyse the system.

We are adding a new transformational deliverable (**D15.6.8**) to enable more advanced EMT modelling and relevant analysis, which will provide greater confidence and forward-planning of the impacts of voltage oscillations, system interactions and power quality on the system. We are creating a new team to develop and maintain EMT models and to carry out EMT and power quality analysis.

The key deliverable will be development of capabilities, after which performance and maintenance of the modelling itself will become an ongoing deliverable. We will begin building the capability in Q1 of BP2 year 1.

We will also explore carrying out more detailed and effective system analysis using a co-simulation approach with the legacy OLTA system combined with EMT capabilities. This has a new transformational deliverable (**D15.6.9**) to set out the timeline and expectations.

Failure to take on these new capabilities could impact our ability to accurately model future system operation and balancing needs. This work also directly supports TOs in developing their own models for the ETYS, which feed into our NOA process.

Dependencies and assumptions

These deliverables are dependent on findings from deeper outage planning work (**D16.3.2**).

Successful delivery is dependent on delivery of the data and analytics platform under **A1.4**.

Key investments for this sub-activity

This sub-activity is aligned to IT investment lines **360**: Offline network modelling, **350**: Planning & outage data exchange and **220:** Data and analytics platform.

Offline network modelling will implement EMT and additional tools by extending and enhancing PowerFactory and PS-CAD simulation software to complete our modelling capability. By March 2023 the networks teams will build an EMT proof of concept by using the PS-CAD simulation software for system transient simulation package.

Developing the ability to carry out co-simulation analysis (RMS and EMT together) could reduce overall simulation time and enable analysis of small and large signal behaviour on the system.

The forecasted BP2 investment costs remain unchanged. The detail behind these investments can be found in Annex 4 – Technology investment.

7.3.14.7. (Materially changed & name changed) A15.7 Deliver enhanced frequency control by 2025

This sub-activity was formerly named ‘Deliver an operable zero carbon system by 2025’, however as the deliverables are specific to delivery of the enhanced frequency control tool it has been renamed to reflect this. This change more accurately demonstrates that **A15.7** will deliver a monitoring and control system (MCS) to provide fast and coordinated frequency response for the low inertia system required to achieve the bigger zero carbon and net zero ambitions. These represent the proposed staged roll-out of the Enhanced Frequency Control Capability innovation project’s MCS. The first stage is targeted for 2024/25 (**D15.7.1**) and the second for 2025/26.

This plan puts actions in place so, as inertia decreases, the risk of incidents on the system is reduced. Through implementation of the MCS system we will be able to monitor the electricity network at a regional level and coordinate regional frequency response from a range of service providers to maintain frequency stability.

During the BP1 period, a phase 2 milestone applicable to the first stage roll-out of system-state Enhanced Frequency Management and control system (**D15.7.1**) to analyse the preferred future states (MCS system for non-operational demonstration, end state MCS system for future implementation) and change strategy was introduced, which was not in the original five-year plan. Its purpose was to develop requirements and a technical design to contribute to the phase 1 non-operational demonstration works and meant the process was delayed. The current status is that we have engaged with industry parties to participate in the non-operational demonstration and completed design. NIA funding for this has been sanctioned and the project team is working on implementing and testing the phase 1 MCS system.

To avoid further delays, resource profiling for 2024/25 and 2025/26 will remain consistent.

What are our updated RIIO-2 plans?

As a result of introducing phase 2, which was not originally in the plan, phase 1 non-operational demonstration is delayed. However, it is expected to be completed within BP1 timescales. The subsequent milestones on operational demonstration (phase 2 and phase 3) are now expected in BP2. The roll-out of the first stage (phase 4) is still on track for delivery in 2024/25 as specified in BP1.

Dependencies and assumptions

Delivery is dependent on the onshore TOs installing required system capabilities needed to utilise the phase 1 non-operational demonstration. One TO is active with the capabilities so far, with a second expected by August 2022. The MCS architecture will use components common to projects such as inertia monitoring (deliverable **D1.2.2**) and frequency visibility (IT investment **170**) projects. The current phase 1 timeline is aligned with these project deliverables.

Timely delivery of the MCS is dependent on consideration and assessment of how it will operate in conjunction with/interface with the ongoing developments to the Enhanced Balancing Capability.

Key investments for this sub-activity

This sub-activity is aligned to IT investment lines **500** Enhanced frequency control. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.14.8. (Materially changed, name changed & cross-role) A15.8 Facilitate distributed flexibility and whole electricity system alignment

Updated ambitions for this sub-activity are found in the facilitating distributed flexibility cross-role section of this chapter.

7.3.14.9. (Materially changed and name changed) A15.9 Net Zero Operability

Activity **A15.9** in the five-year plan was named 'Identify future operability needs across whole energy system' and entirely focused on cross energy vector work with whole system operability. As Government targets towards net zero have become more focused, and with the emergence of the Future System Operator discussions and its future role in whole system development, it is appropriate to re-define this activity to focus on reaching zero carbon whole electricity system requirements. The Government has set out clear goals towards operating a net zero electricity system by 2035, and we have a key role in having the right capabilities and tools to operate the system. Building on the work from the operability strategy on delivering tools in the short term, the addition of a Zero Carbon Operability team in BP2 will stretch our horizon in meeting the challenges.

A15.9 will see a new deliverable (**D15.9.5**) replacing the existing deliverables, which will focus on engaging with stakeholders on implementation of technologies for effective zero carbon operation. This reinforces our role as a trusted partner, engaging and advising stakeholders in developing new technologies and enabling policy changes.

Through Role 2 and the new activity **A20**, focused on net zero market reform, we have been developing proposals which will facilitate the procurement of tools and capability to meet operational needs. To support this, we need to articulate the needs of the system and the interdependencies between these and the role for new technologies, such as hydrogen or smart demand.

The activities under **A15.9** will evolve our capability in three ways to deliver this. Firstly, we are enhancing the operability strategy report (Role 1, **D.1.1.6**) to focus on the long term, increasing the scope from the current five engineering workstreams (voltage, thermal, restoration, stability and frequency) to also focus on adequacy and flexibility needs.

Secondly, to enable this, the Zero Carbon Operation team will coordinate across all Roles in driving the analysis to derive the requirements for all of the workstreams as follows:

- Role 1 on the development of requirements for restoration (**A3**)
- Role 2 on the development of frequency and inertia requirements through an enhanced frequency risk and control report, as detailed in activity **A4 Building the future balancing services markets**
- Role 2 on the development of the future energy mix (**A5**)
- Role 3 on the development of needs for thermal, stability and voltage (this work is directly linked to the development of Pathfinders – **A8**)
- Role 3 on the approaches needed to meet whole electricity system operability needs.

The third activity will be to coordinate and manage support in the early phases of industry and stakeholder policy development relating to new technologies such as CCUS, hydrogen, long duration electricity storage and EVs. This will be where most of the work is focused - on deploying our knowledge and capability into decision-making forums and cross-industry working groups to ensure new technologies develop in line with system needs.

These ambitions will require more resource from FY23 (against an original plan of one in FY24 and three in FY25) to perform the engagement and co-ordination activity across all stakeholders on the deployment of new technologies. The engagement is required against both small-scale and consumer level changes, such as the adoption of EVs and how smart technologies can support the development of the grid. There will also be stakeholder engagement as new policies develop in delivering new large-scale technologies including CCUS, bioenergy with carbon capture and storage (BECSS), new nuclear, hydrogen and large and long duration storage. The engagement will require working with OEMs, technical working groups, trade bodies and Government departments.

The changes driven by the activity in **A15.9** will be visible elsewhere (as outlined in the cross-role net zero section) through a more thorough, in depth and longer-term view of the requirements to meet the operational challenges as we further decarbonise.

This work will also support the development of the network planning review outlined in **A22**, which will be tackling many of the same issues on a longer horizon.

As we evolve our ability to manage a low carbon network for short periods in 2025 to a fully decarbonised electricity system by 2035, the operational needs, especially in the new flexibility and adequacy workstreams, will become key in leading the debate around where market interventions and support are required. The ambition of the Government to support these emerging technologies requires us to be engaged earlier than anticipated in the BP1 plan, hence the additional focus to enable us to act as a trusted partner on developing new technologies. The strategy will be taken forward via significant net zero/zero carbon sessions, with additional development expected for the final business plan.

Key Investments for this sub-activity

This sub-activity is not yet aligned to an IT investment but will be solution assessed and included as appropriate in our final Business Plan.

7.3.14.10. (Reallocated) A15.10 Develop a regime for an integrated offshore grid

This sub-activity has been moved to the new activity **A22**, alongside the Network Planning Review. This is in recognition of their combined ambitions, and their expected impact on Role 3's overall ongoing activities.

7.3.14.11. A15 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A15 - Whole electricity system approach to promote zero-carbon operability		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	2.6	9.8	12.7	15.4	11.3
	BP1	8.1	9.1	11.0	11.3	13.0
	Variance	**(5.5)**	**0.7**	**1.7**	**4.1**	**(1.7)**
Opex (£m)	BP2	5.2	7.5	9.0	11.1	12.3
	BP1	5.2	6.3	8.0	9.8	10.9
	Variance	**(0.0)**	**1.3**	**1.0**	**1.3**	**1.5**
FTE	BP2	60	69	94	96	94
	BP1	48	52	56	62	67
	Variance	**12**	**17**	**38**	**34**	**27**

Table 25: cost and FTE for A15

The forecast for the opex, capex and FTEs needed to **A15** activities in BP2 has increased since our first Business Plan submission. The main drivers of the support increase are:

- Capex increases by around £4m by FY25 due to our IT investment **500** Enhanced frequency control.
- One FTE (FY25) to support the growth in complexity of new connection types and continue to support the connection application process and the commissioning of new connections (**A15.2)**.
- Two FTEs (FY25) will be required as we improve the quality of system data and models used to analyse future network needs and operability solutions by moving to an automated approach of data and model maintenance **(A15.4)**.
- Four FTEs (FY25) will be needed, as the number of RDPs in delivery increases, to drive changes to RDP BAU processes and systems, and collaborative work with partner DNOs (**A15.5)**. One of the four FTE will be needed to support the delay in GEMS programme dates meaning slower connection than forecast.
- Six FTEs (FY25) will be added in **A15.6** to develop and maintain EMT models and to carry out EMT and power quality analysis
- The enhancements to the ambitions within **A15.8**, as detailed in the Facilitating Distributed Flexibility section, will require 17 FTEs (FY25) for delivery throughout the BP2 period.
- Four additional FTEs (FY25) will be needed to deliver our new zero carbon operation team, which will focus on engaging with stakeholders on implementation of technologies for effective zero carbon operation **(A15.9)**.

7.3.14.12. A15 Cost-benefit analysis

The NPV of the updated **A15** CBA is £1,246m over the RIIO-2 period and £4,046m over 10 years. The NPV for **A15** has increased by approximately £780m and £3,103m over five and 10 years respectively. A new benefits case called 'DER visibility savings' has been included to account for the benefits of new deliverables in **A15.8** (which are supported by new deliverables in **A15.6**). The associated benefits total £73m.

By far the largest contributor to the increase in NPV is the 'whole-system operability NOA-type assessment' benefits case. Originally, we calculated these benefits by estimating the difference between the costs of operability challenges over the next 40 years and a physical solution. This methodology was aligned with the most recent stability Pathfinder. Our updated methodology removes ambiguity from this calculation and can be easily updated with each subsequent Pathfinder project. The large increase in total benefits is unsurprising given the increases in constraint costs since we created the original CBA.

For further information see Annex 2 - CBA.

7.3.14.13. A15 Stakeholder feedback

(A15.1) Stakeholder engagement is an important part of the process in developing the SOF, sub activity 15.1. We use forums such as the Grid Code Review Forum to work through technical challenges and inform our processes, which we will continue throughout BP2.

(A15.2) See section A14 for stakeholder feedback relating to the connections process.

(A15.3, A15.4) We have not received any specific feedback in these areas that have resulted in significant changes to BAU activities.

(A15.5, A15.8) Our sub-activities **A15.5 RDPs** and **15.8 facilitating distributed flexibility** have significant components dedicated to working with partners and stakeholders as these impact a broad group of stakeholders. We have set up the whole electricity system joint forum and stakeholders are telling us that they see the ENA Open Networks project as the common forum to facilitate this coordination in many key areas. More information on this activity is in the facilitating distributed flexibility Cross role activity chapter of the plan.

(A15.6) To establish the correct EMT modelling requirements we have been working with TOs within our Transmission Owner Tools for EMT Modelling NIA project to effectively create the EMT model in partnership along with our model supplier. We have also been discussing with the TOs how we should be making use of the model.

We have also been regularly engaging with the TOs in the early stages of the co-simulation project which all the TOs are in broad support of. We ultimately intend to establish an NIA project to create a working regime of both our OLTA and EMT models, which have both impacted our BP2 delivery schedule. The main forum for engagement is the Joint Planning Committee Modelling Group. These are sessions where we are sharing learnings across organisations to develop these tools in the interests of all attendees.

(A15.7) We are taking a multi-channel approach to stakeholder engagement regarding our Activity **A15.7** Electromagnetic frequency control (EFC). As well as setting up a monthly working group, we also presented the project overview at the Technical Advisory Council (TAC). As a result of feedback, we engaged with experts to develop cyber security requirements for the future system, added resources into our BP2 plan to manage the business change capabilities and we are looking at technologies used internationally to shape our work. A full programme of engagement will accompany the development of this project throughout 2022.

(A15.9) The roll-out of activity **A15.9** will involve a programme of stakeholder engagement as described in the sub-activity section. Bilateral engagement for this activity will commence early 2022.

For further information see Annex 3 – Stakeholder engagement.

7.3.15. (Materially Changed) A16 Delivering consumer benefits from improved network access planning

Our Network Access Planning team continues to work closely with customers and stakeholders in the delivery of efficient outage plans, facilitating system access for the TOs to carry out their construction and maintenance activities. Minimising network constraints is central to our activities, and we work with the TOs to optimise their system access, so that the costs are as low as possible.

The network is in a period of intense change, and requirements for operating the system are changing as a consequence. In some areas, the network is ageing and needs more maintenance than before. In others there are unprecedented levels of system development, meaning more connections and construction-based activities needing an even greater amount of system access. The rapid advance of renewable generation has led to a high increase in network constraints while we wait for future system development to mitigate some of those costs. In some areas, access to the network is now dependent on favourable weather conditions, whereas in the past it was more likely to be dependent on the time of year or season. This means that optimisation of the running of the power system is now more challenging and complex than ever. We have been working closely with TOs to reduce constraint costs by using measures such as outage realignments, reviewing protection settings, circuit rating enhancements and post fault switching agreements. We estimate these changes have created around £1 billion worth of savings over a twelve-month period and this is demonstrated via our quarterly incentive report via activity RRE 1H - Constraints cost savings from collaboration with TOs.

The impact of maximising the efficiency of the TOs' own outage activities is an increase in the flexibility of their outage plans. The ratio of outages planned within current year timescales continues to be much greater than presented in the TOs' year ahead plans. Whilst network access planning continues to manage the impact of short-term outage changes or outage churn to the TOs' system access plans, this adds more complexity and can also cause challenges for system users.

As full electricity system decarbonisation has been accelerated to 2035, we must bring forward our plans for operating a much more heavily constrained network, with greater uncertainty from renewable generation and demand profiles. In the past, the demand profile shape varied little from day to day. The advance of renewable and flexible generation, much of which is embedded in distribution networks, has created much more variable demand profiles. Demand uncertainty will increase further with the electrification of heat and transport. So, analysis and modelling will need to be carried out much more frequently. In the past it was possible to study the most challenging points of the day, such as the evening peak and the overnight low, but the future is likely to require a time-slicing approach cut over many periods.

We have already started to mitigate the impacts of a more constrained system through our work on whole electricity system, the constraint management five-point plan[1] and many major projects to increase capacity on constrained boundaries. Network access planning has also implemented two-year ahead forecasting of constraint limits and constraint costs, which will improve the accuracy of BSUoS forecasts and provide a much clearer view of the cost challenges associated with system access.

We have also started working with our DNO customers across the transmission-distribution interface in developing efficient whole electricity system processes for access planning, ensuring our decision-making results in the lowest costs to consumers. We will support increased levels of coordination to deliver significant consumer benefits, facilitating the connection of low carbon generation and the development of new flexibility market opportunities.

A16 sub-activities and deliverables

7.3.15.1. A16.1 Manage access to the system to enable the TOs to undertake work on their assets, liaising with customers where access arrangements impact them

Our first RIIO-2 Business Plan set out to build on our automation techniques to optimise access planning solutions, taking full advantage of the greater availability of data and modelling.

The BP1 deliverables are currently on track. We have initiated work on a 'sandbox' environment where new automation can be tested. In August 2021, we automated our minimum voltage study set-up, saving four hours work per week for our voltage engineer.

We have created a new Constraint Forecasting and Optimisation team within Network Access Planning to deliver activities as part of the constraint management five-point plan. The team provides two-year ahead forecasts for constraint limits, published on our data portal.

We have also implemented a New Grid team to work with a third party for enhanced short-term modelling capability. This provides system-wide reconfiguration solutions for congestion relief on specified boundary constraints and has already proved successful in providing greater constraint limits on congested boundaries and creating consumer benefit.

We have also implemented a NOA support long term process within Network Access Planning, ensuring TOs develop the outage requirements of the NOA options in a coordinated way by the optimisation of the timing of the schemes. We calculated the potential additional benefit that a co-optimised outage requirements plan could have, when compared to the outage requirements initially submitted in NOA 2020/21 for the South and East region, can amount to a £5 billion saving in that area alone.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2. However as full electricity system decarbonisation has now been brought forward to 2035, we must create a dedicated team to consider our long-term network access planning requirements, and create efficiencies in the existing structure, processes and systems to support it. This will enable greater focus on the operational needs of the future transmission system as well as assessing the impacts on the approach to net zero. This will ensure that future risks are identified and mitigated for much earlier in our processes, helping to strategically plan the path towards 2035 and consider the impact of an increasingly complex transmission system on our customers and stakeholders.

We have also introduced new sub-activity **A16.5** focused on further system modelling automation, which will build on the previous activity under **A16.1.**

Dependencies and assumptions

Meeting the requirements for full electricity system decarbonisation in 2035 and the progression of whole electricity system coordination and our coordination with distribution networks.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **350:** Planning and outage data exchange. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.15.2. (Name changed) A16.2 Scope a whole electricity system decision-making policy

In our five-year plan, this sub-activity was named 'Enhance the network access policy (NAP) process with TOs' but has been renamed to reflect the ambition from a whole electricity system perspective. This sub-activity's ambitions are focused on unlocking consumer benefits by transforming our approach to system access and expanding the Scottish cost recovery mechanisms (STCP 11-3 and STCP 11-4) across England and Wales, with the NAP procedure and provision of greater visibility of the costs associated with changing outages through increased system analysis and cost assessments. This will improve our ability to make the right trade-offs between spending to progress, defer or cancel outages and a recognition that taking a broader view of system access is likely to unlock greater consumer value.

The NAP was extended in BP1 to also include England and Wales, and this has been a successful undertaking already leading to constraint cost savings associated to the outage change process and enhanced service process.

Steps were taken previously via NAP to design a process which would allow us to make an informed decision on whether to accept an outage, considering the cost and risk to the affected TO compared with the potential constraint costs. The current status is recognition that a broader range of information from a wider group is required for a decision to be made on an outage request. In the future the carbon intensity of decisions could also be considered.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this activity for BP2.

In conjunction with deliverables in **A16.3**, and the development of tools to coordinate deep access planning throughout the BP2 period, we will work with our stakeholders to explore incorporating whole electricity system planning into the NAP process. Deeper access tools and visibility will enable us to make a more holistic commercial assessment of an outage request.

Change is necessary as facilitating distributed flexibility will lead to a need for us to factor in more information when assessing outage requests. Feedback from customers and stakeholders also indicates a desire for us to be more engaged in commercial decision-making across the transmission-distribution interface. Customers have asked us to trial processes which allow more holistic considerations, and to agree formal procedures. There is also potential to save additional consumer costs, and a more formal carbon intensity measure could be built into any decision-making process.

We need to remain flexible, as the outcomes of the push for all DNOs to create DSO functions is still in progress. As DNO and DER services become better understood (further to the work in **A16.3**) and joint operating procedures are put into place, whole system decisions around network access planning will become easier. The formal scoping work, which will form most of the early stages of this deliverable, will depend on the progress in the Whole Electricity System Joint Forum, between ourselves and the DNOs, and led by groups who have ownership of the **A15** activities.

Dependencies and assumptions

The development, acceptance and embedding of joint operating procedures with trial partners in WPD and UKPN may determine how fast any additional wider scoping can occur.

The speed of progress on developments to the Planning and Outage Data Exchange (PODE) platform could determine the best time to perform scoping in this sub-activity. The evolution of the system and the ability of DNOs to provide the relevant information will guide us as to when trials can begin, and whether we have enough detail.

7.3.15.3. A16.3 Work more closely with DNOs and DER to facilitate network access

We need to work more closely with DNOs to coordinate requirements and ensure we are collectively optimising flows across the network, helping to lower system operation costs. This is driven by distribution networks becoming more active as greater volumes of DER connect. DNOs are developing system operation capabilities and provision of flexibility services is increasing.

We have been working closely with DNO partners to trial data transfer processes, offline model testing and drafting of high level joint operating procedures. Results will be shared with all DNO partners.

What are our updated RIIO-2 plans?

There are no material changes to the ambitions of this sub-activity for BP2. However, our approach will remain flexible since the DNO to DSO transition is taking place at different rates across the 14 DNO regions, and some have progressed further than others through the RDPs. We estimate this work could realise savings between £10m and £40m per annum from service coordination activities related to NAP across the transmission and distribution interface.

Dependencies and Assumptions

The outcomes of Grid Code modification GC0139, which will require delivery of complex systems changes for all DNOs.

This sub-activity is also directly linked to how network access planning processes intersect with developments on the whole electricity system planning activities reflected in **A15**, particularly **A15.5 Regional Development Programmes**. The direction of NAP deliverables may be shaped further in early 2022 by whole electricity system deliverables for BP2.

Key investments for this sub-activity

This sub-activity is aligned to IT investment lines **350** Planning and outage data exchange, **360** offline network modelling and **220** data and analytics platform. The detail behind these investments can be found in Annex 4 – Technology investment.

Investment in the PODE IT system is ongoing. The PODE is undergoing development through BP2 to allow optimal exchange of data both ways across the transmission-distribution interface.

7.3.15.4. A16.4 Whole system outage notification

Sub-activity **A16.4** extends our advanced outage notification system (eNAMS) to cover a wider range of stakeholders and makes it more interactive.

Following the release of eNAMS in September 2021, we are now enhancing the application via our PODE workstream 1. Development sprints have been set up to deliver the leading enhancements requested by customers and stakeholders. We delivered the first set of enhancements in February 2022 and the rest in April 2022.

There are no material changes to the ambitions of this sub-activity for BP2.

Dependencies and Assumptions

Deliverables **D16.4.1** and **D16.4.2** are currently delayed due to the late release of eNAMS (delivered 01 September 2021 as opposed to RIIO-1 close in March 2021) and the dependency on **A16.3** to complete its discovery and scoping exercise.

Key investments for this sub-activity

This sub-activity is aligned to IT investment lines **350** Planning and outage data exchange, 360 offline network modelling and **220** data and analytics platform. The detail behind these investments can be found in Annex 4 – Technology investment.

None identified beyond those already allocated to eNAMS enhancements through PODE Workstream. Future investments required for **A16.4** will be delivered through the PODE project.

7.3.15.5. (New) A16.5 Network access planning automation

Despite incremental improvements to our automation, we still rely on manual processes for modelling system set-up and analysis. The acceleration of full electricity system decarbonisation to 2035 means bringing forward our plans. Our team will need to expand to facilitate this delivery, with more resource required to lead on this work. This work will create efficiencies in our modelling processes to allow a more optimised constraint management plan tracking across each 24-hour period.

We will develop capabilities which allow us to understand and optimise vastly different scenarios on the transmission system. This will lead to a need to study greater ranges of conditions over many more time periods, at different times of the day and at potentially much finer granularity.

The arrival of new technology such as smart valves, new HVDC interconnection to Europe along with HVDC interconnection within the GB network, and the power electronics associated with these, makes modelling and analysis more challenging and requires more and more scenarios to be mitigated for. This leads to a greater requirement for automation and less reliance on our manual processes.

These changes, and the numerous Pathfinders in progress, are set against a less predictable generation and demand profile than in the past. This will require much more scenario and time stamp study work. The volume of network outage change directed by TOs can also be difficult to address as quickly as needed. We recognise that a probabilistic approach to outage planning could be achieved and that BP2 is the time to begin scoping methodologies that could allow us to offer this service.

Automation improvements through BP2 within network access planning will remove time-consuming manual processes, make system security studies more accurate, and provide greater scope for cost optimisation of the transmission outage plan.

What are our RIIO-2 plans?

We will focus on setting out an automation plan for the path to 2035, scoping and agreeing a future platform for automation and developing the environment for application development. Our team will need to expand to facilitate these ambitions.

Delivery will contribute to maintaining system security due to the multitude of new scenarios needing to be studied to mitigate the associated risks. This, in turn, will create benefits for consumers through constraint costs management as the increase in scenario studies enable delivery of an even more efficient and economic outage plan. We estimate that significant consumer value can be realised via automation of our system modelling process of up to £100m per year in reduction of constraint costs realised through an increase in running many more system studies tracked through each twenty-four-hour period with greater optimisation of our constraint management activity. Added automation will also benefit the Electricity National Control Centre by enabling more appropriate scenario studies as part of delivery of an increasingly complex operational plan.

A ‘sandbox’ environment for testing has been introduced and enhanced automation schemes are being developed for use by NAP engineers. Progress has been made on stability automation in greatly reducing the system set-up and analysis times, allowing more stability studies. We will take the same approach in other system study areas, such as thermal and voltage studies. Some smaller automation initiatives have also been completed.

Key investments for this sub-activity

This sub-activity is aligned to IT investment line **360** offline network modelling. The detail behind this investment can be found in Annex 4 – Technology investment.

7.3.15.6. A16 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A16 - Delivering consumer benefits from improved network access		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	2.0	1.4	1.2	1.4	1.4
	BP1	0.4	0.4	1.2	1.4	1.4
	Variance	**1.6**	**1.0**	**0.0**	**(0.0)**	**(0.0)**
Opex (£m)	BP2	5.4	5.6	6.0	6.1	6.1
	BP1	4.7	4.8	5.2	5.2	5.2
	Variance	**0.7**	**0.8**	**0.8**	**0.8**	**0.9**
FTE	BP2	68	68	78	77	77
	BP1	62	63	68	67	67
	Variance	**5**	**4**	**10**	**11**	**11**

Table 26: RIIO-2 cost and FTE for A16

The forecast capex for BP2 has remained broadly in line with our BP2 forecast. The FTEs and opex required to support **A16** has increased since our first Business Plan submission. The main drivers of the opex increase are the growing complexity of network planning requirements and support our new Automation deliverables. The increase of headcount to 11 FTEs in FY25 is driven by:

- Four FTEs to deliver our long-term network access planning requirements and create efficiencies in existing processes
- Two FTEs to support the development of tools to coordinate deep access planning, which will enable us to make more holistic commercial assessments of outages, throughout BP2.
- Five FTEs to lead on the Network Access Planning automation deliverables in **A16.5**, which will create efficiencies in our modelling processes.

7.3.15.7. A16 Cost-benefit analysis

The NPV of this activity is £254m over the RIIO-2 period and £640m over 10 years. The NPV has increased by approximately £50m and £221m over five and ten years respectively. This change has been driven by the increase in constraint costs. For further information see Annex 2 - CBA.

7.3.15.8. A16 Stakeholder Feedback

(A16.1, A16.3, A16.4) We have not received any specific feedback in these areas that has resulted in significant changes to BAU activities.

(A16.2) Feedback from customers and stakeholders indicates a desire for the ESO to be more engaged in commercial decision making across the Transmission-Distribution interface and customers have asked us to trial processes which allow more holistic considerations, and for formal procedures to be agreed. How we put this into practice is an area we will continue to engage on during our BP2 consultation and beyond.

(A16.5) Change in this area is not predominantly driven by stakeholder feedback.

For further information see Annex 3 – Stakeholder engagement.

Cross-role actvities

When building the content for BP2, it became clear that a number of activities affect more than one, or all three of our Roles. To ensure a consistent approach on how we tackle these activities, we have created a category of cross-role activities. These are defined as activities that impact more than one ESO Role and require ownership across multiple Roles via independent sub-activities. The following content sets out the cross-role activities identified for Role 3.

7.3.16. (New) A22 Offshore coordination and network planning review

Both our existing Network Planning Review (NPR) and Offshore Coordination (OC) projects are expected to have a significant impact our ongoing Role 3 activities. Indeed, we expect the level of alignment between these projects will mean that, in time, they will operate as a coherent whole. Further work is planned for 2022 to investigate how to bring these related activities together but, for this draft Business Plan, we present a summary of the NPR and OC projects as they currently stand.

7.3.16.1. Network Planning Review – current position

The NPR will bring together the capability and operability challenges faced by the electricity transmission network into a coordinated process, developing an end-to-end network planning process that supports the delivery of net zero at best value to consumers. It will support the delivery of strategic network planning capabilities envisaged by Ofgem's ETNPR project and will also undertake a more general review of network development and planning processes, to ensure they remain fit for purpose as we work towards a net zero electricity system.

The NPR project currently has resource shared with OC. These are expected to be required for at least two years to deliver a two-stage project scope:

- Identifying gaps in current planning processes and options for closing them; and
- Developing an end-to-end centralised strategic network planning (CSNP[33]) methodology, as envisaged by Ofgem's ETNPR programme.

Consultancy support has been procured to assist the progression of the NPR in early 2022, part of which will be to assess the FTE and capability impact of acting as Central Planner to deliver an enduring strategic approach to network planning.

NPR activities will touch on a wide range of teams, and we expect there will be activities that other business-as-usual teams will need to pick up, with additional accompanying FTE uplift (to be defined).

7.3.16.2. Offshore coordination – current position

In July 2020, BEIS established the OTNR, with the objective:

"To ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, considering the increased ambition for offshore wind to achieve net zero. This will be done with a view to finding the appropriate balance between environmental, social and economic costs."

Offshore wind is a critical technology for achieving net zero by 2050. To realise this target, a step-change in both the speed and scale of deployment is required, and this growth must be enabled efficiently for consumers and take account of the impacts on coastal communities and the environment.

By the time of BP2, our OC project will have delivered actions relating to the workstreams of early opportunities and the pathway to 2030 (PT2030). During BP2 we will implement an enduring approach to planning and connecting the offshore network - a large part of which will be steered by the wider ETNPR.

The focus of OC during BP2 will be on key areas such as:

- Further developing planning of seabed leasing and offshore connections and networks
- The potential for the application of Early Competition to offshore networks and the arrangements for multi-purpose interconnectors
- Developing proposals for changes to industry codes and standards related to the above developments.

Some of these activities will be dependent on decisions being taken by BEIS and/or Ofgem, such as on multi-purpose interconnectors.

7.3.16.3. Activities to develop an Enduring Offshore Regime

The **potential business impact** of the enduring network planning part of our offshore coordination work is set out later in this chapter. There are, in addition, five areas of activity required to establish and deliver offshore-specific parts of strategic network planning, as outlined below. For further information see Annex 1 – Supporting information.

1. **Strategic seabed leasing plan**

BEIS has consulted on the introduction of strategic seabed leasing, to coordinate with their associated network connections. The concept is planned to be finalised in BP1 and additional resources would be required for us to support the development and maintenance of the strategic seabed leasing plan in BP2.

Potential FTE impact: five FTEs for the first year of BP2 to support the development of the strategic seabed leasing plan as well as the two activities below.

2. **The treatment of multi-purpose interconnectors (MPIs)**

BEIS has also consulted on multi-purpose interconnectors becoming a specific form of licensable activity. Within the BP2 period we expect to further develop and implement any necessary changes within our control

[33] For the purposes of this paper, 'CSNP' is used to describe both the process of Centralised Strategic Network Planning, and the end-result – a Centralised Strategic Network Plan.

as a result of a decision from BEIS, and subsequently Ofgem, on the creation of a multi-purpose interconnector in the expected Energy Act and licences.

Potential FTE impact: The same resource as outlined above will continue to support the development of the multi-purpose interconnectors in the first year of BP2. However, it is highly likely that BAU implementation resources could be required if MPIs become a specific form of licensable activity. The potential impacts on our resources and systems are yet to be identified; further assessment would be required to understand them in detail once the changes to MPIs are known.

3. **How Early Competition is applied to the offshore network**

We assume the HND and ETNPR transitional arrangements related to any offshore transmission system would not be delivered via a process involving Early Competition due to time constraints and is therefore unlikely to commence in the BP2 period.

The upcoming Ofgem decision on offshore delivery models related to the HND will validate or challenge this assumption.

Potential FTE impact: The same five FTE resources as outlined above will support the development of early competition offshore more generally in the first year of BP2. As we assume an offshore-related early competition would not be undertaken in the BP2 period, we assume no additional FTE impact. However, the preparatory work to allow an early competition to be launched in BP3 would need to be undertaken in BP2. We therefore assume that an additional 10 FTEs and £250k external consultancy support would be required for FY25 in BP2.

For further information see Annex 1 – Supporting information.

4. **Stakeholder engagement resources**

Stakeholder engagement is an important part of the development of the CSNP. We will work closely with the TOs, developer(s) of the offshore network and offshore wind generators to understand their views, benefit from their knowledge and expertise and help them understand the plan and its methodology.

Drawing on experience in BP1, there may also be a requirement to deliver a third HND/transitional CSNP in the first year of BP2 to provide connection designs to offshore developers that apply after the scope is finalised for the second coordinated design process. This will require sufficient resources to plan, coordinate and carry out engagement, take account of the feedback and lead external organisations contracted to support us. There are key stakeholders we will need to engage in depth, such as offshore developers, onshore TOs, and environmental and community representatives. We are also likely to utilise governance groups in the network design process to facilitate stakeholder consultation. The assessment of objectives related to the environment and communities requires us to engage with relevant stakeholders in these areas too, with resources required to plan, facilitate and carry out the engagement.

Potential FTE impact: Our initial view is if we are progressing a further transitional design process, we will require five FTEs in the first year of BP2 plus the relevant time input from key experts of the CSNP team and £80k for external support.

5. **Project team**

There will be a need for strong project management for the implementation of the CSNP to ensure successful delivery to time, cost and quality. There will also be a need for policy development resources to continue to influence the development of ongoing OTNR activities that go beyond those considered by the NPR. We will continue to optimise the structure of the NPR and OC projects through the BP2 period, with the transitional and enduring regimes sitting within the Network Planning Review project.

Potential FTE impact: Our current view is that this will require three FTEs. As previously mentioned, two of these (one project manager and one administrator) will be shared with the NPR.

7.3.16.4. Stakeholder engagement across the NPR and OC projects

For NPR, stakeholder engagement will be essential during both the key stages of the NPR i.e. development of the end-to-end strategic planning methodology, and the more general review of network development and planning processes), followed by further engagement as part of Ofgem's ETNPR.

To date, stakeholders have provided feedback on our OC projects through a number of routes.

They challenged analysis and provided views on the direction of the project through the phase 1 consultation in October 2020. By engaging 76 organisations through 40 written consultation responses and 11 workshops, this consultation helped ensure the findings of the phase 1 cost-benefit analysis were robust. Based on feedback, we conducted a new sensitivity analysis on the impact of commencing coordination in 2030, compared to 2025, as in our original analysis. This confirmed significant benefit in moving quickly to an integrated network and the importance of considering flexibility for coordination between 2025 and 2030.

Stakeholders were generally positive about our approach and findings in phase 1. There were recommendations that we proceed immediately with necessary code changes, so we have been identifying these with input from the Central Design Group (CDG) commercial subgroup and a series of code change workshops. There was a view that Pathfinder projects before 2030, enabled by a flexible approach to regulation from Ofgem and BEIS, will be essential to realising the most substantial benefits, reinforcing the drivers for our early opportunities work.

More recently, stakeholders have provided technical input on phase 2 deliverables, through meetings and dedicated working groups. These include regular CDG meetings and subgroups, helping to inform various elements of the HND in the Pathway to 2030 workstream.

Finally, stakeholders have helped to shape the project's engagement approach, through responding to multiple surveys. Feedback has highlighted the following as important themes for stakeholders: empathy for and understanding of stakeholders and the impact of the project on their businesses; transparency and timely communication on timelines; and helping stakeholders to understand how the project's workstreams interact with each other and wider industry activities. We have reviewed root causes and solutions in detail and have implemented an action plan to address these points and improve stakeholders' experiences.

BEIS and Ofgem have also carried out public consultations on policy changes that will impact our activities.

7.3.16.5. A22 Financials and Headcount

		Five-Year strategy				
		Forecast		BP2		BP3
A22 - Offshore coordination / Network planning review		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	2.7	4.2	3.2	3.4	3.4
	BP1	-	-	-	-	-
	Variance	**2.7**	**4.2**	**3.2**	**3.4**	**3.4**
FTE	BP2	36	41	48	47	50
	BP1	-	-	-	-	-
	Variance	**36**	**41**	**48**	**47**	**50**

Table 27: RIIO-2 cost and FTE for A22.

The consequences of the NPR and OC projects on our enduring Role 3 activities are set out in Annex 1 – Supporting information, which goes into more detail on the activities we expect to have to undertake to deliver CSNP, along with our current best view of the potential FTEs, capability and systems impacts.

The NPR project is currently assumed to close at the end of FY23, with project-related activities moving into the enduring CSNP activity from FY24 onwards. We currently expect the OC project to continue with the transitional activities set out into FY24 and FY25.

CSNP FTEs are the incremental resources required to undertake a transformed strategic network planning process, from development of scenarios through to the delivery of a plan. These have been optimised across the NPR, OC and EC projects and incremental BP2 resource for both FES and BAU network development activities – again to ensure no duplication of requirements.

FTE numbers in Table 27 are based on a best view of potential business impacts, noting that further work is planned for 2022 to investigate the requirements in more detail. Decisions taken by BEIS and Ofgem during the year will also have an impact. We expect these numbers to be refined as that work progresses.

This new activity will see 47 FTEs actively engaged in FY25. This resource is applied to the different areas of overall network development activity as follows:

- 13 FTEs for Offshore Coordination, including:
  - Five FTEs working on the strategic seabed leasing plan, and in support of developing multi-purpose interconnector strategy. They will also support the development of early competition offshore.
  - Five FTEs focused on stakeholder engagement, working closely with TOs and developers to contribute to the CSNP plan and methodology
  - Three FTEs committed to project managing the implementation of CSNP to ensure timely and quality delivery
- 34 FTEs for NPR, and to deliver CSNP capability, including:
  - Six FTEs for electricity generation and demand modelling and model development
  - Two FTEs to manage the impact of development and implementation of the strategic seabed leasing plan
  - Six FTEs to contribute to identifying and modelling system operability needs
  - 16 FTEs for the detailed design of strategic options and design activities
  - At least four FTEs for the options appraisal process

Opex is applicable entirely to resource costs.

The table above does not include resources attributable to Early Competition, as this is covered within the table under its sub-activity, **A8.4**.

7.3.16.6. A22 Cost-Benefit Analysis

Annex 2 - CBA contains a break-even analysis for **A22**. We have not created a CBA for this activity because it does not forecast delivery of consumer benefit until 2025, with the benefit only becoming significant from 2030 onwards. Further information can be found in Annex 2 - CBA.

Please see Annex 1 – Supporting information for more information on our best view of enduring requirements to deliver a holistic approach to planning the onshore and offshore transmission network on a strategic basis.

7.3.17. Facilitating distributed flexibility

The decentralisation of the energy sector has accelerated since our first Business Plan with significantly greater volumes of energy resource connecting to distribution networks. This is now extending even into our homes with greater number of EVs and smart devices.

DER can provide valued services to the ESO. Facilitating these services can help decarbonise the sector and create value for consumers. Aggregators and electricity suppliers are already developing new products to enable consumers to participate in a flexible energy system but are finding current market arrangements and frameworks do not work for smaller distributed assets. To meet GB's 2035 decarbonisation targets we need to take a stronger role to facilitate whole electricity system outcomes.

In BP1 we have started opening up our markets and the Balancing Mechanism (BM) to smaller parties. New products through programmes such as the RDPs and local constraint markets have brought new revenue opportunities for DER. Our Power Responsive programme has continued to work closely with demand side providers to enhance market opportunities.

In BP2 we will facilitate aggregator and supplier models to allow consumers to reduce their energy bills through a broad range of our services and markets. This isn't just for us. There is great consumer value in Distribution System Operation (DSO) flexibility markets and we need to take a whole electricity system view to ensure all opportunities can be realised for DER service providers.

Facilitating greater market access for smaller distributed parties creates new operational challenges for us. We need to have sufficient operational visibility of our service providers to understand the impacts of their actions and gain assurance of delivery of services. We also need to increasingly coordinate our operations with those of the DSO as distribution networks become increasingly constrained.

These new and enhanced activities will be delivered through:

- A new sub-activity in Role 1 **A1.5 Operational coordination with DER and DSO**. This reflects the growing impact of DER on our real-time operations. We will ensure our control room systems and processes account for increased operational visibility, and operational coordination.
- New Role 2 deliverables within the existing sub-activity **A4.5 Facilitate whole electricity system market access for DER** (formerly Alignment of ESO-DSO flexibility markets). These deliverables investigate how our markets can be designed and implemented in a way that will unlock the potential of distributed flexibility. They will remove barriers for aggregators and energy suppliers facilitating DER assets in our markets. We will consider the impact of the DSO transition on our current and future markets, and on any changes to frameworks in A6.9 Whole system codes reform.
- In Role 3, we are proposing new work to enable greater procurement of services from DER. This includes IT solutions to ensure continued system operability through greater visibility of DER and operational coordination of DER services. Building on our work to review BM operational metering standards, we will work with stakeholders to review our technical requirements for service provision to ensure these remain appropriate for smaller distribution assets. Further details are under **A15.8 Facilitate distributed flexibility and whole electricity system alignment**. This is in addition to our work on DSO policy and RDPs.

What have we carried out so far?

In BP1 we have stepped up our support to facilitate distributed flexibility and support the DSO transition including**:**

- In the first Business Plan for RIIO-2 we proposed to ensure our markets are coordinated with others when delivering a single day-ahead response and reserve market
- Publishing details of procurement activities to act as a repository for a single source of information for flexibility providers to understand commercial opportunities.
- Publishing more information on the location of balancing service units to facilitate DSO coordination
- Undertaking a reserve scarcity trial with Octopus Energy to understand how domestic flexibility could resolve real system issues.
- Reviewing BM operational metering standards to facilitate smaller distributed assets providing services to the ESO.
- We led an engagement programme further to the 'Enabling the DSO Transition' publication to understand stakeholder feedback, which, alongside RIIO-ED2 Business Plans, has informed our proposals in this second Business Plan
- Stepping up our leadership in the ENA's Open Networks Programme.[34] This includes developing flexibility market arrangements as well as primacy rules and the whole system CBA
- Using our RDPs (**A15.5 Regional Development Programmes**) to develop transmission constraint management markets for DER
- Establishing a 'Whole Electricity System Joint Forum' which ensures the development of future coordinated markets is consistent, and which is now a valuable engagement channel for other activities with the DSO community.
- Deliverables have also contributed to the DSO transition including the Whole System Technical Code (WSTC) ambition of **A6.5**, issuing its first consultation and progressing the Distributed ReStart project.

Additional detail is outlined in the role-specific sections below.

[34] https://www.energynetworks.org/creating-tomorrows-networks/open-networks/

7.3.17.1. Role 1 - (New) A1.5 Operational coordination with DER and DSO

In BP1, as projects such as RDPs have entered the delivery phase, we have begun to provide greater operational support into the development of DSO.

We have also worked with Octopus Energy on a DSR exploratory which builds on previous projects into domestic flexibility and increases our understanding of what a service of this type could offer to real system issues.

What are our RIIO-2 plans?

This is a new sub-activity to address the impact of increased distribution connected flexibility resource on our real-time operations. In BP2 this will be achieved through greater operational visibility of DER alongside increased operational coordination.

Our plans consist of providing operational support for key distribution-facing deliverables such as operational visibility, RDPs, and also operational input into the design of new services affecting DER. We will also be providing operational input into the development of DER flexibility markets in projects such as RDPs and the Local Constraint Market (LCM).

D1.5.1 Increased DER visibility in real-time operations

The accelerated growth and impact of DER requires increased operational visibility to ensure Control Centre actions are coordinated in the best interests of the end consumer.

We will work with the project delivery team in Role 3 to ensure our Control Centre systems accommodate greater volumes of real time data from DER, and also provide operational input into the project. Facilitating increased visibility of DER in real-time operations will enable balancing and security actions to be coordinated across the whole electricity system. The work will also include operational input into the need for greater real time transmission data exchanges with DSO.

D1.5.2 Whole electricity system operational service coordination (continuous)

We will be providing operational input into the development of whole electricity system operational service coordination and delivering functionality into control centre systems. This will involve:

- Working with our operational co-ordination project in Role 3 to deliver appropriate IT functionality into our control centre IT systems.
- Translating operationally facing policies into our Control centre4 processes and providing training to our Control centre staff on their impact.
- Working with DSO and DER service providers on enhancements to initial rules and ensuring these are reflected in our Control Centre processes.

D1.5.3 Development of RDP and LCM functionality into real-time environment

Our RDPs and LCM functionality are introducing coordinated flexibility markets into our Control Centre environment for specific use cases. For any future ESO-DSO model we need to use learnings from these projects to inform real time operational processes. We will deliver RDP and LCM functionality into real time operations as an established business as usual activity to manage system security and cost.

This deliverable will provide technical support and real time operational experience to RDPs in the design phase and delivery of these systems into the Control Centre.

D1.5.4 Increased operational liaison (continuous)

In a highly decentralised sector, the need for operational coordination will become more critical. We will work with stakeholders to understand the future requirements for operational coordination and the impacts of longer-term developments.

We will extend our operational liaison channels with DNOs to include DSO liaison, ensuring we are learning from real time use of flexibility services We will work with DNOs to develop appropriate forums for this knowledge exchange.

7.3.17.2. Role 2 - (Materially changed) A4.5 Facilitate whole electricity system market access for DER

In the first Business Plan for RIIO-2 we proposed to ensure our markets are consistent and coordinated with other markets when delivering a single day-ahead response and reserve market, to maximise the potential for distributed flexibility to deliver value to the whole electricity system. Additionally, we proposed to work with DNOs through ENA Open Networks to develop simplified and common contract terms and to investigate where procurement processes can be aligned.

By the end of the BP1 period, we will have made significant progress in the facilitation of DER in flexibility markets.

In market design and reform, we will have launched new products for response (**D4.3.6**) and reserve (**D4.3.3**) that level the playing field for distributed flexibility to participate. DER will have opportunities to help ESO manage transmission constraints through our new Local Constraints Market (**D4.6.6**) at the Anglo-Scottish boundary, as well as through the growing number of RDPs. We will also have opened the door for aggregated residential consumers to participate in the BM by allowing suppliers to submit appropriate aggregated real time signals to the ESO. These arrangements will be developed in conjunction with the industry under the banner of the Power Responsive campaign.

We have facilitated greater and easier access for DER into our markets by developing enablers and removing technical and commercial barriers, which our Power Responsive programme (**D4.2.1**) has continued to work with the distributed flexibility community to identify. Our Single Markets Platform (**D4.4.1**) is already live, providing frictionless access for DER to ESO markets.

To enable DER to choose where they can best add value to the whole electricity system, it is key that we align with DNOs to provide DER with a clear, coherent set of markets to participate in. We are coordinating throughout BP1 to increase the visibility of ESO-DSO procurement for flexibility services (**D4.5.2**). This includes publishing details of procurement activities across the whole system as a repository for a single source of information for flexibility providers to understand commercial opportunities. We have led key deliverables in the ENA Open Networks flexibility workstream to deliver a common framework agreement for flexibility services and increase the visibility of procurement timescales. We are also increasing the information available on the location of balancing service units. We now publish locational data for successful firm frequency response tenders and will be expanding this to our new suite of frequency services in 2022 (Dynamic Containment, Dynamic Moderation and Dynamic Regulation).

What are our updated RIIO-2 plans?

Since the submission of our original Business Plan there has been continued growth in the volume of DER on the system. We need to develop our markets to facilitate access for these parties. This is particularly true for smaller energy resources, including residential assets such as EVs. Aggregators have told us that the current arrangements do not work for these devices and we have already started to implement changes.

We want our markets to be accessible to all parties and we will do this in a stakeholder-focused manner to facilitate interoperability. This extends to DSO markets. We will build on our work leading key elements of the ENA's Open Networks projects through some new deliverables.

D4.5.3 Reforming markets to facilitate future distributed flexibility technologies and models (new)

We will build on the work undertaken in BP1 to continue reforming our ancillary and balancing services markets to enable distributed flexibility participation. Our Markets Roadmap activities will continue to identify opportunities for market reform to achieve this. For example, our investigation into new markets for reactive power (**D4.6.2**) and stability services (**D4.6.1**) will look to understand how to remove technical, commercial and regulatory barriers to DER participation. We will undertake similar analysis across our suite of markets. We will also carry out horizon scanning activity, to understand how distributed flexibility technologies and business models, particularly in the residential sector, will evolve over time.

It is important that distributed flexibility is also enabled through wider GB electricity markets and policies. Our net zero market reform work (**A20**) will continue to investigate what reforms, particularly to the wholesale market, could enable these assets to unlock their full potential. It will also assess what potential Government interventions might be necessary to stimulate the huge levels of investment required in this space.

D4.5.4 Facilitating market access for DER (new, continuous)

Our new services are facilitating entry to flexibility markets for many DERs, but we believe we need to do more particularly for smaller DERs. Through our channels, including Power Responsive, we will engage with this valued stakeholder community to ensure our new designs work for distributed flexibility wherever possible, simplifying access to and participation in our markets.

We also recognise the importance of interoperability, not only between our markets but also DSO markets. Through increased interoperability we can ensure that providers can seamlessly access a range of potential revenue opportunities and clearly understand those of greatest value. In BP2 we will enhance our SMP to ensure interoperability with third party platforms including those being developed for DSO markets. We will also ensure our new services are developed in a standardised interoperable manner that facilitates coordination with DSO flexibility markets.

The work to allow aggregated real-time signals into the control room from portfolio providers will unlock new markets for domestic flexibility as well as more traditional Industrial and Commercial assets. Combined with the ongoing systems developments under Role 1, this will ensure DER assets continue to increase their market share of balancing services.

D4.5.5 Ensure co-ordination of markets across the whole electricity system (New)

This activity will see the development and embedding of processes and systems to coordinate markets across the whole electricity system. National Grid ESO's Transmission Licence requires us to coordinate our market development with DNOs, including emerging DSOs. These requirements have been recognised by Ofgem and BEIS through their 2021 Smart Systems and Flexibility Plan update.[35]

Throughout BP1, we have led work in ENA Open Networks on service coordination, resulting in a common framework structure for flexibility services and aligned procurement processes. In BP2, this work will extend to facilitate greater coordination across all relevant balancing services. This will include greater visibility of locational information of our service providers which will allow more efficient management of all networks across the system.

To achieve this, we will improve our processes and systems for managing data relating to service providers, ensuring locational data is made available to those that need it. We will also be expanding the use of contractual arrangements initially developed through the RDPs and the Distributed Restart Network Innovation Competition (NIC) project to a wider range of use cases. This will provide clarity to service providers of roles and responsibilities when procuring services connected to distribution networks.

We will continue to develop our longer-term Markets Roadmap with a lens of whole system coherency, to ensure markets are designed in a way that enables distributed flexibility to maximise their value across the whole electricity system.

7.3.17.3. Role 3 - (Materially changed and name changed) A15.8 Facilitate distributed flexibility and whole electricity system alignment

The activities in our first Business Plan included supporting the ENA Open Networks Programme, engaging with stakeholders and ensuring alignment in our activities with the RIIO-ED2 Business Plan process.

We have engaged extensively on our 'Enabling the DSO transition'[36] consultation and with the RIIO-ED2 Business Plan process. We have met with DNOs and reviewed their strategies to understand implications for us and where we need to support the DSO transition. This has resulted in more positive feedback from stakeholders.

We have also initiated work to review operational metering standards for ESO services to ensure they are appropriate for smaller service providers.

What are our updated RIIO-2 plans?

Our updated plans reflect both the increased urgency to facilitate DER access to ESO markets. Recognising this, and informed by stakeholder feedback, our ambition is expanded with new deliverables. This has started already; in BP1 we grew the team in response to stakeholder feedback that we needed to take a more proactive role. We have increased our involvement and coordination with the ENA Open Networks

[35] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[36] https://www.nationalgrideso.com/document/190271/download

Programme, leading six of the key 2022 deliverables. Through our Whole Electricity System Joint Forum, we have also facilitated key DSO input into projects including SMP and Restoration Standard. In 2021/22 we have started work on greater DER operational visibility by drafting a position paper to facilitate stakeholder feedback to support our proposals for BP2 and will expand this work further to cover transmission to distribution operational visibility.

D15.8.1 Develop policy areas to facilitate distributed flexibility and whole electricity system alignment

This deliverable sees milestones updated to reflect the need for ongoing policy development. This includes work in facilitating distributed flexibility into ESO markets to support the revised 2035 target, the needs of DER stakeholders and supporting the changes led by Ofgem for DSO governance. We will also continue the engagement to develop coordination with DSOs in line with the ambitions of each DNO.

D.15.8.2 Enabling distributed flexibility service provision to the ESO (New)

This new deliverable will see the ESO removing technical barriers for smaller assets participating in ESO services. We will work with aggregators and suppliers to understand how our technical requirements need to change to facilitate flexibility down to the residential level.

This includes developing the processes and IT infrastructure to manage a more greatly decentralised energy system. Key to this will be having greater operational visibility of DER.

There are significant benefits from us having greater operational visibility of DER, ranging from facilitating greater aggregation of DER services through to enhanced situational awareness to allow better management of system events. Our initial work has shown a range of use cases indicating a potential annual benefit of up to £150m per annum.[37]

In BP2 we will deliver greater operational visibility of DER into our Control Centre systems building on early work through the RDPs. This will facilitate market access for distributed resource and aggregator business models. Underpinning this will be the Installation of high-speed inter control centre protocol (ICCP) data links[38] to the remaining DSO control centres without this capability, which will enable transfer of operational data in both directions.

This work will be led by a core team in Role 3, established on a phased basis, with support from the other role areas.

D15.8.3 Enabling whole electricity system operational service co-ordination (new)

Co-ordinating service requirements across the whole electricity system will reduce the overall cost of managing electricity networks and ensure consumer value is realised. A co-ordinated approach will also support service providers' access to markets. To manage service co-ordination efficiently and transparently, whilst facilitating the potential for flexibility market platforms, we are leading the development of a set of 'primacy rules' through the ENA Open Networks project.

This co-ordination extends to operational timescales, where we will need to ensure there are robust and transparent systems in place to co-ordinate our activities in control room environments.

Co-ordination frameworks will be in place at the start of BP2 and initial use cases will be delivered into control centre systems through the RDPs. In BP2 we will broaden our delivery of operational co-ordination systems to enable the dispatch of services to be influenced by whole system value; this will make sure that the division between market/price-driven actions and the electricity system hierarchy of operations/needs is clear and transparent.

Facilitating distributed flexibility key dependencies

We are proposing to create a central team to deliver this work. The work will build on **A15.5**'s RDP learnings. The additional headcount requirement to lead co-ordination of this work in Role 3 will be introduced on a phased basis from FY24. Operational support for control room IT system integration will be provided from Role 1 and this is covered in the Role 1 DSO section (**D1.5.2**).

Dependencies and assumptions

Successful delivery is dependent on delivery of the related deliverables in each of the Roles. The Data and Analytics Platform (IT investment **220**) will host the Data Portal, which will have service provider data and

[37] DER Visibility Benefits Assessment is not yet published and may not be prior to BP2
[38] ICCP is a real time data exchange protocol providing features for data transfer, monitoring and control

provide a service to market participants, plus Network Control (IT investment **110**) will enable the exchange of operational data (e.g., network topology and flows – both static and dynamic data).

The move to increase and coordinate the interactions across the ESO-DSO interface will require the delivery of both of our Balancing (IT investment **180**) and Network Control IT investment (IT investment **110**). They will deliver the required IT systems into the real time operation of the Transmission system. This will also be complemented by the delivery of the associated market and code changes outlined in the relevant sections of the Business Plan.

Effective future system monitoring and reporting of system performance relies on the IT investments in ENCC Asset Health (IT investment **210**) and Frequency Visibility (IT investment **170**).

Our work is heavily influenced by external factors. At a high level these start with the BEIS Smart Systems and Flexibility Plan. In their 2021 update BEIS stressed the need for progression in this area.

Facilitating distributed flexibility key investments

In addition to our work on **A15.5 Regional Development Programmes** that were highlighted in the original Business Plan we have identified the following new investments in BP2:

- For our increased operational visibility, we propose to have operational data exchanges or ICCP links with all DNOs. There will also potentially need to be updates to existing control centre systems to accommodate additional data requirements. These will be scoped at the start of BP2.
- Implementation of operational co-ordination systems into our control room will require new IT functionality to be developed and delivered.
- In Role 2 we can see a need for IT system changes to share service provider information more efficiently with DSOs to ensure overall co-ordination.
- We can also see a need for enhancements to our SMP (IT investment **400**) and Digital Engagement Platform (IT investment **250**) to ensure interoperability with DSO platforms described in their RIIO-ED2 Business Plans. The detail behind this investment can be found in Annex 4 – Technology investment.

Relevant sub-activities are not yet aligned directly to an IT investment, as they are still to be solution assessed, however we will provide further detail in our final Business Plan in August 2022.

7.3.17.4. Facilitating distributed flexibility cost-benefit analysis

Distributed markets for flexibility are a significant enabler for delivery of BEIS' Smart Systems and Flexibility Plan. In the Plan, BEIS highlight*, "…the transition to a smarter and more flexible energy system is an opportunity. It will reduce the costs of our system by up to £10bn a year by 2050, by reducing the amount of generation and network we need to build to meet peak demand".*

We have been able to quantify the benefits of enabling distributed flexibility in the following areas:

- Our initial work on DER visibility has shown a range of use cases within the ESO and described benefits for each. In many areas we have been able to quantify these benefits which indicated a potential annual benefit of up to £150m pa.
- As stated in our first RIIO-2 Business Plan, continued deployment of RDPs will save consumers over £40 million and over half a million tonnes of carbon.[39]

The RIIO-2 CBA for activity A15 includes benefits cases for DER Visibility Savings and RDPs. For further information see Annex 2 – CBA.

7.3.17.5. Facilitating distributed flexibility stakeholder feedback

Following our April 2021 'DSO Vision' consultation, we engaged through webinars, and bilateral and round-table meetings with stakeholders. We have taken the feedback from that consultation, our ongoing engagement and from our review of the RIIO-ED2 Business Plans to help form our proposals.

At a recent webinar solar developer highlighted this work as a priority:

[39] https://www.nationalgrideso.com/document/158051/download (p98)

> *"This is a massive challenge for the industry and it's really important for us to see that UKPN & NG are understanding the severity of this."*

We have ongoing engagement with key stakeholders through the ENA Open Networks Programme and our monthly Whole Electricity System Joint Forum is a key aspect of how we engage to support the DSO transition.

We shared our proposals with ERSG in January 2022 and received positive feedback on our proposed activities for BP2 and agreement that the right focus areas were included. The inclusion of specific deliverables regarding distributed flexibility in Role 2 reflects the feedback received on the importance of effective, clear, and dynamic market mechanisms and the need for deep service co-ordination. Greater operational visibility of DER was seen as important with the most cost-effective solution being needed and the sharing of this visibility with others.

At the March ERSG, the group provided further feedback around DSO/ESO cooperation. Whilst the group felt cooperation was important, it challenged that the ESO to consider its role beyond the traditional utility-focused lens and that it should look at how it can better engage with all parties who play a role in interacting with consumers. We have taken on board this feedback, recognising the importance of consumer flexibility in enabling a net zero system. As a result, the Business Plan proposals have been updated to provide further clarity on the ambition in this area.

We will continue to engage with stakeholders throughout the drafting of BP2 to ensure that we are capturing feedback and informing our planning processes appropriately.

7.3.18. Net zero operability

The UK Government has committed to fully decarbonising the UK electricity system by 2035. This brings with it a raft of operational challenges to the system, and alongside these there are other investment, policy, socioeconomic and market challenges for the ESO and the wider industry to tackle together.

The 2035 target represents a paradigm shift in the makeup and characteristics of the energy system. The scale of the challenge to get there is significant and, in the world of planning and delivering large-scale infrastructure, 2035 is just around the corner. We therefore need to recognise a sense of urgency.

The ESO is well positioned to solve these challenges, through a multitude of existing projects and programmes that are highlighted in this section.

This is not a challenge that the ESO can deliver on its own. We need to evolve and adapt our organisation to work alongside an industry that is rapidly diversifying and digitising, and our relationships with BEIS and Ofgem need to transform to much more of a partnership approach. Again, the ESO is well positioned in this respect, with most of our RIIO-2 strategic and transformational programmes already happening in close partnership with our customers and stakeholders, and/or with BEIS and Ofgem.

We need to ensure we understand whether all of our strategic initiatives are, in aggregate, sufficient to meet the 2035 challenges.

- Energy use will be transformed, with a significant increase in overall electricity demand.
- By 2035, according to our FES 'Leading the Way' scenario[40] (note: all figures in this section refer to this scenario), total electricity demand will have increased by 50% from ~300TWh to ~450TWh. Approximately 15 million homes (almost half of all homes) will have heat pumps installed, which will more-than double electricity demand for home heating, from 25TWh to 57TWh. The development of local hydrogen networks will also lead to an increase in hydrogen boilers, as the sale of natural gas boilers is banned by 2035.
- The number of battery EVs will grow from less than 0.5 million today to 27 million by 2035, with electricity demand for road transport increasing to 84TWh, from ~1TWh today.
- High electricity prices and strong carbon pricing will incentivise significant energy efficiency investments in industry from the mid-2020s, and industrial customers will be switching away from fossil fuels.

[40] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

- Electricity supply must increase to meet demand but must be zero carbon and flexible.
- Total electricity generation capacity will more-than double from 104GW today to 248GW in 2035, with offshore wind representing almost half of this increase in capacity. Generation output more than doubles to 568TWh, with over 110TWh (net) exported across interconnectors. The proportion of supply from wind and solar increases from 37% to 85%, with the carbon intensity of generation falling to 16 gCO_2/kWh from over ten times that today, or -18 gCO_2/kWh including negative emissions from bioenergy with carbon capture and storage (BECCS).
- Flexible sources of electricity supply, including biomass, hydrogen, interconnectors and storage increase from 54GW today to 71GW in 2035, with a reduction in gas and coal more than offset by new technologies such as storage and interconnection. BECCS and hydrogen generation combined make up 10GW of generation, representing new forms of dispatchable thermal generation that provide zero or negative carbon emissions.

It is against this backdrop of massive change to our energy system that we have considered how to ensure operability of the electricity network as we transition towards net zero.

What are our plans for RIIO-2?

Ensuring the right networks: pace and coordination are critical.

The scale of investment in transmission infrastructure will be unprecedented. Last year's Networks Options Assessment (NOA) recommended >£16bn investment in new onshore transmission assets over the next 10 years, and this will only increase due to further increases in renewable generation forecast by FES 2021. Devoid of these network investments, the increase in power flows driven by increased generation and interconnection will contribute even more significantly to constraints experienced across the entire GB transmission system. By 2035, we will be thinking less about discrete transmission and distribution electricity networks, and instead taking holistic regional views of electricity requirements.

Connecting an additional 66GW of offshore wind and 22GW of interconnectors by 2035 could have an enormous cost impact, as well as broader societal impacts on coastal communities and the environment. We are leading and progressing work as part of the BEIS-led OTNR to deliver a more coordinated network in the short, medium and long-term. This work will have dual focus: one on delivering speed and certainty to the process for the 2030 ambition of 50GW of offshore wind to be connected, and a longer-term, enduring strategic regime to ensure the onshore and offshore transmission network facilitates the rollout of much higher levels of offshore wind out to 2050.

Great Britain's ability to connect new generation currently exceeds the pace at which the industry can approve, consent and deliver major infrastructure projects. The time taken from approval to delivery of subsea HVDC projects is evidenced at ~8-10 years, while new onshore overhead lines would be a few years longer. This means that under the current frameworks and planning regimes, we need to develop options to meet 2035 challenges immediately. The ESO's ongoing onshore and offshore network planning reviews are looking at how we collaborate to identify strategic investments - both to ensure transmission network capability is there ahead of need and also to identify potential whole energy system optimisations that deliver value.

Role 3 details our network development ambitions in this area further, including our new Offshore Coordination and Network Planning Review activities **(A22)**, and making step-changes to the effectiveness and efficiency of the connections process **(A14)**.

Ensuring the right resources: capacity adequacy will become a different challenge.

The fully decarbonised electricity generation mix in 2035, combined with the significant increase in demand, will present new challenges in ensuring system adequacy. We will be hugely reliant on a much higher penetration of weather-dependent generation (wind and solar), and many of the flexible technologies that we will depend on to balance the system may also be impacted by weather (e.g., storage, interconnectors).

Historically, the main challenges for adequacy have focused on being able to meet peak demand. In 2035, adequacy challenges could occur away from winter peak demand, manifesting at times when demand is high and/or output from renewables is low (e.g., how will we meet demand during a prolonged period of low wind?).

We are in the process of undertaking a capacity adequacy study covering the period 2025-2040. This will help us better understand the risks. It could also help to inform how the current Reliability Standard[41] may need to

[41] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202021.pdf (A.2.6)

change for a decarbonised power system, and whether there is an ‘optimal’ capacity mix within this standard that provides greater resilience against potential demand disconnection.

A5 Transform Access to the Capacity Market outlines these ambitions and deliverables in further detail.

Ensuring the right markets: delivering the right investment and operational signals.

The current combination of markets and policies that signal investment, including signals for flexibility, location and operability, will not be fit for purpose to deliver the 2035 outcome we need. The ESO's net zero market reform (NZMR) project is looking to address these challenges and recommend a way forward that is optimal for the whole energy system. Our analysis in this project will also be leveraged to influence BEIS and Ofgem by feeding directly into our collaborative Review of Electricity Market Arrangements (REMA) project. We are future-proofing operability through Pathfinders and innovation projects like Distributed Restart and Power Potential that will enable us to procure operability requirements from DER, instead of the dwindling fleet of large, thermal generators.

Role 2 **Activity 20** (net zero market reform), and Role 3 (in particular activity **A15 Taking a whole energy system approach to promote zero carbon operability**) detail our commitments to managing these challenges in a zero-carbon operability environment.

Ensuring consumers are at the heart of a just transition

The contribution of consumers to net zero – in terms of their behaviour and lifestyle choices – is fundamental. The scale of change impacting them over the next three decades will be far-reaching, so we need to ensure that the transition is a fair one. We will need significantly more flexibility from consumers – for example:

- Electric heating, which we see shifting peak demand by as much as 11.5GW in 2035; and
- EVs, which could shift peak demand by 13GW in 2035 from smart charging alone. The addition of Vehicle to Grid (V2G)[42] could see an additional shift of 14GW of peak demand into off-peak periods.

We are transforming the way we think about consumers at the ESO. Our Crowdflex innovation project with Octopus Energy is investigating how much consumer flexibility can be unlocked, which will feed our NZMR analysis on how to unlock it in a fair and efficient manner, as well as our Virtual Energy System innovation project on how to model the impact of consumer behaviour in the wider system.

Further detail is outlined in Role 2 **Activity 20 Net Zero Market Reform**.

Ensuring a smart, flexible system through digitalisation and data

The sheer complexity of the whole energy system in 2035, with smart appliances in homes responding to price signals, millions of EVs and heat pumps, and thousands of decentralised assets taking part in wholesale and balancing markets, means that the digitalisation of processes and systems is vital. Increased data sharing will be needed to provide digital systems with the information needed to optimise markets and control centre decision making. A major digital transformation is required, not just for ESO but for the industry as a whole, and it must be coordinated across different voltage levels, vectors and sectors. Increased visibility of distributed generation and demand will be crucial.

We published our updated ESO Digitalisation Strategy & Action Plan in June 2021, aligned with the recommendations of the Energy Data Taskforce. Transforming our data capabilities is foundational to delivering on our digital objectives, and to the wider digital transformation of the UK’s energy sector. Our data transformation involves strengthening our data and information culture, upskilling our people, building new capabilities and ways of working with data, and delivery of our strategic Data and Analytics Platform. Our commitments to making ESO data ‘open’ and our plans for fully exploiting our new data platforms and technologies are described in activities **Activity A17** (Open Data and Transparency) and **Activity A19** (Data and Analytics Operating Model).

[42] https://www.nationalgrideso.com/future-energy/net-zero-explained/electric-vehicles/evs-electricity

7.4. Transparency, data and analytics

7.4.1. Five-year strategy

Our five-year strategy for Transparency, Data and Analytics has not changed since BP1. We remain committed to our ambition of providing the highest level of transparency possible. We believe that making the data that we hold open and accessible, and enhancing the transparency of our decision-making processes, will deliver significant industry and consumer benefit. At the same time, we will ensure that we actively manage the risk of inadvertent over-sharing of data.

We are committed to becoming a fully data enabled system operator, putting data at the heart of every decision, be it operational, strategic, or tactical. Our recent strategy refresh includes a new ambition to be innovative, digital, and data-driven, reflecting the importance of data to achieving the ESO's mission. We will achieve this ambition through:

- **Our technology:** The Data and Analytics Platform (DAP) will provide a single source of trusted data, discoverable by, and accessible to both internal and external stakeholders, and a self-serve platform for data product development. The Digital Engagement Platform (DEP) will provide external stakeholders with a single point of access into the ESO data, content, and external-facing processes.
- **Our way of working:** Business and Technology teams will work together under a Hub & Spoke operating model to develop and operate data products, underpinned by embedded and robust data governance.
- **Our people:** We will upskill our teams through a focused programme of change management and training, with Communities of Practice driving and embedding best practice.

Whilst we have experienced some delay with respect to our BP1 deliverables for DAP, we now have an achievable plan to complete the build of the platform foundation by December 2022, in line with our RIIO-2 commitments. Good progress has been made with respect to our other BP1 plans for Open Data and Transparency. For the BP2 period and beyond, we know that we must:

- **Consolidate our data onto the DAP platform**, make our data discoverable and accessible to internal and external stakeholders where appropriate, and provide increased levels of transparency of operational decision making.
- **Improve our customer digital experience** through integration of the DAP platform with the DEP platform, making it easier for customers and stakeholders to discover and engage with ESO data and the content that supports it, and drive greater automation into the Open Data process.
- **Continue to develop our analytical capability**, with particular focus on ML, AI, and Digital Twin technology.
- **Bring our algorithms under management on the DAP platform,** standardising our approach to model development to enable greater integration of analytics across the ESO, and driving open-source analytics.
- **Enable continual improvement** to real time decisions through improved data and better day ahead information.
- **Continue to upskill our people and drive data culture** by embedding data best practices into all our processes and promote knowledge sharing through Communities of Practice.
- **Continue to engage with our stakeholders** to better understand their requirements and deliver the data services and products they need.

These actions will also allow us to fulfil the recommendations of the recent Energy Digitalisation Taskforce report on "Delivering a Digitalised Energy System"[43].

[43] ESC-Energy-Digitalisation-Taskforce-Report-2021-web.pdf (esc-production-2021.s3.eu-west-2.amazonaws.com)

To further clarify how we are delivering on these commitments, we have added a new RIIO-2 activity, **A19 Data and Analytics Operating Model**. Our ambitions for digitalisation, including the commitments made in our Digitalisation Strategy[44].

Overview of first RIIO-2 Business Plan

In our first Business Plan we established the activity **A17 Transparency and Open Data**, described in the chapter 'Digitalisation and Open Data unlocking zero carbon system operation and markets'. Within the **A17** activity we committed to deliver a foundational Open Data portal with limited data sets, provide all published ESO data in a machine-readable format, make available an ESO data list and publication schedule, and automate published data to reduce publishing times.

During the Supplementary Questions process for the first RIIO-2 Business Plan, we also established deliverables that better define how we will deliver on our ambitions for transparency. These deliverables were the 6-monthly publication of our Transparency Roadmap, the weekly ESO Transparency Forum webinars and the provision of enhanced data to industry to deliver greater clarity on trading decisions and Balancing Mechanism actions.

Updated RIIO-2 Business Plan - overview

In this chapter we present a new structure for our activities in data, analytics, and transparency, which is summarised by the diagram below.

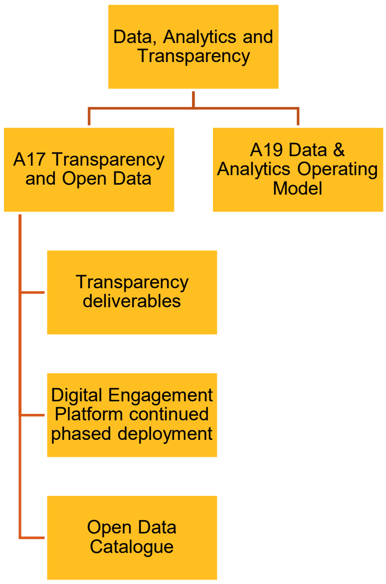


Figure 22: Updated activity structure.

This new structure does not reflect a significant change in the scope of our commitments. Rather, existing activities have been reframed to better describe the nature of our work as we move, in BP2, into enhancing and expanding the foundational IT investments made in BP1 and into a business-as-usual state.

The Open Data Catalogue (**D17.9**) is the updated name for the ESO data list (described in our first Business Plan) and we have created a continuous deliverable to describe our ongoing commitments for it. Our plans for the evolution of the IT investment **250** Digital Engagement Platform are also described in a new continuous deliverable (**D17.8**).

The new RIIO-2 activity **A19 Data & Analytics Operating Model** details our plans for fully exploiting the foundational IT investment **220** DAP. The capabilities of, and resources for, the data stewardship team described within the 'Digitalisation and Open Data unlocking zero carbon system operation and markets' chapter of the first Business Plan are now contained in **A19**.

The DAP investment was established in our first Business Plan under activity **A1 Control Centre Systems and Architecture**, and it remains associated with that activity in this second Business Plan because of the key benefits it will deliver for control centre architecture. However, the DAP is an enabling technology for the

44 https://www.nationalgrideso.com/document/248051/download

whole ESO and therefore, the activities that describe its operating model have been assigned to their own RIIO-2 activity.

7.4.2. A17 Transparency and Open Data

Overview

Building on the foundations laid in the BP1 period, we will continue to deliver on our commitments to Open Data and transparency. We believe that making the data that we hold open and accessible, and enhancing the transparency of our decision-making processes, can deliver significant industry and consumer benefit. We will also ensure that we actively manage the risk of sharing data and information that could be used in dangerous or inappropriate ways. Specifically,

- We will provide transparency on the relevant data that we hold through the publication and maintenance of an up-to-date **Open Data Catalogue.** We will operate a transparent and user-friendly process for customers and stakeholders to request access to data sets not yet published.
- We will continue to operate a **Data Triage Process** to ensure that data is shared responsibly and aligned with the Data Best Practice Guidance published by Ofgem in November 2021.
- We will engage stakeholders and signpost the delivery of our Open Data and Transparency commitments through the **Transparency Roadmap** and **Operational Transparency Forum**.
- We will provide a single point of access into the ESO data, content, and external-facing processes through our **Digital Engagement Platform**. It will make the experience of engaging with the ESO more intuitive and user friendly through providing a consistent and personalised user experience, including access to information and data, codes, connections, and market participation.
- We will deliver the foundational capability in data governance, products, and services to meet both internal and external stakeholder needs through our **DAP**.
- We will continue to work closely with other relevant **data sharing projects**, such as Icebreaker One's Open Energy Data Catalogue and the Energy Network Association's whole system asset register.

What are our updated RIIO-2 plans?

Open Data

We have carried out user research since our first Business Plan submission which has provided insight to inform our target digital customer experience for publication of content and data. Key target outcomes for BP2 include providing:

- A variety of digital content including infographics, video and data visualisations
- Advanced and filterable search options across both data and content
- Publication of open data with access via an application programming interface (API) and other formats
- Subscription to datasets and notifications of data updates and new datasets
- Content and analysis presented alongside the data that underpins it and the narrative that brings it to life

At the beginning of the BP2 period, the Digital Engagement Platform Minimum Viable Product (MVP) will be operational. We are introducing the new continuous deliverable **D17.8 Digital Engagement Platform (DEP) continued phased deployment** to BP2 to describe how we will further evolve the DEP capabilities with phased deployment including:

- Design System and Customer Identify and Access Management (CIAM) solutions applied to further use cases across the ESO digital estate
- Integrated query management
- Co-ordinated interactive ESO calendar, and newsletters

- Alerts and notifications for key developments
- Account dashboard integrated with other ESO systems such as the Single Markets Platform and Connections Portal
- Personalised AI assisted navigation
- Content and analysis integrated with supporting data
- "Digital concierge" functionality linking elements of the digital customer journey, providing visibility and guidance on the end-to-end process of doing business with the ESO as well as progress status and actions linked to dashboard and notifications.

An enduring DEP Product Team will develop further capabilities to improve the digital customer experience.

We are also introducing the new continuous deliverable **D17.9 Open Data Catalogue**. This will include:

- Maintenance of the Open Data Catalogue (referred to as the 'ESO data list' in the first Business Plan), which will be delivered in BP1.
- Continuing to engage with market participants to identify opportunities to enhance our open data service. This will look at improving the transparency of the triage process and managing sector-wide risks relating to inadvertent over-sharing of data.

The interactions of our Open Data deliverables in the target state are described by the following diagram.

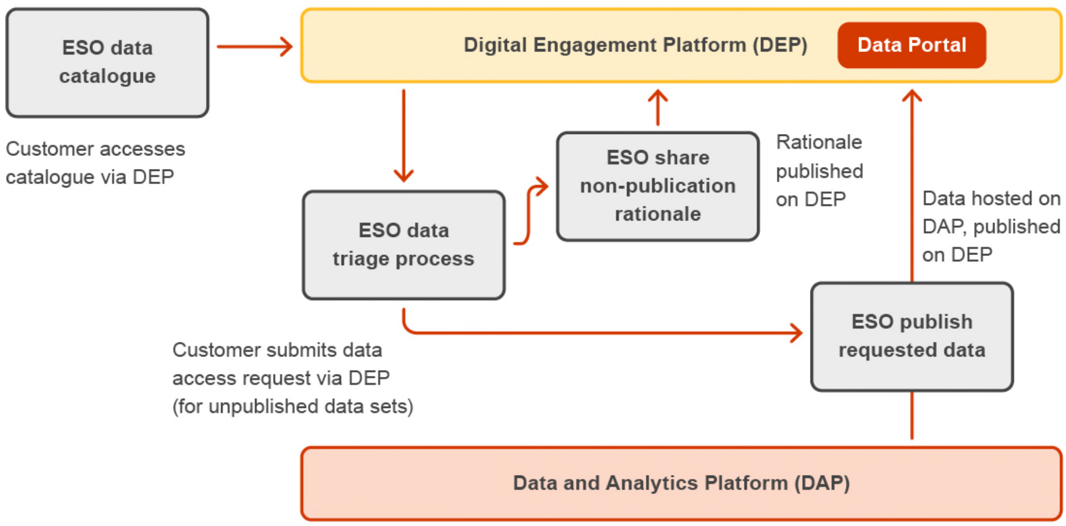


Figure 23: Open Data deliverable interactions

Transparency

The Operational Transparency Forum (OTF), formed during the COVID-19 pandemic, has been enormously beneficial to achieving the ESO's ambition of providing the highest level of transparency possible. The forum was introduced in 2020 when in-person control centre visits became impossible due to COVID-19 restrictions. The format has proved so valuable that we have included the forums as an ongoing RIIO-2 deliverable. The benefits we have seen include:

- Rapid insight is given to industry on recent events, enabling timely feedback to the ESO.
- Experts attend the deep dive sessions, giving stakeholders direct access to the person who can answer their technical questions and demystifying the ESO decision-making processes.
- The format is much more engaging than a written report and has allowed us to effectively establish a two-way dialogue with stakeholders. This two-way dialogue is breaking down barriers and building lasting relationships between ESO and industry organisations.

The OTF is now the weekly stakeholder touchpoint on the ESO's Transparency activities, and it provides signposting to the delivery of our Open Data commitments and deliverables. The forums are supported by the six-monthly publication of the Transparency Roadmap, which outlines the commitments we have made to address stakeholder feedback on Transparency and Open Data over the next year. The continuous deliverable **D17.3 Transparency Roadmap** will continue unchanged into BP2.

The continuous deliverable **D17.6 ESO Operational Transparency Forum** will continue into BP2 with a small change to its scope. In light of the rapidly changing market conditions and environment, the weekly forums will expand to include a focus on Markets and relevant procurement activities.

The new continuous deliverable **D17.7 Proactively driving transparency of ESO decision-making** will be introduced to replace **D17.4 Transparency of operational decision-making** and **D17.5 Trading Transparency**. Through **D17.7**, we will proactively identify areas of ESO decision-making that are of high significance to industry, not limiting ourselves to only operational or trading decision-making, and we will engage stakeholders to understand their priorities for data publication.

Transparency of decision-making in our Balancing Mechanism and Trading actions remain priorities. We are merging these deliverables into **D17.7** so that we can widen our scope to include any ESO decision-making that is of high significance to industry. For example, this could include transparency of our decisions which are further from real-time such as setting market requirements for the BM. **D17.7** is a complementary deliverable to establishing the data catalogue and data triage process. As well as responding to Open Data requests from stakeholders, we will also commit to engaging stakeholders (and subsequently initiating the data triage and publication process, if appropriate) where we can foresee the significance of a dataset to industry.

During the BP2 period we anticipate a further increase in levels of engagement with industry through the weekly OTF. It may be necessary to review the resource requirement in this area to enable improvements to be implemented to the forum's running including providing prompt and comprehensive responses to queries and to ensure that feedback is received and acted upon within ESO. This increase would also enable new dataset requests to be triaged effectively.

Key investments for this sub-activity

The key IT investments for this activity are **250** Digital engagement platform and **220** Data and analytics platform. The exact costs for DEP will not be known until the procurement process for the platform is complete in May 2022 and will be updated in our final Business Plan. The detail behind these investments can be found in Annex 4 – Technology investment.

7.4.2.1. A17 Stakeholder Feedback

(A17.1) We have conducted several rounds of user research interviews with a wide range of individuals who access our data and content. The headline stakeholder feedback remains consistent with pre-BP1 stakeholder engagement insights. A wide range of stakeholders want ESO data to be accessible and usable in a variety of formats. Publication of our data catalogue and triage process in the BP1 period will provide further opportunity to understand stakeholder priorities for specific data sets to be made accessible in BP2.

(D17.6) With the operational challenges brought on by the onset of COVID-19, the ESO set up the Operational Transparency Forum to engage with industry-wide stakeholders and provide them with guidance on the operational decisions being made to manage through this period of uncertainty and low demand. Due to stakeholder feedback being overwhelmingly positive, this has been extended into an ongoing weekly event and continues to draw audiences of over 150 most weeks, from a diverse group of stakeholders. Between January 2021 and February 2022, 1450 questions have been responded to, covering a broad range of operational topics and we will continue with the forum throughout the BP2 period.

(D17.8) In June 2021, we presented an overview of our plans for the Digital Engagement Platform (DEP) at the TAC. The main feedback was that we should not try to build a perfect end to end solution that does many things poorly. We explained that, for BP2, we will introduce the new continuous deliverable D17.8 Digital Engagement Platform with a continued phased deployment. We will deliver incremental build out of the physical platform via a use-case led approach. In this way, the deployment of new capabilities is always aligned with business priorities and value creation for stakeholders.

For further information see Annex 3 – Stakeholder engagement.

7.4.2.2. A17 Financials and headcount

A17 & A19 - Transparency data and analytics		Forecast 2021/22	Forecast 2022/23	BP2 2023/24	BP2 2024/25	BP3 2025/26
Capex (£m)	BP2	1.1	2.3	2.9	2.1	2.0
	BP1	1.3	1.3	1.1	0.6	-
	Variance	**(0.1)**	**1.1**	**1.8**	**1.5**	**2.0**
Opex (£m)	BP2	0.4	0.5	1.8	1.8	1.8
	BP1	1.8	1.9	1.8	1.6	1.2
	Variance	**(1.3)**	**(1.4)**	**(0.0)**	**0.1**	**0.5**
FTE	BP2	-	-	9	8	7
	BP1	9	9	9	8	7
	Variance	**(9)**	**(9)**	**(1)**	**(0)**	**(0)**

Five-Year strategy

Table 28: RIIO-2 cost and FTE for A17 and A19.

The table above includes costs for both activities **A17** and **A19**. The activities relating to **A19** are set out in the section below. The overall FTE headcount remains broadly the same compared to BP1. Seven of the FTEs in each year from 2023/24 are for roles in the Data and Analytics Hub, described in **A19**. The £3m increased capex (including two FTE) over the two years of BP2 relates to the **250** Digital Engagement Platform IT investment.

7.4.3. (New) A19 Data & analytics operating model

Overview

To fully exploit the technology delivered through our DAP, we will work to implement a new Data and Analytics operating model over the remainder of the BP1 period. Under this operating model, Data and Analytics activities will be orchestrated through a “Hub and Spoke” organisational structure, which seeks to balance:

- Centralisation to drive effective data governance and standardisation via a Hub team, and;
- Decentralisation to promote self-serve innovation and data product creation in business Spoke teams.

At the start of the BP2 period, we will have operationalised key elements our Hub and Spoke model and we anticipate that our operating model will evolve over the BP2 period as we bring more complex data products online.

Our first RIIO-2 Business Plan proposed the deliverable **D1.4.1 Data and Analytics Platform.** This deliverable is a transformational investment in a foundational IT capability that will serve the whole ESO and is described in more detail under sub-activity **A1.4**. Our first plan also described our ‘presumed-open’ philosophy to data sharing with industry and committed to establishing a Data Catalogue (previously described as a data list) and a transparent process for assessing any requirement for aggregation or anonymisation of datasets. These commitments are now described by the continuous deliverable **D17.9 Open Data Catalogue**, which is described in detail under activity **A17**.

To support the commitments now described in **D1.4.1** and **D17.9**, we proposed the creation of a data stewardship team composed of data analysts, data engagement and transformation officers and data quality and assurance officers. Whilst this additional resource is still required to fulfil our data management, governance and engagement commitments, our thinking around our data organisational model has evolved considerably. The activities of these resources are now set out under **A19**.

What are our updated RIIO-2 plans?

The activities delivered through the Hub and Spoke model are illustrated in the diagram below. A key concept driving our operating model is that of "Data as a Product" thinking. Data products fulfil the specific needs of the business, and provide the means by which data is managed, organised, presented, interpreted, and used to create insights. The goal of our operating model is to provide a structured framework for the development, operation and governance of the data products required to support delivery of our mission.

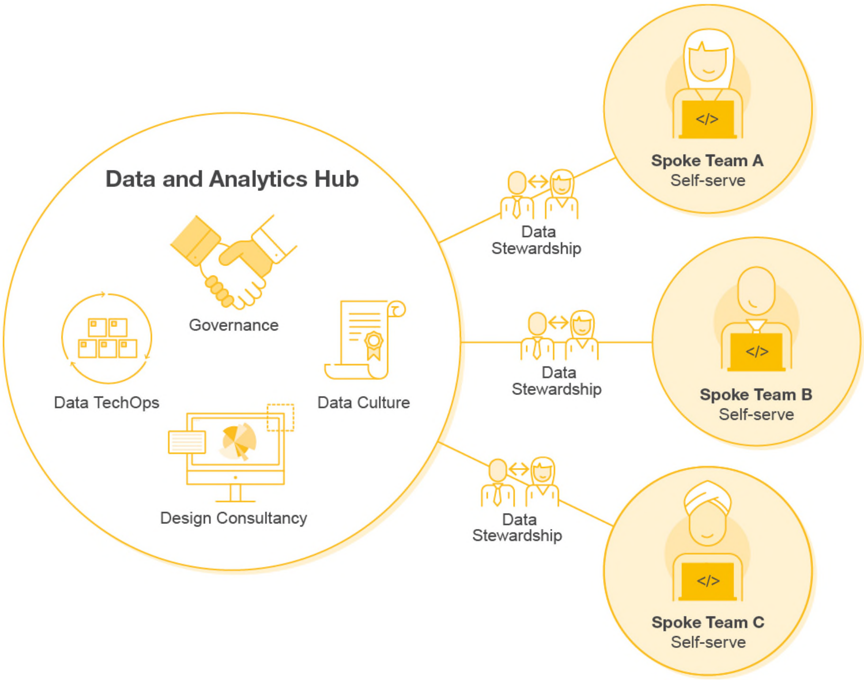


Figure 24: Data and Analytics operating model

The characteristics of our target Data and Analytics operating model, serving both internal and external stakeholders, are set out below:

- **Federated Data Governance:** An ESO Data Governance body implements data quality standards and data privacy policies, controls data access management, and has central visibility of data ownership to ensure consistent and compliant use of data across the ESO. Data Custodians[45] (previously referred to as "Data Owners") are supported by a team of embedded Data Stewards who make sure internal standards are met and regulations are complied with. They will also run the Open Data Triage process and provide a forward view of the data needs of our organisation. The Data Governance body makes recommendations to, and takes direction from, the ESO's Portfolio Review Board with respect to data initiatives.
- **Self-serve Data & Analytics:** The "data as a product" approach is underpinned by our self-serve Data and Analytics Platform (DAP). The DAP platform will remove technical complexity for users and allow them to focus on the value they can create from data for their business domains. A common data management layer enables consistent governance and control and promotes data accessibility to internal and external stakeholders through a centrally maintained data catalogue.
- **Data TechOps:** The application of TechOps to the development and operation of data products draws on:
    1. best practice from agile, DevOps and manufacturing approaches, to deliver timely, trusted, analytics-ready data to the point of use.
    2. best practice from software application deployment, to automate releases of ML/analytics data products.

[45] Data Custodians are ESO staff in operational roles that provide data and support to Open Data and Transparency deliverables. It is important to ensure that these staff have the capacity to provide this support as their subject matter expertise is essential to effective data governance and external stakeholder engagement.

In conjunction with the DAP platform, the Data TechOps capability will enable efficient, robust and repeatable production of ML/analytics applications, freeing up data science resources to focus on innovation and the continuous improvement of their models.

- **Embedded Data Culture:** To embed a data and information culture within the ESO, we are refreshing our Data and Analytics Training Curriculum and certifications, establishing Data Communities of Practice to drive collaboration and knowledge sharing, and defining data related career paths to attract and retain the best talent to support delivery of our mission.
- **Design Consultancy:** In the early stages of adoption of the platform and new ways of working, a Design Consultancy capability within the Hub will work with business teams to advise and guide the development and embedding of data products.

The Data Stewardship activities of the Hub team will be supported by the data resources proposed in our RIIO-2 Business Plan (two data analysts, two data engagement and transformation officers and two data quality and assurance officer), along with our existing Data Quality & Governance Team. The Data TechOps and Design Consultancy capabilities will be delivered through ESO Technology.

Dependencies and assumptions

The success of our Data and Analytics strategy depends upon:

- Implementation of the DAP platform
- Upskilling existing business resources to adopt the new technology delivered through DAP
- Implementation of our Data and Analytics Operating model.

To support our commitment to Open Data, our final Business Plan may include a small uplift in the FTEs for the ESO teams that have significant data custodian responsibilities.

Key investments for this activity

The related IT investment is **220 Data and analytics platform,** described in **A1.** The detail behind this investment can be found in Annex 4 – Technology investment.

7.4.3.1. A19 Stakeholder feedback

(A19) This is a new area for BP2, and we would value further feedback on this area as part of the BP2 consultation. The Hub & Spoke Operating Model was shared at a meeting with the TAC in February 2022 and a few key areas of feedback are below.

The TAC encouraged the ESO to recognise the data journey - quite often data owners aren't always the consumers of the data which can have unintended consequences of groups of data becoming disconnected and uncontrolled. We explained that we are going to ensure we understand the full flow of data from the source to the consumer and engage with all the parties affected.

The TAC gave positive feedback on the current approach and recommended to minimise the distance between decision makers and data producers – we explained that data stewards were going to be embedded within business teams that encompass data analysis and data management skillsets.

The TAC emphasised the challenges involved in bringing people across to new platforms – we explained that our strategy is to show users the benefits of a new platform to help get them on board.

For full details of the TAC feedback please refer to Annex 3 – Stakeholder engagement - we will continue to engage with the TAC community as we move forward with implementation.

7.4.3.2. Benefits

Together with the DAP platform, our Data and Analytics operating model aims to provide the capability for efficient and effective development, operation, and governance of the data products necessary to fulfil our mission, enabling us to, for example:

- Create new insights and tools to enhance the operation and planning of the grid, enabled by leading-edge ML and AI capabilities and consistent data.

- Enhance the Control Centre’s situational awareness by bringing together the data, visualisations and analytics to support optimised real-time decision-making in an increasingly complex environment.
- Promote collaboration and insight-sharing by standardising analytical, modelling, visualisation, and reporting tools across the ESO.
- Create and deploy products and services for ESO customers through our Digital Engagement Platform.
- Drive innovation across the energy sector through Open Data and collaborations.

7.4.3.3. A19 Financials and headcount

The financial and headcount data for this activity are included under activity **A17 Transparency and Open Data.**

Section 3 - Supporting BP2 Delivery

8. Cross-cutting teams

8.1. Supporting the ESO in the delivery of its plans

The ESO has a number of teams who support the outputs and services we deliver. These teams are ESO Regulation, People and Capability, ESO Assurance, Business Change and Customer, Stakeholder and Consumer. This chapter provides more detail about each team's activities, and our proposal for the BP2 period. The below graph and table show the total costs and FTEs for our cross-cutting teams.

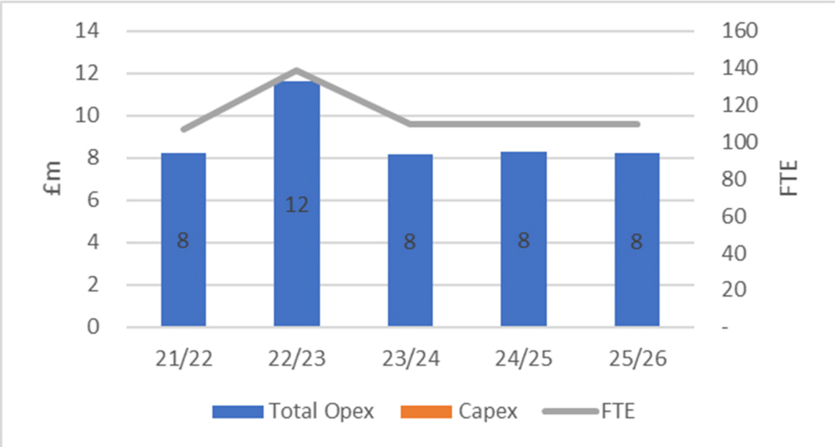


Figure 25: Graph of Role 3 RIIO-2 costs and FTE for cross-cutting teams.

		Five-Year strategy				
		Forecast		BP2		BP3
Cross cutting		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	-	-	-	-	-
Opex (£m)	BP2	8.2	11.6	8.2	8.3	8.2
	BP1	8.5	7.0	6.3	6.3	6.2
	Variance	**(0.2)**	**4.6**	**1.8**	**2.0**	**2.0**
FTE	BP2	107	139	110	110	110
	BP1	63	65	65	64	63
	Variance	**44**	**73**	**45**	**46**	**47**

Table 29: RIIO-2 cost and FTE for cross-cutting teams.

An additional 45 FTEs, in FY24, and £4m opex costs are required compared to BP1. These are to support the increased operational deliverables within the three roles. The main drivers of the increase are:

- £3m opex and 14 FTEs within Innovation.12 FTEs to deliver the Virtual Energy System (VirtualES), plus two FTEs to support the Strategic Innovation Fund (SIF). Please see Chapter 11 Innovation for more information.
- £1m opex and six FTEs within Assurance to deliver a robust assurance programme.
- 25 additional FTEs in Business Change reflecting the change in operating model and an enhanced flexible resource team. This also includes three FTEs for our People and Capability team.
- There is a large increase in FTEs in the last year of BP1, this relates to FTEs supporting the Future System Operator programme.

These supporting teams remain flat over BP2 with the increased costs in FY23 relating to the Future System Operator programme team. Post FY24, Future System Operator programme costs will be part of the Future System Operator project and are included in Annex 5 – Future System Operator.

8.2. Regulation

ESO Regulation is responsible for supporting the ESO on all regulatory matters. This includes providing advice and guidance on regulatory issues and risks, as well as management of the ESO licence. The team is accountable for all formal regulatory reporting under the price control arrangements, regulatory engagement and reporting for our incentives scheme, as well as the development of the regulatory Business Plans. It also supports the business on regulatory policy matters, including external consultation responses.

As a supporting function, there are a number of ongoing activities the Regulation team undertakes on a periodic basis and as such are not set out in detail in our transformative RIIO-2 plans. Over the course of the BP1 period, the team has been supporting the business to adapt to the new RIIO-2 regulatory framework. This has included providing advice to teams across the ESO, adapting our incentives reporting processes to meet the new RIIO-2 requirements, and ensuring that teams across the ESO understand and act on feedback received from Ofgem and the Performance Panel.

The team has also mobilised Business Planning activities, collaborating with the business to develop our BP2 plans. To support our engagement approach, the ERSG has been re-established with a renewed purpose and refreshed membership. We believe this group provides valuable ongoing scrutiny and feedback to support the development of our second Business Plan under RIIO-2.

Overview of our updated RIIO-2 plans

Due to the uncertain regulatory environment at present, and the ongoing work being carried out by BEIS and Ofgem on the ESO's wider governance framework, it has been necessary to make some assumptions about the level of regulatory support which will be needed by ESO colleagues during the BP2 period. Our assumptions are as follows:

- The regulatory environment and scrutiny remain the same and therefore the same level of resource is appropriate as we continue into BP2.
- The BP3 submission is of a similar magnitude to the BP2 submission. The RIIO-3 framework will be developed concurrently, during the BP2 period.
- The RIIO-3 framework will be significantly different from RIIO-2 and will require a substantial change to align with any future business model.

8.2.1. Regulation financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
Regulation		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	1.5	1.6	1.6	1.7	1.7
	BP1	2.3	2.0	2.0	1.9	1.9
	Variance	**(0.8)**	**(0.4)**	**(0.3)**	**(0.3)**	**(0.2)**
FTE	BP2	21	20	21	21	21
	BP1	19	19	19	19	19
	Variance	**2**	**1**	**2**	**2**	**2**

Table 30: RIIO-2 cost and FTE for Regulation.

Based on our assumptions, ESO Regulation team cost and FTEs remain in line with our original RIIO-2 submission. Therefore, our BP2 plans have not materially changed from BP1.

8.3. Business change

The Business Change team is responsible for defining, monitoring and managing our change portfolio to make sure we deliver our RIIO-2 Business Plan. The team oversees portfolio governance and reporting processes, as well as guidance and support to individual business areas so that all change activities remain on plan.

The team leads on portfolio management including planning, prioritisation, reporting and programme assurance. This includes ensuring all change initiatives have robust business cases and trackable benefits for customers, stakeholders and consumers.

Our first RIIO-2 Business Plan described the programme of work that the team would set up to ensure its successful delivery. We have set up a Portfolio Review Board with representatives from each business delivery function as well as IT, Finance and Assurance. This board provides senior-level oversight of project sanctioning, delivery progress and programme assurance.

A key benefit of this is a single-team approach to project delivery across IT and business teams. This was highlighted in our original Business Plan as a key area of focus due to the critical role that technology change will play in achieving our RIIO-2 ambitions.

Overview of our updated RIIO-2 plans

A key development for the Business Change team in the BP2 period will be to set up a business partnering service to support change delivery. The service involves a senior change specialist working closely with management teams to understand each role-based portfolio. This approach supports the identification and resolution of delivery risks and issues, as well as making sure that dependencies between business areas and activities are managed effectively. The business partnering role is also important to ensure portfolio planning and prioritisation activities are based on accurate information and are keeping us on track with delivery of Business Plan commitments.

8.3.1. Business Change financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
	Business change	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	2.9	5.1	1.4	1.4	1.4
	BP1	2.5	1.5	0.9	0.8	0.8
	Variance	**0.4**	**3.6**	**0.6**	**0.6**	**0.6**
FTE	BP2	37	56	33	33	33
	BP1	8	8	8	8	8
	Variance	**29**	**48**	**25**	**25**	**25**

Table 31: RIIO-2 cost and FTE for Business Change.

The headcount for Business Change in BP2 is higher than in the original RIIO-2 Business Plan due to changes in the wider National Grid Group structure made in April 2021. Our original plan described a ‘hub and spoke’ model where a small change team of eight FTEs was supported by a central UK Change function providing services including change framework development, programme assurance and access to a flexible pool of resources.

This model was amended in April 2021, resulting in the establishment of a standalone Business Change function. The increase of 25 FTEs for FY25 is broken down as follows

- five FTEs (FY25) for the core team
- 17 FTEs (FY25) for a flexible resource pool, with resource costs charged directly to individual project and programme budgets. The changes were cost-neutral because they included removal of the cost allocation from National Grid Group to fund the UK Change function.
- this table also includes three FTEs (FY25) for our People and Capability team in BP2.

There are significant benefits to the revised structure, as delivery support services provided by the Business Change team can be fully tailored to our needs in the BP2 period. For example, recruitment for the flexible resource pool will focus on individuals with experience directly relevant to our activities.

The structure changes also mean the team can develop and refine the centralised Change Delivery Frameworks to accurately meet our requirements. This work will drive standardisation of methods and will include a training programme and associated guidance documents to help build change delivery capability in all business areas.

Lastly, in FY23 there are increased costs and headcount relating to the Future System Operator programme team. Post FY24 Future System Operator programme costs will be part of the Future System Operator project and are included Annex 5 - Future System Operator.

8.4. Business Assurance

The vision for ESO Assurance is to design an effective integrated assurance framework which provides a coordinated approach to all assurance activities, minimises waste, reduces duplication, and improves the collation of knowledge.

Assurance is typically explained using our three lines of defence model. The first line owns risk and controls and check that these are operating in line with the business's risk guidelines. The second line is specialist support teams who own business standards, advise on specific areas, and provides information on how the first line is operating to governance committees. The third line is independent from the business and audits activities to provide assurance over the effectiveness of first and second line processes.

To deliver this vision, we have a centralised second line assurance team which reports directly to our Director. The team sets assurance standards, provides advice on risks and controls, and conducts assurance over their effectiveness.

Assurance is undertaken across all three lines of defence, with the Assurance team working within the second line to upskill the first line. It also provides assurance to governance committees that we have the right coverage and maturity of risk and controls across the business. Supported and led by the Audit and Risk Committee, we are improving the understanding, framework, and maturity from all areas to embed enduring ways of working.

The current service from ESO Assurance covers risk and controls, health, safety and wellbeing, compliance and audit, engineering assurance, and portfolio assurance. Most of these teams provide reporting and support across all departments, with the others focusing on high-risk delivery and operational areas only. This approach means we can provide insights to inform, protect and strengthen fundamental aspects of our business, from people to performance, systems to strategy, and Business Plans to business resilience.

Key deliverables

ESO Assurance delivers an annual assurance programme, approved by the Executive, which includes providing assurance to the business through services including audit, consultancy, risk assessment, peer reviews, and oversight of first line self-assessments.

We will continue our transformation journey to a more mature risk and controls-based assurance methodology. To succeed, we need to significantly improve the quality of our risk and control landscapes, so we will continue to designate resource to engage and enable the first line of defence to improve this.

Our first RIIO-2 Business Plan focused on building a small centralised second line assurance capability. This prioritised a high-level risk landscape on our Archer risk management system, completing data and licence checks across high-risk areas and maintaining our statutory health, safety and wellbeing responsibilities.

Overview of our updated RIIO-2 plans

In BP2, we will continue the Portfolio Assurance activities we began in BP1 and continue our safety management activities. Under BP2, we will expand the capabilities for wellbeing and engineering assurance which we introduced in BP1. We will also develop new assurance capability for sustainability and environment, fraud and bribery.

Portfolio assurance, which is delivered by an external provider but managed by the Assurance Senior Manager, will improve our confidence around portfolio delivery to achieve our five-year strategy. We will also enhance our wellbeing expertise in line with our focus on colleague satisfaction in an open and comfortable working environment. Engineering assurance will support our front-line experts in having a 'critical friend' to contribute to the mitigation of key operational and engineering risks. Sustainability and environment will support our five-year strategy for a more sustainable future. The new fraud and bribery capability will improve our testing of controls recorded in our risk management system Archer.

Second line assurance is built at the discretion of the Executive team, to provide an additional layer of scrutiny and challenge on a risk basis across the business. There is a huge dependency on the delivery of assurance that is related to the resource and capability of the first line of defence. Accordingly, the services will be planned in advance (per financial year) and may be subject to change in line with executive and business priorities.

8.4.1. Business Assurance financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
Assurance		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	1.6	1.5	1.7	1.7	1.7
	BP1	1.3	1.3	1.2	1.2	1.2
	Variance	**0.3**	**0.2**	**0.5**	**0.5**	**0.5**
FTE	BP2	22	22	19	19	19
	BP1	14	14	14	14	14
	Variance	**9**	**8**	**5**	**6**	**6**

Table 32: RIIO-2 cost and FTE for Business Assurance.

The insight and independence ESO Assurance brings is an invaluable safeguard across our complex and changing operating environment. To deliver the vision for this team we need to increase our resource by 5 FTE (FY25) to make sure we can provide engineering assurance and audit support which can continue to identify, test and validate key engineering risks.

8.5. Customer, stakeholder and consumer

The Customer, Stakeholder and Consumer team supports the delivery of our customer experience (CX) strategy. This is driven by our ambition to be a Trusted Partner to all our customers and stakeholders by 2025. We use the the four elements of the the ‘Trust equation’ to measure this:

- **Credibility** – we provide credible expertise
- **Reliability** – we deliver our commitments
- **Familiarity** – we are transparent
- **Self Interest** – we care about our customers and how our decisions and activities impact them.

We support teams to improve their performance against these criteria, delivering stakeholder engagement in a consistent way, which ensures we give our customers consistent support. Central to this is the gathering of meaningful insights. Other functions of the team include:

- We manage insight and engagement plans. We also provide best practice advice, develop new tools and provide training to upskill our people, helping to embed customer capabilities across the business.
- Deliver the bi-annual roles-based customer and stakeholder survey as part of the feedback required by Ofgem.
- Co-ordinate stakeholder engagement across our business.
- Own the CRM IT system.
- Deliver our consumer strategy.

In BP1, we committed to deliver greater value for our stakeholders through delivery of six workstreams. We have made good progress on these and on embedding customer perspectives into our business and improving the overall experience for our customers.

In developing the BP2, we recognised the central role consumers have in the energy transition. To operate an efficient net zero system, we need develop an energy system that empowers consumers to change their behaviour around energy usage. Understanding how consumers currently interact with their energy supply and the wider energy ecosystem, and how this might change, is crucial to the delivery of net zero. We support teams by facilitating a greater understanding of consumers, their characteristics and what drives their decisions and behaviours, as well as what actions our business can take to ensure consumers are best placed to benefit from the energy transition. To start this **Consumer Strategy** work, we have:

- Developed a better understanding of how consumers interact with the energy ecosystem, today and in the future.
- Provided a framework for describing the consumer experience of the energy ecosystem.
- Introduced consumer insights to develop colleagues' understanding of evolving consumer behaviours as we move towards a net zero system.
- Conducted research to explore the societal transformation, as described in our FES, and what needs to happen to support communities through the energy transition.
- Commissioned research to enrich the insights in our Bridging the Gap publication to understand how consumers might react in times of high generation and low demand, and vice-versa.
- Set up a consumer sub-group as part of our ERSG, to gain further insight. The team is also starting to build relationships with consumer groups and other organisations with a direct relationship with consumers, to gain a deeper understanding of how to enable consumers to participate in a decarbonised energy system insight and to support consumer messaging about the energy transition.

Overview of our updated RIIO-2 plans

Continuous improvement is key to our CX strategy as is developing a culture where the customer is fully understood and considered by everyone. For BP2, the team will continue to work on the areas of focus outlined in the original Business Plan, building towards our Trusted Partner ambition.

Insights collected during the first period of RIIO-2 have shown customer expectations and needs are changing, in particular around transparency of decision-making, improved prioritisation, explaining how project work fits together, and quicker access to the right teams and information. This team will support our business to continuously review our approach to ensure we meet evolving customer needs.

New activities we will working on in BP2 include:

- Insights and Feedback
    - Review the roles survey process after first 12 months and improve how we analyse and act on feedback from our customers and ensure we are transparent in how we are improving our customer experience.
    - Embed the segmentation process into our CRM system to enable greater visibility.
- Engagement and communications
    - Bring customers into our business at all levels to hear the 'customer voice' first-hand.
    - Provide clarity to our customers and stakeholders on how we and the TOs interact, along with respective roles and responsibilities, to clarify where they can get the support they need.
- Culture and capabilities
    - Improve relationship management, rolling out a training programme for all customer-facing teams.
    - Review staff objectives from the top down to ensure they are driving the right outcomes for customers.
    - Introduce new incentives to reward excellent customer work by teams and individuals.
    - Embed the new Customer Impact Assessment work into our projects and processes, so it becomes a BAU activity for all teams.
    - Embed other key customer experience tools into our business change processes.

- Digital technologies
  - Provide customer insights to transform our customer digital experience through a Digital Engagement Platform (DEP).
  - Integrate survey data with our CRM system.
- Customer Journeys
  - Help teams to improve their customer journeys, focusing on the pain points and linking findings to product development.
- Performance data and metrics
  - Refine and improve governance processes to ensure customer issues are flagged quickly and enable leadership to act accordingly.
  - Use BI data to identify customer concerns earlier and build better relationships with, and understanding of, our customers.
  - Increase analysis of query and complaints data to identify and resolve root causes and to provide better customer service and reduce query volumes.

In BP2 our consumer team will:

- Build towards a position where we have a strong understanding and ability to articulate consumer needs and interests and balance this with the needs of the system.
- Provide improved consumer insight to market design activities.
- Agree and evolve our longer-term consumer role with stakeholders.
- Work together more actively to deliver improved consumer outcomes.
- Develop stronger relationships with key customers and stakeholders with an interest in consumer work, including energy suppliers and consumer groups.

The team will continue to manage risks associated with the delivery of our customer and stakeholder experience strategy, through our standard risk management approach. The key dependency, as a business partnering and support function, is reliance on our colleagues to engage with us to improve the experience they provide.

8.5.1. Customer and Stakeholder financials and headcount

		Five-Year strategy				
		Forecast		BP2		BP3
Customer and stakeholder		2021/22	2022/23	2023/24	2024/25	2025/26
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	1.4	1.5	1.4	1.4	1.4
	BP1	1.6	1.6	1.6	1.5	1.5
	Variance	**(0.2)**	**(0.1)**	**(0.2)**	**(0.1)**	**(0.1)**
FTE	BP2	14	14	13	13	13
	BP1	13	14	14	14	13
	Variance	**1**	**0**	**(1)**	**(1)**	**(0)**

Table 33: RIIO-2 cost and FTE for Customer and Stakeholder.

Our BP2 plans have not materially changed since our original BP1 submission.

9. People, capability and culture

Achieving our ESO mission requires building a talented and diverse workforce to overcome challenges on the path to net zero. This is reflected in a new ambition to be the net zero employer of choice, for all present and future employees who want to be part of achieving a net zero future. To successfully deliver a whole energy system strategy that supports net zero by 2050, requires the right people with the right capabilities.

We need to have an agile approach to **sourcing** the right people with the right capabilities. We need to **attract, retain, develop, motivate and engage** our people to successfully tackle the challenges and maximise the opportunities presented by the energy transition. At the same time, we will further **develop the culture** of our organisation to be ever more purpose driven, where our people relate to our goals and are passionate about achieving them because they align with their own beliefs and aspirations for a clean energy future.

9.1. People and capability trends

The most impactful people trend since the submission of our first Business Plan has been the pandemic, which has challenged and changed traditional ways of working. As we come out of the pandemic, we continue to see fluctuations in the job market, as workers seek organisations that enable and support hybrid ways of working. This, alongside other best practice considerations and the evolution of the ESO's activities, means that in BP2, our people strategies must reflect that:

- Employee and prospective candidate expectations have changed. To keep and attract new employees we need to treat them more holistically, giving stronger consideration to things such as their work-life balance, health and well-being.
- We need to continue to develop a diverse workforce that fosters inclusivity and a sense of belonging. Increasing diversity will ensure we represent the communities we serve as well as enabling better problem solving.
- Technology is moving fast. These advancements mean we need to continually adapt the technology skillset and capabilities we have and think about the most efficient and cost-effective ways to do this.
- There is increasing competition for STEM students and candidates, who remain in short supply. The industry has been working to tackle this shortage but more needs to be done.
- The challenge of resourcing specialist skills means we must be more flexible about how we bring in talent. This includes being more open to short term assignments for specialist skills, or cross sector placements.

We take these factors into account when considering how we:

- identify the capabilities we need,
- source those capabilities,
- attract and retain skilled people,
- develop our existing people,
- motivate and engage our people, and
- develop the culture of our organisation.

9.2. Identifying our capability needs

Our first RIIO-2 Business Plan outlined five core capabilities that we need to ensure our future success. During BP1, we have completed detailed work to understand where and how large our capability gaps are, and how to best invest in solutions, e.g. recruitment, upskilling and/or partnerships. Building capabilities will require a combination of short- and long-term solutions (e.g. new sourcing strategies, external partnerships, and expanding our new talent schemes).

The core capabilities are:

	Why is this important?
Power System Engineering	In addition to the capabilities related to the onshore electricity transmission networks, we need to develop our knowledge, skills and experience to meet the challenges of whole electricity system operation including the expansion of offshore networks. This requires engineers with a niche skillset which we have not sourced before.
Data & analytics	Improving data skills is essential to make best use of all available data to maintain system security and stability. This will be required to successfully drive innovation.
Commerciality	Commerciality continues to ensure the needs of the power system can be sourced through competitive processes, such as through the effective design of new markets. There is a requirement for novel and strategic thinking, combined with sound understanding of economic modelling, market optimisation and customer strategy to support market design.
Leading the debate	Our people will need to employ content expertise, to articulate the wider energy market needs, to be able to influence stakeholders.
ESO technology	The need to digitalise our operations and interact with our customers continues to grow, requiring continuous investment in a customer-focused capability. This will require greater levels of digitalisation, one of the key enablers of a more flexible, smarter, and more sustainable network.

Table 34: RIIO-2 ESO core capability requirements

Some of these skills are increasingly difficult to source in the UK. For example, we are competing not just with the Technology sector but with most other industries to recruit the capability we need in data science disciplines. Our plan to address these key skills and capability challenges during BP2 is:

- Leveraging our strong sense of purpose and our position as the Net Zero Employer of Choice to attract candidates.
- Using targeted and collaborative recruitment of new and experienced talent from the UK and overseas, testing novel recruitment and retention methods.
- Refining our university strategy and ‘STEM in Schools’ work to develop a pipeline of future talent and partnership opportunities, including considering the options for the creation of a central hub within the energy industry for innovation, training, webinars, development competitions and discussions.
- Building an internal skill base that supports business engagement, intellectual property development, strategy, and IT architecture. Where greater depth or breadth of technical knowledge is required, we will draw upon a close partnership network of suppliers.
- Building an alumni network of previous employees who may be interested in returning to the ESO with knowledge and experience gained elsewhere, or in recommending ESO roles to their wider network, or to enhance cross-industry collaboration.

During BP2 we will also continue to enhance our foundational capabilities such as economic analysis, leadership, innovation, change management and stakeholder engagement as these are critical to our success.

9.3. Our sourcing strategy

Strategic workforce planning has identified emerging future workforce needs, capability gaps and risks. This will need to be revisited during BP2, in light of the Future System Operator announcement.

To build up the capabilities described above, along with any new ones identified, we will rely on a sourcing strategy comprised of three pillars - see below.

Figure 26: Sourcing strategy

'Growing our own' through our new talent schemes

New talent (NT) is a crucial pipeline for bringing future leaders and skilled employees into our organisation. We have four schemes: graduates, higher apprentices, Power Academy and industrial placements.

Moving into the BP2 period, we plan to update and improve our NT strategy, the schemes we are using and the way we run them. We will increase our NT intake in line with workforce requirements and be mindful of the heightened competition in the NT market.

Collaboration with external partners

During BP2 we will increasingly work with organisations that allow us to broaden our reach in attracting a range of diverse candidates. For example, we will make use of initiatives such as Generating Genius - an organisation that works to inspire students from disadvantaged backgrounds and develop the geniuses of tomorrow in STEM. We are also part of a pilot project looking at bringing candidates with a STEM background, who have previously left the workforce, back into the industry.

In terms of ensuring a strong pipeline of engineering capability, we have a long-established relationship with the IET Power Academy which offers students placements and is a key talent pipeline for engineering graduates into the company. This will continue into BP2, as we also increase our focus on developing new relationships with more universities and other educational institutions, including running a pilot with Aston and Brunel Universities.

We are piloting membership with the Energy and Utility Skills group to focus on sector attractiveness, developing the right competencies and skills to take the sector forward. We are also partnering with Innovate UK to attract university graduates into the sector; this is a programme for graduates to work in different energy companies. If successful we will continue with these in BP2 as well as continually scanning the market for new opportunities.

We also work with the Engineering Assurance Committee (EAC) which allows external experts, including academics, to understand our role and to make sure we have the correct processes in place to attract talent. Every time we look at engineering innovation, we refer it to the EAC to get an expert opinion.

ESO alumni

We will create a network of alumni for colleagues who have chosen to continue their career outside our business. This will be used during the BP2 period to further enhance cross-industry collaboration, and for talent acquisition purposes.

9.4. Attraction and Retention: our Employee Value Proposition

The changes to employee expectations and working arrangements has meant we needed to strengthen our employee value proposition (EVP) to attract and retain the best talent to help us deliver our ambitions. This will focus on our intent to develop a purpose-driven, innovative and delivery focused workforce to achieve our critical net zero mission.

> We are already recognised as industry leaders and as a great employer. We were shortlisted in the Top 10 Employers of the Year at the 2021 Utility Weekly Awards, and for the Net Zero Award. Being recognised for these awards will add to how we are perceived by future talent.

Our unique selling point is offering employees a strong sense of purpose, through tackling climate change, working towards net zero and being at the heart of the energy transition. This enables us to hire and retain people with highly sought-after and hard-to-find skills. We are planning to do further work to document our EVP over coming months, particularly in light of the Future System Operator announcement, and will include more details in our final Business in August 2022.

9.5. Development

Our people are our most valuable resource, so it is vital that we continue to develop them and create an inclusive and diverse workforce. Offering fantastic development opportunities will not only help us to attract and retain the right talent, but it will also help us to get the best out of our people and our investment in them. During BP2 we will therefore continue to build on our existing development offerings, including:

- Encouraging a more learning-centric culture, through further development of our learning & development platform and materials.
- Showcasing our work on potential career paths in the ESO – the ones completed thus far pertain to three of our priority capabilities: power system engineering, commerciality, and data management and analytics.
- Continually reviewing and refining our best-in-class talent management and succession planning processes to identify diverse talent early and enable cross-functional succession/development.
- Upskilling our leaders in communicating change and developing their teams to think with a leadership mindset; and
- Conducting further capability needs analysis and identifying the right approach to filling gaps.

9.6. Motivation and Engagement

Our approach to motivation and engagement of employees starts when they first join us and continues throughout the employee lifecycle.

Onboarding external hires

External hires make an important contribution to our workforce, bringing skills and knowledge gained elsewhere. It is important they feel part of our community from the start to ensure they want to stay with our organisation long term. During BP1 we have put in place an onboarding process where all new joiners come together to learn about the organisation and to meet others to start to build up a network. Since this new onboarding process was introduced in March 2021, almost 160 new starters have attended. Feedback has been overwhelmingly positive, with an average internal Net Promoter Score (iNPS) of 8.85. We will continue to review and evolve this programme throughout BP2, for example in light of the Future System Operator announcement.

Employee engagement, health and wellbeing

During the pandemic, safety was our top priority and we responded quickly to reassure our employees through what was a difficult and worrying time for many. We have now moved into a phase of hybrid working and continue to adapt our support mechanisms, recognising the advantages that home-working can bring in terms of work life balance, whilst also appreciating the benefits to collaboration and creativity by being together in the office. To support our employees with the post-pandemic transition, we created a “Build Back Better” forum to develop our hybrid ways of working and look at ‘welcome back’ initiatives focusing on bringing people together again and promoting wellbeing. We also gathered employee insights via surveys to target what will work well for different business units.

We have almost doubled the number of wellbeing champions across our business to raise awareness, facilitate campaigns and cascade key messages. ‘Managing mental wellbeing in the workplace’ training has been assigned to all managers on how to recognise signs and symptoms of poor mental health.

These actions have led to an increase across all indices in the recent 2022 National Grid-wide employee survey; the engagement score increased from 78% in 2021 to 80% in 2022 and enablement from 70% to 72%. In particular, the ‘safe to say’ index, up 10% to 79%, demonstrates the positive impact these actions have had on people feeling they can express any issues or concerns safely. Lastly, the question “I feel able to be myself at work” improved by 5 points to 84%.

During BP2 we will continue to build on this, seeking out and implementing best practice approaches to employee engagement, health and wellbeing.

Pay and reward strategy

We remain committed to the principle of pay-for-performance, so that employees can be rewarded in accordance with how well they perform and deliver their objectives. This ensures we reward fairly and competitively whilst offering the right value for consumers. As the labour market has become increasingly competitive, we are also considering options to enhance elements of our reward package during BP2, for example relocation support, welcome payments or retention incentives, particularly for those with hard-to-find skills.

9.7. Developing our culture

In August 2021, we carried out a high-level assessment of the current culture within the organisation. The most prevalent aspects of our current culture are:

- **Caring nature** - The organisation has been described as one big family and employees want to help and support one another. This builds loyalty and trust and high engagement levels.
- **Order-seeking** - Our employees play by the rules and a high value is placed on stability and efficiency. However, we do need to become more agile to adapt to the rapid pace of change in the energy sector.
- **Purpose** - This is an important factor that drives our employees and helps us attract new talent. Many people relate to our goals and are passionate because it aligns with their own beliefs and aspirations for a clean energy future.

Given the fast-changing and increasingly complex nature of our environment, our culture needs to evolve whilst leveraging our strengths such as a deep sense of purpose.

These characteristics will be important as the business moves forward, but we may need to evolve our culture as our role in the energy transition develops. Later this year, we will complete a diagnostic to gain a deeper understanding of our current culture, including its benefits and pitfalls. We will then start shaping our future culture – one that allows us to deliver our ambitions, attract and retain top talent and be the net zero employer of choice. We anticipate being able to provide more details on a target cultural model in our final Business Plan in August 2022.

Diversity, Equity and Inclusion (DEI)

A key part of our culture stems from our focus and belief in the benefits of diversity. Our diversity metrics have continued to improve, with the number of women in the organisation increasing from 31% in the previous Business Plan to 35.9% in December 2021, and from 24.6% to 30.1% for ethnic minorities.

We want to meet the needs of an increasingly diverse pool of employees, as well as ensuring that the organisation achieves the benefits of diversity of thought and experiences. To support this, we have set up an ESO Belonging Forum, made up of volunteers from around the organisation, which has three roles:

- To understand the extent to which our employees currently feel that they can ‘belong’ in the organisation, and what the barriers are to a greater sense of belonging.
- To identify ways to remove those barriers, in particular around education of our employees around DEI and belonging topics.

- To create a network of belonging champions to make this part of our everyday conversation and embed it in our culture.

The Belonging Forum also piloted a 'Recognising and Tackling Microaggressions' course, to increase colleagues' understanding of microaggressions, the impact that they have on individuals, and how to tackle them when observed. This is now being rolled out across all our employees.

We have promoted the DEI Knowledge Hub to educate our people on current best practice and offer virtual courses to build knowledge and confidence with conversations around diversity and inclusion.

These activities have contributed to the National Grid Group's DEI agenda, which has seen the company win the Most Outstanding Employer at the 2021 Ethnicity Awards as well as being featured in the 2022 Financial Times Diverse Leaders listing.

National Grid Group has recently launched a new DEI strategy (see Figure 31) which we will also adopt within the ESO. It will support the aspiration to be among the most diverse, equitable and inclusive companies of the 21st century – and not just in the energy and utilities industry. We will continue to drive awareness, educate and implement against our DEI commitments throughout BP2.

Figure 27: Our DEI commitments

10. Technology

In the original RIIO-2 Business Plan (2019), we outlined how our technology landscape at the time provided the services required to safely and securely operate electricity networks driven by carbon-centric generation. There was clear recognition that these systems and services required significant transformation in order to enable the capability to operate the electricity system carbon free by 2025.

The transformation is significant and requires not just a refresh or our core systems but also the adoption of new ways of working. Through BP2, we will continue to transition from a project focused approach to a digital and product model approach, bringing our business operations and technology teams closer together to create a “TechOps” community with a one-team mindset.

In BP2 we will see an increase in the solutions being built from discrete building blocks where features and functionality are rolled-in or rolled-out of service as required. The architecture will accommodate legacy applications alongside new subsystem components through the use of integration technologies (application programming interfaces – APIs) that minimise the disruption of transformation from legacy system and services to new solutions.

We will provide a standardised way of engaging with our customers to create the products and services they need, including them in the product lifecycle process. These new ways of working will remove silos, enabling us to better manage dependencies, change impacts, and speed up our delivery. For further detail, please see our Digitalisation Strategy[46], dated March 2022.

10.1. Financials

The IT investments proposed in the original RIIO-2 Business Plan were part of a five-year roadmap. IT investment is comprised of three components:

- Specific investments that directly support our outputs in this plan. These include both capex and opex expenditure.
- Shared investments in cyber security, IT infrastructure, and business services made by National Grid Group IT on our behalf and based on the universal cost allocation methodology (UCAM). These include both capex and opex expenditure.
- IT running costs. These are the costs to provide our operational IT services. This also includes the increases to the base value following investment in technology change. These are allocated based on the UCAM.

Given investments classified as shared are linked to RIIO-2 arrangements across the National Grid Group[47], their costs remain unchanged for this BP2 submission. This plan therefore only covers the specific ESO investments and associated IT running costs. IT costs have increased for BP2. The increases from the original RIIO-2 Business Plan have been driven by a number of factors, as outlined in Figure 28 below.

[46] https://www.nationalgrideso.com/document/248051/download

[47] Note we have written to Ofgem to set out proposals to provide a submission on our cyber security investments alongside the NGET cyber resilience reopener in January 2023.

10.1.1. Key Drivers of BP2 IT Cost Increase

Accelerated drive to zero carbon operation	Accelerating the pace and complexity of some investments and leading to new requirements in others
Challenging operating conditions during the COVID-19 pandemic	Leading to reprioritisation of work, whereby activities intended for BP1 have been delayed and will now be progressed in the BP2 period
Increased need for Whole Electricity System coordination	Increasing the complexity of original requirements
Exponential increase in volume of data and information	Leading to higher costs in data handling and associated hardware and software solutions
Rapid development and deployment of new technology	Leading to the need to productionise and integrate higher volume of tools and adoption of more frequent updates to developed tools
Increase of cyber security threats	Adding new scope to protect against malware driving costs up
Original Business Plan assumptions which did not materialise	Higher vendor quotes and inflated market rates to secure resources and skills plus impacts from events not planned for in original business plan

Figure 28: Drivers of IT cost increases

When we developed our original RIIO-2 Business Plan we were working on a high-level set of assumptions of what the IT requirements may be to enable our zero carbon operability ambition. We based our estimates on past experience, alongside benchmarking, to challenge the robustness of the numbers we were providing at the time. A year into the price control, we are clearer on the specific technology requirements for many parts of the business and have been able to test some of these requirements with the market, which has led to a revision of the forecasts of IT costs we anticipate for BP2. There is some further work to do in this area and, as such, we are providing cost ranges in this submission, rather than specific point estimates, for some of our major IT investment programmes whilst we continue to refine our forecasts for the final submission.

Our investment plan now ranges from between £433m and £574m over the whole RIIO-2 period, compared to £407m in our original RIIO-2 Business Plan. Our IT running costs have also increased to £80m from £50m. These revised figures do not include new business initiatives, such as Early Competition, Offshore Coordination and the Network Planning Review, Facilitating Distributed Flexibility or Net Zero operability. These projects are not sufficiently progressed to enable us to define what their IT requirements might be or their related costs. We anticipate being able to provide a high-level forecast of the costs for these new business initiatives in our final business plan submission in August.

Details of the revised cost ranges for relevant IT programmes (i.e. those where we are not providing a specific point estimate at the draft business plan stage) are set out below. These costs will be subject to further scrutiny as well as external assurance between April and August 2022, prior to the submission of the final business plan.

Investment	Whole RIIO2 FD	Whole RIIO2 BP2 data tables/TBM submission	Variance	Whole RIIO2 proposed range
Network Control	30	50	(20)	45-50
Balancing Programme	58	142	(85)	83-142
Data and Analytics	25	38	(13)	29-38
Interconnectors	6	14	(8)	12-14

Single Markets	18	33	(15)	23-33
Settlements, charging and billing	14	31	(17)	24-31
GB regulations	15	21	(6)	19-21
EMR	8	21	(14)	18-21
Connections Portal	3	3	(0)	4-7
Total view	177	353	(178)	257-357

Table 35: Revised cost ranges for IT programmes

A financial summary of our total revised IT expenditure estimates, based on the higher numbers where a range is given, is provided below. More detail on the specific investment lines and programmes is given in Annex 4 – Technology investment.

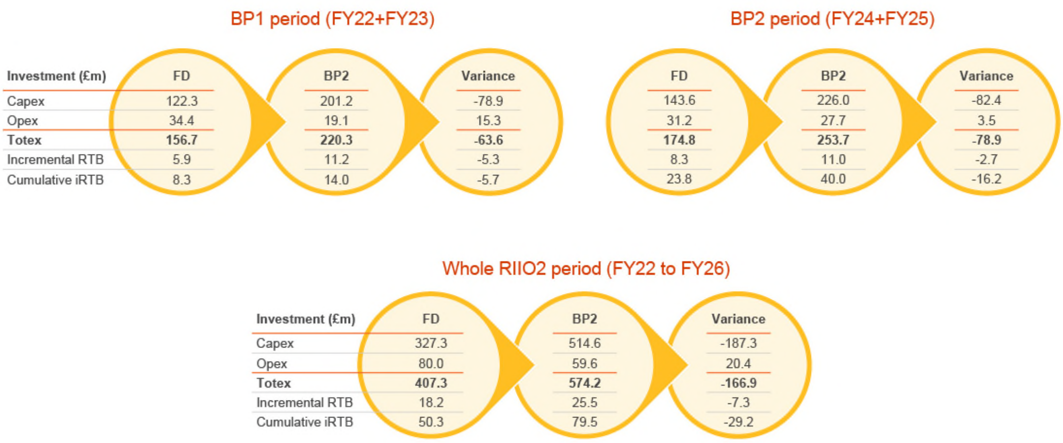


Figure 29: Summary of revised IT expenditure estimates

10.2. Governance and structure

In our original Business Plan, we said the organisational structure was going through significant transformation. Since the start of the BP1 period we have seen the introduction of the ESO Chief Information Officer (CIO), a member of the leadership team (as well as the UK IT leadership team), directly reporting to our Director.

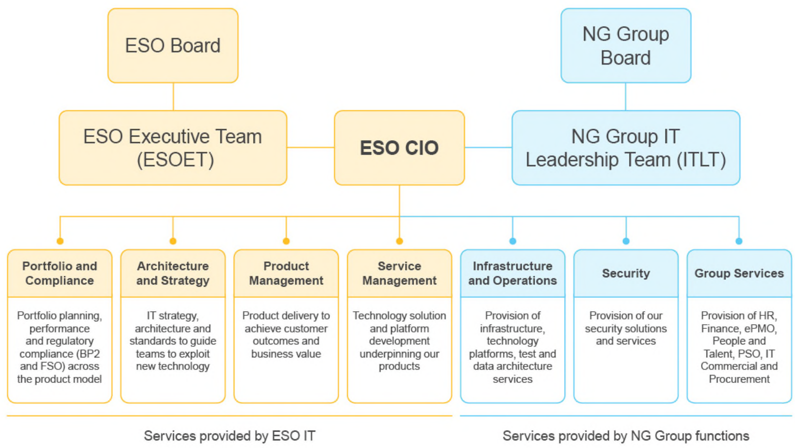


Figure 30: UK IT Team Structure

The new ESO IT leadership team, led by our CIO, provides thought leadership into the short and long-term business and technology plans. They are paving our transition into a product model way of working and changing our culture to move into a TechOps/ one team mindset.

Our leadership team owns the IT strategy and investment plan. ESO-specific IT investment is delivered by IT resources dedicated to ESO projects. General business IT projects, such as infrastructure or cyber security, are delivered by a central National Grid Group IT function.

In May 2021 we recruited a Head of Data, who will create a hub and spoke model to integrate our data strategy within our day-to-day delivery. Projects and programmes draw from this central expertise and have established multidisciplinary teams that adopt agile practices to deliver customer-centric products incrementally.

In March 2022 we were joined by a Director of Product, who will oversee the ESO's transition from a project to a product model and drive the ways of working transformation across the TechOps community, working closely with the wider ESO IT Leadership team.

ESO's specific investments go through different levels of internal governance depending on level of spend with only investments above £150m going to National Grid Plc Board. All shared investments across the group have to be approved by all functions (NG Gas, NG Electricity Transmission, NG Ventures and ESO); their detailed solution plans are set annually and reviewed quarterly across the National Grid Group for decision making.

To ensure deliverability of all its commitments, ESO's monthly Portfolio Review Board reviews the integrated implementation plans between direct and shared approved investments prioritising resources and deliverables, managing risks and dependencies. The below diagram shows the IT investment governance structure:

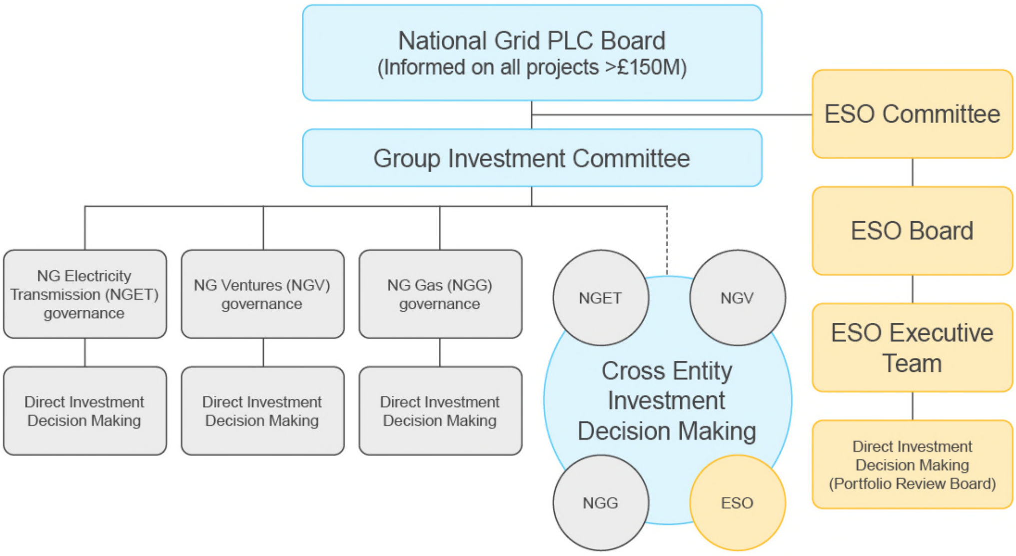


Figure 31: IT Investment governance structure

10.3. Technology Business Management (TBM) Taxonomy

In its IT guidance[48],Ofgem requested our investments be submitted through a TBM taxonomy. The below diagram illustrates the overall TBM taxonomy structure, outlining the four principal 'layers' of the TBM (Cost Pools, IT Towers, Solutions and Business) and the corresponding sub-level components that make up these layers. We have consulted with Ofgem over the course of 2021 and 2022 to refine the contents of our model.

[48] https://www.ofgem.gov.uk/publications/decision-it-guidance-eso-business-plan-guidance

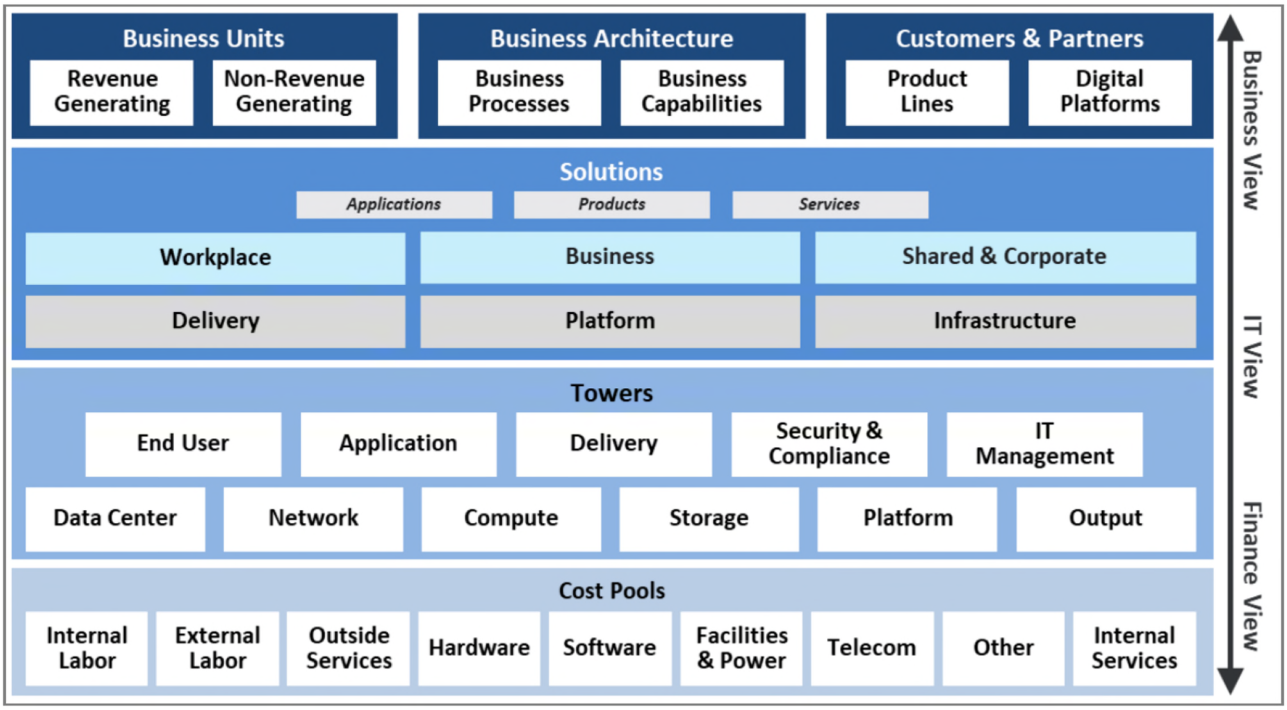


Figure 32: TBM taxonomy structure

This methodology brings the following benefits:

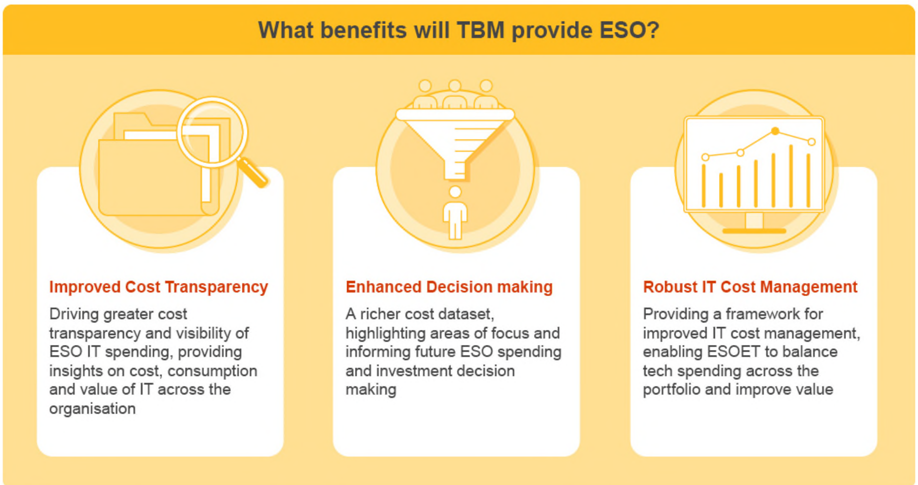


Figure 33: TBM taxonomy methodology benefits

We fully support the decision to move to TBM. For the ESO, this is a new way of expressing our investments and, as such, our current maturity in this area is low. We need time to enable this transition. In Annex 4 – Technology investment, we explain our approach to transitioning to the TBM model, as well as the process by which we will provide the necessary data requested in the guidance.

11. Innovation

RIIO-2 is a critical period for achieving Great Britain's net zero targets, including the Government's target to fully decarbonise the power system by 2035. As the Electricity System Operator, we must identify, test and develop the optimal solutions now. Ofgem's RIIO-2 Final Determinations included an expectation for us to be proactive and innovative, since the cost of any delayed or missed opportunities to GB consumers may be much higher than the costs of investment.[49]

NIA funding is key to us being able to achieve our targets. NIA funding is unique in its flexibility and agility, and is the best resource available to quickly generate, develop, and trial new solutions. Thanks to NIA, we have managed to support early stage, higher-risk activities to better understand, de-risk, and scale new solutions in a timely manner.

NIA is also a 'use-it-or-lose-it' mechanism, which means we can rapidly undertake any beneficial investments as they emerge, as long as there is NIA available to tap into; but we don't keep unused NIA funding. NIA also protects consumers by limiting how funding can be used by licensees, ensuring projects are responsibly undertaken and deliver sufficient consumer benefits compared to costs.

Our innovation capabilities have developed significantly over the first year of RIIO-2. With increased funding and a growing team, we have initiated a series of very ambitious innovation programmes aimed at tackling the challenges of the energy system transition. Our increased capacity has allowed us to set up larger and more impactful activities with new partners and suppliers. We aim to continue building on this momentum into BP2 and beyond.

For the first two years of RIIO-2 we were awarded innovation funding by Ofgem of £20.7m of NIA plus a required 10% contribution funded through totex passthrough costs, totaling an overall allowance of £23m. Ofgem then agreed that we could ask for additional funding for years three to five of RIIO-2 by providing more details of planned innovation activity and evidence of how these activities will build upon the activities in our wider Business Plan.

We believe our innovation activities for years three to five of the RIIO-2 period (linked to our wider Business Plan activities), require a minimum additional NIA funding of £24.3m.

11.1. Our progress on activities in our first RIIO-2 Business Plan

11.1.1. Virtual energy system

The Virtual Energy System (VirtualES) is a new programme we initiated in BP1, which brings together stakeholders to create an ecosystem of connected digital twins for the entire energy system of Great Britain. It will facilitate the secure and resilient sharing of energy data across organisational and sector boundaries, enable scenario modelling and whole-system decision-making, resulting in better outcomes for society, the economy, and environment.

The programme will eventually become industry-led, with two key focus areas: creating a common framework and principles for industry (a project has already started to explore the framework requirements of a whole system digital twin); and developing use-case projects to test new applications and prove the benefits of a VirtualES (this workstream explores specific use cases, beginning with a future dispatch optimiser). These workstreams rely on NIA funding and may also apply to the Strategic Innovation Fund (SIF) as relevant.

However, until the programme reaches the stage when it can be industry-led, we need to undertake a large amount of initial stakeholder engagement and facilitation, funded by our own totex funding. For example, we are facilitating the collaboration between networks, Government, academia, and the wider industry to agree on standards and a governance model, as well as identifying use-case projects. This progress is being achieved through advisory groups, covering technology, policy/regulatory considerations and how use-case applications can be developed.

[49] Ofgem (2021) RIIO-2 Final Determinations – ESO Annex. *"… we need [the ESO] be proactive, forward-looking, and ambitious. We also need it to work closely with other industry parties and wider stakeholders to ensure there is a coordinated, whole system approach to solving energy system challenges. Finally, we need the ESO to be agile and ready to adapt to emerging issues."* (para 1.5), "*Our overall approach to the ESO's incentives and price control design recognises that much greater value is drawn from the ESO's delivery of wider energy system outcomes, than from achieving efficiencies within its internal expenditure. The introduction of a pass-through funding approach, supported by incentives to deliver value for money, will enable the ESO to be agile and adapt quickly as the pathway to Net Zero evolves."* (para 1.8), and when consumer protection through DIWE disallowance is introduced, Ofgem reminds that "*[the] focus is encouraging the ESO to maximise overall benefits for consumers rather than driving efficiencies in its totex*" (para 4.47).

11.1.2. Applications to Strategic Innovation Fund (SIF)

The SIF mechanism offers an alternative to fund specific larger, long-term projects, replacing Network Innovation Competition (NIC) funding.

In addition to projects that we have been developing with our partners since the start of the RIIO-2 period, we have seen a significant increase in third party requests for us to join and/or lead collaborative projects[50]. Calls for ideas as part of the SIF process, particularly the 'whole system' challenge[51], saw us receive more proposals than we currently have the capability to process within a short timeframe. For instance, in the final two weeks of our application window, we received 43 Discovery-phase proposals from third parties, which we had to review in addition to progressing our existing proposals. This has put significant strain on our Innovation team and SMEs.

Ultimately, we submitted two proposals and supported a further nine from other networks for the first SIF 'Discovery phase' window in late 2021.

We plan to grow the Innovation team further throughout 2022 to support the application windows for Discovery and Alpha phase challenges. We also expect a further increase in project requests when SIF availability is extended to the DNOs as part of RIIO-ED2. Our expansion plans are based on our resource management experiences from 2021, where each application to SIF took an estimated 60 person-days to complete.

11.1.3. Innovation team resources

The ESO Innovation team has been growing since the start of RIIO-2 in line with our new Innovation Business Partnering model. This model embeds dedicated innovation support for each Role, and ensures projects are developed and delivered in close cooperation with the relevant teams in the business units responsible for implementing the outcomes.

However, the growth of the pipeline of new projects has outpaced our team's growth. One of the largest challenges is finding sufficient resource to properly run and then embed these projects in our BAU.

With the increasing demands of the new SIF process and VirtualES programme, there are even more requirements on the team for resources to deliver innovation successfully. Due to our leading role in the GB energy system, we are increasingly being asked to participate in and enable innovation activities led by others. This will continue into BP2, with the demands of the SIF mechanism and VirtualES programme. Accordingly, we recently expanded our innovation resources across the business in a BP1 amendment to allow us to run the NIA and SIF processes in parallel. We currently envisage being able to absorb any further resource requirements within our current BP2 resource pool (which has already increased during BP1). We will seek to use the cost-pass through model if additional requirements increase substantially during the BP2 period.

11.1.4. ESO Labs

At the start of BP1, we embedded our Labs team within the Innovation team to leverage their capabilities for the benefit of the wider business. The Labs team has the data science capabilities required to identify new and emerging technologies, feed these into the innovation processes and assist teams around the business to adopt these into BAU.

The Labs team is currently focusing on **carbon intensity monitoring** and **leveraging ML techniques for control centre operations**. This is so we can implement critical reforms to the dispatch approach recommended by BEIS (such as creating a merit order curve not only based on the marginal costs of generators but also on their carbon intensity). Key achievements in BP1 include:

- Delivery of a ML model for demand forecasting, which was recognised in the State of AI Report 2021. Forecasting demand accurately is essential to meet net zero ambitions, and our ML model has more than halved the mean absolute error of our previous hour-ahead forecast, while reducing the mean absolute error of the day-ahead forecast by 14%[52]. In January 2022, this model out predicted the nearest competitor model, resulting in reduced balancing costs. We estimate that this single event alone saved consumers c. £600k.

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[50] This is partly due to the SIF requirement to support each project proposal with at least two different types of network licensees.
[51] These SIF 'whole system' projects aim to support innovation which benefits the wider system (and not the ESO directly). They need to be prioritized alongside existing BAU and NIA-funded ESO Innovation activities.
[52] State of AI Report 2021, page 100. https://www.stateof.ai/2021-report-launch.html

- Enhancing the open data carbon intensity system[53], a publicly available data platform on our website. Here, we added features to visualise interregional transfers and provide information on where each region's power is sourced from. ESO Labs supported delivery of our first externally facing dashboard[54], showing the carbon intensity of GB power generation, which has been widely used.

BP2 presents an opportunity to grow the unique expertise of ESO Labs further to meet the changing needs of our wider business. For BP2, we are working the Lab into two key pillars, which we will transition into over the next 6 months. First, we will establish a centre of excellence that shares ML and analytical methods internally and externally with the energy industry, to facilitate the net zero transformation. Second, we will look outwards and source intelligence into ESO about emerging and disruptive technologies, and how they can be used to support the ESO and the energy system transition. We call this the 'ESO Optics' and it will work in collaboration with the centre of excellence, wider industry and our innovation partners.

11.1.5. Innovation Projects by ESO Role

At the beginning of RIIO-2, we recruited innovation business partners for ESO Roles 2 and 3 and will similarly recruit a business partner for Role 1 in the near future. The business partner model has improved how we coordinate, develop and deliver new innovation projects. Having dedicated resources has ensured closer engagement between teams and our Innovation function, facilitating better collaboration with external partners and suppliers to develop new ideas into robust project proposals.

Role 1 - In Control Centre Operations, we have been working on completing our Control REACT NIA project from RIIO-1 for implementation into business as usual. The Solar Nowcasting project is investigating closer to real-time methods for estimating generation from solar photovoltaic generation on the system, using satellite imagery and ML.[55]

Role 2 - In Markets, we completed a RIIO-1 project on investigating short term system inertia forecasting. We have started four new projects under RIIO-2, exploring stability market design and future reactive power market requirements. We have a further three projects in development.[56]

Role 3 - In Networks and Strategy & Regulation, we have completed five RIIO-1 projects, including studies on the impacts and risks of extreme weather on the system (MIVOR), a Year-round voltage assessment tool and developing tools for. We have started four new projects in BP1, including studies on Hydrogen Electrolysers as an Electricity System Asset, and Efficient ESO and DSO coordination to access DERs via national-local markets. There are currently fourteen additional projects in various stages of development.[57]

11.2. Current level of NIA use and projected levels until the RIIO-2 ends

11.2.1. Overview

NIA remains the most important funding available for innovation, as it allows networks to innovate outside of conventional Business Planning and budgeting processes and focus on new challenges and solutions. Proposals can be researched, tested and developed more rapidly than otherwise possible with other funding sources (i.e. SIF) or within business-as-usual (BAU).

During the first six months of the RIIO-2 period we introduced the new NIA guidelines to our procurement contracts and completed project negotiations on these. Despite the six-month delay, the innovation portfolio looks very healthy one year after the start of the RIIO-2 price control period. Many projects are in development or in progress, and we have reached a sustained level of potential new proposals which are considered for funding each week. At the start of year 2, the snapshot value of approved innovation projects and proposals in

[53] https://carbonintensity.org.uk/
[54] https://dashboard.nationalgrideso.com/
[55] **Control React**: https://smarter.energynetworks.org/projects/nia_ngso0032/; **Solar Nowcasting**: https://smarter.energynetworks.org/projects/nia2_ngeso002/
[56] **Inertia forecasting**: https://smarter.energynetworks.org/projects/nia_ngso0020/; **stability market design**: https://smarter.energynetworks.org/projects/nia2_ngeso005/?msclkid=3f1753f4c79811ecaf44abd60302fbb0; **reactive power market**: https://smarter.energynetworks.org/projects/nia2_ngeso008/
[57] **MIVOR**: https://smarter.energynetworks.org/projects/NIA_NGSO0023; **voltage assessment**: https://smarter.energynetworks.org/projects/nia_ngso0029; **advanced modelling with uncertainty**: https:/www.smarternetworks.org/project/nia_ngso0028__;!!B3hxM_NYsQ!h3Ec0r4I5LELLV 8NlH8Ot9wRhAhKDks7DHKqMNv5o9zQT5oEsSXzvvDnKcbNKV6RTt_evwt15g$; **hydrogen electrolysers**: https://smarter.energynetworks.org/projects/nia2_ngeso010/

our portfolio, including delivery and development costs, was forecast around £11m (shown in Figure 34 below).

We have been refreshing innovation strategy priorities as we progress within RIIO-2, and we now have better clarity on which activities we should undertake in years three to five of RIIO-2. We believe our innovation activities over the full period will require a budget of c.£50m (£45m NIA with 10% recovery through totex). An initial £20.7m of NIA funding was already approved in the BP1 Final Determinations on the basis of the clarity on year 1-2 projects. It was also clear in the BP1 FD that the ESO may request additional NIA funding for years 3-5 as part of BP2.[58]

11.2.2. NIA-funded innovation in the first two years of RIIO-2 (BP1)

Ofgem published the RIIO-2 NIA governance document in March 2021, almost at the very start of RIIO-2. We then had to implement the changes to the governance process and contracting arrangements, which has led to a six-month delay between funding being approved and new projects commencing. This slow start to RIIO-2 can be seen in Figure 34 below. Although approval of NIA project proposals has been increasing rapidly since April 2021, the corresponding new project registrations (which had to wait for the formal contractual arrangements to be put in place) did not catch up until Q3 FY 21/22.

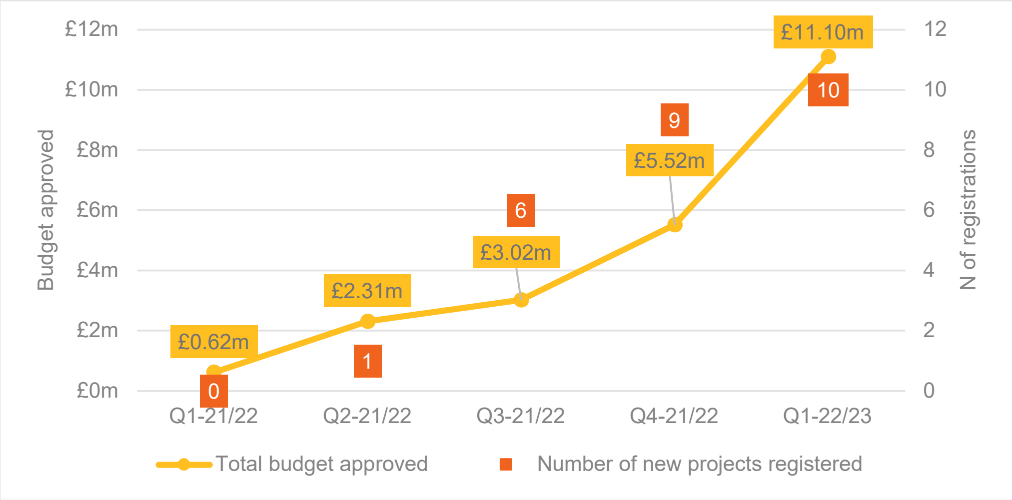

Figure 34: Budget for new projects approved since the start of RIIO-2

As shown on Figure 35 below, NIA spend over the first year of BP1 (FY21/22), despite this six-month delay to new project registrations, is estimated to be c.£4.5m (incl. RIIO-T1 NIA carried over). Forecast NIA spend for the second year of BP1 (FY22/23) is currently estimated to be c.£8m. The current forecast spend for first two years of RIIO-2 is therefore already much higher than the annual allowance of c.£4.6m implied by the initial NIA awards[59]. This rate of spend will only continue to increase as new innovation projects are approved.

[58] Ofgem Final Determinations – ESO Annex, para. 6.6.
[59] Whereby Ofgem initially allowed a total NIA of £23m, i.e. an average of c.£4.6m annually – but also clarified that this award was only based on the year 1 – year 2 plans, until year 3-5 plans have more visibility.

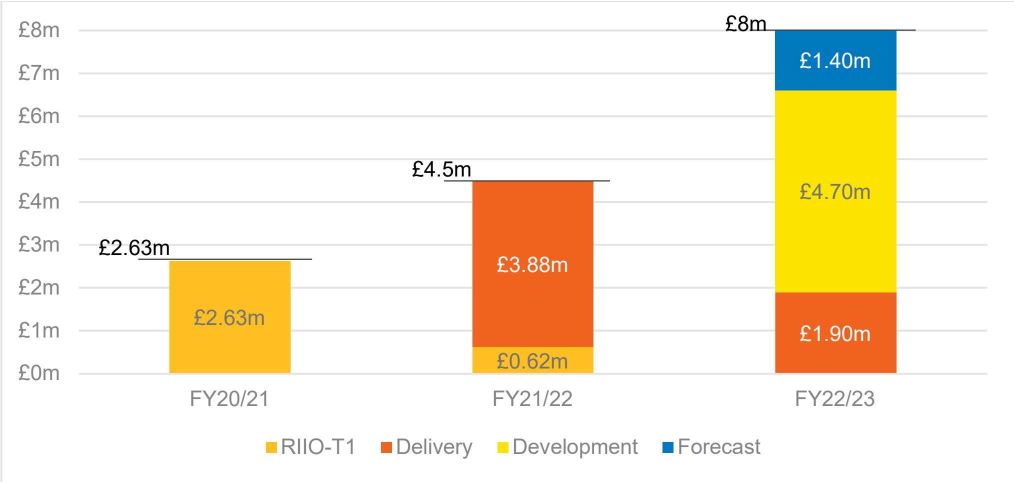

Figure 35: Actual and Forecast NIA annual budget in BP1: spend profile with the current £23m allowance for RIIO-2

11.2.3. NIA-funded innovation planned for the rest of RIIO-2 (BP2)

Each year we continue to refresh our strategic priorities for innovation, based on stakeholder feedback (internal and external), our understanding of the evolving challenges, and the level of funding and number of projects already in hand.

Given the rapid changes taking place within the energy sector, the order of priorities for innovation projects has already changed significantly since BP1 was written[60]. The forecast NIA spend against each priority has also shifted. We have aligned our latest forecasts for NIA spend against the refreshed 2022/23 innovation priorities.

We predict innovation activities in the BP2 period against each of the Roles. These predictions reflect the longer-term strategies for each Role, as well as the outcomes from current BP1 projects (which are due to be implemented or could be developed further in BP2). Our innovation process ensures we continuously monitor the benefits-case of projects to ensure we deliver the most value for consumers and the system. On top of this, all completed projects must capture their 'lessons-learned' as a requirement of the NIA funding. This informs future innovation projects and any improvements needed to our own processes.

Projects typically start at research/feasibility stage. If successful, there is often a follow-on development project and a demonstration project.

- Role 1 is expected to undertake more development and demonstration projects.
- Role 2 projects are spread across the three project types: research, development, and demonstration.
- Role 3 are typically research projects.

Table 36 summarises the typical duration and cost for each project type:

Project Type	Project Length	Project Cost
Research	0.5 year	£200k
Development	1 year	£0.5m
Demonstration	2 years	£1m

Table 36: Typical project length and cost by project type

Currently, the innovation portfolio is weighted towards research stage projects, a proportion of which will mature into demonstration projects over the course of RIIO-2.

We anticipate a 30% increase in the innovation portfolio, with the introduction of a business partner for Role 1 in April 2022. This is expected to result in a further c.£2m of projects annually once fully embedded. So, we forecast annual spend of approximately £11.5 million in 23/24 and 24/25. We expect an additional increase in spend over 25/26 to deliver a larger share of mature-stage projects ahead of RIIO-3.

[60] Please see: "2022/23 ESO Innovation Strategy" available at: https://reports.nationalgrideso.com/innovationstrategy/

Based on these current assumptions, and anticipated ramp in activity over RIIO-2, we predict a total NIA spend of over £50 million during the five-year RIIO-2 period and will start an average of five new projects each quarter, reaching to a peak of about 50 live projects at any one time. Please note that (1) this does not account for growth in collaborative projects, where we partner on other network-led NIA projects; and (2) the total NIA spend could increase as DNOs begin their RIIO-ED2.

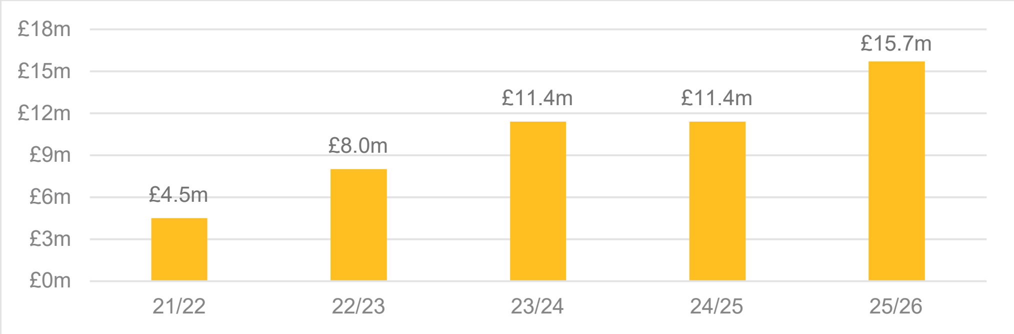

Figure 36: Forecast NIA spend profile across RIIO-2

Our understanding of the challenges of the energy system is constantly shifting. Innovation activities must adapt and refocus each year to take advantage of the latest research and technology. The nature of innovation leads to inherent uncertainty, so funding must be flexible. Indeed, the NIA funding mechanism was designed to support the type of activities which are difficult to plan very far in advance[61].

Although we rely on our totex funding or the cost pass-through mechanism where we can (e.g. team resources to deliver the VirtualES programme in BP1 or review the SIF proposals of applicants), for the majority of innovation activities, NIA funding is necessary due to the inherent uncertainty and increased risk, as well as the need to respond to emerging challenges when they become apparent. Without dedicated innovation funding available and outside of regular Business Planning process (including commercial hurdles to fund such activities within a regulated business) progress towards net zero would be severely diminished. Indeed, this was acknowledged and confirmed by Ofgem in the RIIO-2 NIA Governance[62] document: "*1.4. […] certain innovation Projects are speculative in nature and yield uncertain commercial returns. In addition, where benefits are linked to the decarbonisation of the network or addressing consumer vulnerability, it may be difficult to commercialise the respective social, carbon and/or environmental benefits and shareholders may be unwilling to speculate on such Projects. This additional funding is designed to underpin the ethos, internal structures and third-party contracts that facilitate innovation.*"

This is why we rely on trends in the current portfolio to anticipate future activity levels. We use our most recent innovation strategy to attach indicative spend profiles against areas we believe will require continued focus from innovation. Based on this, we anticipate additional innovation activity in the following areas:

Role 1 Control Centre Operations

Advanced ML techniques and automation will continue to be investigated to help the ENCC be future-ready for new challenges from the energy system transition. This includes the ability to forecast increasingly uncertain supply and demand patterns and re-think how we continue to operate and maintain a secure, reliable system, at lowest cost and environmental impact.

VirtualES will form a key component of this work, bridging complex models and data from across the energy system, to enable better operational decisions and new strategic insights for planning. In BP2, new projects under the VirtualES will build on the Advanced Dispatch Optimisation project with Google X to begin testing of new tools and advanced techniques to help the ENCC balance the future electricity system.

Modelling the relationship between climate and weather parameters to power system response will help us ensure future scenarios and projections are aligned to weather trends.

Role 2 Market Development and Transactions

Future markets will need to facilitate increasing levels of competition and a greater variety of participants on the energy system. The Future of Reactive Power trial will follow the initial NIA project delivered in BP1, which

[61] If further certainty was available, innovation projects would arguably be better suited for business-as-usual in the Business Plan and therefore not meet the conditions of NIA funding.
[62] https://protect-eu.mimecast.com/s/0nIjCDRwMFQAqWOfWU7dn?domain=urldefense.com

investigated the potential for a market-based solution to procure reactive power. In BP2, we will also finalise the design for a stability market, building on the initial BP1 innovation project.

Research will support the development of a 2045 cross-border strategy in BP2. This will be a 'north star' for all future cross-border arrangements and will likely generate further NIA projects.

New methods will assess the risk and impact to consumers from service interruptions. We will also develop better tools to calculate a more complete value of avoiding an outage event, including measures of societal costs, impact on vulnerable consumers, etc.

Role 3 System Insight, Planning and Network Development

We will continue to play a central role in innovation across networks, in relation to not just the continued transition to whole system thinking from a DSO/ESO perspective, but also the interaction of electricity and gas networks through, for example, hydrogen.

Extensive studies are being requested to cover DSO, whole energy system challenges, interconnectors, and achieving net zero.

The issues of constraint management will also continue to be an important focus for innovation in BP2. This includes better ways to forecast, plan for and solve constrained network boundaries using no-build options.

11.3. Stakeholder engagement

We will continue to ask stakeholders for feedback on our projects and innovation process. This is done through regular surveys of suppliers, partners and other stakeholders, usually through publications such as the NIA Annual Summary or our Innovation Strategy document.

We are planning to engage further with internal stakeholders as part of annual innovation strategy refresh. Stakeholders are asked to assess the current priorities, suggest changes to the definitions, and identify any new priority areas for focus over the next year.

The VirtualES programme will be built around stakeholder engagement, with advisory groups established to ensure this is being led by energy system stakeholders. Stakeholders were asked to shape the programme in an initial input survey, and more in-depth interviews will further refine a roadmap.

We are seeking feedback on our proposals through the BP2 consultation process. We hope to further increase our innovation activities for the benefit of the energy system, and we welcome comments and constructive challenges.

11.4. Innovation team financial overview

		Five-Year strategy				
		Forecast		BP2		BP3
Innovation		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	-	-	-	-	-
	BP1	-	-	-	-	-
	Variance	**-**	**-**	**-**	**-**	**-**
Opex (£m)	BP2	0.7	2.0	2.0	2.1	2.0
	BP1	0.7	0.7	0.7	0.7	0.7
	Variance	**0.0**	**1.3**	**1.3**	**1.3**	**1.3**
FTE	BP2	12	27	24	24	24
	BP1	9	9	9	9	9
	Variance	**3**	**17**	**14**	**14**	**15**

Table 37: RIIO-2 cost and FTE for innovation.

Compared to BP1, we require an additional £3m opex over the FY24 and FY25, as well as 14 more FTEs.

- 12 of these FTEs are to support the delivery of the Virtual Energy System programme, including FTEs to support across the workstreams, project management resource and a director to lead the programme
- the other 2 FTEs will be to support the increased resource requirements driven by the SIF scheme applications.

These additional FTEs are being included during BP1.

Please note that the FTE headcount in BP2 has a reduction of 3 FTEs from the second year of BP1 (from 27 FTEs in 22/23, to 24 FTEs in 23/24). This recognises that with a growth of headcount across the whole ESO, there will be more opportunities to flex resource across the business. The nature of the Innovation team is that its workload flexes with changes in activities and the FTEs will be flexed upwards using the pass-through model as required.

12. Outputs: Performance measures

For our first RIIO-2 Business Plan we developed a set of performance measures with our stakeholders which were finalised by Ofgem.

For BP2, Ofgem does not expect us to propose revised performance metrics or Regularly Reported Evidence (RRE). Instead Ofgem will propose revised measures at the BP2 Draft Determination Stage.

12.1. Stakeholder satisfaction surveys

We use a Roles-based survey to measure the level of stakeholder satisfaction in our performance against each of our Roles.

We agreed to target our stakeholders who are leaders, key decision-makers and experts across industry groups who regularly interact with us on one or more of the Role areas (approx. 650 contacts). These surveys are carried out every six months to align with our performance reporting timescales.

Following these surveys, we identify the key feedback themes and then set up local action plans in response. This is backed up by a review of the data (which includes other insights) using problem-solving sessions to identify root causes and possible solutions.

A summary of some of the feedback from stakeholder satisfaction surveys is available in Annex 3 – Stakeholder engagement.

Our most recent survey was sent out to our stakeholders in March and the results will be available by mid-April. This will be reviewed, and resultant actions included in our final Business Plan update.

12.1.1. Updated proposals for stakeholder satisfaction surveys

As part of our BP2 submission, Ofgem expects us to update proposals on aspects of the stakeholder satisfaction surveys, including the questions, survey method, participants, and performance benchmarks.

To date, we have analysed the results of one Roles-based survey which was only introduced for the first time in September 2021. We therefore believe we do not yet have enough insight to put forward proposals on how to update these surveys for BP2.

Therefore, we propose to wait for the results of our second survey, analyse this data against our first survey, engage with Ofgem and stakeholders on potential changes and then put forward proposals within our final Business Plan submission in August 2022.

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13. Internal costs: shared services

In our BP2 guidance, Ofgem acknowledged our shared service[63] submission is prepared at Group level, with the methodology and allocation agreed for the whole RIIO-2 period. However, if there were material changes to our costs for BP2, we were invited to provide details.

For BP2, we expect no change, apart from an update to IT indirect opex expenditure and a planned refurbishment of our Wokingham office, which is fully owned by the ESO and was last refurbished around 2014/15.

The refurbishment is being driven by us and designed with these key outcomes in mind: attracting the next generation of talent, showcasing our unique identity, demonstrating our commitment and contribution to net zero, and creating a workplace that can facilitate better connection and collaboration.

The estimated costs of this refurbishment are in the region of £7m, which includes £3m to replace the aged atrium roof and a £1m spend for office refurbishment in FY23.

We are also considering setting up small offices in Scotland and Wales. Having these offices will support engagement with devolved governments and would also give us access to a wider talent pool and bring us closer to customers including, for example, developers of Scottish and Celtic Sea offshore wind projects. This will come at an additional cost; however we feel the benefits in terms of access and proximity to important customer and stakeholders will more than outweigh this. The cost of these offices is expected to be small and will be managed within the property operating costs that have remained unchanged to BP1.

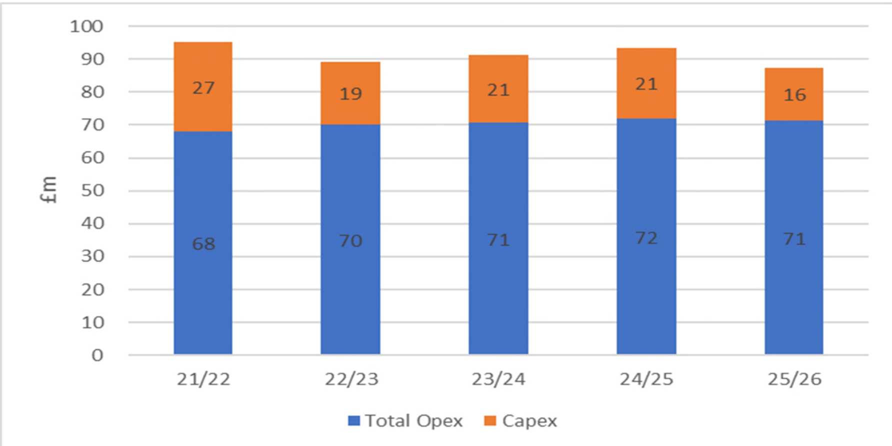

Figure 37: Graph of RIIO-2 cost and FTE for Shared Services

		Forecast		BP2		BP3
Support functions (Excluding direct IT)		**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Capex (£m)	BP2	27.4	19.3	20.7	21.4	16.0
	BP1	36.5	23.8	18.2	18.1	16.0
	Variance	**(9.2)**	**(4.5)**	**2.5**	**3.3**	**(0.0)**
Opex (£m)	BP2	68.1	70.3	70.6	72.0	71.4
	BP1	67.5	67.3	66.0	67.6	68.5
	Variance	**0.6**	**3.0**	**4.6**	**4.5**	**2.9**

Table 38: RIIO-2 cost and FTE for Shared Services

We forecast an additional £6m capex and £9m opex over BP2 compared to BP1. These are to support the property refurbishment in Wokingham and increased IT operational expenditure within the underlying run the business costs driven by decisions made post the original Business Plan submission.

[63] Please note that shared services represent Human Resources, property, insurance, finance and audit, CEO, pensions and procurement as well as indirect IT costs. No FTE numbers are included as they are not considered a shared service.

14. Finance and DIWE

Ofgem's RIIO-2 Final Determinations (FDs) established our finance framework, setting the funding components, methodologies and parameter values for the RIIO-2 period. Some of these values were set only for the first two years, with the intent to review them again as part of the BP2 submission.

We agree with Ofgem's FD arrangements and methodologies and propose the same funding package components and methodologies are maintained for the BP2 period for the same activities. Arrangements should also be put in place to discuss potential additional funding to cover changes in our risks, such as those from BSUoS reform and any new roles we may be asked to undertake.

Snapshot of BP2 funding proposals

With our current roles and BSUoS arrangements at the time of draft BP2 submission, we do not see a need to change financial parameters around the additional funding already set in BP1 for the revenue collection role (including the costs of maintaining the WCF) and the risk asymmetry (including the DIWE cap level):

- Only a short period of experience has been accumulated with the new framework to merit changing parameters; and
- Despite the increase in some regulatory cash timing risks and a reduction in others, our overall estimates of capital required in BP2 to fund the revenue collection role remain within the original CEPA range that Ofgem's FDs used when calculating the additional funding parameters for BP1.

When approved, the BSUoS reform may significantly increase the risks borne by us under our revenue collection role. In this draft, we present our current assumptions on the increase in required capital and the resulting increase in additional funding for the equity employed following the methodology used by Ofgem in the BP1. We welcome further discussions with Ofgem prior to our final Business Plan submission in August 2022, when there is further certainty on the future of the BSUoS reform.

Some of the new roles we take on, for example, relating to Early Competition and Offshore Coordination, may cause a material change in the risk we bear, meriting consideration for additional funding.

14.1. Overview of our RIIO-2 Business Plan funding arrangements

Ofgem's FDs[64] arranged a funding framework taking into consideration our roles in the energy industry and our unique asset light nature:

- A total expenditure (totex) approach, where 'fast money' will be passed through in the year incurred; and 'slow money' added to the regulatory asset value (RAV) and a return received for the weighted average cost of capital (WACC) as well as depreciation over a 7-year period
- Additional funding to cover activities with no or little RAV, or for risks that remain unremunerated
- The outcome (reward or penalty) of the overall incentive scheme, and
- Absence of a 'totex incentive mechanism' (applicable to networks), creating a framework where all efficiently incurred costs of the ESO are passed through to consumers.

The funding model is summarised in Figure 38 below. It illustrates the totex components, which recover our costs and deliver a return on investments funded through the regulatory asset base (RAV*WACC and depreciation). It also shows the non-RAV layers of funding, namely the additional funding, and the outcome of the incentives scheme (a reward or a penalty).

[64] RIIO-2 Final Determinations (Revised 3 February 2021) – Electricity System Operator Annex. Summary of all financial parameters forming the RAV*WACC plus Additional Funding package is on Table 10 (p.65).

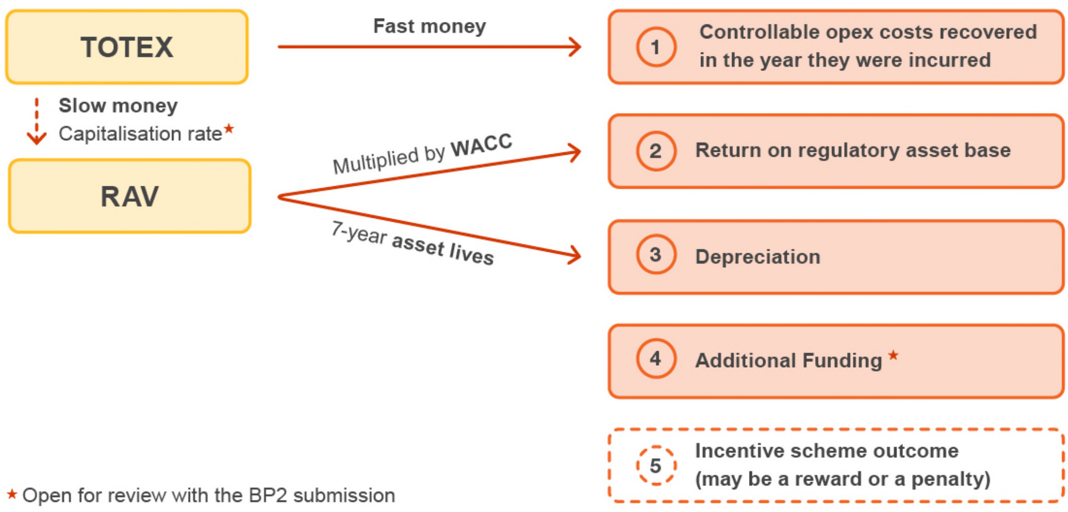

Figure 38: Illustration of RIIO-2 funding framework for ESO.

All financial parameters, except for **additional funding** and **capitalisation rates,** were set for the full RIIO-2 period (in summary tables with the applicable timeframes in Section 5 of the Annex of the Ofgem FDs).

We provide an overview below of the RIIO-2 FD arrangements for the additional funding and capitalisation rate, which we are revisiting as part of our BP2 submission. As we review the additional funding for risk asymmetry, we will also cover the **Disallowance of Demonstrably Inefficient and wasteful expenditure ('DIWE') cap**, which is also open for revision in BP2[65].

14.2. Additional funding

Ofgem's FDs agreed that one of the critical roles we undertake on behalf of the energy industry, i.e., the revenue collection role, carries risks and costs not reflected in the RAV. Linked to this role, we rely on a WCF to manage potential cash shortfalls. Procuring and maintaining the WCF has associated fixed fees. Lastly, the cost disallowance mechanism creates a realistic investor perception of risk asymmetry. The FDs acknowledged these three sources of risks and costs are not remunerated through the totex fast/slow money model (RAV*WACC), and thus allocated 'additional funding' in our funding model.

14.2.1. Revenue collection and WCF fees[66]

Ofgem decided to follow a 'return on capital employed' approach to remunerate the risks and costs associated with the revenue collection role, including the costs of procuring and maintaining the WCF to manage the cash flow risk.[67]

Funding was based on the following assumptions (£m values are nominal annual forecasts):

- As per CEPA's estimate, the role requires capital of £165m (low scenario) to £260m (high scenario)
- The capital split would be 10% equity-90% debt in the low scenario vs 20% equity-80% debt in the high scenario

[65] In RIIO-2 Final Determinations, DIWE was originally discussed under 'Internal Costs'. Our BP2 plan does not have such a separate section, and hence we will present our DIWE cap proposal in this section when discussing additional funding for risk asymmetry.
[66] Final Determinations – ESO Annex, Table 13, Table 14, and paragraph 5.36 with associated footnotes.
[67] ESO's response to Draft Determinations had recommended the alternative approach of margin-on-revenues collected/transferred, following the CMA's SONI precedent. Ofgem has considered that this approach has a disadvantage, mainly the assumption of a constant relationship between the amount of revenues collected and the underlying costs and risks. Ofgem has decided that a constant return on capital employed to manage these costs and risks was more appropriate. Final Determinations – ESO Annex, paragraph 5.37.

- Equity employed (£16.5m in low and £52m in high scenario) attracts a return based on our inflation-adjusted equity return of 9.72%. This results in a return of £1.6m in the low and £5.1m in the high scenario. Ofgem picked the midpoint of these, i.e., £3.3m
- Debt capital (£148.5m in low and £208m in high scenario) is remunerated based on the WCF costs of 0.45%, and results in a range of £0.7m to £0.9m. Ofgem estimated the pass-through of observable and efficient WCF costs will be the midpoint of these, i.e., £0.8m.

14.2.2. DIWE cap and compensation for perceived net risk asymmetry

Ofgem's FDs included an annual cost disallowance ('Demonstrably Inefficient and wasteful expenditure, DIWE') exposure capped at 2.5% of RAV. This means that, while Ofgem want us to be proactive and innovative to reach and exceed our ambitions and take on new activities in line with these goals, we can at best recover our costs and at worst be subject to cost disallowance.

Ofgem's FDs recognised that although they 'designed the RIIO-2 price control to focus more on the delivery of outputs' and they 'see disallowance of DIWE as a backstop measure', investors may reasonably evaluate the risk of DIWE disallowance as higher than Ofgem do. More specifically, 2.5% of RAV assumed at £312m creates a -£8m maximum downside risk due to cost disallowance. The upside asymmetry in the incentive scheme (reward cap minus the penalty cap) is +£9m. However, Ofgem acknowledges 'there may be a realistic perception on behalf of investors that the -£8m is more probable than the +£9m'.[68]

Assuming a 20% likelihood (high scenario) of £8m loss and considering small rewards for other asymmetry claims such as non-RAV systemic risk and contingent capital, Ofgem decided on £1.5m of funding under the title of asymmetry and other risk claims[69].

The additional funding of £1.5m, which Ofgem refers to as in the 'high end' of the estimated range, has been awarded mostly due to the realistic perception of risks by investors:

"… we recognise that the price control framework is new and the lack of a totex incentive is untested. We therefore accept that it is possible investors may have a different perception of disallowance risk than we do, and it may take time and experience for this perception to change."[70]

BP 1 Additional Funding for:	£m nominal, annual
Return on equity capital employed for the revenue collection role	3.3
Estimated pass-through costs of fixed fees of the WCF	0.8
Asymmetry and other risk claims	1.5
Total additional funding forecast	**5.6**

Table 39: Ofgem's additional funding decision applicable for the BP1 period

14.2.3. Capitalisation rates

Capitalisation rates determine the proportion of costs added to the RAV ('slow money') to be recovered through return on RAV and depreciation. Accurate rates ensure charges are fair and reflect annual and economic investment. Ofgem's FDs set annual capitalisation rates of 37% in 2021/22 and 34% in 2022/23, with rates for subsequent years to be confirmed alongside BP2 decisions.

14.3. What changes have there been since the start of BP1?

14.3.1. Revenue collection role

CEPA estimated the capital required by the revenue collection role as between £165m to £260m per annum. Although our committed facilities have exceeded the estimates in BP1, we forecast our required capital for the BP2 period to be within CEPA's range, specifically at £250m.

Our committed facilities in BP1 exceeded the size estimated by CEPA due to:

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[68] Final Determinations – ESO Annex, para. 5.38.
[69] Final Determinations – ESO Annex, para. 5.35 and 5.38.
[70] Final Determinations – ESO Annex, para. 5.39.

- CEPA's estimate not recognising the capital associated with the transition to the new TNUoS revenue collection risk arrangements, as well as £60m of pass-through costs incurred in RIIO-1 which will not be recovered until the end of 2022/23.
- Our commitment to fund deferral of balancing costs related to two industry code modifications in the BP1 period:
    - In 2021/22, we committed to fund £100m of higher balancing costs resulting from the COVID-19 pandemic, under CMP345 and CMP350, and
    - In January 2022, we committed to fund up to £200m of the exceptionally high balancing costs seen in the market to protect against further energy market company failures.

Our forecast for the revenue collection role capital requirements in the BP2 period is £250m, as shown in the last column of table 41 below, which remains in line with CEPA's original estimates. This is because some of the costs and risks (supported by the WCF) have reduced and some have increased since submission of our Final Business Plan for RIIO-2. We present these in table 41 and in detail below:

TNUoS recovery, billing, and collection, *reduced*: Following Ofgem's decision to re-allocate TNUoS revenue collection risks to the onshore TOs, there is no longer a requirement for us to fund these risks.

Other transmission billing *increased*: We rely on the WCF to cover the cash flow risks associated with the revenue collection role, namely the risk of under-forecasting pass-through costs for collection, and timing risks (advance payments versus collections made in 12 monthly instalments). However, there will be an additional source of cash flow risk in the BP2 period: our WCF will also make provision for a new risk around the funding of the new strategic innovation funding (SIF) arrangements[71]. This requires us to collect cash based on a forecast of which projects may be approved by Ofgem, with lump sum payments regardless of the timing of revenue collection. The SIF programme is expected to be far more ambitious than the Network Innovation Competition (NIC) in RIIO-1, and we estimate up to 73 projects being approved in 2024/25 and an expected award of £77m. We estimate that £20m of our WCF would be ringfenced to support this cashflow risk.

Major Customer Failure *reduced*: Our view of the amount of capital required to support a large supplier failure has reduced, given our recent experience of the special administration regime (SAR) which is used for large energy supplier failures. We have reduced our provision to cover a shortfall of three weeks' billing only, rather than two months'.

Regulatory obligations risk *increased*: Since the preparation of our original RIIO-2 Business Plan in December 2019, an unprecedented amount of turbulence has impacted the energy market, driven by the COVID-19 pandemic, exceptionally high gas prices and more recently the global sanctions in response to the crisis in Ukraine. Charging reforms have also begun and discussions are under way about how a new Future System Operator could accelerate the transition to net zero. Though we cannot predict with certainty what risks will emerge we provide examples below of risks we have recently supported and some additional risks that could emerge:

    - We committed up to £200m to support industry to defer balancing costs through three separate code modifications
    - Due to unforeseen market conditions, we incurred higher-than-expected bad debt costs in the first year of RIIO-2 to only be recovered in future periods
    - We continued to fund TNUoS recovery and billing risk until the System Operator Transmission Owner Code (STC) changes could be implemented in July 2021
    - BSUoS reform could create significant tax cash flow timing risks with any profits associated with over recovery being chargeable to tax in the year incurred and offsetting losses generated through future recovery only being monetised through offset against future profits, and
    - A potential future risk of starting Future System Operator activities in 2022/23 with no cost recovery until 2023/24.

We consider it prudent to ringfence a proportion of our WCF to cover these types of potential risks.

[71] SIF Governance Document: https://www.ofgem.gov.uk/sites/default/files/2021-08/SIF%20Governance%20Document.pdf

Capital requirement for the revenue collection role		£m nominal, annual forecast	
Risk area	Detail	BP (2019) estimates	BP2 period estimates
TNUoS recovery	Under-collection risk with a two-year lag. Sized 2x historic peak.	140	0
TNUoS billing & collection	Customers pay us based on their own forecasts. Sized on 5% under-collection.	150	0
Other transmission billing	Timing of true-up of pass-through costs and other site-specific charges.	32	48
Terminations	Mismatch between amounts paid to TO and termination sums. Sized based on possible significant mismatch from historic data modelling.	67	67
Major customer failure	Based on the average monthly billing of a top six customer with a 2-month exposure (revised to three weeks for BP2).	100	40
Regulatory risk	Unknown risks largely arising from the industry code modification process	0	45
Other	Smaller unexpected customer failure, BSUoS final settlement billing, AAHDC, spend prior to agreement of funding arrangements, income adjusting events.	61	50
Total		**550**	**250**

Table 40: Estimates of funding required for costs and risks associated with the revenue collection role.

14.3.2. Planned BSUoS reforms

In our December 2019 RIIO-2 Business Plan, we committed to looking at partially or fully fixing BSUoS charges to provide greater certainty to our customers. In December 2020, following the publication of the report of the second BSUoS taskforce, Ofgem confirmed that setting BSUoS charges on a flat volumetric basis can have benefits. A code modification was subsequently raised in line with the taskforce recommendations.

Compared to the current situation, where the ESO recovers balancing costs within 23 days, fixed volumetric BSUoS charges will increase the payment recovery timeline up to 2 years (depending on the solution alternative). As all potential solutions involve us funding at least a proportion of the cash flow (liquidity) risk, this is the primary risk type that increases in our portfolio. In addition, there would be a new profit volatility risk: In the event of under-recovery for two consecutive years, we might not have enough retained earnings to make dividend distribution possible in not only year 1 but also year 2. Then, in a year of significant over-recovery, if we suffer a tax charge as a result and we do not make an equal and opposite loss to offset in the following year, there would be adverse corporation tax cash flow issues leading to a long-term cash shortfall.

Once BSUoS reforms are approved and put into place, there should be a re-evaluation of our risk metrics and proportionate increases to our additional funding for the revenue collection role.

14.4. What is our proposal for BP2?

Area	Amount £m	
	Current BSUoS arrangement	If fixed BSUoS charging reform is approved
Capital required for the revenue collection role	*250*	*550 (£250m + additional £300m to support increased cash flow risk, based on current available headroom in existing facilities)*
Return on equity capital employed for revenue collection role	3.3	7.7
Return on debt capital employed for revenue collection role (pass-through of observable, efficient costs of the WCF)	0.8	0.8
Asymmetry and other risk claims, assuming a continued annual DIWE cap of 2.5% of RAV	1.5	1.5
Total additional funding	**5.6**	**10.0**

Table 41: Comparison of current versus proposed BSUoS charging arrangements and potential financial impact

14.4.1. Revenue collection role

We estimate an annual capital requirement of £250m to support revenue collection activities during BP2. This sits within the CEPA range of £165 - £260m, which Ofgem had used to arrive at the £3.3m midpoint estimate for the annual return on equity capital estimate. We consider the same £3.3m would be an appropriate annual return on equity employed for the revenue collection role in BP2, provided that the ESO activities remain the same as in BP1 (i.e. the same BSUoS arrangements and no new roles).

However, if proposals to fix annual BSUoS tariffs are implemented in BP2, increased additional funding may be necessary. Ofgem acknowledged this in the Final Determinations as follows:

"BSUoS reforms: Industry has proposed changes to charging arrangements that potentially increase cashflow risk on the ESO. This could also lead to the consideration of new arrangements that could move cash flow risk from the ESO to another body. As a result, funding may need to be increased or decreased."[72]

Current solution alternatives from the code modification workgroup all lead to increased cashflow risk for the ESO. In this case, we propose the same remuneration approach as above (return on capital employed) is applied after adjusting for the increase in capital needed to cover the increased liquidity risk. We consider this would provide a proportionate and flexible way to fund the additional risk. Assuming that we would make £300m available to manage the cash flow risk created by fixing BSUoS tariffs[73] the equity part of this additional capital employed would be £2.9m in the low-equity and £5.8m in the high-equity scenario. The midpoint would be £4.4m, which, added to the £3.3m return on equity employed for the revenue collection role without the BSUoS reform, would result in an overall funding of £7.7m for the equity component of the revenue collection role after the BSUoS reform.

Since the risks we are mitigating are highly unpredictable and we cannot forecast how facilities would be drawn during any given period, we cannot accurately predict the fixed costs of the WCF. So, we consider that pass-through of observable and efficient costs continues to be the most appropriate way to provide for WCF costs in the BP2 period. In the FDs, Ofgem based the additional funding for revenue collection role – debt component on the estimated fixed costs of a £550m facility, deciding on £0.8m per annum. As the actual size of our facility has not changed for BP2, we still estimate the fixed costs associated with the WCF to be £0.8m per annum.

[72] RIIO-2 Final Determinations – Electricity System Operator Table 15, page 86
https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_eso_annex_revised.pdf
[73] Based on current available headroom in existing facilities. Current proposed code modifications require that the amount of support available would be reviewed and agreed with Ofgem to reflect changes in ESO liquidity risks and amount of overall credit facilities available to the ESO.

14.4.2. DIWE cap and Additional Funding for Asymmetric Risk

Ofgem acknowledged in the RIIO-2 Final Determinations that the disallowance of DIWE mechanism, even when capped at 2.5% of RAV and when considered together with the net upside asymmetry of the ESO Incentive Scheme, creates a "realistic investor perception" of a higher likelihood of a loss. Ofgem stated that this 'realistic investor perception' was linked to the new and untested nature of the price control, including the new Incentive Scheme and the lack of a Totex Incentive Mechanism, and that "it may take time and experience for this perception to change".

Given that only one full year of the RIIO-2 price control period has passed, and we have not yet completed a full regulatory reporting cycle, we do not believe that there has been sufficient opportunity to test the new framework. Ofgem's 20% probability of disallowance assumption (employed in the FDs when evaluating DIWE net downside against incentive scheme net upside) equates to a one-in-five-year event and so we do not believe the new framework could be considered fully tested until the end of the five-year RIIO-2 period.

Therefore, we see no rationale at this stage to change the level of the DIWE disallowance cap from 2.5% and the risk asymmetry funding from £1.5m per annum.

We propose the funding of £1.5m per annum and the DIWE cap of 2.5 per cent on RAV should be retained across the full RIIO-2 period.

14.4.3. Capitalisation rates

As planned in the Ofgem FDs, we agree that updating the annual capitalisation rates in line with the totex spend plans in BP2, reflecting the split between capex and opex expenditure, is appropriate.

14.5. Additional considerations for BP2

In our Business Plan submission, we expressed concerns there was no reward for us in taking on any new activity where there was a minimal addition to the RAV, which could drive a risk averse culture and fail to deliver consumer benefits. We disagree with Ofgem's FDs suggestion that new roles such as those relating to the **Early Competition Plan** or **Offshore Transmission Coordination** are not likely to materially change our risk profile nor merit consideration for additional funding.

Now that we have further developed plans for Early Competition, we are aware that certain roles such as the procurement body and contract counterparty could, due to their scale and complexity, present significant additional risks. We do not believe any commercial organisation would take on such additional activities with the prospect of, at best, recovering costs and, at worst, incurring fines, penalties, legal challenge, and reputational damage. As new roles develop relating to the Early Competition regime and offshore transmission coordination, we would welcome discussions with Ofgem around additional risks, possible mitigations, and additional funding.

14.6. Conclusion

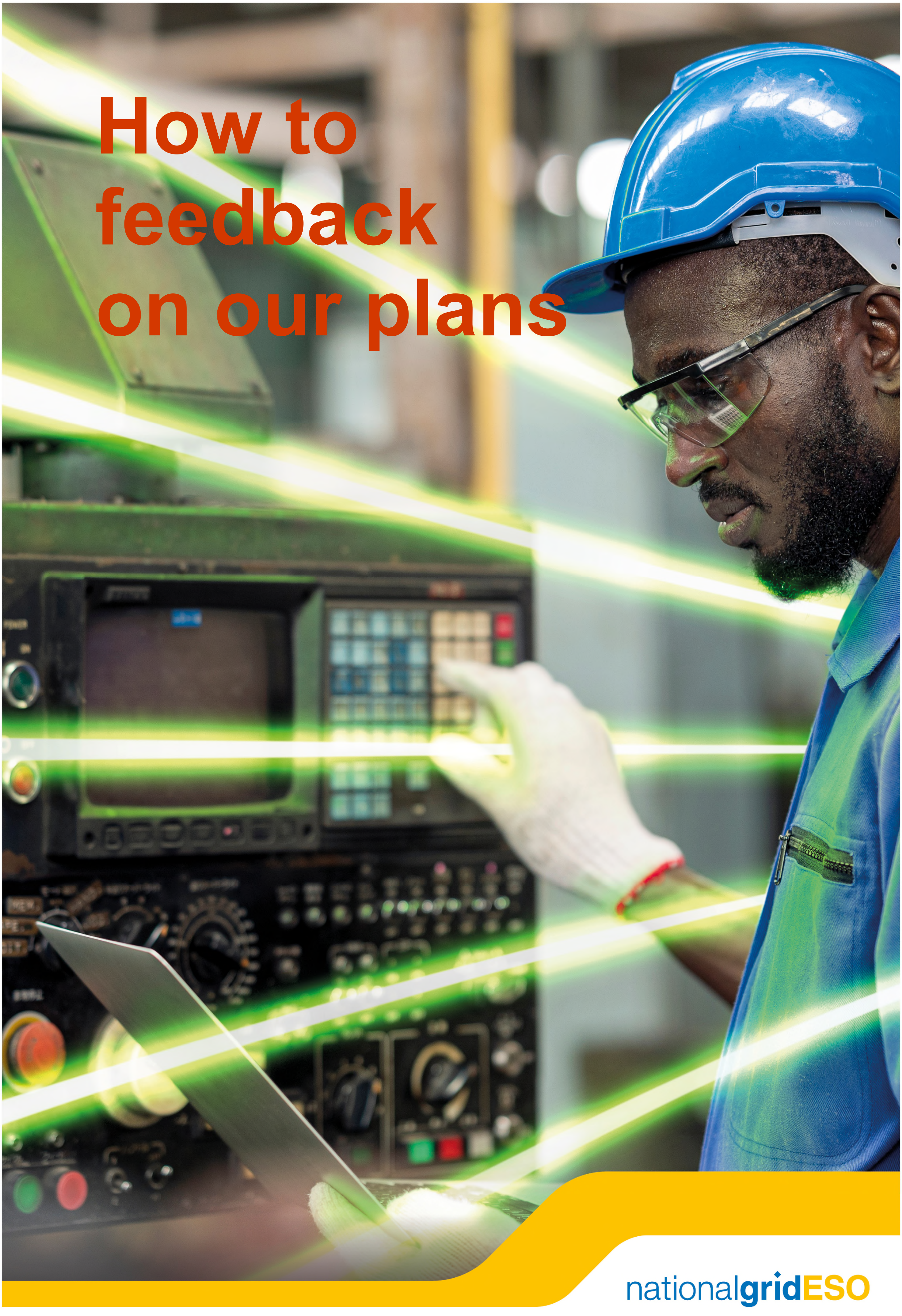
Much of the RIIO-2 funding framework was set for the full RIIO-2 period, with additional funding, capitalisation rates, and DIWE cap to be reviewed in our BP2 submission.

Regarding our current set of activities and roles, we currently do not see a justification for changing the financial parameters set for BP1, due to no material changes in the overall netted out risks and a relatively short period of experience in the new ESO regulatory framework.

We do see emerging risks around BSUoS reform if it is implemented. We propose to extend Ofgem's return on capital methodology to provide a fair and flexible way to remunerate additional risks if BSUoS reform is implemented.

Some of the new roles we take on, such as those relating to early competition or offshore transmission coordination, may create material increases in risks and costs. When we receive clarity on potential new roles, we propose to review with Ofgem the changes in risks and costs that merit additional funding.

How to feedback on our plans



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15. Help us to further shape our plans

We've already tested our activities with stakeholders and shaped our proposals in line with the feedback. Now we want to hear your views on our draft plan. We encourage you to review, challenge us and provide your feedback as we refine our proposals, before submitting the final Business Plan August 2022.

Our BP2 consultation is open from 29 April until 10 June 2022. We will be running a variety of events and providing a range of ways for you to feedback across the entire plan. To get involved visit our RIIO-2 pages of the ESO website.

We look forward to continuing to work with you as we deliver a sustainable, secure and affordable electricity system for the future.

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