The voice of the energy industry

Energy UK response to National Infrastructure Commission Consultation on The Electricity Distribution Network

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Submitted via email to electricitydistributionstudy@nic.gov.uk

Executive Summary

Energy UK is the trade association for the energy industry with over 100 members - from established FTSE 100 companies right through to new, growing suppliers, generators and service providers across energy, transport, heat and technology. Our members deliver nearly 80% of the UK's power generation and over 95% of the energy supply for 28 million UK homes as well as businesses.

The sector invests £13bn annually and delivers nearly £30bn in gross value - on top of the nearly £100bn in economic activity through its supply chain and interaction with other sectors. The energy industry is key to delivering growth and plans to invest £100bn over the course of this decade in new energy sources.

The energy sector supports 700,000 jobs in every corner of the country. Energy UK plays a key role in ensuring we attract and retain a diverse workforce. In addition to our Young Energy Professionals Forum, which has over 2,000 members representing over 350 organisations, we are a founding member of TIDE, an industry-wide taskforce to tackle Inclusion and Diversity across energy.

Energy UK welcomes the NIC review of Electricity Distribution, an area in serious need of reform in order to enable effective whole system planning and to deliver a basis for the establishment of Regional Energy System Planners (RESPs).

Energy UK would welcome the NIC focussing on:

- Ensuring the plans for distribution are sufficiently anticipatory and adaptable to local uncertainties at the distribution level.
- Potential standardisation of markets and connection processes across DNOs.
- Opportunities to remove barriers to better utilisation of flexibility, without disincentivising necessary network buildout.
- Improving the quality of and access to data at the distribution level.
- Clarity of the state of connections and issues behind delays to connections at distribution level, and actions needed to address this such as streamlining planning barriers, ensuring adequate organisational resourcing, and tightening DNO delivery obligations.

If you have any questions about this response or wish to engage with Energy UK and its members, we would welcome further engagement.

Kind regards,

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Consultation Questions

Policy, regulation and governance

1. **Does the current RIIO-ED2 price control do enough to enable required investment in additional capacity? What changes should be considered for the next price control period (RIIO-ED3) to ensure that required investment is identified and enabled?**

The current price control does not do enough to enable required investment in additional capacity, and more can be done to enable investment to be delivered in the context of Net Zero, moving beyond the current short time-frame for allowable investment.

To deliver Net Zero, network planning needs to focus on delivering cost-effective investment toward 2050, with improved coordination across government, better processes for justifying investment, and addressing wider considerations all important to effective delivery.

Improved coordination

Energy UK agrees with the principles of the network price controls. Wholesale change to the RIIO process could create more uncertainty and undermine investor confidence, leading to a higher cost of capital and delayed investment in infrastructure. The price control framework on its own will not be enough to support the energy transition and must be delivered alongside other regulatory reform including the Connections Action Plan (CAP), the Strategic Spatial Energy Plan (SSEP), and wider reforms to the roles of the regulator, network companies and the newly-established National Energy System Operator (NESO).

Work across the Department for Business and Trade (DBT) to reform regulatory frameworks surrounding delivery, and wider sector decarbonisation pathways across businesses, housing and public buildings must be better coordinated with energy infrastructure delivery to enable cost-effective delivery of utility infrastructure over the coming decade.

It is essential that the RIIO-ED3 process considers both the broader top-down direction and guidance from the SSEP to support a net-zero system and a bottom-up process that includes managing regional uncertainties from local demand and supply changes through an adaptive process. Coordinating the SSEP and the decision to establish Regional Energy System Planners (RESP) with planning reform and local community engagement will be critical to delivery of a cost-effective national system.

Building for Net Zero

The enormous amount of network investment required following a decade of under-investment and a significant increase in the amount of distributed and demand-side technologies is stark and there is a serious concern that, in its current form, RIIO-ED3 may not be sufficiently adaptable to challenges already emerging at the distribution level. The volume of infrastructure required justifies an increased level of certainty and long-term strategic planning to minimise the cost of capital for network companies while delivering a cost-effective net-zero electricity system.

RIIO-ED2 has improved incentives and capabilities for Distribution Network Operators (DNOs) to invest in additional capacity ahead of need to deliver the capacity required for the uptake of low carbon technologies and distributed generation. During RIIO-ED1, Ofgem provided capital allowances to DNOs far above what was actually required, having expected a much faster uptake of low carbon technology from 2013-2021. By one estimate, the total load-related underspend during RIIO-ED1 was £2bn, and Citizens Advice estimated that Networks accrued £7.5bn in excess profits over the price control period[1], underinvesting at the behest of Ofgem.

RIIO-ED2 as a whole shows progress, with a more adaptive framework allowing longer-term forecasts to be used in justifying network investment, primarily delivered via 'Net Zero Reopeners'. Ofgem also tightened some elements in favour of consumers so that companies are less able to pick up windfall gains.

Energy UK members continue to note consistent delays to projects when connecting at the distribution level, often having to wait multiple years to connect, with a postcode lottery apparent across Great Britain (GB). While the level of underinvestment has been reduced, delays in the rollout of new connections may indicate that current incentives do not sufficiently prompt DNOs to facilitate strategic delivery ahead of need.

It is essential too that DNOs business plans include sufficient resources to address the large, and increasing, workload of connection requests and necessary upgrades throughout RIIO-ED3. Where DNOs fail to provide high standards of support to connecting parties (both demand and generation) this has a significant negative impact on the transition to a cleaner energy system, and a negative impact on economic growth. Given this, the Ofgem should very seriously consider the enforcement of penalties for delayed delivery.

Ofgem's response to the underspending of allowances during ED1 has been to double down on its scrutiny of networks' investment plans. It evaluated over 600 Engineering Justification Papers as part of the development of ED2 alone, delving as far as possible into the very detailed levels of planning undertaken by networks for their investments.

Under the RIIO framework and Ofgem's high scrutiny regulatory model, decisions around upgrades need to either be defined at the outset of the price control or through an ongoing series of reopeners. While the design of reopeners is broadly viewed positively, industry is concerned that Ofgem will struggle to analyse potentially thousands of individual engineering projects across the country.

Wider considerations

As has been seen in the ongoing CAP, supply chain demand will result in higher costs and constraints for network upgrades, as cables, transformers, pipes and switchgear needed for this transition, not to mention the skilled workforce to install these, will be in demand in significantly higher volumes than before, with the International Energy Agency (IEA) projecting that global investment in electricity networks alone would triple by 2040.[2]

[1] https://www.citizensadvice.org.uk/policy/publications/energy-consumers-missing-billions/
[2] Executive summary – Electricity Grids and Secure Energy Transitions – Analysis - IEA

It is unclear how Ofgem intends to progress with the benchmarking of costs for business plans prior to the start of the RIIO-ED3 price control. Russia's illegal invasion of Ukraine and wider uncertainty in global supply chain conditions present a serious risk that Ofgem's benchmarking of costs will quickly be out of date by the time the price control begins. Ofgem must maintain a high degree of coordination with industry on their initiatives, in collaboration with the Government, to manage supply chain costs and pay attention to the impact it may have on business plans feeding into RIIO-ED3.

In addition to concerns about supply chains and skills, there are wider issues surrounding the coordination of network buildout with wider utility delivery, with energy-intensive processes in the water sector and communications sector increasingly linked to the energy system. Datacentres for example will be critical to establishing a smarter energy system, but cannot be connected if network infrastructure, suitable land, and smarter demand side offerings are unavailable. As such, price signals, market reforms (both the Review of Electricity Market Arrangements (REMA) and energy retail reform), and wider planning reform must be coordinated more effectively across sectors and utilities to give clear signals to all areas of the economy.

On top of this, upgrades are needed in the telecoms and water sectors which will also impact customers at the Distribution level and it's important that all these works are coordinated across utilities to:

a. reduce costs and customer disruption and,
b. reduce traffic and emissions levels within cities which are already heavily congested.

2. Does current planning policy impede the deployment of distribution network upgrades? If so, what solutions could alleviate this? Please provide examples.

Distribution Network Connections are often delayed or prevented by planning policy, whether it is the effective ban on onshore wind projects, or the challenges presented by land access rights for electric vehicle (EV) charging hubs. More coordinated delivery of reform would help to establish a streamlined approach to planning and infrastructure delivery.

<u>Planning policy challenges – Grid connecting assets</u>

Where landowner or local authority permitting is required, such as for larger substations or overhead cabling, a frequent issue noted by Energy UK members is the long delays in landowner responses to the DNOs. The system relies on the DNO's legal team finding the landowner and contacting them often by inefficient postal processes which landowners may ignore. While the law does state that the landowner has 21 days to reply, after which the DNO may escalate the issue to a wayleave hearing, it is rare that DNOs invoke this process unless the works in question are for their own purposes. Furthermore, the hearing process can be lengthy and costly process for all parties involved. One remedy to this would be for Government to consider routes for the party seeking a connection to pursue a hearing, rather than relying on the DNO alone.

The current voluntary process system for wayleaves and easements is costly, complicated, and regularly serves to delay the deployment of renewables and cause uncertainty. The process is “one size fits all”, making it more suitable for certain developments (e.g. property development) but unsuitable for energy infrastructure such as EV charging equipment or embedded generation. Such energy demand and generation are often smaller in size than property developments, making the standard wayleaves process a proportionately greater burden on a site-by-site basis. The impact is felt more acutely as the electrical connection dictates the early critical path for the development of energy infrastructure.

When developing clean technologies, it can be beneficial to agree separate land leases for the technology and the electrical connection. Doing so can simplify the process by avoiding the need for subletting, shared site occupancy and / or specific site access, particularly beneficial when there are multiple customers for the connection. However, the land acquired for the electrical connection can be leased over a different, typically longer, period than the development it is supporting. In the case of EV charging, sites are typically leased for 10-30 years, whereas DNOs will typically pursue leases for over 99 years for electrical connection. This length of lease for the electrical connection often makes it difficult to agree a voluntary wayleave/easement with the landowner, particularly as most DNOs will not negotiate on the length of lease.

In appropriate circumstances, shorter lease terms for electrical connections could present more agreeable terms to landowners, shortening the negotiating period to attain a voluntary wayleave/easement. The terms of lease for the electrical connection should, wherever possible, be matched to the terms of lease for the development.

Energy UK welcomed the Government’s recent proposal[3] to integrate the installation of EV chargers into the permitting regime for street works under the New Roads and Street Works Act 1991 (NRSWA) and the Traffic Management Act 2004 (TMA). The policy change allows greater flexibility and agency for installers to fit EV charge points where there is demand without being hindered by lengthy application processes.

Concerning network infrastructure itself, some in the industry believe that the permitted development rule allowing substation construction up to 29m^3 should be raised to 40m^3 given the expected increased need for reinforcement. This would accommodate solutions that package different electrical components into a single asset.

Planning Policy challenges – Building decarbonisation

At present, system planning does not fully consider the long-term direction of travel for demand-side connections, whether this is the increased demand for energy intensive connections like datacentres and manufacturing centres, or the anticipated rapid uptake of EVs and low carbon heat.

Permitted development rights and connections processes for low carbon technologies at the building-level, e.g. solar panels, storage, heat pumps and EV chargers, continue to be

[3] DESNZ, Street works access: electric vehicle chargepoint operators

complex and challenging for developers, businesses, and domestic consumers. Energy UK welcomed the Government's recent consultation on permitted development rights[4].

Requiring planning permission on things like materials used for additions exterior to a building, multiple EV charging equipment housing, or installing more than one heat pump in a detached house or stand-alone block of flats can create knock-on issues when planning local network buildout over time.

The Future Homes Standard will inherently increase the amount of low carbon technologies connected for new-build homes, a welcome change but one that will encounter the same issues with community consents and long wait-times for connections and planning consents.

The role of coordinated delivery and adequate resourcing

Effective delivery requires a joined-up and collaborative approach between stakeholders, regulators and Government, as well as across government departments. For example, it may be beneficial to match available grid capacity and connection applications in local geographies alongside planning arrangements in order to invest in the network ahead of need based on anticipated energy supply, demand patterns, travel patterns (for low carbon transport planning) and local development plans. Such a process will be essential for the functioning of RESPs.

The first element of this approach would be improving information sharing, including opening up data about the actual state of the network, including energy flows and available capacity, and about local development plans. Standardisation of monitoring and data availability at distribution level is a critical enabler of this process, and to date has been slow to be delivered. Local authorities have developed Local Area Energy Plans and Net Zero plans without any level of standardisation over what details and data streams should be made available to enable cost and time effective delivery.

There is a significant lack of resourcing among local planning authorities and statutory consultees resulting in lengthy delays to projects being assessed, leading to material impacts on project timelines. This occurs in spite of there being clear statutory timelines for planning applications to be assessed, which do not appear to be widely enforced. Unless the lack of resourcing is addressed, this issue is likely to become further exacerbated as the transition to a Net Zero energy system continues to pick up pace. As the energy network is vastly expanded over the coming decade and increasing numbers of low carbon assets are deployed closer to demand, the importance of a properly resourced planning process to ensure timely decisions are taken will become even more critical.

A first step to mitigating many of the coming challenges, as part of the emerging workstreams related to the delivery of an effective SSEP and establishing RESPs should be to synchronise work on removing barriers relating to permitted development, reviews to the NPSs at the national level, work to improve the visibility and interaction of network capacity at the transmission and distribution level and work to standardising the distribution connection process.

[4] DLUHC, Permitted Development Rights Consultation

3. **To what extent can a move to more strategic planning of the network at transmission level be replicated for the distribution network? What would be the benefits and costs of doing so? In answering this question, please consider the interaction with forthcoming changes to strategic energy planning, such as the introduction of Regional Energy Strategic Planners.**

Strategic Planning of the Networks

Energy UK believes the SSEP / CSNP process being developed has the potential to be a valuable route for managing the scale of the build-out of large-scale infrastructure needed for Net Zero. The problem of insufficient network build is clearly defined and there is a strong consensus of the need to build additional connectivity. Given the intention to focus the interim SSEP on electricity generation, Energy UK is not confident that the process will do enough to effectively coordinate planning across the energy system. Further work is required to address the integration of energy demand, gas infrastructure, and future energy networks for Carbon Capture, Utilisation and Storage (CCUS) and hydrogen.

The many challenges at the electricity transmission level have been identified through the Winser Report, with many being addressed within the CAP and Transmission Acceleration Action Plan (TAAP). The intended actions within this work are not expected to deliver against the rapidly increasing connections queue, and further work will be required beyond the coming process and energy code changes. This work must be progressed with consideration of how distribution-level processes can be adapted to be better standardised, harmonised, and otherwise streamlined.

The full details of the move to more strategic planning at the transmission network remains to be seen. A more strategic and anticipatory approach to network investment is very welcome and should also be pursued at the distribution level. However, the way that the forthcoming SSEP, and the RESPs will influence the development of the network is as yet unclear. Especially when considering the distribution network, an adaptive approach will be needed for planning infrastructure to respond to uncertainty in a way that draws upon the deep knowledge of market participants and enables the market to respond to price signals to derive optimal locations and the optimal mix of technologies to deliver Net Zero.

Energy UK welcome the commitment from Electricity System Operator (ESO) that the methodology for the SSEP will be consulted on and look forward to engaging with the process.

Information disparity

While issues at the transmission level are increasingly clear and the state of these networks is being better understood and fed into strategic planning and delivery, both in the existing ASTI and NOA processes and in the developing SSEP and CSNP, electricity distribution remains a difficult and opaque section of the system.

Currently, distribution network planning is more decentralised and more reactive than for the transmission networks. There is limited national system coordination across distribution networks and the attempts made to modernise and standardise distribution processes have been slow to deliver this. DNOs have faced challenges in assessing investment needs, with significant limitations in the availability of data regarding the state of the network and the connected parties on said network. At lower voltages, processes to streamline connection notifications for low carbon technologies are welcome but remain imperfect. Attempts to heavily rely on smart meter data rather than rolling out on-network monitoring capabilities will only continue this information disparity across network areas and fails to give an accurate reflection of real-time energy flows across distribution networks.

To efficiently schedule upgrades closer to demand, a planner needs to know the available network capacity and typical energy flows, what assets are connected to the network, when new assets will be connected to the network, and the likely behaviours of those assets. For domestic assets like heat pumps and electric vehicles, this means having insight to what consumers will be buying and when.

The Climate Change Committee's (CCC's) Balanced Net Zero pathway includes 15 million electric vehicles on GB's roads by 2030 supported by nearly 400,000 public charge points and millions of individual domestic chargers. Fulfilling this pathway would mean that five million homes will have a heat pump of which two million will be households currently connected to the existing gas network, a number that will triple by 2035.

The uncertainties facing the regulator and the future planning of the electricity distribution network include: the location of changes in demand and how policy may affect this; the cost of future network equipment; consumer technology preferences and potential resistance to uptake; and the changing role of current and future utility infrastructure, including the future of the existing gas network and role of hydrogen and CCUS.

The role of the RESP

Establishing RESPs is a first step towards managing many uncertainties, coordinating with local interests while considering the national system. If executed well, RESPs could be an essential aspect of whole system planning going forward.

A plan that does not recognise and seek to manage the many trade-offs and uncertainties in the transition to Net Zero is a plan that will be stuck in almost permanent delay. The RESP will need to engage local authorities (LAs) and communities ahead of network buildout if it is to gain public consent and approval for the delivery of effective infrastructure.

RESPs will also need to be able to look beyond LA boundaries in order to deliver the most effective approach to delivery. This places the RESP in a position of needing to be able to effectively engage with resource-constrained LA's on complex decisions, balancing a level of democratic input with the desperate need to deliver infrastructure fit for the future. Current planning frameworks across the country, without a coordinated approach, could impact which areas see investment and which see continued delays, impacting the ability of consumers in different areas to choose how and when they decarbonise their energy usage.

In order for RESPs to be effective, more work will also be needed to clarify the interaction across the distribution and transmission interface. Energy UK is pleased to see work progressing on enhancing visibility of capacity availability at the distribution level and understanding its interaction with transmission capacity to enable DNOs to secure and allocate capacity to embedded generation more easily. Nonetheless, the work here is facing a number of roadblocks, namely difficulty in understanding the interaction of forecasting future capacity while the other connection reform processes remain incomplete. As further policy understanding is developed of the local generation and demand trajectories in coming years, and as new roles and responsibilities are defined, the NESO and Ofgem will need to give greater priority to this workstream and consider its implications on other workstreams relevant to distribution network build-out and the SSEP.

The NESO, Government and Ofgem will need to work collaboratively to manage localised uncertainties, developing pathways for RESPs to deliver where local barriers emerge. The emerging centralised, top-down process under the SSEP and CSNP must be married with a more adaptive, bottom-up approach at the level of distribution. A clear steer and more coordinated approach to infrastructure delivery both nationally and regionally will be needed for the Government to meet its objectives and obligations under the Climate Change Act and the Energy Security Strategy, but the local and regional considerations that a RESP could bring into the national approach could be fundamental to the most cost-effective delivery for bill-payers and taxpayers.

The 'adaptive planning' process[5] endorsed by the Department for Environment, Food and Rural Affairs (DEFRA) and Ofwat as a method for planning the expansion of water and sewage projects, and wider work to develop Smarter Regulation under DBT have gone some way to understanding the methods for delivery that could be adapted for regional planning.

4. To what extent will making the distribution network fit for net zero also help ensure that it is adapted to a changing climate? Are there any potential conflicts between meeting additional demand and adaptation, or any additional steps required to ensure adaptation is effective?

Climate change is expected to result in more erratic weather patterns in the decades to come. Technical risks noted in the past by industry regarding distribution networks include:

a. Overhead lines' thermal capacity being affected by higher temperatures, especially during heat waves.
b. Ground movement from drought or flood damaging underground cabling infrastructure.
c. Substations damaged by flooding, increased rainfall, heavier snowfall and higher windspeeds.

[5] Ofwat, PR24 and beyond Final guidance on long term delivery strategies

d. Risks from all these mentioned weather events to non-technical factors including the functioning of routine business, customer service and emergency response.

Actions required include increased flood defence investment, reinforcement of substation operating headroom, regular condition monitoring of infrastructure and their operation, and efforts to ensure adequate staff allocation and reallocation as needed.

To deliver this, it is important that the right regulatory arrangements are in place to ensure that the distribution networks have the framework to facilitate adapt its assets to a changing climate. There also needs to be measures in place to ensure that the right adaptions are being made.

All of these actions should align with the need for greater substation capacity as a result of greater electrification and the expected increased number of connections. Greater understanding of potential conflicts between the need for adaption and network buildout is needed. Energy UK is working with industry and Government to better understand what challenges may emerge namely through the work under DEFRA's Adaption Round 4[6] investigation, in collaboration with other bodies across the sector.

5. Are there any other ways in which policy, regulation and governance could be improved to deliver a resilient electricity distribution network fit for net zero?

Introducing elements of a 'bottom-up' adaptive approach to both RIIO-ED3 price control and the RESPs will help provide a more optimal environment for localised, innovative solutions to ensuring the distribution network can be made ready as soon as possible for a decarbonised energy system while meeting the needs of consumers.

Technologies and solutions

6. What solutions could be used to provide additional capacity without new network investment? Does the current price control do enough to encourage non-network solutions? Please provide evidence of their real world or potential impact on avoided network investment.

Various flexibility solutions at the regional and local distribution level have shown the potential to help avoid significant amounts of reinforcement needed to the network. All of these solutions, alongside the necessary network reinforcement itself, must be applied if GB is to deliver the most cost-effective net-zero energy system for consumers.

Flexible technologies in robust competitive markets

[6] DEFRA, Consultation o the Fourth Round of the Climate Adaptation Reporting Power

Analysis conducted by Carbon Trust, in cooperation with Imperial College London[7] indicated that flexible solutions like Demand Side Response (DSR), energy storage, and interconnection can deliver net savings of £16.7bn per year in 2050, 13% lower than if there were no flexibility. Of this, around £2bn of savings come from the decreased investment in network infrastructure to cope with higher peaks in demand.

As a case study, UK Power Networks (UKPN) removed more than £400m of network investment from its 2023-28 business plan on the basis that it could manage these constraints using flexibility[8]. Without flexibility, it would need to use this money on network reinforcements to accommodate additional demand.

Locational markets for flexibility across GB are taking time to emerge, as the price signals and investment signals are slow to develop. Intended reforms across energy markets, network charging arrangements, and the SSEP, must be fully coordinated to ensure that the right technologies, in the right places, are able to play into multiple markets to best meet the needs of the system.

The Local Constraint Market operating North of the B6 boundary, delivers real benefits, reducing the need for constraints payments at the transmission level. Further regionalised measures of this nature will doubtless limit the need for future reinforcement. Such measures could similarly reduce reinforcement needs at the distribution level.

Increasing the liquidity of these regional markets will require the markets to be more accessible with lower transaction costs. Whilst efforts to engage all relevant distribution connection assets are important, aggregated domestic assets will be particularly key. In some part of the network, these will be the only assets readily able to respond and, unless consumer assets such as electric vehicle chargers can be incentivised to support the network, they will act as ‘parasitic loads’ driving congestion and increasing the need for network spend.

The key remedy for this is to ensure customers are sufficiently incentivised to participate in flexibility actions. Progress on accessible and coordinated markets will be key to this. The value of any flexible action, even with a larger load such as an EV is low. To provide a customer proposition with enough revenue to outweigh the inconvenience and loss of control for the customer, the FSP will need to work across markets to optimise the number of events/ markets that the customer can participate in, seek out the highest paying and then amalgamate the revenues.

Energy UK has noted that the Locational Constraints Market arrangements at present disadvantage suppliers by undermining the business case for time-shifting demand - suppliers cover the cost of imbalance caused without additional revenue from higher consumption - and undermining value derived for the system.

The Demand Flexibility Service (DFS) has shown great potential in reducing system constraints and in engaging customers in system balancing but remains an out-of-market service. Participants - energy customers - are not being compensated fairly for grid support

[7] Carbon Trust, Flexibility in GB

[8] Alex Howard, ‘UKPN's top tips for participating in DSO flexibility competitions’

when compared to the value across the system, particularly when compared to other resources eligible for multiple revenue streams. If customers cannot fully realise the benefit of their flexibility, then the DFS and wider flexibility will not reach its full potential. The Government should explore aligning DFS with other flexibility markets, enabling participants to stack revenues across markets and increasing in-market balancing services. Other measures could include allowing payments for both turn-up as well as turn-down within DFS and clarifying dispatch signals, so they are aligned to wider system needs.

Other, more notable barriers members have mentioned include the ESO being able to directly procure flexibility services at lower rates than Distribution System Operators (DSOs), pushing them out of the market, and the inability for Demand Flexibility Service (DFS) to be stacked with other DSO services.

Indeed, there has been limited progress on allowing DFS to be stacked with other services and this issue is now hampering the further deepening of these market – as became clear last winter with the second iteration of the DFS. The DFS is an exclusive market and requires FSPs to not participate in other flex markets for a 3-month period. As it is more lucrative on a per event basis (£3,000/MWh – before competitive auctions), it pulled volumes away from both the new Local Constraint Market and DNO markets, leaving these markets struggling. Work to progress coordinating markets in this area should now be an urgent focus of both the ESO and Ofgem. Energy UK welcomes Ofgem work to establish a common digital infrastructure and a new market facilitator role in this space but the success of these will partially depend on the agreements between the network operators that underlie them.

Standardisation of flexibility markets

A key barrier to distributed flexibility was the absence of common digital infrastructure to enable the market, especially market action across distribution networks. This was the key point made in the Energy UK response to Ofgem's 2023 Call for Input on Distributed Flexibility[9]. The lack of standardisation in flexibility markets at the DNO-level presents a notable barrier to the ability of DNOs to procure flexibility. Whilst the volumes of flexibility tendered have climbed year on year, DNOs have consistently struggled to procure the flexibility that they have assessed to be cost-effective. In 2022-3, for example, DNOs tendered for 3.7 GW of flexibility but only ended up procuring under 2 GW.

An increased focus on standardisation across data standards, products, contracts and pre-qualification process would reduce the transaction costs of entering these markets. Whilst not complete, there has been some move towards standardisation in DNO markets facilitated by intervention from Ofgem and its support of the Energy Networks Association's (ENA's) Open Networks programme (which coordinates work but cannot require adherence). However, it is not clear what the current progress on the Open Networks programme is and further clarity on this would be welcome.

Network Price Controls

[9] Energy UK, Response to Ofgem's Call for Input on Distributed Flexibility

The GB market is one of the few commercial DNO markets tendering significant volumes in Europe. This is primarily down to Ofgem's total expenditure (TOTEX) approach to price control which has encouraged cost-effective solutions such as flexibility services. This contrasts with the traditional Capex-based approach which predominates across Europe and incentivises spending on 'pipes and wires'.

The current price control (RIIO-ED2 - 2023-8) includes new measures to encourage non-networks solutions. These include a requirement to submit a DSO plan, a new DSO incentive, reopeners to support additional spend on flexibility markets or digital infrastructure, as well as baseline expectations for DNOs to facilitate efficient dispatch of distribution flexibility services and engage with third-party platform providers.

Whilst these were welcome, more could have been done to prioritise standardisation to drive an outcome of 'one market' rather than six different DNO markets. Facilitating this would mean create minimum standards for DNOs to meet on areas like data visibility.

Incentives in place under RIIO-ED2 can go much further to create sufficient incentives for 'non-wire' based solutions. The price control largely bases its assumptions on the delivery of established network technologies and leaves little room for incentivising innovation that can reduce the need for reinforcement.

The key new lever for ED2 is the DSO incentive which rewards or penalises DNOs (+ 0.4% / -0.2% of RoRE per year) for how effectively they have managed and invested in the network, taking into account flexible alternatives. Nonetheless, given how frequently members have pointed out instances of delay or non-delivery, Energy UK would question how well enforced this penalty is. Ofgem's decision[10] to 'switch off' the three outturn performance metrics formed part of the assessment. The decision was made due to a lack of historic data and too much variability across DNOs. Whilst Energy UK recognises the need for robust metrics, this highlights the key barrier for flexibility service providers (FSPs) engaging in these markets – the lack of standardisation.

Work under the Open Networks project[11] is already investigating how best to facilitate local flexibility options and must work in close collaboration with NESO, in its capacity as Market Facilitator, on removing various barriers. This work has been ongoing for years now and there remain significant issues in the lack of standardisation across data streams, network monitoring, and flexibility services. It may be that the NESO will need to take a more proactive approach to ensure that all DNOs are aligning their approach with the national market and system balancing approach.

Under an Ofgem decision[12], flexible network technologies are distorting the flexibility market by allowing networks to use network assets to participate in competitive markets, particularly Project CLASS technology, pushing other flexibility services out of the market.

Any technology deployed as part of network management should be utilised as part of business as usual, outside of competitive markets. Energy UK has no view on if these

[10] Ofgem, DSO Performance Metrics
[11] ENA, Open Networks
[12] https://www.ofgem.gov.uk/publications/decision-regulatory-treatment-class-balancing-service-riio-ed2-network-price-control

measures to fluctuate voltage or frequency should be applied before or after flexibility services, but there should be clearly defined rules on how and when this technology should be used, and clear incentives to ensure all networks are capable of this active network management if this will aid in maintaining security of supply and reducing outages.

Coordination across price signals

Enabling regionalised constraint management requires ensuring assets are deployed in the right locations across GB, something they are currently insufficient incentivised to do in most locations. The Government must consider the best route to creating the appropriate locational price signals to deploy these technologies, in harmony with the various ongoing workstreams concerning market signals (including REMA, Transmission Network Use of System (TNUoS) charging reform, and the SSEP).

7. What role could digitalisation and data play in supporting efficient management of existing capacity and targeting of investment in new capacity? Are there examples of where the benefits have been realised through trials or examples used in other markets?

Digitisation and data access are essential to enabling cost-effective delivery of investment in both capacity and low carbon technologies. Improving the quality and granularity of data across the system will be a fundamental element of how effective the SSEP / CSNP, and the wider approach to regional price signals, balancing markets and connections processes, can be in incentivising investment.

Network Connections

At present, the issue for those requesting connection at the distribution level is impacted by the lack of clarity over the exact nature of assets installed, including the capacity of local substations and typical energy flows on the network. When customers put out requests for connections, DNOs frequently need to send engineers on site to assess the local substation and wiring in order for the DNO to provide a proposed design and quotation. This process can take several months, and as connection requests become increasingly frequent, there is significant concern that DNOs will not be able to process these requests in a timely fashion if more automation and digitalisation is not adopted.

Nominated spare capacity of a substation compared to its actual spare capacity presents an additional issue. When these substations were put in place, sometimes decades ago, they were placed there with the assumption of a certain level of utilisation, building in expectations of the number of homes built in and area, population growth and other metrics. From this, DNOs calculated a nominated level of capacity use for their substation and thus how much spare capacity there was available for further buildout in the future. However, the level of housebuilding, population growth and other factors impacting capacity are increasingly going beyond those initial metrics. Without accurate data on substation capacity usage, it is difficult for DNOs to assess the actual spare capacity available on the network.

Whole system planning

Greater granular visibility of data across the system, in terms of network assets, what is connected to the network, and the state of the connections queue could go a long way to speeding up connections as well as establishing the actual level of spare capacity available, saving time and money on future grid reinforcement, and giving investment certainty to the private sector that will fund the vast majority of investment towards Net Zero.

Such data will prove essential to using the NESO and RESPs to educate and inform local consumers and developers on the necessary projects in their area. The Department for Energy Security and Net Zero's (DESNZ's) work on the development of a 'digital spine'[13] and the Cabinet Office's work to develop the National Underground Asset Register (NUAR)[14] can help facilitate this. The Government will have to prioritise these workstreams urgently and closely coordinate them given their importance and the current lack of visibility of data at the distribution level.

Wider considerations

The increasing level of interdependence between digital and energy infrastructure requires better coordination of the approach. Firstly, connectivity will be fundamental to the ability for consumers to install and effectively utilise smart controlled devices. Ensuring that the UK has an effective and comprehensive digital infrastructure will have a knock-on impact for the ability to use DSR in the delivery of more cost-effective system planning and management.

Smart metering also has a role to play as an enabler of a smarter system, and the continued deployment of smart meters must be prioritised in order to realise this potential.

The backlog in connections and challenges with the cost of connections and wider planning considerations also means that datacentres, critical to managing the effective and accelerated modernisation of the energy system and uptake of smart demand-side devices, struggle to connect to the system. This barrier to investment is actively pushing datacentre providers to look elsewhere as the UK falls behind.

Connecting to the distribution network

8. **What barriers or delays are currently being experienced in the process for managing connections to the distribution network? Why do these occur? To what extent are these issues likely to be addressed by the government and Ofgem's Connections Action Plan? Please provide specific examples, differentiating between different users (e.g. domestic and non-domestic demand, distributed generation, etc).**

[13] DESNZ, Digital Spine Feasibility Study

[14] UK Cabinet Office, New digital map of underground pipes and cables on track to grow economy by £5 billion

Energy UK members frequently report that the core cause of delays to connection of distributed assets is all stages of the distribution connection application process, rooted in unclear and unstandardised processes, poor communication between the DNO, the customer and other third parties, and a lack of access to information at the distribution level.

Standardisation

There is no standardised process for new grid connections across DNOs to support the installation of a number of assets, for example EV charging infrastructure. When installing infrastructure across the country, developers are having to complete different forms, pay different fees, are subject to different timescales, and do not always have the ability to make bulk applications to deploy a network of chargers across the GB or even to the same DNO.

During pre-application, the lack of data available to the DNO regarding existing assets in the area where the customer is applying to connect prevents simple identification of which sites may have the capacity headroom needed. Where applicants were able to access this information, there was no common timeframe for receiving it. Customers are also sometimes charged for requesting and receiving information but with no consistency across DNOs.

There is no publicly available common form across DNOs for the 'connect and notify' process, and there are variations in the required information for each DNO. This leads to duplication in some places and an overarching lack of clarity on what exact information is required when connecting demand-side assets. This is exacerbated by the fact that even within individual DNOs – with the exception of UKPN – there is no form for multiple applications by the same customer. Even once the application is completed, members report long delays to DNOs responding to these notifications, and in some cases no response at all is given.

Concerningly, despite a rule change by Ofgem from April 2023 obligating DNOs to cover the cost of reinforcement works associated with EV charge points, some in the industry have reported that DNOs have continued to attempt to charge customers for the full extension and reinforcement works, only reneging when reminded that the secondary legislation had indeed changed. Indeed, developers of other technologies have reported receiving a reduced cost offer from DNOs upon revising their plans and challenging the DNO offer.

The process of challenging an incorrect offer is resulting in a breakdown in trust while also causing additional delays to connection processes, and additional costs for those not intricately familiar with DNO processes and responsibilities.

Delays to processes

Long delays in receiving a quotation and design proposal from the DNO following a connection application continue, and are expected to become, worse as the connections queue at transmission level pushes more developers to connect elsewhere. Initial quotes for any required works are only currently valid for six months, so could expire before connecting customers even begin their works, with the obligation then falling on the connecting party to re-initiate the process.

Once DNO works commence, these frequently take longer than the illustrated timeframes indicated by DNOs and there is no real maximum timeframe for completion. Delays are often

blamed on the absence of service level agreements that DNOs are expected to fulfil as part of their Ofgem obligations, however further information on exactly which agreements are absent is lacking.

One member, RWE, has provided the following case study to illustrate this point:

RWE was looking to connect 49.9 MW of solar energy with 10 MW of battery storage to the distribution network. Initially, the DNO suggested that Q3 2024 would be a viable commercial operation date (COD). The developer requested that survey works start in October 2022. Survey works were repeatedly delayed; scheduled survey dates were missed with no communication. In February 2023, the developer was informed that the connection date had been pushed back to Q4 2024, and this was subsequently amended again to Q1 2026. This amounts to a doubling of the timescale initially proposed by the DNO. After escalating the issues and raising concerns about insufficient communication / information, the date was brought forward again to Q2 2025 – raising questions regarding the justification behind the Q1 2026 date.

The current voluntary process for wayleaves and easements related to barriers inherent in the planning system continue to pose a barrier. DNOs frequently exacerbate this problem, as wayleave officers within DNO's legal departments have been reportedly difficult to reach and unforthcoming with information when requested by those seeking connection. Further, DNOs may sometimes negotiate a separate easement with the landowner without informing the customer. There have been reports from some members of legal teams working on securing land rights being restricted with no coordination or notice given to the connecting customer.

The NIC review should analyse the reasons given for delays and where these could be addressed by simplification or standardisation ahead of wider significant reforms.

Lack of staffing and resources

Connections are frequently being delayed because DNO connection teams are under-resourced and key non-contestable activities[15] do not happen on time. If the DNO makes a mistake or fails to do something, developers have no recourse. The only meaningful obligation DNOs face is a requirement to provide connection offers within a specified period. This creates a distortion by incentivising the DNO to divert scarce resources to get offers out on time.

Connections reform impacts on Distribution

As it stands, the work to date on the CAP has not done enough to alleviate issues with the distribution level connection queue. There is a serious question as to whether DNOs are being sufficiently incentivised to bring measures to manage their queue forward in line with CAP.

The CAP principally focuses on improving the visibility of distribution capacity, understanding the interactions between transmission and distribution capacity and advancing the connection of embedded generation at the distribution level. While work is progressing, there

[15] 'Non-contestable activities' are activities that must be delivered by the relevant DNO and cannot be carried out by an Independent Connection Provider (ICP).

remain significant barriers, namely difficulty in understanding the interaction of forecasting future capacity while the other connection reform processes remain incomplete. Forecasting capacity will remain difficult until further clarity on the specifics of the 'Gate 2' queue criteria is established, and until much more clarity on the state of the distribution network is delivered.

Most developers of generation projects connecting at distribution level have experienced issues with DNOs failing to submit Project Progression[16] requests for transmission capacity to the ESO in a timely manner. One member, Centrica, reported one solar farm developer said its average delay in Project Progression submission across 6 projects was 24 months. Centrica itself has been experiencing delays closer to 8 months, but this still has a significant impact on the overall project timeline.

Under the ESO's proposals for transmission reform, Project Progression will be replaced by new arrangements, but these will include new time-dependent steps where developers are reliant on DNOs engaging with the ESO on their behalf.

Ofgem has a live action under the CAP (number 3.5d) to "undertake an end-to-end review of the incentives, obligations and requirements, relating to transmission and distribution connections". They are due to consult with industry and publish their findings this summer before proposing needed policies. This is a key deliverable, and it is important that due attention is given to embedded generation connections at the distribution level.

All these issues appear at least partly rooted in the lack of easily accessible data available to DNOs, a lack of standardised processes, and understaffing in their departments related to connecting customers and reaching legal settlements. These compound misaligned incentives for DNOs leading to delays, cost overruns and uncertainty. Without addressing this challenge, as more customers seek connection in the coming years, there is significant potential for the above-mentioned issues to escalate.

9. How does transmission network capacity cause delays in connecting to the distribution network and what is the scale of the challenge? How far are these issues addressed by transmission network policy, particularly the government's Transmission Acceleration Action Plan? Please provide examples, where possible.

The transmission connection queue now stands at over 700 GW. While work on CAP is progressing and the TMO4+ proposals are welcome, much work is still to be done. In the meantime, the queue will continue to grow and there remain a number of outstanding concerns that could delay or even undermine work to restructure the connection queue.

Whole system coordination

[16] 'Project Progression' refers to the formal request that a DNO makes for transmission capacity on behalf of distributed generation projects that require transmission reinforcement. The date-stamp when the ESO receives the Project Progression determines it's place in the transmission queue.

Further transparency is required regarding coordination of connections reform and changes including but not limited to the SSEP and CSNP, REMA, Energy Code reform, planning reforms and Network Charging reforms. Policy and regulatory clarity must be delivered as early as possible to minimise the risk of legal challenge and give investment confidence.

While the ESO's recent *Beyond 2030*[17] publication provides welcome proposals on how the future SSEP may enable capacity through connecting offshore wind, it remains to be seen how the SSEP and later CSNP will address capacity constraints originating from other areas of the grid, including at the distribution level. It is also unclear how and when the public, communities, and regional and local authorities will be engaged on the process of building new infrastructure across GB, with a clear need for more work to improve public acceptance and give clarity of where new works will be required.

Pace of change

Energy UK welcomes the intention to vastly accelerate the connection timelines and reduce the delays seen to firm connection dates. It is unclear how much of an impact this process is having at this stage at Transmission level, let alone at the broadly less transparent distribution level.

It is concerning to see a heavy reliance thus far on non-firm connections, with a lack of clearly defined limitations and guardrails to ensure that these offers do not simply result in an increase in avoidable risks for connecting parties and a more strained energy system. Clear timelines for when a connection becomes firm and how much reliance on firm connections is deemed acceptable before network reinforcement is mandated would be welcome to ensure non-firm connections do not become the standard. There is also need for greater clarity around the nature of a non-firm connection – not just for how many hours per year it will be curtailed, but when. A solar farm facing 1000 hours of over-night curtailment will be significantly less affected than the same solar farm facing 500 hours of curtailment over summer between 11am and 3pm. DNOs are not currently required to inform customers when their curtailments are likely to occur. Until this issue is addressed, development of the connections to the network will face uncertainty.

10. How could processes requiring contact with, or work from, the distribution network operators be improved? Is there a case for more standardisation of processes between network operators to improve the customer experience and, if so, where would standardisation be most beneficial?

Many of the issues with DNO processes would be addressed with greater standardisation of a common, regulated process for grid connections and customer communications across the DNOs. The significant variation in the experience of installing infrastructure across differing regions presents a risk that connecting customers might be encouraged to delay the process in specific locations, thereby delivering disparities in infrastructure requirements across

[17] ESO, Beyond 2030 A national blueprint for a decarbonised electricity system in Great Britain

different DNO areas. This in of itself may lead to a postcode lottery should existing processes continue, with some areas receiving low carbon technology and associated benefits sooner than others. The long-term economic and political ramifications of this could be significant.

Standardisation

Standardisation to address this should take place at each stage of the application process:

a. Pre-application: Each DNO should be able to present customers with a standard mechanism for accessing information on existing grid capacity through and address-based online portal.
b. Application: Each DNO should have a common application form covering grid upgrades easily accessible on DNO websites in addition to other associated parties like the ENA.
c. Quotation and design: quotations should be standardised and should have a standard fee, or at the least a standard system of itemising costs for quotes. Quotes must be subject to an extension request beyond the existing 6-month window.

At the same time, like UKPN, all DNOs should allow a standard process to facilitate multiple, coordinated bids at once.

All timelines agreed between the DNOs and customers must be subject to the DNO's license conditions and overseen by Ofgem. Obligations should be placed on DNOs spread out along the connections journey, such as minimum time periods to:

a. hold a first formal 'kick-off' meeting after offer acceptance to discuss the plan of work.
b. appoint a project manager and designer to each large project over a MW threshold.
c. submit requests/evidence to the ESO where a project needs transmission capacity.

These particular reforms are especially important for ensuring incentives for DNOs are sufficiently incentivised to progress connections and keep connecting customers informed.

The common forms and processes to facilitate this should be led by the ENA in collaboration with DNOs. DESNZ and the Cabinet Office must coordinate and advance work on improving data visibility at the distribution level in collaboration with industry experts. In line with this, the ENA can then develop standards for displaying distribution grid-level capacity data online for DNOs. Ofgem and DESNZ must hold the ENA and DNOs to account for delivery to prevent delays to implementation of common approaches seen to date.

At the same time, Ofgem should review DNO Guaranteed Standards of Performance (GSoPs) to incorporate existing connections and create required response times at each stage of the grid connection process. This would allow businesses to know when to expect information on the cost and process for installing power and to seek alternatives where upgrades are too costly or too complex. Where such standards are missed, enforcement action should be considered.

Ofgem could also work to establish clear processes for DNOs to consider where upgrades by businesses in similar locations could be coordinated to reduce costs and delays. There

has been work to explore the approach to connecting multiple parties in one area and spreading the costs across parties to address all costs applying to those last to connect to a specific area. This work has not been transparent and it must be a core function of the RESP to set out where demand and supply in any given area justifies a more significant upgrade, particularly where this will impact on business users' ability to meet their own emission reduction obligations.

Customer satisfaction

The RIIO-ED2 Major Connections Customer Satisfaction Survey (MCCSS) measures customer's satisfaction in relation to pre-application, quotations, and final connection. This fails to capture the period after offer acceptance and before final connection, where 80% of the work and also 80% of the problems occur. Ofgem could address this by requiring DNOs to survey their customers every 6 months, instead of just post-offer and post-connection.

11. What best practice examples exist of network operators improving processes and information for customers looking to connect to the network (either for demand or generation purposes)?

There are emerging areas of good practice by some DNOs. For example, UKPN has created a site planning tool through their Optimise Prime[18] project which allows fleet to estimate the capacity of their sites using their online live map and database of substation data. Not only is the project itself a welcome approach, utilising data and digitalisation to amplify the ability of flexibility providers to deliver services, the process to develop the project brought in a wide range of stakeholders from across the sector particularly effectively.

UKPN also has a separate form for enquiring about existing grid capacity (known as a "nature of supply" request) which facilitates business accurately knowing how much capacity is available on their site, depot or at branches. This should be adopted across the other DNOs.

SP Energy Networks is currently developing an online tool[19] for customers to see where the electricity network has the capacity to support installations and provide cost estimates for this, as part of their Charge project.

Scottish and Southern Electricity Networks (SSEN) has also recently launched their Local Energy Net Zero Accelerator (LENZA)[20] which is designed to inform local authorities looking to plot the future development of the distribution network in their area.

Similarly, of all the DNOs, SSEN has shown good performance in maintaining clear guidelines for escalating disputes between the DNO and connecting customers. Establishing

[18] UKPN, Optimise Prime
[19] Charge - SP Energy Networks
[20] LENZA - SSEN

clear escalation routes for all connecting customers will be critical to effectively holding DNOs to account for delivery.

All of these solutions need to be better standardised and the information better distributed to that lessons learned and best practice can feed into the RESP and SSEP processes once they are formed.