Victoria Low, Head of DSO Governance
10 South Colonnade, Canary Wharf,
London
E14 4PU

Chris Harris, Regulation Manager
Inveralmond House, 200 Dunkeld Road,
Perth
PH1 3AQ

06 June 2022

Dear Victoria,

Scottish and Southern Electricity Networks (SSEN) Distribution response to Ofgem's 'Call for Input: Future of local energy institutions and governance' ("Call for Input"), dated 26 April 2022.

Scottish Hydro Electric Power Distribution (SHEPD) and Southern Electric Power Distribution (SEPD) response to the Call for Input. For avoidance of doubt Scottish Hydro Electric Transmission (SHET) have responded separately.

World leading energy system change already being driven today

1. The energy system is changing rapidly as we pursue legally binding net zero targets. Decarbonisation of the generation mix and electrification of demand from heating and transport, with the growth of Distributed Energy Resources (DERs) are causing the decentralisation of the supply mix to smaller scale facilities, and digitalisation is enabling new technologies. Simultaneously there continues to be strong public, regulatory and political focus on overall energy prices in context of the current cost of living crisis. In short, the way we use, manage, and even think about energy is changing every day.

2. Great Britain has been world leading in facilitating a smart and fair energy transition. Through strong performance based regulatory mechanisms and commitment of Distribution Network Operators (DNOs) over 30GW of DER has already been deployed onto the system. In just four years DNOs have gone from using 116MW (2018) of this to help manage local grid constraint issues to using 1.6GW in 2021[1] (1280% increase!), and a further 2.9GW was put out to tender by DNOs in 2021 alone, despite the COVID-19 challenges.

3. At SSEN we have a proven track record in fulfilling the Distribution System Operation (DSO) functions which are critical to the transition through a learning by doing approach, which enables us to be ambitious, credible, and efficient. In RIIO-ED1 we have saved consumers over £60m through flexible connections and made important strides in increasing wider system optimisation through our Project Local Energy Oxfordshire (LEO) which is increasing broader market competition and local participation opportunities. Our RIIO-ED2 DSO Strategy enables over £460m of value through flexibility services and flexible connections over the five years 2023-28. We recently complemented this with our DSO Action Plan which highlights the outcomes and opportunities we will enable, and the steps we are taking and engagement we are committed to in being fully transparent in our decision making.

[1] 1609 MW of contracted flexibility up to 30 July 2021. Data source: ON21-WS1A-Flexibility s 2021 Full Update (30 Jul 2021)

We are at a critical juncture

4. We welcome the opportunity to respond to Ofgem's Call for Input which comes at a critical juncture for our sector and for society. The scale and speed of the transition will rapidly accelerate in the next five years and it is important we enable a smart and fair transition which is whole system in nature and reduces total costs to consumers. The Call for Input raises several important points in the strategic case for change, many of which we agree with Ofgem on. However, the Call for Input is very light on evidence in many of the points made, and on some points wrong.

   The work of the next five years will predominantly focus on extending system coordination to lower voltages (e.g. 11kV and below) to enable the huge value potential from electric vehicles and heat pumps; a challenge of significantly greater magnitude than higher distribution voltages. With the significant expected volume and widespread coverage of these technologies, all parts of our lower voltage network will be potentially impacted, compared to only localised constrained areas for higher voltage levels seen to date. Our view, which we expand on in our response to question four in the Call for Input, see Appendix A, is that there are five critical barriers we need to overcome:

   i. **The potential for a lack of agile regulatory allowances and incentives –** we have set out a clear DSO Strategy for RIIO-ED2. As market liquidity grows and market scope extends to lower voltages and closer to real time trading, there will be a need to continually maintain and scale investment in the underlying systems and capabilities, including monitoring devices, and OT/IT. This is crucial to enable technologies based on consumer demand side response to participate. We need an agile regulatory framework which keeps pace with the scale and pace of investment required, especially in IT/OT and cyber for DSO.

   ii. **Potential for significant policy uncertainty on institutional arrangements and fragmentation which undermines confidence and ability to achieve net zero –** whilst we welcome this Call for Input we are acutely aware that without policy certainty DNOs will struggle to focus full attention on physically delivering net zero infrastructure, which is the highest priority to reaching 2045 and 2050 targets. Policy certainty is also critical for investors and private financiers across the sector. We need to avoid significant policy uncertainty which has the potential to slow or distract from the main task at hand.

   iii. **Limited capacity and capability of local authorities to engage and lack of democratically appointed local energy and transport strategic coordinators –** there is a clear need for a role beyond that undertaken by DNOs or the Electricity System Operator (ESO) to provide cross vector coordination at a local level. This is a gap we clearly identified in our RIIO-ED2 business planning process and we proposed a Consumer Value Proposition (CVP) to help address. As set out in Appendix A and our proposal for a new Local Net Zero Coordinator, (cf "A way forward", below) we regard the limited capability and capacity of local authorities as the key issue to address and believe effort and resource is needed urgently to overcome.

   iv. **Limited and/or conflicting incentives on the wider value chain participants (e.g., not price control regulated entities) to coordinate on the achievement of common goals –** securing fully committed engagement from aggregators and suppliers on DSO activities can be challenging. More needs to be done to align on goals and principles with the energy networks. We also need to address the potentially distorting behaviour from some participants. DNOs have an important role in enabling markets, but liquidity is ultimately driven by the wider value chain participants engaging. There are examples of larger generation developers incentivised through participation in national markets creating constraints on the local electricity network, whilst not participating in local flexibility markets to alleviate constraints they are partially responsible for creating, especially in areas where diversity of local market participants is low. This could be because participation undermines project needs cases or for revenue maximation reasons. Either way more needs to be done to investigate and resolve these issues at a policy level to ensure full market participation and connections provide net benefits to consumers when all points of the system are examined.

v. **Clarity on Whole System roles and accountabilities in enabling net zero** – this Call for Input makes a good first step in the need to find a way through the sometimes-confusing accountabilities for enabling and delivering different energy system functions. However, much more needs to be done to provide clarity especially in whole system planning and market development. There are no clear accountabilities across energy and transport at a national or local level, for example.

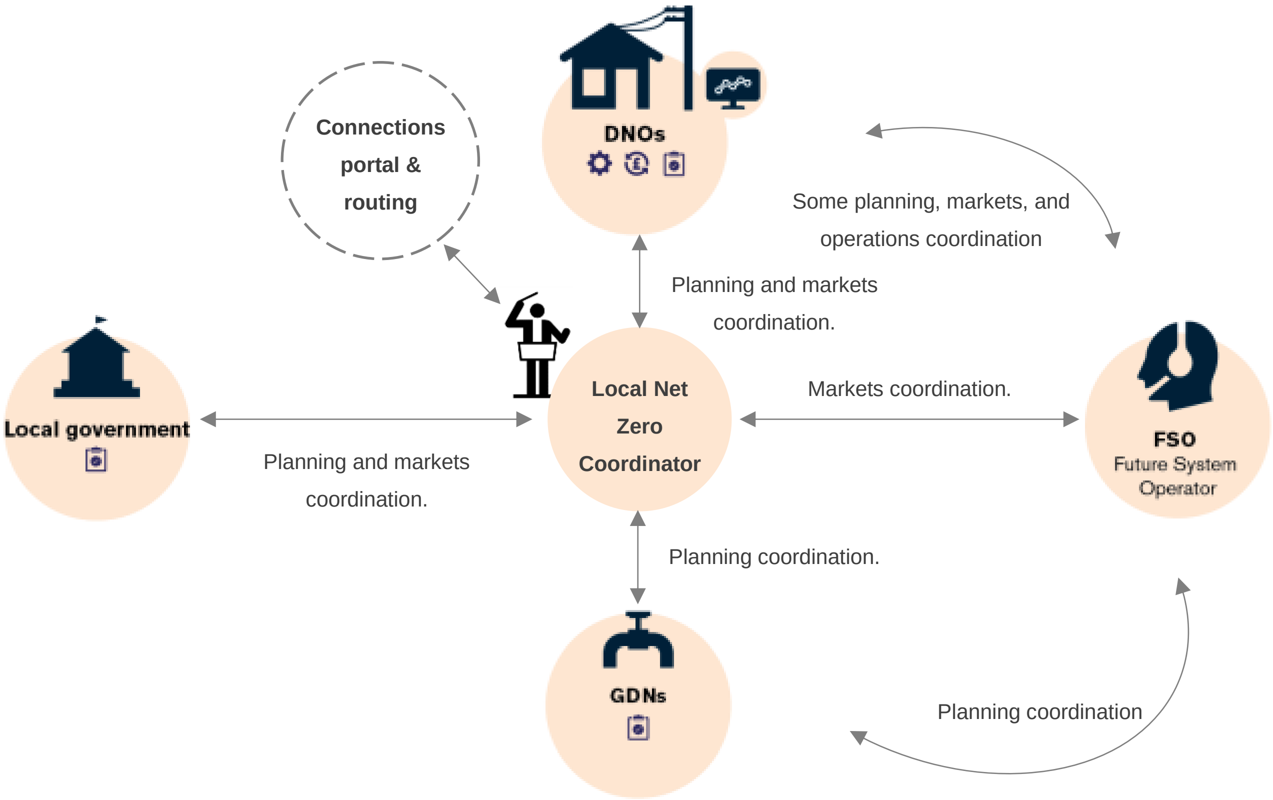
A way forward

5. Enabling net zero at lowest costs to consumers both today and tomorrow requires our stakeholders to trust the decisions we take as a DSO; it also requires industry collectively to coordinate together to overcome challenges and blockers. This means it is important we evolve the model we have today in a balanced and efficient way which protects consumers from excessive cost and lost synergies. We understand potential concerns around managing perceived conflicts of interest through the integration of DNO and DSO functions, which is why we recently commissioned NERA Economics to undertake an empirical assessment of some future DSO governance models and publish this online.

6. We have asked NERA to update their modelling to account for some of the thinking in the Call for Input and we include a draft copy of their updated work with this letter. Whilst limitations on model assumptions in the Call for Input prevented a full quantification of the costs of separation by NERA at this stage, what is clear is that potential benefits of separation are still unlikely to be more than 1- 2% of DNOs' avoidable expenditure as stated by NERA in their original report. The results produced by NERA suggest that the costs of separation above ring-fencing (or internal separation of DSO within DNOs as defined in the Call for Input) would be unlikely to be justified. Forms of separation above ring-fencing would require in the region of 4.2% efficiency benefits, which are significantly unlikely to occur. Further, any form of separation would remove the TotEx Incentive Mechanism which is an important mitigant against DNOs favouring wires-based solutions over flexibility.

7. Regardless it is vitally important we continue to consider the barriers to the realisation of effective energy system planning and operation at sub-national level. This requires industry collectively to coordinate together. This means it is important we evolve the current arrangements in a balanced and sensible way. In the figure below we propose a suggested new model. In our response to question 11, see Appendix A, we have set out more detail on how we think this could work, and we would be pleased to work with Ofgem on developing the detail. This is a variation on framework model one in the Call for Input, and it leverages key features from other models. We believe this to be a model which address the key barriers, retains accountability for network

capacity and security with the DNOs but importantly is simpler to implement and retains the synergies in the DNO/DSO relationship. It does not negate the need to keep institutional and governance frameworks under review as market liquidity grows, but it does address several of the key issues we find today. In our RIIO-ED2 Business Plan we proposed a comprehensive and well calibrated DSO financial incentive proposal, and since publication we have been working with Ofgem's working group on DSO incentives to iterate the required key performance indicators on DSO needed for RIIO-ED2. We think the metrics and incentive could be a good tool for monitoring how institutional arrangements are working, providing the crucial data needed to make a more informed assessment later about whether we need to go further.



8. In Appendix A to this letter we provide specific responses to the Call for Input questions. We look forward to working with Ofgem constructively through any subsequent statutory consultation and impact assessment that may follow. Our response is non-confidential and in the interest of transparency, we are also proactively making our response available on SSEN's website. Thank you for taking time to consider our response and please feel free to contact me to discuss any aspect.

Yours sincerely,

Chris Harris
Regulation Manager

Appendix A

Strategic energy context

1. **Are the three energy system functions we outline (energy system planning, market facilitation of flexible resources and real time operation of local energy networks) the ones we should be focusing on to address the energy system changes we outline?**

We agree that these three energy system functions, plus digitalisation as an enabling function are the right energy system functions to focus on at a high-level. These functions are broadly consistent with the three DSO roles defined in the RIIO-ED2 Busines Plan Guidance, and SSEN's Business Plan submission is consistent with this. However, while the functions are acceptable at a high-level, the next layer of detail in terms of definition, scope and interactions is unclear especially given the broader context of the Call for Input. For example, there is no description for how these functions would be applicable to gas networks or where accountability would sit in exceptional events, such as extreme weather.

At a minimum we believe it is necessary to be broader in the definition of these functions, so that they are fully consistent with RIIO-ED2 baseline expectations on DSOs, the need to incorporate other vectors, and broader stakeholder expectations. Therefore, we suggest:

- **Energy system planning** becomes **Whole system planning and optimisation**: There are two crucial forms of optimisation required, which should be reflected in the title: (1) The vital role required of DSOs in wider system optimisation to increase broader market competition and opportunities for local participation in power markets. It is critical DSO enable the DER to provide the right services at the right time. The impacts of wider optimisation must also be reflected in planning decisions and DNOs funded to enable the right digital capabilities and data flows between local and national systems; (2) Optimisation through whole system working across vectors, especially transport. Decarbonisation of transport will be essential to reaching net zero and this presents many well-versed opportunities and challenges for the energy sector at a local level. DSOs have an important coordination role to support the optimisation across vectors.

- **Market facilitation of flexible resources** becomes **Market development and facilitation of flexible resources**: We think the addition of 'development' is necessary to align with the definition of DSO baseline expectations in the RIIO-ED2 Business Plan Guidance. DSOs need to play a role in creating new products and deep coordination of the design of products and market arrangements with the ESO. An example of development is the role the DSOs will need to take on in developing implicit flexibility (e.g. flexibility enabled through dynamic tariffs). The role of suppliers in accurately and fairly reflecting network/ price signals down to customers must also be considered, and likewise the interaction with any proposed market reforms from the ongoing government Review of Electricity Market Arrangements (REMA), such as Locational Marginal Pricing must be accounted for.

2. **Do you agree with the criteria we have set out for assessing the effectiveness of institutional and governance arrangements?**

Partially. The criteria outlined are useful as a starting point, but the list needs to be more specific to the challenges faced at a local level. Ultimately the key criteria any model should be assessed against is ensuring a 'whole-system least cost and most expeditious path to achieving net zero'.

For the qualitative criteria outlined in the Call for Input we recommend it includes the following additions, some of which we adapt from FTI Consulting's original GB System Operator Review for Ofgem (January 2021)[2]:

- **Efficiency** – The extent to which institutional and governance arrangements maximise available synergies in operations, finance, information, and know-how. All future models involve the interaction of multiple stakeholders to deliver net zero at lowest cost to consumers. The prevailing model must be one which maximises the greatest synergies whilst adhering to the constraints applied by other assessment factors.

- **Adaptability** – The enduring arrangement must be resilient and versatile to accommodate continued sector and economic change to the greatest extent possible. Consumers and investors value policy certainty in the net zero transition but recognise the need for evolution of arrangements. However, continued large scale institutional change erodes confidence, creates delays by diverting resources from delivering net zero and increases costs. The prevailing model must be one which promotes seamless adaptation.

- **Ease of implementation** – As Ofgem acknowledge in the Call for Input (Table 1) ease of implementation needs to be considered for all potential framework models. Some models for example are dependent on primary legislation and require new industry codes to define new transactional relationships. Ofgem should bring ease of implementation into the core criteria for assessing institutional and governance arrangements, but in doing so it needs to go further than the narrow question of primary legislation. Ease of implementation must consider the wider set of implementation requirements and costs of alternative governance models, including for example new regulatory framework design, industry codes, procedures, and contracts.

- **Net zero** – In setting the context and strategic imperative for issuing the Call for Input Ofgem are clear that the primary driver is delivery of net zero. Therefore, we think it necessary to have an assessment criteria directly linked to this goal. Any new policy framework model proposed must be assessed relative to its ability to deliver net zero at a local level in the fastest possible time at the lowest possible cost to consumers today and tomorrow.

We also ask that Ofgem makes explicit reference to security of supply in the 'Accountability' criteria. Testing the clarity of roles and responsibilities must include a reasoned assessment on whether consumers are likely to face detriment to the level of service currently experienced on interruptions, exceptional events, and minutes lost because of any change.

Finally, the criteria in the Call for Input appear only qualitative and it will be essential that a robust quantitative impact assessment is undertaken on potential new governance and institutional arrangements. Any quantitative assessment should be grounded in evidence, not based on qualitative judgements around perception of conflicts of interests. The impact assessment should include a clear articulation of the threshold of benefits that would be needed to justify alternative institutional or governance arrangements.

[2] https://www.ofgem.gov.uk/sites/default/files/docs/2021/01/final_-_fti_consulting_-_ofgem_gb_so_review_2021-01-22_0.pdf

Strategic case for change

3. **Do you agree with our assessment of how far the current institutional arrangements are, or are not, well suited to deliver the three key energy system functions?**

Ofgem's RIIO framework is seen globally as a world-leading performance-based regulatory mechanism. It has led to several world leading initiatives and implementations, all while maintaining very high service and quality of supply. These have been partially co-ordinated by ENA's Open Networks projects, which provide consistent and consolidated strategies for rolling out flexibility. Over 30GW of DER has already been deployed nationwide; and the industry has implemented the world's largest local flexibility markets, with 2.9GW being put out to tender by DNOs in 2021 alone. Under current arrangements, we have been able to deliver these functions and activities with incremental change rather than large scale institutional reform.

In the Call for Input Ofgem articulate several perceived challenges with the current institutional arrangements in delivering the three key energy system functions. We agree with some of Ofgem's assessment of challenges but disagree with others. In many cases there is clear evidence to the contrary of Ofgem's perceived challenges.

- **Energy system planning**: Ofgem broadly define the challenges as: (i) competence - skills gaps in local authorities; (ii) credibility - perceived conflicts of interest in decision making by DNOs; (iii) accountabilities and coordination - limited democratic accountability for strategic whole system coordination on large scale net zero delivery.

  We agree with (i) and (iii) in the round. Significant progress has been made by DNOs working with local authorities and devolved government to standardise approaches to coordinate local energy planning. Our RIIO-ED2 Business Plan is a case in point and is fully aligned with Ofgem's baseline expectations. The Local Area Energy Plans (LAEPs), which SSEN have in place in several regions are a good example of this. There are however limits to the capacity and capability of local authorities to engage, coupled with a lack of democratically appointed local energy and transport strategic coordinators to fulfil a role which goes beyond that of DNO/DSOs or the ESO. Many local authorities have a high willingness to engage with the energy transition, but there is no consistency in aspiration level or financial backing to implement. We often find a common barrier exists in that capacity and capabilities of local authorities to participate in detailed examination of need in their regions is limited. We believe that coordination and cooperation across electricity and gas networks, as well as Local Authorities and all other players in the energy sector, will be fundamental to achieving Net Zero. As recognised in the Smart Systems and Flexibility Plan, coordination across markets will be critical to operating an efficient zero carbon system.

  We disagree with (ii). It is correct to say that DNOs face choices between wire-based solutions and DERs; and there is a perceived risk DNOs favour solutions they own and deliver. However, Ofgem have offered no substantive evidence of a conflict of interest through this Call for Input or any previous publication. The design of the price control framework also provides important mitigations on any incentive for DNOs to favour their own solutions. Importantly the use of TotEx incentives provides a crucial mitigant to any DNO incentive to favour asset solutions over DERs. As NERA point out in their Assessment of Alternative DSO Governance models:

"*The TIM treats all categories of totex in the same way, so that if a DNO spends £1 above its target, it bears the same share of this additional £1 of expenditure irrespective of the cost category in which it is incurred. It achieves this by applying a common sharing factor to all categories of costs, and a fixed capitalisation rate, such that the same proportion of DNOs' expenditure enters the RAV, irrespective of the actual ratio between operating and capital costs. The TIM therefore seeks to remove any incentive to favour capital over operational expenses, or to favour DNO-provided solutions over flexibility contracts.*

Indeed, within the control period, DNOs may have an excessive incentive to deliver flexibility solutions over capital solutions. For example:

- *Consider the case of an increase in demand that the DNO can accommodate either with a £100 capex investment lasting 40 years or with a £10/year 5-year flexibility contract.*
- *Evaluating the two options with a very simplistic approach, the capex solution would imply annual costs of £5.83 and the flexibility service of £10.*
- *While this capex solution may be preferrable (least-cost) in the long term if the demand increase is permanent, within the price control the DNO is incentivised to choose the flexibility contract. Using flexibility allows the DNO to make £50 of savings in the current control period and retain part of these savings through the TIM".*

In addition to the TIM consumers are also protected by other regulatory mechanisms and policies which help ensure DNOs maximise flexibility. These include a "Flexibility First" approach commitment by all DNOs in December 2018; the cost assessment and benchmarking process in the RIIO business planning process; and the introduction of the Common Evaluation Methodology tool across all DNOs to allow for an objective evaluation of the choice between flexibility investments and network wire- based solutions.

Flexibility is crucial to enabling the delivery of the local system capacity required for net zero. The demands for capacity are expected to grow exponentially and DNOs will simply, not be able to build network at a fast-enough rate to meet capacity requirements. Flexible market-based resources are therefore a crucial incentive to enabling the transition at scale and pace.

- **Market facilitation of flexible resources**: Ofgem define three perceived challenges: (i) credibility – DSOs may not have sufficient capacity and capability to operate flexibility markets with high liquidity and may have perceived conflicts of interest; (ii) coordination – potential for misaligned incentives between DSO and ESO; and (iii) simplicity – existing arrangements are not easy to navigate for market participants.

  We disagree with Ofgem's assessment on (i) DSO capacity and capability. Our ability to enable flexibility markets is linked to the funding made available to do this. However, we can only enable, and growing flexibility market participation requires wider energy actors to engage and be aligned in principles. We have seen in some areas a lack of willingness to engage in these markets. Therefore, we need broader incentivisation on market participants through government policy. Additionally, we consider it likely that any transfer of responsibility to run local flexibility markets to a new entity (e.g. the ESO) would incur a steeper capability acquisition process and greater costs to consumers to upskill and upscale. The ESO has very limited prior experience of distribution voltage and local specific factors in each region.

On point (ii) specifically the ESO and DNOs, through their DSO capabilities, are working closely to coordinate markets. We believe Ofgem's statement in para 3.18 within the Call for Input, that the DSOs and ESO may have misaligned incentives, whilst representative of a potential future challenge negates to mention that such a challenge will only occur because of a failure of regulatory design on the part of Ofgem. In so far as there are strong complementary incentives, including licence conditions on system operators then consumers should expect to see efficient outcomes from coordination on market design. Moreover, the Call for Input fails to consider existing regulatory mechanisms and ongoing activity including Whole Electricity System licence conditions which came into effect in 2021 which includes a requirement to publish a coordination register.

Even if Ofgem were to conclude that DSOs and ESO may still not have sufficient incentives to coordinate under the current regulatory arrangements and therefore hinder the efficient development and deployment of flexibility services, resorting to the separation of the DSO to address this coordination challenge may lead to added coordination challenges which could be more costly to customers. For instance, whilst the amalgamation of the DSO function within the ESO may solve some of the coordination challenges between local and national markets, it would cause other losses of synergies between the DNO/DSO:

  - Each of the fourteen DNOs would still need to provide detailed information to the ESO regarding their flexibility needs at the local level which, as flexibility markets grow over the coming years, may require a constant and exponentially growing number of requests and interactions between the DNOs and ESO, especially as flexibility needs move down voltage levels.

  - The separation of the DNO and DSO functions would make it more challenging and costly for DNOs to efficiently trade-off asset vs. flexibility solution when assessing their network needs as they would need to interact and coordinate with the ESO. Any delays in information sharing or lack of coordination in the procurement process of flexibility resources by the ESO for DNOs may prevent DNOs from making efficient least-cost decisions and result in additional costs to customers.

- **Real time operation of local energy networks**: Ofgem define three perceived challenges: (i) competence – DNOs will require significant investment in skills and resources to integrate complex software systems of multiple parties (e.g. aggregators); (ii) Credibility – DNOs could be conflicted in performing efficient dispatch; and (iii) Coordination – risk of inefficient or conflicting market signals from the ESO and DSOs.

  We agree with (i). We are already in the process of building our workforce capabilities, as outlined in our RIIO-ED2 plan, and this will be supported by targeted necessary investment in IT capabilities. Ofgem must ensure that sufficient investment is allowed by DNOs to do this and the regulatory framework is an enabler of agility. On (ii) and (iii) as with our comments on 'Energy system planning' and 'Market facilitation of flexible resources' we believe the issue here will only arise because of a failure of regulation and licence requirements rather than a failure of institutional arrangements.

Across all three-energy system functions we would challenge the point on DNOs hindering market facilitation, growth, and liquidity – DNOs have built the world's largest local flexibility markets in effectively four years. We are not resting on our laurels. We know that more needs to be done and recognise that markets will become closer to real-time. We believe that these are natural, iterative steps from where we are now, and we are already building and learning about real-time markets for example through our innovation projects LEO and Transition.

4. **Overall, what do you consider the biggest blocker to the realisation of effective energy system planning and operation at sub-national level?**

We are extensively developing our capabilities as a DSO to further unlock the significant value potential at a local level. To date the greatest need for coordination has been on the higher voltages of distribution grids (e.g. 33kV and above) where because of the penetration of DER the resultant local network constraint impacts have been greatest. Extending system coordination to lower voltages (e.g. 11kV and below) to enable the huge potential value from technologies like vehicle-to-grid is a challenge of significantly greater magnitude than higher distribution voltages. With the significant expected volume and widespread coverage of electric vehicles, all parts of our lower voltage network will be potentially impacted, compared to only localised constrained areas for higher voltage levels. Similar challenges will also be true for heat electrification. To scale our ability to deliver system coordination the biggest potential barriers we could face include:

- **The potential for a lack of agile regulatory allowances and incentives** – critically this will be required for the common digital capabilities needed across DNOs to enable coordination and optimisation as a DSO. Regulatory funding must keep pace with the required updates to critical systems we will need to install and the associated monitoring and communication infrastructure across our lower voltage network. We currently apply for allowance approval on five yearly cycles with some limited provision to adjust allowances within regulatory periods. The potential barriers we could face are: (a) Ofgem sets insufficient allowances to deliver prescribed outputs; and (b) allowance renewal windows do not keep pace with the rapidly evolving requirements, especially cyber security requirements.

- **Continued policy uncertainty on institutional arrangements and potential fragmentation of DSO governance arrangements** – review processes like this Call for Input are welcome, but bring the potential for prolonged policy uncertainty, potentially lengthy transition periods, and possible fragmentation of critical institutions. Significant time and resources are increasingly being devoted to this DSO question already. Whilst the policy debate persists, and including any transition periods to new arrangements, there could be a substantial interference with achieving whole system coordination and net zero targets; and this could result in higher transition costs and delays. Should the construct of institutional arrangements change in the future, greater fragmentation of critical institutions are likely to present a significant barrier to system coordination during any transition.

- **Limited capacity and capability of local authorities to engage and lack of democratically appointed local energy and transport strategic coordinators** – as mentioned in our response to question three, significant progress has been made by DNOs working with local authorities and devolved government to develop standardised approaches to coordinate local energy planning. Our RIIO-ED2 Business Plan is a case in point and is fully aligned with Ofgem's baseline expectations; and the Local Area Energy Plans (LAEPs), which SSEN have in place across several of our regions is a good example of this. There are however limits to the capacity and capability of local authorities to engage, coupled with a lack of democratically appointed local energy and transport strategic coordinators to fulfil a role which goes beyond that of DNO/DSOs. Many local authorities have a high willingness to engage with the energy transition, but there is no consistency in aspiration level or financial backing to implement. We often find a common barrier exists in that capacity and capabilities of local authorities to participate in detailed examination of need in their areas is limited. From time-to-time this barrier can be exacerbated by a lack of understanding on roles and responsibilities within local authorities and limited clarity on 'who pays' for infrastructure upgrades.

- **Limited and/or conflicting incentives on the wider value chain participants (e.g., not price control regulated entities) to coordinate on the achievement of common goals** – greater system coordination can only be enabled through participation across the full value chain aligned with common goals and principles. Whilst there are significant requirements, and supporting incentives, on DNO/DSOs and the ESO to play a full enabling role by virtue of regulatory frameworks, there is risk that goals and principles do not extend to other participants (e.g., aggregators and suppliers) or are conflicting with those on DNO/DSOs and the ESO. There are examples of larger generation developers incentivised through participation in national markets creating constraints on the local electricity network, whilst not participating in local flexibility markets to alleviate constraints they are partially responsible for creating. This could be because participation undermines project needs cases or for revenue maximation reasons. More needs to be done to investigate and resolve these issues at a policy level to ensure connections provide net benefits to consumers when all points of the system are examined. Another example of uncoordinated common goals is that there is no standard for energy data that is easily accessible and understandable to local planning authorities. ENA is working with members on a National Energy System Map (NESM[3]) which will help, but we need the rest of the energy industry to step-up as well.

- **Clarity on Whole System roles and accountabilities in enabling net zero** – this Call for Input makes a good first step in the need to find a way through the sometimes-confusing accountabilities for enabling and delivering different energy system functions. However, much more needs to be done to provide clarity especially in whole system planning and market development.

5. Do you agree with the opportunities of change we outline and the potential benefits they may create?

We infer this question relates to whether we agree with the functional synergies (described in paragraph 3.27) that need to be maximised regardless of the design of enduring institutional and governance arrangements. We would not define these as 'opportunities of change' because Ofgem have not provided evidence that these functional synergies are not being delivered today or cannot be delivered in the future without change to institutional or governance arrangements.

Setting the definition aside we agree with the functional synergies described in paragraph 3.27, albeit defined at a very high- level, and their benefits are those that need to be maximised; but we note that these are all functional synergies we are delivering today and are striving to continue to maximise within the current institutional and governance framework. There are strong incentives and licence conditions in place today to drive these functional synergies and we believe there are other options to unlock the full value from these synergies that will deliver greater consumer benefits in the context of net zero transition other than full reform of institutional and governance arrangements suggested by this Call for Input.

6. Are there additional opportunities for change and benefits that we have not set out?

Synergies in planning with other whole system vectors, such as transport, have not been outlined and are important to capture as areas for maximisation. It is critical a whole system approach is taken to planning and synergies are

[3] https://www.energynetworks.org/newsroom/new-digital-energy-system-map-shows-the-power-potential-of-energy-digitalisation

maximised with the deployment of electric vehicle charge points and heat electrification. Further, synergies across energy system vectors (e.g. electricity and gas) need to be called out more clearly.

7. **We set out a number of risks associated with change. Do you agree with these risks and the potential costs they create? Are there additional risks of change and costs that have not been set out?**

Any changes to institutional or governance arrangements entails significant costs, including one-off and on-going costs, as well as losses of synergies from operating the DNO and DSO separately. Further the significant difficulties including time and resources required both for companies and the regulator, would also interfere with achieving net zero. We agree with Ofgem's high-level listing of some of the risks of change identified in the Call for Input, including: impacts on delivery of net zero, the impacts of significant change potentially required through industry (e.g., introduction of new codes), one- off and ongoing cost implications of change, and the loss of operational synergies.

In recent work we commissioned from NERA Economic Consulting some of these one-off and on-going costs are quantified and discussed in greater detail. They also identity and provide substantive evidence for the potential loss of synergies from separation of the DSO and DNO which would be occurred to varying extents in any of the framework models. Below we highlight some of the most important conclusions reached by NERA which we think Ofgem should consider carefully as next steps to the Call for Input:

"*Economic theory suggests that the benefits of vertical integration are more efficient coordination between different parts of the value chain, the avoidance of transaction costs, avoidance of duplicated overheads. These benefits are greater especially when the contracting involves highly complex activities, may be infrequent, involves durable and large assets or services, involves large degrees of uncertainty over the value of assets or services, and where that value is difficult to verify by the contracting party.[4] Based on the economic theory therefore separation of a vertically integrated company would therefore result in incremental costs associated with increased coordination requirement, duplication of overheads and overall losses of vertical synergies. These costs are likely to vary depending on the level of functional and business separation of the chosen DSO governance model, and, …, tend to increase with stronger and deeper levels of separation between the DSO and DNO functions*".

In Table 1 below we summaries the key categories of costs associated with separation of institutional and governance arrangements. A full description is available within the NERA report.

Table 1: Summary of potential losses of synergies (source: NERA)

Loss of Synergy	Description
Loss of cost synergy (economies of scope)	• Duplication of overheads and shared costs from creating vertically separated DNO and DSO entities.
Loss of operational synergies	• Vertical integration allows operational synergies in delivering the services required by customers from the DNO and DSO functions. Separation results in increased costs of coordination and creates "transaction costs" when the DNO and DSO need to interact. • Also, because the requirements the DNO and DSO may have for services from each other may be complicated to codify, there may be a

[4] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 33.

		problem known in the economics literature as "imperfect contracting", resulting in DNOs and DSOs interacting less than would be economically efficient, and the services they provide to each other not always being conducive to minimising their combined costs and maximising service quality for network users.
Loss of informational synergies	•	Similar to the loss of operational synergies, separating the DNO and DSO functions may reduce information exchange between the two entities. This could increase costs and reduce service quality if some parts of the business face costs or delays in obtaining the information they need. For example, control room operation, market development and planning functions may need to regularly exchange information to ensure security of supply.
Loss of other, less tangible, synergies	•	Vertical integration allows a firm to use its resources flexibly, e.g., allowing staff to move flexibly between DSO and DNO functions depending on business need. This would become more difficult / costly under the more strictly separated governance models.
Financial synergies	•	An integrated entity is likely to benefit from lower financing costs, given its larger size and potential risk from having a diversified set of activities. Financing costs could increase under the more strictly separated governance models of ownership unbundling.

Ofgem are correct to point out in the Call for Input (para. 3.29 - 3.30) that there are significant differences between transmission and distribution level reform which introduces different risks. NERA note these key differences present risks at distribution such as the potential for lack of coordination and misalignment of incentives negatively impacting reliability and security of supply:

"Under the current regulatory framework, DNOs have a responsibility for achieving security of supply targets through a range of different regulatory mechanisms. First, DNOs must adhere to minimum standards of performance outlined in their licences. They have to achieve the required restoration times required under Engineering Recommendation P2/7, have obligations regarding Guaranteed Standards of Performance, and commit to maintain and improve asset health as a "secondary deliverable" under the RIIO price control.

In addition to these obligations that contribute to security of supply, DNOs are also held responsible for network reliability through security of supply standards and the Interruptions Incentive Scheme (IIS) that rewards (or penalises) DNOs for not meeting target levels of performances for unplanned and planned Customer Interruptions (CIs) and Customer Minutes Lost (CMLs).

The combination of these mechanisms ensures DNOs have a balance of incentives and obligations that protect the security and reliability of supply provided to customers. Hence separation of the DSO requires that these responsibilities be assigned to:

- *The DSO which would be responsible for network planning and procuring network and non-network solutions for network expansion and maintenance; and/or*
- *The DNO, which would still be responsible for delivering and implementing those plans, would retain operational responsibility for restoring service after faults arise, and may retain some degree of discretion and autonomy in the decision-making around specific investment decisions.*

In practice, therefore, both the DNO and DSO could be responsible for ensuring reliability and security of supply, depending on the allocation of responsibilities between them. This creates a risk that responsibilities for maintaining security of supply will "fall between the gaps" of the roles defined for the separated entities. Indeed, as noted by Burger et al (2019):

> *"The DNO would then be responsible for implementing IDSO network expansion and maintenance plans, although the IDSO may not have the legal authority to force a legally distinct DNO to make any specified investment. The DNO will retain some autonomy in determining how to implement network plans. Neither the IDSO nor DNO would be solely responsible for ensuring reliability, which creates a "moral hazard in teams" problem; that is, both parties have an incentive to free ride off of the other party's efforts to ensure reliability"*[5]

To make some practical examples:

- *Under a separated model in which the DSO is responsible for network planning, it is likely that the security of supply standard (P2/7) would need to become an obligation on the DSO, as the DNO would not be able to choose itself whether to comply with it because it would not take planning decisions. For instance, National Grid ESO is required by its licence, to plan, develop and operate the National Electricity Transmission System (NETS) in accordance with the Security and Quality of Supply Standard (SQSS). However, whether the system actually delivers the required levels of network capacity following the planning decisions taken by the ESO to adhere to the planning standards would be determined by the DNO's ability to deliver investments. If the ESO's understanding or knowledge about the time required to deliver certain upgrades to the network are wrong, or there are delays or inaccuracies in the communications between DNO and DSO, the network upgrades may not be delivered at the time or for the cost expected by the ESO when taking planning decisions.*
- *Under a separated model, the current IIS mechanism that rewards/penalises DNOs for changes in CIs/CMLs may need to be revised. Depending on the responsibilities allocated to the DNO and DSO businesses, DNOs would almost certainly retain responsibility for at least some activities that affect CI/CML performance, such as maintenance policies and emergency fault restoration capacity, while the DSO would also influence CIs/CMLs through longer-term planning decisions. Hence, both parties would be exposed to each other's decisions if they are both incentivised to improve interruption performance. This risks a "moral hazard" problem that would reduce service quality for customers, described above by Berger (2019), and potentially increases costs because each party could – depending on the redesign of the IIS – be exposed to the performance of the other.*

These practical examples of "transaction costs" may cause higher costs for consumers, delays in connections and/or security of supply problems. Such higher costs may arise both in a business-as-usual operating mode, but the same costs could increase exponentially under extreme event conditions (e.g., storms) where the clear identification and attribution of responsibilities is essential to ensure reliability of the network and security of supply for customers. It follows that business separation may result in a deterioration in the level of network security and reliability because of the challenges in defining responsibilities between the DNO and DSO, the potential moral hazard problems, and the costs and delays entailed in the interactions between the separated businesses."

NERA go on to note that coordination challenges may arise at the transmission level too, but would be far more significant in distribution systems:

"It is possible that coordination problems exist at the interface between the TO and the ESO. As Ofgem noted in the ESO legal separation impact assessment, under the joint ownership model, the SO is an integrated part of National Grid. As a result, National Grid (as a TO) has an incentive to make decisions that help reduce constraint and other

[5] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 41.

operational costs incurred by the SO. However, legal separation of the ESO from the TO will impair such an incentive.[6]

While there are challenges in the interface between TOs and the ESO, the transmission system is considerably simpler than the distribution networks:

- *While transmission systems comprise a relatively small number of large assets, distribution systems are considerably more complex, as they comprise many more assets of a lower value.*
- *As such, information availability is likely to be lower, e.g., DNOs themselves may not have full information about the nature and performance of their assets, as they are small (e.g., LV), potentially very old and often located underground. Hence, DNOs sometimes have to make planning decisions flexibly and pragmatically, and it would be more challenging to align such decisions between separated DNO and DSO businesses.*

As a demonstration of this, the number of interventions in the network is also much larger:

- *DNOs all interact with the network much more frequently than TOs. We estimate from the 2020/21 RRP data that the 14 DNOs have added 531,067 assets per year to their networks since the start of the ED1 period.*[7] *However, the number of interactions with the network increases exponentially as the voltage level of the network reduces. At the 132kV voltage levels, the DNOs together have added 2,424 asset units per year over ED1, as compared 8,449 asset units per year in the EHV network, 55,597 asset units per year in the HV network and 464,598 asset units per year in the LV network. The number of asset additions for LV are orders of magnitude higher than in the EHV or 132kV networks. Taking the 132kV network as a proxy for the transmission system, this shows that the DNOs interact far more frequently with their networks than the TOs.*[8]
- *The 14 DNOs have also repaired 170,411 faults per year in total over the ED1 period to date.*[9] *The ED1 RRPs also illustrate how the number of faults falls at higher voltage levels. At the 132 kV voltage levels, the DNOs have dealt with 474 faults per year over ED1, as compared to 3,106 faults per year in the EHV network, 32,583 faults per year in the HV network and 134,249 faults per year in the LV network. Each of these incidents requires DNOs to make planning decisions in operational time horizons, e.g. on choices between repairs and replacement, and it would not be practical (i.e. prohibitively costly) to consult an independent DSO on this choice. The average number of faults are orders of magnitude higher at LV and HV than at EHV and 132kV, therefore, it is reasonable to believe the DNOs need to take many more planning decisions than the TOs.*
- *Similarly, we estimate that the DNOs manage over 29 million connections and provide around 78,000 new connections each year.*[10] *This number of new connections is considerably higher than the number of connections to the transmission system.*
- *The complexity of – and need for flexibility in – DNOs' planning decisions would also be significantly greater in case of unexcepted and exceptional events which require almost real-time and very fast response times by the operational DNO/DSO teams. For instance, severe winter storms require DNOs to respond quickly and pragmatically, in effect taking many planning decisions without prior notice, and all within a matter of hours.*

[6] Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, Appendix 2 – Impact Assessment, para. 1.18.

[7] Data source: 2020/21 DNO RRP data: V1 – Total Asset Movement sheet.

[8] When calculating the total number of asset additions, we add up the number of assets of different types added by the DNOs in over the relevant period. This requires one particular approximation, that each kilometre of cable or overhead line is treated as a single asset. However, given that lines for higher voltage networks are in general longer than lines at lower voltages, we consider the bias will underestimate the asset additions for lower voltage and potentially overestimate the number of interventions in higher voltage systems, so our estimation is conservative.

[9] Data source: 2020/21 DNO RRP data: CV26 – Fault sheet.

[10] As indicated by the ED1 RRP data, over the course of ED1, the total number of customers for the DNOs has increased from 29,142,564 in 2016 to 30,091,839 in 2021, which is equivalent to a 78,162 increase per year. Data source: 2020/21 DNO RRP data: M14 – Driver's sheet.

The complexity of planning and operating a distribution system, as measured by the required number and speed of planning decisions, is therefore orders of magnitude greater than at the transmission level."

NERA go onto note that in principle, new codes or contracts could address coordination challenges, but they are unlikely to be adequate in practice:

"Conceptually, the challenges above from separation and the coordination between DNOs and DSOs could be addressed through the development of new codes, licences or contracts. Such agreements should clearly specify the roles and responsibilities of both parties, ensuring both the DNO and DSO have aligned incentives to ensure reliability, and provide the DNO with prescriptive instructions on what investment decisions it should make when managing and operating its network.

However, such codes, licences or contracts are unlikely to cater for all eventualities. The economics literature characterises these gaps in vertically separated companies' responsibilities as "imperfect contracts", which can cause inefficiency. The number of assets involved and the need to negotiate maintenance, deployment as well as factoring in contingencies to limit liability for failures by the other party mean the contracts would inevitably involve significant costs in negotiating and be incomplete.[11] The contingencies would also lead to haggling and re-negotiation after the fact.[12] When coordination requirements are high, the costs of separation increase due to the challenges that arise with designing contracts that are complete and efficient.[13]

Economic literature suggests that a key benefit of vertical integration is the improved coordination of investments in network infrastructure because it allows [a DNO] to internalise the costs of network externalities. As Meyer (2012a) notes, "only a vertically integrated company takes overall costs into account and therefore internalizes those network externalities by a joint decision-making over-all supply stages".[14] The physical realities of power networks means that network externalities exist,[15] and therefore coordination is needed in infrastructure investments. Bauknecht and Brunekreeft (2008) and Brunekreeft and Ehlers (2006) acknowledge that that the benefits of enhanced coordination of investments in network infrastructure and distributed generation could justify vertical integration.[16]

A benefit of vertical integration between DNOs and DSOs is therefore that planning and operational decisions are all internalised within a single entity, ensuring full accountability of that company for all aspects of the interface. In other words, under a more integrated model, DNOs can make operational decisions based on an assessment of how best to meet customers' needs and deliver the requirements placed on it, considering the incentive regime created by the regulator.

This conclusion is reflected in a more recent discussion of the case for DNO-DSO separation by Burger et al. (2019) which state:

> *"The durable network assets involved would have high degrees of locational specificity (they must be located in the right area), capital specificity (they would have little value outside of the power system), and temporal specificity (they must be available when needed). The IDSO and DNO would negotiate these contracts in*

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[11] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 41.

[12] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 42.

[13] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 42

[14] Meyer, R. (2012a), Vertical Economies and the Costs of Separating Electricity Supply—A Review of Theoretical and Empirical Literature, The Energy Journal, 33(4), p. 167-168.

[15] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 39.

[16] (1) Bauknecht, D. & Brunekreeft, G. (2008), Chapter 13 Distributed Generation and the Regulation of Electricity Networks in Competitive Electricity Markets, [book auth.] Fereidoon P Sioshansi, Competitive Electricity MarketsDesign, Implementation, Performance; and (2) Brunekreeft, G. & Ehlers, E. (2011), Ownership Unbundling of Electricity Distribution Networks and Distributed Generation, Competition and regulation in network industries, 1(1): 63-86

the face of significant uncertainty over load growth, DER penetration, etc. … This lends itself to a high degree of integration between the IDSO and DNO." [17]

The authors conclude that a result of the specificity and uncertainty is that such contracts would inevitably be incomplete, and the cost of negotiating would "dramatically increase transaction costs".[18]

The potential increase in transaction costs from increased coordination requirements has also been acknowledged by BEIS and Ofgem in their recent impact assessment for the creation of an independent FSO. In this context, BEIS/Ofgem cite a prior study conducted by Ofgem regarding evidence that difficulties exist currently between the National Grid ESO and both the Scottish TOs and the OFTO in coordinating and that these "may be significant".[19] *Likewise, in its 2019 response National Grid identified several barriers to the efficient operation of the ESO and TO interface, especially to make whole system decisions in the best interest of consumers, including flaws and shortcomings in the regulatory design and commercial incentives, and the high administrative burden.*[20]

Separation at the distribution level would be more difficult than at the transmission level, due to the greater number of assets and coordination requirements across the network. Distribution networks are significantly more complex than transmission systems, both making it harder to regulate and harder to design appropriate and complete contracts in the form of codes, licenses or agreements.[21] *It follows that vertical integration may the most efficient outcome in the DNO-DSO context both in terms of minimising coordination costs as well as guaranteeing network reliability for customers."*

In para 3.28 of the Call for Input, Ofgem reference "*the urgent need to decarbonise and deliver the net zero transition, time and resource will be a key factor in any decision to proceed with change.*" NERA in their report comment on the risk of change to the delivery of net zero, noting:

"The stated aim of the government at this point in time is for a complete decarbonisation of the electricity grid by 2035.[22] *The steps needed to achieve net zero by the legally binding dates of 2045 in Scotland and 2050 in England and Wales, require both significant investment and coordination among all different levels in the supply chain for electricity. Distribution and transmission operators will have to accommodate new sources of generation, and the increased role of renewables and flexible energy sources. As noted by the government, the models used for operating distribution networks "need to be updated" which will require coordination across "the regulator, networks, industry and government".*[23] *Therefore, undertaking the significant tasks and challenges associated with separating DNOs and DSOs at the same as pursuing net zero would exacerbate both challenges and potentially put both at risk.*

The exact requirements that will be faced by network operators in order to reach net zero are uncertain. Whilst the pathway to net zero has been outlined by the government, the in-depth detail is still to be determined. However, what is clear is that there will be significant network investment needs to accommodate the shift in electricity generation, and the roles of network operators is expected to shift.

According to the government, to fully decarbonise the power sector and keep pace with increasing demand, a total of public and private investment of between £280 billion and £400 billion is needed.[24] *Specifically reinforcing and*

[17] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 41.

[18] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 41.

[19] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 41.

[20] BEIS (20 July 2021), Impact Assessment: Future of the System Operator, p. 22.

[21] Burger, S. et al. (2019), Restructuring Revisited Part 1: Competition in Electricity Distribution Systems, The Energy Journal, 40(3), p. 40-41.

[22] UK Government Website (7 October 2021), Plans unveiled to decarbonise UK power system by 2035, URL: [Plans unveiled to decarbonise UK power system by 2035 - GOV.UK (www.gov.uk)](). Visited on 9 December 2021.

[23] HM Government (December 2020), Energy White Paper: Powering our net zero Future, p. 85.

[24] HM Government (October 2021), net zero Strategy: Build Back Greener, p. 99.

maintaining electricity transmission and distribution networks will cost between £20 billion and £30 billion by 2037.25 These costs will be passed on to consumers through the allowed revenues by Ofgem.[26] More broad estimates on the investment needed in the power grid to reach net zero by PWC points to an annual investment of £8.9 billion to 2030 being required.[27]

Large investments are needed to deal with both changes in electricity generation and large increases in demand. In order to reduce carbon emissions from other sectors, many industries will have to switch to electric options (such as in transport and heating) leading to increasing demand. The Climate Change Committee, the independent body established to advise the government on climate change, estimates that new demands will mean demand rises by 50 per cent by 2035, and by 100 or 200 per cent by 2050.[28]

This will coincide with a rise in the portion of production from low carbon sources and an increased need for storage. The rise of renewable sources and distributed energy resources needed to decarbonise the grid will lead to a more decentralised grid with the need for increased coordination across the different levels of supply.[29]

NGESO has already published information on how they believe the system will evolve to cope with these challenges, at least in the short term. In their vision for 2025, NGESO discusses the new roles DSOs will have to undertake, with changes to market design in response to distributed energy and a much greater need for coordination with the ESO. This will see significant changes to the role of a DSO and the tasks they have to take on.

As a result, separating DNOs and DSOs at this stage will likely come into conflict with the goal of net zero. The changes needed to achieve net zero are major and present a major evolution for the role of the DSO. Separating DNOs and DSOs would also create difficulties in coordination and come with major costs, with an uncertain upside. These would only add to the difficulties that will be faced in the transition to net zero. Additionally, the costs faced when separating would also be on top of the investment needed to reach net zero, costs which would ultimately be passed onto consumers.

From the perspective of an economic welfare analysis, in which we assume there is no hard limit on resources that can be purchased by ESOs, DNOs and DSOs in the labour and factor input markets, there would be no theoretical reason to assume net zero cannot be achieved under any of the DSO separation models. However, this assumption may not be correct in reality. The government policy objective of achieving net zero will require enormous levels of investment and will absorb a lot of human capital and therefore overall resource constraints, which could put at risk the objective of achieving net zero by the legally binding dates described above, must be considered.

DNO-DSO separation would also require substantial one-off and on-going separation costs and would absorb resources (including staff within the DNO) that could be deployed on other aspects of meeting the net zero challenge. This suggests that business separation would be detrimental to achieving net zero due to the higher costs that would then be required to achieve this goal.

Of course, if it were the case that there were benefits to separation from the avoidance of a material and well-evidenced asset ownership bias, this argument would not hold, as the unnecessary investment resulting from such a bias would also absorb resources. However, no such evidence of inefficiency caused by an asset ownership bias exists. We accept this evidence may become available in the future, at which point Ofgem could reassess the need for separation, but at the moment it does not exist. There are also a number of costs associated with the new interface

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[25] HM Government (October 2021), net zero Strategy: Build Back Greener, p. 99.

[26] HM Government (October 2021), net zero Strategy: Build Back Greener, p. 338.

[27] PWC (November 2020), Unlocking capital for net zero infrastructure, p. 8.

[28] Climate Change Committee (December 2020), The Sixth Carbon Budget, p. 25.

[29] NGESO (2021), Enabling the DSO transition, p. 7.

between the DNO and DSO that we have not considered quantitatively which would reinforce this conclusion. These costs include the costs associated with imperfect contracting, stringent oversight and regulation among other costs which are likely to be significant and cannot be discounted.

Hence, the costs and resource requirement associated with business separation would distract DNOs, Ofgem and others in the industry from other challenges associated with achieving net zero, with no evidence that it would achieve a benefit. Enforcing and managing separation of DNOs and DSOs would place a significant regulatory burden among other costs, and given the benefits are uncertain to materialise, there is limited upside to separation.

There are also risks at the DNO-DSO interface that would result from business separation, that some outputs required by network users would be delivered to a lower quality. For example, neither party being responsible for reliability could result in a less dependable service as neither party is solely accountable for interruptions.

To the extent these outcomes are needed to achieve net zero, delays caused by DNO-DSO interface issues could hamper efforts to decarbonise and could take several years to fully resolve efficiently across industry. The risks from interface issues would be minimal under a ringfencing option, as a single legal entity would be responsible for ensuring the delivery of services required by network users, and in this capacity could be held accountable. This includes in the delivery of new network capacity required to accommodate low carbon technologies onto the distribution network.

Creating a net zero electricity grid requires significant changes and investment at all levels of electricity supply. There are challenges both in terms of the overall resource requirement needed to reach net zero, and the changes specific entities will need to make to deal with the differences of a net zero grid. Regarding DSOs, a net zero grid which is much more decentralised will require a greater degree of coordination with the ESO than is currently the case. The additional challenges coordinating with the DNO would compound this issue if separation were to occur. The other costs involved with separation are also significant and would interfere with the goal of net zero."

Framework model options for enduring arrangements

8. **For each model, we have set out the key assumptions which need to be true for the model to offer the right solution. Which of these assumptions do you agree with?**

Whilst Ofgem have set out some high-level assumptions no qualitative or quantitative impact assessment of the 'right solution' has been undertaken, therefore it is impossible to comment on the veracity of the assumptions in the context of being 'right'. We have elected therefore to re-interpret this question as 'do you agree with the underlying assumptions that need to be true in order for the model to offer a workable solution'?

Generally, the description of the models and the underlying assumptions outlined by Ofgem in the Call for Input are lacking in detail. Additionally, we do not believe the range of models presented is exhaustive and many 'sub-options' are missing. The lack of detail and range of considered model designs hinders the ability to determine whether the underlying assumptions are correct and exhaustive and therefore whether they are 'workable'. At a minimum we have identified 10 assumption areas which have not been defined for any of the models and would need to be defined by Ofgem to judge a model as 'workable':

i. **The degree of functional separation between the DNO and DSO at an activity level needs to be defined for each framework model.** A choice is required as to which of the activities currently performed by the integrated DNO should be allocated to the DSO. In its recent joint consultation document on the ESO, BEIS and Ofgem have noted that they may consider different levels of "functional separation" of the three DSO roles (planning, operation and market facilitation) or even elements within these functions[30]. There are several activity areas such as determining capacity, responsibility for charging and settlement, and managing system security that need to be clearly delineated at an activity level between the DNO and DSO.
ii. **Roles and responsibilities of local government and the ESO need to be defined at an activity level.** Whilst there are some helpful diagrams depicting interfaces with these organisations it is not clear what is being assumed about delineation of accountabilities with organisations such as the ESO and the Regional System Planner. Further clarity must also extend to the role for local government in the consenting and wayleave process; and how the recommendations of the Energy Digitalisation Task Force will be incorporated. Various interfaces already exist, and many are being actively further developed; Ofgem needs to explain its assumed changes to these responsibilities.
iii. **How local government will be financed and resourced to upskill and upscale to interface with new models.** All models assume at a high- level an enhanced role for local government, especially in system planning. Assumptions are therefore required on how enhancements will be enabled, including the interlink with consenting and wayleaves, which must evolve in unison with net zero planning. As we discuss in response to question three, one of the biggest blockers to the realisation of effective energy system planning and operation at sub-national level is a lack of local government resource to work at a detailed needs case level with entities such as the DSO. Assumptions are required here on this to determine a model as workable.
iv. **How national and devolved government will interface into each framework model.** The framework models focus on an enhanced role for local government in local area energy planning, but it is unclear what role is being assumed for national and devolved government (e.g., BEIS, Scottish Government etc.). Whether or not this changes from today must be stated and made clear for the avoidance of doubt.

[30] Ofgem (July 2021), Energy Future System Operator consultation, p. 40.

v. **The extent of new codes and contracts required, including which entities will bear risks and associated costs.** The framework models which create new entities by splitting the role of an existing entity will need to be accompanied by codes which define the accountabilities of the different entities to fulfil the functions of the energy system. Assumptions are required on what codes are required, their administration and the extent of their coverage to judge models as workable. Careful consideration is also required to understand who bears risks for security of supply, capacity development and market delivery and last resort provisions in each of the models and how costs associated with these risks are allocated.

vi. **How system and network charging will work and who will bear one-off costs of change in different models.** Assumptions are required on how money will flow in each framework model and what changes to charges levied onto consumers through network and system charges may be required. Further, an assumption on who bears the one-off costs of separation is required, including the impacts on consumers.

vii. **The role of the regulator in each framework model and any internal changes required within Ofgem to interface at a local level.** It is unclear what role Ofgem would fulfil with each entity in each framework model. Whilst there are passing references to needing new regulatory frameworks it is not clear how the regulator would interface with local government for example and the role for democratic accountability. Moreover, a statement of assumption is required on whether Ofgem believes it has the capacity to regulate effectively across multiple local areas.

viii. **The role and obligations for other energy and transport actors such as aggregators and suppliers in each framework model.** The models are noticeable for the absence of assumptions on how wider energy and transport actors will interface with the model. If Ofgem assumes their roles do not change then this needs to be stated, but at present this is not clear enough to determine the models as workable.

ix. **How existing entities, such as the DNO, would be compensated for any loss of functionality in the event of separation.** Assumptions are required on how valuations would be undertaken and who would bear the costs of compensation (e.g. local or national consumers or via general taxation).

x. **The implementation timeline and sequence of activities to transition to each framework model.** The changes required by some of the framework models will be time and resource intensive, including in some case requiring primary legislation. Assumptions are required on how activities will be sequence and how this will interface with delivery of wider policy and market reforms ongoing to determine if they are workable.

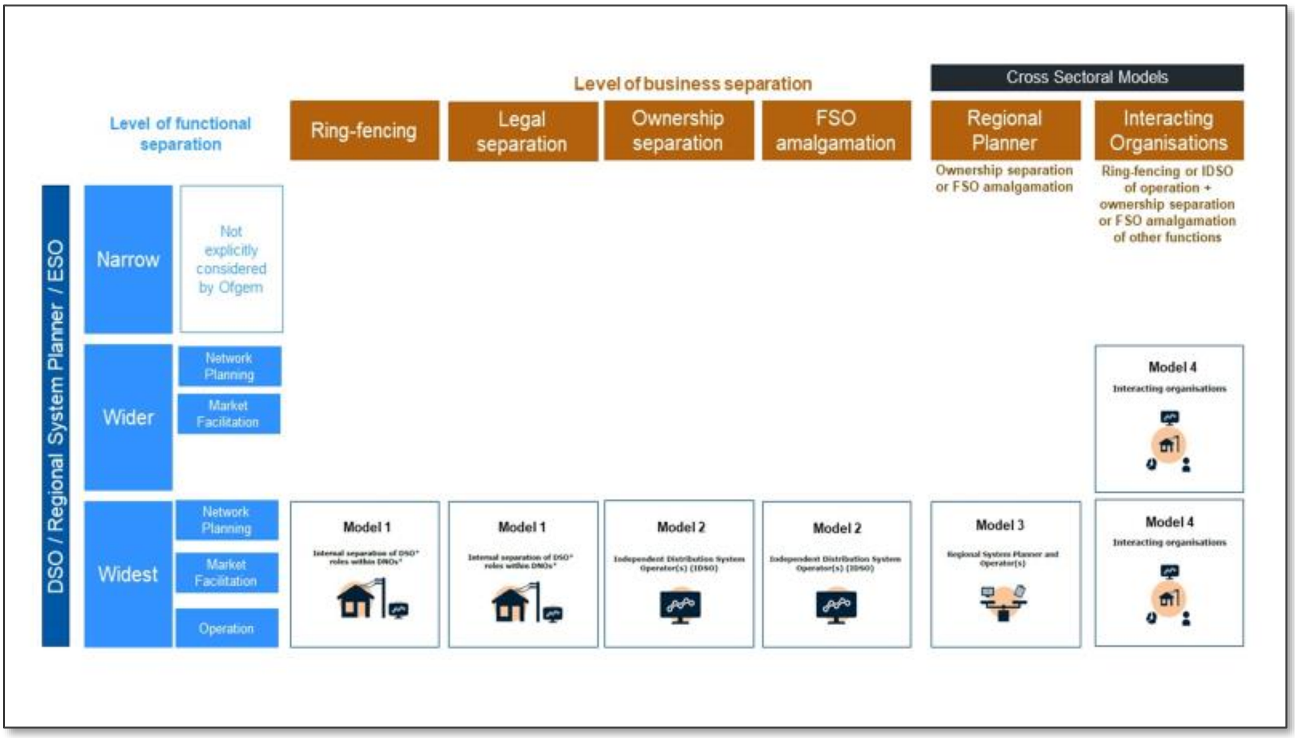
9. **Out of the framework models we have developed which, if any, offer the most advantages compared to the status quo? If you believe there is another, better model please propose it**

There is insufficient detail provided for each model for a credible assessment of benefits compared to the status quo to be performed. To undertake this, a more thorough set of assumptions are required for each model, see response to question eight. A quantitative cost benefit analysis would also be required which outlines the welfare impacts considering the various one-off and on-going costs of change and importantly what threshold of benefits would be needed to justify change. Moreover, it would need to include quantitative transparent evidence provided by Ofgem of failures in the current model that necessitate considering the level of change outlined in models 2-4 in the Call for Input.

In recent work undertaken by NERA, alternative DSO governance models were identified and a top-down assessment of the costs and benefits associated with them undertaken to evaluate their impact on economic welfare. Following the Call for Input release we have asked NERA to update their report with an additional annex including high-level analysis of the framework models suggested by Ofgem and an initial assessment of their welfare effects, where possible. A draft has been included alongside this letter.

NERA in their original analysis examined a range of possible governance models include ring-fencing, legal separation, ownership separation, and even amalgamation with the ESO. As well as considering possible governance models a range of possible definitions of the business activities that could be included within the separated DSO business were also defined (“Narrow”, “Wider” and “Widest”, with the “Widest” exploring the DSO taking on the largest role). Whilst the range of governance models is slightly different to the framework models defined in Ofgem’s Call for Input there is overlap, as defined in figure 1.

Figure 1



In their original study NERA found that the separation costs rise with the degree of functional separation as well as with the level of business separation. Overall, NERA’s analysis shows that, regardless of the degree of DNO-DSO separation, the costs of separation would be substantial, and could be up to around £2.8 billion in Present Value (PV) terms at the GB level. This equates to around £41 (2020/21 prices) for a typical residential customer.

The high costs of separation mean that Ofgem and government would need to make a very clear case that benefits exist before deciding to incur them. While quantitively assessing the costs of separation is possible, estimating the potential benefits from separation is qualitative in nature. NERA therefore estimated the required percentage reduction in avoidable expenditure needed to offset the costs associated with each form of separation. In table 3 below we show the required threshold of benefits required under each DSO governance model at the GB sector level (2020/21 prices) with update values to capture some additional costs for gas (‘Cross sectoral models’) to align partially with the Call for Input models. Full details on the underpinning assumptions and calculations can be found in the attached additional report by NERA to this letter.

Table 2

	DSO Separation Models								Cross Sectoral Models					
	Ring-Fencing		Legal		Ownership		Amalgamation		Ring-Fencing		Legal		Ownership	
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
Narrow	0.5%	1.3%							0.7%	1.5%				
Wider	0.8%	2.0%	4.2%	5.9%	5.5%	7.7%	4.2%	7.8%	0.9%	2.0%	3.2%	4.5%	4.0%	5.8%
Widest	1.0%	2.5%	5.3%	7.3%	6.6%	9.3%	5.1%	9.4%	1.0%	2.3%	3.9%	5.5%	4.8%	6.8%

As noted by NERA in their report the potential benefits of separation are unlikely to be more than 1-2% of DNOs' avoidable expenditure. The results in table 3 suggest that the costs of separation above ring-fencing (or internal separation of DSO within DNOs as defined in the Call for Input) would be unlikely to be justified. Forms of separation above ring-fencing would require in the range of 4.2% efficiency benefits to be justified, which are significantly unlikely.

Enabling net zero at lowest costs requires our stakeholders to trust the decisions we take as a DSO; it also requires industry collectively to coordinate to overcome challenges and blockers, such as those set out in our response to question four. This means it is important we evolve the status quo model in a balanced and sensible way which protects consumers from excessive cost and lost synergies. In our response to question 11 we provide detail on an alternative model we are proposing.

10. What do you consider to be the biggest implementation challenges we should focus on mitigating?

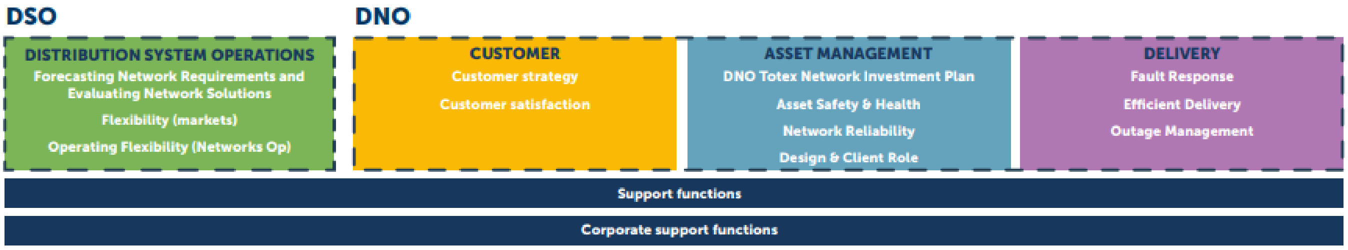
Further to the risks associated with change that we set out in our response to question seven, which need to be mitigated, each of the framework models will incur significant costs, time, and resource to implement. This includes but is not limited to achieving primary legislation to implement some of the framework models. Ofgem will also have to act to mitigate the uncertainty any change brings to the wider industry including reductions in investor confidence in the sector which could arise. Any implementation will also have to be done concurrently with connecting and delivering the infrastructure required to enable net zero. Ofgem need to ensure that they are assessing the motivations and drivers of all key players in the sector including suppliers and aggregators then designing the appropriate incentives and regulation to ensure that the whole supply chain is motivated to deliver their part of the challenge. There is a need for all energy participants to work together in delivering net zero and the institutional arrangements and incentives which enable this most efficiently. Any change to local energy institutional and governance arrangements will also be undertaken whilst there are broader institutional and market design reforms under consideration by Ofgem and BEIS (e.g., Future System Operator and Review of Electricity Market Arrangements).

11. Taking into account the varying degrees of separation of DSO roles from DNOs under framework model 1, do you consider there are additional measures we should consider implementing, in particular in the short term (e.g. changes in accountability etc)?

Enabling net zero at lowest costs today and tomorrow requires our stakeholders to trust the decisions we take as a DSO. Our RIIO-ED2 plan and DSO Action plan are centred on being a neutral market facilitator. We highlight the steps we are taking and engagement we are committed to in being fully transparent in our decision making.

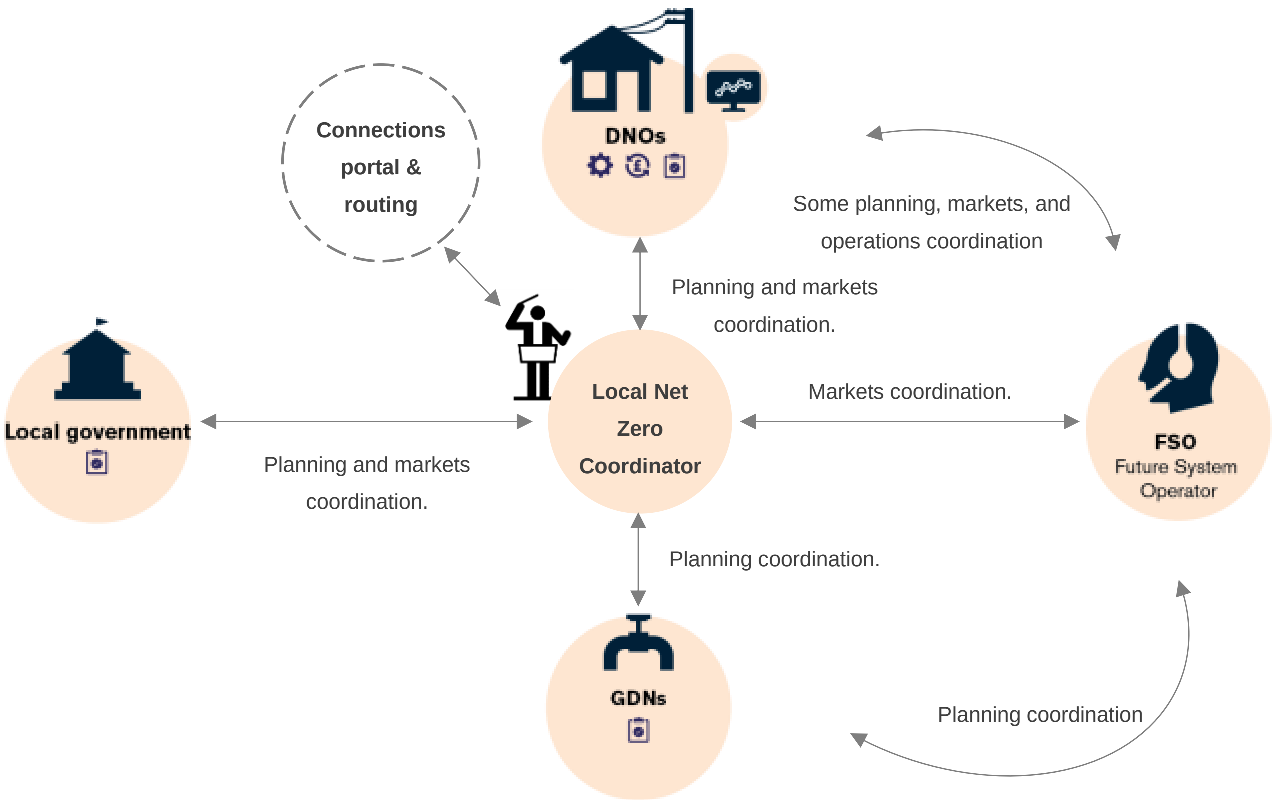
In December 2018 SSEN (and the wider electricity industry) made the 'Flexibility First' commitment to government to openly test the market for provision of flexibility services as an alternative to significant reinforcement and to implement them where they are economically efficient. To ensure that SSEN focusses on delivering smart networks at pace and gives equal consideration to flexible and traditional reinforcement; a separate DSO function was established in 2019 with distinct DSO Director on our Distribution Executive Committee. Figure 2 shows the organisational structure we have implement with the DSO in SSEN. As we go into RIIO-ED2 we are strengthening our measures to manage perceived conflicts of interest and to be transparent in our decision making. Our existing layers of mitigation will be supplemented by audit functions and stakeholder governance board to provide input on evolving requirements and review our progress. We have also identified the opportunity to strengthen conflict mitigation measures by separating out flexibility and traditional network solutions from the team driving the long-term strategy and cost benefit analysis decisions within DSO. This ensures greater independence of strategy and solution choice for provision of capacity from those providing different solution options.

Figure 2



It is vitally important we consider the barriers to the realisation of effective energy system planning and operation at sub-national level as outlined in our response to question four. It requires industry collectively to coordinate to overcome challenges and blockers. This means it is important we evolve the existing frameworks in a balanced and sensible way which protects consumers from excessive cost and lost synergies. Below in figure 3 we propose an alternative model which we have developed through dialogue with NERA. This is a variation on model one, but which leverages key features from other models and focuses on the most critical barriers.

Figure 3



At the heart of this model we are proposing to formalise the process and methodology of the Local Energy Planning (LEP) in Scotland and Local Area Energy Planning (LAEP) in England and Wales, along with the LAEP methodology issued by the Energy System Catapult into a new Local Net Zero Coordinator (LNZC) organisation. These publicly funded not- for- profit bodies could be based on a model like Local Enterprise Partnership regions in England and Wales. They would have accountability for delivering the local net zero plan and change control. They would undertake cross vector coordination in planning and markets, including administering an online connections portal routing service that acts as a standardised route for local market participants on network connections and energy market participation. Importantly as democratic entities overseen by Local Net Zero Commissioners (akin to the Police and Crime Commissioners in England and Wales) they would be accountable for producing local street by street transport and energy plans and scenarios used by DNOs and GDNs, as well as inputting into business plans as a stakeholder, including representation on the Customer Engagement Groups and any DSO incentive stakeholder panels.

DNOs and the ESO would provide a mixture of full and part time seconded resources to support full time LNZC staff on coordination activity and the DSO Director of the local DNO would be appointed as a special advisor to the LNZC board but without voting rights to preserve independence and democratic accountability.

We believe the creation of the LNZC would not prevent to the evolution of institutional arrangements in the future and the one-off and ongoing costs of creating these bodies would not be prohibitive to consumers, if designed appropriately. We would like to engage with Ofgem and industry on a more detailed study on how this could be developed and implemented.

12. **Are there other key changes taking place in the energy sector which we have not identified and should take account of?**

As noted in our response to question ten it will be vital that Ofgem take account of broader institutional and market design reforms under consideration by other parts of Ofgem and BEIS. This includes but is not limited to the Review of Electricity Market Arrangements, reforms to charging, changes to the national planning and consenting regime, and developments in ancillary services markets. Ofgem must also take account of regulatory framework developments related to RIIO-ED2 and Access SCR[31]. For RIIO-ED2 this includes the development of financial incentives on the DSO to promote delivery and exceedance of baseline expectations. Consideration must also be given to changes in national planning regimes beyond DNOs and Ofgem's purview. Ofgem must also be cognisant of new and emerging aggregator and platform models which could have a significant impact on energy market function.

The biggest implementation challenge will be sequencing and harmonising any, and all changes to avoid emergent behaviour outcomes in markets which increase the costs and time for consumers in delivering legally binding net zero targets.

13. **What do you consider to be the most important interactions which should drive our project timelines?**

As noted in our response to questions 10 and 12 it is vital Ofgem take account of broader institutional and market design reforms under consideration by other parts of Ofgem and BEIS. This includes but is not limited to the Review of Electricity Market Arrangements, reforms to charging, changes to the national planning and consenting regime, and developments in ancillary services markets. Ofgem must also take account of regulatory framework developments related to RIIO-ED2 and Access SCR. It is vitally important Ofgem provide a clear view on the sequencing and harmonising of their multiple work streams so that we can be confident of consumer benefits.

If Ofgem choose to further pursue the examination of reform options, then it is critical these are supported by robust quantitative impact assessment, as required under section 5a of the Electricity Act. This must have due regard to different possible future pathways and options to achieving net zero. We are happy to support Ofgem with this.

[31] https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions