

Octopus Energy is one of the largest users of the GB electricity distribution networks (DNOs). We are the largest electricity supplier to GB customers, a leading installer of low carbon technologies and a leading provider of flexibility services to the DNOs. As such, we recognise the importance of the DNOs in enabling the Net Zero transition. The RII0-ED3 price control is crucial to continue delivering the low carbon and tech-enabled power system that will allow us to achieve Net Zero whilst minimising bills for customers.

We return to the following overarching points throughout our response to Ofgem's ED3 framework proposals:

- 1. Flexibility will play a crucial role in the future Net Zero power system and must not be undermined in ED3:** Current wording in the Ofgem ED3 framework consultation risks undermining flexibility markets at distribution level, discarding a potentially huge source of system value that should be used to reduce costs and create optionality for efficient network build out. Instead of turning away from flexibility after the progress made in ED2, Ofgem should focus on designing a robust and scalable set of market incentives for local flexibility. We continue to propose that using a dynamic price signal to reflect local network constraints will make best use of this valuable resource, without creating the 'false economy' that Ofgem is concerned about. Although the RESP methodology is out of scope for this consultation, it is also crucial that Ofgem designs a strong feedback loop between flexibility volumes revealed by the market and RESP planning assumptions, to avoid inefficient use of customer funds on overbuilding network reinforcement.
- 2. A more input driven framework is welcome, given the failure of totex based incentives to deliver investment:** Both transmission and distribution networks have consistently underspent capex allowances. The totex incentive mechanism has allowed them to profit from doing so and there is limited evidence this incentive has driven a corresponding increase in efficiency in how the networks are managed. Ofgem has also responded to information asymmetry by taking a conservative approach to load related capex allowances in ED2. Using the RESP and an input driven framework helps break out of this dynamic. In principle, we therefore agree with Ofgem's

proposals to move towards more specified delivery requirements for network investments as well as reducing spend fungibility across the portfolio. Ofgem should also consider how specifying inputs can reduce risk for the DNOs and therefore help reduce the cost of capital. However, we agree that funds provided to deliver RESP specified inputs should be clawed back and returned to customers if the inputs are not delivered by the DNOs on time.

- 3. More clarity on the RESP is needed, but their proposed role should unlock an expanded role for competition to keep costs down:** Ofgem has positioned the RESP as playing a critical role in determining how large sums of customer money are spent in ED3 and beyond. However, industry currently has little clarity on the content and methodology underpinning RESP plans, including the tRESP that will drive ED3 plans (we are awaiting Ofgem's responses on the RESP consultation from Jul-Oct 2024). Although the exact models will depend on how the RESP defines network needs, competition should be leveraged to ensure these needs are met in the lowest cost way for customers. This could be competition between wires/non-wires solutions at the design and optioneering stage, between DNO/non-DNO asset owners at delivery stage, or simply between contractors via continued use of competitive delivery tenders by the DNOs. All options for increasing competition should remain on the table for ED3.
- 4. Incentives must drive a step change in DSO and customer service performance in ED3:** With load related capex planning effectively 'outsourced' to the RESP, Ofgem should prime a renewed focus on digital, innovation and customer service functions delivered by the DNOs ahead of ED3. Simply rolling over ED2 incentives will not be enough. Many of these functions sit within current DSO divisions and so a strengthened DSO incentive framework is needed. The full 'end to end' review of connections incentives is welcome and Ofgem should consider taking a similarly ambitious approach to network visibility, data transparency and innovation deployment. Faster progress in all of these areas is needed to deliver a low carbon and low cost energy system, which will itself be underpinned by data and digital capabilities.

Consultation question responses:

Drivers for change

Q1. Do you agree with our characterisation of the wider context for ED3? Are there any other areas of context that you consider material for ED3?

Overall, we agree with the overall context set out by Ofgem, particularly regarding the expected rapid uptake of consumer low carbon technologies and distributed generation. We agree that it is critical that the DNOs can meet this demand and process a rapid growth in new connections over the coming decades.

However, it is important not to draw simplistic conclusions about volumes connected and the impact on peak demand and associated network constraints. In reality, the net demand profile impact from low carbon tech and distributed generation is highly uncertain and will be heavily influenced by the incentives and signals provided to operators/owners. Many other factors will compound this uncertainty:

Figure 1 - factors driving uncertainty on LCTs impact on net load profiles (non-exhaustive list)

EVs	<ul style="list-style-type: none">• Availability of public vs at home charging• Travel or transport patterns• Vehicle models and capacities• Vehicle technology (e.g. bidirectional charging, autonomous driving)
Heat pumps	<ul style="list-style-type: none">• Home thermal efficiency• Achieved efficiency of heat pump systems by installers• Customer preferences and usage patterns• Weather and temperature• Government mandates
Distributed solar	<ul style="list-style-type: none">• Planning permission reforms• Level of self consumption vs export• Government incentives• Battery and solar system costs• Code reforms and impact on commercials

In practice, loading ever more reinforcement capex onto customer bills could also promote more self generation and consumption, further spurred on by falling solar and battery prices. In this future, whole or partial grid defection means that reinforcement cost risks becoming stranded and/or recovered regressively from a smaller customer base. We are not claiming this is the most likely outcome, rather than future outcomes are highly uncertain.

The impact on network constraints is made even more uncertain by the lack of visibility/understanding by DNOs on what network capacity is at the lower voltage levels. Although progress has been made, most DNOs are still lacking a complete understanding of headroom at secondary network

levels. This has led to significant variation in estimates of build requirements at DNO level out to 2040/2050¹.

This compounding uncertainty means reliance on any one set of future predictions / scenarios is almost certain to be wrong. For example, FES forecasts of future demand have consistently predicted imminent demand growth for >10 years but demand has continued to fall².

These issues of certainty are crucial to determining what network reinforcement needs to be built and where. In general, we urge Ofgem to acknowledge this uncertainty and the resultant value of 'non-wires' solutions in providing optionality over network reinforcement. Flexible/software/non-wires solutions offer a low-regrets way of managing network capacity as more information on future network demand becomes available. As markets for low carbon tech mature, our collective understanding of load profiles, customer behaviour and network requirements will improve.

Instead of focussing on building more as the ubiquitous solution, RESP, Ofgem and the DNOs should therefore prioritise improving data and visibility, use this to prioritise reinforcements in areas of least regret, and refine assumptions on future demand as markets mature. Optimal use of flexible resources is the key to enabling this approach in practice. Doing so will help make sure we use precious customer funds as efficiently as possible over the long term, an absolute imperative during a time of high customer debt, energy poverty and affordability challenges across GB.

We also strongly recommend Ofgem include greater recognition of the ongoing challenges faced by customers in relation to energy costs and affordability in the ED3 debate. Not only is this a critical issue for social, health and economic welfare³, it is also a major risk to delivery of Net Zero. If real benefits can't be delivered to customers (e.g. through cost, control or convenience), we are concerned that societal support for Net Zero will break down rapidly⁴. The impact of ED3 on customer bills must be given more attention.

Distribution use of system (DUoS) charges have increased from £91.06 in 2015 to £144.9 in 2024. The relative change in standing charge component was even more significant, with a c.450% increase over the same period⁵

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<https://assets.publishing.service.gov.uk/media/6690f4320808eaf43b50ce42/electricity-networks-strategic-framework-appendix-1.pdf>

2 <https://watt-logic.com/2023/07/19/are-the-fes-useful/>

3 <https://www.resolutionfoundation.org/app/uploads/2024/04/Electric-dreams.pdf>

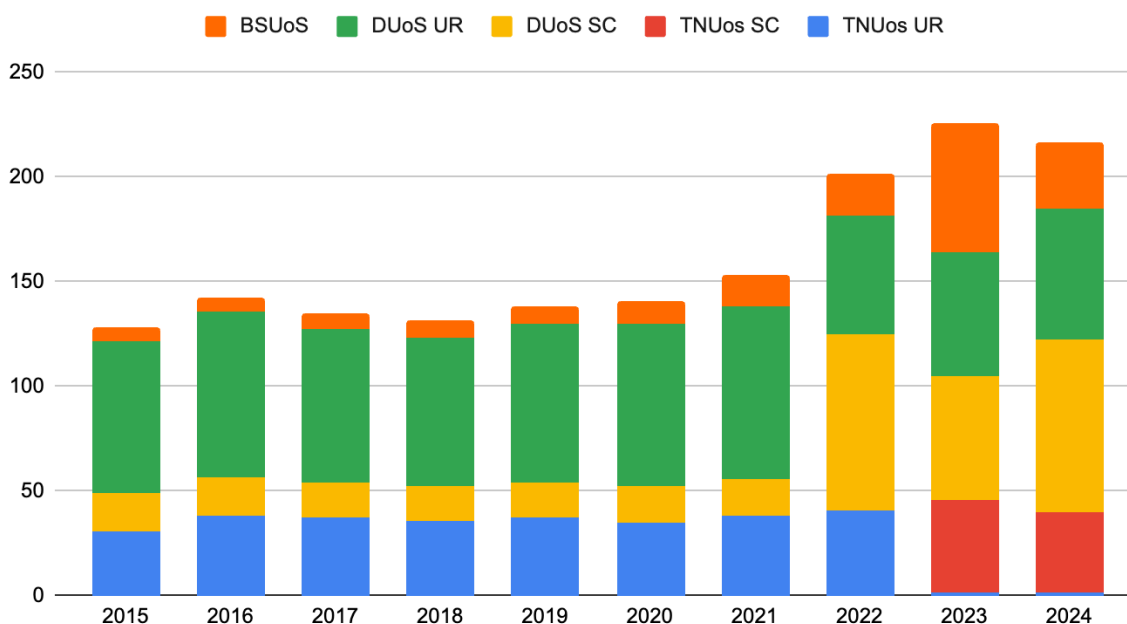
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<https://www.politicshome.com/news/article/rishi-sunak-net-zero-climate-change-u-turn-polling-pollsters>

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<https://www.warmthiswinter.org.uk/news/reforming-energy-standing-charges-could-cut-them-in-half#:~:text=The%20options%20paper%20commissioned%20by%20the%20Warm,Shift%20some%20policy%20costs%20to%20general%20taxation.>

Figure 2 - annual network charges (£) for average household⁵



Given Ofgem's duty to protect consumers and the growing cost of the distribution networks in consumer bills, the lack of any mention of customer affordability in the wider context section is a concerning omission. Ofgem should elevate this concern to being a top priority throughout ED3, as without billpayer benefits there will be no long term Net Zero transition.

ED3 objective and consumer outcomes

Q2. What are your views on our overarching objective and proposed consumer outcomes?

We agree with the overarching objective of enabling decarbonisation goals at least cost. However, it is not clear what the caveat 'based on whole system value' is referring to, as the term whole system can be used to refer to transmission/distribution, electricity/gas, energy/transport/economy or other conceptual system couplings. In practice different interpretations will suggest different trade offs and regulatory decisions. Clarifying the logic here will help all stakeholders to understand the direction of travel.

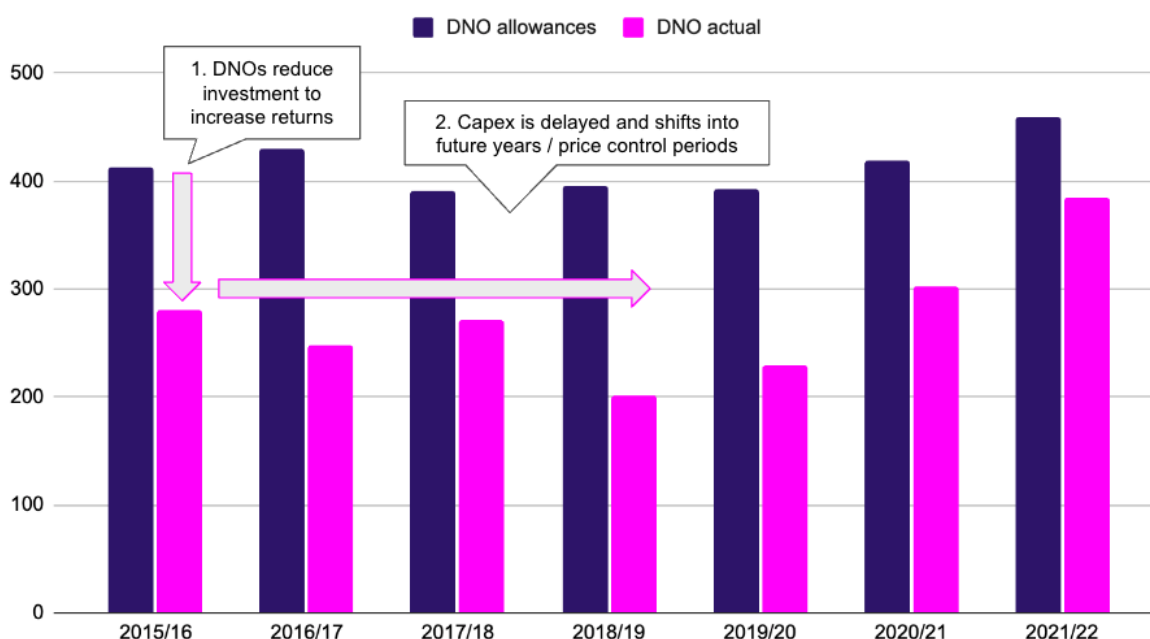
We agree with the proposed consumer outcomes, although we would position delivering all of this cost effectively as an overarching outcome. Customer bills must be minimised and where customers do pay more for the networks, this should deliver tangible value for them in return. Networks must deliver this by simultaneously maximising use of the lowest cost sources of capacity, whilst minimising the cost of delivering any new investment.

Regulatory framework

Q3. Do you agree that the network investment elements of the framework should be more input based?

Under the output based framework, DNOs have to date largely failed to deliver the level of investment promised in business plans agreed at regulatory settlements. Levels of capital investment have been depressed and/or pushed into the future and DNO shareholders have been rewarded for this via the totex incentive mechanism (TIM).

Figure 3 - DNO load related capex over RIIO-ED1⁶



In parallel, DNOs have largely failed to create a consistent and accessible market structure for flexibility providers, or rapidly deploy the monitoring and software capability required to manage the network without reliance on capital investment. We have therefore not seen evidence that use of flexibility has been responsible for depressing the level of capital investment from the DNOs.

Without a change in regulatory regime, there is a risk that this trend of underinvestment continues. Ofgem has rightly recognised the risk of increased constraints if peak demand grows rapidly under an environment of long term stalled investment. At Octopus, we have already seen instances of limited network capacity holding back ability of our customers

⁶ Ofgem RIIO-ED1 databooks

to install low carbon technologies (without incurring significant connection charges that breach the high cost cap).

We therefore broadly support Ofgem's proposal to move to more input driven 'plan and deliver' controls over what gets built and where, to ensure customer network charges are being spent on network infrastructure rather than simply returned to shareholders; with the exception of Northern Powergrid, interest and dividend payments have exceeded 40% of total gross capex at all the network companies.

Figure 4 - DNO investor returns as a proportion of gross capex and revenue⁷



We are not concerned about the potential detrimental effect on innovation or efficiency as we are not aware of evidence that DNOs have become more efficient following introduction of a totex based, output driven regulatory framework⁸.

However, the success of an input driven framework for capital investment depends entirely on how the inputs are set. Unfortunately, as Ofgem has not yet published its decision on the RESP methodologies, it is difficult to assess how effectively the RESP will define load related investment requirements.

For Octopus to fully support the use of a 'plan and deliver' framework for DNOs, inputs like the RESP must be defined in a way which:

⁷ Distribution Company Parent Capital Payments, 2014-2023, Common Wealth

⁸ <https://www.jbs.cam.ac.uk/wp-content/uploads/2023/12/eprg-wp2126.pdf>

1. Maximises scope for competition between wires and non-wires (e.g. flexibility based or digital) solutions to meeting network constraints. Although reinforcement may be required in future, as set out in Q1 we fundamentally disagree that any entity can predict the future accurately, which means the benefits of flexibility in providing optionality over capex profiles must be properly valued in any input driven framework.
2. Crowds in expertise and different perspectives from a diverse range of system users when defining inputs. Doing this is crucial to avoiding group think, over-confidence and systemic bias in forecasts used to drive investment decisions.
3. Continually update in light of real consumer behaviour and evidence. As we expect innovation in energy to continue accelerating, inputs must be able to adapt to ensure customer money is not wasted. As new energy markets mature our understanding of customer behaviour and net load impact will improve rapidly.

Q4. Do you agree that we should consider introducing additional controls around network investments and what features should these controls contain?

Yes, the use of an input framework should not be limited to approving funds for investment. Controls must be in place to ensure that capital projects are delivered on time and on budget.

We welcome the proposed use of price control deliverables (PCDs) for primary network investments. Funds must be returned to customers if they are not used to deliver the projects they were released for.

At secondary level, specific PCDs may be too administratively complex for individual projects. However, we propose that Ofgem design an aggregate delivery metric for secondary reinforcements at an appropriate spatial scale (this could be at secondary region, local distribution zones, investment planning zones or regulatory reporting zones). This metric should track delivery of new capacity either through wires or non-wires solutions, as prioritised and specified in the input framework. A similar, volume driven metric could also be set for new connections delivery, incentivising new connections in line with the CP30 volumes.

This delivery incentive should coincide with a rapid acceleration of secondary network visibility and data transparency to enable this. If DSOs achieve the baseline level of secondary network visibility needed for a smart and flexible electricity system, sharing the necessary data for this new delivery metric should not be a significant additional burden. This data should also be made publicly available for market participants to

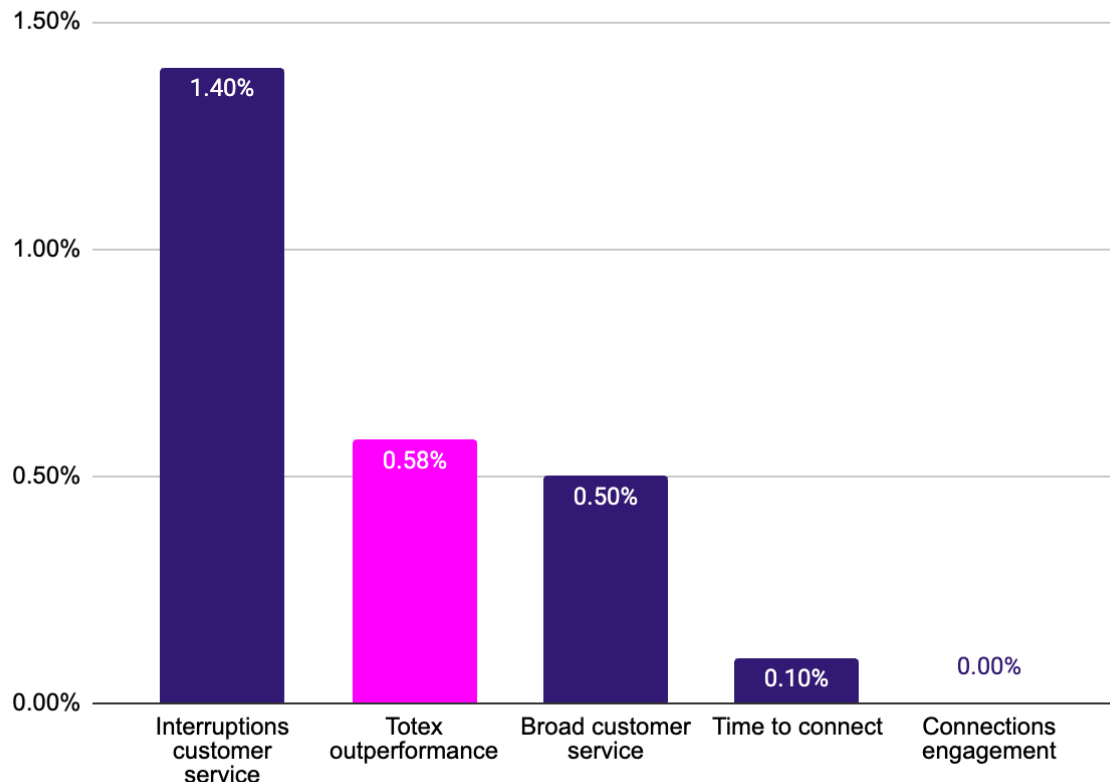
respond to, e.g. prioritising connection requests or LCT delivery in regions where there is good available capacity, or providing flexibility resources in areas where the network is likely to be constrained and additional optionality is valuable.

Q5. Do you agree that the incentives on DNOs will need to adapt from RIIO-ED2 and if so, how?

Yes, in our view the incentives in RIIO are generally skewed towards increasing leverage, totex outperformance and the interruptions incentive scheme in ED1. It is still too early in the price control to see if this holds for ED2, but we note significant capex outperformance in year 1. The rewards available to network operators for these behaviours are not necessarily commensurate with the value customers gain.

On the other hand, connections incentives, the DSO incentive, delivery incentives and penalties for poor performance on customer service are too weak to drive a step change in performance. For example, we are routinely told by DNOs that connections teams are underresourced and that this is causing delays in processing applications for customers. This may be due to the fact that rewards available to DNOs for minimising totex are stronger than rewards available for processing connections at pace.

Figure 5 - actual contribution to RoRE, selected drivers in ED1⁹



⁹ Ofgem RIIO-ED1 databooks

We do not include further comment on connections incentives here, as this is covered in the Ofgem 'end to end connections incentives' consultation which is to be submitted separately.

Given Ofgem's position on the 'plan and deliver' archetype, we expect load related planning and delivery to be increasingly outsourced away from the DNOs during RIIO-ED3 and beyond, to RESP and third parties / contractors respectively. As discussed in Q8, asset health interventions should also be treated consistently. As such, the DSO function will become increasingly prominent as the distributors' 'value add' to system outcomes - covering processing of customer connection requests (even if more connections themselves are delivered by third parties e.g. iDNOs), data monitoring and transparency, innovation and active network management.

With this in mind, Ofgem should step up expectations on DSOs. The DSO incentives should be strengthened and extended for RIIO-ED3, backed by clear quantitative expectations on network visibility, volumes connected over time, customer service and resilience.

Innovation roll out and deployment is another area that should have stronger incentives attached, closely linked to DSO performance. As discussed in our RIIO-3 SSMC response, late stage SIF funding should be linked to deployment outcomes and delivery of the customer benefits case set out in funding applications. This would mirror the risk/reward case for innovation in competitive markets and provide a real incentive for DNOs to scale innovative concepts which provide benefits for customers.

Q6. Do you agree that there is still a role for re-openers in ED3, particularly given the timing of the future full RESP output and how should these be triggered?

With more funds for investment linked to an inputs framework like the RESP, the need for periodical ex ante business plan reviews is reduced. Instead, the update of the RESP becomes the key driver of revisions to the network capex delivery plans. For ED3, re-openers should therefore be included on this basis, updating funding allowances and forward capital planning profiles in response to updates to the RESP. These should be triggered once a new RESP is available.

Without clarity on the content of the tRESP vs the full RESP it is difficult to comment on the need for a re-opener to adjust the price control for this update, but we expect it will be required.

Q7. Using RIIO-ED2 as the counterfactual, what alternative regulatory models or characteristics are needed in ED3 to ensure the DNOs deliver the above consumer outcomes? What are the trade-offs we should consider?

Overall, we expect the following changes will be needed in ED3 to enable these proposals:

- **Reduced spend fungibility across categories:** Instead of a totex category covering c.75% of ED allowances, more expenditure will need to be linked to specific projects and cost assessed on a project specific basis. Where competition is not used for delivery, upside returns available to the DNO should be linked most closely to speed of commissioning (via faster addition to the RAV or specific ODIs related to commissioning date, as with ASTI projects at transmission level).
- **Tighter linkages between business plans / investment plans and the RESP outputs:** We expect that inclusion of projects in the RESP plan will reduce the information asymmetry faced by Ofgem when assessing capex proposals. The structure of the business plans and the RESPs should be designed to exploit this benefit as much as possible - e.g. with close links between network needs identified in the RESP, assessment of wires/non-wires alternatives, and detailed optioneering in DNO business plans.
- **Introduction of an enduring market design for local flexibility:** We agree that we should not rely on DNOs as monopsony buyers of local flexibility, but disagree with Ofgem's conclusions that local flexibility therefore has less of a role to play in delivery system value for customers. Instead of sidelining flexibility, Ofgem should take a step forward in market design for local constraint management, for which we recommend a dynamic price signal (discussed more in Q15).
- **Increased role for competition in delivery:** Competitive tendering for engineering, procurement and construction services is a key lever to reduce costs and should be mandated in delivery processes as a means for the market to reveal costs for specific projects, reducing the role for ex ante cost assessment / unit cost assessment.
- **Increased role for competition in asset ownership:** With major new primary reinforcement projects identified based on RESP inputs, there is scope for a wider competition regime to emerge for separable and high-value projects, as with transmission. We expect Ofgem to exploit this as a means to introduce competition in both capital provision, delivery and ownership.

Q8. Do you agree that the regulatory framework for ED3 should have features of the Plan and Deliver model for network investment and Incentive Regulation model for other elements?

Yes, we refer to our responses to Q3, Q4 and Q5 in overall support of this concept, with the caveat that success relies on the RESP being effective as an input framework. We acknowledge that the RESP is not being consulted on here and look forward to engaging on future policy development on the RESP in due course.

We also expect that asset health / replex interventions will need to be rolled into overall capital works planning and driven by RESP assumptions, in line with load related expenditure. As Ofgem notes, disentangling these two investment drivers may not be possible in practice. Treating both types of investment consistently is likely to be necessary to avoid customers paying twice for investments (e.g. once through capex allowances and another through rewards under the NARM or another asset health metric), or inadvertently creating perverse incentives that DNOs can arbitrage through how investments are classified.

Q9. Do you think that there is a greater role for elements of ex post regulation or of cost pass through in ED3, either specifically in assessing cost changes resulting from changes to investment requirements during the period, or more broadly to reflect the changing context?

The move to a 'plan and deliver' regime for a large proportion of network investment, coupled with constraints in the interest rate, supply chain and workforce environment, creates challenges for the ED2 approach to ex ante cost assessment. Less ex ante assessment will be required at portfolio level if more projects are driven by the input framework, which can streamline the price control and may unlock faster delivery. More use of stage gate cost assessment may be appropriate for higher value projects, as well as ex post assessment of whether procurement processes followed are best practice. Unit cost benchmarking / volume driver based approaches may remain appropriate for smaller, modular works (e.g. service cable unlooping).

Wherever these approaches are being used to reduce risk held by the DNO (e.g. removing exposure to overspend reducing returns), Ofgem must ensure that consumers benefit through a commensurate reduction in the cost of capital afforded to the DNOs.

Networks for Net Zero

Q10. What is the potential availability of network flex across GB for DNOs in the short term and on the journey to net zero during ED3?

Greater uptake of low carbon technologies, particularly EVs, will increase the volume of flexible resources available to help balance the networks and provide other sources of system value (discussed in more detail in Q14 below).

Our top-down analysis, based on Octopus market experience and averages of FES uptake scenarios suggest that up to c.20GW of customer flexibility could be available across GB by 2030, up from c.7GW today. Of this, c.10.5GW will be automated/controllable load, which can be optimised to

respond to a range of market signals and customer preferences. As discussed in questions below, designing the right stack of market signals for this load is crucial to maximising its system value.

Unlocking this capacity in practice will also require the right customer propositions, engagement and market design. Ofgem rightly notes that the market has struggled to meet volumes demanded in DSO tenders. To date, flexibility providers have been held back by:

- Complex market access processes and rules meaning that flexibility providers face high costs in registering to participate in multiple DSO tenders;
- Inconsistent approaches to technical specification of flexibility products across baselining, contract terms and APIs. This provides another barrier to entry to flexibility provision, reducing liquidity in tenders and leading to higher costs for customers overall;
- Limited provision of necessary data for flexibility providers to build business cases varies across DSOs. Efforts to move towards more real time network constraint monitoring/forecasting would help providers prove the benefits of their services and justify investment to expand capacity;
- Inconsistent approaches, price signals and revenue stacking criteria between ESO and DSO procurement.

Q11. To what extent are global supply chain and workforce pressures contributing to longer lead times for delivery network reinforcement?

We note that distribution network electrical equipment (e.g. pole mounted transformers, low voltage cabling) is generally more modular and readily available than transmission scale components.

Q12. Do you agree that the risk and downside for consumers of network underinvestment in network reinforcement would be greater than the downside of overinvestment?

We agree that total annual load growth is likely under any electrified future and network upgrades will be required. Given the dominance of fixed costs in the cost of network reinforcement, we also agree with the 'touch the network once' hypothesis; where load related investment is happening then creating additional headroom can avoid multiple rounds of civils works / disruption out to 2050, ultimately reducing overall costs for customers.

However, it is too simplistic to argue that this shifts the entire balance of risk in favour of investing in the network by default, at the expense of

incentivising demand to operate flexibly as our understanding of future system dynamics matures.

Instead of designing the framework in response to an either/or proposition, Ofgem should focus on maximising the value available from treating reinforcement and flexibility as complements, rather than substitutes. This is discussed in more detail in Q13 and Q14 below.

Q13. What are the benefits and risks to deliverability if network reinforcement is deferred to future periods?

Deferring reinforcement across the network asset base has the benefit of saving customers money today but carries the risk of storing up a 'delivery crunch' in future periods. Today's DNOs have not historically delivered major capital investment programs at scale and need time to build up the supply chain, workforce and organisational capability. If a high volume of interventions are needed pre-2050, it is likely to be lower risk and lower cost to start earlier and smooth these over a longer period. We are already seeing this today, e.g. with long lead times for regional service cable unlooping programs that are necessary to enable LCT uptake at scale across DNO areas.

However, pivoting away from 'flexibility first' and towards 'reinforcement first' is the wrong approach to achieve this and risks costing customers more in the long run through overreliance on capital intensive options to provide network capacity. This would fail against Ofgem's stated overarching objectives for ED3.

Instead, Ofgem should view flexibility and reinforcement as complements, rather than substitutes. Flexibility can support network reinforcement in three ways:

1. Flexible use of demand, storage and generation will help to maximise volumes that can be connected to the network *for any given level of network capacity*. Since the fixed cost of networks (and generation) must be built to meet peak demand, operating connected capacity in a way that avoids contributing to peak consumption will increase the volumes that can be connected. This is about getting the best 'bang for buck' out of the physical infrastructure the DNOs build. Centre for Net Zero modelling suggests this can translate into a £2-3bn saving per annum by 2030 through reduced need for network capacity and expensive dispatchable generation capacity¹⁰.

¹⁰ <https://www.sciencedirect.com/science/article/pii/S0306261924019056#fig4>

2. Flexibility can provide optionality in reinforcement delivery profiles and buy time for uncertainty to reduce. Managing network constraints dynamically buys more time to gather much needed data on real time network constraints, dynamics and customer behaviour, vital to developing efficient network build plans via the RESP.
3. Flexibility can help to profile investment and control for various delivery risks that grow in line with the volume of work that has to be delivered in parallel. There will be real constraints to how much network intervention for capital projects can be delivered simultaneously (e.g. due to planning, supply chain, workforce and financial constraints). Flexibility creates value by extending the options for reinforcement interventions to be sequenced over time, helping to smooth out workload and reduce the risks of additional cost created by supply chain / workforce constraints. If network build stalls for any reason, active flexibility provision and clear price signals can also help to mitigate the delivery risk by managing constraints dynamically whilst longer term mitigations are put in place.

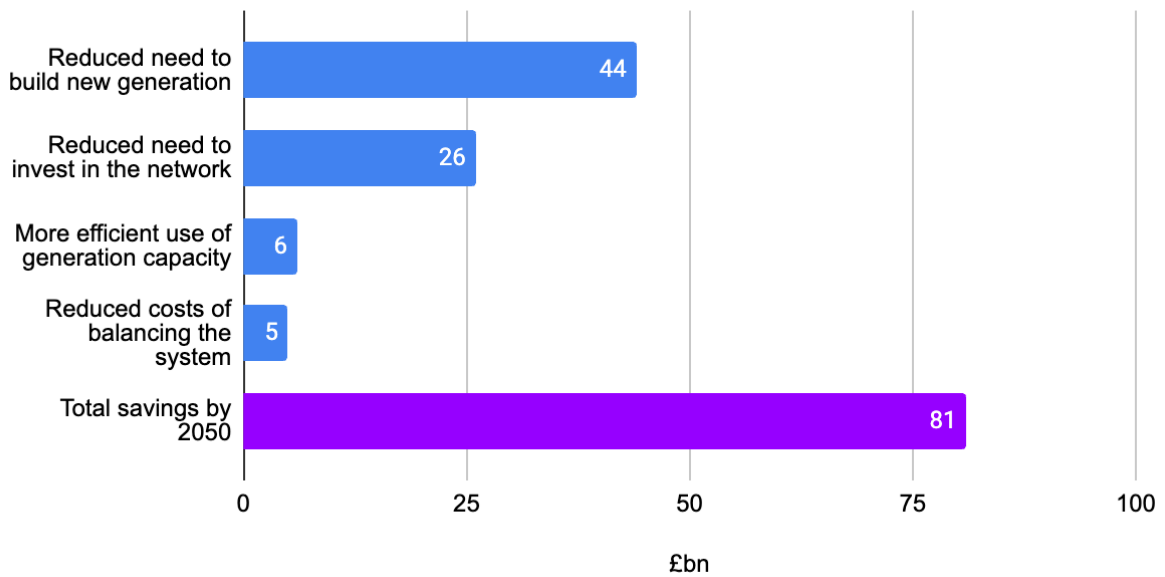
Q14. What do you see as the role of distributed flexibility, both in the short and longer term, to manage distribution network constraints?

Flexible use of low carbon technologies will be critical to the energy transition. Multiple academic studies have shown that the costs of Net Zero will be significantly higher without building a flexible electricity system, including Ofgem/BEIS own study in the 2021 Smart Systems and Flexibility plan.

Figure 6 - total system savings by 2050 in high flexibility scenario¹¹

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<https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021>



Reducing distribution network constraints is one important function of flexibility, but flexibility can provide system value in many more ways, including:

- Reducing losses by managing powerflows
- Voltage control
- Fault management and resilience
- Consumer engagement, including potential to eliminate or significantly reduce both energy bills and net electricity consumption from the grid, as shown by our Zero Bills Homes proposition
- Tx constraint management
- Dx constraint management - maximising the volumes of generation or demand that can be connected for any given distribution network capacity
- System balancing
- Load shifting to maximise use of lowest cost power

Ofgem is right to open discussion on how to design incentives for flexibility which maximise system value across all of these potential use cases. We agree that an exclusive focus on distribution reinforcement deferral will not maximise the whole system value of flexible resources.

However, current proposals for ED3 risk suggesting that Ofgem intends to limit the role of local flexibility overall, potentially undermining a growing market and sending a message to DSOs (and ultimately customers) that flexibility is no longer a priority. This risks reversing years of progress under ED2 and a recent step change in public engagement from the ESO DFS. Whilst Ofgem's stated priority is utilising flexibility for whole system balancing instead, it should be efficient market signals that drive how flexible assets are used.

Limiting the role of flexibility in management of distribution constraints in ED3 risks creating two unintended consequences:

1. Removing distribution constraint management from the business case for flex risks undermining the nascent but growing market for flex by reducing incentives for new capacity to come online. Flexibility service providers generally stack revenue sources across markets wherever possible to manage tight margins and several barriers to entry (discussed above in Q10). Reduced revenues will reduce capacity available, in turn then limiting the overall potential for flex to create system value across all of the use cases noted above.
2. Blunting incentives for distribution constraint management risks creating major inefficiencies in the way that flexible capacity operates. By removing price signals for distribution constraints from the commercial model, flexible capacity is likely to respond to wholesale/transmission level signals in a way that can exacerbate localised constraints, potentially increasing costs for everyone. Relying exclusively on building distribution network capacity as the solution to this will become extremely expensive, particularly given the potential peak demand impact of EV chargers 'herding' their load at the local level.

Lower volumes of flexibility coming forward and operating in a less efficient way will increase costs for customers and increase delivery risk over the NESO CP30 plan objective of achieving a 4-5x increase in low carbon flexibility by 2030.

Q15. How do we ensure that network flexibility is used only when it is in consumers' long-term interests in ED3?

We agree that relying on DSO tenders for flexibility procurement is unlikely to be a scalable and efficient route to operating a flexible electricity system. As noted in Q10 and the consultation document, DSOs have struggled to design an accessible and consistent market for flexibility and liquidity has suffered as a result.

The solution to this is not to discard local constraint management as a use case for flexible assets. Instead, Ofgem should focus on developing a consistent market signal for flexible assets that reflects local network constraints. This signal should allow flex providers to respond dynamically as part of their ongoing optimisation of flexible capacity.

We propose embedding a dynamic price signal into DNO network charges as the most efficient way to achieve this (a.k.a dynamic DUoS)¹². We have

¹²

https://octoenergy-production-media.s3.amazonaws.com/documents/Octopus_Energy_-_Local_Flexibility_Markets_Future_Proofed.pdf

ran multiple trials with DSOs to test this solution, demonstrating that secondary peaks created by wholesale market signals are likely to become a problem with more automated load, and showing that a dynamic network charge can resolve this¹³.

As well as helping to protect the network from localised constraints whilst reinforcement programs are delivered, dynamic network pricing also has the benefit of creating a reliable signal as to where reinforcement should be prioritised (e.g. if congestion prices are consistently high, then this shows that flexible capacity is no longer able to manage local constraints).

Although DUoS reform is not strictly in scope for the ED3 framework, we urge Ofgem to work with DSOs to develop an efficient market signal for localised flexibility as part of ED3. For reasons set out in questions above, this is not a substitute for reinforcement, rather a complement to it. Effective and comprehensive network visibility is a pre-requisite for this and incentives in the ED3 framework must drive a step change in ambition for low voltage monitoring deployment and modelling capabilities within the DSOs.

Q16. How are unexpected constraints dealt with currently? How quickly can these be eased, and what is the impact of these unexpected constraints (eg on LCT uptake)?

Flexible demand and generation is used today across the networks to respond to unexpected local network constraints through availability based agreements (including in non-firm connections for renewable generators). These solutions to enhancing reliability and security should continue to be scaled up in ED3 and beyond. Even in a system managed with a dynamic local congestion price, we expect DSOs to maintain some 'back up' options for high impact low frequency risks.

Q17. Do you agree that the tRESP output outlined for early 2026 will help create a level playing field for DNOs' business planning and support the ED3 objective and consumer outcomes?

We agree in principle that a common set of assumptions and projections will help to drive consistency in DNO business planning and reduce both perverse incentives and information asymmetry in the business planning/price control negotiation process. However, without more detail on the content of the tRESP (and final RESP), it is difficult to agree conclusively that this will promote good consumer outcomes. As we note in Q3, the RESP must be developed collaboratively and incorporate the latest evidence on customer behaviour to best support the ED3 objective in the business planning process.

¹³ <https://innovation.ukpowernetworks.co.uk/projects/shift-2-0>

Q18. Can anticipatory network reinforcement be used to smooth the long-term build profile to avoid creating pinch points for the supply chain and workforce? What are the risks and trade-offs?

We agree in principle that smoothing the long term build profile is desirable to avoid a pinch point in delivery capability. As well as 'anticipatory investment', we also note that effective use of network flexibility can create optionality that enables reinforcement works to be smoothed over time.

Q19. Do you agree that investment optioneering should aim to reduce the lifetime costs by sizing elements of works for long-term need, including considering the impact of thermal losses?

Yes, as set out in Q12 we broadly agree that 'touching the network once' by sizing for long term need will reduce lifetime costs for customers. However, improving reliability of estimates of long term need is important to maximise the potential of this approach. More reliable estimates will only come from experience and iteration based on real life customer behaviour.

We are consistently finding evidence of customer appetite to operate assets flexibly that exceeds prior expectations (e.g. 95% of our customers who have an EV are on a smart tariff today and 60% of those are automated, significantly higher than uptake assumptions in many industry scenario models).

Given the early stage of consumer uptake of both LCTs and flexibility propositions, the RESP and subsequent optioneering approaches must not assume that the past is a good predictor of the future. If peak demand ends up significantly lower than expected today then sizing for long term need will increase costs for customers across generations.

Investment optioneering must therefore balance the need to right-size urgent reinforcements and avoid repeated interventions, with the need to use flexibility to maximise optionality and buy time for accuracy of long term assumptions to improve as these new markets mature.

Q20. Is a 5-year price control (2028-33) the right duration to achieve the objective of securing timely network capacity for the net zero transition at least cost to consumers over the long run?

A 5 year price control remains a good balance for setting incentives and outputs required from the networks. We expect that a more input driven framework for capex planning (both reinforcement and asset health related) will reduce the significance of the 5 year business planning process. Instead, capex plans can become more iterative as inputs are updated based on new information, with greater use of re-opener style mechanisms to enable this.

Q21. To what extent should the price control be more directive on specific anticipatory and strategic investments to achieve the 'networks for net zero' consumer outcome?

We refer to our responses in the previous Networks for Net Zero questions.

Q22. Do you agree with our characterisation of strategic and anticipatory investment and our expectation that these activities would have different regulatory drivers and controls?

We agree with the definitions provided in the consultation document but expect that a consistent capex planning approach is likely to be the most efficient and methodologically straightforward approach to enabling these works to be delivered in ED3. As set out in Q23, this approach will work best when coupled with a scalable market design for local flexibility and a consistent approach to comparing wires and non-wires solutions in the reinforcement planning process.

We agree that different regulatory controls are likely to be required for larger investments (e.g. around project level cost assessment, delivery incentives and/or use of PCDs).

Q23. Should the price control provide more guidance or guardrails around the use of particular network solutions to achieve the 'networks for net zero' consumer outcome?

Yes, in our view a dynamic local congestion price is needed to optimise the use of flexible resources (which will inevitably optimise across whole system and local price signals over time). The price control should drive uptake of this approach and deployment of key enablers (e.g. network monitoring) consistently across network areas.

In some cases, DSO procurement of flexibility or use of other non-wires solutions will be the most cost effective way to meet network needs, either on an enduring or temporary basis as reinforcement plans are smoothed over a longer time horizon. In this case, the input framework (RESP) and any subsequent optioneering approaches must explicitly consider these options. Ofgem should give clear guidance on consistent methodologies to the RESP and/or DSOs to execute this in practice, including the necessary adjustments that Ofgem highlights in the consultation (e.g. for network losses or potential whole system value from enabling local flexible resources to respond to wholesale price signals).

Q24. Should we consider how we might bring all network capex investment together within the framework, irrespective of driver (eg load, asset health, resilience), to ensure a common approach to future proofing and delivery?

Yes, we agree that this is necessary to avoid creating duplicative incentives that potentially end up with customers paying twice to reward DNOs for

network upgrades. Disentangling drivers of network capex is unlikely to be feasible without excessive methodological complexity and risk of gaming through the price control determination process. As such we propose that Ofgem take a consistent approach and capture this in both RESP and business planning guidance.

Responsible business

Q25. How can we better strengthen accountability for consumer outcomes?

Ofgem must drive a step change improvement in data transparency from the DSOs in ED3. Although good progress has been made in this area, DSO data portals remain complex, inconsistent and datasets are often inaccurate and usefulness for decision making is limited. We are concerned that licence obligations on data transparency (particularly on system data being 'presumed open') are not being fully delivered against today. Ofgem can improve the situation with stronger guidance and clarity on prioritisation and data quality and/or stronger enforcement of existing obligations.

This should be coupled with a stronger approach to consolidated reporting of reputational incentives across DNOs, driven by Ofgem. Current disclosure is limited to financial performance and is published in a format which is inaccessible to laypersons and most stakeholders without specialised knowledge of RIIO. If reputational incentives continue, Ofgem should publish a live dashboard of DSO performance on its website, with clear outcome based metrics. We recommend that Ofgem also consolidate and publish reporting on generation volumes connected and KPIs that are relevant to customers on time to connect low carbon tech (e.g. % of applications auto approved, average time to approval for reviewed applications).

Q26. What are your views on ED company reporting and the overall transparency of performance and compliance?

ED company reporting typically involves very long pdf documents spread across multiple company websites or network areas. Documents are inconsistent across companies, often with 'cherrypicked' case studies and data or anecdotal evidence. These issues were highlighted in the findings of the DSO performance panel in their first DSO metric review¹⁴.

This inconsistency makes drawing any consistent sector wide conclusions very challenging and limits the value of these disclosures to most stakeholders. The situation would be improved with more digitalisation of reporting over time and more consistent reporting formats of key

¹⁴ https://www.ofgem.gov.uk/sites/default/files/2024-09/DSO_Incentive_Report_2023-24.pdf

datapoints that matter to stakeholders. Particular metrics we would highlight as benefitting from standardisation relate to low carbon tech connection KPIs, flexibility uptake and pricing, network carbon intensity, network reinforcement delivery, reliability and interruption data, cash flows and charging impacts.

Q27. Do you consider that ISGs alone are sufficient to ensure high quality and effective consumer and stakeholder engagement throughout the ED3 price control? What alternative or complementary approaches should we consider?

We broadly agree with Ofgem's decision to streamline stakeholder engagement during the business planning process for RII0-3, and propose independent stakeholder groups (ISGs) should also have a role in ongoing challenge to network company delivery throughout the price control period. These forums should have dedicated resources, facilitate input from broader social interest groups, and have teeth (including feeding into qualitative assessments of network performance alongside Ofgem decisionmakers).

Given the critical role of the RESPs in determining how customer money will be spent on network reinforcement, Ofgem must also bring together thinking on consumer and stakeholder engagement across the RESP and RII0 process. Separating responsibilities between NESO and the DNOs risks creating an accountability sink with dysfunctional interfaces, as we have seen in the grid connections space with frequent examples of poor communication and blame shifting for problems between parties involved in the process.

Q28. Do you agree that Ofgem should adopt research approaches, such as deliberative techniques to ensure that the consumer voice is heard and considered throughout the ED3 and company Business Plan process?

Octopus Energy will not respond to this question.

Q29. How should our approach to enhanced stakeholder engagement be adapted to better include the perspectives of all vulnerable customers, including those that are seldom heard, digitally disengaged/excluded and those that are worst served?

Octopus Energy will not respond to this question.

Q30. What alternative or additional approaches might we use to ensure that the consumer voice remains central to our policy setting process?

Octopus Energy will not respond to this question.

Q31. Has the BMCS incentive served its purpose in driving performance improvements and how can we adapt the metrics to better incentivise

performance across a wider range of interactions between DNOs and their customers, particularly relating to connections?

DNOs have made progress in improving their scores in the BMCS incentive throughout ED1. Ofgem should set a clear expectation that this level of service continues as 'business as usual', with cap/collar levels for reward and penalty adjusted accordingly. Ensuring robust sample sizes and coverage for any survey based approaches is also important to ensure reliability of a financial incentive.

Ofgem is also right to recognise that DNOs are increasingly involved in the customer journey for low carbon tech installation. This is a major source of complexity, delay and administrative burden today that needs stronger standards to adapt to DNOs changing role. We welcome the inclusion of LCT connections in the recent end to end review of connections incentives.

Ofgem should respond to this new role with both an adaptation of the BMCS metric (e.g. new survey questions and coverage) **and** stricter guaranteed standards of performance over DNOs role in the LCT install journey, with penalties and consumer redress available for breaches.

The incentive and standards framework designed by Ofgem needs to cover:

1. **Transparency of requirements for auto approval of low carbon tech:** DNOs currently all have different standards over what customer applications will be auto approved and DNOs generally refuse to share this information with installers. Standards also frequently change and are interpreted in different ways. For LCT markets to scale, the rest of the install supply chain needs to understand where the networks can accept LCT, where flexible usage profiles or other mitigations can be used to accept LCTs, and how this will change in future with network reinforcement. Ofgem should set clearer guidance and requirements on how this information is provided to the market.
2. **Deadlines and criteria for DNO approval of LCT applications where review is required:** Divergent processes between DNOs remain an issue with many applications exceeding 45 working day deadlines for approval. At time of writing we have >1,000 customer install requests at 45+ days across the DNOs. Many administrative hurdles can be introduced by DNOs (e.g. separate load checks, site visits, requirements for additional GDPR letters from customers, reaching out directly to customers for further information etc.). Some DNOs will proactively look for solutions to speed up the process (e.g. as we have achieved clearance to accelerate fuse upgrades with UKPN and NGED). Ofgem should set clearer expectations and minimum standards to drive all DNOs to this level.

Q32. How should the CVI be adapted for ED3 and should we consider greater alignment with the GD sector?

Octopus Energy will not respond to this question.

Q33. Should DNOs have a role in delivering energy efficiency measures to homes and businesses? What might the scope of these services be and how should they be funded?

We can see the benefits of DNOs delivering energy efficiency, given their fixed relationship with the customer, large fixed asset bases that improve financeability, and inherent benefits to system load profiles following electrification of heat if the housing stock is more efficient.

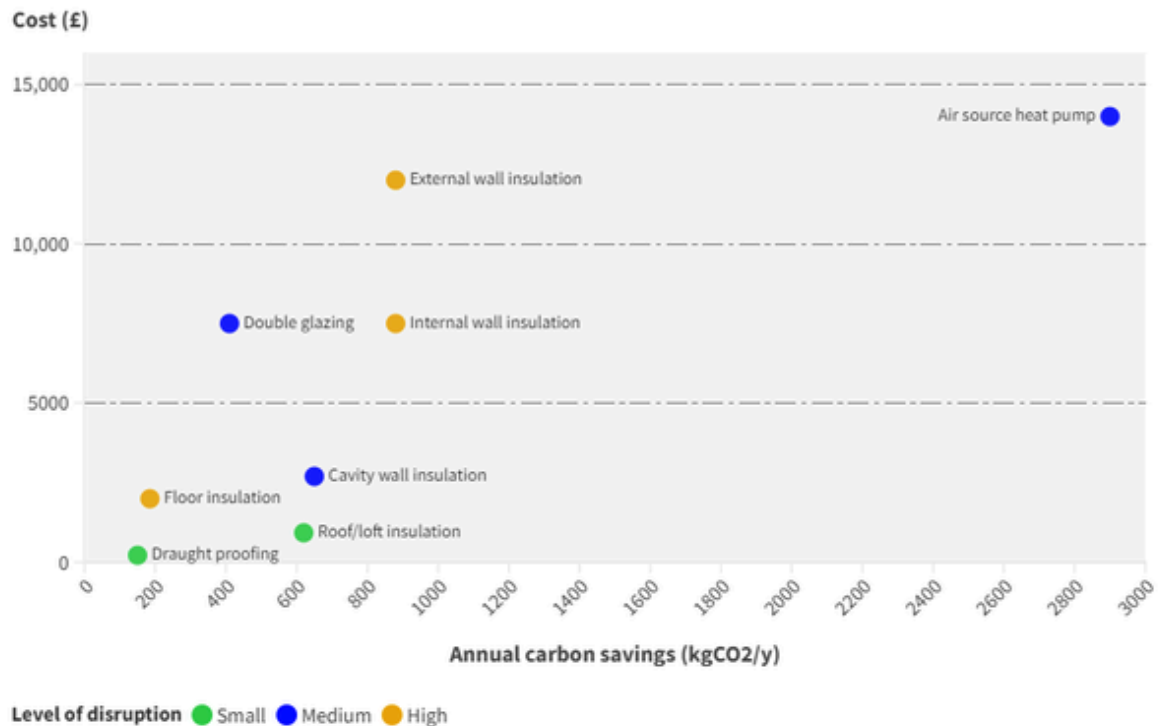
However, we have also seen challenges in DNOs delivering new functions e.g. in standardising flexibility markets, pro-actively managing the growing connections queue and now managing exponential growth in LCT demand. DNOs will likely also be required to deliver a step change in network reinforcement delivery throughout ED3. Ofgem must first be confident that DNOs are willing and able to deliver energy efficiency upgrades before allocating responsibility for any new programme.

We also note that recent evidence shows that the biggest cost and carbon impact is achieved by installing a heat pump in a customer home, rather than taking a 'fabric first' approach to efficiency improvement. DNO efforts and incentives should be prioritised accordingly.

Figure 7 - cost vs carbon savings for retrofit options¹⁵

¹⁵

<https://www.nesta.org.uk/report/insulation-impact-how-much-do-uk-houses-really-need/#:~:text=In%20our%20view%2C%20the%20UK,of%20around%20%C2%A360%20billion.>



Q34. How can we drive further service improvements under the TTC incentive?

We refer Ofgem to our submission to the end to end connections incentives consultation to avoid duplication.

Q35. Should the TTC also apply to domestic connection upgrades ie fuse/cutout/service cable upgrades, including unlooping?

Domestic connection upgrades should be covered by an incentive and guaranteed standards framework. This does not necessarily have to be TTC.

Q36. What is the best approach towards incentivising services to major connections customers and how should the MCI be adapted for ED3?

We refer Ofgem to our submission to the end to end connections incentives consultation to avoid duplication.

Q37. How should the ED3 framework adapt to ensure that customers connecting to the distribution network are provided with the service that they need from the DNOs?

We refer Ofgem to our submission to the end to end connections incentives consultation to avoid duplication.

Q38. In the context of greater electrification, is our current approach towards regulating reliability appropriate for ED3?

We recognise the progress made in improving reliability of the distribution networks throughout the RIIO frameworks lifetime. We agree with Ofgem's approach but note that flexibility based solutions should continue to play a key role in managing system intermittency, faults and resolving constraints at distribution level. As discussed elsewhere in this response, undermining this market risks holding back further progress on reliability standards across DNOs.

Q39. What role should bespoke outputs and CVPs have in ED3?

Octopus Energy will not respond to this question.

Q40. How can we optimise late and early competition models for application in electricity distribution?

Ofgem has a valuable and important opportunity to increase levels of competition in the distribution sector through ED3. As more primary reinforcements are specified in the input framework, Ofgem can define criteria by which these projects can be tendered for competitive delivery and ownership (e.g. a value threshold, size threshold or separability criteria as used in the CATO framework). NESO is already developing capabilities to improve competition at transmission level. The 'hub' of the hub and spoke model of the RESPs therefore could therefore be well positioned to expand competition to distribution level too.

Competition can help to drive down delivery costs, reveal the true cost of capital required from the market to fund network infrastructure, help to expand network delivery capability beyond incumbent monopolies, and catalyse innovation. Early competition models, which allow for comparison between various solution designs, including wires vs. non-wires solutions, are most likely to support innovation in the sector. We have already seen improved outcomes for customers through competitive delivery of last mile connection services through ICPs and iDNOs and urge Ofgem to consider how to expand these benefits to other network functions and asset classes.

Q41. How should our approach to cost assessment evolve, to enable us to better manage increasingly pronounced trade-offs between consumer protection, efficiency and investment in the distribution network?

Octopus energy will not respond to this question.

Q42. How should our guidance for cost benefit analysis evolve to better enable optioneering between different interventions, taking relevant long-term risks and benefits into consideration?

Octopus energy will not respond to this question.

Q43. Do you agree that the current Real Price Effect (RPE) methodology should form the basis for adjusting allowances in ED3?

Yes.

Q44. Do you agree that the current approach to setting the ongoing efficiency challenge is a suitable starting point for ED3?

Yes.

Q45. Do you see any reason why we should not implement the proposed changes to the calculation allowed returns, consideration of investability and assessment of financeability that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

Octopus energy will not respond to this question.

Q46. Do you see any reason why we should not implement the proposed updates to financial resilience requirements that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

Octopus energy will not respond to this question.

Q47. What are the key factors (including benefits and costs to consumers) that Ofgem should take into consideration when conducting its review of the appropriate approach to regulatory depreciation in ED3 and beyond?

Octopus Energy will not respond to this question.

Smarter networks

Q48. How should the price control encourage ongoing development of the DSO role and activities to optimise whole system benefits for existing and future consumers?

Network visibility, data provision, effective customer service and connections and smart network management will all remain important functions of the DSO despite the network capex planning approach changing in RIIO-ED3. The DSOs will also continue to play an important role in procuring flexibility options, although as discussed elsewhere we strongly recommend Ofgem consider moving towards a scalable market design for local flexibility. This will ensure the distribution network is protected while flexibility providers optimise across various whole system value streams.

Given the wide range of practice in DSOs today and increasing importance of digitally enabled distribution networks to the energy transition, Ofgem should strengthen the reward/penalty available in the DSO incentive and revive the quantitative metrics used to set an objective benchmark for strong DSO capabilities. Low voltage visibility coverage and forecasting accuracy, in particular, are key quantitative metrics that should be incentivised or mandated.

Q49. What should the role of the DSOs be in identifying and delivering whole system benefits?

Flexible energy resources will maximise whole system benefits when exposed to cost reflective market incentives. Neither DSOs, nor a central planner, will be able to optimise distributed flexible resources through tenders or procurement exercises to truly maximise whole system benefits. Ofgem and the flexibility market facilitator should therefore focus on improving market design and market access for flexibility.

We agree that network options assessment methodologies should be enhanced to consider the whole system value of allowing local flexibility resources to respond to system level price signals (e.g. for system balancing purposes). DSOs can inform this through improving visibility and monitoring of low voltage network capacity and demand/generation profiles.

Q50. Our historic approach to publishing and sharing datasets has been stakeholder led and focused on establishing good digital foundations in the DNOs. With the rapid pace needed for enhanced data and digitalisation, should we instead be considering incentives around strategic priorities, such as network planning, flexibility, and connections?

DSO data provision continues to improve and these data resources are valuable for innovators across the energy sector and beyond. This is an ongoing journey and there is scope to improve in:

- Data coverage and improved visibility of close to real time network dynamics
- Providing visibility over network development plans and linking this to availability of capacity for new connections
- Data accuracy, or transparency over limitations on data collection/validation
- Standardisation of data formats for key datasets across DSOs
- Signposting or curation of datasets as volume of data increases. AI can play an important role here
- Use of third party service providers to enhance, collate and improve access to data resources

Ofgem should improve the financial incentives available to DSOs for quality of the data portals, as well as continue to increase the strength of enforcement over licence obligations to follow data best practice. We recommend that specific feedback questions or surveys continue to be required in the DSO performance metric stakeholder submission to ensure that DSO data users are listened to.

Q51. How can we enable greater development of internal digital expertise in its licensees?

Stronger incentives will drive DSOs to continue improving their digital capabilities.

Q52. How should network companies use AI to improve network insight and decisionmaking (both operating expenditure (opex) and capital expenditure (capex)) and how should we be encouraging this through the ED3 framework?

Supporting third parties to access network data and innovation support is likely to provide the best 'return on investment' for any Ofgem effort expended on deployment of AI in the network sector.

Q53. Our aim is for the ED3 framework to be structured to deliver high impact, transformative innovation – do you think that further changes, alongside those proposed for the other sectors in our RIIO-3 SSMD, are required to deliver this?

Yes - Ofgem must look seriously at the full incentive framework around network innovation to challenge why customer funds are spent on extensive trials but without any consistent roll out into business as usual for promising ideas.

Q54. Are there any factors particular to DNOs that facilitate or challenge deployment of innovation on their own and across networks?

Internal fragmentation across licence areas is an issue in some networks, making it harder for new innovations to scale.

DNOs often recognise the need for consistency in approach between DNOs. However, working groups set up to reach consistency often fail to agree any consensus. This creates another challenge to the sector.

Resilient and sustainable networks

Q55. Do you agree that we should retain the Network Asset Risk Metric (NARM)? How should it further evolve in ED3?

Octopus Energy will not respond to this question.

Q56. Do you agree that we should consider a more integrated approach to managing asset health, together with load-driven expenditure, given the need to future proof for resilience (climate, cyber and physical security) and future demand? What might the risks and benefits of this approach be?

Yes, we agree with pursuing an integrated approach to asset health and load driven expenditure. This will avoid the risk of incentives becoming misaligned across different types of intervention and potential double payment by customers for interventions that provide different types of benefits.

Q57. In the context of making anticipatory investment decisions, what do network companies and other stakeholders need to enable the planning and delivery of cost-effective network resilience measures against our changing climate? What risks and opportunities do you see linked to an input-based approach to these investment plans?

Octopus Energy will not respond to this question.

Q58. How should we monitor progress on the delivery of climate change resilience? Do you have any specific learnings which can help shape this?

Octopus Energy will not respond to this question.

Q59. Do you have any comments on the suitability of current incentives to ensure that consumers continue to receive a reliable service in the face of climate hazards?

Octopus Energy will not respond to this question.

Q60. Do stakeholders agree with retaining and strengthening the main components of the environmental framework from RIIO-ED2?

Octopus Energy will not respond to this question.

Q61. Do stakeholders agree with building on the approach taken to cyber resilience in RIIO-3 for ED3?

Octopus Energy will not respond to this question.

Q62. What specific issues are network companies facing in relation to the skills and capacity of their workforce and what measures should we take through the regulatory framework to mitigate these issues?

Octopus Energy will not respond to this question.

Q63. What specific issues are supply chains facing and what measures should we take through the regulatory framework to mitigate these issues?

Octopus Energy will not respond to this question.

Q64. Given our comments in Chapter 6 around taking a more proactive approach, are there any specific features of a more anticipatory or strategic investment approach that might create risks or opportunities for supply chain and workforce constraints?

Octopus Energy will not respond to this question.

Q65. What would the benefits be of a geographical approach to delivering new and upgraded assets in terms of supply chain and workforce constraints?

Octopus Energy will not respond to this question.