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Quicker and more efficient connections – next steps

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Overview:

Some stakeholders have been telling us that getting connected to the electricity distribution network can take too long. This can limit the opportunities for economic growth and new sources of renewable energy.

Earlier this year we explained the process of getting a new electricity connection and we consulted on different and, in some instances, new ways of making it easier to connect.

This paper summarises the responses we received and explains how we now intend to take this work forward to improve the connections process.

Context

Getting a new electricity connection to the local distribution network promptly is important. Along with service and choice of provider, one of the most important factors in getting connected is whether or not the network has enough spare capacity to accommodate a new connection.

If significant work is needed then it can take a long time for a connection to be completed. However, it is not just about the time. For some customers, the network reinforcement costs can affect whether or not their project goes ahead.

Delays can be avoided if the capacity that remains is used more efficiently or if new capacity is created in anticipation of future connection requirements. This can be done by finding smart ways to reduce the need for additional capacity on the network – or through funding models that enable reinforcement to take place in anticipation of future connection customer requirements.

However, the cost of any work will ultimately be passed onto consumers – either directly to the connection customer, or to consumers more generally through their electricity bill. In our consultation we sought to find solutions which will benefit new customers without making other customers worse off.

Associated documents

You may find the following associated documents helpful –

- Quicker and more efficient connections (February 2015)
- How to get an electricity connection
- A guide to electricity distribution connections policy
- Non-traditional business models
- Position Paper: Making the electricity system more flexible and delivering the benefits for consumers

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Executive Summary

Some stakeholders feel that getting connected to the electricity distribution network can take too long and that this slows down the benefits they can offer by being open for business. Having quicker and more efficient connections could therefore help to support economic growth and increase our ability to use low carbon energy. So earlier this year we consulted on how to improve the connections process.[1]

In our consultation we explained the current arrangements for getting connected. We described a range of measures that could make better use of the existing network and avoid the need for time-consuming (and costly) reinforcements to accommodate a new connection. These potential improvements were well received by respondents.

We also presented three different models (two of which had been put forward by stakeholders) which could enable investment to be made in anticipation of a connection, instead of in response. Respondents broadly supported progressing all of the options presented, and told us that they were eager to see these different approaches developed further.

Next steps

We are keen to support changes that improve the connections process. We think that there are a number of improvements that can happen now within the existing connections framework which would enable network capacity to be used more efficiently. **In Chapter 2 we set out the actions and timescales that are necessary to progress these improvements**. There are other changes that may take longer to implement and many of these are linked to our work on Flexibility and Non-Traditional Business Models (we provide more detail on these in Appendix 2).

We also think that facilitating investment in anticipation of connections could also improve the process. In Chapters 3, 4 and 5 we set out the details of the three models we consulted on in February. We need to understand how these models might work in practice. **We therefore invite DNOs and stakeholders to bring forward schemes that could serve as case studies under these different models. We ask that these be submitted by 12 November 2015.** To a large extent this relies on DNOs being proactive to identify appropriate sites and participants. We'll be assessing how effective they are at doing this through our Stakeholder Engagement Incentive.[2]

We want to use these 'real-life' examples to understand what might be possible under current regulations/legislation. Although current arrangements already allow for anticipatory

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[1] Quicker, more efficient distribution connections, February 2015
[2] Stakeholder Engagement Incentive

investment, in general this is not what happens. We need to know why not and whether we should change this. We hope that these examples will help to establish models that can be commonly employed across the industry.

We recognise that some stakeholders may suggest arrangements that are not permitted (by the licence or the Electricity Act 1989). We still want to know about these schemes. While we can't allow DNOs to act outside of what is permitted, our understanding of the costs and benefits which may flow from changes to existing obligations could provide the justification needed to amend the 'rules' that govern connections.

1. Introduction

Background

1.1. In our consultation we explained the current connections process for the electricity distribution network. Electricity Distribution Network Operators (DNOs) are required by law[3] to provide a connection offer to anyone who asks. DNOs cannot discriminate and the system operates on a first come, first served basis – with no differentiation between types of projects.

1.2. Customers who request a connection must pay for some of the cost of the work involved. If a new connection requires reinforcement of the network, this cost will be shared by the connecting customer and all customers on that network. The cost of a connection can vary between projects. It depends on the size of the connection, where the connection is, the distance from the existing network and whether the network can accommodate the capacity needed. The other costs of the DNO are recouped through the electricity bills paid by all consumers.

1.3. We recognise that timely and cost-effective connections help the economy to grow and help decarbonise the energy we use. In seeking to improve the connections process for both demand and distributed generation (DG), a balance has to be struck between providing affordable connections and keeping electricity bills down.

The consultation

1.4. In February 2015 we published a consultation on quicker and more efficient connections. We wanted to identify how the connections process could be improved.

1.5. In the consultation we explained how the existing framework for distribution connections works in practice and asked stakeholders how getting a new electricity connection affected new developments, and what could be done to improve the process. We outlined a range of activities that could make smarter use of the existing network without the need for additional reinforcement.

1.6. We also described three models that could enable earlier investment to support new connections:

[3] Electricity Act, 1989

Model 1 where the DNO makes anticipatory investment and the costs are recovered from all consumers;

Model 2 where the DNO funds anticipatory investment but recovers these costs from subsequent connection customers, and

Model 3 where a third party/parties (developer/landowner) funds anticipatory investment on behalf of future connecting customers (from whom they recover the cost).

1.7. In principle all these approaches are possible within the existing regulatory framework, but are not commonly employed. We asked stakeholders to tell us when they felt each approach would be appropriate, and whether there were any barriers (financial or regulatory) which prevented their use.

High level summary of responses

1.8. We received 56 responses from a range of stakeholders including DNOs, local government organisations, renewable companies and bodies, private developers (construction), community groups and consumer representatives. The responses broadly supported the different approaches, acknowledging that some models may be more suitable for different types of customers (eg demand and generation).

1.9. There was a lot of support to take forward the measures proposed that would make better use of the existing network. Stakeholders were keen to see immediate action taken in these areas.

1.10. There was some reservation among respondents about the increased levels of risk that would be placed on consumers in general with Model 1. They acknowledged a need to manage these risks appropriately before undertaking this kind of investment.

1.11. Many respondents supported the general principles which underpin Models 2 and 3. Respondents were more cautious, however, in their support for changes to existing arrangements that might be needed to enable some features of the models proposed by stakeholders. These included; restrictions on who would be allowed to connect to new network and additional charges applied to future connection customers. At the very least the benefits associated with changes of this nature would need to be clear and affected customers must know how the changes could affect them.

1.12. A number of respondents also highlighted how having a national strategy for economic development and renewable energy could allow more certainty in the development of a long-term plan for the network. Although this is a salient point it goes beyond the scope of this consultation. Our focus is on what the DNOs can do to improve the process.

2. Improvements to the existing connections process

2.1. In our consultation letter we asked stakeholders for their views on changes that could improve the existing connections process. We asked stakeholders if there were opportunities to:

- Reduce the need for reinforcement via network management
- Reduce the need for reinforcement by managing connection offers
- Provide more flexible terms for the recovery of connection charges.

2.2. We received a positive response from stakeholders, who were keen to see progress as soon as possible in all of these areas.

2.3. There is already a large amount of ongoing work across industry that relates to the potential improvements we consulted upon or which stakeholders suggested in their consultation response. In this section we highlight how we will build on this existing work, but we have also identified where industry could go further. A summary of the actions arising is provided in Table 1 at the end of this chapter.

2.4. Stakeholders identified more changes that could improve the connections process that go beyond the actions outlined in this chapter. Some of the other changes identified by stakeholders will require ongoing work. We think that we, DNOs and connecting customers all have an important role to play in progressing improvements. We are keen to see DNOs take a more active role in network management, and to manage their networks more flexibly. As part of our work on flexibility, we are intending to work with DNOs and other stakeholders to clarify the future role of DNOs, and the nature of interactions with the system operator. We will also be thinking about the steps that are necessary to effect the transition. We are also aware that there has been a wave of new entrants into the energy market with new and non-traditional business models, which could transform the energy market. We are currently considering how to take forward these issues and will publish a proposed course of action by the end of this year. More details on these projects are provided in Appendix 2.

Reduce the need for reinforcement via network management

Making better use of available capacity

2.5. The need for reinforcement is driven by the extent to which a new connection adds to the peak demand on the network and whether this exceeds the remaining capacity. If a new connection can avoid adding to the peak, or if the profile of the peak can be reduced, then reinforcement can be avoided. This is arguably the most efficient way of enabling growth. To achieve this, the network needs to be managed in a different way than it has been in the past, with increased use of sources of flexibility. It needs individual customers to moderate the demands they place on the network at certain times. This may be by accepting a non-firm connection offer that might require them to curtail their use of the network at times of peak demand.

2.6. DNOs have been exploring these issues in recent years and we have supported them in this through our innovation funding – various projects, with a combined value of £70m, have been trialling new ways of enabling customers to connect in constrained parts of the network. If they are proven successful, these arrangements should be rolled out as business as usual across all networks.

2.7. We asked stakeholders what else could be done to better manage available capacity in order to support new connections. Some respondents suggested giving more consideration to how wind and solar profiles align (or complement each other). This could result in reducing the overall peak as different types of generation would be generating at different times. Some respondents noted that it would be useful for developers to have more information on network capacity and how DNOs calculate available capacity to help inform their decision on where to connect. Other suggestions included increased use of innovative approaches such as ‘Quote Plus’, which gives developers more guidance and assistance on where to connect. This approach could potentially reduce the number of unnecessary speculative applications made for different sites. Some respondents called for the reservation of capacity for independent generators and community-owned projects.

Our view:

2.8. There are many ways DNOs can make better use of available capacity. Some will emerge from the ongoing innovation trials, others will develop through closer engagement between a DNO and its connection customers. By listening and responding to their suggestions, DNOs should be able to improve information on network capacity, simplify the connections process and refine their assessment of peak demand requirements.

2.9. DNOs are incentivised to talk to their customers in this way through the Incentive on Connections Engagement (ICE),[4] which is part of the RIIO price control. Stakeholders should be prepared to use the ICE to ensure DNOs understand their expectations and seriously consider their suggestions for improvement. If DNOs don’t engage with customers effectively, the customer should tell us and we will consider whether the DNO should face a financial penalty under the ICE regime.

[4] Incentive on Connections Engagement

2.10. We note the suggestion from the Community Energy sector that capacity on the network should be reserved for their schemes. The current framework treats all customers equally. Reserving capacity for one category of customer (e.g. community schemes) would change this and could make it more difficult and expensive for other customers. To allow this type of preferential treatment we would need a clear justification, including how all consumers ultimately benefit. We do not yet have this justification. We recognise that it is difficult for small market actors to demonstrate this evidence, particularly community-led energy projects which can often be operated by volunteers. These are the type of issues that our work on non-traditional business models is considering. We provide more detail on this work in Appendix 2.

2.11. We agree with stakeholders that new sources of flexibility such as storage will be important in how we manage electricity networks in the future. We will be considering the legal and commercial status of storage in our work on flexibility which is also described in more detail in Appendix 2.

Flexible connection offers

2.12. In our consultation letter we asked stakeholders for suggestions of other ways to improve connections. Many noted that flexible connections are a useful way to maximise existing capacity. It is evident from the consultation responses that connecting customers require more information from DNOs on the flexible connections options available. Some stakeholders highlighted that flexible connections are not always offered in some network areas, while others (independent generators and community groups) noted that they are not always aware that a flexible connection offer might be available.

Our view:

2.13. It is important that all connecting customers facing high connection costs are aware that there may be alternative ways to connect to the network. We note that some DNOs already offer, or are in the process of being able to offer, flexible connections as a matter of course. However, we are concerned that not all DNOs are moving at the same pace in this regard and that it is not always clear to a connecting customer when a flexible connection may be a viable option. Many of the current arrangements to facilitate flexible connections were developed through trials funded by all consumers through the Low Carbon Network Fund[5] and we expect to see these rolled out across all networks. We recognise that arrangements may differ by region, but it is important that customers in one part of the country are aware of what is possible elsewhere – this helps to

[5] For example: Flexible Plug and Play, a £9.7m LCNF project to trial new technologies and commercial arrangements in order to connect distributed generation (DG), such as wind or solar power, to constrained areas of the electricity distribution network.

promote best practice. It is also important that DNOs roll out these arrangements as business as usual as soon as possible.

2.14. We expect DNOs – through the ENA - to make information publicly available on the different arrangements for flexible connections that are offered across the DNOs. DNOs should clearly explain how a flexible connection offer works including an explanation of the risks involved (e.g. being constrained off). This should be done by December 2015.

2.15. DNOs should also clearly outline on all issued connection offers that there may be alternative methods of connecting to the network. This will ensure that all connecting customers, including smaller customers are aware of the full range of options that are available to them. This should be done by December 2015.

Consortia

2.16. Some respondents suggested that increased use of consortia could improve the connections process, as it would allow a group of customers to share the cost of connecting.

Our view:

2.17. We agree that consortia can be a useful way of sharing high connection costs across a number of users. We acknowledge that whilst a consortium may not be a practical solution in many situations, DNOs should encourage and facilitate consortiums when appropriate. We were pleased to note some DNOs provide information on their websites and customers can register their interest in a particular area of the network to assist them in making contact with other prospective consortium members.

2.18. We expect all DNOs to clearly publicise the potential advantages of forming a consortium and the arrangements available for consortia. We expect DNOs to report to us on this by December 2015.

Changes to engineering standards

2.19. In our consultation letter we asked stakeholders what benefits the changes to engineering standards could bring. More flexibility in assessing what work must be done for individual connections (while ensuring wider network reliability) could reduce the need for reinforcement. At present this assessment is carried out in line with the requirements of engineering recommendation P2/6.

2.20. Respondents welcomed a review of P2/6, with some noting that any change to engineering standards should not make the network less reliable. A number of respondents also mentioned the importance of consistency in the application of engineering standards by DNOs, which they felt should reduce costs.

Our view:

2.21. A distribution code review panel sub group is reviewing engineering recommendation P2/6. The analysis which compares the merits of the current arrangements to others will be completed by May 2016. If this analysis suggests changes are beneficial then a consultation will follow. If a consultation is held we encourage stakeholders to use it to provide their views on how this standard could be developed.

Reduce the need for reinforcement by managing connections offers

Managing the connections queue

2.22. Only around 50 per cent of all distribution connection offers result in an actual connection being made (for generation connections this proportion can be less than 20 per cent). Yet every connection offer that is made reduces the capacity that a DNO can assume is available for other prospective connections – at least until the offer is either accepted or rejected, a process that can take many months. Even offers that have been accepted do not always result in a connection. Projects may be delayed (sometimes indefinitely) but the customer may prefer to hold onto the capacity they have been allocated rather than making it available for others to use.

2.23. In our consultation letter we asked stakeholders when it might be reasonable to withdraw capacity previously offered to customers. Respondents recognised that this is an important issue and that managing the queue more rigorously could release unused capacity thereby enabling others to connect.

2.24. The majority of respondents supported using milestones in connection offer contracts, with enforcement of milestones when no reasonable evidence of progress is provided. It was acknowledged that this will be unpopular with customers directly affected, but a clear set of rules consistently applied across DNOs should avoid individual DNOs from being unduly criticised.

Our view:

2.25. We believe that connection customers in general will benefit from a regime which allows capacity that has previously been issued to be withdrawn if there is little prospect of it being used as intended. We therefore want to see connection offers issued with clear milestones that allow a DNO to nullify the offer if the project is not progressing as planned.

2.26. We are aware that a number of DNOs already use milestones and we think this will serve as a useful base for developing common arrangements. This common arrangement should be applied consistently across DNOs, and connection stakeholders should be involved in formulating the approach.

2.27. We want the DNO-DG steering group to develop the principles and rules that will apply to using milestones in connection offers. The DNO-DG steering group should provide high-level principles to us by December 2015. These principles will be subject to wider consultation with stakeholders before they are implemented.

2.28. The DNO-DG steering group should also consider wider queue management issues such as how to withdraw capacity from connection offers that have already been issued but which did not contain milestones. We expect this group to identify the different issues, and by December 2015 to have developed a work programme to resolve them.

2.29. We note that operational sites which are underusing capacity for prolonged periods of time can also contribute to a lack of available capacity for new connections. The modification proposal DCP 115, which was approved by us in July 2015 amended the national terms of connection to clarify the rights of DNOs to take appropriate action when customers underuse their capacity.[6] We expect that this clarification will enable DNOs to proactively approach customers who are underusing capacity for prolonged periods of time.

Assessment and design fees

2.30. In our consultation letter we asked stakeholders about the benefits of allowing DNOs to charge upfront for assessment and design activities associated with producing a quotation. At present these are only charged to customers that accept a quote and include the cost of work in producing quotes that are not accepted.

2.31. The majority of respondents supported the ability to charge assessment and design fees, noting that it could reduce speculative applications. A number of respondents noted that improved service would be expected in return (faster service and more information available). Some respondents however, cautioned that making these charges could have

[6] Distribution Connection and Use of System Agreement (DCUSA) DCP114 - National Terms of Connection Amendments - Capacity Management (over utilisation) and DCP115 - National Terms of Connection Amendments - Capacity Management (under-utilisation)

a disproportionate impact on independent and community-owned generators as they have less access to finance at this point in the project process.

Our view:

2.32. The ENA has submitted a business case to DECC requesting the reintroduction of 'assessment and design' fees. The views expressed by stakeholders on this will provide a valuable contribution to DECC's consideration of the issue. If DECC decides to reintroduce such fees, we would expect DNOs to develop the associated charging structure fairly and consistently.

Letter of authority

2.33. A number of stakeholders suggested that customers seeking a connection offer should be required to have a letter of authorisation. They noted that this could reduce the number of speculative applications from parties that have no contractual relationship with the property they are seeking to get connected. We note that some DNOs already require a letter of authority from customers applying for a DG connection.

2.34. The DNO-DG steering group looking at queue management should also explore the impact of rolling out the requirement of a Letter of Authority across different types of connections. As part of their consideration they should remain mindful of any impact this might have on competition in the connections market. We expect an update on this work by December 2015.

Provide more flexible terms for the recovery of connection charges

2.35. The requirement to make a single upfront payment for a connection can present some customers with difficulties.

2.36. In our consultation we asked for views on DNOs offering flexible terms for connection charges. We received a mixed response from stakeholders on this issue. There was general support for flexible payment terms pre-energisation rather than post-energisation. Stakeholders recognised the benefit that flexible payment terms could have for connecting customers, particularly independent generators and community energy groups. However, many stakeholders also cautioned that flexible payment terms (post energisation in particular) would increase the risk to consumers more generally of having to fund the cost of work that cannot be recovered from a connecting customer. It was also noted that a lower initial obligation to pay the full cost of the connection might increase the number of speculative applications. Some respondents noted that a DNO has a low cost of capital, and as such if they were to offer more flexible payment connection terms to connecting customers, this would decrease the cost of connecting.

Our view:

2.37. We recognise that financing can be a challenge for some customers, particularly for smaller, community projects. For these schemes deferring payment would clearly help. We encourage DNOs to offer flexibility in their terms for connection payments and we note that some DNOs already provide flexible payment terms for connections (pre- and post-energisation). DNOs must however remain mindful of the general need to protect customers from higher costs, which includes protecting their own low financing costs by managing the level of risk their business is exposed to.

2.38. To ensure that all connecting customers are aware of the payment terms available, we expect each DNO to publish the availability and criteria for flexible payment terms pre-energisation, post-energisation or both by December 2015.

Table 1: Summary of actions to improve the current process

Action	Who	What will be delivered and when
Review of Engineering Recommendation P2/6.	Distribution code review panel sub group	Analysis on the merits of current arrangements compared to others will be complete by **end of May 2016**. If this analysis suggests changes are beneficial then a consultation will follow.
Develop a set of principles for when DNOs can withdraw capacity from DG projects which aren't progressing.	ENA and industry: DNO-DG steering group	A set of high level principles to be agreed in the DNO-DG steering group and submitted to Ofgem by the **end of December 2015.** These principles will then be subject to a wider consultation.
Consider wider queue management issues and develop options to release capacity for historic connection offers .	ENA and industry: DNO-DG steering group	The DNO-DG steering group will hold a workshop on queue management issues. Identify the different issues and develop a work programme to resolve them by the **end of December 2015**
ENA to publish information on the different arrangements for flexible connections offered across DNOs.	DNOs and ENA	A page will be created on the ENA website to explain the various flexible connection arrangements with links to DNOs' websites for further details by the **end of December 2015.**
Explore the feasibility of all DNOs requiring a letter of authority from DG customers applying for a connection.	ENA and Industry: DNO-DG steering group	The DNO-DG steering group will consider the feasibility of all DNOs requiring a letter of authority from DG customers applying for a connection. ENA to provide an update to Ofgem on progress by **end of December 2015.**
DNOs to publish availability and criteria for flexible payment terms pre-energisation and post-energisation.	DNOs	DNOs to publish this by **end of December 2015.**
DNOs to publish information on the availability of consortia.	DNOs	DNOs to provide an update to Ofgem on progress by **end of December 2015.**

3. Model 1 – the DNO funds the anticipatory investment

3.1. In our consultation we presented three different models that could enable investment to be made in anticipation of a connection instead of in response. In this chapter we describe Model 1 and summarise the feedback we received from stakeholders.

3.2. Under Model 1, a DNO will reinforce its network in anticipation of future connection requirements. The costs of doing so are spread across all of the DNO's customers. Therefore customers that wish to connect in the future do not have to pay – directly – for this reinforcement.

3.3. DNOs can already undertake this type of investment and we expect them to do so in circumstances when it's more cost-effective (and therefore cheaper for all consumers in time) than a piecemeal approach. This would be consistent with their obligation to develop and maintain an efficient and economic network.

3.4. There are however difficulties in doing this. A DNO needs to forecast what it believes will happen in the future in order to justify why investing early is more efficient than an incremental approach. But forecasting the need for future connections is notoriously challenging: economic conditions, government policy and a whole host of other factors influence what needs to connect and where.

3.5. If a DNO invests ahead of need and its forecasts prove to be wrong, then infrastructure will be built that is not needed. This expenditure will still need to be paid for by either consumers or, if we were to consider this spend inefficient, by DNO's shareholders.

3.6. We wanted to know what could be done to give DNOs sufficient visibility and certainty to know when early investment was appropriate.

3.7. Lots of stakeholders supported this approach, but many also recognised the inherent dilemma facing the DNOs and felt that this could place too much risk on the wider customer base of having to pay for 'stranded assets'.

What we expect of DNOs

3.8. We expect and incentivise DNOs to carry out effective stakeholder engagement. Through liaising with local authorities, government (both central and devolved administrations), planning authorities and developers, a DNO may be able to identify areas where there are plans for future developments and where it is sensible to reinforce the network.

3.9. **In assessing each DNO's stakeholder engagement activities, as part of the price control, we will take into account the extent to which this information-gathering and sharing is taking place.**

3.10. Armed with this information, DNOs should then be able to identify where additional network capacity may be required. They should also consider what indicators are available to assess the likelihood of potential developments going ahead.

3.11. This knowledge should then inform what benefits (to the development and to customers more widely) would flow from earlier investment. The key factor for the DNO to demonstrate is that this investment is in the consumer's interest by being cheaper than smaller individual investments on an ad hoc basis. Where this approach can be justified, then the DNO should make the investment.

3.12. This expenditure should be funded through the revenues we have allowed each company to recover during the price control period (RIIO-ED1, 2015-2023).[7] If appropriate, a DNO may also be able to use one of the mechanisms already in place (High Value Projects or Load Related Reopeners) to help recover the costs of unanticipated expenditure.[8]

What a trial could reveal

3.13. Through working with a DNO on a trial of this type we hope to establish criteria that could be used to demonstrate the benefits of undertaking anticipatory investment. We would also like to understand the indicators that could minimise the risk of creating stranded assets. This could result in a model that other DNOs could employ. A trial could also identify the impacts of this approach on current and future customers.

3.14. Our endorsement of the model used to justify the investment may help to reduce the concern of subsequent regulatory disapproval of this expenditure.

3.15. We invite DNOs to come forward with schemes that may fall within this approach.

[7] In its business plan, UKPN proposed £100m of strategic investment projects in London. We stated in our strategy decision that we were open to DNOs submitting a case for strategic investment projects in their business plans if they appropriately shared the risk of stranded assets between themselves, connecting customers and all other customers (DUoS customers). We stated that if a DNO could demonstrate benefits to DUoS customers of a strategic approach, then we would consider allowing DUoS customers to fund up to the level they would have done under an incremental approach. UKPN had demonstrated that the strategic investment projects it proposes are significantly lower cost and less disruptive for all its London customers than incremental approaches.

[8] For further information on these two mechanisms, please see the strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment, available online at https://www.ofgem.gov.uk/ofgempublications/47072/riioed1deccostassessment.pdf

4. Model 2 – the DNO funds initial investment, but recovers this from connection customers

4.1. Under Model 2, when providing an initial connection a DNO would reinforce its network in anticipation of further connections in the region. The additional cost of doing so would then be recovered from subsequent connection customers who would use the new network capacity that has been created.

4.2. The ability to charge a connecting customer for expenditure that had been undertaken when connecting a previous customer is provided for in the Electricity (Connection Charges) Regulations 2002.[9] This is more commonly referred to as the 'Second Comer' rule.

4.3. The approach we consulted on was illustrated by a model developed by DNOs. In this model, it was suggested that an additional premium would be charged to subsequent connection customers (known as 'second-comers'). This would serve to reduce the time taken to recover the cost of the initial expenditure. Adding a premium to each future connection charge would also provide some protection if future anticipated connections failed to materialise. DNOs also suggested new mechanisms, outside of existing price control allowances, to finance additional expenditure associated with this type of scheme.

4.4. There was significant support for the general principle, which underpins this approach – that connecting customers pay for the infrastructure which enables them to connect. It was felt to be applicable in areas of high demand with little or no capacity and potential regeneration sites.

4.5. Again, having the foresight to anticipate future connections and the confidence that these will materialise is challenging and could be a factor limiting the extent to which this approach is used. If connections don't happen as anticipated, DNOs may be concerned at how we would treat any 'unrecovered' expenditure.

4.6. There was limited support to restrict where future connection customers could connect and a mixed response to the proposal to charge those customers an additional premium. There was a strong emphasis on the need for transparency in charging for connection costs. There was a mixed response as to whether DNOs should be reimbursed by an upfront revenue adjustment or through existing mechanisms.

[9] https://www.gov.uk/government/publications/potential-changes-to-the-electricity-connection-charges-regulations-2002

What we expect of DNOs

4.7. This approach is already possible but DNOs need to be proactive in enabling it to happen. Through their stakeholder engagement with local developers, for instance, they could identify what the 'pipeline' of current and future developments might look like in a particular region. This should make it easier to see where enhancing a scheme for an initial customer could make it easier for those following to connect. This may involve establishing a consortium of prospective customers whose requirements could inform the scheme design and whose members give some (financial) commitment to using the enhanced scheme.

4.8. **In assessing each DNO's stakeholder engagement activities, as part of the price control, we will take into account the extent to which this interaction is taking place.**

4.9. DNOs need to consider what type of costs the second comer rules allow them to recover from subsequent connections. Any scheme that is proposed must be consistent with these. DECC is currently reviewing these second comer rules and this provides DNOs and other stakeholders with the opportunity to suggest changes to remove any unnecessary restrictions placed by the current drafting.

4.10. There may be other restrictions on what a DNO can charge associated with the need to comply with its connection charging methodology. We welcome opportunities to discuss these with DNOs and will consider scheme-specific requests to derogate a DNO from complying with its published charging methodology.

4.11. We do not, though, believe that the current regulations permit DNOs to add a premium to connection charges in order to ensure the recovery of initial investment. Neither do we believe that DNOs are allowed to restrict who can connect to the new network created.

4.12. In the first instance this expenditure should be funded through the revenues we have allowed each company to recover during RIIO-ED1. If appropriate, a DNO may also be able to use one of the mechanisms we have introduced to help recover the costs of unanticipated expenditure (high-value projects and load-related reopeners).

What a trial could reveal

4.13. Through trialling this approach we hope to establish a working model that could be applied by other DNOs. In particular we are keen to see DNOs develop an arrangement, which:

- is permitted under the current arrangements, or clearly identifies what amendments to the second comer rules (and other regulations) are required (and why);

- establishes how a consortium of prospective customers can be identified and maintained;

- obtains the necessary commitment from prospective customers that initial costs will be recovered; and

- identifies the impacts on current and future customers of this approach.

4.14. Our endorsement of the model used to justify this type of scheme may help to reduce the risk of DNO expenditure (that could not be recovered from future connection customers in the event that these customers did not materialise) being subsequently disallowed by us.

4.15. We invite DNOs to come forward with schemes that may fall within this approach.

5. Model 3 – a third party funds initial investment, but recovers this from connection customers

5.1. Under Model 3, a third party or group of parties (which could be an initial connection customer) would fund the cost of additional reinforcement to allow others to subsequently connect. The third parties provide a vehicle for funding investment, which means that investment can take place ahead of need. The second comer rules allow the third party to be reimbursed by customers connecting to that reinforced part of the network.

5.2. The approach we consulted on was illustrated by a model developed by stakeholders, including the Greater London Authority (GLA) and HM Treasury. In this example the third party was a Development Company, or DevCo. The DevCo example proposed by stakeholders included a potential requirement on future customers to pay an additional 'premium' to their connection charge and for this to be paid back to the original investor. They also proposed that the initial investor might stipulate who would be allowed to subsequently connect to the reinforced network they have helped create.

5.3. This approach may be suitable where the DNO can't justify funding the work itself either because the wider customer base are unlikely to get any benefit from the new infrastructure, or because there is lack of certainty on future development plans in an area. Although it would not be appropriate for a DNO to invest in these circumstances, a third party may still be prepared to do so.

5.4. Under the existing arrangements a third party can request (and pay for) the DNO to carry out additional work over and above the work strictly required to provide an initial connection. The second comer rules allow the third party to be remunerated for this expenditure. This type of scheme already takes place, but only to a limited extent. Difficulties in identifying a third party who has a vested interest in speeding up the process for future connectees could be a reason why this approach is not commonly undertaken. The third party also faces the risk that if forecasted connections don't come forward they will not recover their initial expense.

5.5. There was significant support for the general principles that underpin this approach – connecting customers pay for the infrastructure and this is returned to the initial contributor. Respondents felt that this model would be most suited to large new demand developments and urban regeneration projects. Several respondents noted that this type of arrangement can already happen and there are examples of where this is the case.

5.6. As with Model 2, the majority of respondents were not in favour of limiting who can subsequently connect to the network, although a few respondents saw justification in the DevCo controlling who connects as they will be taking the initial risk. There was also a mixed response to the proposal of charging a premium. Respondents considered that if it could be justified, it would still need to be reasonable, transparent and subject to regulation.

What we expect of DNOs

5.7. Although this model depends on a third party identifying themselves and a location where this approach might work, DNOs can also play a role in this process. Through their stakeholder engagement activities we expect DNOs to work with developers and local authorities to help inform a more strategic view of current and future work plans. Third parties may be unfamiliar with the potential flexibility that the current arrangements offer and we expect DNOs to help them consider different options to enable future connections.

5.8. In assessing each DNO's stakeholder engagement activities we will take into account the extent to which this type of interaction with third parties is taking place.

5.9. DNOs need to consider what type of cost the second comer rules allow them to recover from subsequent connections. Any scheme that is proposed must be consistent with these rules. As we noted in the previous section, DECC is currently reviewing the second comer rules and DNOs and other stakeholders should feed into this if they see the need for changes to be made.

5.10. We've also considered the additional features inherent in the DevCo arrangements proposed by stakeholders. At this stage, we do not believe DNOs would be permitted to allow a third party to restrict who can subsequently connect to their (the DNO's) network. However, we believe that a third party that wants to specify who can benefit from their investment could employ other mechanisms, such as sale of land or planning permission, to control who can access a reinforced area of the network.

5.11. We also do not think that the regulations currently permit DNOs to add a premium to connection charges in order to reimburse the third party for their initial investment risk.

5.12. We also note that under this approach, the third party could choose to use a competitive alternative to a DNO, such as an Independent Distribution Network Operator (IDNO), to carry out the reinforcement works.

What a trial could reveal

5.13. Through developing a trial of this approach we hope to establish a working model that could be applied by other stakeholders. In particular we are keen to see schemes progressed which:

- are permitted under the current arrangements, or clearly identify what amendments to the second comer rules (and other regulations) are required (and why);
- establish the type of projects that are suitable for this approach and what the constitution of a DevCo might be; and
- identify the benefits to future customers of this approach.

5.14. Our support for this type of approach may help raise awareness of the flexibility already provided by the current arrangements. With the assistance of DNOs and IDNOs this may encourage others to take a similar approach.

5.15. We invite stakeholders to engage with DNOs or IDNOs and come forward with schemes that may fall within this approach.

6. Next steps

6.1. We have set out a plan to take forward measures that will improve the process without the need for further reinforcement. These are outlined in Chapter 2. We will share an update of this work with stakeholders in January 2016.

6.2. **We are inviting stakeholders to come forward with specific schemes that fit within the three models outlined in our consultation letter by 12 November 2015**. We will then work with the parties concerned to trial schemes that can be taken forward within the current regulations, but where we may need to provide some additional guidance or clarification.

6.3. We intend to progress the trial schemes with immediate effect and will work closely with DNOs and other stakeholders to do this. **We will publish an update on these schemes in January 2016**.

6.4. We remain interested in proposals that would require changes to what is permitted. We do not however, at this stage have the evidence we would need to justify these changes. We welcome any further information that could be provided, including details of schemes that will otherwise not go ahead.

6.5. Please send details of any proposed trials to olivia.powis@ofgem.gov.uk.

Appendices

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Appendix 1 - Consultation Responses

Summary of consultation responses

We received 56 responses to our February consultation. Responses were from a wide variety of stakeholders including DNOs, IDNOs, representatives from renewable generators, community energy groups, Citizens Advice, development companies and city and regional authorities. Non-confidential responses are published on our website.[10]

The following is a summary of respondents' views on the questions posed. We have also included a general summary of the response to each of the four scenarios (or models). Many respondents noted that all of the scenarios should be explored to enable customers and DNOs to choose from a range of alternative approaches.

CHAPTER: One

Model: 1: DNO funds cost of anticipatory reinforcement

Twenty-one respondents supported this option, subject to some suggestions and reservations, which are described in further detail below. Support came from a wide range of stakeholders. Thirteen respondents had reservations about this option. An additional three respondents expressed strong opposition to this approach. They noted that connecting customers should always have to make a contribution to the cost of work they benefit from, that this approach did not incentivise DNOs to spend efficiently and that it may impact on competition in connections.

Q1. Would a DNO be sufficiently confident about future connections demand and the benefits to Distribution Use of System (DUoS) customers to justify this approach? If so, in which circumstances?

Several respondents acknowledged the difficulty of accurately forecasting connections and noted that a DNO could never be fully confident of future connections. Many respondents noted that increased stakeholder engagement with local authorities, planning authorities and developers would provide some evidence of future connections and increase certainty.

Some respondents felt that this approach would put too much risk on the generality of customers, and did not see the need to socialise the entire cost of reinforcement, noting that connecting customers should pay a fair proportion of the reinforcement cost. One respondent believed that this approach would not incentivise DNOs to efficiently reinforce the network as investment risk falls on the general consumer.

[10] https://www.ofgem.gov.uk/publications-and-updates/quicker-and-more-efficient-distribution-connections

Q2. What other barriers are there to DNOs taking this approach? How might these be overcome?

The key barrier noted by respondents (in addition to those already mentioned above) was the lack of a strong incentive on DNOs to assess the capacity that could be required in the future and to carry out anticipatory investment where they believe it is justified. It was noted that complete socialisation of costs may not be warranted as it places an undue burden on the general consumer.

These barriers fundamentally stem from a difficulty in forecasting connections and the resulting risk on customers of creating stranded assets. Some of the suggestions to overcome this included:

- development of a clear national renewables target and a long term grid development plan
- DNOs basing their decision on a discrete geographic location (informed by stakeholder engagement)
- Ofgem providing clear criteria of what is expected to build a business case
- requirement of an independent cost benefit analysis demonstrating cost savings to consumers
- any regulatory review to be extensive, but not overly burdensome.

CHAPTER: Two

Model 2: DNO funds (via DUoS) cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers)

Thirty-seven respondents expressed support for this option, subject to some suggestions and caveats. This includes the majority of the renewable generators, DNOs, regional and city authorities, development companies, community energy and the wider energy industry. Two respondents (one DNO, one IDNO) had reservations, while one respondent (community energy) did not support this approach.

Q3. What are your views on this type of approach and the RAV Buyback Model? Are there any elements which are essential, not required or should be changed – and why?

Elements considered to be essential included basing any investment decision on extensive stakeholder engagement and being able to demonstrate that early investment would reduce the overall need for reinforcement. Increasing the time period in which the second comer rules apply was also seen to be essential. Some respondents also wanted to base the model on the

Strategic Wider Works[11] process (used for certain projects on the Transmission system) but find ways to streamline the process.

Other suggestions included interpreting or amending legislation to avoid the need for there to be an initial connecting customer before a DNO could create additional reinforcement and recover this cost from future customers. Others wanted smaller generators to be given priority access to the capacity created.

One respondent noted that this is a risk-free model for DNOs and as such does not provide the right drivers for efficient and economic investment. Another respondent noted that this model would not deliver truly 'strategic' investment because work would always be in reaction to an initial connection request.

Q4. Please give details of any projects or schemes this type of arrangement could have helped progress which would have not otherwise gone ahead?

A number of respondents provided examples of generation projects, for example wind farms in Scotland, which were unable to proceed as the first customer faced prohibitively high reinforcement costs, exacerbated by the 'high cost cap' requiring that customer to pay the full cost of reinforcement. If the requirements of other customers had been taken into account, or the costs among this group, these projects may have been able to proceed.

Other respondents cited developments in areas where demand was high but capacity was limited such as the City of London, and potential regeneration sites where there is a strong commitment from a local authority but the high reinforcement cost is deterring investment.

A couple of respondents mentioned Registered Power Zones as an example of a similar arrangement.[12]

Q5. What would justify requiring subsequent connection customers to only be able to connect to the new, enhanced part of the network?

The majority of respondents did not support this proposal, noting that all customers should be offered the lowest cost scheme available.

Q6. What would justify a DNO charging a premium to subsequent connection customers to reimburse DUoS customers for the risk they bear in funding this work? What might be the impact of this? How should the premium be calculated?

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[11] https://www.ofgem.gov.uk/publications-and-updates/strategic-wider-works-sww-factsheet

[12] A previous price control mechanism to encourage DNOs to develop and demonstrate new, more cost effective ways of connecting and operating generation on their systems.

We received a mixed response to this question. Fifteen respondents noted that a premium could be justified. Respondents who supported the possibility of a premium said that it would have to be transparent, reasonable and justified by providing a faster connection, and some felt that it would still have to be the cheapest connection option for the customer. Other respondents noted that a premium was not justified, and that it may unduly discriminate against customers connecting to that area of network, and to smaller connections.

Q7. Over what time period would it be reasonable to expect DUoS customers to be reimbursed for their initial funding?

The majority of respondents stated that DUoS customers should be reimbursed over the lifetime of the asset, with some suggesting a tapered approach that applies a depreciation factor to the asset. A large number of respondents also suggested a 10-year period as appropriate.

Q8. When might it be appropriate for a DNO to have an upfront revenue adjustment to cover this type of scheme? Or should existing mechanisms be used?

Five respondents supported an upfront revenue adjustment. Some highlighted the prerequisite of a case demonstrating the need for the strategic reinforcement and the benefit to the generality of consumers, and an appropriate balance and controls to ensure it is not over used. A number of respondents noted that an upfront revenue adjustment could be suitable for large-scale reinforcements; otherwise only small-scale reinforcements could take place. Two respondents noted that a DNO should be able to submit an application for investment at any time for regulatory approval.
Four respondents favoured using the existing arrangements, and did not see a clear need for an upfront revenue adjustment. Three respondents flagged that the solution should not create charging volatility.

Q9. Do you consider that this approach would have any implications on competition in connections?

A number of respondents noted that reinforcement works are generally non-contestable and as such this model would not affect competition in connections. However, several respondents noted that where the reinforcement work required the expansion of network assets, it could limit competition in connections and consideration should be given to introducing competition in the delivery of strategic distribution system works.

CHAPTER: Three

Model 3: Connection customer funds cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers).

Twenty-nine respondents expressed support for this option, subject to a number of caveats and exceptions. Support came from renewable generators, all network companies, city/regional authorities, development companies, community energy groups and the wider energy industry.

Eight respondents had reservations about this option. A further three respondents (two community energy and one from the wider energy industry) did not support this option.

Q10. What are your views on the DevCo model and process set out in Appendix 2? Are there any elements which are essential, not required or should be changed – and why?

Although many respondents supported this option, it was generally noted that it would be most suitable for large new demand developments and regeneration projects. Some respondents noted that, if there was difficulty in finding a consortium willing to take the risk, it could still be suitable for distributed generation if it was underwritten by a local authority/development authority.

Several respondents noted that this type of arrangement can already take place and there are successful examples of this working. One respondent noted that the DevCo could be used to address all utility connections – saving on cost and public disruption.

Q11. Please give details of any projects or schemes this type of arrangement could have helped progress which would not have otherwise gone ahead?

Suggestions of projects which could be assisted by this type of arrangement include developments which could have secured funding from government/regional development authorities/Green Investment Bank, some developments in the City of London, New Anglia (a Local Enterprise Partnership), strategic connections such as the East Wales Ring, and a science park facing prohibitively high connection costs.

Q12. What would justify requiring subsequent connection customers to only be able to connect to the new, enhanced part of the network?

The majority of respondents did not think it was appropriate or necessary to require connection customers to connect to the new part of the network. Some respondents noted that this proposal would disadvantage community groups and small generators who cannot move locations. One respondent noted that it could be justified in rare occasions where the DevCo area was tightly defined.

Q13. What would justify a DNO charging a premium to second-comers to reimburse the customer? What might be the impact of this? How should the premium be calculated?

We received a mixed response to this question. Eleven respondents disagreed with the premium, believing that customers with little choice in where to connect should only be required to pay for the minimum amount of work needed to connect them. Sixteen respondents noted that a premium might be justified. They believed that the premium should be set at a reasonable level to reflect the risk but also be transparent and subject to regulation.

Q14. Over what time period would it be reasonable to expect the customer to be reimbursed for their initial funding?

Several respondents stated that the DevCo should be reimbursed over the lifetime of the asset, while several others suggested 10-15 years as an appropriate period of time.

Q15. What would justify the initial investor being permitted to restrict the type of schemes that would connect using the infrastructure it has paid for? For which type of schemes might this be appropriate?

The majority of respondents did not see any justification for the initial investor being permitted to restrict the type of schemes that would connect to the infrastructure.
One respondent noted that it would be justified for a development such as a business park where all the connecting customers were part of the DevCo. A couple of respondents noted that it could be justified as the DevCo is taking the financial risk, but that a clear business need for the restriction would be necessary. One respondent noted that the DevCo could have first rights over a proportion of the capacity, while another respondent suggested using a preferential connection rate to attract a particular type of development instead of refusing to connect types of customers.

Q16. Do you have any comments on the recommendations proposed in Appendix 3 to enhance consortium arrangements? What would justify these recommendations? Are there any other changes which would support consortium arrangements?

Several respondents cautioned at the practical difficulties of establishing a consortium, including issues relating to timings, costs of arranging a DevCo and the risks associated with a developer dropping out of the planned project. Some respondents noted that a consortium approach might be more suitable for demand developments.

Suggestions to improve consortium arrangements included a more proactive approach from DNOs, requiring all members to have planning permission and a penalty system in place for those who drop out.

One respondent queried if it was possible for the DevCo to buy the capacity for the area in which it has paid for the reinforcement, and then sell the capacity with a proportion of the reinforcement costs.

CHAPTER: Four

Scenario 4: Other ways of making it easier to connect

Q17. What role, if any, could changes to engineering standards play in helping to accelerate the connections process without damaging reliability levels? In what circumstances would this be appropriate?

A number of respondents welcomed the P2/6 review. But it was generally noted that any change of standards, should not lead to a reduction in network security standards or have a detrimental impact on quality. One respondent noted that while some projects may be workable with reduced security of supply it is not a sustainable solution for all. A number of respondents mentioned the importance of consistency of application of standards by DNOs, and that this should lead to reduced costs. One respondent noted that unspecified disconnections without compensation are unviable and so security of supply standards is the wrong area to focus on.

Q18. Which particular standards might most benefit the connections process if changed?

We received a number of suggestions of where technical enhancements could benefit the process (but not changes to specific standards). Respondents highlighted how encouraging time limited export, demand management, storage, and active network management of EHV networks could speed up the process. Considering the barriers of basic thermal and steady state voltage limits, exploring benefits from Dynamic Transformer Ratings and Dynamic Line Ratings, and consideration of how the generation/time profiles solar and wind align would also lead to a more efficient system. Two respondents suggested harmonisation of reactive power requirements across DNOs and better harmonisation with National Grid.

Q19. What benefits might the introduction of assessment and design fees bring?

The majority of respondents supported the reintroduction of assessment and fees, noting that it could lead to a reduction in speculative applications. A number of respondents felt that DNOs should provide an improved level of service in return (faster service and more information available). Six respondents cautioned that assessment and design fees could have a disproportionate impact on independent and community generators who may be less able to make an upfront payment on a scheme that does not proceed. Four respondents noted that the introduction of assessment and design fees would not necessarily bring about a reduction in speculative applications as these may not be deterred by relatively low value fees. Those respondents noted that approaches such as “Quote Plus” could be more effective, as could DNOs providing more information and transparency on availability of capacity.

Q20. Could more flexibility in the way assumed available capacity is calculated help accelerate the connections process? Are there any other improvements to be made in how DNOs manage interactivity between schemes looking to connect to the same part of the network?

We received a number of suggestions from stakeholders. Five respondents suggested that DNOs should offer flexible connection contracts as business as usual. Three respondents suggested that DNOs should give more consideration to how wind and solar profiles align, and seasonal variations. Three respondents noted that increased availability of information on network capacity and transparency on how capacity is calculated would be useful, and that there was a need to harmonise the approach across DNOs. Other suggestions included exploring use of storage, simplification of the interactivity process and having reserved capacity for independent generators and community energy projects.

Q21. When might it be reasonable to withdraw capacity that has previously been offered to customers?

Stakeholders generally supported (DNOs and industry) use of milestones in connection offers, with enforcement of milestones when no reasonable evidence of progression is provided. It was noted that it is difficult for a DNO to withdraw capacity and further direction from Ofgem would be welcome. Two respondents suggested withdrawing capacity from operational sites after a reasonable period of underutilisation – however it was noted that there is no incentive on DNOs to do this. A number of other respondents noted that flexibility was required to allow for ramp up of usage etc. One respondent noted that they did not believe a DNO could withdraw capacity without consent. One respondent suggested incentives on customers, such as offering a partial refund of a design fee to those who voluntarily offer back capacity.

Q22. Are there any other changes which could be made to reduce the need for reinforcement?

We received several suggestions from stakeholders such as; more active management by DNOs of EHV networks (including procurement of services such as reactive power, using demand-side management), investment in reducing demand, increased spatial planning, use of storage, dynamic line rating, increased use of consortiums and a requirement to have 5-10 per cent spare capacity at all substations.

A number of suggestions were made about queue management, including the requirement for all connecting applicants to have a letter of authorisation, increased advice to connecting applicants in advance of applications, and educating connecting customers on the correct amount of capacity that would meet their needs and actively monitor unused capacity.

We also received several suggestions relating to flexible connections, such as making this business as usual, sharing or capping the curtailment, and recording the energy constrained through constrained connections to use as a signal to trigger reinforcements (linking to work by Work Stream Six).[13]

Q23. What would justify a DNO offering more flexible terms for connection charges? What might be the impact of this?

We received a mixed response to this question. Five respondents suggested a DNO could justify offering more flexible terms for connection charges if it had sufficient financial commitment from the customer, and it did not pass on too much risk to general consumers. Two respondents noted that the DNO has a lower cost of capital so it would reduce the overall costs to consumers if the DNO initially funded the reinforcement and then charged the connecting customer over the lifetime of the asset. Two respondents noted that it might increase speculative applications so financial commitment would need to be high enough to deter this.

Three respondents noted that it would never be justified (post-energisation) as DUoS would take on too much risk, with another noting that it could affect DNOs' credit rating. Five respondents expressed some support for staged payments in line with project planning and

[13] Work Stream Six

expenditure (pre-energisation). One respondent noted that it could be justified if the increased reward to DNOs and DUoS matches the increased risk.

Q24. What type of schemes would most benefit from this arrangement?

Stakeholders noted that all developers would stand to benefit from more flexible arrangements but that community energy and independent generators/small developers with less access to finance would benefit most. A number of respondents felt that connection terms should be applied consistently. One respondent noted that it was not the purpose of the DNO to provide financing to schemes that would otherwise struggle to be funded.

Q25. What could be done to protect other customers from picking up any costs which cannot be recovered from the original connection customer?

Four respondents suggested using a form of user commitment, with suggestions including a liability and security scheme, or use of bonds or escrow accounts. Five respondents did not agree with the proposal and noted that the DNO or other customers should not have to cover any cost associated with bad debt.

Q26. Are there any other measures that would reduce the cost impact of connecting to the network?

We received a number of suggestions from respondents. Five noted that increased competition in connections would improve the connections process; six respondents noted that smart grids and innovation were important factors (including increased use of ANM) and two respondents suggested revising the charging boundaries and charging methodology and creating a national reinforcement strategy. Other suggestions included reforming the second comer legislation, preferential payment terms for flexible connection offers, greater transparency in connection pricing, improvements in transmission constraints and enhanced funding for reinforcements and innovation.

Summary and next steps

Q27. Which of the arrangements described above would deliver the greatest benefit to the connections process without placing additional risk or cost on the generality of customers, and why?

Many respondents did not express a strong preference for a single option, noting that each option had merits and should be explored.

Q28. Should wider benefits beyond energy system benefits (such as those provided by NTBMs) be taken account of in DNOs' or third parties' considerations of any of the measures or mechanisms described in this paper?

Nine respondents supported giving consideration to NTBM benefits and an additional three favoured it once the benefits to the DUoS customer could be clearly defined and quantified. Two respondents supported this once it did not create any additional costs for customers. Three respondents disagreed and two respondents suggested exploring the benefits through a separate review.

Q29. Do you have any other suggestions for delivering quicker and more efficient connections?

We received a number of suggestions to this question including the need for a more active role for local authorities helping to place demand with generation, progression of Workstream Six recommendations on flexible connections, more consistency across DNOs, provision of a sliding scale for connection quotes (to avoid connecting customers applying multiple times for a quotation), and a system architect to develop a grid strategy.

Appendix 2 – Wider areas of work

1.1 The connections process is closely linked to, and affected by, other areas of ongoing work in Ofgem. We have provided a summary of the relevant areas of Ofgem work here.

Flexibility

1.2 We define flexibility as the modification of generation and/or consumption patterns in order to provide a service within the energy system. [14] Flexibility is a key feature of energy markets and is used by several market actors across the value chain to efficiently manage their operations.

1.3 The transition to a smarter, more flexible electricity system has the potential to bring many benefits to consumers. Historically, the main source of flexibility has been generation. But system needs and consumers' needs are likely to change. New sources of flexibility, both on the supply and on the demand side, could help respond to consumers' changing needs while delivering a resilient, sustainable and affordable electricity system.

1.4 This year we worked on understanding how to facilitate the efficient use of new flexibility sources across the value chain. We propose to initiate work, focused around priority areas, to make sure that regulation supports an efficient, flexible energy system. We have prioritised areas where we can play a role, and where we have found there to be broad consensus that action is needed now to achieve benefits for consumers. We will:

- Encourage Distribution Network Operators to take a more active role in network management, moving to future Distribution System Operator roles and engaging effectively with the System Operator.
- Clarify the role of aggregators.
- Clarify the legal and commercial status of storage.
- Explore how to support more large industrial and commercial customers to participate in providing flexibility.

[14] For a more detailed definition of flexibility, see here

1.5 We will also:

- Examine and feed into European discussions on how future distribution charges may need to evolve. We see this as a longer term piece of work which we will be initiating thinking on now.

1.6 These actions do not seek to complete the necessary changes, but rather address specific, priority issues as a step towards enabling key new roles and business models for the future system. We recognise that the journey to the future electricity system is a longer term transition which will require work on many fronts, and ongoing engagement with industry and others.

1.7 We look forward to moving our work on flexibility forward as part of a broader programme of work with the DECC, intended to manage the transition to a smarter energy system. This work will also form part of a wider portfolio of related work in Ofgem, looking at issues related to the future development of the system.

Non-traditional business models

1.8 Recently, there has been a wave of new entry to the energy market and many of these entrants have new and non-traditional business models (NTBMs). This is a trend we expect to continue.

1.9 Some of these NTBMs could in the future transform the energy market and deliver desirable outcomes for consumers. These include: lower bills; lower environmental impact; improved reliability and safety; better quality of service; and, better social outcomes.

1.10 We want to ensure that regulation does not stand in the way of organisations which can deliver these outcomes. But, because energy is an essential service, we must also protect the interests of existing and future electricity and gas consumers. And this means we need to understand the benefits, costs and risks of any change to regulation.

Discussion paper

1.11 Earlier this year we released a discussion paper for comment, to engage in a dialogue with stakeholders on this area. We hoped to better understand the drivers, consumer benefits and risks of NTBMs. Ultimately, we are interested in their transformative potential and how regulation may impact upon them both now and in the future.

Consultation responses

1.12 Four main themes have emerged from our ongoing analysis of stakeholders' responses. Two themes relate to how NTBMs could transform the energy system, the other two are cross-cutting themes concerned with the implications for regulation.

1.13 A summary of responses to the NTBM discussion paper was also published today. The key issues and recommendations from stakeholders are as follows.

Transformative theme - new models of flexibility in a changing energy system

1.14 Many of you indicated that NTBMs are well placed to help consumers and communities engage with the changing energy system. They unlock benefits of embedded generation, demand-side response and storage. However, you told us that NTBMs wishing to provide flexibility services cannot reach their full potential under current regulatory arrangements. You raised a range of concerns related to the installation and use of these sources of flexibility, and the market signals that support the provision of flexibility in the system.

1.15 Ofgem is taking forward work on flexibility in a number of priority areas relating to these issues.

Transformative theme – local energy

1.16 In response to the low-carbon transition, consumers' disengagement with energy markets and their desire for better services, and to better realise the social and economic benefits of energy for communities, many of you expressed a desire to develop localised energy solutions.

1.17 You told us that retail market policy relating to switching and tariffs and the national nature of supply licensing, balancing and settlement are key regulatory issues for you. Many NTBMs told us that the regulatory system should be reviewed so it can better accommodate local energy undertakings.

Cross-cutting theme – enabling diversity and innovation

1.18 The majority of you commented that regulation needs to become more flexible and agile to accommodate, to respond to and to enable a changing energy system. Many of you argued that the status quo is maintained by the current regulatory regime, which is complex and prescriptive, stifles innovation and more suited to larger participants, not NTBMs. Many of you suggested that regulatory changes including an increased reliance on principles, less burdensome regulation, and bespoke regulation could improve the situation for NTBMs and consumers.

1.19 Many of you told us that the current regulatory framework doesn't offer the flexibility to develop and trial innovative business models and, therefore, to demonstrate the impact of NTBM approaches. You have asked for an 'innovation space' within the regulatory framework to trial your business models and demonstrate your impacts.

Cross-cutting theme – consumer protection and service

1.20 You identified consumer protection and service benefits as key cross-cutting issues. While NTBMs may have positive consumer benefits, some of you highlighted potential consumer risks such as data misuse, the emergence of new local monopolies, increased market complexity and system instability. Some of you also mentioned that future consumers might want a bigger say in the kind of protections available to them. While this might allow for more service differentiation and competitive pressure, others cautioned against establishing a potentially multi-tiered regulatory framework, citing the need for a consistent and level playing field.

1.21 Many of you told us that enabling the growth of NTBMs will have implications for consumers, both positive and negative. You told us we should consider these risks and opportunities when developing options for regulatory change.

Next steps

1.22 The vast majority of you said that regulation needs to become more flexible and agile to enable NTBMs. It needs to accommodate, respond to and enable energy system change. We already have a number of projects underway examining elements of this change. In light of your responses we are considering whether we should examine these issues in the wider context of our work on regulation and future energy system arrangements.

1.23 With this in mind, we are considering where our efforts are best focused next, and will publish a proposed course of action by the end of the year.

Appendix 3 – Glossary

C

Community Energy (CE) –Community energy covers aspects of collective action to reduce, purchase, manage and generate energy. Most schemes are geographically targeted, although some focus on communities of interest (e.g., a certain group of vulnerable consumers). These projects emphasise community engagement, ownership (this can include shared ownership or joint ventures), leadership and control with the community benefiting from the outcomes.

D

Department of Energy and Climate Change (DECC) - Government department responsible for Energy Policy and also for meeting the climate change targets detailed in the Climate Change Act (2008)

Distributed Generation (DG) – Any generation which is connected to the local distribution network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK.

Distribution Use of System (DUoS) – The DUoS charge reflects the cost of receiving electricity from the national transmission system and feeding it directly into homes and businesses through the regional distribution networks. All customers of DNOs pay DUoS charges on an ongoing basis. They are recovered from a customer's electricity supplier and will be one of the elements of their bill.

Distribution Network Operators (DNOs) - Own and operate electricity distribution assets which form a connection between a transmission system and most customers. They are holders of electricity distribution licences, which are granted for specified geographical areas in Great Britain. Currently there are 14 DNOs owned by six different groups.

H

High-value projects – Schemes specified and agreed with individual DNOs to be undertaken during a price control period. There is also a process whereby revenue allowances can be re-set during the price control period to account for schemes which could not be agreed upon at the start of the price control.

L

Load-related reopener – A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances relating to load) under a price control before the scheduled next formal review date

P

Price control – The process that we, as the regulator, use to set the revenue that network companies are allowed to recover over a set period of time and the outputs that they are expected to deliver. We set output targets and allowed revenues by taking account of consumer needs and company performance over the last control period and predicted expenditure in the next. The next price control, RIIO-ED1 will run from 2015 to 2023.

R

Regulatory Asset Value (RAV) - The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution business (the 'regulated asset base').

S

Second-comer legislation – The Electricity (Connection Charges) Regulations 2002 (ECCR) (also known as the 'second-comer' regulations) say that where someone connects using electricity infrastructure that was initially provided to make an earlier connection, the party that contributed to the initial connection can be reimbursed for a share of their cost by the subsequent connecting customer. This currently only applies if the subsequent connection is made within five years of the first.