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for energy consumers

Illustrative examples note

Summary

This section provides five illustrative examples to help explain the potential benefits of options we are considering under the Access and Forward-looking Charges Significant Code Review (SCR):

- Wind generator seeking to connect at distribution
- Local energy scheme
- Existing large industrial user
- Business with large vehicle fleet
- Storage operator

It also outlines the types of investment and operational signals we are seeking to send to users through these reforms to help promote our objective and principles for this review.

1.1. These illustrative examples are intended to explain the expected outcomes that we want to achieve, the potential impacts of the proposed options for reform on different types of network user, and how the potential reforms under the Access SCR could impact their access to, and use of, the network.

1.2. These options are purely illustrative to help explain the potential investment and operational decisions of individual network users that our reforms might influence. The accompanying chapters explain the different options in more detail. As part of our further work, we will do additional analysis to better understand and quantify how options for reform will affect individual network users and the overall energy system.

1.3. We have chosen these illustrative examples because they represent a range of different network users. The examples focus on the impacts of reforms to arrangements for large users. The impact of our proposals on small users is very important and our second working paper will include several illustrative examples for small users.

1.4. For simplicity, the illustrative examples focus on the options for reform under the Access SCR and on other options of valuing flexibility (ie procurement of flexibility). They do not discuss wider reforms (eg the changes to residual charges or reform of the retail market) which could also affect individual network users. The illustrative examples also do not identify the enablers required to help deliver a smarter, more flexible energy system (eg the rollout of smart meters and settlement reform).

Illustrative example 1 – A wind generator seeking to connect at distribution

1.5. In this example, a wind generator is seeking connection to the distribution network.

Desired outcomes

1.6. We want arrangements to facilitate the decarbonisation of energy at least total cost, taking into account the costs for networks. We want access and charging arrangements to incentivise the wind generator to install and manage their generation in a way which takes into account network costs. For example-

- In **deciding where to locate.** The generator should not just take into account the ease of receiving planning permission and how windy an area is – they should also take into account the network costs of bringing that generation to market. Consideration of all of these factors should lead to an optimised decision which helps to decarbonise the electricity sector at lowest cost. This might mean that projects in slightly less windy areas become more competitive if they are located where the costs of transporting the electricity across the network is low.
- In **deciding what technology to install**. For example, in taking account of network costs, the generator may decide that it is worthwhile installing a battery to store electricity generated during times of generation-led network congestion, or discharge into the system at other times.

1.7. We do not want these decisions to be influenced by arbitrary differences in network access and charging arrangements across voltage boundaries.

1.8. We also want arrangements to provide high quality information to network and system operators about where and when new sources of generation, like wind generators, need or value new network capacity. We do not want difficulties in obtaining network access being a major cause of delay to the development of new generation projects (eg those needed to facilitate decarbonisation of electricity supplies).

Current arrangements and issues

1.9. The wind generator has limited distribution access choices -

- Under **standard connection offers**, the wind generator would be able to export with limited likelihood of the DNO having to curtail this. However, if there is limited capacity available, the DNO may need to reinforce the network to facilitate the connection and the wind generator would face a charge for a proportion of these costs which could be significant. The need for reinforcement may also delay the connection date.
- Alternatively, a '**flexible connection' offer** allows the connecting customer to connect while avoiding the need for reinforcement. This can allow a quicker and cheaper connection, but it also means that the wind generator would have to accept a greater likelihood of their exports being curtailed by the DNO if the network is congested (ie their access is "non-firm"). Under a flexible connection offer, the customer is not compensated for any curtailment. Generally DNOs provide an estimated curtailment

rate, but no cap is defined on the level of curtailment that can be incurred.[1] This uncertainty could make it difficult for the wind generator to invest on the basis of a flexible connection offer.

1.10. As part of the connection process, the DNO works with the Electricity System Operator (through the "Statement of Works process") to establish whether there are transmission constraints that could affect the ability to provide network access to the wind generator. If there are transmission-level constraints the ESO will consider whether the "Connect and Manage" regime should apply. If it does not, this could delay the potential connection date.

1.11. We are also concerned that, under current arrangements, the wind generator's charges may not be cost-reflective. As distributed generation, under the CDCM this generator won't pay distribution network charges, but may receive network credits. The rationale is that the generation nets off demand and so, historically, would reduce pressure for new network capacity. Yet this occurs regardless of location - so in an area where generation is driving network reinforcement costs, the distribution-connection generation still receives this credit. The majority of distribution-connected generation do not pay any transmission network charges, even if it is driving local transmission constraints.

Relevant options for reform

1.12. Our potential options for reform could have the following impacts on the generator-

Improving access choice and definition	The wind generator could have additional or better options for access to choose from. • **Time-profiled access:** The wind generator could buy a battery and obtain access overnight (eg between 22:00-07:00) when there may be more spare network capacity. • **Better defined, non-financially firm access:** The terms of the non-financially firm access could state that the generator's output can be curtailed up to a maximum level (which could be set in hours or MWh), with the network operator required to take action to ensure that the level of curtailment doesn't exceed this level, or otherwise compensation may be payable. When the generator is curtailed, it could also potentially trade with other users on the local network to reduce its own curtailment obligation.
Wide-ranging review of DUoS charges	This could improve cost-reflectivity by ensuring that forward-looking charges better reflect where locating in certain areas of the lower distribution voltages could add to or reduce network costs. For example, the wind generator may face a charge (rather than a credit) in areas of the network where it is contributing to exports to higher levels of the network. Changes to forward-looking charges for users connecting 'higher up' the network (at extra high distribution voltages) could make them more predictable, better supporting the wind generator's decision about where to invest. Changes to the design of forward-looking charges could also inform the wind generator's operational decisions about when to export onto the

[1] ENWL have introduced a new curtailment forecast and index for flexible connections, which gives more information about average level of curtailment and introduces safeguards from excessive curtailment.

	network as charges could be higher during peak network periods. These could be set ahead of time, but vary by season and time of day, or the periods could be notified by the DNO a set amount of time (eg 24 hours) beforehand. Alternatively, forward-looking charges could be solely based on the wind generator's agreed access right (ie agreed capacity and the level of physical firmness). In that case, the wind generator may receive operational signals through being curtailed by the DNO, by trading curtailment obligations with other users (if they have a non-financially firm access right) or through flexibility procurement by the DNO or ESO. For further information on valuing flexibility see the box below on "Work outside of the SCR".
Focused review of TNUoS charges	As part of the Access SCR we are considering the design of TNUoS charges for distribution-connected generation users that are contributing towards, or alleviating, costs at transmission. Our second working paper will include further information on this.
Work outside of the SCR	The ESO and DNOs' work to develop the procurement of flexibility could provide the generator with additional opportunities to earn revenue. In exchange for a payment from the DNO, the generator may be willing to be curtailed more often than agreed as part of their access right. The cost of this "flexibility contract" may be cheaper to the DNO than the cost of reinforcing the network. Alternatively, this generator may be able to trade the extent to which they are curtailed through better enabling the exchange of access rights. If this generator valued staying on the network more than another generator in the local area, then it could pay to exchange its curtailment obligations with another generator. The ENA is progressing work to develop the exchange of access rights as part of their Open Networks programme.

Illustrative example 2 – Local energy scheme

1.13. A community energy project is seeking to connect a new 'solar farm' and large, new community centre at separate sites. Both of these connections are to the low voltage (LV) electricity distribution network. This party is seeking to be self-sufficient, by matching generation and demand locally. Both sites are half-hourly settled.

1.14. The area in which the community energy project is located has no capacity for new generation further up the distribution network on the high voltage (HV) network (ie it has a 'generation constraint'). This means that new sources of demand connected downstream of the constraint are beneficial in alleviating the generation constraint, but new generation can trigger the need for expensive network reinforcement.

Desired outcomes

1.15. We want all large users, including community energy projects, to be able to choose the type of network access that most suits their needs and helps to support efficient network development.

1.16. We want to ensure that access and forward-looking charging arrangements reflect where local energy can bring benefits to network management. For example, incentivising users to match generation and demand locally at certain times may make better use of existing capacity, thus avoiding network constraints and the need for expensive reinforcement. We want charging and access arrangements to influence the development of community energy projects, so that the projects are designed to take into account network impacts (eg contributing to decisions on the value of introducing local matching of supply and demand in their particular location).

Current arrangements and issues

1.17. Currently the solar generator and the community centre would need to apply for access (via connection requests) separately.

1.18. For each site, that community energy project would need to decide whether it wants a "standard connection offer" or a "flexible connection offer"-

- Under **a standard connection offer**, the DNOs would have no way to be assured that the two sites would match their demand and supply and so would therefore need to reinforce the network to accommodate the new generation. Under the current shallow-ish connection boundary, the community energy project would need to pay for a share of this and may also face a delay in being able to connect the solar generation.
- Alternatively, the user could choose to accept a **flexible connection offer** for the solar generation sites. However, this would leave the user facing an uncertain level of uncompensated curtailment to their solar generation.

1.19. The current DUoS charging methodology doesn't accurately reflect the costs or benefits of the community energy project matching demand and generation. For example, once connected, the solar generator would receive a credit (rather than a network charge), regardless of whether it is contributing to the network constraint or not. The community centre would pay a charge despite the fact that it would actually help to offset network constraints if its demand coincided with peak generation periods in the area.

1.20. Under the current TNUoS demand charging methodology suppliers are charged according to the aggregate demand of their Half Hourly-settled customers during three critical peak periods each year. These critical peak periods are defined as the three half-hours with the highest net system demand, between November and February, separated by ten clear days. However, we are concerned that the critical peak periods may not always align with periods of peak network constraints in particular areas, that the timing of critical peak periods is becoming increasingly uncertain to predict and that it may cause distortions between directly-connected generation and on-site generation (due to the differing charging regimes for demand and generation).

Relevant options for reform

1.21. Our potential options for reform could have the following impacts on this user-

Improving access choice and definition	The community energy project could have additional or better options for access to choose from. This user would be able to choose from a range of access choices (eg those access choices identified in illustrative example one), but there may be specific access options that are more relevant to this user. For example: • **Shared access:** The development of an option for 'shared access' could allow the solar farm and the community centre to

	share access, up to a jointly agreed level. The parties could then coordinate to share access between themselves. Sharing access to stay within a specified level may reduce the need for expensive network reinforcement. • **Better defined, non-financially firm access:** The DNO could offer better defined, non-financially firm access. These options could more clearly specify when the solar generator may be interrupted (eg setting caps about the level of curtailment that the user could occur). This could make curtailment risk easier to manage. The community energy project could also invest in an on-site battery storage to avoid any electricity being wasted (ie electricity generated when the solar generator is curtailed).
Wide-ranging review of DUoS charges	This could result in improved locational signals at the lower distribution voltages and improved cost-reflectivity. If the community energy project is balancing generation and demand locally, helping to avoid the need for network reinforcement, it could receive lower distribution network charges or network credits. This could influence investment decisions about where to progress community energy projects. Changes to the design of network charges could also influence the design and operation of community energy projects. For example, capacity-based charges could encourage the solar generator to invest in, and operate, a battery to store some of the electricity generated during the day to reduce the maximum export capacity required.
Focused review of TNUoS charges	This could result in changes to the current approach to critical peak pricing. For example, we could notify critical peak periods in advance to provide more certainty to suppliers about when the peak period will occur, we could introduce greater locational granularity in critical peak signals to reflect local network conditions or we could introduce more critical peak periods to smooth signals to suppliers. These reforms could improve cost-reflectivity and certainty of signals to suppliers to avoid contributing towards transmission network peaks. These signals could influence the design and operation of the community energy project – for example the changes may incentivise the relevant supplier to reduce the community centre's demand during critical peak periods. As part of the Access SCR we are also considering the design of TNUoS charges for distribution-connected generation users that are contributing towards, or alleviating, costs at transmission. Our second working paper will include further information on this.
Outside the SCR	The ESO and DNO is progressing work to develop the procurement of flexibility. Under these proposals, the local energy project could sell a service to the network operator to avoid the need for reinforcement (eg the local energy project could be paid to reduce generation or increase demand). Alternatively, better enabling the exchange of access rights could allow the generation site to trade curtailment obligations with other generators in the local area. These others generators may be more able to be flexible about their network access.

Illustrative example 3 – Existing large industrial user

1.22. In this example, an existing large demand user with the ability to participate in demand-side response, that is connected to the extra high voltage (EHV) distribution network. The industrial site has an on-site generator and is considering increasing the size of it.

Desired outcomes

1.23. We want this demand user to be able to amend its access rights to meet its needs as efficiently as possible. The arrangements should result in more efficient use of the network and better information to network operators about how the network needs to develop.

1.24. We want the demand user to face cost-reflective forward-looking charges that reflect the incremental costs or benefits it confers on the system. Forward-looking network charges should be simple, transparent and predictable. This should enable the user to make investment decisions (eg whether to invest in new on-site generation) and dispatch decisions (eg when to optimise use of their on-site generator) based on the charges or wider arrangements (eg flexibility markets). Arrangements should also mean that the on-site generator competes on a level playing field with directly-connected generation (ie facing broadly equivalent forward-looking charges if they are having a similar impact on the network).

Current arrangements and issues

1.25. Under the current regime, the customer determines what level of access they require. However, beyond that, the user has a very limited choice of access rights. If the industrial site's revised access rights require reinforcement of distribution assets, then the customer will be required to pay for a proportion of these costs through the connection charge.

1.26. Forward-looking network charges for customers connected to the EHV distribution network are specific to the user's particular location on the network and calculated based on forecasts of the user's contribution to future network reinforcement needs in that area. This means that they can be unpredictable, quite volatile and hard to respond to. Without clear, predictable signals to influence user behaviour, the user may not take into account network charges when making investment decisions (eg whether to invest in additional on-site generation) and operational decisions (eg when to import electricity and when to use their existing on-site generation).

1.27. There are currently differences in how directly-connected generation and on-site generation are charged. These differences may incentivise users to invest or not invest in directly-connected generation. These differences may also send different operational signals to directly-connected generation and on-site generation about when to generate electricity.

1.28. Under the current TNUoS demand charging methodology suppliers are charged according to the aggregate demand of their Half-Hourly settled customers during three critical peak periods each year. However, the critical peak periods may not always align with periods of local network constraints where the industrial site is located. The current approach may cause distortions between directly-connected generation and on-site generation. This is because a reduction in demand by the industrial site (due to the on-site generator), is charged differently to an increase in generation by directly-connected generation.

Relevant options for reform

1.29. Our potential options for reform could have the following impacts on this user-

Improving access choice and definition	This could provide additional options for this user to choose from. The user would be able to choose from a range of access choices (eg the access choices identified in the other case studies), but there may be specific access options that are more relevant to this user. • **Time-profiled, non-financially firm access:** The DNO could offer better defined non-financially firm access. These options could specify time periods when the industrial site may be interrupted. For example, the user may be willing to be curtailed during peak hours in the winter months. During these times, the industrial site could use their on-site generation to continue operating. These are examples of how access choices could be defined and are not definitive.
Wide-ranging review of DUoS charges	Changes could lead to greater stability of forward-looking charges for those connecting at extra high voltages through changes to network charging cost models and/or by setting charges on a zonal basis rather than for each individual site. Clearer, more predictable charges may incentivise the industrial site to take into account network impacts when making investment decisions (eg deciding whether to install additional on-site generation). Changes to the design of forward-looking charges could also inform the industrial site's operational decisions about when to use their existing on-site generation. For example, demand charges could be designed so that they are higher during peak network periods (as explained further in illustrative example one). This would incentivise the industrial site to reduce the amount of electricity that they import during these periods. Alternatively, forward-looking charges could be solely based on the industrial site's agreed access rights and these operational signals could be sent via the procurement of flexibility.
Focused review of TNUoS charges	Changes to the design of transmission demand charges may impact on the industrial users' investment and operational decisions. For example, a move towards an agreed capacity approach for charging demand may encourage the large industrial user to invest in, and operate, additional on-site generation to reduce the maximum import capacity required by the site. This is also more consistent with the approach for charging directly-connected transmission generation.
Outside of the SCR	The development of the procurement of flexibility may inform the industrial site's operational decisions about how to profile their work and when to use their existing on-site generation. For example, the industrial site may agree to a flexibility contract with the local DNO that requires them to reduce its level of consumption at specific periods (eg peak periods in winter), in exchange for a payment. To achieve the reduction in demand, the industrial site may need to use its on-site generator.

Illustrative example 4 – Business with fleet of electric vehicles

1.30. In this example, a delivery company is looking to invest in a fleet of electric delivery vans. The delivery company is located in a demand constrained area and is considering increasing its maximum import capacity to connect several rapid electric vehicle (EV) chargers for its fleet of delivery vans.

Desired outcomes

1.31. We want arrangements to facilitate the decarbonisation of transport at least total cost, taking into account the costs for networks as well. We also want the delivery company to be able to obtain access to the network that reflects their needs.

1.32. We want forward-looking charging arrangements to incentivise users, like this delivery company, to charge EVs in ways that are cheaper for the network. This might include influencing decisions on where to charge the fleet, when and how (eg potentially using some self-generation), and on whether to discharge electricity back to the system during peak times (vehicle-to-grid arrangements).

Current arrangements and issues

1.33. Under the current arrangements, the customer determines the level of network access they require (ie the maximum amount of import capacity required). Beyond this there are limited networks access choices available to demand users. In some areas, network operators have engaged with users to provide bespoke access arrangements, but generally there are limited "flexible connection" offers available for demand users.

1.34. If the delivery company wanted to increase its level of access to accommodate several new EV chargers, this could trigger expensive network reinforcement. Under the current charging regime, the delivery company and wider electricity consumers would share the cost of this reinforcement. The need to undertake network reinforcement may delay the company from being able to install new EV chargers.

1.35. We are also concerned that the delivery company's ongoing network charges may not be cost-reflective. Under the current arrangements, if connecting at lower voltages the customer's DUoS demand charges would be based on a generic network model for each DNO region and include static time-of-use charges that may not reflect peak times for the local network. Demand network charges are therefore the same, regardless of whether the user is located in demand-dominated area and contributing towards additional network costs. Under the current arrangements at the lower voltages, DUoS charges are based on a combination of the volume of electricity consumed during different periods, the amount of capacity required and a fixed charge. We are questioning whether this is the most cost reflective approach.

1.36. Under the current TNUoS charging methodology suppliers are charged according to the aggregate demand of their Half Hourly-settled customers during three critical peak periods each year. However, these critical peak periods may not align with periods of local network constraints in the area where the delivery company is located.

Relevant options for reform

1.37. Our potential options for reform could have the following impacts on this user-

Improving access choice and definition	This could provide additional options for this user to choose from. The user would be able to choose from a range of access choices (eg those access choices identified in the other illustrative examples), but there may be specific access options that are more relevant to this user. • **Time-profiled, non-financially firm access:** the delivery company may be willing to accept a cheaper, non-financially firm access right. For example, the user may be willing to be interrupted (up to a cap) during working hours when the majority of their vans are delivering goods and not based at the site. This is an example of how access choices could be defined and is not definitive.
Wide-ranging review of DUoS charges	Improved locational charges would improve the signals to the delivery company about how their behaviour can increase or reduce network costs. This may influence the delivery company's investment decisions. For example, the introduction of credits for demand users in generation-dominated areas could encourage the company to install EV chargers at another site in a generation-dominated area, where it could reduce the need for network reinforcement and receive network credits. Changes to the design of forward-looking charges could also influence the delivery company's operational decisions. Network charges could dynamically vary by season or time-of-day to reflect peak network periods. This could incentivise the delivery company to charge their EVs at off-peak periods (eg overnight) when there is more spare capacity on the network. The delivery company may also be able to use vehicle-to-grid (this enables energy stored in electricity vehicles to be fed back onto the system) to help reduce demand during peak periods. Alternatively these signals could be sent via the procurement of flexibility.
Focused review of TNUoS charges	Making changes to the current approach to calculating transmission demand charges may also influence the delivery company's operational decisions. For example, introducing more locationally granular critical peak periods may encourage the delivery company to charge their EVs when there is spare capacity on the local transmission network. This may be at a different time than the system peak, which is reflected in the current arrangements.
Outside of the SCR	Outside of the SCR, the procurement of flexibility is an alternative method of delivering a more flexible energy system. The development of flexibility markets would improve the signals to the delivery company about the value of the being flexible. This may influence the delivery company's investment decisions. For example, the delivery company may decide to install EV chargers at an alternative site in a region where the DNO has issued a request for new providers of flexibility. The development of flexibility markets could also influence operational decisions. For example, the delivery company may sign a flexibility contract to increase or decrease demand at specified times, in exchange for a payment from the DNO.

Illustrative example 5 – Storage operator

1.38. In this example, a storage operator is looking to invest in a new battery storage site. The storage operator can choose whether to connect to the transmission or the distribution network. The local distribution and transmission network both face generation constraints.

Desired outcomes

1.39. We want storage operators to be able to get access to the energy system that meet their needs as efficiently as possible. The arrangements should result in more efficient use of the network and better information to network operators about how the network needs to develop.

1.40. We think that storage facilities should face forward-looking charges or credits for both 'import' and 'export'. These credits or charges should reflect the costs or benefits that the storage operator confers on the network; where storage operators are only operating in ways that help reduce network constraints then they would receive credits. We want charging and access arrangements to influence the development of storage projects, so that the projects are designed to help make best use of network capacity.

1.41. We do not want decisions about where to connect to be influenced by arbitrary differences in network access and charging arrangements between transmission and distribution or across distribution voltages.

Current arrangements and issues

1.42. There are differences in how forward-looking charges are calculated for 'import' and 'export'. For example, at distribution level, generators do not receive charges, even in areas where they contribute towards the need for network reinforcement. In comparison, demand users are not eligible for credits, even where they help avoid the need for reinforcement.

1.43. Under the current charging design, EHV-connected users incur a charge based on the volume of energy imported or exported during "super-red period". These super-red periods are set for a whole DNO region and, although charges vary to reflect differences in costs across the region, the periods may not reflect local network peak periods.

1.44. There are differences in how forward-looking charges are applied to distribution and transmission-connected customers. For example, distribution network charges for EHV connected users are less predictable than transmission network charges. These differences could be distorting investment decisions.

1.45. Transmission demand charges are currently based on a user's average gross consumption during three peak half hour periods between November and February (ie the 'triad' methodology). Whilst the current approach has been effective at eliciting demand response, it is becoming a source of uncertainty and the critical peak periods may not always align with periods of peak network constraints in particular areas.

Relevant options for reform

1.46. Our potential options for reform could have the following impacts on this user-

Improving access choice and definition	This could provide additional options for this user to choose from. The user would be able to choose from a range of access choices, but there may be specific access options that are more relevant to this user, for example- • **Better defined, non-financially firm access:** The user could accept non-financially firm access to allow quicker and cheaper connection to the distribution network (that avoids the need for expensive network reinforcement). The access choices could include well-defined limits on the extent to which the storage operator can be curtailed (eg it will face a maximum of 10 hours of curtailment per month). The storage operator may be willing to accept this in exchange for lower charges as it will be flexible enough to import/export electricity outside of local network peak periods. This is an example of how access choices could be defined and is not definitive.
Wide-ranging review of DUoS charges	We are considering cost model options where generation and demand receive equal and opposite charges and credits. This could influence a storage operator's operational decisions. For example, credits for demand may incentivise storage to import electricity at times when it can alleviate generation constraints. Options to introduce locational differences in the "super-red" period to reflect local network conditions may also influence the storage operator's operational decisions. For example, the storage operator may amend when it exports or imports onto the network to avoid contributing towards local network constraints. Differences in how network charges are calculated at transmission and distribution level may also influence the storage operator's investment decisions. Using an alternative network cost model (eg an ultra long-run marginal cost approach) or a different level of locational granularity (eg zonal charges) may improve the predictability of distribution network charges for EHV-connected users. It may also minimise a potential distortion between transmission and distribution arrangements that may affect investment decisions.
Focused review of TNUoS charges	If it decided to connect to the transmission network, then reforming how transmission demand charges are calculated could influence the storage operator's operational decisions. For example, introducing an 'ex-ante' approach to critical peak charging where the ESO notifies parties in advance of a critical peak period occurring would allow the storage operator to adjust their operational activities and avoid a critical peak period. The critical peak period could also vary regionally to reflect local network peaks. Alternatively moving towards an agreed capacity approach could influence the storage operator's investment decisions by incentivising the storage operator to reduce the amount of capacity requested and smoothing the amount of import and export over a longer period. As part of the Access SCR we are also considering the design of TNUoS charges for distribution-connected users that are contributing towards, or alleviating, costs at transmission. Our second working paper will include further information on this.
Outside of the SCR	Outside of the Access SCR, the development of flexibility procurement is an alternative method of achieving a smarter, more flexible energy

	system. The ENA is progressing work to develop the procurement of flexibility as part of their Open Networks programme. Selling flexibility services to the local network operator may provide an additional source of revenue for the storage operator. This may influence the storage operator’s investment or operational decisions. For example, signing a flexibility contract with a local DNO may financially incentivise the user to connect to the distribution network, rather than the transmission network. Alternatively, a flexibility contract may influence a storage operator’s operational decisions about when to export and import onto the network. Alternatively, if the storage operator has agreed to access rights that allow it to be curtailed, then it may be able to trade the extent to which it is curtailed. The ENA is working to better enable the exchange of access rights as part of their Open Networks programme. If the storage operator valued staying on the network less than another user in the local area, then it could be paid to exchange its curtailment obligations.