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Dear Alex

Key enablers for DSO programme of work and Long Term Development Statement

We welcome the opportunity to comment on the key enablers for distribution system operation work programme with specific emphasis on the Long Term Development Statement (LTDS). The review is timely in view of the expected changes in network usage due to increased take up in low carbon technologies (LCT) forecast for RII0 ED2.

Our key comments on the two sections of the consultation are detailed below whilst our detailed responses to the question raised in the consultation are contained in Appendix 1 attached.

Part 1 – The Long Term Development Statement

Electricity North West recognises that all data is theoretically useful, but it is necessary to prioritise which data is collated and shared based on potential utility versus its costs. We already share network information beyond the LTDS requirements on our website. For example, single line diagrams of the HV network and HV network modelling data are available in the secure LTDS webpages. Plus, users can also register to access to our GIS data. Information sharing has increased over time as all DNOs have responded to stakeholder requests for network capacity / headroom information to be provided in the form of heatmaps by providing these on their websites

Whilst the current LTDS mandates the publishing of data for the 33kV and 132kV networks an extension to include HV and LV networks data will see a significant increase in the cost of compiling and making the data available due to the scale difference in the number of assets of HV and LV networks. The type of data being shared is likely to change. For example, network usage data will need to be more than just maximum demand, especially as flexible connections become more common.

Increased data sharing is likely to require the creation of data repositories to which access is granted as an alternative to the current publishing of network data in secure areas of licensees' websites. A key part of our digital strategy is specifying a data platform that will aid business intelligence and analytics, where third parties can come and extract data relevant to them.

It is imperative that all network and system operators share network data not only to provide a level playing field but to enable whole systems and DSO solutions, and it is becoming increasingly important for more real time data sharing across network boundaries.



Increased data sharing coupled with increased network visibility at lower voltage levels has an associated cost and network operators will need to be appropriately funded to carry out this activity.

We believe that a common set of high level principles for estimating load growth will improve stakeholder understanding and engagement in the D-FES process resulting in greater confidence in the forecasts. Our [ATLAS](#) forecasting methodology (an output from a NIA project) has provided a robust forecasting methodology. The detailed methodologies for all of ATLAS forecasting steps and building blocks have been published. The forecasts used in D-FES, LTDS and Week 24 submission are subsets of the overall forecast produced using our ATLAS methodology.

Part 2 – Key enablers for DSO programme of work

Is it disappointing that the lack of smart meter data is currently hindering network operators unlocking the potential benefits originally identified for the programme.

We see enhanced monitoring and the active management of the electricity distribution networks providing significant benefits to customers and both are key enablers of unlocking more DSO functionality. It would be beneficial for all interface points between network operators (eg IDNOs, TOs, and other DNOs) that both parties have access to their counterparties' network monitoring points data in real time. To enable sufficient monitoring and data sharing to be delivered DNOs will need to be appropriately funded to carry out this activity.

We believe that Active Network Management is integral to DNOs own systems to provide the most efficient solution. Where Active Network Management systems are utilised, we believe there is a need for clearly defined rules which promote the most efficient solution to be utilised and delivers the most benefit to customers.

We maintain that some of the DSO functions which Ofgem have identified should inherently be under the control of DNOs to allow them to fulfil their licence obligations and where it is in the best interest of our customers.

Yours sincerely

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Steve Cox
Engineering & Technical Director

Appendix 1 – List of consultation questions and responses

Part 1 – The Long Term Development Statement

Question 1: We consider that improvement is required in the visibility of DG and LCTs connected to the distribution network. In addition to DG and LCT connections, can you identify areas for improvement in the current data that is shared in the LTDS?

Electricity North West already shares the following additional network information on its website beyond the LTDS requirements:

- Single line diagrams are available for the HV network
- A snapshot of our high voltage (6.6kV and 11kV) network modelling data is provided via the secure LTDS webpage, and
- Users can also get access to our GIS data by registering.

Anonymised data for DG over 1MW and above is already provided in LTDS Table 5. This will be formalised in the production of a System Wide Register under the ENA Open Networks project (WS2 P1) and enhanced by the approval of and publication of the information required by DCUSA modification proposal 350.

The existing Form of Statement requires information regarding “**Network Development Proposals**” where those proposals have secured finances. This requirement could be expanded into a forward-looking statement of expectations. We could include a set of future forecasts, based on our Distribution Future Electricity Scenarios (DFES) document.

In addition, as the penetration of flexible services increases, the visibility of the type, size, and location of contracted flexible service provision to the distribution network will assist existing and potential customers understand business opportunities.

Question 2: Can you identify areas for improvement in the presentation of network information in the current FoS?

Access to information: The current presentation of network information in Microsoft Excel workbooks for download by users is manageable whilst the information contained in the workbooks is limited to the EHV networks. The information requires an understanding of the way a distribution network is designed and operated to identify network opportunities.

If the information provided is to be expanded to cover lower voltage networks, the Microsoft Excel form of data would not be appropriate, for collation and interpretation of the data, because of the volume of data to be provided. Network operators would need to adapt their approach to the open availability of data, potentially by providing access to a data repository and allowing users to access the databank and retrieve whatever data is relevant to them. When considering this it would be important to consider the practical restrictions of delivery of this level of data sharing in a relatively short timescale.

Presentation of network information: It is noted that to facilitate power system analysis by third parties the data will need to be provided in an agreed consistent and interoperable format. For those stakeholders that require high level guidance in the identification of network opportunities (demand/generation headroom, fault level limitations etc) a suite of interactive tools should be provided. These tools can be built on the best practice of current DNO provisions, but consistency and standardisation of interpretation needs to be established across the industry.

Question 3: The EDTF and others have identified the need to collate and share 11kV and lower voltage network data. Is there value in creating a sharing mechanism for 11kV and LV network data ahead of the expected roll out of network monitoring and telemetry in RIIO-ED2 and the limited data availability in RIIO-ED1?

It would seem sensible to create an industry standard data sharing mechanism which includes HV and LV data; but it is anticipated that this sharing mechanism would not be restricted to HV and LV network data alone.

The appropriate sharing mechanism will need to be developed to satisfy a variety of data sharing

requirements. Development of the appropriate mechanism will require industry collaboration which Electricity North West is committed to taking a full and active role in. We do not believe that it would be desirable to mandate, via LTDS, the creation of a sharing mechanism for network data at this stage. We note that HV networks include 20kV, 11kV and 6.6kV networks.

A key part of our digital strategy will be specifying a data platform that will aid Business Intelligence & analytics. One component of such a system could be externally facing, where third parties can come and extract data relevant to them after registration.

Within our current business practices, we only propose targeted HV and LV network monitoring depending on LCT penetration. Within multiple future price control periods it is anticipated that we will continue to deliver HV and LV monitoring as required by LCT penetration. To fully deliver HV and LV network monitoring in ED2 would represent a significant cost for network and system operators in the infrastructure required to gather the data on site as well as the communication, storage and analysis infrastructure.

Question 4: Given the complexity of future distribution networks, static data alone may not satisfy user needs. Should the FoS be enhanced to mandate the development of a common network model to allow power system simulation that each licensee must make available for exchange to users and interested parties? If so, what do you consider to be an appropriate standard?

We do not feel that at this time a common network model is not required, however common standards for sharing of network data could possibly be mandated as discussed in response to Question 5. This item could be revisited at a late date once the modifications to the LTDS have been implemented.

The question implies a dynamic model created from a current configuration of the distribution networks. This is a development that will be required, in time, to facilitate whole system planning between transmission and distribution networks. There is a need to consider the utility vs the effort in creating the models for publication as they could take significant effort to prepare and may not open up the opportunities arising from other initiatives, such as providing raw (half hourly) power flow data.

In the short term; providing a number of network models that relate to specific demand/ generation cardinal points would be a useful addition to the LTDS. The network models should be presented in an industry standard format to aid understand and application of the models by customers and/ or stakeholders.

The appropriate standard to provide the network models is the IEC Common Information Model standard. This standard has already been adopted by the European Network of Transmission System Operators for Electricity (ENTSO-e) data exchanges for the Ten-Year Network Development Plans and Regional Investment Plans so is well understood by NGESO. Some DNOs have also developed CIM capability for internal data exchanges or as part of innovation projects.

Question 5: From a review of industry publications we consider that interoperable standards will underpin future DSO activities. Should the FoS mandate the adoption of a IEC 61970 CIM and IEC 61968 CIM for Distribution Management, such that data is collated and constructed in a manner similar to WPDs CIM innovation project model? Are these standards mature and what are the likely benefits and costs?

The adoption of a single standard would be a sensible approach, but the choice of standard should be discussed in the working group. The main benefit would be that the data is provided in a format sufficient to allow power system simulation irrespective of the power system analysis software being used.

It is not clear whether the LTDS FoS is the appropriate place to mandate this approach; the CIM standard is not a static standard and will probably be applied to more than network data, therefore an appropriate form of governance needs to be established.

Network companies could be mandated to produce data sets in CIM format and also participate in a UK CIM governance group. Furthermore, the UK governance organisation should represent the UK at international working groups, ensuring that there is no divergence between the international (IEC)

standards, and the standard developed to meet UK needs.

Question 6: Should the FoS also be retained in its current Microsoft Excel form? Is there value in this format?

There is value in this format whilst the volume of data is limited. Providing the EHV data in this format has proven to be an accessible data sharing mechanism.

However, should the LTDS be expanded to incorporate HV and LV network data then Microsoft Excel would not be appropriate because the volume of data would be unmanageable. The critical point is to ensure that data is provided in a format which allows for easy extraction for use by a power systems analysis tool. We would suggest that the choice of standard should be agreed in the working group.

Question 7: Ensuring network information remains accessible is a priority. At present there is no formal requirement for the production of heatmaps. In order to ensure future customer can access the required data, should the scope of the LTDS and FoS be extended to mandate the production of heatmaps?

Heatmaps are a visual method of presenting data but they are not the only method.

The heatmaps are underpinned by the data that is and will be available in another format. If heatmaps were to be mandated in the LTDS FoS then a minimum standard will need to be specified e.g. all heatmaps are to be presented as an interactive tool and the backing data is accessible so that there is consistency of interpretation of displayed values.

The priority is that that the network data is shared appropriately. Heatmaps and their complexity could either be left to the discretion of the network company and be a form of differentiation or dependent upon the capability of the analytics tools associated with the industry data repository.

Question 8: Would there be benefit to adopting common guidance or formats on information presentation within heatmaps, including the presentation of technical information and cost information? What are the barriers to its adoption?

Prescribing common guidance or formats on the information presentation within heatmaps is not an issue per se as long as the guidance or format is in terms of a minimum requirement, which still leaves the licensee the opportunity to innovate and introduce new methods as they emerge. This also allows licensees the freedom to present data in a manner which suits their individual stakeholder's requirements.

Question 9: The core focus of the LTDS is to assist users to enter into arrangements with the licensee and evaluate the opportunities for doing so. Should the scope of the heatmaps include other network needs, such as flexibility requirements? What is the best mechanism to notify network users of opportunities to enter arrangements with the licensees?

The scope of the LTDS FoS would need to be extended to cater for other network needs. Once the other network needs are identified their presentation (for example as heatmaps or in tabular form) can be agreed.

The benefit of presenting flexibility requirements within a heatmap are minimal. As detailed in the response to Question 2 it is preferable to develop a suite of interactive tool that allow "opportunity" identification in a specific manner, rather than looking at a map.

The scope of the data shared and presented in Heat Maps will need to be more than maximum demand, especially as flexible connections become more common. Networks are no longer always going to be constrained by maximum demand or cardinal points, and current published data / heatmaps will need enhancement to ensure it reliably informs customers of the feasibility of their connections.

There is a risk that if too much information is mandated for inclusion within the LTDS the document that the document will become unwieldy to produce by licensees and read by stakeholders.

Question 10: On what frequency should these maps be updated? Should they be updated as there are changes to the underlying data or periodically?

Presently, the LTDS is updated annually; this is appropriate because the LTDS applies to the EHV networks which do not change significantly during the year and because the update is typically a manual process.

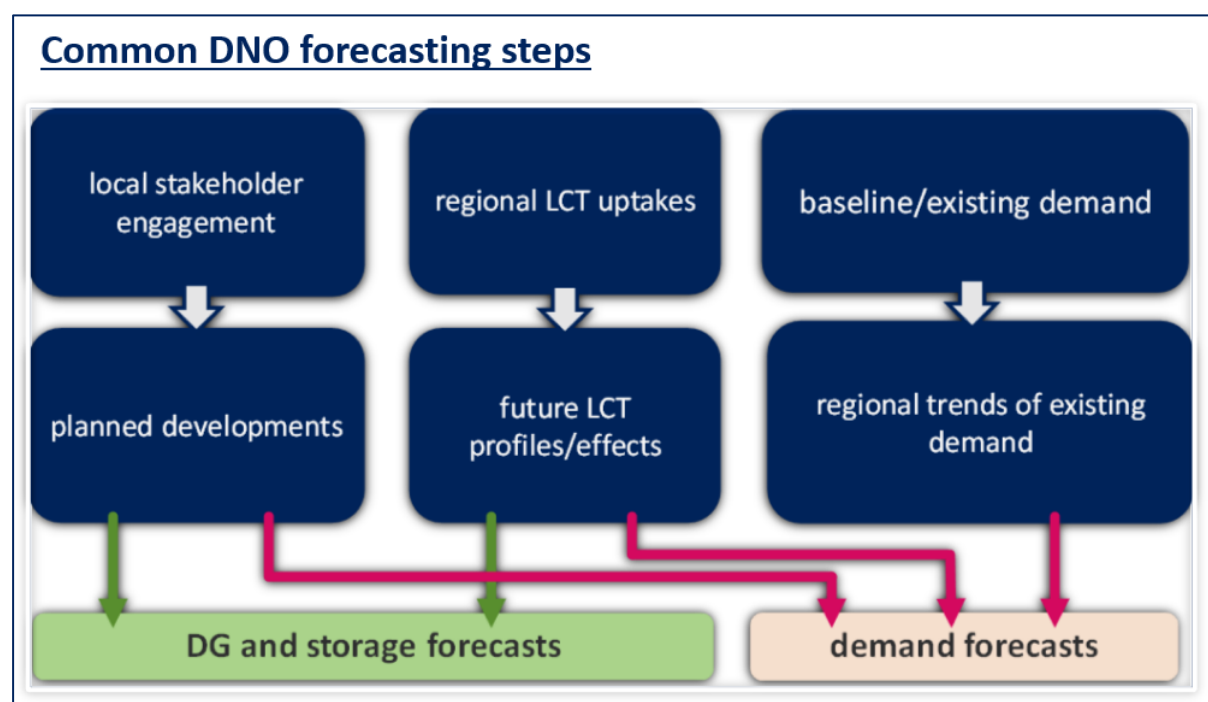
Expanding the LTDS to incorporate the HV, LV and other data set will require investment to automate the collation and publication processes. Periodic updates are more practical with an appropriate balance needing to be struck between frequency of updates and costs.

Question 11: Is there a need for a common methodology or principles for estimating load growth? What potential role could the D-FES play in informing the load growth forecasts on the LTDS?

A common set of high level principles, forecasting steps, building blocks and scenarios will improve stakeholder understanding and engagement in the D-FES process across all DNOs, resulting in greater confidence in the forecasts.

All forecasts included in our LTDS, DFES and used in our network planning / reporting are subsets of the full forecasting results of our ATLAS forecasting methodology. These ensure that there is consistency between the D-FES forecasts, the LTDS forecasts and potential network development proposals.

Our proposed approach for a common high-level framework of forecasting steps is indicated in the diagram below:



Our proposal will be discussed in the associated ENA Open Networks product (WS1B P2) with all other network companies and the ESO.

Question 12: Are there any lessons that can be learned from other industry documents such as the ETYS and the NG FES?

The NG ESO's FES, and ETYS processes provide examples which could be followed at distribution network level, however this should only be applied at the EHV level as the speed of change of the HV and LV networks is too fast to produce any sensible results.

Question 13: Do you agree that the LTDS should be enhanced to present the key assumptions for network requirements forecasting and the uptake in LCTs, or is this a role better served by the D-FES or other documents?

We agree. Since the LTDS is derived from same data used in D-FES (see our response to Question 11) and in the interest of transparency the key assumptions in demand and generation forecasting and how LCT uptake impacts on these should be published. The forecast in LTDS and the forecast in D-FES are both sub-sets of the of the full forecasting results of our ATLAS forecasting methodology. We

intend to continue reference D-FES in our LTDS document to show the consistency of forecasting.

Question 14: Forecasting tools have been a focus of a number of innovation projects. Are there any mature tools or techniques that could be adopted to enhance the transparency or robustness of the load growth forecasts?

Electricity North West's [ATLAS](#) methodology which was created under a NIA project has provided a robust forecasting methodology. The detailed methodologies for all of ATLAS forecasting steps and building blocks have been published. The produced business as usual publications (ie LTDS, DFES are subsets of our ATLAS forecasts) can now bring value to our stakeholders by taking into account not only sophisticated modelling (eg, bottom up, consumer choice modelling, high geospatial resolution and half-hourly through year), but importantly also the interaction of DNO stakeholder engagement (customers/LAs/LEPs) and DNO planning with regional trends (eg customers planning, network reconfigurations etc). Combined with Electricity North West's Real Options Cost Benefit Analysis tool (ROCBA - developed under [Demand Scenarios](#) innovation project) it has delivered a process that aids delivery of an efficient investment programme that recognises the benefits of flexibility services, short term (low cost) investment and significant investments.

Question 15: Do you agree that IDNOs should be issued with a direction to produce a LTDS?

Yes. IDNO networks represent an increasingly significant proportion of the distribution networks, particularly at the HV and LV level. If it is deemed important, for stakeholder benefit, that DNOs publish such data then to ensure a complete picture IDNOs should also publish equivalent data. We have recently issued a [consultation](#) that lays out our plans for data sharing between ourselves and IDNOs, explaining our reasons for requesting information more frequently from IDNOs, and to gather feedback on our plans

Question 16: What summary information should IDNOs publish? This is currently found in section one of the LTDS FoS, such as information relating to the design and operation of all voltage levels of the distribution network. Please explain your reasoning.

It would be appropriate for each IDNO to reference the host network operator's summary information, in respect of the network technical data, detailing only where their data differs from that of the host network operator.

Each IDNO should reference its own published non-technical policies and practices ie charging information, competition in connections information, flexible service opportunities/ requirements etc.

We suggest each IDNO should publish data that indicates the headroom for each embedded network connection as part of their LTDS as this is crucial for customers who want to connect to the IDNO network to understand whether this is sufficient capacity.

Question 17: What information on network data should IDNOs publish? This is currently found in section two of the LTDS FoS. Please explain your reasoning.

In order to provide comprehensive visibility of the whole distribution network IDNOs should provide the same data as the DNOs insofar as it applies to their networks. At the very least we suggest IDNOs should provide the following information equivalent to that found in LTDS tables 1 to 5.

Question 18: Do you agree with our proposal on how the LTDS delivery body should be convened and governed?

We agree with the proposed approach of setting up an industry working group and a delivery group. However, we question why an independent delivery body is required to develop, test and finalise the new FoS. It seems more practical that the LTDS delivery body is a sub-group of the industry working group and is chaired by Ofgem. This reduces the risk of the industry working group creating a "wish-list" of LTDS deliverables that are of questionable cost benefit.

Question 19: Would you like to nominate an individual to take part in the LTDS working group? Please set out reasons for their inclusion and any qualifying experience the nominated person has to function as a strong contributor to the group.

Electricity North West proposes Ian Povey as its nomination to the LTDS working group. Ian is our senior representative to the ENA Open Networks Project where he leads Workstream 1B, is involved in the delivery of number of Products and is taking forward modification proposals in Grid Code and Distribution Code for the industry as part of the Open Networks project. He is a professional electrical engineer and has over thirty years' experience in the electricity industry. Prior to his secondment to Open Networks he held the role of Head of Strategic Planning and had responsibility for creating Grid Code Week 24 and Long Term Development Statement publications.

Part 2 – Key enablers for DSO programme of work

We understand that the questions in this section were seeking information from stakeholders on the DSO areas for Ofgem to prioritise, but we would like to share our views from a network perspective.

Question 20: What network monitoring parameters would you like to have access to? At what frequency?

It seems appropriate that for all interface points between network operators both parties have access to their counterparties' network monitoring points data in real time. This data could be fed into the operational and planning tools (e.g. ANM system) and would allow both parties to more effectively co-ordinate network flows across the whole distribution network. We note some network licensees have embedded networks connected to our distribution network and have a mix of demand and generation customers and potentially may have some customers who are offering flexible services to the network or to other network users. Yet, currently we have only static data from the other network licensees (eg IDNOs, TOs, and other DNOs) at many of the interface points, and when required in operational timescales this data is currently updated via telephone conversations between control engineers.

Currently there is a general lack of quality smart meter data available to network operators due to the low number of SMET2 meters installed, the delayed registration of SMET1 meters in the DCC systems and the issues with communications system. Due to rules governing the collection and the use of data which can be used at a disaggregated level currently network operators are having varying degrees of success on the usefulness of data from the meters. Until we have a greater penetration of smart meters in clusters we will be unable to make full use of smart meter data.

Question 21: What would enhanced 33kV network monitoring enable that cannot be undertaken today?

The majority of the distribution network at 33kV is monitored currently only for current flow and voltage at key network infeed points. The measurements do not indicate direction of current / power flows, power factor, or fault level. The reason for this lack of data is directly linked to that historically the network power flows were predominantly single directional i.e. electricity flowing from the higher voltage network to lower voltage networks. Given these single directional flows as well as cost and complexity of measuring, transmitting, processing, and storing bi-directional power flow data meant that it was not economically and practical to do so.

As the power flows on distribution network becomes more dynamic the lack of penetration also means that it is difficult to build a clear picture of exactly where power is flowing and any network constraints which may be occurring, important information for Active Network Management systems/ schemes.

The roll out of Active Network Management systems and enhanced monitoring at 33kV would allow for improved knowledge of network constraints and would also enable optimisation of elements such as voltage which can be varied to decrease network losses. The increased level of data will also mean that it is far clearer where network constraints are occurring and to a more granular level. This means that investment decisions can be more focused on specific constraint areas and will open up

more opportunities for constraints to be managed using flexible services, flexible connections and flexible assets rather than relying upon conventional reinforcement options.

Realtime monitoring of asset health will help reduce the probability and severity of asset failures within the network. With modern monitoring techniques it is often possible to detect early signs of asset deterioration and take mitigating steps to rectify these before they develop into more widescale health issues that can result in disruptive failures, loss of supplies, and risks to staff and the public. For example the monitoring of transformer gases, and partial discharge can detect if the insulation materials within the winding of the transformer are starting to degrade. Left untreated this can result in a flashover between phases igniting the transformer oil and resulting in a disruptive failure generally resulting in an unplanned replacement of the transformer and surrounding equipment, and loss of supplies to customers.

Enhanced monitoring helps improve insights into demand and generation patterns. These insights will in turn lead to being able to guide customers as to where there is capacity available or where DSO services may be required.

At all voltage levels enhanced monitoring allows network operators to:

- Facilitate the use of flexible services to provide grid balancing services
- Connect and manage a greater amount of low carbon technologies
- Facilitate trading of curtailment obligations and capacity between different parties
- Operate the network closer to design limits, increasing asset utilisation through Dynamic Asset Rating
- Provide better insights to stakeholders to allow them to make informed investment and policy decisions
- Utilise more automation to improve supply restoration times
- Increase supply reliability
- Improve power quality
- Maintain and improve on existing high operational safety levels, and
- Maintain supplies within statutory design limits

Recognising the benefits attributed to this additional monitoring we have already begun the transition to gathering more of this type of data. We have revised our procurement specifications, for much of the new equipment being installed within the network, to include Bi-directional metering giving real and reactive power flows as well as voltage and current monitoring. This addresses the need to gather more data where new sites are being located on the network and where replacement of existing equipment is being carried out. However, due to the scale of network incorporating assets which have existing outdated data gathering it is not practical or economically efficient to retrofit modern data capture at all sites.

Question 22: What would enhanced 11kV network monitoring enable that cannot be undertaken today?

As with the 33kV network enhanced voltage, current, power flow, and asset data can improve network management decisions. Historically the HV network has been less well monitored than the 33kV network. Monitoring data becomes more important at HV because the majority of embedded generators between 50kW and 5MW will be directly connected to the HV network. Bidirectional MW (active power) and MVar (reactive power) monitoring can facilitate the real time control to mitigate HV voltage and capacity issues, as well as release network capacity via real time voltage control and

switching. But the benefits for customers only flow when enhanced monitoring is implemented within an Active Network Management system.

A large proportion of commercial and medium scale industrial units connect directly to the HV network and rely upon a stable electricity supply. Fluctuations in power quality, voltage, and power factor can impact sensitive processes.

The LV network is mostly fed using off load or fixed tap transformers. This means that fluctuations on the HV network in voltage will in turn have a direct effect on the LV network voltage. It is therefore important that monitoring points are established on the HV network to ensure the LV voltages are within statutory limits and do not fluctuate outside of design parameters.

Being able to monitor and control the HV network has a direct correlation to being able to connect more customers to the network and facilitate the uptake in low carbon technologies.

As with the 33kV network it has not been practically or economically viable to retrofit modern data capture at all sites within this price control review period. Current processes will install enhanced network monitoring at most new network sites, and where replacement of switchgear is being carried out. Selected areas of the network will also be targeted where a clear benefits case can be provided.

Question 23: What would enhanced LV network monitoring enable that cannot be undertaken today?

The LV network historically has the least level of monitoring. The uptake in LCT devices and changing lifestyle patterns have made demand patterns less predictable. With the LV network representing the most significant element of the distribution network (most assets and connected customers) it is not economically or practically viable to reinforce the entire network to enable the uptake in LCTs. It therefore makes sense to make use of a greater number of monitoring devices to understand demand trends, uptake patterns, and constraint locations. This would allow for targeted investment, improved connections, and the ability to allow trading and sharing of capacity.

Electricity North West's LCN Funded [Smart Street Project](#) has shown a range of benefits which come from installing digital monitoring and control to the LV network. As a primary benefit we have proven, using Smart Street technology includes LV monitoring, we could cut an average customer's electricity bill in the North West by up to £70 a year by deferring or avoiding network reinforcement. The biproducts of this investment in monitoring and control means that 1) we can make appropriate investment decisions as the penetration of LCTs increases, and 2) we know sooner when network faults occur and can often take mitigating measures faster to reduce the impact of network faults to our customer.

Question 24: What constraints in data systems architecture do you perceive are limiting network monitoring and visibility?

Network architecture is generally designed to be closed loop to reduce the likelihood of cyber security issues. As such data measuring points are fed back to remote terminal units within the substations, the data is then transferred to the DNO control system via dedicated secure communication paths, and then the control system is held on a secure server which does not have an internet connection. Where data is required to be shared internally this is carried out through a dedicated secure firewalled pathway. In terms of modifying this so that all network data is available will require either a more cloud based version of data capture and storage or more data to be transferred from the control system through the firewall to be hosted on the internet. DNOs currently are not historically set up to carry out this type of data sharing exercise. To enable DNOs to carry out this type of activity may open up more potential pathways for cyber-attacks, these vulnerabilities will need to be identified and mitigated before a pathway could be given.

Question 25: What operational data is most important to prioritise opening up first and why?

More information of the cause of wide scale network incidents should be shared earlier with relevant external stakeholder organisations. Following the 9th August 2019 frequency event and subsequent reports detailing the findings it was clearly identified that although the ESO and DNO control rooms were aware of the cause of the power outage that the lack of suitable data available to other stakeholders was more limited. Early reports from the media and social media gave rise to the potential that the event could be a result of a cyber or terror related attack. The event lasted less than 45 minutes in the majority of cases however the media coverage that quickly escalated the event into a full-blown emergency caused an unnecessary level of panic and confusion.

As part of a clear and open data sharing policy we believe it is key that there is a need to quick routes of information sharing to Media organisations, government, emergency response services, and essential service providers.

From a system user's perspective we believe that they would like to see clear data regarding system availability, including information linked to fault restoration. e.g. real-time updates on the cause of a fault, the work required to resolve the fault, and when they can expect to have their supplies restored. We also believe users would like data which will help them to make informed choices regarding the UK energy mix to allow them to decarbonise e.g. if you know that by charging your EV at 7pm rather than 6pm you will reduce the carbon footprint of this activity; many users would likely choose this option if it does not impact their travel plans.

DNOs would like to have a greater access to disaggregated data from smart meters. A greater depth of data at a more individual level would reduce the amount of DNO owned monitoring equipment which needs to be installed onto the network both at LV and HV. This unlocks more benefits of the Smart Meter Rollout program which can be achieved. An example of this is where there are currently looped services on the DNO network; DNOs could use disaggregated smart meter data to identify where significant increases in demand (e.g. EVs, Heat Pumps etc) may lead to service cable and/or service termination overloading. This would allow DNOs to carry out more targeted investment decisions in areas of the network which require interventions. The principle benefits case for smart meter data currently are limited due to the lack of penetration and clustering of meters which we have access to the real-time data for.

Question 26: How does a lack of access to this data impact the delivery of flexibility to the system?

Currently the lack of information (either from DNO owned monitoring equipment or smart meter data) on the operation of LV networks hinders network operators from utilising domestic scale flexibility. Having granular smart meter data would enable network operators to identify localised LV constraints, as well as being able to view individual responses from LV DER providers if they were to enter into a flexible services contract. Without granular metering it would not be possible to identify if a DER provider had delivered contracted services. This currently could only be resolved by either an aggregator or the DNO installing additional metering within the customer's property; this is not cost efficient and is likely to be off-putting to potential service providers as this is viewed as invasive.

Question 27: Are there any real or perceived conflicts of interest with DNOs owning and operating ANM platforms at scale? What additional protections could be required for ANM customers?

Where customers have a flexible or an un-firm connection agreement there is a risk that Active Network Management systems may over utilise these connections rather than network operators using flexible services contracts or reinforcing the network. To mitigate the risk of this Electricity North West developed the curtailment index methodology. Customers are assigned a curtailment index annually which defines a level to which they should not expect to be curtailed beyond. Where a customer's curtailment index is breached this is a clear trigger that enhanced network studies need to be carried out with the potential to procure flexible services or to trigger reinforcement. Electricity North West also proposes to utilise the curtailment index within their Active Network Management system to choose how customers will be constrained in the event of network constraints.

We would also endorse being able to assign a value to curtailment within a CBA which will allow it to be ranked on a level playing field against other Active Network Management actions.

Where a network operator has assets which can be used flexibly (eg onload taps changers, switching points, reactive power compensation), we believe that it is in the best interest of customers that where they provide the best value for money these should be used first. These assets have been funded using customers' money and we believe that these should be utilised where they offer the lowest cost solution to network constraints with resultant cost efficiency savings providing lower electricity bills for customers.

Question 28: In order to preserve optionality over ANM scheme operations, what technical and commercial protections, such as technical ring-fencing, may be required?

Active Network Management systems make split second decisions about dispatch and control of assets which will impact customer supplies and procured services. In order that there is no potential of the perception of a DNO unfairly affecting customer supplies unequally, a clear set of guidelines should be adhered to. These would be commercially and technically defined system parameters which are open, transparent, and easily auditable. It should be easily replicable that when presented with the same input parameters that the Active Network Management system will make the same decisions. Provided the systems have been developed in such a manner, the Active Network Management systems decrease the risk of unconscious bias in decision making.

To ensure that Active Network Management systems do respond in a neutral and fair manner the commercial factors which feed into the system will need to be fully defined and regulated. For example flexible services, assets, and connections could all be assigned a 'pseudo price' which the Active Network Management can use to determine the cheapest cost option for any actions it takes. The pseudo price will also need to take all relevant factors into consideration which will affect the cost of using different assets. Through comparing all possible options the ANM system could utilise it can be clearly demonstrated why one option has been selected compared to another. The pseudo price will need to make considerations for other factors such as value of lost load, vulnerable customers, environmental impact, security of supply, essential supplies, previous curtailment etc. These factors currently may be considered in part by control room staff however in a world where control decisions are automated unless these factors are programmed into the system there could be unintended consequences.

In order to preserve optionality, network and system operators would need to refrain from signing long term contracts with Active Network Management providers, unless there are extenuating circumstances. This may however mean that they not be able to make as efficient purchase decisions, as software providers will need to reclaim the fixed development and customisation costs which normally would be spread over a long contract.

Ring fencing is not devoid of issues; in order to make quality decisions Active Network Management systems ideally should be integrated into other core network/ system operator systems e.g. Network control systems, asset management systems, SCADA, contract management systems etc. By ring fencing systems it may mean that the Active Network Management system is not as well integrated or may require more customisation of different software than a fully integrated platform.

Where trading of flexibility occurs, this should be carried out externally to the Active Network Management system and should be ring fenced, ideally to a regulated third party. Where a third party takes on this role there should be relevant technical and relevant commercial checks by the network and system operator to prevent market gaming and un-practical trading.

Question 29: Please provide real world examples where lacking timely access to usable network data, or regulatory barriers, have limited your ability to provide a DSO function or support service. Please submit any relevant evidence and documentation of examples cited.

As the penetration of low carbon technologies has increased there have been instances where some installers of distributed generation, electric vehicle chargers, heat pumps have failed to share the relevant information with the network operator. This results in the network operator not being able to make a clear picture of what is connected to the distribution network, both directly and indirectly.

Both Ofgem, and the ESO noted within their reports from the 9th August 2019 low frequency event that more distributed generation is believed to have disconnected than expected. The collection and appropriate sharing of data, both static and real time data, is vital for system/ network operator to manage the risks posed by the increase in low carbon and renewable technologies connected to distributions systems. For example there are discrepancies in the information held by network operators on SSEG (small scale embedded generation) installations funded by government tariffs; yet the electricity retail companies are aware of these installations. But due to data protection and separation between retail businesses and system/ network operators it is not possible to share this data. Due to the unknown quantities of these types of installations the network operators and the ESO have to estimate data, which can result in inefficient solutions e.g. over procuring frequency response services.

Question 30: Are there any other issues related to enabling DSO that have not been considered that you think are important? Please provide details of your considerations.

With regards to sections 3.7-3.9 there may be a lack of practicality in some instances of sharing all dynamic data in real time. There will be a high resource requirement to share all operational data openly, securely, and accurately at all supply voltages. We recognise that this data is theoretically useful but it is necessary to develop a benefits case that supports this additional resource requirement at distribution level.

From our own research, we are seen by stakeholders as a trusted, neutral party and they are looking to us to take a leading role in helping our communities achieve their decarbonisation and clean growth aims which are at a different pace to the national targets.

Within the remaining period of ED1 and moving into ED2 there is going to need to be consideration of additional resourcing required to develop the data gathering and sharing capabilities required to open up the full potential benefits of the transition to DSO. Ofgem and the EDTF have clearly identified the intrinsic link between quality data at a granular level resulting in more efficient decision making. We would like to scale up the level and quality of data monitoring and control which we have access to also well as being able to share this data openly with external interested parties to help the capitalise on the benefits.

We see a clear role for the DNOs taking a leading role in many of the DSO functions however we also see clear functionality which is already open to market competition or is subcontracted directly by the DNOs where it is not feasible to transfer full liability for the function.

DNOs have defined responsibilities within the Electricity Act, Electricity Distribution Licence, Distribution Code and Grid Code. One such responsibility is to:

“Permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity;” (licence condition 21)

To fully discharge these requirements it is imperative that the network operators maintain control over how the network is designed, maintained, and operated. It is key to maintaining a safe, secure, efficient, and reliable distribution network that there is a defined legal entity which holds the responsibility for co-ordinating how the network is operated.

If there is no single legal entity that retains overall control over a distribution networks operation this will lead to un-coordinated decision making and could leave the network vulnerable. In turn this decreases network reliability and creates an unclear liability for development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity.