Enhancing Resilience in UK Energy Networks

Final Report

April, 2024

UK Government

CS-NOW

Climate services for a net zero resilient world

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Sign off date	16/07/2024
Version	1

About CS N0W

Commissioned by the UK Department for Energy Security and Net Zero (DESNZ), Climate Services for a Net Zero Resilient World (CS-N0W) is a 4-year, £5.5 million research programme, that uses the latest scientific knowledge to inform UK climate policy and help us meet our global decarbonisation and resilience ambitions.

CS-N0W enhances the scientific understanding of climate impacts, decarbonisation and climate action, and improves accessibility to the UK's climate data. It contributes to evidence-based climate policy in the UK and internationally, and strengthens the climate resilience of UK infrastructure, housing and communities.

The programme is delivered by a consortium of world leading research institutions from across the UK, on behalf of DESNZ. The CS-N0W consortium is led by Ricardo and includes research **partners Tyndall Centre for Climate Change Research**, including the Universities of East Anglia (UEA), Manchester (UoM) and Newcastle (NU); institutes supported by the **Natural Environment Research Council (NERC)**, including the British Antarctic Survey (BAS), British Geological Survey (BGS), National Centre for Atmospheric Science (NCAS), National Centre for Earth Observation (NCEO), National Oceanography Centre (NOC), Plymouth Marine Laboratory (PML) and UK Centre for Ecology & Hydrology (UKCEH); and **University College London (UCL)**.

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Executive summary

This report is the second part of the final report for Work Package D3 Enhancing Resilience in UK Energy Networks of the Climate Services for a Net Zero Resilient World (CS-N0W) programme. The remit of this Work Package is to support DESNZ in improving UK energy resilience – in line with the Departmental Objective 4.3 "Ensure our energy system is reliable and secure" – by improving Departmental understanding of climate risks to UK energy network infrastructure, including cascading and systemic risks.

This report outlines the primary weather and climate driven risks seen to have the highest priority for electricity (flooding, windstorms, high temperatures) and gas (flooding, river scour, high and low temperatures) distribution network operators (DNOs), including compound and cascading effects arising through secondary weather hazards and sector interdependencies. We present the available adaptation options for enhancing resilience to these risks and summarise the current understanding around measuring resilience. This information, collected through one-to-one interviews and an in-person workshop with members of DNOs, can help inform decision making within Ofgem's current RIIO-ED2 and next RIIO-3 five-year price control periods.

The options available for enhancing resilience that were uncovered in the interviews fell into four categories:

1) **Infrastructure Upgrades:** These include the replacement of current assets with higher specification assets, the hardening of assets, and the use of redundancy in the network (extra capacity). Widespread replacement of infrastructure is generally not considered realistic and so low-regret options in this category are mostly targeted at critical parts of the network, considered on a case-by-case basis.
2) **Emergency Response** and its continuous improvement is a low regret option which comprises ensuring organisational preparedness (reprioritisation of workload, staff training, availability of equipment), making effective use of weather forecasts, and minimising impact to customers using mobile generators. In some cases, this is considered a more cost-effective solution to infrastructure upgrades if the loss of supply can be minimised during an extreme weather event.

3) **Network monitoring** is a low regret option, but also very costly, and includes vegetation management, regular monitoring of asset health and the quantification of risk posed by hazards such as flooding and windstorms. Currently, risk assessments are generally carried out qualitatively except for fluvial flood risk.
4) **Demand flexibility** is identified as a valuable no-regret addition to the energy system that can be used to mitigate power outages during extreme weather events. Demand flexibility mechanisms are also useful for balancing the increased electricity demand from heat & transport with renewable supply and thereby deferring network investment.

Resilience planning considers these options within a synergistic approach which aims to optimise the cost-benefit of investment across the entire network in the context of a finite pool of funding. Options are prioritised based on the risk rating of assets which depends on multiple factors including health, age and expected lifetime as well as their criticality (number of customers served), exposure to weather conditions and likelihood of failure in extreme weather. Further research will be required to quantify such exposure and likelihood from primary, compounding, and cascading risks to help best inform this decision making.

The conclusions from the resilience workshop suggest that the thinking on what are the best metrics to measure resilience is relatively immature. ETR (Engineering Technical Reports) 138 is currently widely accepted as good practice for providing resilience against flooding of grid and primary substations and it may be possible to develop an equivalent to this for other hazards. However, there are still differing opinions on whether ETR 138 is a resilience metric, technical specification or level of service.

It is generally accepted that the climate risk modelling and simulation capabilities of the energy network sector should be improved.

1. Introduction

This work is the second part of the final report of Work Package D3 Enhancing Resilience of Energy Networks of the CS-N0W project. The CS-N0W project is a DESNZ-funded research project which aims to enhance the scientific understanding of climate impacts, decarbonisation, and climate actions and to improve accessibility to the UK's climate data. Additionally, the project envisages that the outputs will contribute to evidence-based climate policy both in the UK and internationally, and strengthen the climate resilience of UK infrastructure, housing and communities. It proposes to meet these aims through the use of the latest scientific knowledge to inform UK climate policy and help the UK meet its global decarbonisation ambitions. The remit of this work package is to support DESNZ in improving UK energy resilience – in line with DESNZ Departmental Objective 4.3 "Ensure our energy system is reliable and secure" – by improving Departmental understanding of climate risks to UK energy network infrastructure, including cascading and systemic risks.

The original Invitation to Tender had 6 questions to be addressed, namely:

1. What are current weather and climate risks to energy network infrastructure, assets, and processes, including cascading and systemic risks?
2. What are the future weather and climate risks to energy network infrastructure, assets, and processes, including cascading and systemic risks? This work should quantify risks where possible, look at timescales of 5, 10, 20, and 30 years from now. The work should identify the role of critical energy infrastructure in propagating these cascading and systemic climate risks in the UK.
3. How will trends and projections in the identified risks, consumer energy demand, and energy infrastructure changes (out to 2050) interact to enhance or diminish climate resilience of energy networks?
4. What are existing and new no- or low-regrets options to enhance climate resilience of infrastructure, assets, and processes against current and future risks, including cascading/systemic risks?

5. What are appropriate approaches or metrics for GB gas and electricity network companies to measure their resilience to climate change and monitor/demonstrate their progress in improving this?
6. What standards or levels of service (new or existing) should the GB gas and electricity network companies be developing and have in place by 2050 considering the consequences of climate change and expected future developments of the UK? Standards could consider particular resilience measures, or broader standards such as year-round requirements for service delivery. This should consider the availability of resources and budgets to integrate climate resilience into strategies over the short-term, and should draw on recommendations from organisations such as the National Infrastructure Commission where appropriate.

The project has delivered two reports additional reports:

1. Interim report which answered question 1
2. Final Report Part One which answered questions 2

This report will address questions 3, 4, 5 and 6.

Question 3 is answered using a desk-based study into the current use of future energy scenarios, resilience challenges and demand profiles for resilience analysis. To answer questions 4, 5 and 6, two activities were conducted. The first activity was a series of one-on-one interviews, which explored new and low-regret options (question 4). The second activity was a workshop of key stakeholders which captured the latest thinking around metrics and levels of service (question 5 and 6). The report is organised into three main sections, one which addresses question 3, another that addresses question 4 and a final section that addresses question 5 and 6 together.

2. Future energy scenarios, resilience challenges and demand profiles for resilience analysis

2.1 Introduction

The electrification of heating and surface transport along with the deployment of renewable energy generation technologies, such as wind and solar, are core to delivering greenhouse gas emission reductions consistent with the Paris Agreement. Electricity demand is expected to increase due to the electrification of transport, heat and industry; and renewable energy generation may lead to increased variability in the electricity supply (Bellamy et al., 2023). Meanwhile, the decarbonised energy system needs to operate in a world that might be impacted by global warming of 1.5 to 4°C by the end of the century as greenhouse gas emissions continue to rise. The UK's third Climate Change Risk Assessment (CCRA3) indicates significant impacts on energy infrastructure from increased frequency and intensity of heavy rainfall and heatwaves from a changing climate (Department for Environment Food and Rural Affairs, 2022). The CCRA3 identified the risks to people and the economy from a climate-related power system failure as one of the eight government priorities for action within the next two years from 2021 (Department for Environment Food and Rural Affairs, 2022). The future risks include flooding of energy infrastructure, reduced water availability for thermal and hydropower generation, reduction in power generation and distribution efficiency from high temperatures, increased summer electricity demand from cooling and physical damage to onshore and offshore energy infrastructure from storms (Jaroszweski et al., 2021). Against this backdrop, this section explores the projections of electricity supply and demand out to 2050 and identifies how these changes could interact to enhance or diminish the vulnerability of the UK's power distribution networks to climate hazards.

This section consists of four parts. Firstly, the report reviews (a) the key future electricity scenarios available in the UK (at both national and regional scales); (b) theoretical and empirical diurnal demand profiles published for electric vehicles (EVs) and heat pumps (HPs); and (c) summarises the key vulnerabilities of both energy end use and supply to climate hazards.

Finally, the section provides (d) an overview of the key challenges from the scenarios and recommends the datasets that could be used for electricity distribution network modelling; and offers an impact assessment of high wind events on network resilience.

2.2 Future UK energy scenarios

Several organisations including the National Grid ESO have produced a range of future energy scenarios that explore supply and demand pathways out to 2050. Dixon et al. (2022) presented a comparative analysis of seven published Net Zero pathways for the UK energy system. Two scenarios are from the Energy Systems Catapult (ESC) 'Clockwork' (ESC-C), and 'Patchwork' (ESC-P); both are from the ESC's 2019 Innovating to Net Zero report. Three pathways are taken from the 2023 edition of National Grid's Future Energy Scenarios (FES), 'Leading the Way' (FES-LTW), 'System Transformation' (FES-ST) and 'Consumer Transformation' (FES-CT), where all of them meet the 2050 Net Zero target. The sixth scenario is from the Centre for Alternative Technology's (CAT) 2019 'Zero Carbon Britain' pathway (CAT-ZCB). The last scenario is from the Climate Change Committee's (CCC) 'Balanced Net Zero Pathway' (CCC-BNZ), released as part of the 2020 Sixth Carbon Budget recommendation to the UK government. A comparison of key characteristics of energy makeup between the scenarios is shown in Table 1. Scenarios differ in their assumptions of behavioural and societal changes as well as technology use and performance. All scenarios suggest a significant increase in future electricity demand due to the electrification of heat and transport but a reduction in final energy consumption. The scenario's future electricity demand in 2050 ranges from an increase of 75% (565 TWh) to 189% (886 TWh) compared to 323 TWh in 2019. The majority of the generation within the scenarios to meet demand is from variable renewable sources - mainly wind. The storage, flexibility and use of hydrogen in the system also play a key role in all scenarios. Hydrogen is produced through a mix of three sources at varying scales: fossil gas with Carbon Capture & Storage (CCS), biomass gasification with CCS, and electrolysis using low-carbon electricity (e.g. surplus renewable generation) (Dixon et al., 2022; National Grid ESO, 2023).

The main difference in electricity demand between scenarios stems from their assumptions on the proportion of total heat demand (domestic, commercial, and industry) supplied by HPs; ranging from 23% to 72% due to assumptions on the level of hydrogen used. In contrast, all scenarios have more than 90% of cars being battery-electric but differ in the total number of cars on the road. The development of technologies assumed in the scenarios to allow decarbonisation in some sectors highlights areas of conflict between an ‘idealised pathway’ and the ‘real world situation on the ground’. For example, electrified heat and transport are well-established now, whereas there are several bottlenecks (e.g. financing, dedicated policy support for infrastructure development, public acceptance) to the feasibility of technologies related to CCS to meet the 2050 target (Dixon et al., 2022; Wachsmuth et al., 2023).

In addition to the National Grid’s annual publication of Future Energy Scenarios, all six electricity distribution network operators (DNOs) publish annual Distribution Future Energy scenarios (DFES) for their 14 license areas that inform network planning. The DFES combines top-down with bottom-up assessments. The top-down assessments include consistency of the DFES framework with the NGFES and national-level assumptions on the economic outlook, population projections, technology availability, efficiency, and performance. The DFES are augmented with a bottom-up assessment to provide a regionally reflective view based on regional ambitions and targets, development plans, project pipelines, local knowledge, and stakeholder inputs. Thus, the assumptions and inputs for the bottom-up datasets vary, such as the viability of business models for specific generation and demand technologies (e.g. wind, district heating) for a region. As a result, there are some variations in the scenario details between electricity DNOs as shown in Table 2. All electricity DNOs provide spatially disaggregated datasets at the primary substation level (33kV to 11kV or 6.6kV). Each DFES presents five scenarios, four based on the NG FES titles and a 5th called ‘Best View’, which is a short-term (1-10 year) scenario that focuses on high certainty changes based on national/ regional policies and stakeholder views. The scenario datasets are then used to produce Network Development Plans (NDP) and other reporting processes such as Long-Term Development Statements (LTDS) with a 1-5 year horizon (Barnacle et al., 2013).

Table 1: Comparative summary of the seven UK 2050 net zero scenarios[1] from Dixon et al. (Dixon et al., 2022) and National Grid ESO FES 2023[2] (National Grid ESO, 2023).

	ESC- C	ESC-P	NGFES LW	NGFES ST	NGFES CT	CAT ZCB	CCC BNZ
Electricity Generation (348 TWh in 2019)	565 TWh (40% wind 50% nuclear)	743 TWh (53% wind, 23% nuclear)	779 TWh (73% wind, 11% PV, 9% nuclear)	796 TWh (71% wind, 6% PV, 11% nuclear)	886 TWh (71% wind, 8% PV,11% nuclear)	840 TWh (78% wind, 9% marine, 9% PV)	780 TWh (70% wind, 14% PV)
Electricity demand (323 TWh in 2019)	75% increase on 2019 levels	130% increase	154% increase	159% increase	189% increase	160% increase	141% increase
Heat	58% from HPs, 17% from H_2	61% from HPs, 6% H_2	55% HPs, 10% H_2, 16% district heat	23% HPs, 34% H_2, 16% district heat	72% HPs, 0% H_2, 19% district heat, 23 million domestic HPs.	63% HPs, 18% biomass	52% HPs, 5% H_2, 42% district heat
Transport supply & demand	93% cars BEV, 45 million private cars	95% cars BEV, 38 million private cars	21million cars, 100% electric cars, 86% electric HGVs & 14% H_2, more public transport & efficient transport systems	31million cars, 94% electric cars, 45% electric HGVs & 55% H_2	28million cars, 100% electric cars, 93% electric HGVs & 7% H_2.	More public transport, low per capita car miles, 90% electric, 10% H_2	Per capita car miles reduce by 17%, 100% BEV, HGV & Bus H_2 and electric
Flexibility & storage	8 GW electricity, 600 GWh H_2	4 GW electricity, 600 GWh H_2	Electricity 52 GW, V2G 39 GW, H_2 19 TWh, DSR 9 GW	Electricity 33 GW, V2G 16 GW, H_2 56 TWh, DSR 6 GW	Electricity 46 GW, V2G 34 GW, H_2 12 TWh, DSR 13 GW	80 TWh synthetic methane, 200 GWh electricity	18 GW of electricity, 13% of electricity for H_2 production
Lifestyle & behaviour changes	Minimal changes in transport & diet	Moderate changes in transport, diet	High consumer engagement & energy efficiency measures	Low consumer engagement	High consumer engagement & energy efficiency measures	Significant changes to transport, diet	Compromise to changes in transport, diet
Hydrogen & low carbon fuels	250 TWh; 86% SMR with CCS, 14% biomass gasification	185 TWh 6% SMR with CCS, 59% renewable, 35% biomass gasification	242 TWh 73% electrolysis, 11% SMR with CCS, 3% biomass gasification; Limited H_2 uptake	446 TWh 39% electrolysis, 49% SMR with CCS, 7% biomass gasification, High H_2 uptake	120 TWh 93% electrolysis, 1% SMR with CCS; High bioenergy uptake	100 TWh 100% electrolysis using renewables	225 TWh 45% renewable, 32% fossil gas CCS, 11% biomass gasification

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[1] Scenarios differ on how storage capacity is shown such as power capacity in GWs and energy stored in GWhs. DSR is demand side response and SMR is steam methane reforming.

[2] The National Grid FES are for Great Britain whereas other scenarios cover all of the UK.

Table 2: Comparative summary of the Distribution Future Energy Scenarios by electricity DNOs

	SP Networks	**Scottish & Southern**	**National Grid (Western Power Distribution)**	**UK Power Networks**	**Northern Powergrid**	**Electricity North West**
Scenarios	4 NG FES	4 NG FES	4 NG FES	4 NG FES	4 NG FES	4 NG FES
Bottom-up inputs (PV, HP, EV, demand, storage, flexibility)	LA dataset, MHCLG, ONS, Xoserve, OS map, EV-Up tool	LA dataset, FiT, RHI, EPC, DfT, Elexon class 1 profiles, substation data set, ONS	LA dataset, EPC, DfT, Elexon class 1 profiles, substation data set, ONS	Detailed i/p model, ONS, MHCLG, pipeline, DfT, CCC projections, Building stock model+ thermal efficiency+ tech uptake model	LA dataset, CLNR project	ATLAS forecast method using LA dataset
Net zero date	2045 to 2050	2045 to 2050	2050	2050	2040-45 to 2050	2038 + 2050
Macro assumptions	NG FES, National, Welsh & Scottish policies	NG FES, National & Scottish policies	NG FES, National policies	National policies	NG FES	NG FES
Demand & Generation	Weather normalised for the starting year and future years based on load factors	Weather normalised datasets	Weather normalised datasets	NA	Weather normalised datasets	Weather normalised datasets
A/C demand	NA	NG FES	NG FES	Tyndall Manchester	NA	NA
Consistency with NG FES	Yes	Yes	Yes	Yes	Yes	Yes
EV profiles available	No	No	Yes	No	No	Yes
HP profiles available	No	No	Yes	No	No	Yes

Aviation & shipping are generally recognised as sectors that are difficult to decarbonise fully in the timescale required under net zero policies. Hence detailed impacts from electrification for those sectors are excluded in this analysis. Electrification is identified as one of the promising approaches to decarbonise regional & short-haul flights (up to 100 seats) (Zhang et al., 2022) and reduce fuel consumption for auxiliary engines of ships while at berth in ports, as well as battery full electric propulsion for passenger ships. Electrification of short-haul flights alone would require an additional 1.2–3.6 GW of electricity generation capacity for charging the aircraft batteries (Guo et al., 2022). However, the electrification of aviation also enables valuable flexibility services to the power grid with estimated annual revenues of £46.58 million from frequency services alone across eight UK airports (Guo et al., 2022). The annual electricity demand across the UK ports could increase to more than 4,000 GWh under an ambitious emission reduction scenario whereas the peak demand could be between 9 MW for a small port to 80 MW for a large port (Raucci et al., 2019).

To enable the net zero ambitions, all electricity DNOs are required to publish their Network Development Plans (NDP) to inform stakeholders about their network reinforcement plans, use of upcoming flexibility services, and network headroom capacity (Energy Networks Association, 2021). The objective of this NDP is to assess the gap between the power rating of the network to the actual demand in that part of the network. As part of this DNOs provide heatmaps of headroom capacity, which enables developers to assess the level of capacity that might be available for new connections, supply, and demand, in the network.

Section 2.3 discusses the main uncertainties related to future electricity demand, in terms of both magnitude and time of use. Section 2.4 discusses the vulnerabilities of key supply and demand technologies to climate hazards.

2.3 Diurnal demand profiles for electric vehicles and heat pumps

High uptakes of EVs and HPs as shown in Table 1 are necessary to achieve the net zero target. This section provides a review of diurnal demand profiles for two key end-use technologies, EVs and HPs. The increase in electricity demand from both EVs and HPs poses challenges to the operation of the power distribution network. The performance of EV batteries and HPs due to changes in future temperatures are explained in section 2.4.

2.3.1 Electricity demand from electric vehicles

High uptake levels of EVs along with an increase in use could have potential implications for network capacity from higher peak electricity demand. Conversely, high levels of EV usage also offer opportunities to enhance the flexibility in the system where EVs can be used as distributed energy storage units (Ramirez-Mendiola et al., 2022). Various methods have been proposed in the literature to model EV charging demand profiles. These include bottom-up charging models based on a set of deterministic rules such as vehicle use, and charger availability; stochastic conditional probability of charging with parameters such as vehicle use, state of charge, and cost; and top-down charging models (Crozier et al., 2021; Gonzalez Venegas et al., 2021; Western Power Distribution, 2022). At the same time, it is essential to capture the diversity of users and their charging behaviours to accurately estimate the aggregated charging demand on the distribution network. The use of locally representative vehicle usage data is essential when estimating demand (Crozier et al., 2021). The ‘Electric Nation’ smart charging trial (Gonzalez Venegas et al., 2021) showed that EV users in the trial charged their vehicles two to three times a week, with a lower charging frequency for EVs with large batteries. The large heterogeneity in user charging preferences and behaviours reduces the impact of EV charging on the network peak demand, notably for price-responsive charging which reduced peak charging. Meanwhile, the current EV trend of larger battery sizes could result in reduced flexibility (power and stored energy) in the system due to reduced charging frequency and higher energy requirements per charging session (Gonzalez Venegas et al., 2021). Moreover, it is essential to better conceptualise the temporal rhythms of everyday practices such as the timings of energy-relevant activities at homes along with commuting patterns for maximising the demand flexibility from residential EV users (Ramirez-Mendiola et al., 2022). Furthermore, data from on-street charging and charging from commercial premises is also needed to adequately capture the overall impact on the network.

2.3.2 Electricity demand from heat pumps

An empirical model of Great Britain’s half-hourly domestic heat demand shows three principal patterns of heating: daytime (morning to evening), bi-modal (morning and evening), and continuous (24 h) (Watson et al., 2021). Individual heat pumps (HPs) (both air source and ground source) are an important technology in all scenarios to provide space and water heating. The aggregated demand on the distribution network is determined by the individual HP performance and diversity in heat pump operation. The driving factors for the HP performance are poorly understood so far and they are dependent on heating system configuration, installation, control, building fabric, and user operation (Carroll et al., 2020).

Various diurnal demand profiles for HPs are available in the literature (Love et al., 2017; Watson et al., 2021; Western Power Distribution, 2022). A cost-optimal heating portfolio and heating technology mix study shows complete electrification of heating in Great Britain increases the peak demand by 170% (Hoseinpoori et al., 2022). This is based on a heating demand profile from buildings for typical cold weather and applying heat performances of ASHP with outside temperature. Meanwhile, the study by Watson et al. (2023) shows that a 100% uptake of HPs in existing dwellings leads to an increase in peak demand by 120% in a cold year similar to 2010. This study is based on a statistical model using measured performance data from over 550 HPs installed under the Renewable Heat Premium Payment[3] (RHPP) scheme (Watson et al., 2023).

To alleviate the electricity grid reinforcement requirements and costs from increasing demand, demand-side options of thermal storage (e.g. hot water tank) and lowering temperature output of HPs from 55°C to 45°C, have been proposed for diurnal load shifting (Hoseinpoori et al., 2022; Kelly et al., 2021; Wang et al., 2022).

2.4 Impacts of climate change on electricity demand, storage, availability of demand flexibility, and supply technologies.

Changes in future temperatures due to climate change can reduce the amount of electricity generation from thermal generators and affect the temporal and seasonal profile of energy demand. Milder winters in the future can contribute to lower winter average demand, and hotter summers may trigger a rising number of air-conditioning units installed on buildings. The UK climate projections suggest cooling degree days in England could increase by 2 to 7 times whereas heating degree days may reduce by 11% to 32% between 1.5°C and 4°C of global warming by 2050 (Hanlon et al., 2021). The effects of climate hazards on supply technologies vary as detailed in Table 3. The risks to the electricity sector are influenced by

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[3] The UK Government's Renewable Heat Premium Payment (RHPP) scheme ran over the period December 2011–March 2015 and datasets were made for ~700 domestic heat pump installations.

the future profile of energy demand and supply. Improvements in system flexibility for the electricity sector have therefore been considered as a measure to manage future risk (Jaroszweski et al., 2021).

2.4.1 Electricity demand from cooling

Studies on cooling demand are under-represented in the UK compared to heating demand, despite overheating risks associated with climate change being identified as a key risk by all UK climate risk assessments published to date (Khosravi et al., 2023; Psiloglou et al., 2009). Although the space cooling demand is currently small for buildings in the UK (~10% of total electricity use), an increase in comfort cooling requirements during summer is anticipated due to climate change (Khosravi et al., 2023). The current demand for cooling in the UK is dominated by non-domestic buildings. However, by the end of the century[4], it is estimated that the domestic stock will need 75% to 85% of the total cooling energy consumption due to the larger domestic building stock, mainly concentrated in the South and East of the UK (Department for Business Energy and Industrial Strategy, 2021).

Under current weather conditions about half of all the UK homes suffer from overheating[5], in particular the South and in London. The overheating risk increases to around 90% of existing homes under a 2ºC climate change scenario and 100% under a 4ºC climate change scenario. A significant amount of retrofit works (passive measures) is therefore required across the housing stock to mitigate the overheating risk under a 4ºC warming. However, even the most effective (but expensive to install) passive measures may not be sufficient for 90% of dwellings under 4ºC warming, resulting in greater reliance on cheaper-to-install active cooling devices leading to a large increase in electrical demand and operational energy cost (Bouhi et al., 2022). A significant increase in electricity demand may lead to exceeding the existing available network capacity.

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[4] Most of the increase in annual cooling energy demand occurs after 2050.

[5] CIBSE TM59 presents two criteria for overheating in homes that are ‘predominantly naturally ventilated’. (i) The number of hours where the operative temperature exceeds the comfort temperature by one degree Kelvin or more during the period May to September inclusive, shall not be more than 3% of occupied hours in living rooms, kitchen and bedrooms. (ii) Provide comfort (CIBSE states to ‘guarantee comfort’) during typical sleeping hours, the operative temperature in the bedroom from 10 pm to 7 am shall not exceed 26°C for more than 1% of all annual hours (Bouhi et al., 2022).

The BEIS, 2021 study on the UK's future cooling demand under different climate scenarios suggests that with no policy intervention, annual demand could be ~12 TWh and 6.3 TWh for the high (RCP 8.5) and low (RCP2.6) emission scenarios[6] respectively by 2100. However, if the UK government prioritises passive cooling measures or efficient cooling technologies energy demand could be reduced by around 34% and 21% respectively. The use of efficient technologies could also reduce the UK peak cooling power consumption by around 3.5GW and by adopting a passive first approach, around 5.1GW might be saved under a high emission scenario in 2100. During a heatwave event, peak demand could be approximately twice as high as compared to an average summer week and the energy consumption could be between 20 to 65 times the average summer demand. In addition to reducing average and peak energy consumption, passive first measures and efficient technology strategies are also cost-effective. The cumulative capital costs associated with no policy intervention or active cooling technologies could increase to £60-70bn by 2050 compared to £20-30bn for the passive first approach. However, further work is needed on policy development for cooling due to synergies between cooling, low-carbon heating, fabric energy retrofit of buildings, and potential benefits to building occupants and their economic productivity. (Department for Business Energy and Industrial Strategy, 2021).

There are limited studies at a distribution network scale. The Resilient Electricity Networks for Great Britain (RESNET) scenario tool suggests electricity demand could increase up to 600 MW by 2030 for the Electricity North West (ENW) license area from ENW's business-as-usual uptake rates of air-conditioning units combined with a 50th percentile UKCP09 high emission temperature scenario (McLachlan et al., 2016). Within the DFES publications, only SSEN, UKPN and WPD have provided uptake rates of air conditioning units for their license areas based on either disaggregated NG FES data or the RESNET model (McLachlan et al., 2016).

2.4.2 Impacts of ambient temperature change on heating electricity demand

A reduction in winter heating energy consumption is expected due to warmer winters in the future (Deroubaix et al., 2021). The performance of ASHP reduces at lower ambient temperatures, whereas for GSHP the Coefficient of Performance (COP) remains constant

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[6] The rationale for low and high emission scenario assessment is to highlight what might be the resulting electricity demand from 'no policy intervention'.

below 5°C. A lower HP performance would increase the electricity demand (Watson et al., 2023). Whilst annual electricity demand for heating buildings with HPs is expected to decrease in the future, peak electricity demand is likely to remain the same. This is because although icing days (daily maximum temperature <0°C) and frost days (daily minimum temperature <0°C) are projected to decrease in the future, such days can still occur under a high emission scenario (RCP 8.5) (Hanlon et al., 2021).

2.4.3 Impacts of ambient temperature change on storage technologies

An increase in future ambient temperatures due to climate change will reduce the overall efficiency and functionality of batteries. The ideal ambient temperature range for lithium-ion batteries (energy storage and electric vehicles) is between 15°C and 35°C (Ma et al., 2018; Olabi et al., 2022).

Ambient temperatures have a significant impact on the energy consumption of EVs. A study based on data collected from real-world driving in the UK's West Midlands roads shows energy consumption was lowest at ambient temperatures between 21.8°C to 25.2°C (Al-Wreikat et al., 2022). The increase in energy consumption outside the temperature range is due to the use of auxiliary devices (heating and air-conditioning) for user thermal comfort and reductions in recovered energy during regenerative braking. The regenerative braking system shows lower efficiency due to the decreased battery charging capability outside the ideal ambient temperature range. A drop of up to 28% in the vehicle range is observed at low temperatures compared to moderate temperatures in urban driving. Although the study data didn't capture extreme summer ambient temperatures, the trendline for specific energy consumption and ambient temperature suggests a similar drop in vehicle range during hotter days (Al-Wreikat et al., 2022).

The heat generated by battery charging and operation combined with high ambient temperature accelerates the chemical reactions in lithium-ion batteries leading to degradation and ageing processes. Additionally, prolonged exposure to extreme temperatures (low & high) increases battery degradation, self-discharging and thermal ageing. Adequate thermal management systems that are necessary to operate the battery at optimal conditions increase the battery energy consumption. Extreme high temperatures could cause thermal runaway issues through overheated batteries leading to fire and explosion risks (Ma et al., 2018; Olabi et al., 2022).

The ideal operating temperature for air compressors is between 10°C to 30°C (Liu et al., 2022). Within this temperature range, the mechanical components can operate safely without the risk of freezing or overheating with additional temperature tolerance for the protection of equipment. Compressors used in storage technologies such as compressed air storage and liquid air storage may have to revise the design of their system considering the changes in ambient temperature due to climate change (Liu et al., 2022).

2.4.4 Availability of demand flexibility during extreme events

Demand flexibility is identified as a valuable addition to the energy system for balancing renewable generation and demand from electrified heat and transport thereby deferring network investment (Capper et al., 2024). A range of flexibility capacity has been assumed in the NG FES as shown in Table 1. However, major policy changes are needed for flexibility to be adopted widely in the UK. For example, regulation of flexibility markets and flexibility aggregators is needed to ensure flexibility aggregators do not take advantage of households or negatively affect the energy system (Capper et al., 2024). Additionally, social and ethical dimensions of demand flexibility also need to be considered beyond technological benefits. For example, understanding the barriers faced by low-income and other households in accessing and using smart technologies for demand-side response or financial implications of different forms of time of use (ToU) tariffs is essential (Abi Ghanem & Mander, 2014; Calver & Simcock, 2021). Moreover, a case study from Texas shows that individual flexibility mechanisms are likely to fail in avoiding power outages during extreme weather events due to decaying marginal effects. However, mixing a portfolio of demand response mechanisms such as interruptible loads and residential load rationing could avoid outages during extreme weather events (Wu et al., 2022).

2.4.5 Electricity supply technologies and their vulnerability to climate hazards

Climate risks for supply technologies include lack of resources, reductions in generation efficiency and physical risks including structural damage. Climate change risks identified for the supply technologies are summarised in Table 3.

Table 3: Summary of climate change risks for electricity supply technologies in the UK

Supply technology	Climate change risks
Wind	The risks to power generation may emerge from changing wind conditions such as an increase in storm conditions or an increase in low wind events. Predicting the magnitude of change in windspeed and its effect on energy yield due to climate is challenging and highly uncertain (Jaroszweski et al., 2021; Juhola et al., 2024). The mean surface wind speed data from the UKCP18 RCP8.5 scenario suggests an increase in the duration of low wind events during the summer and autumn seasons in the 2061–2080 period for all the UK regions (Abdelaziz et al., 2024). Consequently, reduced wind power generation is forecasted in the summer and autumn periods under a high climate change scenario. Wind farms will have reduced power output during storms exceeding 25m per second for safety reasons. Hence changes in storm patterns could affect wind power generation. Sea level rise was identified as a potential risk to offshore wind farms, which are built for specific sea levels (Juhola et al., 2024). Other risks for offshore wind include structural damage during storms, seabed scour damaging the cables, and challenges for maintenance and repair (Jaroszweski et al., 2021).
Solar photovoltaics	The effect of climate change on solar power generation is still quite uncertain. Energy generation is directly affected by the amount of solar radiation, cloud cover, and changes in ambient temperature. The intermittency of solar radiation due to changing seasons is another challenge. The efficiency of solar panels decreases with increasing temperature (Juhola et al., 2024). A reduction of power output between 1 and 3% is possible due to increasing temperatures (Jaroszweski et al., 2021). The CMIP6 model suggests an increase in all-sky radiation due to a reduction in 10% of cloud cover despite a decrease in 3-5 W/sq. m clear-sky radiation. The decline in summer cloud cover outweighs the decrease in clear-sky radiation and is of greater relevance for PV generation (Hou et al., 2021). Physical risks include storms and heavy winds that may cause damage to solar panels or cover them with debris reducing the power output (Juhola et al., 2024).
Hydropower and pumped storage	Hydroelectric generation is vulnerable to both low river flows and extremely high river flows, which are dependent on rainfall amounts. Seasonal variations in precipitation and long-term changes in precipitation patterns can have large effects on the performance of hydropower production. Low flows reduce power output. Very high flows can damage generation equipment and the associated infrastructure, but conversely, moderate-high flows have the potential to improve the output (Jaroszweski et al., 2021).
Biomass feedstock for energy generation	Direct and physical risks from storms, fires and pest outbreaks. Climate change may impact biomass feedstock supply potentials due to droughts, impacts on land use and competition with other sectors such as food production. Degradation of soil fertility from future climate may offset by longer growing seasons and increased CO_2 fertilisation (Climate Change Committee, 2020; Jaroszweski et al., 2021; Juhola et al., 2024; Yalew et al., 2020).
Thermal power generation including nuclear, hydrogen, energy from waste plants, and biofuels	Ambient atmospheric conditions (mainly temperature) affect the performance of steam and gas turbines, auxiliary systems, and cooling systems. Climate change is expected to reduce cooling-based thermal power capacity. The impacts may be exacerbated due to environmental regulations on cooling water withdrawal, consumption and release into natural water bodies resulting in power generation curtailments. Extreme high summer temperatures (of air and river water) can constrain plant operation due to permitted temperature limits at water discharge outlets (Jaroszweski et al., 2021; Yalew et al., 2020). On extreme days about 50% of freshwater thermal capacity may not be available under climate change (Byers et al., 2020).
Hydrogen and Carbon capture and storage	For hydrogen production, high-quality water is required as a feedstock. Annual freshwater consumption of over 350 Mm^3 pa is estimated for hydrogen production as

	well as for the operation of hydrogen and CCUS-fitted power plants in 2050 under the NG FES: System Transformation. These values are much greater than those today (20-30 Mm^3 pa). The availability of high-quality water is considered to be a potential risk even under the current climate unless the required feedstock is sourced through desalination or other supply routes (Gasparino & Edwards, 2021). Climate change exacerbates this risk even further as about 50% of freshwater thermal capacity may not be available on extreme days (Byers et al., 2020). There are challenges for generating the amount of electricity needed for electrolysis during extreme events.

2.5 Summary of Future Energy Scenarios (FES)

The future resilience of power systems to climate change will be influenced by the spatial distribution of wind and solar generating farms; location of thermal generators and hydrogen production and high-quality water availability for such plants; demand flexibility that can be accessed during extreme events; responses to overheating through passive first measures and efficient technology strategies as well as protection systems to infrastructure from extreme events. The potential increase in summer cooling demand coupled with the likely reduced supply from wind and network capacity during the summer is a future consideration in the planning of system operation, especially during heat waves.

A case study from South Australia shows compounding events can cause wide-scale physical, social, or economic disruption with significant magnitudes (Finkel et al., 2017). The heatwave events in February 2017 (temperatures in Adelaide peaked at 41.6°C at 4.00 PM) put the grid system into insecure operating states. A combination of events including higher peak demand and reduced wind generation than the forecast coupled with gas-fired generators being forced to reduce capacity due to high temperatures and low solar resources in the evening led to a deteriorating supply and demand balance. The interconnectors were operating at full capacity and since no additional capacity was available, the system operator was forced to direct load shedding for some of the customers. However, errors in the load-shedding software resulted in an additional 60,000 customers left without power (Finkel et al., 2017).

Wide-area power failures can cause cascading effects across the economy due to multiple interdependencies between power supply and economic sectors. The consequences of power outages are likely to become far more consequential unless actions are also taken to increase societal resilience (Pescaroli et al., 2017). Case studies from previous events have shown that during disruptions people tend to co-operate and perform altruistic acts which suggests impacts can be reduced by good communication and better community amenities (Cox, 2021). Increasing interdependencies between ICT and economic services necessitates the importance of incorporating critical infrastructure failure in disruption impact modelling. The UK case study on estimating economic losses of flooding shows a 300% increase when power outages are included in the risk assessment, compared to just considering economic losses from flooded business premises (Koks et al., 2019).

3. GB power system model and assessment of high wind events on network resilience

3.1 Development of scenario datasets

There is considerable variation in the supply and demand scenario details, methodology, and assumptions for individual technologies between DNOs (Table 2). As the primary objective of this project is to assess resilience under ‘Net Zero’ strategies, the most ambitious decarbonisation scenario, ‘Leading the way’ is used for further data analysis.

The DFES reports provide sufficient details on the uptake rates of EVs and HPs, but they lack sufficient information on the diurnal profiles for each area. Available diurnal profiles for the specific DNO license areas are used wherever possible. National Grid ESO has provided detailed assumptions on the diurnal profiles for EVs and HPs (Western Power Distribution, 2022) which has been used for all other areas along with uptake rates.

DFES datasets for the North West license area managed by Electricity North West Limited (ENWL) and the South West license area managed by National Grid Electricity Distribution were produced using the 'Leading the Way' scenario. The scenario datasets for these two geographically distinct areas are converted into inputs for the electricity network modelling, Multi Energy Vector (MEV), to examine the resilience of a power system (Ashfaq et al., 2021; National Grid ET, 2021b). The input data collection for two DNO license areas, North West and South West, is described in the following sections of 1.6.1 and 1.6.2

3.1.1 Data collection for the North West license area

The summary of data collected for the North West license area is shown in Table 4 which is primarily sourced from ENWL’s DFES workbook and the heatmap tool. The DFES dataset spans annually from 2022 to 2051 and covers primary substations, aggregated to the Bulk Supply Points (BSP) and Grid Supply Points (GSP), as well as data for local authorities and counties within the license area. The data gathered include uptake rates of individual technologies such as EVs and heat pumps among others (e.g., electrolysers, combined heat and power, etc.), maximum and minimum demand values (used for network planning) along with annual energy consumption (used for economic and carbon calculations) by sector. Similarly, for the supply, capacity values by generation, storage, and energy mix have also been gathered. The energy mix incorporates a broad spectrum of technology categories, from small-scale domestic to large-scale commercial installations of solar and wind farms, micro-CHP, biomass generation, etc. The diurnal profiles for EV charging and heat pump demand are taken from the DFES workbook. Finally, projections of household numbers have been obtained from the Office for National Statistics to assess future electricity demand for a given location.

Table 4: ‘Leading the Way’ scenario data set for the North West license area

No	Data type	Data variables	Timeline	Spatial extent	Source
1	Uptake rates of individual technologies	Count of EV and HP	2022 to 2051 (annual)	BSP & Primary Substation	(Electricity North West, 2023a)
2	Demand data	Maximum Demand, Minimum Demand, Total Energy Consumption	2022 to 2051 (annual)	BSP & Primary Substation	(Electricity North West, 2023a)
3	Supply data	Generation and Storage	2022 to 2051 (annual)	BSP & Primary Substation	(Electricity North West, 2023a)
4	Energy mix	See note*	2022 to 2051 (annual)	DNO	(Electricity North West, 2023a)
5	Projected household numbers	Total Household projections	2001-2043	Local Authority	(Nash, 2020)
5	Population growth rates	Population projections for all age groups	2018-2043 (annual)	Local Authority	(Nash, 2020)
6	Headroom data	Demand and Generation Data	Current Capacity	BSP & Primary Substation	(Electricity North West, 2023b)
7	Diurnal profiles	Demand profiles for EV charging and HP	2022, 2030 and 2050	DNO	(Electricity North West, 2023a)

*Note: The energy mix includes several categories such as Domestic PV, Small industrial & commercial PV, Large PV, Domestic wind farm, Small industrial & commercial wind farm, Large wind farm, Domestic micro-CHP, Industrial & commercial CHP, Flexible generation, Biomass generation, Other generation, Domestic storage, Large storage, Total.

3.1.2 Data collection for the South West license area

The summary of data collected for the South West license area is shown in Table 5 which follows a similar categorisation to the North West area but contains certain unique elements. The data has been primarily sourced from the DFES Portal and the NG HeatMap Tool. The timeline for the projection data spans annually from 2022 to 2035, with projections available for the year 2040, 2045, and 2050. There are more technologies specified in the uptake data including air conditioning, biomass & energy crops, CCGTs, geothermal, hydro, hydrogen electrolysis, and marine. The spatial distribution also differs, with demand data at the local authority scale and uptake and generation data at the Electricity Supply Area scale. The weather data is taken from the UK Met Office's Yeovil station to determine diurnal profiles for heat pumps as representative for the South West license area.

Table 5: 'Leading the Way' scenario data set for the South West license area

No	Data types	Data variables	TimeLine	Spatial Extent	Source
1	Uptake rates of individual technologies	Volume of Air Conditioning, EV and HP	2022 - 2035, 2040,2045, 2050	Electricity Supply Area	(National Grid Electricity Distribution , 2023a)
2	Demand	Demand data	2022 - 2035, 2040,2045, 2050	Local Authority	(National Grid Electricity Distribution , 2023a)
3	Supply	Generation and storage	2022 - 2035, 2040,2045, 2050	BSP & Primary Substation	(National Grid Electricity Distribution , 2023a)
4	Energy mix	See note*	2022 - 2035, 2040,2045, 2050	Electricity Supply Area	(National Grid Electricity Distribution , 2023a)
5	Projected household numbers	Total household projections	2001-2043	Local Authority	(Nash, 2020)
5	Population growth rates	Population data	-	-	(Nash, 2020)
6	Headroom data	Demand and generation	Current capacity	BSP & Primary Substation	(National Grid Electricity Distribution , 2023b)

7	Weather data	Hourly temperature	2010, 2021, 2011	Yeovilton and Liscombe station	(Met Office, 2023)
*Note: The energy mix includes several categories such as Air conditioning, Biomass & Energy Crops, CCGTs, Electric vehicles, EV Charge Point, Geothermal, Heat pumps, Hydro, Hydrogen electrolysis, Hydrogen-fuelled generation, Marine, Micro CHP, Non-domestic, Non-renewable CHP, Non-renewable Engines, OCGTs, Other generation, Renewable Engines, Resistive electric heating, Solar Generation, Storage, Waste Incineration.					

3.1.3 Diurnal profile for heat pump demand and electric vehicle charging.

Diurnal profiles for HP demand and EV charging are developed for the South West DNO license area which do not have profiles to use. The diurnal heat pump electricity demand profile for a given substation area can be calculated based on Watson et al. (2021) using Equation 1 (Eq.1).

$$E_{d,t} = \frac{N_{GB}\ x\ HT_{b,t}\ x\ HT_d}{COP_d} \quad \text{(Eq.1)}$$

Where:

- $E_{d,t}$ is the heat pump demand profile for a given substation area on day d at hour t.
- N_{GB} is the number of dwellings in the substation area with heat pumps.
- $HT_{b,t}$ is the half-hourly normalised heat demand for temperature band *b* and half-hour *t*
- HT_d is the total heat demand per dwelling on day *d* (at outdoor temperature, T_d)
- COP_d is the heat pump Coefficient of Performance (COP) on day *d.*

Hourly temperature data from 5 different days were selected to account for diversity in outdoor temperature and their effect on the diurnal HP electricity demand. December 2010 was the coldest in 100 years in the UK which is considered as an extremely cold winter and the winter of 2020/2021 is considered an average winter period. The weather conditions chosen are shown in Table 6.

Table 6: Dates and weather conditions for heat pump diurnal profile analysis

Conditions Name	**Weather Condition**	**Data used to simulate**	**Dates**
ANW	Average day in Normal Winter	2020-2021 Winter	14/01/2021
CNW	Coldest day in Normal Winter	2020-2021 Winter	13/02/2021
AEW	Average day in Extreme winter	2010-2011 winter	18/02/2011
CEW	Coldest day in Extreme winter	2010-2011 winter	20/12/2010
ANS	Average day in Normal Summer	2021 Summer	14/07/2021

The hourly temperature data is obtained from the Met Office's Yeovilton weather station in Somerset council, within South West license region through the Centre for Environmental Data Analysis (CEDA) Archive. By inputting the hourly temperature data for the 5 days in Table 5 and using the datasheet created by Stephen et al. (2021), the corresponding hourly $HT_{b,t}$ HT_d and COP_d values were determined. The number of households under each substation (N_{GB}) was obtained from Census 2021 (Office of National Statistics, 2021) which is then multiplied by the percentage of households that own a domestic heat pump in the UK under the 'Leading the Way' scenario. Finally, by applying Equation (1) to each substation, the diurnal heat pump electricity demand profile was determined for the 5 days. The diurnal profiles per household are shown in Figure 1. The methodology can be applied to other license areas where diurnal profiles are not available.

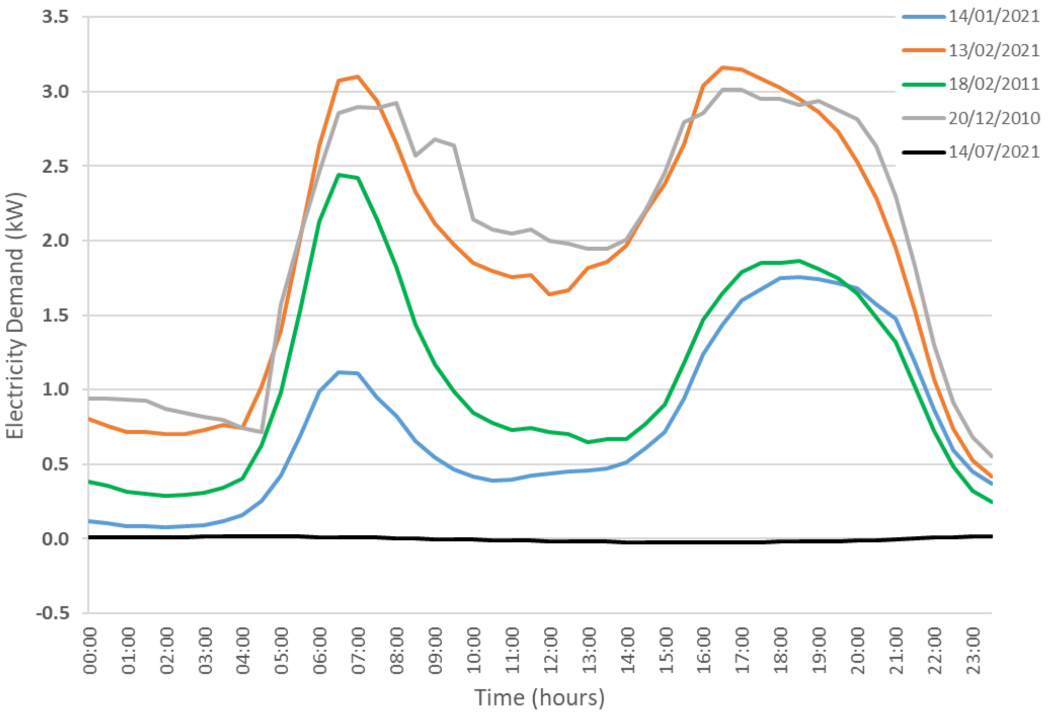


Figure 1: Per household diurnal heat pump electricity demand for Yeovilton for 5 days (Somerset Council)

The EV charging demand profile is taken from Zhu et al. (2021) which was based on the Electric Nation trial (Zhu et al., 2022). Data from the Electric Nation was filtered and only charging data that was not managed or controlled was used to obtain the electric demand of normal charging behaviour (Zhu et al., 2021). The hourly EV electricity diurnal demand profile for future years is estimated based on the uptake of electric vehicles under the 'Leading the Way' scenario.

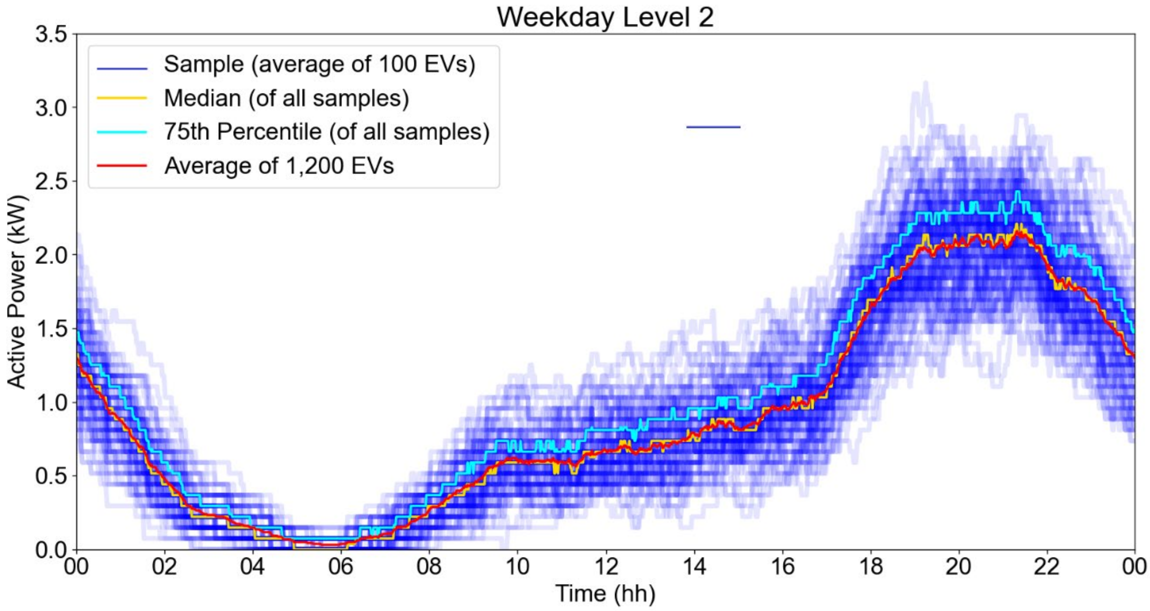


Figure 2: Diversified Profiles (Weekday Level 2): Comparison of 100 EVs and 1,200 EVs (Zhu et al., 2021, 2022).

3.2 Comparison of the scenario data

There are considerable differences in data variables available for the two DNO license areas as shown in Table 6. The list of technologies presented in the DFES database for Electricity North West is focused solely on EVs and HPs, whereas National Grid's South West area takes into account a broader set of technologies. The timelines also differ, with continuous annual data available from 2022 to 2051 for the North West, whereas for the South West only up to 2035 is available with additional data in five-year intervals thereafter. The spatial distribution of data also varies, in which North West data is primarily available at a BSP and Primary Substation level, whereas, for South West, data is available at a local authority and the Electricity Supply Area level.

Table 7: Differences in data variables between North West and South West regions

No	Variable	North West region	South West region
1	List of technology presented in the DFES database for the two license areas	Only EV and HP data	An extensive list including Air conditioning, Biomass & Energy Crops, CCGTs, Electric vehicles, etc.
2	Timeline of the data	Continuous annual data from 2022 (base year) to 2050	Continuous projected annual data from 2022 (base) to 2035. Beyond this, the projected data is available only for the years 2040, 2045 and 2050
3	Spatial distribution of the data	The uptake, demand, and generation data for scenarios are available at the BSP and primary substation level	The demand data for the scenarios are available at the local authority level. The uptake and the generation data are available at the Electricity Supply Area level
4	Energy mix	The available data is aggregated at the level of the complete DNO	The data is available for each Electricity Supply Area
5	Diurnal profiles	Demand profiles for EV charging and HP data is available at the DNO level	Only case studies are available for diurnal profiles

3.3 Windstorm impact analysis

The demand scenarios were used to model the GB power system model and the windstorm impact assessment tool developed in the “Forward Resilience Measures” (FRM) project led by National Grid (National Grid ET, 2021a). The impact assessment tool has now been further developed in the WELLNESS series (National Grid ET, 2024) of UK innovation projects. The models use historical information to model the path, speed and propagation of selected windstorms, or to generate large numbers of windstorms in a probabilistic manner. The former approach, which is more aligned with current UK practices, focuses on evaluating the resilience of a system against selected extreme events. The latter, which aligns with emerging research, focuses on identifying the events (e.g., storms with different intensities, directions, etc.) that can lead to the greatest network impact.

The FRM tool models the potential evolution of a windstorm across the GB network as presented in Figure 3. The propagation of the windstorm is modelled every time-step (e.g., 1h, 30 mins, etc.) whereas its potential to affect network assets (highlighted in yellow in the figure) or causing them to fail (highlighted in red in the figure) are modelled using fragility curves. When using the tool to conduct probabilistic studies, simulation trials are used to model the GB network across the entire year where multiple storms (typically up to three) can impact the network. Large numbers of trials (e.g., about 3000 or more) are used to produce simulations with statistical significance, such as those determined with the coefficient of variation.

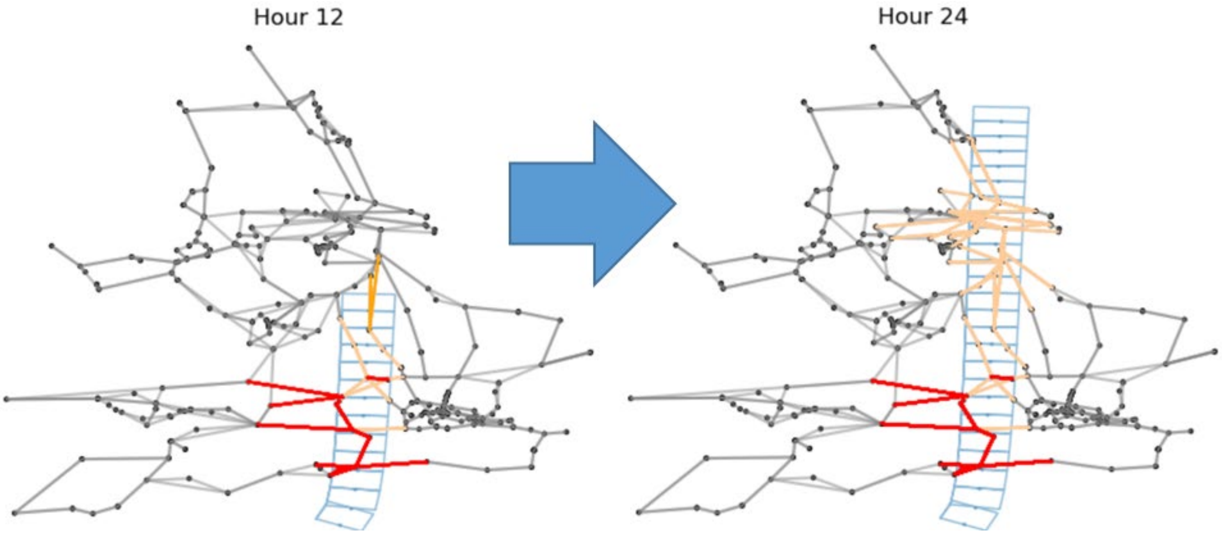


Figure 3: Spatiotemporal modelling of a windstorm and its impacts on the GB network.

The Quantitative Resilience Assessment (QRA) is a physical network model with detailed geographical asset information and a geographical weather hazard model to provide detailed information on asset resilience. QRA model has been used to explore the potential of different network interventions to strengthen the GB network. Specifically, currently planned network investments (i.e., from the network options assessment), asset hardening, and network flexibility) have been considered (National Grid ET, 2022). An example of the Energy Not Supplied (ENS) associated with the impacts of different windstorms (i.e., a function of the number of customers that lose electricity services and the duration of the interruptions) and baseline conditions is presented in Figure 4.

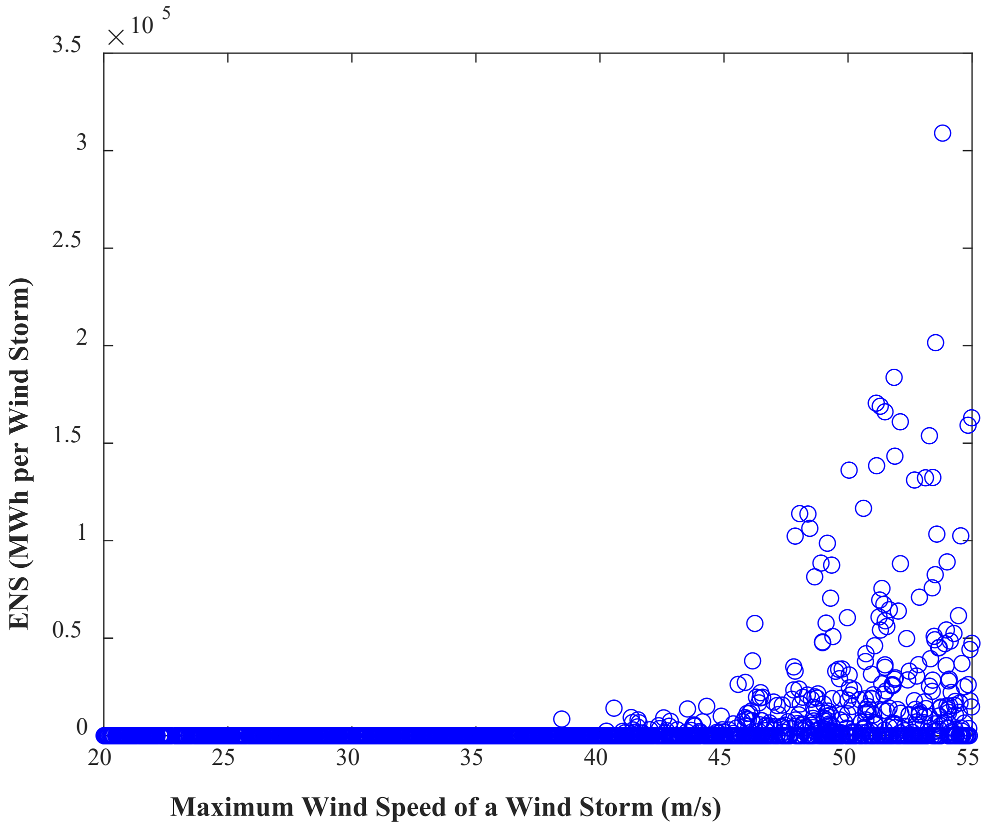


Figure 4: Energy not supplied associated with the impacts of windstorms with different intensities.

3.4 Summary of assessment of high wind events on network resilience

The outputs of the model highlight that currently planned network investments offer little or no reduction in the expected ENS. That is, even though the planned network investments offer increased network capacity, they do not improve the capacity of the UK system to mitigate the impacts of windstorms. Conversely, as expected, dedicated investments to harden the network offer the greatest ENS reductions, but potentially at the highest costs. For example, the hardening options considered within the FRM project offered up to 26% higher breaking points (i.e., wind speeds that cause customer interruptions calculated with a 95% confidence), whereas the flexibility options only increased the breaking points by 5.2%. Finally, flexibility, which can be provided from the demand side offers ENS reduction at potentially modest costs, as the enabling technologies (e.g., from the smart coordination of PV, EVs and other technologies) are expected to naturally emerge as the energy system is decarbonised. That said, the active coordination of these technologies to support the network after a contingency occurs has only been explored in simple, academic, examples. Further research is needed to use these options under practical applications.

4. Low Regret options for Enhancing Resilience of Existing Infrastructure

Individual meetings were arranged to discuss the company's current adaptation strategies, and what resilience enhancements were being implemented (or were being considered for implementation). Each meeting was recorded (after seeking permissions), transcribed and a summary of each meeting is provided anonymously in the **Error! Reference source not found.** of this report. These meetings were focused on the six key questions presented in Section 1; however, to simplify conversations after presenting the summary of the project and the questions outlined in the tender, discussions were formulated around the more specific questions below. These questions were given to the energy companies in advance:

1. What are the primary and cascading hazards that affect your network and why?
2. What are the low or no regret options for mitigating risks posed by these hazards to enhance resilience?

All DNOs and GDNs, including National Gas transmission, were emailed to organize an interview. If emails were not answered, follow up emails were sent. The DNOs interviewed were:

- Electricity North West - North West England
- Northern Powergrid - North East England
- National Grid Electricity Distribution - South West England, South Wales, East and West Midlands
- Scottish and Southern Energy Networks – Northern Scotland and Central Southern England
- UK power Networks (South East England)

The gas network operators, including distribution (GDNs) and transmission, interviewed were:

- National Gas (transmission network) Great Britain
- Cadent Gas (distribution) - North West, Midlands, South Yorkshire, East of England and North London
- Northern Gas Networks (distribution) – Northern Cumbria, North East, North Yorkshire
- Wales and West Utilities (distribution) - Wales and Southwest England

The number of people in attendance at each meeting varied between one and five people. Attendees had various responsibilities in their organisations (detailed in **Error! Reference source not found.**) which largely included roles related to resilience planning and risk management. It is important to note that the perspectives presented by a participant may depend on one's role and experience within the organisation and so one person may not have all the relevant information held within an organisation. It is also possible that a 1-hour interview is not long enough to cover all options in detail. However, we believe we have captured a broad range of experiences that will provide a comprehensive assessment of resilience planning and the options available for enhancing resilience in electricity and gas distribution networks.

We summarise the adaptation options for a set of key primary and cascading hazards that energy network operators are most worried about and identify the synergies and asynergies of these options. This report does not give an exhaustive list of hazards and their mitigation options, see the ENA's adaptation report (ENA, 2021b) for an overview of these. For the hazards not discussed here, DNOs and GDNs felt they have effective risk management already in place and the low regret option was a continuation of these practices.

Options for enhancing resilience fell into three categories: 1) Infrastructure Upgrades, 2) Emergency Response, and 3) Network Monitoring. Options within these categories are presented in tables below for each key hazard and discussed in the accompanying text. Within the tables, adaptation options are classed as either low or high regret, although this separation is often not clear cut and can depend on factors such as the criticality of an asset (e.g. number of customers it serves), risk rating of an asset (e.g. assets in flood zones are high-risk), the climate projections of a given hazard and the perceived cost-benefit of the option. Findings from the interviews are presented for DNOs and GDNs separately.

4.1 Electricity DNOs

The key hazards that DNOs were most worried about include flooding, windstorms and high temperatures. Other hazards that were mentioned included cold temperatures, rainfall and high humidity. These mainly have secondary effects that can compound the impact of primary hazards and so adaptation options to these hazards are included with those of the key hazards above.

4.1.1 Electricity Distribution Network Overview

The electricity networks transport electricity from where it is generated to its customers over networks managed by transmission and distribution operators. The distribution network comprises a mixture of overhead lines, underground cables and sites called substations where voltage transformation takes place, switching and control equipment are located in substations. The design of the overhead line network takes account of the typical winds and ice loading it is likely to face, with stronger infrastructure used in locations with higher winds and ice loadings. These lines are often close to trees which can fall on or grow into the lines causing a power interruption. There are three types of substations including grid substations (bulk supply points), primary substations and distribution substations. They each have different characteristics and levels of criticality in terms of the number of customers they serve. For example, in the Northern Powergrid network, grid substations serve 50,000 - 125,000 customers, primary substations serve 5,000 - 30,000 thousand customers while distribution substations serve up to 500 customers.

4.1.2 Flooding

The assets most at risk of flooding include substations and the equipment within them including telemetry equipment. If telemetry equipment is under water, they can no longer remotely operate a site. Low regret mitigations are available to either prevent a flood impacting a substation or get customers back online quickly if a substation is inundated. Adaptation options to mitigate flooding risks are summarised in Table 8 and discussed below:

Infrastructure Upgrades: The low regret infrastructure upgrades include flood barriers at primary substations, raising equipment within a substation and building redundancy into the network. The latter involves having extra capacity than needed in a normal situation and running transmission lines in parallel to separate substations such that if one substation is flooded, an alternative substation can supply power. Such interventions would mainly be considered for primary substations of a certain criticality (e.g. serves 10,000 customers) that lie within 1-in-1000-year flood zone in line with the ETR 138 policy guidance. For less critical assets such as distribution substations or assets that are not at risk of flooding, these interventions would be seen as high regret though it is worth noting that interventions are considered on a case-by-case basis.

Emergency Response: Continual improvements to emergency response procedures are considered a low regret option. This involves ensuring the correct procedures are in place including reprioritisation of workload and staff training. In a situation where a flood alert is issued, DNOs can construct mobile flood defences if available to protect the substation. Some DNOs noted that they have carried out training exercises to inform staff of their roles and work out logistics of how many staff would be required and how long it would take to construct the temporary defence. DNOs can also monitor water levels and use water pumps to keep the level below a critical level. Assets such as transformers are sealed and work under water if their breather pipe remains above water. If water levels can't be controlled, the equipment can be switched off and dried afterwards. Switching off equipment before water levels become too high avoids replacing equipment and the associated costs. DNOs can also use mobile diesel generators to restore power to customers where power outages are likely to persist for a long duration. However, it was noted that many DNOs hire generators from the same providers, and it is unknown if access to generators may be limited in a large-scale power outage where multiple DNOs require them.

Monitoring: Quantitative risk assessments are considered a low regret option to inform resilience planning that allows them to take a proactive approach. These risk assessments are mostly informed by flood maps provided by the Environment Agency. However, they note that this has potential to be a high regret option if they build a flood defence based on an inaccurate quantification of the risk such as the 1-in-1000-year return level and how this may change in a future warmer climate.

Table 8: Flooding impacts to electricity networks and resilience strategies for mitigating risks

Flooding Impacts to Electricity Networks		
• Large scale loss of electricity supply • The main risk from flooding is damages to equipment in primary substations that serve thousands of customers. In the absence of alternative power supply, the duration of a power outage can last until flood levels subside.		
Resilience Strategies		
Monitoring	Infrastructure Upgrades	Emergency Response
Low regret: • Quantitative Risk assessments (DNO 1-5) **High regret:** • Inaccurate risk assessments leading to poor design of flood defence (DNO 1, 3, 5)	**Low regret:** • Flood barriers for primary substations (DNO 1-5) • Raising equipment in substation (DNO 1, 2, 4, 5) • Building redundancy into network (e.g. connecting network to more than one substation) (DNO 2, 4) **High regret** • Relocation of substation (DNO 1, 2, 3) • Flood barrier for distribution substations (DNO 1, 2, 3)	**Low regret:** • Mobile generators (DNO 1-5) • Monitoring water level during flood, switching off equipment before flooding • Use of water pumps to keep water below critical level (DNO 3, 4) • Mobile flood defences (DNO 3, 4) •

4.1.3 Windstorms

Windstorms can cause large-scale power outages, the assets most at risk to strong winds are overhead lines due to falling trees or broken poles. The impact of a windstorm can be amplified by secondary hazards. For example, emergency response is inhibited by inaccessible roads due to snow/ice or flooding which prevent staff getting to impacted locations. Furthermore, the persistence of adverse weather conditions (strong winds, heavy rain, extreme cold) after the initial impact creates unsafe working conditions for responders which can prolong the outage if they cannot carry out tasks such as climbing poles. Impacts to telecommunication systems can also prevent response staff communicating with control room staff. Adaptation options to mitigate windstorm risks are summarised in Table 9 and discussed below:

Infrastructure Upgrades: The undergrounding of overhead lines would remove the risk posed by windstorms. DNOs note that this would have enormous benefits. However, widespread undergrounding would come with huge cost, it is therefore unrealistic and a high regret option. The low regret option would be to underground lines in critical areas of the network or in largely forested areas. Another option mentioned by one DNO is to reconfigure parts of the network into sections that would prevent a failure in one part of the network causing power outages in other areas. Lastly, insulated cables can prevent overhead lines tripping when in contact with broken branches, though there was no consensus between DNOs. This option may not prevent faults due to a falling tree or broken pole and the insulation would prevent cooling of lines in summer leading greater sag and derating of lines.

Emergency Response: Continuous improvement of emergency response procedures is a low regret option and potentially a more cost-effective approach than infrastructure upgrades if power outages can be restored in an acceptable amount of time. In emergency situations, DNOs reprioritise staff workload and could increase the number of emergency responders. Mobile generators can be used to restore power quickly, though there are limitations to their use in some remote locations. DNOs can hire 4x4s to manage difficult road conditions and ensure staff can reach the required locations. They also provide welfare to affected customers: each DNO has a register of vulnerable customers in their areas who are given priority, and other welfare is provided such as food and community hubs where customers can access electricity for cooking and heating. Lastly, improvements in weather forecasting and impact forecasting can enable DNOs to better position their responders in locations most likely to be affected prior to the impact occurring.

Monitoring: Continuous monitoring and risk management is a low regret option to inform planning of resilience enhancements. Regular pole inspections are used to assess the condition of poles and identify those in need of replacement. Vegetation management such as tree cutting is a continuous task which represents significant portion of budget for risk management and resilience budget, though this may vary between DNOs. Some DNOs note that they have already increased the frequency of cutting cycles due to longer growing seasons as a result of warmer and wetter autumns. However, vegetation management can be difficult in some areas where landowners and communities do not want trees cut back or removed.

Table 9: Windstorms impacts to electricity networks and resilience strategies for mitigating risk

Windstorm Impacts to Electricity Networks		
• Large scale loss of electricity supply • The main assets affected by wind are overhead lines through poles being blown over and trees falling on lines. • Event recovery can be inhibited by poor road conditions (e.g. ice, snow, flooded roads) which can stop responders accessing sites • Recovery is also inhibited if telecommunication infrastructure has been impacted preventing remote operation of sites, detection of faults and contact between ground staff and control room staff		
Resilience Strategies		
Monitoring	Infrastructure Upgrades	Emergency Response
Low regret: • Regular pole inspections (DNOs 2, 3, 4) • Vegetation management (DNOs 1-5)	**Low regret:** • Undergrounding of overhead lines for certain cases (DNOs 1-5) • Insulated cables for specific areas (DNO 3, 5) • Reconfigure network into sections (DNO 1) **High regret:** • Widespread undergrounding of overhead line network (DNOs 1, 4)	**Low regret:** • Reprioritisation of workforce (DNOs 1-5) • Increased number of responders (DNO 3) • Mobile generators (DNOs 1-5) • 4 x 4 vehicles to manage adverse road conditions (DNO 1) • Prioritisation of vulnerable customers (DNOs 1, 2 5) • Welfare provision (meals, etc.) (DNOs 1, 5) • Improved forecasting of impacts (DNO 3)

4.1.4 High Temperatures

Extremely high temperatures affect the efficiency of assets and can cause some assets to fail. Thermal expansion in high temperatures increases electrical resistance in overhead lines leading to a reduction in their efficiency. The thermal expansion also causes overhead lines to sag which can bring them into contact with surrounding vegetation leading to a power interruption. High temperatures can cause transformers to fault. The reason for these faults was not clear for all DNOs but one mentioned it was due to the expansion of oil within the transformer. It was also noted that assets in urban areas can age quicker due to the urban heat island effect which can cause high temperatures to persist at night preventing assets from cooling. They expect this effect to become more important due to the electrification of transport and a potential increase in the use of air conditioning during summer. Many DNOs have so far not experienced extremes outside the operating range of assets, though some are worried about the occurrence of temperatures above 40◦C if this is to become more common. Finally, humid conditions can lead to condensation within instruments causing them to fail. Anecdotally, this has mainly been observed withrainfall occurring after a period of high temperatures. Adaptation options to mitigate risks due to high temperatures are summarised in Table 10 and discussed below:

Infrastructure Upgrades: Not all DNOs have experienced large power outages due to high temperatures and so there was little consensus between DNOs on low regret options for upgrades. The operating range of assets varies, some assets are designed to operate up to temperatures of 40◦C, others can operate up to 70◦C. A low regret option would be to upgrade assets to a higher operating range when replacing them, though widespread replacement of assets prior to the end of their design life would be seen as a high regret option due to the expense. Alternatively, the use of air conditioning to prevent overheating and dehumidifiers to prevent condensation within switchrooms is seen as a cost-effective low regret option, though there is no consensus across DNOs and it is noted that substations are designed to maximise natural or passive ventilation. Another possible low regret option is to build redundancy into the network. This involves having more transformers than necessary which run below capacity in normal circumstances leaving room for manoeuvre should some transformers fail. For some DNOs, any upgrades would prioritise assets in urban areas due to urban heat island effects. Lastly, taller poles with shorter spans can be used to reduce the sagging of lines and the potential to come into contact with vegetation.

Emergency Response: High temperatures have not seemed to yield any large emergency responses within DNOs. This is likely because they have yet to see large power outages due to high temperatures. However, emergency response may become more important in the future and DNOs are worried about the potential increased frequency of days exceeding 40◦C.

Monitoring: As many DNOs have not experienced temperatures outside the operating range of their assets, a low regret option may be to stress test their equipment under high temperatures to understand their performance and likelihood to fail. Vegetation management is also a low regret option to prevent overhead lines contacting vegetation, particularly in high temperatures when they can sag.

Table 10: High temperature impacts to electricity networks and resilience strategies for mitigating risk

High Temperature Impacts to Electricity Networks		
• High ambient temperatures impact the efficiency of assets, they can cause assets such as transformers to fault and overhead lines to sag coming into contact with surrounding vegetation leading to a power interruption. • Higher temperatures in urban areas compared to surrounding rural areas due to an urban heat island effect can accelerate ageing of assets due to lack of cooling effect at night. • The occurrence of rainfall after high temperatures can lead to humid conditions which in turn can cause assets to fail due to condensation within them.		
Resilience Strategies		
Monitoring	Infrastructure Upgrades	Emergency Response
Low regret: • Vegetation management (DNO 1, 3, 4) • Stress testing of equipment under high temperatures (DNO 5)	**Low regret:** • Upgrade equipment specification when replacing, e.g. assets that operate in higher temperatures (DNO 3) • Use taller poles to deal with sagging overhead lines (DNO 3, 4) • Prioritise urban assets due to greater exposure to high temperatures (DNO 1, 3) • Use of air conditioners and dehumidifiers in switchrooms (DNO 3, 4) • Redundancy in network (extra capacity and transformers) (DNO 4) **High regret** • Widespread undergrounding of lines and replacement of assets with higher specification equipment (DNO 1)	• Generally, there have been no large-scale power outages due to high temperatures that require an event response. • Some DNOs are worried about extreme temperatures (> 40oC) their networks have not experienced before (DNO 1, 3, 4, 5)

4.2 Gas Distribution and Transmission Networks

The key hazards that GDNs were most worried about include flooding and river scour, cold temperatures, high temperatures and hazards that might cause a large-scale power outage. There are also secondary hazards that can compound primary impacts causing these to cascade. These include hazards that affect the availability of road networks and telecommunication systems.

4.2.1 Gas Transmission Network Overview

The gas transmission network is run by National Gas, while distribution networks are run by 4 regional network operators. The role of National Gas, as the operator of the transmission network, is to balance the supply of gas into the Great Britain with demands from the 4 gas distribution networks and direct industrial users of natural gas on the transmission system such as power stations or factories. The transmission network comprises 23 compressor stations that are used to balance the system and are remotely operated from a control centre in Warwick. The network also comprises 7660 kms of pipeline which has approximately 530 above ground installations that can be used to isolate parts of the network for maintenance or redirect gas to other parts of the network to balance it.

4.2.2 Gas Distribution Network Overview

The 4 regional gas distribution network operators (GDNs) draw gas from the transmission network and deliver it to home and businesses. GDNs operate an array of pressure reduction sites and other above ground assets as well as an underground pipe network. The number of assets will vary by the size of the GDN. As an example, Northern Gas Networks provides gas to approximately 2.7 million homes across Northern England[3]. Their network covers roughly 25,000 km^2 and consists of 37,000 km^2 of underground pipes and 5,500 above ground installations including 23 off-takes where they draw gas from the National Gas transmission network, 178 Pressure Reduction Stations where they reduce the pressure of gas from the transmission system to feed their high, intermediate and low pressure networks, and 5,673 governors (comprising small cabinet to kiosk size assets) which regulate gas flow through the network. The pressure reduction sites all have electrical equipment and telemetry which allow them to remotely control the pressure of the system. If the telemetry breaks, the network will still run but they lose the ability to remotely operate the system and see the pressure. A minimum pressure will always be met, but if the pressure is too high, they may start to see gas leaks.

4.2.3 Flooding and River Scour

The gas network is sealed so it can continue to work under water in a flooding scenario. Flooding mainly impacts telemetry equipment preventing remote operation and can also block access to the site. Erosion as a result of high river flows (river scour) can expose pipes running along riverbanks and underneath rivers. Such exposure can leave pipes open to damage leading to water ingress, this can also happen to corroded pipes underground. This requires a large operational response and can take days to resolve. Adaptation options to mitigate risks due to high temperatures are summarised in Table 11 and discussed below:

Table 11: Flooding and river scour impacts to gas networks and resilience strategies for mitigating risk

<table>
<tr><th colspan="3">Flooding and River Scour Impacts to Gas Networks</th></tr>
<tr><td colspan="3">• Flooding of pressure reduction sites can damage telemetry equipment preventing remote operation of a site.
• High river flows can increase river scour (erosion of riverbed and banks) leaving gas pipes running under or alongside a river exposed to potential damaging objects.
• Water ingress within pipes underground or under rivers requires large operational response to remove water.</td></tr>
<tr><th colspan="3">Resilience Strategies</th></tr>
<tr><th>Monitoring</th><th>Infrastructure Upgrades</th><th>Emergency Response</th></tr>
<tr><td>Low regret:
• Quantitative risk assessments for flooding (GDN 1)
• Regular monitoring of pipes under rivers or estuaries by divers</td><td>Low regret:
• Raise height of telemetry
• Covering pipes under or beside rivers with rock armouring for protection</td><td>Low regret:
• Routine practice runs for staff to manually operate equipment in the loss of telemetry equipment (GDN 1-3)</td></tr>
</table>

Infrastructure Upgrades: A low regret option to prevent loss of telemetry and remote operation of a site is to raise equipment to a level unlikely to be reached by flood waters. To mitigate the effects of river scour, pipes along riverbanks and under the riverbed can be protected using rock armouring.

Emergency Response: If telemetry equipment is lost but the site is still accessible, the site can still be operated manually which involves a member of staff travelling to the site and making adjustments that are given by control room staff over the phone. A low regret option is routing practice runs with staff that would ensure smooth operation in such an event.

Monitoring: Divers regularly monitor pipes under rivers. Continuing this practice is a low regret option. Another low regret option is to carry out quantitative risk assessments to identify sites most at risk of flooding and river scour. This would give them a more proactive approach to mitigating risk.

4.2.4 High temperatures

Compressors can fail in high temperatures outside their operating range. This means they will no longer allow gas to flow which can create issues with meeting gas demand. This is mainly an issue for the transmission network. Few direct issues of high temperatures are seen for the gas distribution network. However, wildfires that can accompany hot conditions can impact pressure reduction sites situated in remote locations. However, in general, they do not have a lot of experience with wildfires so far. The impacts and resilience strategies are summarised in Table 12.

Table 12: High temperature impacts to gas networks and resilience strategies for mitigating risk

High Temperature Impacts to Gas Networks		
• Compressors can fail in high temperatures. • Wildfires occurring alongside high temperatures can lead to loss of some remote sites.		
Resilience Strategies		
Monitoring	Infrastructure Upgrades	Emergency Response
Low regret: • Vegetation management around sites (GDN 3) • Working with utility providers in Australia and Canada who have more experience with mitigating risks due to high temperatures and wildfires	**Low regret:** • Redundancy in network (GDN 1) **High regret:** • Widespread use of cooling units for pressure reduction sites in distribution network (GDN 3) •	**Low regret:** • Use of cooling units for critical sites in periods of extremely hot temperatures (GDN 1) • Health and safety measures for staff (e.g. lighter clothing) (GDN 2)

Infrastructure Upgrades: The gas transmission system already has significant redundancy built in with regards to compressor units. Each compressor site has at least one more compressor than needed. They can also reroute gas from different compressor sites if one site cannot handle the demand due to loss of multiple compressor units. A low regret option is maintaining this level of redundancy.

Emergency response: For critical parts of the network, cooling units can be brought in during periods of very high temperatures to prevent equipment becoming too hot. Although this is an expensive option, it would be considered low regret as the cost is relatively small compared to the consequences of losing multiple compressors in the transmission network. Health and safety measures for staff working in high temperatures are also considered low regret, these may include lighter clothing, keeping hydrated and regular breaks.

Monitoring: GDNs actively maintain a concrete perimeter around their sites and cut back vegetation that might overgrow on to their sites. The continuation of these practices is seen as low regret for mitigating the potential for sites being caught up in wildfires. GDNs are also part of a network of utilities providers from Australia and Canada who have more experience with mitigating risks due to high temperatures and wildfires. A low regret option is to continue working within these networks to learn best practices.

4.2.5 Cold Temperatures

The main impact to GDNs during cold spells of temperature is the increased number of detected gas leaks that arise due to the higher demand and resulting flow of gas. GDNs have standards of service for this where they must arrive to the site of a gas leak within one hour in 97% of cases. The ability to perform to this standard can be impacted by weather conditions in that cold weather amplifies the number of gas leaks while blocked roads due to snow/ice, flooding, or felled trees in high winds can impede their response. In the transmission network, compressor units can freeze over and prevent them working. The impacts and resilience strategies are summarised in Table 13.

Table 13: Cold temperature impacts to gas networks and resilience strategies for mitigating risk

<table>
<tr><th colspan="3">Cold Temperature Impacts to Gas Networks</th></tr>
<tr><td colspan="3">• Increased demand due to cold temperatures can lead to a high number of detected gas leaks that must be responded to within two hours.
• Secondary hazards can impact the response times to gas leaks such as blocked roads due to snow or ice, trees felled by wind, or flooding.
• Freezing temperatures can cause compressor units to ice up and shut down.</td></tr>
<tr><th colspan="3">Resilience Strategies</th></tr>
<tr><th>Monitoring</th><th>Infrastructure Upgrades</th><th>Emergency Response</th></tr>
<tr><td>• No monitoring options were reported</td><td>Low regret
• Significant redundancy already in network mitigates risks of loss of compressors (GDN 1)
• Replacement of metal pipes with high density polyethylene pipes (GDN 3)</td><td>Low regret:
• Continuous improvements of response following significant events (GDN 2, 3)
• Reduce non-essential workload to prioritise essential workload (GDN 3)
• Manage staff hours to avoid fatigue (GDN 3)
• Hire 4x4s to manage challenging road conditions (GDN 2)</td></tr>
</table>

Infrastructure Upgrades: As described for high temperatures, the transmission network has significant redundancy built in that allows it manage demand in the loss of a compressor unit. It is noted that compressors can be kept ice free when not in use by running them in neutral. Many GDNs are currently replacing older metallic pipes with high density polyethylene pipes which may reduce the number of gas leaks.

Emergency Response: Continuous improvement of emergency response procedures are seen as a low regret option which generally occurs in the aftermath of a significant event. Such practices include reducing non-essential workload, managing staff hours to avoid fatigue and hiring 4x4 vehicles to manage challenging road conditions and mapping out what teams have or don’t have 4x4 capabilities.

Monitoring: No practices related to monitoring were reported.

4.2.6 Impact of Power Outages

All sites require electricity. Power outages due to hazards such as flooding and windstorms can lead to a loss of operations at some sites, a loss of telemetry preventing remote operation of equipment that does not require electricity and prevent the odorization of gas. Many sites have back-up diesel generators with 10 days of supply. Major impacts may start to occur in a long duration power outage, particularly if sites cannot be reached by refuelling trucks if the road network is unavailable. The low regret options for handling power outages include increasing the number of sites with back-up diesel generators as well as increasing the size of diesel tanks. One GDN note that they have done the latter following Storm Arwen which caused them difficulties but did not lead to a loss of supply.

Table 14: Impact of power outages on gas networks and resilience strategies for mitigating risk

Impact Power Outage on Gas Networks		
• Power outages can prevent the operation of key assets in gas networks such as compressors, pressure reduction equipment. Electricity is also required to odourise gas. • Many sites will have back-up generators with 10 days of diesel supply. Issues would start to arise if power outage lasts longer than 10 days and diesel supplies cannot be refilled due to blocked roads that are flooded or covered in snow/ice.		
Resilience Strategies		
Monitoring	Infrastructure Upgrades	Emergency Response
• No monitoring options were reported	**Low regret** • Increase number of sites with back-up generators (GDN 1, 2, 3) • Increase size of diesel tanks for the short-term (GDN 2)	• No emergency response options were reported

5. Resilience Metric Workshop

On the 1st March 2024 a stakeholder workshop was held to disseminate findings and to explore resilience metrics and levels of service. The workshop programme is contained in Appendix 2. In this report, only resilience metrics and levels of service (questions 5 and 6) are discussed as the work associated with the other sessions are contained in the previous reports. It should be noted that the current thinking on questions 5 and 6 is still developing and there was a diverse range of opinions on the best way to move forward, mainly because it is 1) it is unclear how practical it will be to define resilience metrics and 2) it is unclear what these metrics will be used for (i.e. will they be used penalize companies who fail to achieve an appropriate level of service – as measured by the metrics, even if the event was more extreme than could be reasonably envisaged). For this reason, this report does not provide a definitive answer on what metrics should be adopted, but rather it summarizes the latest thinking on what are appropriate approaches and metrics (as asked in Q5 above) and explored what range of options could be implemented in defining appropriate levels of service.

Another important point to note is that there is not always a universally agreed definition of what is Resilience, what is a Metric or what is a Level of Service;.

For the interviews and workshop, the three definitions used were as follows:

1. Climate resilience – a measure of the ability of an energy network not to be negatively impacted by a climate hazard (note a simplified definition was used in the workshop)
2. Metric – standard of measurement (e.g. weather intensity (m/s), magnitude storm severity index (SSI) or customer minutes lost (CML)
3. Level of Service - a standard which defines the boundary between acceptable and unacceptable performance (also known as a performance requirement). Note a slightly different definition was used in the Workshop – see later.

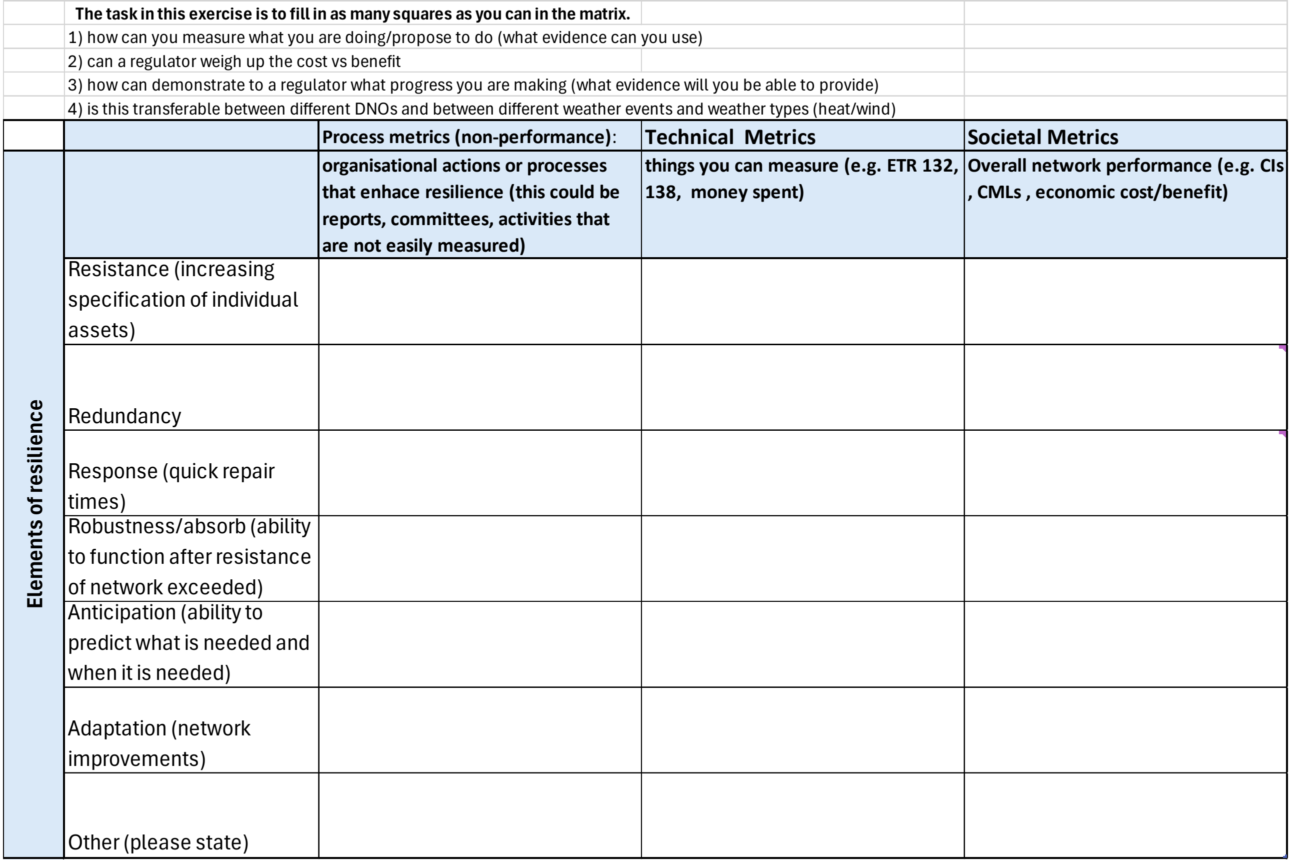
5.1 Metrics

There was agreement that networks should be resilient, and that metrics could play a role in this and before developing metrics there should be agreement on why metrics should be implemented. Reasons for wanting metrics was presented by one of the stakeholders, followed by a discussion and the following is presented as a summary of the discussion (although there was not time for an exhaustive discussion to gain consensus on these).

1. To provide a baseline measure of the resilience of networks across companies that could also be potentially used to:
2. To re-assure government and other stakeholders that networks are ‘sufficiently resilient’.
3. To track progress on whether investments are improving levels of resilience
4. To justify expenditure on the network
5. Be part of an incentive scheme

To explore how metrics could be developed to achieve these aims, a matrix was presented to the participants (see Table 15) and they were tasked with filling in as many of the cells in the matrix as possible. The matrix was designed to enable participation from people with a diverse range of backgrounds and to explore different mechanisms for achieving resilience and therefore ways of measuring this. The first column represented the different elements of resilience as discussed in the position paper while the headings in the first row correlated with how these elements may be achieved or described (and therefore who may be most interested in them) for example the last column is headed Societal Metrics and are measures of how society may be impacted if a network is not sufficiently resilient (overall system performance). Here the most obvious metric is Potential Customer Minutes Lost and an example of a stakeholder who most likely to be interested in this metric might be Ofgem. The second column is technical metrics, and these are things that are relatively easy to measure (specify) and are aimed at engineers or asset managers etc. An example of this metric might be the thermal rating of a transformer, or ETR 138 (specification for flood resilience - it should be noted that different people placed the same metric in different columns, for example ETR 138 is considered resilience metric by some people, a level of service by others and also a technical metric). The first column in the matrix are process metrics and these are measure of actions or organizational structures that enhance resilience. These are often difficult to measure but are important as good systems are an important aspect of resilience.

Table 15: Resilience Matrix



The task in this exercise is to fill in as many squares as you can in the matrix.

1) how can you measure what you are doing/propose to do (what evidence can you use)

2) can a regulator weigh up the cost vs benefit

3) how can demonstrate to a regulator what progress you are making (what evidence will you be able to provide)

4) is this transferable between different DNOs and between different weather events and weather types (heat/wind)

		Process metrics (non-performance):	**Technical Metrics**	**Societal Metrics**
Elements of resilience		**organisational actions or processes that enhace resilience (this could be reports, committees, activities that are not easily measured)**	**things you can measure (e.g. ETR 132, 138, money spent)**	**Overall network performance (e.g. CIs , CMLs , economic cost/benefit)**
	Resistance (increasing specification of individual assets)			
	Redundancy			
	Response (quick repair times)			
	Robustness/absorb (ability to function after resistance of network exceeded)			
	Anticipation (ability to predict what is needed and when it is needed)			
	Adaptation (network improvements)			
	Other (please state)			

5.1.1 summary of the workshop discussions on metrics:

The original resilience matrices as filled in by the workshop participants are contained in Appendix 2. These have been transcribed and are presented in Table 16.

Table 16: Resilience matrix notes from all respondents (note: not all text has been transcribed due to difficulties in interpreting what was written, and some text has been updated to make the meaning clearer).

		Process metrics (non-performance):	**Technical Metrics**	**Societal Metrics**
Elements of resilience		**organisational actions or processes that enhace resilience (this could be reports, committees, activities that are not easily measured)**	**things you can measure (e.g. ETR 132, 138, money spent)**	**Overall network performance (e.g. CIs , CMLs , economic cost/benefit)**
	Resistance (increasing specification of individual assets)	RIO business plan,evidence collection measures, replacement plans, investment into ability to track near misses, specifications that require level of resilience and deisng considerations. Suitable design of replacement assets, working together sharing of resilience learning	incorporate specifications based on climate projections, new materials specifications (e.g. HDPE gas pipes, undergrounding), abioity to categorize events against return periods and confirm/deny an impact, risk are interconnected so difficult to give metric, specify level of resilience for each asset, consistencey of data issues, ETR standards upgrades	Number of CI/CML following upgrades - controlling for climate, challenge of comparing between two different areas
	Redundancy	back-up plans for staff, 100% asset redundancy, multiple sources of supply	specify redundancy (assets/capita) specify levles of gas and electricity storage, specify reequirements for interconnectors, need good fault monitoring, need to measure actual event/ quantify historic events, NARM/CBRM style approach	Specify number of faults before loss of service, 99.98% network reliability (i.e. system modelling)
	Response (quick repair times)	workforce resilienc reports, reporting on repair times, supply chain availability, cross sector coordination in emergency management	specify standards for response and repair times, communication requirements (i.e. robust transport and communication equipment for repair teams)	specify CMLS after erosion event, customers disconnected and length - esp vulnerable customers, time to reconnect, total length of time off supply
	Robustness/absorb (ability to function after resistance of network exceeded)	supply/demand management (dynamic pricing - interuptive pricing), emergency exercise for network gas supply emergencies, inerruption of supply/load shedding	standards for pricing, behavioural standards, flexiibility standards, priority of service standards, SQSS, specify backups e.g. mobile substations	track CML for erosion events,
	Anticipation (ability to predict what is needed and when it is needed)	forecast modlling, horizon scanning plans, emergency excercises, network modelling, Hazard identification, riks assesments, emergency excercies, notification protocols in place, emergency exercise, simulating failures, post event reviews and match sith scenari modelling	incorporating forecasts models into standards, dynamic standards that change with environmental standards, forecasting future climate risk scenarios, whole life risk	Cis/CMLs avoided through anticipation, £ spend on forecasting or simulation (or specify simulation capabilities), use common simulation platform, customer advance notic and communications e.g. text/email
	Adaptation (network improvements)	supply chain availability, joined up decarbonization plans (i.e. incorporate resilience in adaptation), DEFRA adaptation reporting power	mandatory feedback loops, requirements to specify timelines fo replacement of infrastructure with higher specification, can we use machine learning to optimize networks for resilience	CI/CML avoided through adaptations, criticality ratings for assets, networks inter-dependency e.g. not losing telecomms
	Other (please state)	whle energy risk assessments, providing baselines for resilience NESO, readiness metrics - have you assessed the risk, what are the plans, have the plans been tested	Power resilience metrics - how long can you operate without power, telecoms, water etc, are there thresholds of disproportionate consequence	commom risk appetite across GDN/GT/Ofgem and DESNZ, mechanism for ignoring loss of supply if houses evacuated (e.g. flooding), Guarenteed standards of supply

From the discussion at the workshop and the text contained in the matrix, it can be said that there is general agreement that metrics are important for quantifying and understanding resilience in the energy system and communicating this to stakeholders. There are plenty of monitoring and reporting mechanisms in place in the energy system already and there was agreement that, where appropriate, these should be leveraged for developing metrics of climate resilience. One such mechanism is the Network Asset Risk Metric (NARM), which relates to the likelihood and impact of the failure of assets in the energy network. It is calculated for the lifetime of an asset and therefore climate change is an important component to consider. There was general agreement that NARM needs to consider changing risk according to extreme weather in a changing climate. There are also metrics in place for quantifying disruption to customers in Customers Interrupted (CI) and Customer Minutes Lost (CML) which will be important tools in understanding the impacts from extreme weather events as a result of climate change. These could be extended to quantify the economic value of the outage or CMLs for different customers, eg residential, hospital, business, vulnerable people. In relation to quantifying risk, there was a lot of discussion around increasing simulation ability and using climate model output in this regard, especially in the area of early warning and stress-testing platforms. The use of counterfactual analysis to better quantify both the benefit received by adaptation measures in the case of an extreme weather event and the risk posed by near misses. Bullseyes and near misses have been discussed at ENA climate change resilience working group and are a source of concern in the introduction of metrics (i.e. how to differentiate between resilient systems that get hit by an exceptional storm-bullseye and vulnerable networks that have not been tested by a recent storm). Counterfactual analysis is a good tool for exploring the ‘what ifs’. A few participants suggested scenarios should be developed across the sector and historical events put into context of probability of occurrence (likelihood) so future events can be compared to these. Another proposed area of improving process metrics was the implementation or enhancements of emergency management plans and emergency simulations. Some participants suggested that ETR 138 equivalents for other hazards could be developed; however, concerns over how to deal with the location of storm in simulations or bullseyes in population centres for actual events is a concern for energy companies. Another area for improving resilience through metrics is by raising the specification of new assets (technical metrics). It was also suggested that these should be linked to simulations to ensure effectiveness and efficiency of raised specifications.

To summarize areas where metrics could be developed or improved fall into two categories:

1. Long term infrastructure planning and value for money and associated modelling and simulation capabilities
2. Emergency preparedness and response and associated early warning modelling and simulation.

Table 17: Categories demonstrating where metrics could be improved or developed

<table>
<tr><th colspan="3">Long-term infrastructure planning</th></tr>
<tr><td colspan="3">• Quantifying climate risks through NARM
• Counterfactual analysis to determine benefits from adaptation
• Asset supply chain management ensuring climate resilient, sustainable materials and assets
• Increasing asset specification
• Improving simulation capabilities</td></tr>
<tr><th colspan="3">Emergencies</th></tr>
<tr><th>Planning</th><th>Anticipation</th><th>Response/Recovery</th></tr>
<tr><td>• Is there an emergency plan in place for different hazards and multi-hazards?
• Have emergency plans been tested in collaboration with other sectors?
• Criticality ratings for assets and cascading risk plans
• Percentage of network which can be remotely switched off</td><td>• Percentage of assets protected by temporary hazard mitigations (i.e. flood defenses)
• Workforce resilience scores and resource sharing capabilities
• Predictive fault modelling and impact likelihood</td><td>• CI/CML following emergencies
• Response time between first impacts and return to capacity
• Lessons learnt on best practises
• Counterfactual analysis on CML avoided due to investment and anticipation
• Near miss tracking</td></tr>
</table>

These categories relate to how resilient the energy system is to increasing threats from climate change and how resilient the system is to individual extreme events. The two categories are not independent of each other, increasing resilience to climate change will also increase resilience to extreme events and vice versa. However, there were discussions about how different metrics may be relevant to the chronic issues of long-term climate change and the acute effects of extreme weather events. It was also discussed that even without the context of a changing climate, there are opportunities for improving resilience to extreme events today and there may be metrics which can used to measure this. Discussions also focused on the need for measuring resilience and sustainability in the whole supply chain of assets and the need for active supply chain management.

5.2 Levels of service

There was broad agreement that a public discussion on levels of service from the energy sector is necessary, given the changing risk of extreme weather events and associated uncertainty. Discussions around levels of service broadly fell into three categories related to customer communication, response times and support for vulnerable communities. There was an acknowledgement that extreme weather events are going to become more likely in the future and disruption to energy systems will inevitably occur, despite best efforts and investment in infrastructure. In this context, it is important for energy companies to be proactively engaging with customers, so they understand the impacts of extreme weather on energy services. As part of this proactive engagement, there was also an acknowledgement of the need for better knowledge of who vulnerable customers are and where they live so that prioritisation of response can be coordinated. There was also a lot of discussion around moving away from a completely demand managed system (where operators are required to provide as much electricity as demanded irrespective of the size of that demand) to one that allows cheaper electricity that may not be as reliable for short periods of time. This would have to be implemented using technological management solutions and could involve short term energy storage and generation in rural communities; for example. Finally, the role of better forecasting was emphasised since early warnings increases the time for customers and operators to prepare for disruption. More time for preparation and prioritisation of assets prior to extreme events not only reduces the likelihood of impacts, but also reduce the time taken for recovery should impacts occur.

Response time and prioritisation of vulnerable customers is particularly important during extreme hot and cold spells.

5.2.1 Improved Forecasting and Communication:

Weather forecasts capabilities are constantly improving, and the inclusion of AI will increase the lead time of accurate predictions of weather-related impacts. There are opportunities for operators to utilise better forecasts of extreme weather events to ensure customers are prepared for potential disruption and communicate the need for demand management. These communications can be direct via digital communications with customers as well as public messages via national media outlets. Early warning systems are an important step in giving customers enough time to prepare for any potential impacts.

5.2.2 Faster Response and Asset Prioritization

With increases in extreme weather due to climate change, there is an acknowledgement that despite adaptation measures, disruption is inevitable in the future. However, resilience is more than preventing disruption in the first place and includes the ability of the energy system to respond and restore services quickly. When disruption does occur, response time can be improved by anticipating network failures through fault forecasting and prioritising critical assets, so that resources can be in the right place, at the right time. This is particularly important for vulnerable communities in remote areas who typically suffer from the most prolonged disruption during extreme events. These resources are twofold in that they consist of 1) mustering resources to inform customers pre and post event and to minimize the time to restore services (e.g. readying extra lines-people hire of 4wheel drive) and 2) provision of assets that can alleviate storm impacts (e.g. generators, batteries, alternative heating and communication, alternative accommodation). Although this is currently done to some extent, it can be done more effectively and efficiently using sophisticated early warning systems.

5.2.3 Expanded Support for Vulnerable Customers

The impacts from disruption are worse for vulnerable customers such as elderly or disabled people, or electrically medically dependent, particularly when they live in isolated, remote communities. Ensuring that these customers and communities have the support they require during disruption is essential, particularly during extreme heat or cold events. In order to ensure resilience, the customers who need the most support need to be identified before and prioritised during extreme weather events and disruption. Again this is currently done, but future protocols may include a wider definition of vulnerable and a better understanding of their needs.

6. Conclusions

This report highlights the primary weather and climate driven risks to electricity and gas networks, the secondary hazards that compound these risks and the cascading risks arising from sector interdependencies (electricity, gas, telecommunications, transport). Alongside these risks, the report outlines low regret options for enhancing the resilience of these networks and explores methods for quantifying resilience metrics and levels of service. This information was collected through one-to-one interviews with members of DNOs and GDNs as well as during an in-person workshop with members of DNOs and DESNZ. This information comes at an opportune time to help inform decision making within the RIIO-ED2 and next RIIO-3 price control periods.

6.1 Power system resilience under Future Energy Scenarios

The future resilience of power systems to climate change will be influenced by a range of factors including the spatial distribution of supply technologies, specific policies to tackle overheating, demand flexibility that are readily accessible during an extreme event and adequate network investment to protect the infrastructure. Increased cooling demand coincided with a reduced wind power generation and network capacity during heatwaves is of future concern. Case studies from Australia suggest that a combination of events during extreme weather (e.g. communication failure and errors in forecast) can lead to large scale power failures which can cause cascading effects across the economy. The windstorm impact analysis of the GB power system model developed for this project shows that although planned network investments offer increased network capacity, they do not mitigate the impacts of windstorms. Demand flexibility is a valuable addition to the energy system which can defer network investment at potentially modest cost and can act as an enabler for low carbon technologies (e.g. HP, EV and PV). However, major policy changes are needed for flexibility to be adopted widely in the UK and can be used to avoid power outages during extreme weather events.

6.2 Low regret options for enhancing resilience

Resilience planning is already a major source of expenditure in both electricity (DNOs) and gas (GDNs) network operators. Their adaptation options for enhancing resilience are varied and often bespoke to the hazard and asset affected, but generally fall into three categories: 1) Infrastructure upgrades which focus on protecting critical parts of the network, 2) emergency responses to restore supply as quickly as possible, and 3) network monitoring which comprises vegetation management, assessment of asset health and risk assessments. Operators are already implementing many of these options. Their decision making on the implementation of such options are made on a case-by-case basis to optimise the cost-benefit of their investments across the network. This decision making is aided by information from network monitoring as well as the risk rating of assets according to their criticality (number of customers affected in case of failure), exposure to weather conditions, and the likelihood of failure in extreme weather.

6.3 Main hazards and cascading risks for energy networks

Electricity operators are mostly worried about flooding, windstorms and heat waves. The risk of large-scale power outages is highest for windstorms and flooding, although heat waves may have a larger impact in future if assets are exposed to ambient temperatures outside their operating ranges (>40^{o}C for many assets). Flooding mainly impacts substations, windstorms damage the overhead line network via trees falling and branches breaking (amplified by wet soils, unusual wind direction, and leaves on trees), while heat waves can simultaneously impact overhead lines and assets such as transformers, particularly in urban areas where the urban heat island effect prevents overnight cooling.

Gas networks are less impacted by the weather as the majority of assets are underground. There is also significant redundancy built into the networks which allows them to continue working if certain assets become unavailable. Weather mainly impacts their operations such as cold weather leading to increased demand and more detected gas leaks which must be responded to within 1 hour in 97% of cases. Flooding of pressure reduction sites can lead to loss of telemetry and remote operation, while river erosion can expose pipes leaving them open to damage and subsequent water ingress that can require a large operational response.

Both gas and electricity network operators highlight cascading risks that arise through sector interdependencies between themselves and with road and telecommunication networks. For instance, gas networks require electricity to operate pressure reduction sites. In power outages, many sites have back-up diesel generators though problems may arise if the outage lasts longer than their fuel reserves allow for (generally 10 days) and if fuel trucks cannot access the site for refuelling due to poor road conditions. Emergency response for all operators requires that responders are able to access sites. The duration of impact (power outage, gas leaks) is therefore prolonged if roads are flooded or covered in snow/ice. Finally, a reliable telecommunication system is required for remote operation of assets, detecting faults, and maintaining contact with responders in emergency situations.

Climate change will increase the risk of network impacts from the main identified hazards and the co-occurrence of these hazards. For instance, projected wetter winters mean that windstorms will occur over wet soils more often and longer growing seasons will lead to more windstorms occurring when trees are still in leaf (e.g. Storm Ciarán). Furthermore, windstorms will co-occur with extreme rainfall and alongside flooding more frequently in the future (Bloomfield et al., 2023; Manning et al., 2024) potentially causing a higher aggregation of separate impacts (e.g. more power outages). Such events may stretch emergency response resources and expose the limitations of relying on this option too much over upgrades to infrastructure.

6.4 Resilience metrics and Levels of Service

The thinking on what are appropriate resilience metrics (i.e. how to measure resilience) and the associated levels of service (i.e. what value of a resilience metric demarcates acceptable performance from unacceptable performance) is relatively immature for most climate risks. In the case of flooding these are well defined (by ETR 138) and reasonably well accepted (although whether it is a metric, or a level of service is debated); however for other hazards this is not the case and there is a wide range of opinions on what is an appropriate way to define resilience.

7. Recommendations

Before making any recommendations, it should be acknowledged that much of what is about to be recommended is already being explored and developed by the network operators; however, there are still deficiencies in some areas and so we make the following recommendations in an attempt to focus efforts.

Quantitative Risk Assessments: Network operators have a detailed knowledge of the cause of impacts to their network, their knowledge is largely based on anecdotal or qualitative evidence. To continue with qualitative and a single hazard view of risk is likely to lead to an underestimation of impacts and/or mal-adaptations. A greater quantitative understanding of drivers of these impacts would improve impact forecasts to help emergency response, as well as inform requirements for climate risk assessments. As part of this, climate risk modelling and simulation capabilities of the energy network sector should be improved. Models should be developed and used to make quantitative climate impact assessments, and to understand why some storms are responsible for large power outages while others are not, and how this may change in the future. Risk assessments should include analysis of historic events and a methodology for ranking the impacts of these historic as well as their likelihood. These can then be compared to impacts of future events as they occur. The models should also be used to assess future risk using climate projections.

Defining appropriate metrics to measure resilience should continue to be explored with a view of developing equivalents to ETR 138 for other hazards. It should be noted that there are many elements to resilience and many ways of improving it, therefore, other mechanisms for improving resilience and appropriate ways of measuring these should also be explored.

Future Levels of service should continue to be explored and better mechanisms for managing disruption of low probability high consequence events should be developed.

These should include modelling and simulations to inform early-warning systems and communicating their outputs to customers.

Network upgrades should include an assessment of how resilience can be maximized as part of the planned upgrade.

Understanding interdependencies between ICT and economic services. Wide-area power failures can cause cascading effects across the economy, hence critical infrastructure failure should be included in the future risk assessments and disruption impact modelling.

Enhancing demand flexibility in the energy system is a low cost-option to increase power system resilience. Wider adoption of flexibility would require regulation of flexibility markets and flexibility aggregators. A portfolio of flexibility mechanisms is needed to mitigate power outages during extreme weather events.

Further research is needed on the active co-ordination of various low carbon technologies and the use of flexibility during contingency periods.

8. Acknowledgements

The authors would like to thank all who participated throughout the project, particularly to those who shared their insights in two rounds of interviews and at the in-person workshop. The authors would also like to thank Dr. Sarah Dunn and Dr. Hannah Bloomfield for their contribution to the workshop, Mr. James Carruthers for summarising outputs of the workshop, as well as Mr. Gaurav Gharde and Mr. Brandon Law for the data analysis on DFES and the development of diurnal profiles for heat pumps and electric vehicles.

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