Headroom - Whole System Thinking

Stage 2 Report v1.2

CLIENT: National Grid Electricity Distribution

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Whole of System Value of Distribution Headroom – Stage 2 Report

Version history

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Table of Contents

List of Acronyms

ANM	Active Network Management
BM	Balance Mechanisms
BESS	Battery Energy Storage Systems
DER	Distributed Energy Resource
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
DSO	Distribution System Operator
EAC	Enduring Auction Capability
EATL	EA Technology
EDA	Exploratory Data Analysis
EHV	Extra High Voltage
FES	Future Energy Scenarios
HV	High Voltage
LV	Low Voltage
NESO	National Grid Energy System Operator
NZH	Baringa's Net Zero High
PV	Solar Photovoltaic
V2G	Vehicle-to-Grid

List of Figures

List of Tables

1 Executive Summary

The energy transition is driving significant changes in power systems worldwide, with an increasing reliance on renewable energy sources and distributed energy resources. These developments have introduced new challenges to distribution management, particularly concerning headroom—the capacity available in the network to accommodate additional generation or load.

A reduced headroom value can lead to increased curtailments of distributed generation, undermining business cases for renewable projects, raising system costs, and increasing carbon emissions. Efficiently managing headroom is therefore critical to supporting decarbonisation goals and optimising system performance.

The present work is part of the NIA funded 'Headroom – Whole System Thinking' and this report explores the quantification of benefits derived from releasing additional headroom in the distribution network. Using projections of curtailments provided by EA Technology (EATL) for the years 2023, 2028, and 2034, the study evaluates the impacts of headroom on wholesale market system costs, Balancing Services costs, and carbon emissions. The analysis combines a detailed examination of curtailments with modelling of system-wide impacts to identify both the spatial and temporal dynamics of these benefits.

The methodology entails incorporating curtailments into a market model and comparing the results against an agnostic-curtailment model used as a benchmark. This approach allows for quantifying the differences in wholesale market costs, carbon emissions, and Balancing Services. Additionally, a sensitivity analysis on various curtailment levels was performed to assess how these metrics respond to changes in curtailment scenarios. Finally, the curtailments originating from each voltage level were analysed in isolation to determine their specific contributions to the overall benefits, providing a detailed understanding of their impact across the distribution network.

The findings demonstrate that releasing headroom can generate substantial system-wide benefits, reducing wholesale costs, emissions, and reliance on costly balancing actions:

- Sensitivity analyses indicate the aggregated total system benefits range from £445m to £3.5 billion during the analysis period, depending on curtailments level, with the Best-View scenario projecting £2.5 billion. The lower bound reflects scenarios where renewable penetration stabilises and grid flexibility increases (reducing curtailments) while the upper bound aligns with continued renewable growth and limited network investment.
- The benefit-cost ratio, which measures total system benefits relative to system costs each year, starts at 1% in 2023 and reaches 8% in 2034. This progression demonstrates that releasing headroom is a highly cost-effective approach to optimising network performance while delivering substantial economic benefits.
- LV networks are shown to play an increasingly prominent role, delivering 37% (£796m) of total benefits by 2034, while 132kV networks provide the highest accumulated benefit (53%, £1,125m) through to 2028 but declining in their share after. This underscores the

importance of not only identifying where to invest in releasing headroom but also when, ensuring timely interventions to maximise economic benefits and address evolving network constraints.

- Drivers of curtailments vary by voltage level, with Solar Photovoltaic (PV) dominating at LV, while wind generation and Battery Energy Storage Systems (BESS) utilisation have a greater influence at higher voltage levels.
- Additionally, releasing headroom in the distribution network allows an aggregated cost reduction estimated in £350m due to balancing mechanisms by enabling greater Distributed Energy Resource (DER) participation, reducing the reliance on expensive distribution network constraints, and enhancing overall system flexibility.

To support a low-carbon electricity system and maximise system-wide benefits, we propose the following actions:

- **Improve operability at LV in the medium term:** With LV curtailments projected to dominate by 2034, prioritise operability improvements that may include advanced management systems and capacity upgrades to reduce curtailments, unlock savings, and support PV integration.
- **Optimise 132kV performance in the near term:** The 132kV network provides 83% of the total system benefits in 2023 but this share declines after 2028. Targeted interventions, including wind curtailment management and enhanced BESS utilisation, will sustain its value.
- **Align flexibility strategies with whole-system outcomes:** Distribution Network Operators (DNOs) must consider the wider impacts of flexibility procurement and Active Network Management (ANM), balancing local optimisation with system-wide benefits to avoid higher wholesale prices and increased emissions.
- **Strengthen National Energy System Operator (NESO) - Distribution System Operator (DSO) coordination:** Enhance existing collaboration to reduce conflicts between flexibility actions, mitigate cascading congestion, and enable broader DER participation.
- **Integrate whole system impacts into planning and regulation:** Ensure DNO decisions align with Ofgem's ED3 Framework and Clean Power 2030 (CP2030) goals, balancing customer outcomes with broader system benefits.
- **Ensure alignment between national and regional energy plans to improve coordination and efficiency**
  Strengthen coordination between NESO, DNOs, and regional stakeholders to ensure the integration of Strategic Spatial Energy Plan (SSEP) aligns with Regional Energy Strategic Plans (RESPs) to help avoid conflicting flexibility strategies, improve investment decisions, and support a cost-effective transition to a low-carbon system.

2 Introduction

Achieving the GB net zero targets for 2050 involves the electrification of transportation and heat and the increased integration of renewables and BESS. A key challenge is to enable generation to meet demand as we move more towards significant use of DERs (for this report refers to distributed generation and BESS). The range of credible futures for the growth of these DERs and the distribution network[1] are summarised in annual DNO Distribution Future Energy Scenarios (DFES) and form an essential part of strategic network investment planning.

The distribution network was initially designed for energy flows from higher voltages to lower voltages. The increasing penetration of distributed generation can create constraints due to limited asset capacity or restrictions in upstream power flows. These constraints can change the balance of supply and demand locally and the level of services provided to NESO which can increase the costs of meeting demand. Constraints also affect distributed generation owners through reduced income.

There are three types of constraints:

- **Economic constraints** when market prices are too low to justify generation, often occurring during very low or negative pricing scenarios in wholesale markets.
- **Grid or network constraints** due to asset capacity limits or voltage issues.
- **Operational constraints** enforced to balance supply and demand in an area or to maintain system reliability or resilience.

The purpose of the project is to explore the connection between distribution network headroom and its impact on non-distribution network costs related to supply and balancing services In this context, headroom is defined as the difference between peak load and network limits, and it can be released in various ways, including the use of active network management solutions and the deployment of flexibility solutions.

This project aims to evaluate the whole energy system to determine the benefit per unit of added firm headroom. This benefit will be quantified in terms of both the reduced cost of energy (£/MWh) and reduced system carbon intensity (CO_2/MWh) that can attributed to increased distribution network headroom, for each voltage level, at critical times of year, and different constraint scenarios. The outcome will be used to drive timely and cost-effective innovation towards these opportunities. The project was originally envisaged to have three Stages; determine the range of potential benefits of releasing distribution Headroom using a high and a low Headroom impact scenario (Stage 1), refine the potential benefits and produce a variety of high-level cost curves and determine detailed cost curves and investigate how this varies with geography.

[1] Each DNO publishes a DFES that is based on the annual NESO Future Energy Scenarios: NESO Pathways to Net Zero (FES) which propose credible pathways to achieve the net zero target and operate a decarbonised electricity system by 2050

The findings of Stage 1 work[2] can be summarised as follows:

- Analysis determined there was sufficient whole system value associated with releasing Headroom across GB electricity distribution networks to merit further work.
- Analysis using two curtailment scenarios determined the range of potential benefits of releasing distribution network headroom on wholesale prices and carbon emissions.
- The annual benefits from releasing Headroom ranged from a material (£27.5m) to a significant (£1.4bn).
- Further work was required to improve the curtailment methodology so the annual benefits from releasing Headroom is within a realistic range of values.

The scope for Stages 2 and 3 was amalgamated to provide greater focus and is discussed below:

- Conduct more detailed constraint modelling to confirm the materiality of the whole system benefits from releasing distribution Headroom. This work was conducted by EATL, and a detailed description of this data is presented in Section 3.
- Use the constraint modelling outputs for four generation types to create a range of cost curves to narrow the annual benefits from releasing Headroom. This work is summarised in Section 4.
- Assess voltage level sensitivities to determine cost curves for addressing curtailment at different voltage levels. This work is summarised in Section 4.
- Build a model to determine the value of Ancillary Services from releasing Headroom and stress test using the cost curve outputs, which is presented in Section 5

The key questions to be addressed in this report are:

- ***What is the impact of releasing headroom in the distribution sector?*** This requires a sensitivity analysis of curtailment levels.

i. ***What is the impact of each voltage level when releasing headroom in the distribution sector?*** This involves conducting a sensitivity analysis at each voltage level in isolation.

ii. ***What are the main drivers of curtailments in the distribution sector at each voltage level?*** Understanding these drivers is crucial for designing optimal strategies to release headroom.

iii. ***What are the benefits of Balancing Services when releasing headroom in the distribution sector?*** This requires working with aggregated DERs operating in the electricity markets (represented by an aggregator of DERs, for instance).

This report is structured into four key areas: details on the curtailment data (Section 3), the methodology for our analysis and results Section 4 (questions i to iii above) and Section 5 (question iv above), summary of result (Section 6), and discussion and conclusion (Sections 6 to 8).

[2] The Stage 1 report can be found here

3 Network Curtailment Data

3.1 Introduction

The approach developed to address the key questions presented in the previous section comprises two fundamental components:

- Curtailment projections, managed by EATL, which play a critical role in determining the simulation results. Curtailments in the distribution sector are treated as additional load at the transmission-distribution boundary, significantly influencing the outcomes.
- The GB-wide power market model, managed by Baringa, which is essential for analysing price impacts, emissions, and overall market behaviour.

Curtailment projections were calculated using EATL's Transform© Network Model and the Simple Curtailment Tool to model the restrictions of headroom. The Network Model projection utilises data from FES System Transform (ST) to forecast the uptake rates of distributed generation across LV to EHV voltage levels, and it uses seasonal profiles to capture peak demand and generation periods throughout the year. The SCT was developed by NGED to support curtailment forecasts within ANM zones. The methodology assesses the baseline loading and adjusts net export profiles of generators to ensure compliance with thermal limits on constraints. Generators are added using a Last-In-First-Out sequence, with consideration given to their proximity to network constraints. The tool iteratively calculates permissible exports to prevent constraint breaches, generating 'ideal profiles' and 'curtailed profiles' for each generator to maintain network stability. Finally, it is worth to mention that EATL's model assumed reinforcement on a demand basis rather than generation basis, for more information about how curtailments are calculated, readers are referred to EATL report[3].

The curtailment data serve as inputs to the GB-wide power market model, directly affecting the electricity demand perceived by the bulk system. The dataset includes hourly predictions for both generation and curtailments (in kWh) across five technologies: BESS, Gas, PV, Wind, and Vehicle-to-Grid (V2G) Electric Vehicles. It also spans three years within the analysis horizon (2023, 2028, and 2034) and covers four voltage levels in the distribution sector: Low Voltage (LV), High Voltage (HV), Extra High Voltage (EHV), and 132kV.

The dataset totals 893,520 data points. Given this significant volume, an Exploratory Data Analysis (EDA) was conducted to extract statistical insights, identify potential anomalies, explore correlations between features, and derive initial deductions. These insights contribute to addressing the key questions outlined in Section 2.

[3] Whole System Thinking (Phase 2) - Curtailment Modelling, available inhttps://www.nationalgrid.co.uk/downloads/690239/whole-system-thinking-phase-2-curtailment-modelling-v1-21-1-.pdf.

The primary goal of the EDA is to uncover patterns, statistical measures, and relationships within the curtailment data, focusing exclusively on the data itself. While curtailments are ultimately driven by congestion, network management strategies, and dispatch constraints, this section strictly analyses the statistical properties of the data without interpreting their broader system implications. Instead, the insights from EDA serve as a complementary layer of analysis that, when combined with the simulation results in Chapter 4, provide a more comprehensive understanding of curtailments. The interpretation of these results, along with their broader implications, will be addressed in Section 7.

3.2 Exploratory Data Analysis

3.2.1 Preprocessing and anomaly detection

The preprocessing of data began with integrating the original curtailments dataset into the Baringa GB-wide market model (Market Model). The curtailment data provided by EATL was based on FES ST and the Market Model adopts the Net-Zero High scenario (detailed in Section 4.3) and used as follows:

- The hourly percentage of curtailment was calculated from the curtailment data for use in the Market Model.
- This percentage was applied to the Baringa Net Zero High Scenario in the Market Model to derive the curtailment volumes consistent with the capacity build and generation within the scenario.

In this section, all references to curtailment volumes (e.g., in GWh) refer specifically to the Market Model. Additionally, since V2G curtailments were only available at the LV level, these values were merged with the BESS category to ensure consistency across all voltage levels.

Anomaly detection revealed no missing data across the analysis horizon. However, 101 observations (less than 0.01% of the dataset) exhibited curtailment levels exceeding the corresponding generation levels for the same technology. This was identified as an anomaly since the absolute value of curtailments cannot exceed the available generation capacity. To resolve this, curtailments were capped at the maximum value of the available generation for those observations.

3.2.2 Curtailments by technology, voltage level and year

Curtailments change significantly over the years, reflecting the increasing penetration levels of technologies at different voltage levels, as presented in Table 1.

In 2023, **PV technology** presents 275 GWh of curtailments out of 13,521 GWh of generation (2% of curtailments, in average), **Wind technology** grants 206 GWh of curtailments and 14,489 GWh of generation (1.4% of average curtailment), **Gas curtailment** reaches 568 GWh out of 16,771 GWh of generation (average 3.4% of curtailments), and **BESS** presents 30 GWh of curtailments out of 815 GWh of generation, totalling 3.7% of average curtailments.

In 2028, curtailments from **PV** increases to 728 GWh, out of 19,011 GWh of generation, making up an average curtailment of 3.8%. **Wind curtailments** reach 357 GWh from the total generation 19,054 GWh (1.9% average curtailment), **Gas curtailment** level get reduced to 288 GWh, as well as its generation level to 14,113 GWh (average curtailment is 2%) occasioned from the constantly decarbonisation of electrical systems. Finally, **BESS** presents 208 GWh of curtailment from a total generation equal to 2,678 GWh, with a higher average curtailment rate as 7.8%. Curtailments at HV voltage level were negligible during 2028.

In the last year of analysis, 2034, PV curtailments continue to increase reaching 1,789 GWh, from a total generation of 21,148 GWh (8.5% average curtailment), Wind reaches 433 GWh of curtailments out of 22,206 of total generation (average curtailments is 1.9%), Gas Technology presents 123 GWh of curtailments, from a total generation equal to 5,998 GWh (2.1% of average curtailments), and BESS grants 134 GWh of curtailments out of 2,544 of total generation (5.3% of average curtailments).

Table 1: Volume of curtailments over voltage level and years.

Year	Voltage Level	PV (GWh)	Wind (GWh)	Gas (GWh)	BESS (GWh)	Total (GWh)
2023	LV	225	1	0	0	226
	HV	12	4	1	0	17
	EHV	9	19	2	1	32
	132kV	29	182	564	29	805
2028	LV	510	2	0	4	516
	HV	1	0	0	0	1
	EHV	36	72	9	9	126
	132kV	181	282	278	196	938
2034	LV	1552	7	0	26	1585
	HV	53	14	1	0	68
	EHV	74	134	3	9	220
	132kV	111	277	120	99	606

In 2023, curtailments are heavily concentrated at the 132kV level, which accounts for 75% of the total, reflecting the dominance of gas and wind at this higher voltage. Over the analysis horizon, curtailments progressively shift toward the LV level, where they rise from 21% in 2023 to a striking 64% by 2034. This transition underscores the intensifying stress on lower voltage networks as distributed generation, particularly PV, continues to proliferate. By 2034, PV curtailments dominate the LV level, consistently accounting for over 98% of curtailments.

Across the higher voltage levels, wind plays a leading role, particularly at EHV, where it contributes over 60% of curtailments in both 2023 and 2028. However, by 2034, curtailments at EHV and 132kV diversify, with increasing shares from gas and BESS complementing wind's dominance. Notably, BESS sees a substantial rise in its share of curtailments at 132kV, increasing from 3% in 2023 to 16% by 2034, reflecting its growing deployment as a key resource for system flexibility, as detailed in Table 2. This diversification at higher voltage levels contrasts with the concentration of PV curtailments at LV, highlighting the dynamic nature of curtailments and their alignment with technology trends and network integration challenges.

Table 2: Share of curtailments over voltage level and years.

Year	Voltage Level	PV (%)	Wind (%)	Gas (%)	BESS (%)	Share (%)	Total (GWh)
2023	LV	99%	1%	0%	0%	21%	1080
	HV	74%	21%	5%	0%	2%	
	EHV	29%	61%	7%	3%	3%	
	132kV	4%	22%	70%	4%	75%	
2028	LV	99%	0%	0%	1%	33%	1581
	HV	78%	19%	3%	0%	0%	
	EHV	29%	57%	7%	7%	8%	
	132kV	19%	30%	30%	21%	59%	
2034	LV	98%	0%	0%	2%	64%	2479
	HV	78%	21%	1%	0%	3%	
	EHV	34%	61%	1%	4%	9%	
	132kV	18%	46%	20%	16%	24%	

As renewable energy penetration accelerates, the findings reveal a shift in the spatial and technological dynamics of curtailments. While LV networks bear the brunt of the impact due to distributed PV, higher voltage levels experience a more balanced mix of curtailments, pointing to opportunities for leveraging flexibility solutions like BESS and optimising network operations to minimise losses.

3.2.3 Correlation between generation and curtailments

The analysis of aggregated curtailments presented in Section 3.2.2 provides valuable insights into how curtailments evolve over time across voltage levels and technologies. However, to gain a more granular understanding of the relationship between generation and curtailments on an hourly basis, a deeper analysis is necessary. This is where the correlation analysis comes into play. By calculating the correlation between aggregated generation and curtailments for each technology at different voltage levels, we can uncover patterns that highlight how changes in generation levels are linked to curtailment levels. A positive correlation indicates that curtailments tend to increase as generation rises, while a negative correlation would suggest the opposite. This approach allows us to better understand the dynamics driving curtailments at each voltage level.

To perform this analysis, the data was organised by voltage level for every hour of the three analysed years. At each voltage level, the aggregated generation from all technologies was compared against the curtailments of each specific technology. This aggregation over the entire period ensures that the correlation captures the relationship between the magnitude of generation and curtailment, rather than focusing on temporal variations. By taking this approach, we aim to identify the underlying drivers of curtailments and their dependency on generation levels, providing a more comprehensive understanding of the system's behaviour.

3.2.3.1 Analysis for LV

At the LV voltage level, curtailments are consistently dominated by PV, in 2023 and 2028 it is accounting for 99% of the total and slightly decreasing by 2034 to 98%, as highlighted in Table 1. This strong dominance of PV curtailment aligns with the scatterplot presented in Figure 1, which reveals a clear correlation between total generation and PV curtailments. Significant curtailments at LV only emerge after total generation exceeds 2,000 MWh, indicating that curtailments are primarily driven by voltage rise constraints caused by high PV generation. As PV output increases, the network struggles to manage voltage levels within operational limits, leading to curtailments as a control measure to maintain stability.

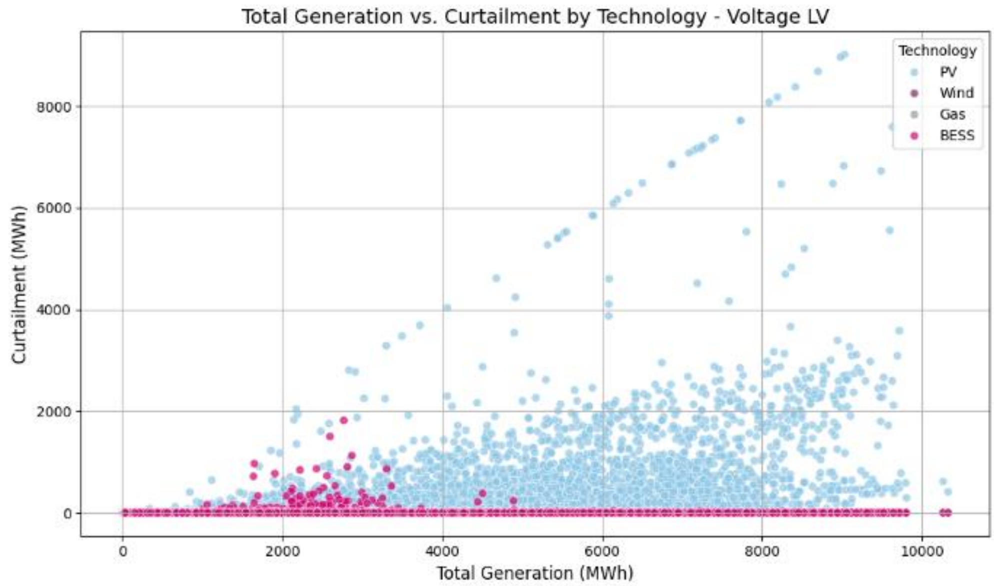


Figure 1: Correlation between the total generation and curtailments at LV.

3.2.3.2 Analysis for HV

As presented in Table 1, at the HV voltage level, curtailments are predominantly driven by PV and Wind, with minimal contributions from other technologies. In 2023 PV accounts for 74% of curtailments, while Wind contributes 21%. These shares remain similar in 2028, with PV at 78% and Wind at 19%. In 2034 PV continues to dominate with 78% of the total, while Wind increases its share slightly to 21%. The contributions from Gas and BESS are negligible across all years, making PV and Wind the primary technologies responsible for curtailments at this voltage level.

However, the relationship between total generation and curtailments at the HV level shows a clear distinction between PV and Wind. As seen in the scatter plot in Figure 2, PV curtailments increase with total generation, indicating a strong correlation between higher generation levels and the likelihood of curtailments. This trend aligns with the prominent share of PV in HV curtailments, as mentioned above. Conversely, Wind curtailment appears relatively stable, consistently remaining below 50 MWh regardless of total generation levels, suggesting that Wind curtailment is less sensitive to variations in total generation. This behaviour is likely driven by the differing generation profiles of PV and Wind, with PV generation being more concentrated during peak sunlight hours, whereas Wind generation is more evenly distributed throughout the day.

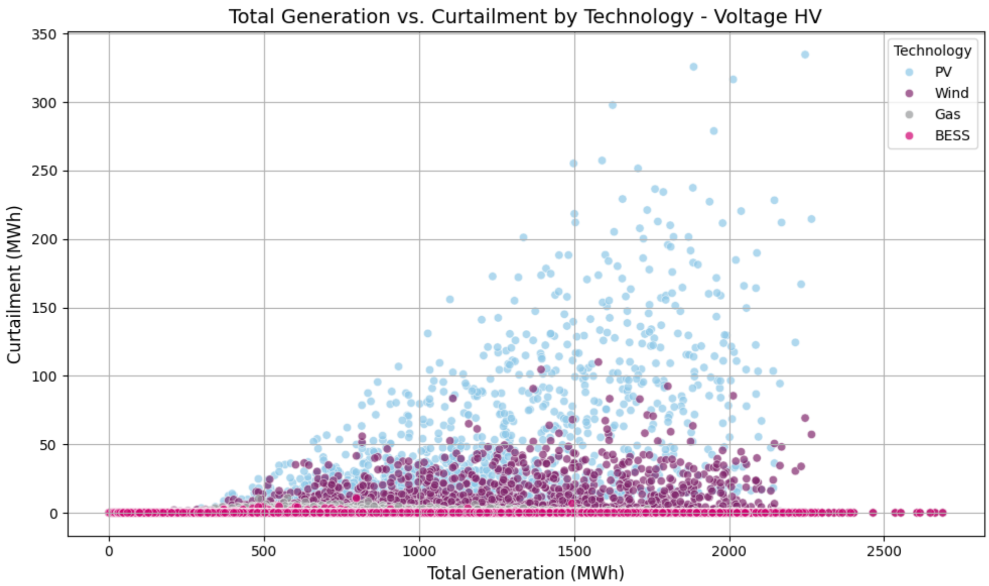


Figure 2: Correlation between the total generation and curtailments at HV.

3.2.3.3 Analysis for EHV

At the EHV level, curtailments show a diverse distribution among technologies over time. As seen in Table 1, In 2023 Wind becomes the dominant technology, contributing 61% of curtailment. This dominance persists in 2028 where Wind accounts for 57%, followed by PV at 28%. In 2034 curtailments become even more balanced, with Wind contributing 61% and PV increasing its share to 34%. Meanwhile, BESS and Gas play marginal roles across the years, consistently contributing less than 10% of total curtailments at this voltage level. This trend can be attributed to the significantly lower generation levels of BESS and Gas at the EHV level compared to PV and Wind, as shown in Table 7 to Table 10 in the Appendix.

This evolution in curtailment shares can be better understood by examining the scatter plot in Figure 3, which reveals the relationship between total generation and curtailments at the EHV level. Wind curtailments display a strong correlation with total generation, growing as generation levels increase, which aligns with its dominant share as seen above. PV also exhibits some correlation with generation, but it is less pronounced compared to Wind. On the other hand, BESS curtailments remain relatively stable, consistently below 100 MWh regardless of generation levels. Overall, curtailment becomes more sensitive to total generation beyond the 1,000 MWh threshold, indicating that higher generation levels at EHV significantly contribute to the magnitude of curtailments, particularly for Wind and PV.

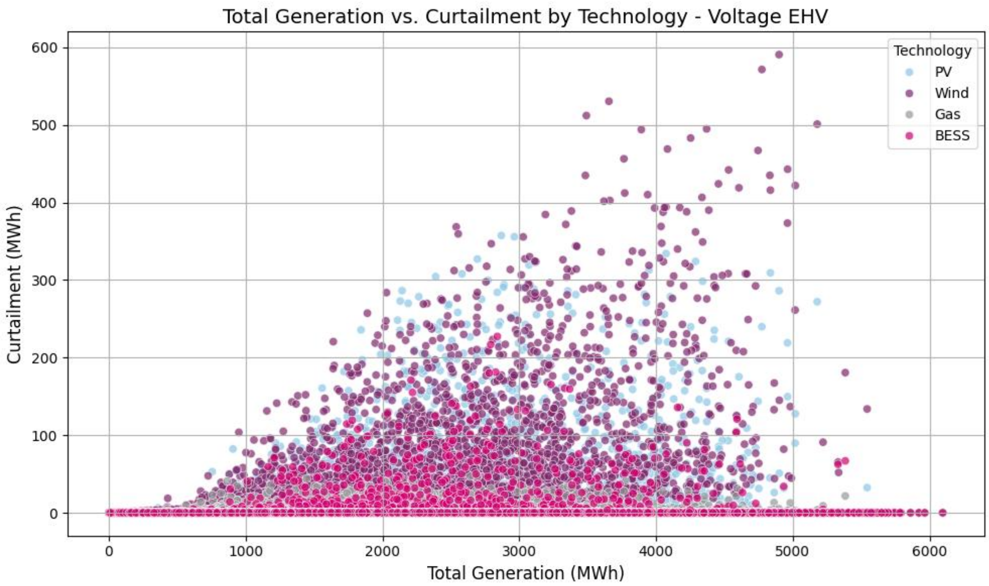


Figure 3: Correlation between the total generation and curtailments at EHV.

3.2.3.4 Analysis for 132kV

In 2023, gas dominated curtailments at the 132kV level contributing 70%, followed by wind at 23%, PV at 4%, and BESS at 4%. In 2028, the share of gas curtailment dropped significantly to 30%, while wind became the dominant contributor accounting for 40%, BESS also increased its share to 21%, and PV grew slightly to 19%. By 2034, BESS emerged as the leading contributor to curtailments at 132kV, representing 45% (277 GWh), followed by wind at 30% (111 GWh) and gas at 19% (120 GWh). PV's contribution decreased further to 6% (99 GWh). These trends highlight the shifting dynamics in curtailment at 132kV over time, as shown in Table 1.

This progression is reflected in Figure 3. Curtailment for BESS show a strong correlation with total generation, particularly beyond 2,000 MWh, where curtailment exceeds 600 MWh at the highest generation levels. In contrast, gas curtailment appears stabilised below 200 MWh for total generation between 4,000–6,000 MWh, highlighting its reduced sensitivity to increasing generation levels.

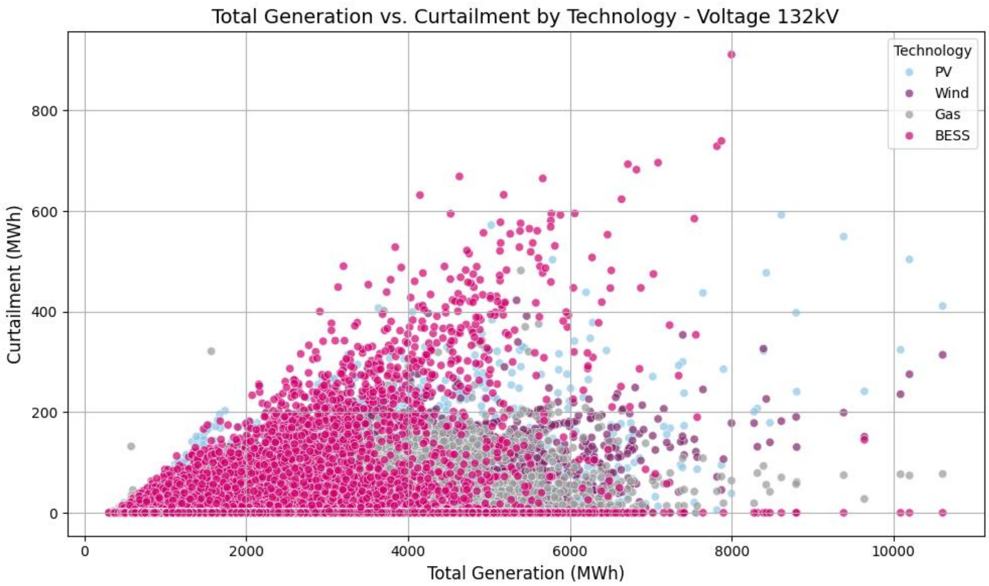


Figure 4: Correlation between the total generation and curtailments at 132kV.

3.2.3.5 Final analysis

The correlation results highlight the varying sensitivities of technologies to total generation and the unique challenges posed by each voltage level. PV curtailments exhibit consistent positive correlations across all voltage levels, underscoring the need to prioritise infrastructure improvements and flexibility solutions, particularly in areas with high PV penetration. Wind curtailments, while significant at higher voltage levels, are less correlated with total generation, suggesting that they are influenced by other factors, such as locational constraints.

BESS curtailments emerge as a key point of concern at higher voltage levels, particularly at 132kV, where their strong correlation with total generation suggests that curtailment events may disrupt their ability to perform system services or energy arbitrage effectively. This indicates a potential reduction in the business case for BESS, as curtailments could hinder their role in balancing the network and optimising market opportunities. Gas curtailments, while stabilised at certain thresholds, remain a critical component at 132kV in the early years but diminish over time as the energy mix evolves.

3.2.4 Cross-correlation between all features

While the previous analyses provided valuable insights into how curtailments evolve across technologies and voltage levels, as well as their sensitivity to total generation, cross-correlation takes this a step further by quantifying the relationships between generation and curtailments in a more detailed manner. This analysis identifies how individual technologies at specific voltage levels interact, highlighting systemic dependencies that may not be evident from simpler year-on-year or aggregated data. This allows for a more nuanced understanding of the drivers of curtailments and their temporal and spatial dynamics.

Correlation measures the degree to which two variables are related. A strong positive correlation indicates that as one variable increases, the other tends to increase proportionally, while a strong negative correlation signifies that as one variable rises, the other decreases. Correlation values range from -1 to 1, where values close to 1 or -1 represent strong relationships, and values near 0 indicate weak or no relationships. In the context of this analysis, strong correlations provide insights into systemic dependencies, e.g. a strong correlation between PV generation and curtailments suggests that high PV output is a primary driver of curtailments, likely due to capacity constraints. These relationships are crucial as they help identify key operational challenges and opportunities for optimising network performance and resource management.

The heatmap presented in Figure 5 visually encapsulates the cross-correlation results, enabling the identification of strong and moderate relationships between features. Red squares represent positive correlations, indicating that higher values in one feature are associated with increases in another, while blue squares signify negative correlations. The intensity of the colour reflects the strength of the relationship. For instance, the heatmap highlights strong positive correlations between PV generation and PV curtailments, particularly at lower voltage levels, suggesting that high PV output often leads to curtailments due to capacity constraints.

The analysis highlights several strong correlations that offer valuable insights into curtailment dynamics across voltage levels:

- **PV Curtailments LV and Wind Curtailments LV (0.8)**: At the LV level, the strong correlation suggests that PV generation is significantly congesting the LV network, resulting in curtailments for other technologies, particularly wind. This aligns with the data in Table 1, where PV accounts for 99% of the total curtailments at this voltage level. Such congestion demonstrates the impact of high PV penetration on curtailment outcomes.
- **PV Curtailments HV and Wind Curtailments HV (0.84)**: Similarly, at the HV level, PV and wind curtailments are strongly correlated, indicating that PV dominance in this voltage level creates cascading curtailments for wind. As Table 1 shows, PV continues to represent the largest share of curtailments at HV, reinforcing the role of PV in driving curtailment dynamics.
- **PV Curtailments EHV and Wind Curtailments EHV (0.70)**: At the EHV level, wind becomes more prominent, contributing significantly to the curtailment mix. This shift likely explains the observed correlation, as higher wind generation may create constraints (for instance overload or voltage rise) that indirectly lead to PV being curtailed.
- **Total Curtailments 132kV and Total Generation 132kV (0.70)**: At the 132kV level, the strong correlation between total curtailments and total generation indicates that curtailments are closely tied to the overall generation at this voltage level. This suggests that network constraints at 132kV are directly influenced by the volume of generation within this segment, reinforcing the need for strategies to balance generation and curtailments effectively.

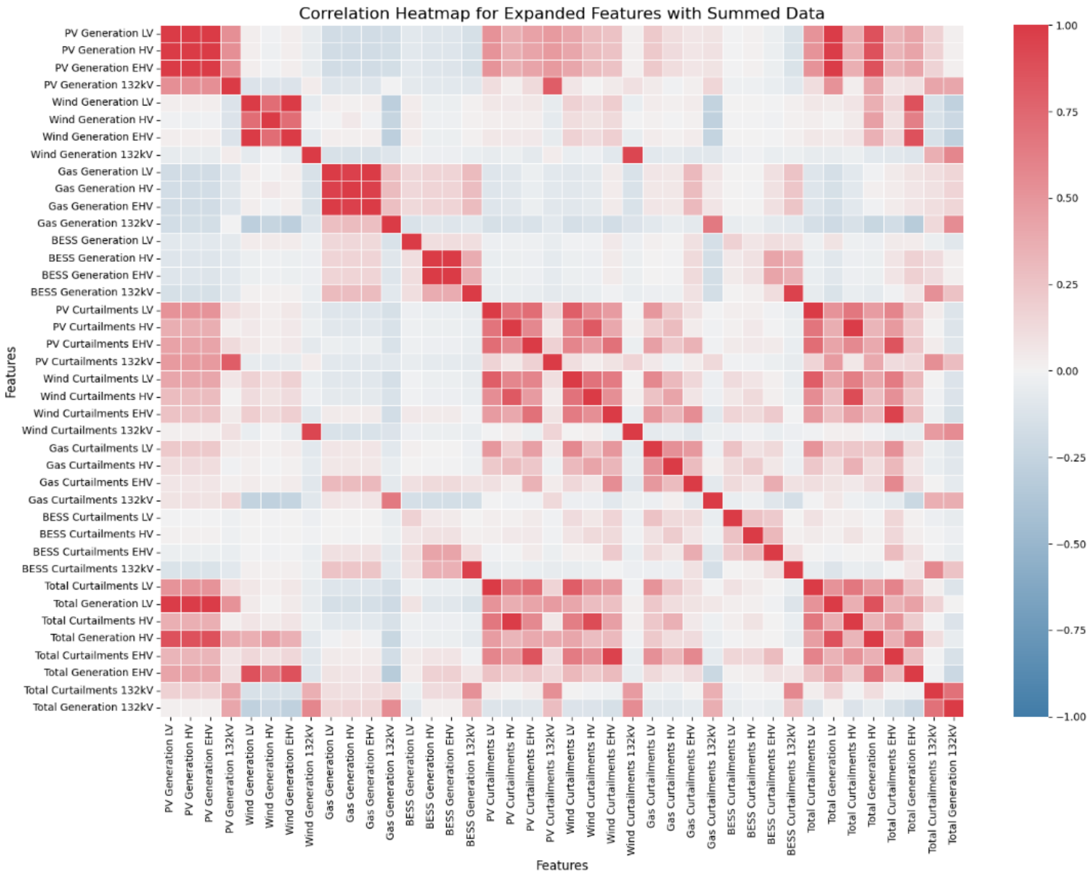


Figure 5: Cross-correlation between all features.

3.2.5 Exploratory Data Analysis Key takeaways

The EDA offers critical insights into the behaviour of curtailments across technologies and voltage levels. PV curtailments dominate at the LV level, accounting for nearly all curtailments due to the prevalence of PV generation in distributed networks. At higher voltage levels such as EHV and 132kV, curtailments become more diversified, with Wind and BESS playing significant roles alongside PV.

The correlation analysis between total generation and curtailments reveals clear dependencies, particularly for PV and Wind. At LV and HV, curtailments strongly align with PV generation, indicating that PV output regularly exceeds network capacity during periods with high irradiance. At EHV and 132kV, the relationship between total generation and curtailments becomes more complex, with Wind exhibiting a stronger influence, especially during high-output periods.

Cross-correlation analysis adds another layer of insight, revealing the interplay between curtailments of different technologies. Strong correlations between PV and Wind curtailments at LV and HV suggest that PV-induced congestion indirectly leads to Wind curtailments. At EHV, Wind plays a more significant role, likely contributing to PV curtailments as both technologies compete for limited capacity. At 132kV, the relationship between total generation and curtailments highlights systemic constraints driven by overall network utilisation.

3.3 Statistical insights on network curtailment data

The EDA presented in Section 3.2 plays a crucial role in uncovering linear interdependencies and patterns within data, providing an initial understanding of the relationships between features. However, as datasets grow in complexity and non-linear relationships become prevalent, EDA may fall short of capturing the full scope of interactions. In such cases, interpretable machine learning algorithms offer a promising approach, enabling a more detailed and nuanced analysis while retaining the ability to draw meaningful conclusions.

Among the interpretable machine learning algorithms, the decision tree stands out as a particularly effective choice. Its hierarchical structure not only makes it easy to visualise and interpret but also provides insights into the relative importance of features. By examining the splits and branches within the tree, we can identify the key variables driving the predictions and assess the magnitude of their impact on the target variable.

The main objective of this analysis is to leverage a decision tree model to predict curtailment levels at various voltage levels. After performing the forecasts, we can then analyse the decision tree to identify the most influential features contributing to curtailments at each voltage level. This approach not only aids in understanding the drivers of curtailments but also supports the development of targeted strategies to address these drivers effectively. It is important to note that the forecast on curtailments is solely aimed at interpretability, and precision in the forecast itself is not a primary concern, once feature importance rankings often remain stable with minor changes in accuracy.

SHAP (SHapley Additive exPlanations) values are a popular method for interpreting machine learning models, particularly when aiming to understand the contribution of each feature to the model's predictions. SHAP is based on cooperative game theory and assigns an importance value to each feature, representing its contribution to the model's output for a particular prediction. Positive SHAP values indicate that a feature pushes the prediction higher (in this case, increasing curtailments), while negative values indicate that the feature reduces the prediction. By visualising SHAP values, we can identify both the overall importance of features and the direction of their influence, providing an interpretable framework for understanding complex machine learning models.

Thus, decision tree models were applied to predict curtailments at HV, EHV, and 132kV voltage levels. These levels were selected for analysis as they exhibit a more diverse mix of technologies contributing to curtailments. In contrast, the LV level was excluded from this analysis because the primary driver of curtailments is evident—PV consistently dominates, accounting for 99% of total curtailments at this level, as highlighted in previous sections. By focusing on HV, EHV, and 132kV, the decision tree models aim to uncover the relative importance of various features influencing curtailments in more complex and diversified network conditions.

The application of Decision Trees to predict curtailments at HV achieved an R^2 score of 0.88, demonstrating a very good quality of forecast. The results for HV curtailments, as illustrated in Figure 6 by the SHAP summary plot, highlight the dominant influence of PV Curtailments at the LV level. This finding suggests a cascading effect where PV curtailments at lower voltage levels likely contribute to congestion further upstream, influencing curtailments at HV. Wind Curtailments at LV also emerge as a significant factor, even with a lower impact when compared to PV.

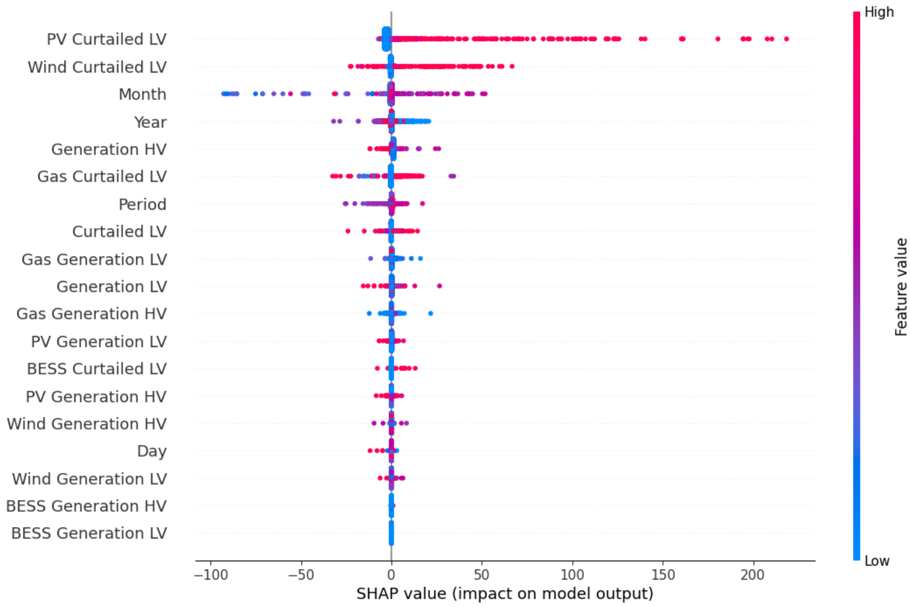


Figure 6: Feature Importance for HV Curtailments.

At EHV level, the Decision Trees achieved an R^2 score of 0.67 when predicting the curtailments, indicating a good quality of forecast and providing meaningful insights into the drivers of curtailments. The SHAP summary plot for EHV curtailments, presented in Figure 7, underscores the influence of Gas Curtailments at the LV level as the most significant feature impacting curtailments at EHV.

This, initially, could indicate a potential upstream congestion effect where gas-related curtailments at lower voltage levels propagate to EHV. However, as Gas plants often operate as peaking or backup resources, curtailment at LV might also indicate times of surplus generation when other, more dominant technologies (like PV or wind) are prioritised. Finally, the relationship between LV gas curtailments and EHV curtailments might be statistical rather than causal. For example, both could correlate with other factors, such as high PV or wind generation at EHV, which leads to curtailments.

The application of Decision Trees to predict curtailments at 132kV achieved an R^2 score of 0.89, indicating an excellent quality of forecast and strong model reliability. The SHAP analysis for curtailments at the 132kV level, presented in Figure 8, reveals interesting insights into the factors driving curtailments. BESS Generation at 132kV emerges as the most significant driver, indicating that high levels of battery storage generation are strongly associated with curtailments at this voltage level.

This suggests that surplus energy stored in and discharged from batteries at 132kV could exacerbate network congestion, requiring curtailments.

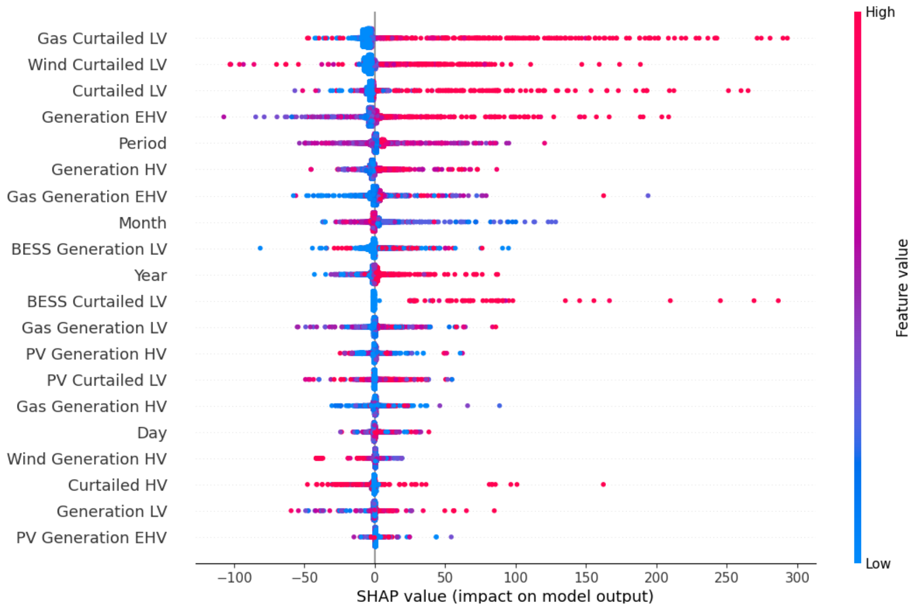


Figure 7: Feature Importance for EHV Curtailments.

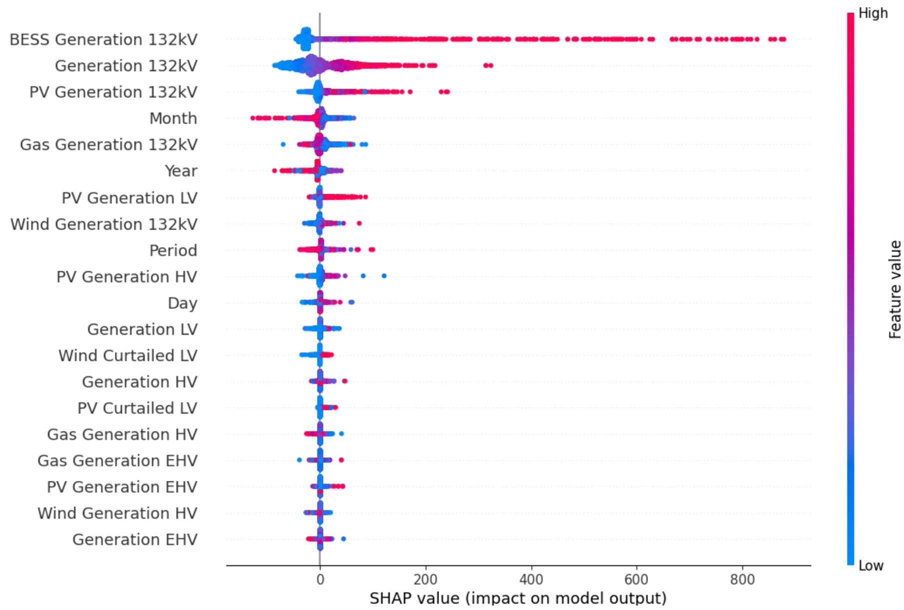


Figure 8: Feature Importance for 132kV Curtailments.

3.4 Discussion and conclusions

The evolution of curtailments across the distribution network from 2023 to 2034 reveals distinct trends in both total volumes and the share of technologies:

- In 2023, curtailments are predominantly concentrated at the 132kV level, driven largely by Gas and Wind, while PV is a major contributor at lower voltage levels, particularly at LV.
- Over time, PV's dominance in curtailments grows substantially, especially at LV, where it consistently accounts for nearly all curtailments due to increasing PV penetration. By 2034,
- PV's share of total curtailments has risen to 73%, with significant impacts at LV and 132kV, while Wind's contribution remains relatively stable and prominent at EHV and 132kV.
- BESS emerges as a growing contributor at higher voltage levels, reflecting its expanding role in network operations.

The correlation analysis between total generation and curtailments highlights how generation dynamics shape curtailment behaviour across voltage levels:

- At LV, where PV accounts for 99% of curtailments, the strong correlation between PV generation and curtailments underscores the challenges of integrating high levels of PV energy.
- At 132kV, the strong correlation between total generation and BESS curtailments highlights a potential challenge in BESS profitability and operational flexibility. This is because curtailments may interfere with their ability to perform effective energy arbitrage, particularly during peak generation periods.

The cross-correlation analysis provides further insights into the interdependence of curtailments and generation across technologies and voltage levels:

- Strong correlations between PV and wind curtailments at multiple voltage levels reflect the shared network constraints faced by these technologies.
- At EHV, the correlation suggests that wind's dominance in curtailments impacts PV's ability to integrate into the network.
- At 132kV, the significant correlation between total curtailments and total generation indicates that generation capacity at this level is a key factor in network congestion.

The decision tree analysis complements the EDA by providing a deeper understanding of the factors driving curtailments at HV, EHV, and 132kV levels:

- At HV, the result suggests a cascading effect where PV at LV level likely contribute to congestion further upstream.
- At EHV the decision tree unveils an unexpected interaction from gas curtailments at LV on curtailments at EHV, despite gas representing a small fraction of LV curtailments. Probably this correlation may stem from a broader network behaviour captured by the model rather than a direct cause-and-effect relationship.

-
- At 132kV, the decision tree uncovers a hidden pattern that EDA could not detect: the critical role of BESS as the primary driver for curtailments.

4 Market Modelling

4.1 Introduction

This section introduces the methodologies and results developed to address stage 2 of the project. As outlined in Section 2, the work focuses on quantifying the headroom-value relationship by evaluating the impacts of varying levels of curtailment on the electrical system and aims to identify the specific contributions of each voltage level to these impacts.

Building upon the findings from Stage 1, the lower bound scenario estimated an accumulated system cost of £324m and a carbon emissions impact of £116m, while the upper bound scenario projected significantly higher values of £16,900m for system cost and £753m for carbon emissions. A comparison between the results from Stage 1 and the new insights obtained in Stage 2 is provided in Section 4.4.3.

It is important to note that distribution curtailments are modelled as additional load on the bulk system. To assess the impact of curtailments on the system as a whole, we consider two distinct instances in the GB-wide Market Model:

- Counterfactual instance: this assumes no distribution network curtailments, allowing distributed generation to fully meet the corresponding load locally.
- Curtailment instance: this incorporates the full level of distribution network curtailments. Here, an equivalent load, corresponding to the curtailed generation, must be met by the bulk system instead of being locally balanced as in the counterfactual instance.

NGED have developed a "Best View Scenario" based on their DFES, which prioritises high-certainty activities within the first 10 years to provide clarity and support optimal network planning. As previously mentioned, the curtailments data utilised in this report were developed following this Best View Scenario. For this reason, we refer to these as ***Best-View Curtailments*** throughout the analysis.

This section evaluates the application of the Market Model by considering:

- The Market Model, a critical component of the GB-wide market modelling approach.
- The Net-Zero-High scenario, selected as the basis for the Market Model.
- The methodology and results of Stage 2.
- The key takeaways from the analysis.
- The limitations of the proposed methodologies.

4.2 Overview of Market Model

Baringa maintains a set of regularly updated wholesale power scenarios (Reference Case, Net-Zero, Net-Zero High, Low Commodities) for 30 markets including the GB, Ireland, and continental European markets. These 'Reference Case' scenarios are provided to a wide range of client subscribers across the industry, including utilities, developers, investors, and lenders.

The scenarios are developed with full consideration of wholesale market drivers including:

- Commodity prices, carbon prices and exchange rates.
- Demand trends (including electrification of heat and transport).
- Generation capacity build and retirement.
- Renewable energy deployment.
- Interconnector developments.
- Political and regulatory developments (e.g. Brexit, Europe Cort of Justice, GB capacity market ruling).

The Baringa power market model[4] is used to simulate the power market investment and dispatch behaviour. Market intelligence around individual market regulation and capacity condition, technology cost and operational constraints are also input into the model to ensure the modelled conditions best represent future deployment trajectory. The Baringa modelling framework with detailed inputs and outputs is presented in Figure 9 below.

[4] Baringa uses PLEXOS, a highly regarded power market simulation software used globally by system operators, utilities, and commodity traders. It has been used extensively over the last 10 years as a commercial tool to model power markets in detail.

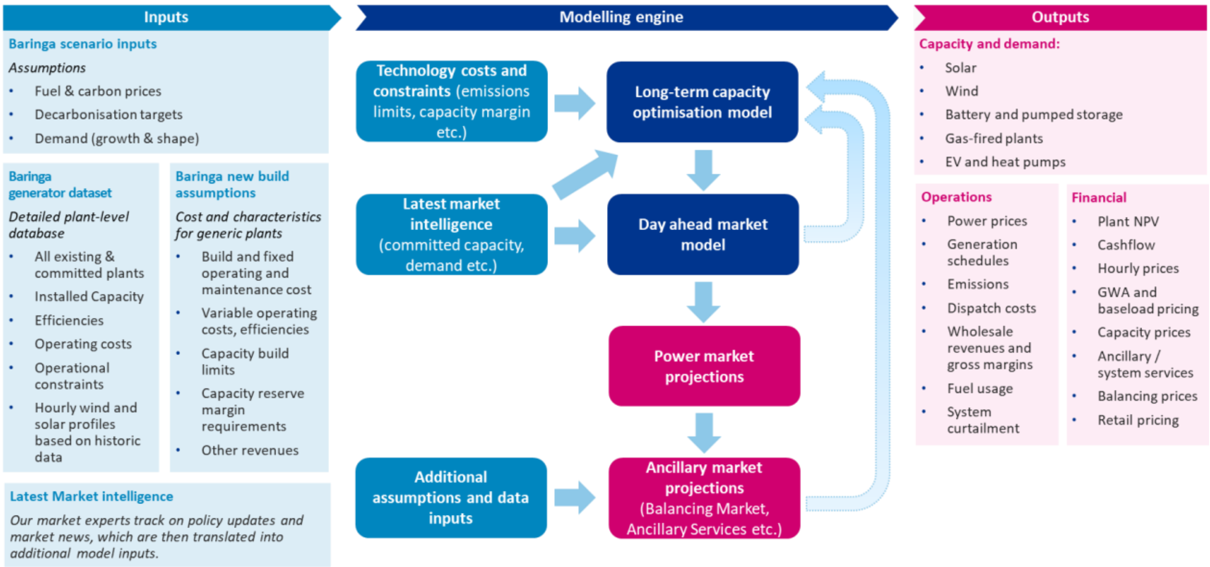


Figure 9: Baringa modelling framework.

In the scope of this project, the day-ahead market model is the main model used to simulate the hourly power dispatch of more than 2,000 generators in GB and Europe over the period 2023 to 2060 to ensure the effects of new generation and retirements are correctly modelled. The result is determined on a least-cost basis, i.e. to minimise the costs of generation in any market. At its heart lies a dispatch 'engine' based on a detailed representation of market supply and demand fundamentals at an hourly granularity. The supply mix is represented with the operating parameters of generating plant including costs and operational constraints. The model determines economically rational market dispatch accounting for interconnection limitations on power transfer capacity between countries.

Power demand in each hour is represented across five categories and is summarised in Table 3**10**. This comprises fixed demand (satisfied in full) and flexible demand (consumed in an optimal manner within specific constraints). The hourly load is determined by both historical demand profiles, new demand sources, and demand side flexibility. The level depends on the annual demand in a country, demand distribution within the year, and daily consumption pattern. Peak demand is one key metric used to assess the capacity adequacy (sufficient generation to meet demand) and drives new build capacities.

It is worth mentioning that curtailments in the distribution sector are treated as additional load in the bulk system, effectively allocated as fixed demand within the model. This approach ensures that the impacts of unmet generation at the distribution level are accurately reflected in the bulk system's operational and market dynamics. By integrating these fixed demands, the Baringa market model provides a comprehensive framework to evaluate how varying levels of curtailments influence system behaviour, costs, and emissions.

Table 3: Demand categories for the market model.

Demand segment	Description	Source
Conventional demand	Conventional demand covers all uses for electricity not covered by the segments below. Broadly, this covers demand as observed today (lighting, appliances, electric resistive heating). Projections account for GDP growth, offset by efficiency savings.	TSO and central government projections
Electric Vehicles	Road based EVs are projected to be a large source of demand growth, with EU and national governments committing to banning sales of new internal combustion engine (ICE) cars and other road transport. We use a detailed transport uptake model, using publicly available data for each country on current sales, typical driving distances, and dates of ICE bans.	Baringa transport uptake model
Heat Pumps	Heat pump projections are based on energy demand projections, which utilise regression analysis grounded in economic and climatic assumptions, as well as the EU and country specific ambitions to achieve Net Zero goals through the electrification of heating. Electric resistive heating is classified as conventional demand and included in that demand segment.	Baringa energy services demand model
Storage load	Storage load corresponds to the total annual demand from energy storage plants when charging, such as pump storage and batteries. We model supply and demand from energy storage separately, with demand being larger than supply due to losses. The operation (and therefore "demand") from storage technologies is modelled as part of our power market dispatch modelling.	Modelled result as part of Baringa power market projections
Hydrogen electrolysis	Demand for hydrogen in Europe uses the Baringa hydrogen demand model, which takes a bottom-up approach to estimate demand requirements from all sectors of the economy. Baringa analysis is used to assess how much of this Hydrogen requirement should be "Green Hydrogen" (i.e., produced using electrolysis), based on economics, policy, and constraints around production technologies and global trade.	Baringa hydrogen demand model

4.3 10Overview of Net-Zero-High scenario

Baringa's Net Zero High (NZH) case was selected as a basis for the GB-wide market model as it aligns closely with FES scenario System Transform (ST) which is used in the network modelling of curtailment. The Net High scenario is a net zero driven by carbon pricing and economics. It assumes faster and deeper decarbonisation of the power system, with much greater cross-sector electrification. The capacity assumptions for NZH are presented in Figure 11 and show a steady increase in capacity over the period with an aggressive reduction in gas capacity at the front end and ambitious DCR assumptions driving the decarbonisation of the GB power market.

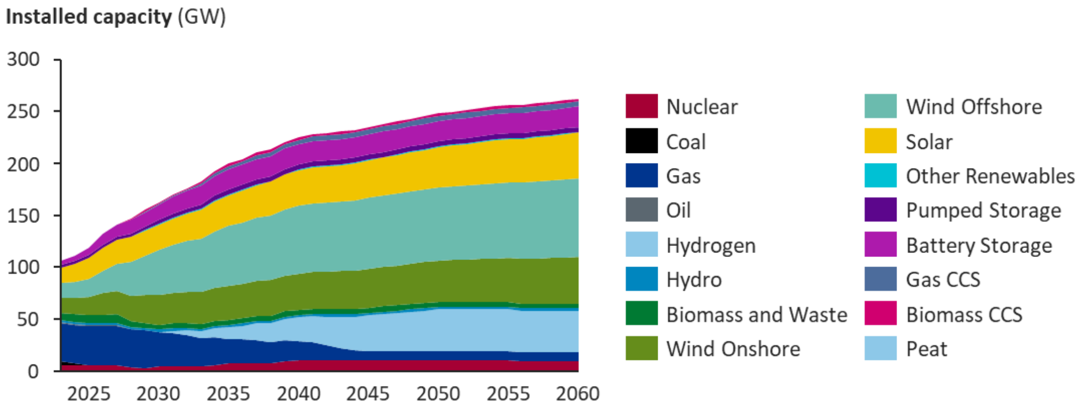


Figure 11: Capacity assumptions, Baringa Net-Zero-High.

In Baringa's NZH, most European countries achieve their net zero targets for the wider economy. High carbon pricing, as shown in **Figure 11**

Figure 12, is a key feature in this scenario, which provides signals for investment. Carbon price reaches £160/tonne by 2034 and plateaus at £260/tonne by 2050. In addition, there is significant growth in power demand due to accelerated and deeper electrification of transport and heat. In the projections, a Net Zero GB power market is achieved by 2035, meeting the Government's ambition for a decarbonised power sector. The overall UK economy reaches net-zero by 2050. A summary of scenario context is provided in Figure 13.

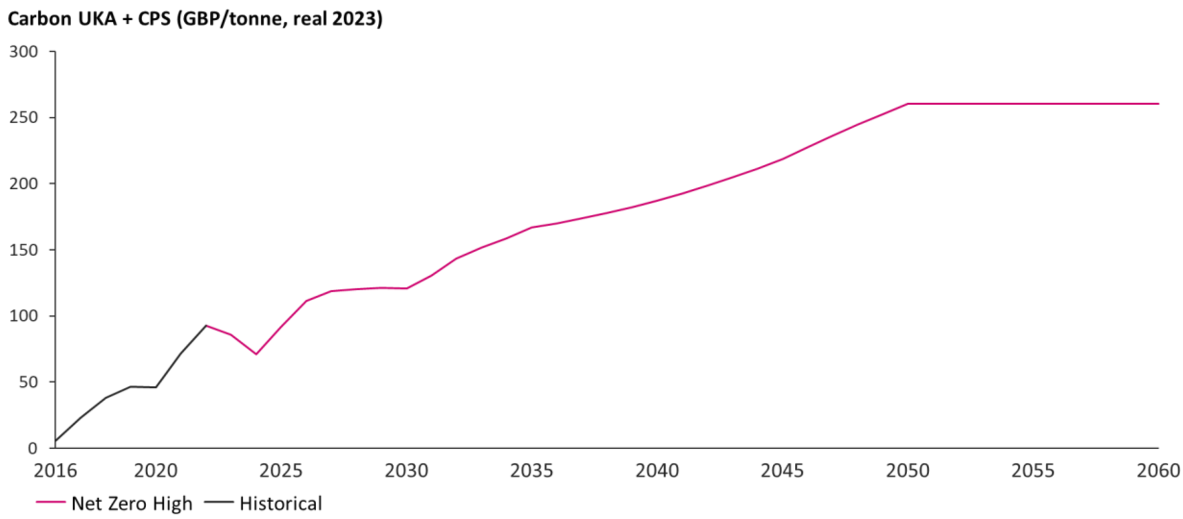


Figure 12: Carbon prices, Baringa Net-Zero-High.

	Net Zero High (NZH)
Net zero trajectory	Most European countries achieve their net zero targets for the wider economy. Public and government interest in achieving those targets is very strong. There is significant investment in low-carbon power technologies.
Demand	High level of electrification of transport, heating and industrial sectors. The drivers behind electrification are largely commercial, rather than policy driven.
Commodity and carbon prices	An initial increase in fossil fuel investment and exploration is dissuaded due to risk of price collapse. In the mid-term, governments restrict further investments in fossil fuels. Fuel prices remain higher for longer. Carbon pricing provides the key signal for investment in low-carbon technologies.
Technology costs	Overall, technology costs decrease over time due to learning rates and economies of scale achieved. Power prices are very volatile and dependent on intermittent renewable generation, increasing revenue risk and therefore WACC for low-carbon technologies.
Government support and intervention	Policy is focused on network and permitting bottlenecks for renewables. High carbon and power prices support merchant renewables. This enables merchant operation to be the main route to market for renewables.
Security of supply	Security of supply is partially ensured via capacity payment mechanisms and strategic reserve and partially by high energy market revenues

Figure 13: Summary of Baringa Net-Zero-High.

4.4 Stage 2 methodology and results

This stage aims to quantify the impact of the Best-View Curtailments on the system, specifically focusing on wholesale markets, carbon emissions, and balancing mechanisms. However, as the methodology to evaluate wholesale market and carbon emission impacts differs significantly from that required to assess balancing mechanism impacts, this section will focus exclusively on the former. The impacts related to balancing mechanisms will be addressed comprehensively in Section 5.

The benefit of releasing headroom in the distribution sector is evaluated based on two key metrics:

- **System Cost Impact**: This measures the impact on wholesale markets when considering the Best-View Curtailments. Essentially, it represents the cost savings in the wholesale market achieved by releasing distribution headroom to mitigate curtailments. The calculation is based on the difference between the average wholesale price in the curtailments instance and the counterfactual instance, multiplied by the counterfactual load.
- **System Carbon Cost Impact**: This quantifies the effect of carbon price (UK ETS) and associated taxes due to the Best-View Curtailments. In essence, it captures the financial benefits of reduced carbon emission taxes when distribution headroom is released to avoid curtailments. The calculation is based on the difference between the total carbon emissions costs in the curtailments instance and the counterfactual instance.

In this report, the System Total Cost Impact is just the sum of the System Cost Impact and the System Carbon Cost Impact.

The raw curtailments data was modelled by EATL using a series of improvements to the modelling methodology employed at Stage 1. A more comprehensive analysis was performed to generate a more accurate representation of likely curtailment across the LV, HV, EHV and 132 kV networks utilising EATL's Transform model and NGED's Simple Curtailment Tool[5]. The methodology included the following components:

- Improving the representation of generation within the seasons.
- Accounting the demand driven network capacity growth.
- Better representation of BESS within the network modelling to align with their expected operating behaviour.
- Consideration of abnormal running arrangements.
- Inclusion of emerging V2G technologies

The methodology to obtain the impact of the Best-View Curtailments on the system cost and the system carbon cost the counterfactual instance which serves as the benchmark for comparison and establishes the baseline for these metrics. Curtailments instance was created by disaggregating the distributed generators across different voltage levels (LV, HV, EHV, and 132kV) and aggregating them by technology (BESS, Gas, PV, and Onshore Wind). This resulted in distributed generators being organised by both voltage level and technology, aligning perfectly with the structure of the Best-View Curtailments as discussed in Section 3. This alignment simplifies the calculation of the curtailed volume for each distributed generator by technology and voltage level. The curtailments are then aggregated to represent the entire distribution sector and are considered as additional fixed demand to be met by the bulk system. Figure 14 below illustrates this process in detail.

This process ensures that the distributed generators is properly scaled to align with the curtailment data. While the curtailments were derived from FES ST scenarios, the distributed generators were based on the Net Zero High scenario from Baringa. As a result, they exhibit different total volumes of curtailment, making it necessary to adjust the distributed generators accordingly to ensure consistency and accuracy in the impact assessment.

The extra load due to curtailments was calculated for the three analysed years. Projections were conducted using linear interpolation between these years, enabling the calculation of values for various metrics related to curtailments, emissions, and costs throughout this section.

[5] More information about the tools can be found in the Stage 1 report referenced in Footnote 1

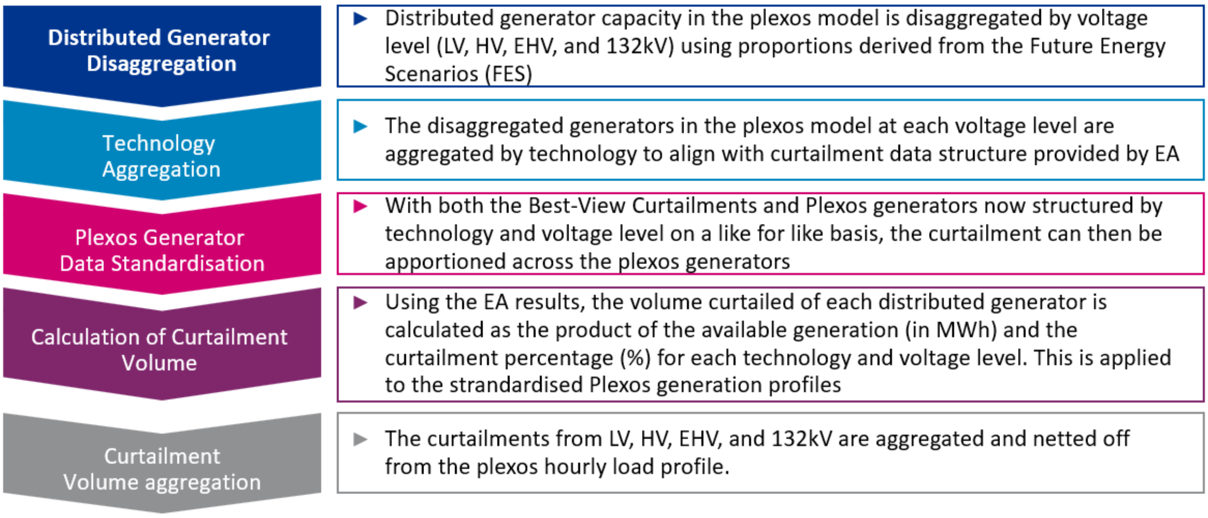


Figure 14: Methodology for allocating Curtailments to generators.

4.4.1 Impact of the Best-View Curtailments

As presented in Section 3, curtailments are projected to increase steadily over the next 12 years, growing from 1.08 TWh in 2023 to 2.48 TWh in 2034. Between 2023 and 2028, curtailments increase by 0.5 TWh, reaching 1.58 TWh (+46%). This trend accelerates between 2028 and 2034, with an additional 0.9 TWh increase, peaking at 2.48 TWh. Over the analysis period, this represents an accumulated curtailment of 20.61 TWh, highlighting a significant upward trajectory.

By incorporating the projected curtailments into the market model, various metrics related to the wholesale market, carbon emissions, and load can be derived, as summarised in Table 3 below. The system cost and carbon emissions impacts are then quantified by comparing the curtailment and counterfactual instances. These calculations, performed for the three analysed years, provide a foundation for further analysis. A linear interpolation is subsequently applied to estimate the impacts for the intervening years between 2023 and 2034, allowing for the assessment of annual trends as well as the aggregated metrics over the entire period. The complete results can be found in Appendix in the Section 9.1.

Under the Best view scenario, the annual system benefits are projected to increase steadily over time, starting at £104m in 2023, growing to £169m in 2028, and reaching £197m by 2034; this represents a growth of 61% in annual system benefit from 2023 to 2028 and a further 17% increase from 2028 to 2034. Over the entire analysis horizon, **the accumulated system cost benefit totals £1,931m.**

Table 3: Comparison of counterfactual and curtailments instances results – Best-View.

Metric	Instance	2023	2028	2034
Average wholesale market price (£/MWh)	Curtailment	98.40	84.33	81.69
	Counterfactual	98.05	83.85	81.28
	Difference [A]	0.35	0.48	0.41
Carbon costs (£m)	Curtailment	3,255	2,798	737
	Counterfactual	3,236	2,778	724
	Difference	19	20	13
*Carbon emissions (Mt)	Curtailment	42.15	25.52	11.11
	Counterfactual	41.91	25.34	11.03
	Difference	0.24	0.18	0.08
Counterfactual load (GWh) [B]		293,033	350,938	481,892
System costs impact (£m) [A*B]		104	169	197
Totals costs impact (£m)		123	189	210

Regarding the carbon cost impact of curtailments, during the period 2023–2028, it remains stabilised at approximately £20m per year. However, from 2028 to 2034, these benefits decline by around 40%, falling to nearly £13m. This trend reflects the ongoing decarbonisation of the energy system, where the increasing penetration of variable renewable energy reduces emissions, and consequently, the financial value associated with avoided emissions. Notably, the avoided carbon emissions from releasing headroom start at 0.24 Mt in 2023, decreasing to 0.08 Mt by 2034. Over the entire analysis horizon, **the accumulated carbon cost benefit amounts to £213m.**

The projected system total cost impact of Best-View Curtailments reveals a significant increase from 2023 to 2028, with total impacts rising by approximately 55% from £123m to £189m. Between 2028 and 2034, while the growth slows, it remains notable, with a further 27% increase reaching £210m. These results underscore the potential of avoiding network curtailment to yield considerable savings in dispatch costs and emissions, **resulting in an accumulated total system benefit of £2,144m** over the analysis period. Figure 15 presents the monthly values of total system benefit for the years 2023, 2028 and 2034.

The benefit-cost ratio, calculated as the ratio between total system benefits and total system costs for the same year, underscores the increasing economic value of avoiding network curtailments over time, as shown in Figure 16. Starting to 1% in 2023, the ratio demonstrates a sharp growth, appearing to follow an exponential trend after 2030, ultimately reaching 8% by 2034. This progression demonstrates that releasing headroom is a highly cost-effective approach to optimising network performance while delivering substantial economic benefits.

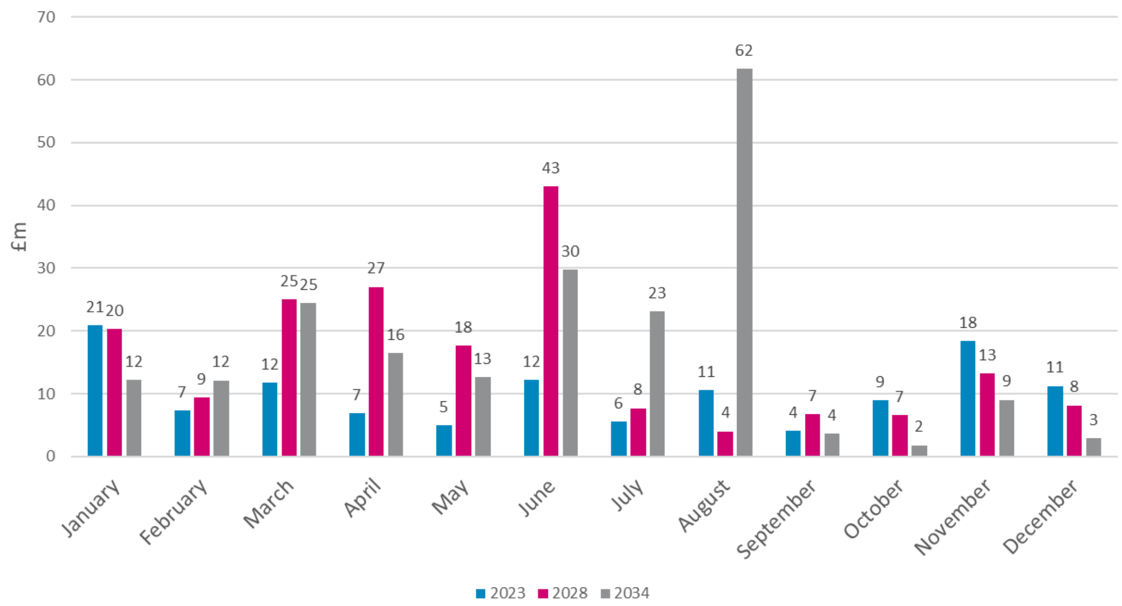


Figure 15: Monthly total system benefit for the years 2023, 2028 and 2034.

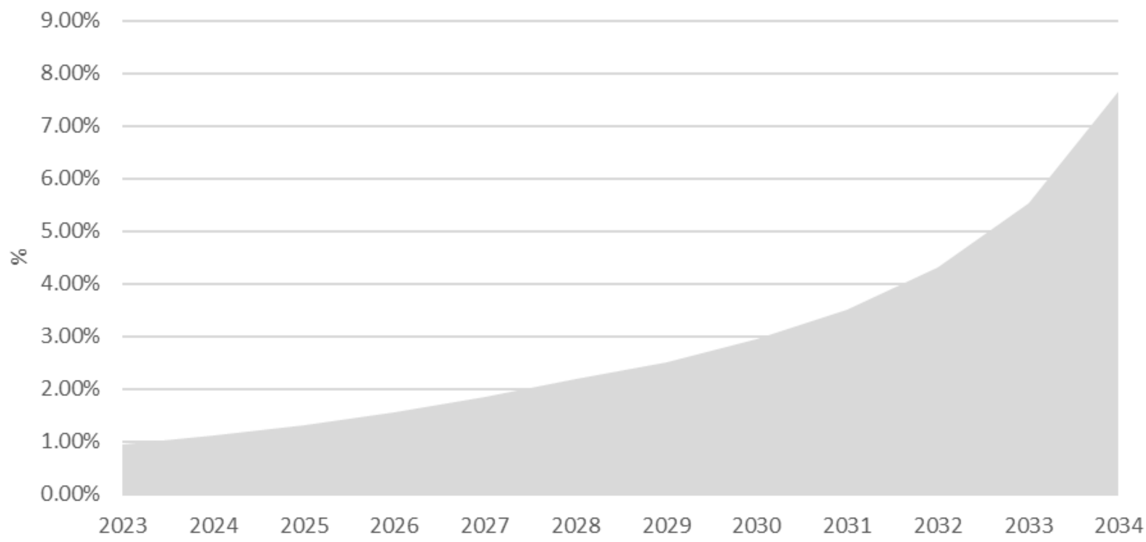


Figure 16: Projected annual benefit-cost ratio when releasing distribution headroom.

4.4.2 Sensitivity Analysis on the Best-View Curtailments

The Best-View scenario's impact on system and carbon costs provides valuable insights over the study period. However, the uncertainty around future buildout of distributed capacity and therefore potential curtailment means that it is essential to evaluate how varying levels of curtailments might affect the system and the associated potential benefits.

To achieve this, the Best-View Curtailments were adjusted incrementally from 20% to 180% (in steps of 20%), and the corresponding system impacts were analysed for each curtailment level. Figure 17 illustrates the projected curtailments under the different scenarios of Best-View modifications (20% to 180%). The accumulated curtailments over the 12-year horizon vary significantly from a minimum of 4.17 TWh for the 20% Best-View scenario to a maximum of 36.33 TWh for the 180% Best-View scenario. The complete result of the sensitivity analysis can be found in the Appendix in Section 9.2.

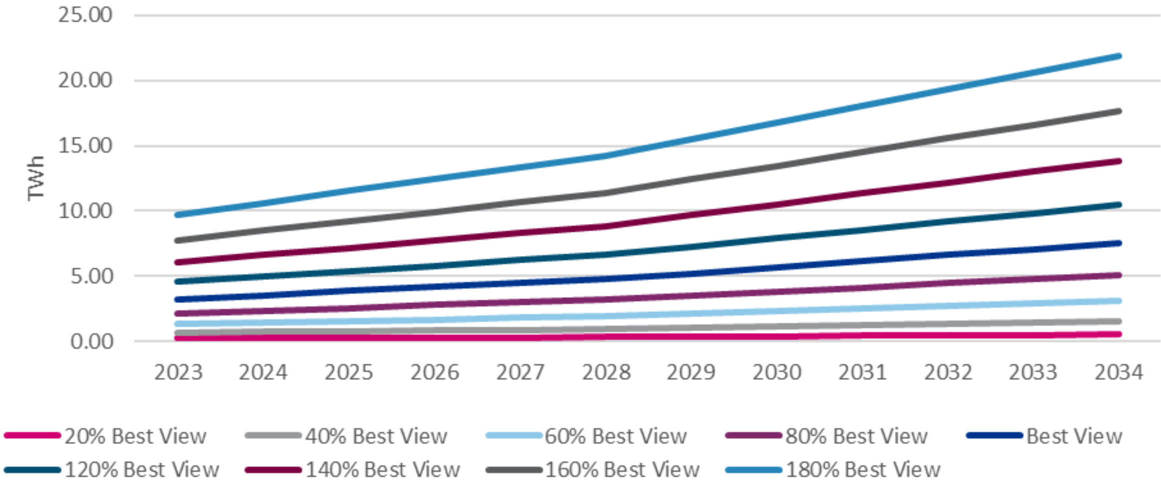


Figure 17: Projected curtailments for different values of Best-View.

Regarding system costs from wholesale markets, the accumulated system benefits over the 12-year analysis horizon display substantial variation depending on the scale of the Best-View scenario, as shown in Figure 17. For the 20% Best-View scenario, the total benefit amounts to £444m, reflecting modest gains. Conversely, at the 180% Best-View scenario, the system benefits soar to £3,496m, showcasing the significant potential of higher Best-View scenarios to optimise system performance and deliver considerable economic value over the analysis period.

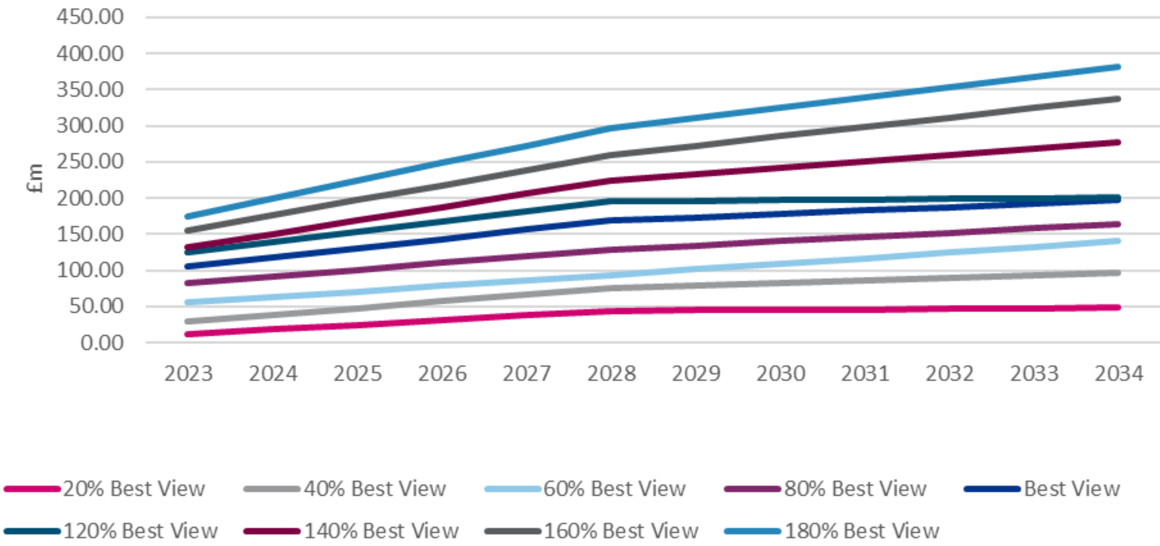
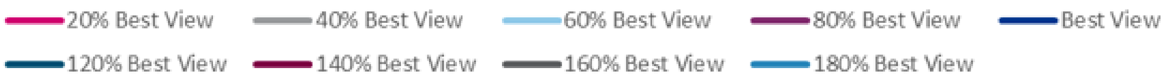


Figure 18: Projected system cost impact for different values of Best-View.

Still in Figure 18, in 2034, the difference in system costs between the Best-View and 120% Best-View scenarios is not too much, suggesting that the additional curtailments in the latter scenario do not significantly alter market outcomes. This could be due to a combination of factors, including the dominance of zero-marginal-cost renewables in price-setting, the presence of excess capacity from low-cost generation sources, or the saturation of demand response mechanisms that limit further price difference.

As expected, the carbon emissions also are very sensitive to the level of Best-View Curtailments; at 20% curtailments level, the accumulated emissions avoided is 0.37Mt while the 180% curtailments level, this number increased to 3.48Mt, over the analysis horizon. For this reason, the system carbon cost also varies from £41m to £378m considering 20% and 180% of curtailments levels, respectively. The emissions impact and the system carbon cost benefits are presented in



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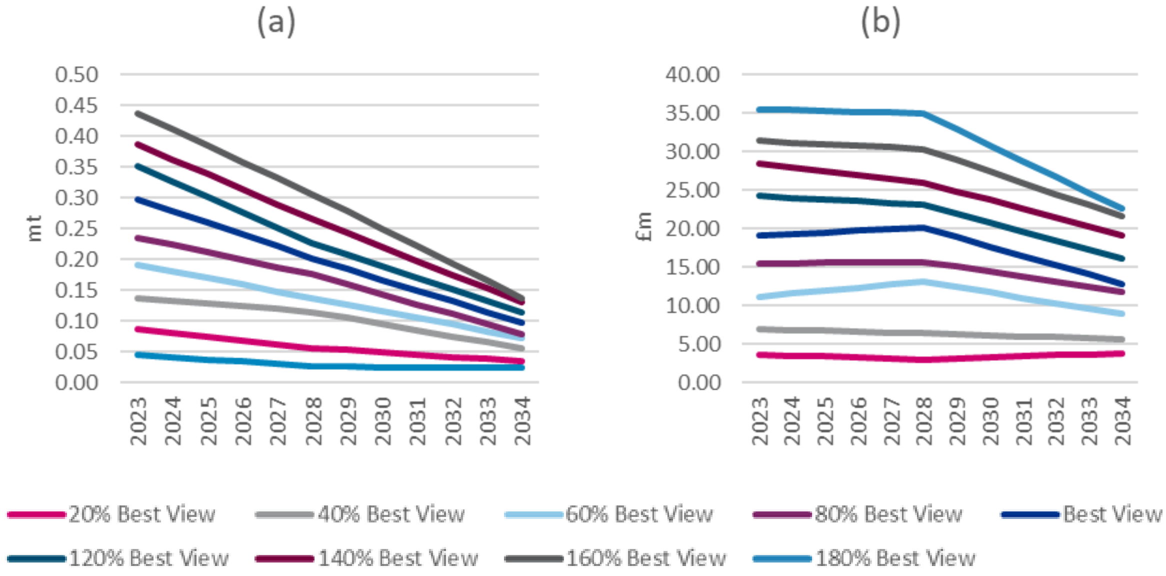


Figure 19: (a) Emissions impact, and (b) system carbon costs benefit for different curtailments level.

The total system cost benefit (system costs and system carbon costs) varies depending on curtailments levels. When curtailments range from 20% to 180% of the Best-View scenario, the total cumulative benefit increases from £486m to £3,875m, respectively. This progression highlights the substantial economic advantages of higher curtailment reductions. While the benefits continue to grow steadily over the 12-year horizon, the rate of increase gradually slows in the later years, reflecting the diminishing marginal returns as the system becomes increasingly optimised, as presented in Figure 20.

When varying the level of curtailments and calculating the system total cost impact for each value, it is possible to construct an annual curve that shows the relationship between these two features, as illustrated in Figure 21. This allows a direct estimation of the total benefit (wholesale market cost savings and carbon emissions reductions) achieved by releasing headroom in the distribution network to mitigate curtailments.

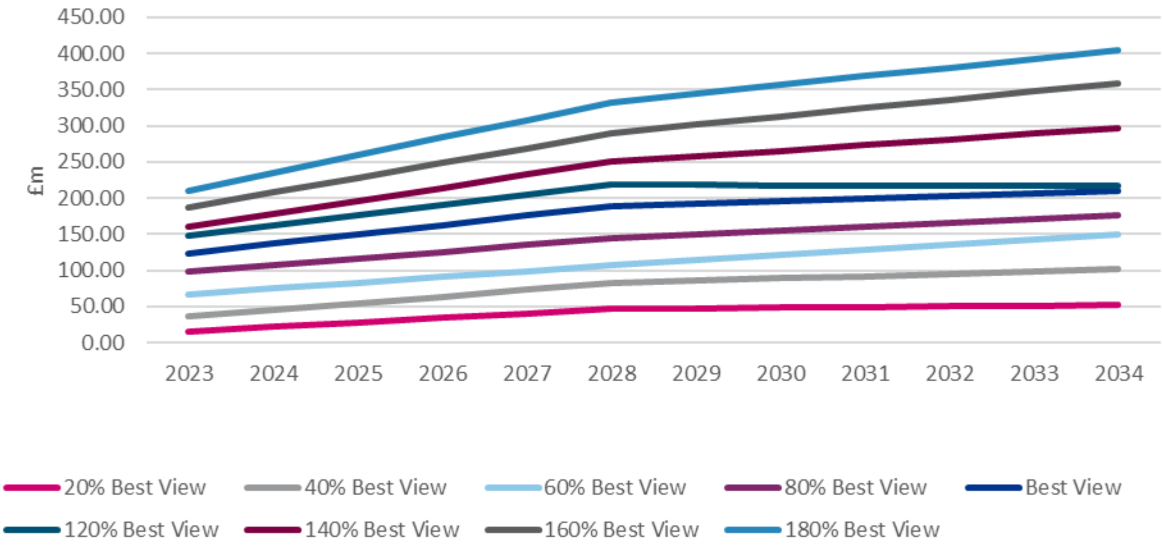


Figure 20: Projected system total cost impact for different values of Best-View.

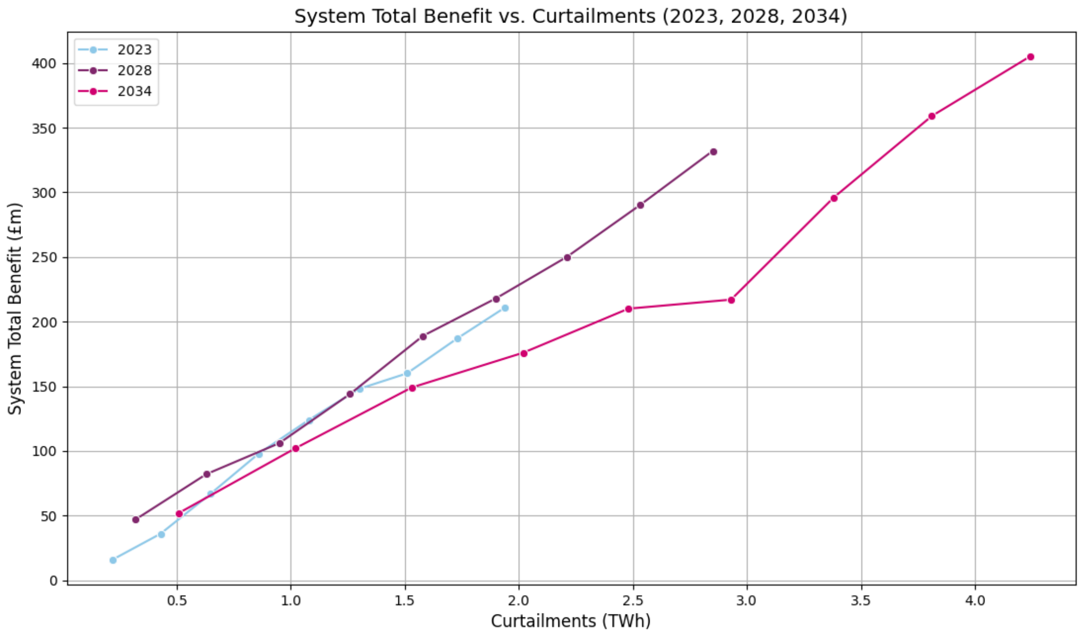


Figure 21: Annual relationship between curtailment and system total cost impact.

4.4.3 Comparisons of Stage 2 and Stage 1 results

Figure 22 compares the accumulated system total benefit of Best-View Curtailments across Stage 1 and Stage 2 results. For Stage 1, the lower bound (LB) provides an accumulated system cost of £324m and carbon emissions impact of £116m. The upper bound (UB) estimates £16,900m for system cost and £753m for carbon emissions. In Stage 2, the accumulated system cost impact is £1,931m, and the carbon emissions impact reaches £213m, positioning it between the Stage 1 lower and upper bounds.

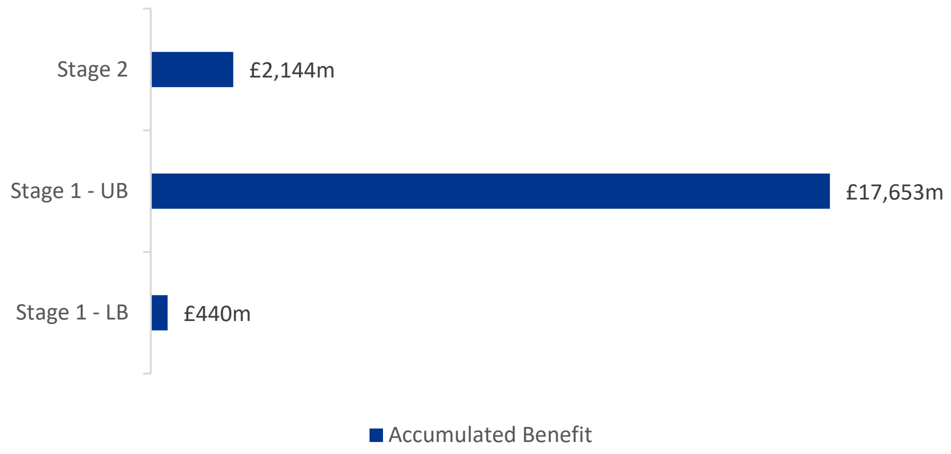


Figure 22: Projected accumulated system total impact of Best-View Curtailments.

4.4.4 Voltage Level Sensitivity Analysis

In this section, the main goal is to quantify the contribution of each voltage level to the overall system impacts caused by the Best-View Curtailments. As previously, the analysis focuses on wholesale markets and carbon emissions, using the same metrics presented in Section 4.4.2: The System Cost Impact, System Carbon Cost Impact, and System Total Cost Impact (the sum of the first two terms).

The methodology for isolating the impact of each voltage level on system cost and carbon cost is closely aligned with the approach outlined in Figure 14. Specifically, the steps related to **Distributed Generators Disaggregation**, **Technology Aggregation**, **Curtailments Allocation**, and **Volume Curtailed** remain unchanged. However, there is a key distinction in the current approach: the curtailments are not aggregated to represent the entire distribution sector anymore. Instead, each voltage level (LV, HV, EHV, and 132kV) is analysed independently to determine its specific share in the overall impact of the Best-View Curtailments. This isolated approach allows for a detailed voltage-level sensitivity analysis, identifying the relative contributions of each voltage level to the observed system-wide impacts on an annual basis. It is important to note that this sensitivity is calculated based on which voltage level generators are connected at, rather than the voltage level causing the constraint.

As discussed in Table 1, LV curtailments are expected to grow significantly, especially between 2028 and 2034, increasing by 203% and peaking at 1.6 TWh by 2034. Conversely, 132kV curtailments demonstrate a marked reduction after 2028, decreasing by 35% and stabilising at lower levels. EHV curtailments show a moderate but consistent increase throughout the years, rising from 0.03 TWh to 1.56 TWh. HV curtailments, on the other hand, begin to grow more visibly post-2030 but remain negligible compared to the other voltage levels. Figure 23 presents the projected Best-View Curtailments distributed by voltage levels over the analysis period.

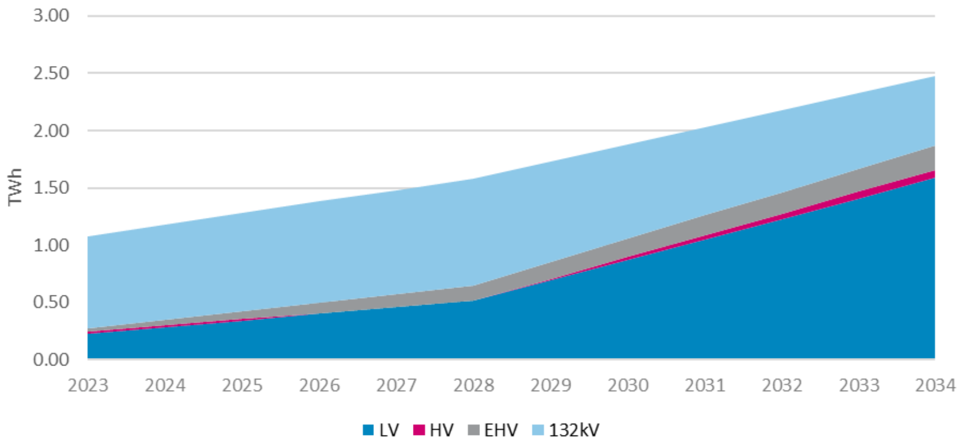


Figure 23: Projected Best-View Curtailments by voltage level.

As previously noted, the system cost benefit, from the wholesale market, is projected to rise from £104m in 2023 to £196m in 2034. At the LV level, the share of benefits starts at 10% (£11m) in 2023 but grows significantly over time, reaching 67% (£131m) in 2034. Conversely, the 132kV level initially holds a dominant share of 82% (£86m) in 2023, but this diminishes to 28% (£55m) by 2034. This shift highlights a crucial insight: **it is not only important to identify where to invest in releasing headroom but also when to make these investments.** Timing plays an important role in optimising the economic benefits and addressing evolving network constraints effectively. Figure 24**Error! Reference source not found.** presents the projected system cost benefits for voltage level over the analysis horizon. Regarding the accumulated system cost impact by voltage level, most accumulated system cost is associated with 132kV curtailments (£987m) followed closely by LV (£732m). Contributions from EHV account for £211m, while benefits from HV is negligible.

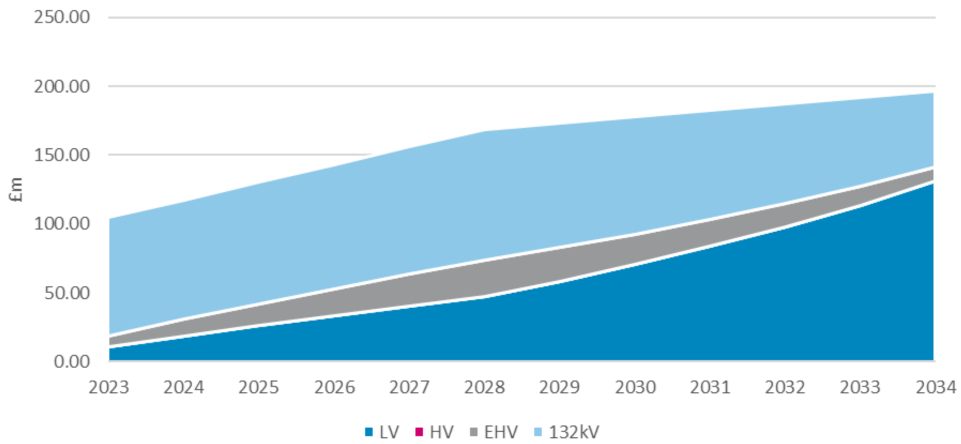


Figure 24: Projected system cost impact by voltage level due Best-View Curtailment.

Carbon intensity by voltage level was also a key focus of this analysis. In 2023, the 132kV accounts for 0.21Mt of the total 0.24Mt of potential carbon emissions avoided through the release of headroom. However, as the system evolves to integrate higher shares of renewable energy, the volume of emissions avoided decreases, particularly at 132kV. By 2034, the emissions avoided at 132kV decline to 0.04Mt, matching the value observed at LV, which remains stable throughout the analysis horizon. This trend is mirrored in the financial benefits derived from system carbon emissions. At 132kV, the benefit starts high at £17m in 2023 but drops to £6m by 2034. In contrast, LV benefits increase from £2m in 2023 to £6m in 2034, highlighting a shifting balance in the distribution of carbon-related benefits over time, as shown in Figure 25.

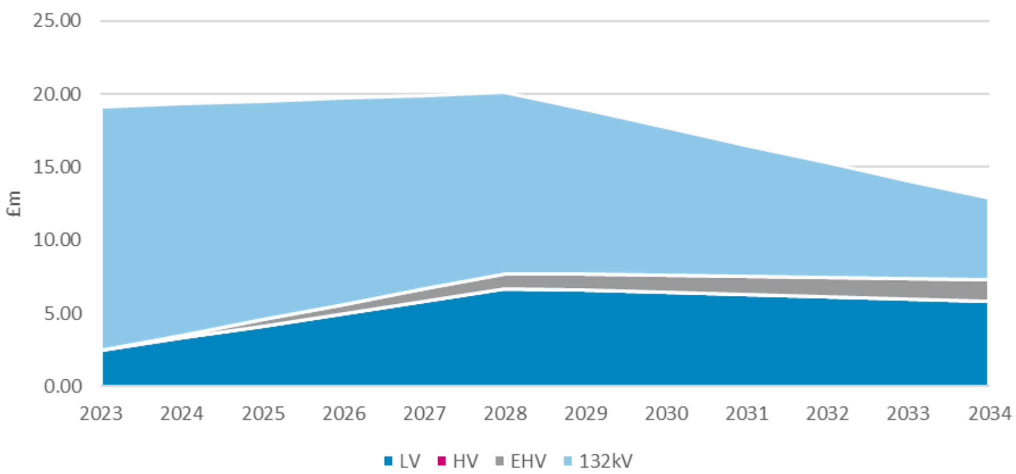


Figure 25: Projected system carbon cost impact by voltage level due Best-View Curtailments.

The total system benefits by voltage level (Figure 26) combines system cost and carbon cost benefits:

- At LV, the total benefit begins with £13m in 2023, growing to £136m in 2034.
- At 132kV, the behaviour is the opposite, £103m in 2023 reducing to £61m in 2034. The accumulated value over the analysis horizon is more than 52% of the total benefit, £1,125m, more than in LV, that remains with 37% of the total benefit, computing £795m.
- The key takeaway is that benefits transition over time from 132kV to LV. This highlights a critical temporal dynamic that underscores the importance of aligning spatial strategies with temporal trends to maximise the benefits of releasing headroom in the distribution network. Balancing these requirements will be essential in optimising outcomes.

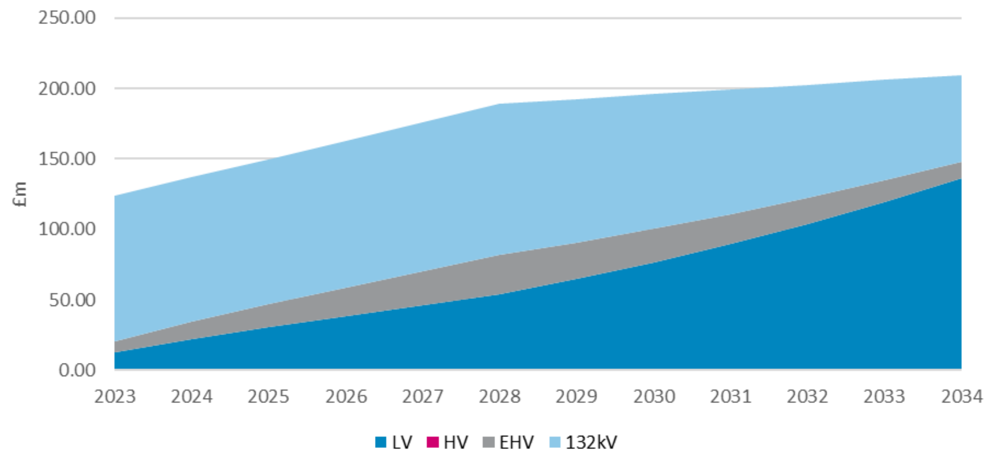


Figure 26: Projected system total cost impact by voltage level due Best-View Curtailments.

4.5 Discussion and conclusions

The main goal of this section was to assess the benefits of Best-View Curtailments on the system, specifically on wholesale markets and carbon emissions. Methodologically, the approach focused on aggregating distributed generators by voltage level and technology, aligning them with the Best-View Curtailments structure. The methodology ensured that curtailments could be allocated efficiently, with their impacts modelled as additional load to the bulk system.

Regarding the limitations of the proposed approach, the presented results are heavily dependent on the Best-View Curtailments derived from the DFES and reflects high-certainty activities and provides a solid foundation for analysis. However, the Best-View may not fully capture future uncertainties.

Changes in policies, market dynamics, or technological advancements could render these assumptions less relevant, potentially impacting the accuracy of the results.

4.5.1 Key Takeaways from the impact of the Best-View Curtailments

The projected variability in curtailments, ranging from 4.17TWh (20% Best View) to 36.33TWh (180% Best View), underscores the wide range of potential impacts that varying levels of curtailments could have on the energy system.

The analysis demonstrated considerable economic opportunities in addressing curtailments by releasing headroom in the distribution network. System benefits, quantified through reduced costs in wholesale markets and avoided carbon costs, range from £486m (20% Best View) to £3,875m (180% Best View) over the study horizon. Under the Best-View scenario, the total system benefit is about £2,144m.

Curtailment reductions offer substantial carbon savings, with emissions avoided ranging from 0.37Mt (20% Best View) to 3.48Mt (180% Best View).

While benefits grow steadily throughout the study horizon, the contributions of different voltage levels vary significantly. LV networks exhibit increasing importance over time, while the contributions from 132kV curtailments tend to decline after 2028, reflecting shifts in the system's dynamics.

4.5.2 Key Takeaways from the voltage level sensitivity analysis

The key takeaways from the analysis are:

- 132kV delivers the highest accumulated benefit over the study horizon, contributing 53% (£1,125m) of the total value but its contribution declines steadily over time.
- Benefits from LV increase almost linearly over time, eventually accounting for 37% (£795m) of the total accumulated value by 2034, underscoring its growing importance in delivering system benefits.
- 132kV curtailments drive most avoided emissions, accounting for 69% of the total (1.34Mt). Its contribution also declines steadily over time.
- Avoided emissions at LV grow steadily throughout the analysis horizon, representing 27% of the total avoided emissions by 2034.
- EHV and HV play minimal roles in carbon emissions reduction.

The results highlight the need for future interventions to prioritize LV networks to manage increasing curtailments and leverage rising system benefits. At the same time, it is essential to monitor trends at 132kV to address its declining contributions and ensure the network continues to perform optimally under evolving conditions.

5 Balancing Services impact

5.1 Context

The modelling in Section 5 examines the impact of constraining DERs on their ability to participate in the wholesale electricity market. DERs connected to constrained areas of the distribution network, and which are subject to curtailment, may face limitations in their ability to offer Balancing Services to the NESO or the DSO.

This section evaluates the potential impact of headroom constraints by considering:

- An overview of energy system balancing, including the costs and volumes associated with the range of Balancing Services (including ancillary services and constraint management).
- The volumes of DER which are providing Balancing Services, and the volumes of DER impacted by curtailment.
- The implications of DER curtailment on balancing costs.
- Broader market considerations which could have a knock-on impact on DERs providing balancing responses e.g. Primacy rules, advancements in ANM, connections reform etc.

5.2 Background to energy system balancing

5.2.1 Balancing overview

NESO is the designated electricity system operator for Great Britain. The NESO's roles include coordinating and managing the flow of electricity onto and over the national electricity transmission system in an efficient, economic, and co-ordinated manner. To balance the grid and ensure electricity supply meets demand second-by-second, the NESO procures Balancing Services and runs the Balancing Mechanism.

Increasing renewable and low-carbon sources of electricity means that NESO must undertake additional balancing actions by increasing or decreasing generation. Setting the system up for increasing intermittent supply is supported by new transmission infrastructure. Network optimisation will form an impactful lever to minimising balancing costs in the future, but it may take a decade to implement fully. Consequently, there is a lag between new generation applying to connect to the network and coming online.

Balancing costs are expected to rise until 2030. In 2023/24 Balancing Services Use of System (BSUoS) charges[6] contributed to approximately 4% of electricity bills for an average domestic consumer,

[6] These are derived from NESO's Monthly Balancing Services Summaries

equating to be about £4 a month on a typical domestic electricity bill. Although balancing costs are projected to rise out to 2030, they are just one of many components making up energy bills, and the energy transition will have variable impacts on these costs.

5.2.2 The role of DERs in Balancing Services

The distribution headroom modelling in this section is intended to show the impact of DERs becoming unavailable for NESO Balancing Services, although determining precisely how the increase in headroom will impact balancing costs is challenging. Firstly, it is important to understand the scale of distributed connected assets which are, and will be, participating in providing Balancing Services.

Baringa estimates, from analysing NESO revenue reporting, that in 2023/24, 37% of Balancing Services revenues for NESO came from DERs, which implies that around this proportion of units participating in Balancing Services could be connected to the distribution network. This is supported by an exploration of Balancing Unit data which highlighted, for auctions across core Balancing Service products in 2023/24, that distribution-connected units were submitting 40% or more of the bids and offers. As NESO sets up Balancing Services to allow more diversity in the types of unit that can provide services, it is likely the proportion of distribution connected assets participating will increase.

Headroom reduction can lead to more constraints on the distribution network, but this is driven by locational, seasonal, and temporal factors. Headroom reduction can lead to two key outcomes:

- **Unavailablity during constrained time periods:** NESO may become unable to access Balancing Services from distribution-connected units during specific time periods, in certain locations during the year, when constraints are active. Access during other time periods remains unaffected.
- **Inability of service providers to guarantee provision of responses at any given time:** A flexibility service provider with a timed connection or an ANM-enabled connection could be unable to guarantee their provision of a service at any specific time. This could result in the provider being unable to contract for services or risking their inability to respond when needed.

The headroom implications modelled in this section not only impact the availability of assets for balancing but could have knock-on implications for the volumes of new generation assets that can connect. A lack of headroom on the distribution network could lead to generators not connecting. Alternatively, generators may accept timed connections, making them unavailable when the network is at risk of constraint, or they might take an ANM connection, where they may be unable to predict their ability for service provision.

In this section, the aim was to understand the implications of headroom on balancing costs. Bottom-up and top-down approaches were considered. Due to the complexity and unpredictabliltiy of headroom impacts, macro-level analysis provided the most robust outcomes.

5.3 NESO Balancing, Current State and Future State

5.3.1 Balancing costs and projections

Constraint costs made up over 63% (£1,500m) of balancing costs in FY23-24[6]. Figure 27 presents the breakdown of balancing costs by type. Thermal constraints contributed to over £1,000m of the constraint costs and this is likely to increase as network becomes more congested.

NESO manages these constraints with Balancing Services, but also via the Balancing Mechanism, constraint management tenders, and infrastructure upgrades. The constraints are not only managed by Balancing Services, it is important to consider the macro balancing costs view, not just the impact of headroom on services, which are just one mechanism for managing system balance.

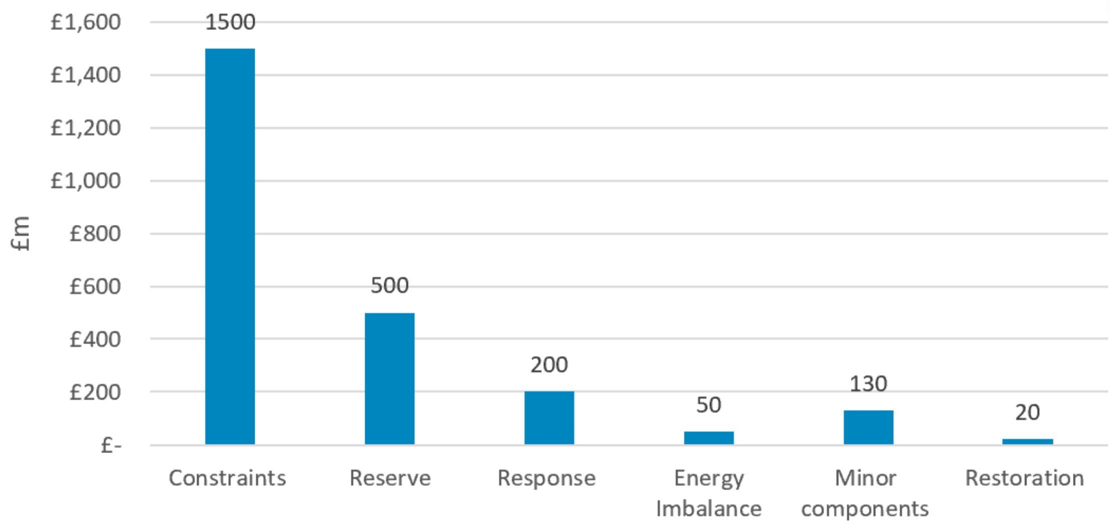


Figure 27: Breakdown of balancing costs by type for FY23-24.

The cost implications of decreased headroom on the distribution network could be explored at a service by service level if more data were available. For instance, it is challenging to determine:

- How often and in what volumes constraint management is being procured by NESO from transmission versus distribution-connected units, as well as the voltage levels at which this is occurring.
- How much NESO is paying for different types of constraints, particularly in different locations.
- The scale of existing inefficiencies in balancing needs between NESO and distribution networks and how reduced headroom could exacerbate these inefficiencies. For example,

there is insufficient data to quantify the scale of conflicts between NESO services and distribution systems. There could be instances where NESO is procuring a turn down but an ANM system on the distribution network enables another unit to turn up into the headroom, negating NESO's action.

Further to this, because there is a lack of data around when or where reductions in headroom, or instances of curtailment, could be impacting balancing costs, it's difficult to predict the actions NESO might take in such instances.

NESO has forecast its balancing costs using the FES[1]. New generation connections will contribute to increased power flows on the network, driving up constraint costs from now until 2040. However, the breakdown of these projected costs is not explicity defined in their report.

As ilustrated in Figure 28, most scenarios (except for Falling Short) project a rise in balancing costs. The disparity between scenarios indicate the uncertainty relating to future costs, driven by the range of factors and assumptions influencing these projections.

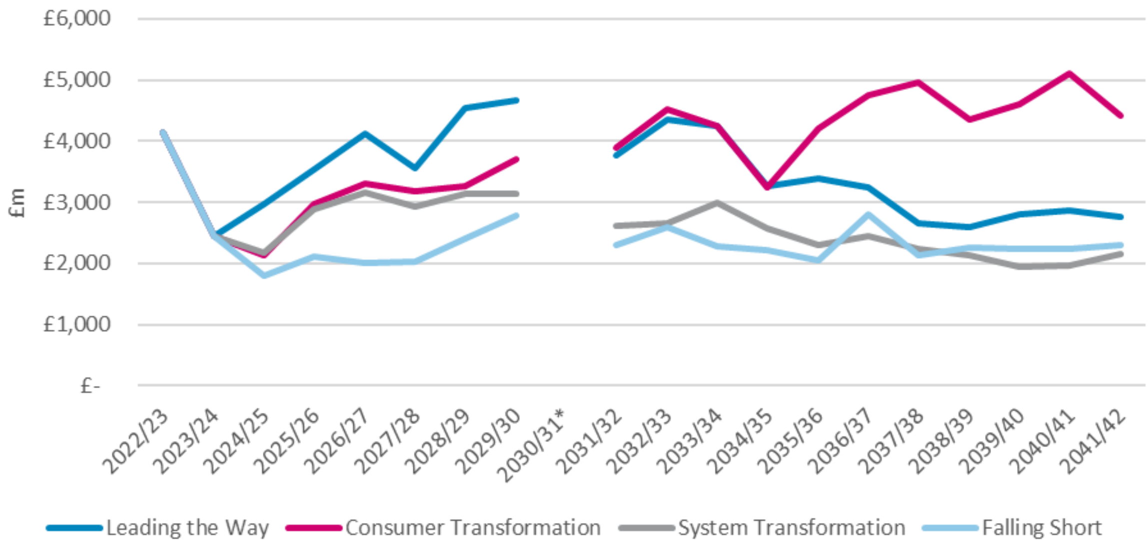


Figure 28 - Cost of balancing NESO projections[7].

[7] Costs for 2030/31 are not published, from that point onwards, the projections are a reflection on uncertainty linked to network build.

5.4 Cost of Curtailment for Balancing Services

5.4.1 Summary of Balancing Services

Balancing Services can be grouped into the categories shown in Table 3. Each of these services could be impacted differently by headroom reduction, depending on the types of assets providing responses and the specific needs of NESO from that service (e.g. need for a locational response).

Table 3: Summary of Balancing Services by type.

Category	Key Services	Description
Reserve	Short Term Operating Reserve (STOR), Balancing Reserve, Fast Reserve, Operating Reserve and Negative Reserve, Super SEL, Hydro Reserve, Balancing Mechanism (BM) Warming, Demand Flexibility Service (DFS), Interconnector NTCs	Reserve services are required to deliver upward or downward energy within a specified timeline to offset power imbalances between generation and demand on the GB transmission system or to cover periods of increased uncertainty. Reserve is dispatched manually by a control room operator following an observed system event or proactively in anticipation of a system need. Reserve can be provided by either a source of generation or a source of demand.
Response	Firm Frequency Response (FFR), Enhanced Frequency Response (EFR), Dynamic Curtailment (DC), Dynamic Regulation (DM), Dynamic Regulation (DR), Optional Frequency Response, Hydro Response	Response services are required to maintain the GB Electricity System frequency between statutory limits of 50Hz ± 0.5Hz and operational limits of 49.8Hz ± 0.2Hz. Major frequency deviations can damage key infrastructure across the energy network. Frequency deviations are caused by instantaneous excesses of demand or generation on the system. Frequency response services are activated automatically to ensure an appropriate change in active power to keep frequency within limits.
Stability	Stability Pathfinder (Network Services Procurement – Query Log 39)	Traditional generation has provided stability as a by-product (inertia, Short Circuit Level, reactive power support). As more non-synchronous generation enters the system the ESO needs to procure alternative sources of stability to ensure security of supply.

Category	Key Services	Description
Thermal	Constraint Management Intertrip Service (CMIS), Constraints Intertrips (CI), BM Constraints, Local Constraint Market (LCM), Megawatt Dispatch (MW Dispatch)	Constraint management is required when there is an excess or lack of generation within a specific location on the transmission network. Constraint services are utilised to manage the system safely and securely. Constraint management increases/decreases the power at different locations of the network to ensure system security and safety. Intertrips disconnect generation in certain situations if its trigger condition is met. Commercial Intertrips can be armed if it is more economic than to constrain generation pre-fault or if it is cheaper than procuring additional generation outside a constrained area. LCM is a new service introduced to help manage constraints at the B6 boundary. MW Dispatch is a new service introduced to manage pre-fault thermal constraints on the South Coast of England.
Voltage	Reactive Power; Voltage Network Services Procurement	Reactive power describes the background energy movement in an alternating current (AC) system arising from the production of electric and magnetic fields. Devices that store energy through a magnetic field produced by a flow of current are said to absorb reactive power; those that store energy through electric fields are said to generate reactive power. The flows of reactive power on the system will affect voltage levels. Unlike system frequency, which is consistent across the network, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. The ESO must manage voltage levels on a local level to meet the varying needs of the system. Without the appropriate injections of reactive power at the right locations, the voltage profile of the transmission system will exceed statutory planning and operational limits.
Restoration	Various Bilateral Contracts and Commercial Tenders	Restoration services are a key pillar for GB energy security to restore power in the event of a nationwide or partial power outage on the national electricity system.

5.4.2 Analysis of NESO Balancing Services

Data from the NESO indicates the connection point of flexibility service providers for some services, allowing an indication of the proportion of providers connected to the distribution network versus the transmission network. Figure 29 highlights the results of analysing this data. More than 40% of auction entries (and 37% of costs) between 02-Nov-23 and 03-Mar-24 were from distribution-connected providers across five of NESO's Balancing Services. This highlights the role of distribution connected assets in balancing the system and the importance of exploring this impact as part of this project.

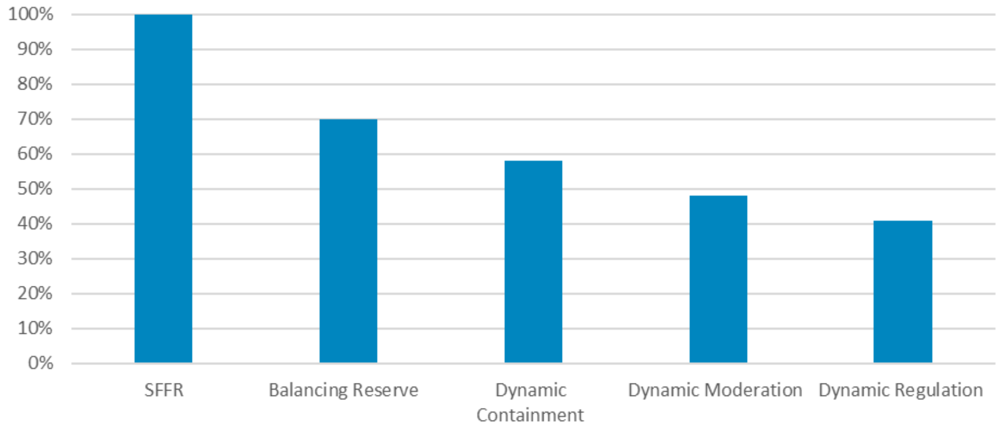


Figure 29 - Summary of proportion of service providers who are distribution connected.

Impact of headroom on Balancing Service procurement costs

One impact of headroom reduction on Balancing Services costs is the unavailability of some units for service provision due to curtailment. For many services, including dynamic and reserve products, flexibility service providers often participate in day-ahead auctions.

In cases where curtailment is required to protect the thermal limit of the distribution network, DSO primacy is assumed. If a NESO flexibility action would create issues for the distribution network or be counteracted by the DSO[8], the DSO would notify NESO of the conflict. NESO would need to exclude or disregard the flexibility service provider from its dispatch queue and secure the required flexibility from an alternative source. This means that if a unit bidding into an auction became unavailable by the time of the service availability window, NESO would have to move further up the supply stack to meet its needs.

[8] For example, if NESO procures a turn-down action, but an ANM system permits another unit to turn up into the newly created headroom, negating the overall effect of the action

NESO currently uses different procurement mechanisms for different services but plans to expand the use of the Enduring Auction Capability (EAC) platform to procure additional services beyond the current frequency response services. Data from the EAC was available for Dynamic products and balancing reserve at the time of this stage of the project, hence this was explored to understand the impact of distribution connected assets becoming unavailble for service provision.

NESO's EAC selects bids by ranking them based on cost-effectiveness while ensuring technical requirements and grid constraints are met. Providers submit bids specifying the service volume, price, and availability, which are then assessed for compliance. NESO optimises the selection to meet the required volume at the lowest cost, considering factors like location and grid needs. Successful bidders are awarded contracts to deliver the service at the agreed price, ensuring reliable and efficient grid operation.

Baringa simulated auction stacks, using historical data, to understand the scale of the impact of removing 1-25% of distribution bids from the stacks. This was done to explore the impact that could occur under the assumption that sufficient market depth is available for NESO to move further up the stack. For the services analysed, even when removing the upper bound, 25%, of the distribution connected bids from the stacks, only small cost increases were observed. Figure 29 shows that for most products there is a negligible increase in cost in the per unit cost.

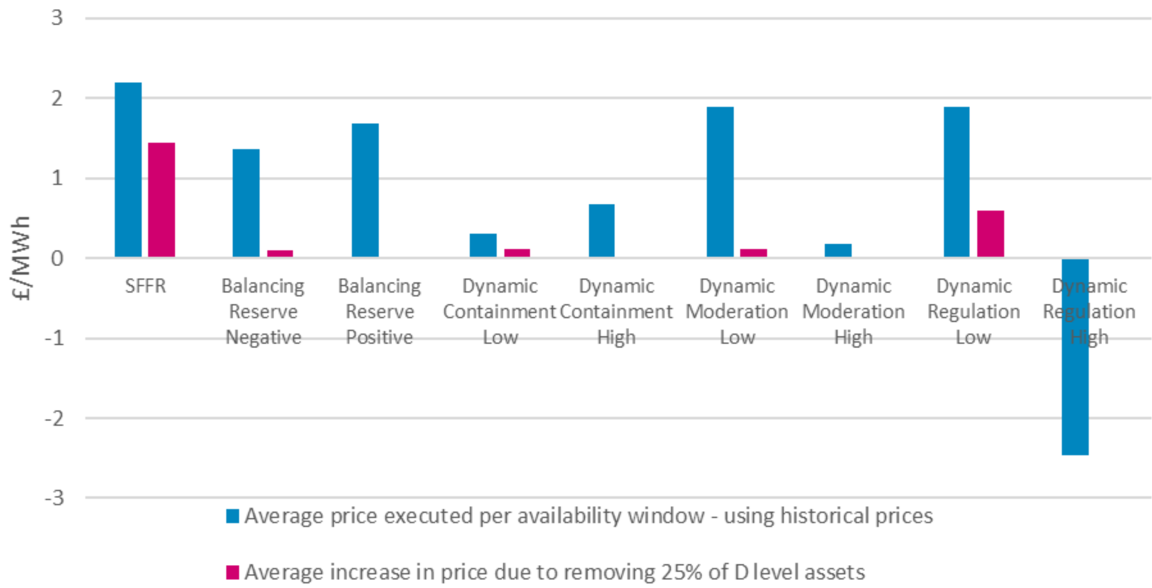


Figure 30**: Indication of the increase in costs because of removing 25% of distribution assets**

However, as per discussion earlier, the action NESO would need to take is unknown, and dependent on their specific balancing need. Flexibility service providers being removed from service supply stacks is only one scenario and may be considered the 'best case' scenario. Figure 31 shows three scenarios illustrating how NESO could address the unavailability of a DER.

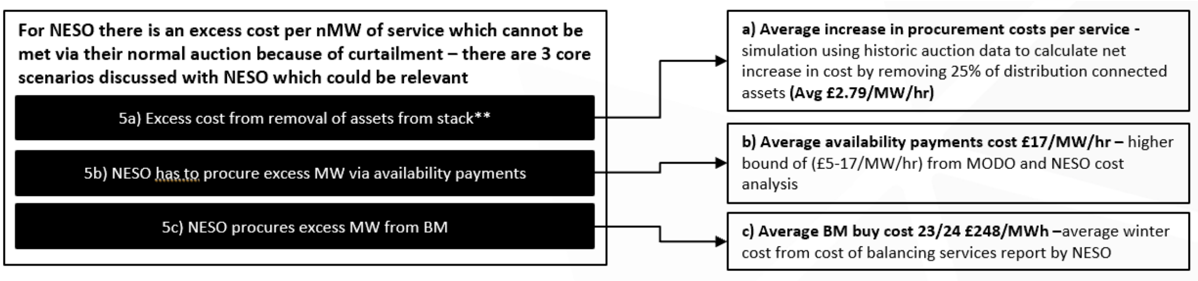


Figure 31 - Three scenarios discussed with NESO which could occur in cases of unavailability from distribution connected Balancing Service providers

The three scenarios in Figure 31 can be further summarised:

- 5a highlights the 'best case' scenario, where there is volume and market depth to enable service needs to be met from existing auctions.
- 5b highlights the scenario where the NESO have more certainty of the unavailability occurring and secures excess availability ahead of time to ensure volume is sufficient.
- 5c represents the scenario where the NESO is 'blind' to what curtailment could occur, meaning they must take a last-minute action, securing capacity via the BM.

Scenarios 5a and 5b require day ahead knowledge of forecasted curtailment which would be expected to be reasonably accurate. This is currently not shared between the DSOs and NESO at scale and hence would require data infrastructure to be put in place.

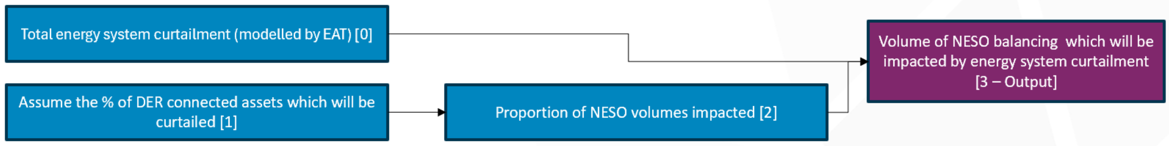
The costs (£/MW/h) resulting from these scenarios represent the range and volatility of costs caused by a lack of unavailability and there is no clear view of which scenario would result from a reduction in headroom. As such, the modelling of outcomes was conducted using a top-down methodology as there was no robust route to ascertain the level of curtailment costs in each scenario.

5.5 Impact of curtailment on system balancing costs

Using Balancing Services data to model the impact of curtailment on balancing costs, would have not have included the full range of costs to NESO. This would not have provided a clear view of the costs for NESO who rely on the Balancing Mechanism, bilateral contracts and other mechanisms, alongside Balancing Services, to balance the system. Further to this, to approach the modelling in a bottom up manner would have involved making numerous assumptions about services and the resultant costs which, in the absense of more data, was not likely to present a robust view. Instead, a top down approach was adopted which is outlined in this section with the outcomes.

5.5.1 Summary and justification of method

Results from EATL's modelling were used to estimate the volumes of NESO balancing requirements which would be impacted by decreased headroom, as shown in Figure 32.



[1] **37% of balancing revenue come from DER** (from previous work conducted by Baringa) – *supported by NESO data which indicated for all services, where data was available, D connected assets were contributing > 40% of the bids*

[2] **Volumes of curtailment which impact NESO balancing** are calculated assuming 37% of NESO costs are met by D-connected assets, and the EAT modelling which indicated the **total energy system curtailment across GB [0]**

[3] **NESO 23/24 required balancing volumes** are known, 15TWh. NESO have also projected balancing costs across the time horizon. In absence of projected volumes, we project the volumes of balancing will grow in line with projected costs (presuming GB follows the Consumer Transformation scenario)

	2023	2028	2034
Total energy system curtailment (modelled by EAT) [0]	1.24%	1.37%	4.00%
Proportion of NESO volumes required impacted [2]	0.46%	0.51%	1.48%
Volumes impacted (MWh) [3]	68,604	100,878	289,839

Figure 32 - Assumptions to define the volume of NESO balancing volumes which could be impacted by modelled curtailment

From NESO's Monthly Balancing Services Summaries, the historic typical cost for NESO of balancing the energy system can be ascertained. From this same summary, it is clear the typical cost of balancing from using the BM is slightly higher, as shown in Table 4.

Table 4: Monthly Balancing Services costs.

Balancing Services	Cost
Entire energy system and all balancing methods, (2023/2024 average)	***£97/MWh***
Typical cost of balancing via BM (2023/2024 average)	**£114/MWh**

From NESO's cost of balancing projections, the cost of balancing for each reference year can be extracted. Using these costs as a baseline, Baringa have modelled two scenarios in modelling the cost of curtailment, as highlighted in Figure **33: Summary of scenario assumptions and the blend case.**

Both scenarios presume when curtailment occurs the NESO incurs an extra cost and need to go to the Balancing Mechanism to procure the volume which was curtailed. Scenario 1 presumes that the balancing costs projected in the baseline remain and the cost of going to the BM is additional to these. Scenario 2 presumes the original costs are negated and only the costs of going to the BM are incurred for that volume. A blend of these scenarios indicates a representive projection of reality.

Scenario 1 (Worst Case): NESO balancing actions are nullified by DNO constraint. Likely to occur where curtailment notification is close to real-time and / or unpredicatble and NESO has already procured service from a provider for which they then have to pay

Scenario 2 (Best Case): Curtailed volume is procured at the average BM cost with pre-exitsing costs for curtailed volume negated. Reflective of the case where NESO could predict or anticipate a conflict and withdraw service payments.

Scenario 3 (Blended Case): Costs reflect a mix of Scenarios 1 and 2. Realistic assumption based on industry progress in data sharing, flexibility co-ordination, transparency, and primacy rules. Presumes negligible primacy co-ordination in 2023/2024 as NESO would be unaware of whether flex providers are within an ANM zone. Presume foresight by NESO to enable Scenario 2 remains low in 2028/2029 but grows to 50% in 2034/2035.

Figure 33: Summary of scenario assumptions and the blend case.

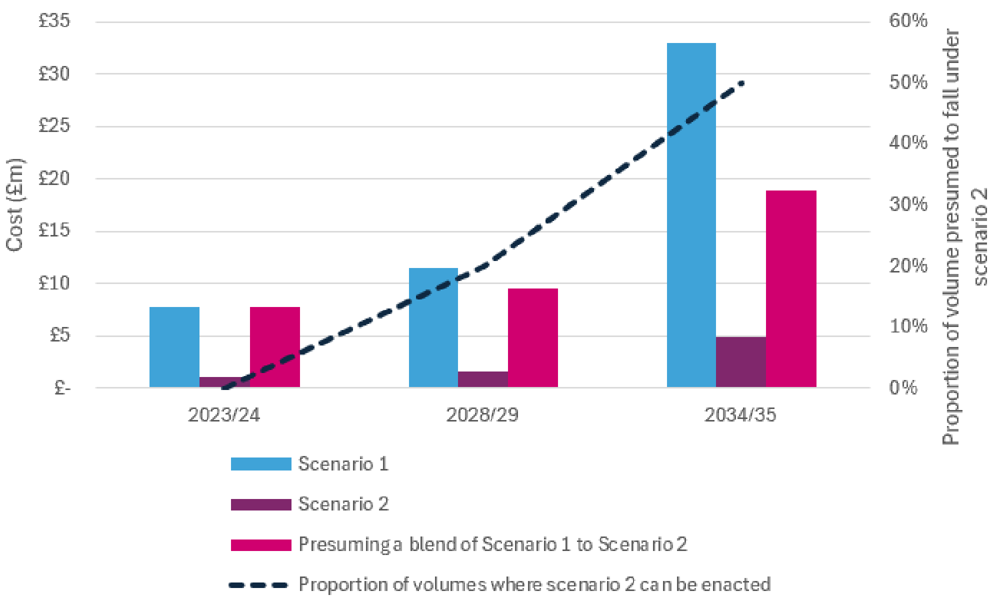


Figure 34: Indication of the proportion of each scenario assumed in the 'Blend' case and the costs of curtailment

5.5.2 Validation and carbon cost calculation

Validation of the quantitative results was achieved by comparing with the Market Model annual projected benefit. The Market Model benefits were inspected to infer the resultant impact on balancing costs, assuming the expected balancing costs would be proportional to the BSUoS component of the wholesale costs. The results of this indicated the modelled costs are proportionate to what would be expected.

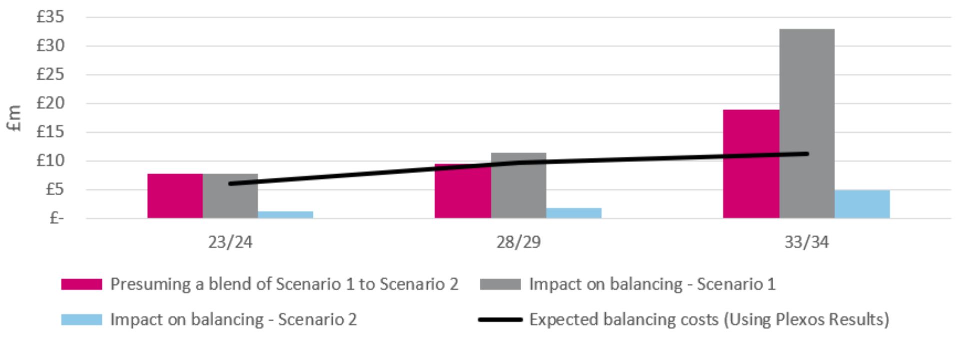


Figure 35: Annual cost under Scenarios 1, 2 and the blended scenario.

Whilst discussion has focussed on the costs to NESO in managing the system when curtailment affects balancing procurement it is important to also consider the broader impacts of the alternative actions which NESO have to take to maintain system balance. The alternative action issued by NESO will be dependent on the conditions of the system needs. For the quantative analysis, an assumption has been made that the NESO would need to activate a gas turbine in place of the renewable curtailment. This leads to an increase in emissions compared to the alternative (of less curtailment). Figure 36 indicates the core assumptions used to model the carbon emissions.

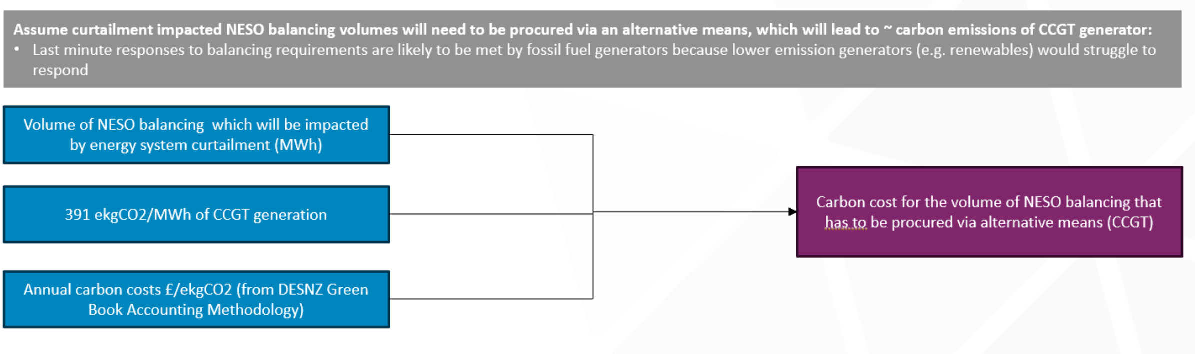


Figure 36 - Summary of assumptions to model carbon costs

5.5.3 Summary of the effect on Balancing Services costs

The modelling undertaken indicates the possible scale of the cost of curtailment on the energy system with a focus on the balancing implications. Over £350m in excess costs to NESO and the general system could result from decreased headroom across the distribution networks in GB. This quantitative modelling is an indication of the scale and the true cost implications on balancing could be impacted by a plethora of changes in the energy system.

Figure 37: Cumulative cost of curtailment and carbon emissions cost

5.6 Discussion

The quantitative analysis in Stage 2 was supplemented by qualitative research to understand the full scope of relevant market changes which could impact distribution curtailment and balancing.

5.6.1 DSO Services - changes to DSO constraint management

DSOs procure services to maintain the stability, reliability, and efficiency of the electricity distribution network. These services offer the future opportunity to address challenges such as increasing renewable energy integration, network congestion, and localised demand fluctuations. Currently, the prices being offered by service providers tend to be higher than the modelled costs per MWh for NESO to manage balancing through a curtailment event. Therefore, it is difficult to justify spending on flexibility, compared to allowing curtailment. In the future, as and when DSO services become cheaper, and markets achieve more liquidity, DSO services could be a viable option for managing balancing on the system.

Decreased headroom, and increased amounts of distribution connections which are ANM enabled or curtailable in some way, will impact the volumes of generation which can participate in DSO services.

5.6.2 Primacy

Primacy rules are being developed to ensure there is a clear resolution mechanism for conflicts between NESO and DSO needs. These rules establish a hierarchy, favouring either the NESO or DSO depending on the conflict case.

Increasingly, there are situations where NESO is trying to dispatch positive flexibility (generation turn-up or demand turn-down) or negative flexibility (generation turn-down or demand turn-up) from assets embedded in the distribution network that are at their import or export limits. To maintain the distribution network within its operating limits, the DNOs (in their DSO role) instruct positive or negative flexibility, either through procured flexibility services or through the automated action of an ANM system. These ANM systems are expected to unwind any action that the NESO attempts to take, by increasing or reducing the curtailment of assets to keep the network within its limits.

Despite a degree of uncertainty around the prevalence of DSO-NESO conflicts, and the costs of the primacy rules, a recent report by the ENA[9] identified the preferred Primacy rule in each case:

- Where NESO primacy requires the creation of distribution headroom ahead of time, this is unlikely to be the optimal approach unless the cost to the NESO of accessing alternative forms of flexibility becomes significantly more expensive. Under these cases, DSO primacy appears to be the preferred approach.
- Where the conflict does not require headroom creation ahead of time, NESO primacy appears to be the optimal solution as it does not create additional variable cost for the DSO or distribution-connected customers. However, there remain questions around the regulatory and contractual changes required to enable NESO primacy in these cases relating to the treatment of curtailable assets when there is headroom on the local network.

[9] Primacy Rules: Rules for ESO/DNO Coordination, Increment 2, October 2024, version 1.0

Both DSO primacy and ESO primacy require investment to enact them. This includes improved data, forecasting, and information sharing between parties. In some cases, it also involves making changes to ANM systems to allow them to adjust their notional headroom based on NESO actions, as well as changing the Principles of Access to prioritise some assets over others. Further work is required to understand the technical changes required to allow data sharing between NESO and DSO, and the costs involved. This project provides a projection of curtailment forecasts, however at the present moment costs are incurred due to conflicts between DSO action and NESO balancing service procurement, which data is hard to retrieve to understand. **Additional real world data will be required to supplement forecasts and understand the prevalence of these DSO-NESO conflicts.**

Apart from the data and system improvements needed to implement these primacy rules, **the impact these rules will have on curtailable customers' needs further assessment**. Collaboration between future phases of this work and the Primacy Technical Working Group, could benefit all parties.

The **primacy report indicated there is a risk for existing and future distribution-connected flex providers that their flexibility revenues are below expectation due to the implementation of primacy rules**. They may be connecting 'firm', and therefore assuming their firm access means their energy and flex is treated at full value. But for the reasons discussed above, this is not necessarily the case.

The implementation roadmap to primacy rules could in turn alleviate some of the costs of balancing which are incurred through decreased headroom. **If dispatch rules between NESO and DSO regarding conflicts are made more efficient and conflicts themselves are made more visible, the impact of curtailment on balancing could be better understood**.

5.6.3 Advancements in ANM

ANM curtailment is one mechanism by which the DSO can affect negative (or positive) flexibility. An ANM system does not require hands-on control by the DSO. It monitors the real-time export (or import) across a network asset (e.g. a substation) and instructs one or more flexibility-connected customers to vary their output to ensure the export (or import) does not exceed the capacity of the network asset. ANM is also used to keep the electricity flows within Technical Limits agreed with the NESO to manage a transmission constraint.

ANM systems across DSOs vary, and the volume of connections which are under ANM or are in ANM zones vary. As ANM technology is being increasingly rolled out, there is a significant role it can play in improving data and understanding around curtailment.

Flexibly connected customers are those that do not have unfettered access to the network, but instead have an obligation to accept curtailment when the network is constrained. A flexibility service provider in an ANM stack can have its output curtailed when required to manage a network constraint.

As data (from e.g. LV monitoring, outage forecasts) is consolidated across distribution networks and monitoring data and analysis, curtailment forecasts from DNOs will likely become easier to produce and more realistic. This can enable better day-ahead balancing forecasts from distribution connected assets and reduce the scale of costs which curtailment can cause for Balancing Services. Improved forecasting will also benefit the flexibility service providers, as they will be able to predict their revenues more easily.

5.6.4 Technical limits

A Technical Limit[10] refers to a maximum import or export for a specific Grid Supply Point (GSP) agreed between the NESO and the DNOs. It allows DNOs to connect customers ahead of the completion of required transmission reinforcement works, under the condition that the DNOs limit the power flow across the GSP to their agreed limit.

Technical limits have been rolled out across the network through 2023/24 and the final phases will continue through to 2025. Where technical limits are in place, there should be increased co-ordination between the DSO and NESO. The impact of technical limits is not thoroughly understood yet, but there could be increased curtailment for DERs if their operation risks exceeeding the technical thresholds.

By using Technical Limits, NESO should have reduced balancing pressures because technical limits should mean an increase in local system balancing, moving away from the focus on centralised grid stability. However, Technical Limits could increase the opportunity for conflict between DSO and NESO needs; DSOs could curtail due to a Technical Limit which restricts the provider from being available to provide Balancing Services. This indicates the range and scale of complications that could impact distribution curtailment and therefore the cost of balancing in the future.

5.6.5 Data improvement

There is currently a lack of data to quantify the instances of conflict between distribution curtailment and NESO balancing requirements. This makes it difficult to understand robustly the current costs of curtailment, but this work has used forecasts to provide some indication. In absense of data to understand true actions occuring on the networks, it is difficult for initiatives like Primacy rules and connections acceleration to occur in an efficient mannner. Gathering data on instances of conflicts and the costs to mitigate for these, requires collaboration between NESO and DSOs and could be achieved by leveraging data from distribution ANMs together with NESO's flexibility dispatch data.

There are several initiatives ongoing to improve data sharing and collaboration between NESO and DSO's, but these need to progress at pace to enable the system to transition succesfully and at lowest cost to the consumer.

[10] Grid Supply Point Technical Limits for accelerated non-firm connections – Energy Networks Association (ENA)

5.7 Conclusion

The quantitative analysis estimates **£350m in curtailment-related costs to NESO balancing actions over the analysis horizon**. The actual figure will depend on changes to co-ordination across the energy system and investment in infrastructure and technology which will impact the costs incurred when NESO balancing actions are affected by distribution curtailment.

The energy system is undergoing significant market changes, some of the key changes which will impact the scale of the curtailment related cost for NESO balancing actions are:

- Primacy rules, which will offer the opportunity to reduce incurred costs from curtailment on NESO balancing. Primacy rules are being developed to manage NESO-DSO conflicts, with preferred approaches depending on cost-efficiency and operational requirements. However, their implementation requires investment in data sharing, forecasting, and ANM system adjustments.
- Advancements in network monitoring and dispatch of distribution connected resources could enhance curtailment forecasting and dynamic balancing, reducing costs associated with curtailment interfering with system-wide balancing needs.
- Real world data is limited when it comes to the prevalence and costs of curtailment being incurred when it impacts NESO balancing. This project has helped to forecast these instances, but in the future network data could supplement this to provide a clearer picture and help ensure costs are reduced. Network visibility data, ie. Knowing where distribution assets are being dispatched for NESO services, will greatly improve the predictability of conflicts between curtailment and NESO balancing. This underscores the need for enhanced collaboration and data sharing between NESO and DSOs, to reduce balancing costs impacted by curtailment.

Better coordination and data sharing between NESO and DSOs and DSOs leveraging capabilities of ANM software for optimal dispatch based on whole system value will be crucial to minimising curtailment costs and balancing inefficiencies.

This work has shown, optimising using flexibility, increasing curtailment, to increase the utilisation of the distribution network has implications for the wider system, including to NESO balancing costs. Ultimately, curtailing low-carbon and low variable cost assets such as wind and solar pushes up wholesale electricity prices and increases the carbon intensity of the electricity system. Periods of ANM curtailment restrict the ability of distributed flexibility, such as batteries, to access wholesale markets and to provide valuable balancing to NESO. This presents a trade-off, where achieving the optimal outcome for the DNO and DUoS customers may not be the optimal outcome for the system as a whole. Understanding this whole-system impact, and factoring this into DNOs' decision-making about the use of flexibility procurement and ANM, is key to delivering a low-cost electricity that meets the ambitions of CP2030. To do this, curtailment needs to be assigned a cost dependent on the market context in that time period, NESO and DSOs need to consider how to ensure there is a standardised approach for this. The speed of the changes to ensure co-ordination will determine the overall impact of curtailment on balancing costs and the costs to consumers.

6 Market and Balancing Services Results

The modelling approaches for this stage, presented in Sections 4 and 5, aimed to quantify the system-wide impacts of curtailments in the distribution network. In Section 4, the analysis focused on understanding the broader energy system cost and carbon emissions impacts of curtailments and explored the contributions of each voltage level to these impacts. In section 5, the analysis focused on understanding the Balancing Services costs to manage the system and mitigate the consequences of reduced headroom.

Table 5 summarises the outcomes of the analysis in Stage 2 by considering the Best-View Curtailments. The cumulative System Cost Impact across all voltage levels, from wholesale market benefits, is approximately £1,931m, with the largest contributions from 132kV (£987m) and LV (£732m). Similarly, the cumulative System Carbon Cost Impact totals £213m across all voltage levels, with 132kV contributing £138m, and LV adding £64m. These carbon costs are associated with a System Carbon Emissions Impact of 1.95Mt over the distribution sector, of which 132kV (1.34Mt) dominates. When these components are combined, the System Total Cost Impact reaches £2,494m. Finally, a Balancing Mechanisms Impact of £350m further adds to the overall picture, bringing the total quantified impact to £2,494m over the study horizon.

Table 5: Impact of the Best-View Curtailments.

Metric	Distribution network			
	LV	HV	EHV	132kV
System cost impact	£732m	£0m	£212m	£987m
System carbon cost impact	£64m	£0m	£11m	£138m
System carbon emissions impact	0.53Mt	0.00Mt	0.08Mt	1.34Mt
System total cost impact	£796m	£0m	£223m	£1,125m
Balancing Services impact	£350m			
Total impact	£2,494m			

As outlined in Section 4.4.2, the magnitude of these impacts is sensitive to variations in curtailments. The projected variability in curtailments, ranging from 4.2TWh (20% Best View) to 36.3TWh (180% Best View), underscores the significant range of potential impacts. System benefits, quantified through reduced costs in wholesale markets and avoided carbon costs, could vary from £486m (20% Best View and not considering Balancing Services impacts) to £3,875m (180% Best View and not considering Balancing Services impact), illustrating the economic opportunities in optimising the distribution network and addressing curtailments.

7 Key Insights from the Analysis

Curtailments, under the Best-View scenario, behave very differently according to the voltage level. In general, over the years, most curtailments are located at LV and 132kV voltage levels; in 2023 they are responsible for almost 96% of the share, in 2028 for about 92%, and in 2034 for 88%. However, LV and 132kV varies differently when it the technology being curtailed is considered. At LV, PV is constantly responsible for about 99% during the period under analysis. On the other hand, curtailments are much more diverse at 132kV; in 2023 BESS is responsible for 4%, Gas for 70%, PV for 4%, and Wind for 22%. Over time, this share changes significantly and in 2034 BESS grows it shares for almost 16%, Gas reduces for 20%, PV increases for 18%, and Wind is responsible for 46% of the curtailments at 132kV voltage level. This analysis is key when releasing headroom because it adds a temporal issue in the original locational concern. **Depending on the year, the action to release headroom can change significantly if this is associated to the technology being curtailed.**

As expected, PV curtailments are very correlated to the total generation at LV, meaning that PV curtailments tend to grow when the generation level grows. The same thing applies to BESS at 132kV, not as straightforward as PV for LV voltage level due to the above-mentioned diversity. However, at 132kV, the curtailment from the remaining technologies also correlates with the level of generation, as show in Section 3.2.4

Due to the mentioned locational characteristics of curtailments, most benefits are located at LV and 132kV voltage levels; 90% of the accumulated benefit over the years are located at these voltage levels. **The accumulated benefit coming from wholesale markets could reach £1,931m** (£732m from LV and £987m from 132kV) when releasing headroom over the period under analysis. Further, **the accumulated benefit coming carbon emissions could reach £213m** (£64m from LV, £11m from EHV, and £138m from 132kV)**,** while **Balancing Services could bring another £350m of benefits**. The results highlight the immense potential benefits of releasing headroom in the distribution network to reduce curtailments.

The variation in benefits between the Best-View scenario and the lower and upper bounds of our analysis is driven solely by changes in curtailment levels, as all other future assumptions remain consistent across scenarios. **The lower bound (20% Best-View), with total system benefits of £486m**, would likely materialise if renewable penetration (particularly at LV) declines or stabilises over time, while investments in grid infrastructure increase sufficiently to enhance flexibility and reduce curtailments. Conversely, if renewable penetration continues to grow and network investments follow historical trends, failing to keep pace with the increasing flexibility needs, curtailments could rise towards **the upper bound (180% Best-View), resulting in total system benefits of £3,875m**. Given the strong policy drive towards Clean Power 2030 and Net Zero by 2050, it is more likely that the system will evolve towards the higher benefit scenarios, reinforcing the importance of strategic planning and investment in network flexibility.

Curtailment causes can be summarised:

- LV - almost exclusively due to PV curtailments. The high penetration of Solar PV, combined with its inherently variable nature, leads to significant voltage rise issues, particularly during peak production hours when local demand is insufficient to absorb the generated energy, resulting in curtailments.
- HV and EHV result primarily from the propagation of LV curtailments but could be statistical rather than causal. For example, both could correlate with other factors, such as high PV or Wind which leads to curtailments. **This is another key output of the project; releasing headroom at LV can also reduce the curtailments upstream and the potential for statistical relationships causing this should be investigated**.
- 132kV - heavily influenced by Wind with contributions from PV (EDA insights). The Decision Tree analysis complements these findings, identifying BESS generation and total generation as critical factors driving curtailments at this voltage level.

8 Conclusions and Recommendations

The project highlights the potential of releasing headroom in the distribution sector to enhance system performance, reduce curtailments, and achieve economic and environmental benefits. By focusing on curtailment impacts and their mitigation, the analysis provides insights into how the distribution network could be optimised to support the growing penetration of renewable energy. The primary goals of this project were to quantify the system-wide benefits of releasing headroom and to assess the role of each voltage level independently in delivering these benefits. The sensitivity analysis to capture the variability in curtailments and evaluated the isolated impact of each voltage level using detailed modelling methodologies.

The project addressed several key questions, enabling a deeper understanding of curtailment impacts and headroom dynamics.

i. **What is the impact of releasing headroom in the distribution sector?**

Releasing headroom in the distribution network can generate substantial system-wide benefits, reducing wholesale market costs, carbon emissions and reliance on costly balancing actions. Sensitivity analysis revealed the total benefits vary significantly, ranging from £486m to £3,875m, depending on the level of curtailments addressed, with the Best-View scenario projecting a total benefit of £2.5 billion. The lower bound reflects scenarios where renewable penetration stabilises and grid flexibility improves, while the upper bound aligns with continued renewable growth and limited network investment.

ii. **What is the impact of each voltage level when releasing headroom in the distribution sector?**

The benefits are not uniformly distributed across voltage levels. LV networks play an increasingly prominent role, delivering 37% (£796m) of the total accumulated benefits by 2034. In contrast, 132kV provides the highest accumulated benefit (53%, £1,125m) but sees its contribution declines after 2028.

iii. **What are the main drivers of curtailments in the distribution sector at each voltage level?**

The EDA and Decision Tree analyses revealed that PV generation is the dominant driver of curtailments at LV, while wind generation and BESS utilisation significantly impact higher voltage levels like 132kV.

iv. **What are the benefits of Balancing Services when releasing headroom in the distribution sector?**

Releasing headroom in the distribution sector provides an estimated £350m benefit to balancing mechanisms by enabling greater participation of DERs in Balancing Services. This reduces the reliance on costly constraints and reserve actions while improving grid flexibility.

There is a clear strategic importance of LV networks in reducing curtailments and maximising system benefits. As PV generation continues to grow, investments in LV capacity upgrades and advanced network management systems are critical to managing the rising stress on these networks. **Leveraging**

insights from the EDA and Decision Tree analyses, interventions should prioritise PV curtailment management and increase flexibility in LV networks. These efforts will enable the network to harness the full potential of renewable energy generation, contributing to economic savings and carbon reductions.

At the same time, the 132kV network requires strategic attention in supporting system performance during the initial years of the study horizon. While their contribution declines over time, targeted measures can help sustain their value. Enhancing BESS utilisation and optimising Wind curtailment management at 132kV will ensure this voltage level continues to provide critical support to the system. Coordination between NESO and DSOs is also essential to address cross-voltage level impacts and prevent conflicts in flexibility actions.

To deliver system-wide benefits and support a low-carbon electricity system, **<u>we propose the following key actions based on the findings of this work</u>**:

- **Invest in LV network upgrades in the long term**
  With LV curtailments projected to dominate by 2034 and PV identified as the primary driver, prioritise capacity upgrades and advanced network management systems at LV. This will mitigate the growing stress on these networks, reduce curtailments, and unlock economic and carbon savings.
- **Enhance 132kV network performance in the near term**
  The 132kV network plays a crucial role in supporting system performance during the initial years of the analysis horizon, contributing 83% of total system benefits in 2023, 75% in 2024, and 69% in 2025. Strategic interventions to optimise wind curtailment management and enhance BESS utilisation at this voltage level will help sustain its value as its contribution declines after 2028
- **Align DNO flexibility strategies with whole-system outcomes**
  As flexibility increasingly shifts from deferring reinforcement to supporting system intermittency, DNOs should account for whole-system impacts when making decisions about flexibility procurement and ANM implementation. Opting not to build out firm headroom risks higher wholesale electricity prices, increased carbon intensity, and reduced DER participation in markets and services.
- **Foster coordination between NESO and DSOs**
  Strengthen cross-voltage level coordination to minimise conflicts between flexibility actions and ensure system-wide benefits. This will help manage cascading congestion effects, particularly from LV to EHV and 132kV, and optimise DER integration.
- **Integrate whole system impacts into planning and regulation**
  Incorporate the wider system implications of curtailments into DNO decision-making frameworks, ensuring that strategic and regional plans, flexibility strategies, and capacity

investments align with the ambitions of CP2030[11] and Ofgem's ED3 Framework[12]. This will enable network planners to strike a balance between optimising customer outcomes and delivering broader system benefits.

- **Ensure alignment between the SSEP and RESPs to optimise national and regional energy planning**
  Strengthen coordination between NESO, DNOs, and regional stakeholders to integrate Strategic Spatial Energy Planning (SSEP)[13] at a national level, with Regional Energy Strategic Plans (RESPs)[14]. This will help avoid conflicting flexibility strategies, improve investment decisions, and support a cost-effective transition to a low-carbon system.

This project has provided a comprehensive analysis of curtailments and headroom impacts in the distribution network, offering actionable insights for improving system performance. By addressing the key questions and exploring the role of each voltage level, the results demonstrate the significant opportunities available through targeted interventions. As renewable energy penetration continues to grow, optimising headroom in the distribution network will be critical to achieving a resilient, efficient, and low-carbon electricity system.

[11] https://www.neso.energy/publications/clean-power-2030

[12] https://www.ofgem.gov.uk/sites/default/files/2024-11/ED3_Framework_Consultation.pdf

[13] https://www.gov.uk/government/publications/strategic-spatial-energy-plan-commission-to-neso

[14] https://www.ofgem.gov.uk/consultation/regional-energy-strategic-plan-policy-framework-consultation

9 Appendix

9.1 Results of the Best-View Curtailments

Table 6: Best-View – Curtailments in TWh

Year	20% Best View	40% Best View	60% Best View	80% Best View	Best View	120% Best View	140% Best View	160% Best View	180% Best View
2023	0.22	0.43	0.65	0.86	1.08	1.3	1.51	1.73	1.94
2024	0.24	0.47	0.71	0.94	1.18	1.42	1.65	1.89	2.12
2025	0.26	0.51	0.77	1.02	1.28	1.54	1.79	2.05	2.3
2026	0.28	0.55	0.83	1.1	1.38	1.66	1.93	2.21	2.48
2027	0.3	0.59	0.89	1.18	1.48	1.78	2.07	2.37	2.67
2028	0.32	0.63	0.95	1.26	1.58	1.9	2.21	2.53	2.85
2029	0.35	0.7	1.04	1.39	*1.73	2.07	2.41	2.74	3.08
2030	0.38	0.76	1.14	1.52	1.88	2.24	2.6	2.96	3.31
2031	0.41	0.83	1.24	1.64	2.03	2.41	2.79	3.17	3.54
2032	0.44	0.89	1.33	1.77	2.18	2.59	2.99	3.38	3.78
2033	0.48	0.95	1.43	1.89	2.33	2.76	3.18	3.6	4.01
2034	0.51	1.02	1.53	2.02	2.48	2.93	3.38	3.81	4.24
Total	4.17	8.34	12.5	16.61	20.61	24.58	28.52	32.44	36.33

Table 7: Best-View – Generation Levels by voltage levels in TWh

Year	LV	HV	EHV	132kV	Distribution
2023	8	4	11	23	46
2028	12	5	15	24	55
2034	15	6	17	14	52

Table 8: Best-View – Generation Levels by technology and voltage level for 2023 in TWh

Year	PV	Wind	Gas	BESS
LV	8	0	0	0
HV	2	1	1	0
EHV	2	8	1	0
132kV	2	5	15	1

Table 9: Best-View – Generation Levels by technology and voltage level for 2028 in TWh

Year	PV	Wind	Gas	BESS
LV	11	0	0	0
HV	2	2	1	0
EHV	3	11	1	1
132kV	3	6	13	2

Table 10: Best-View – Generation Levels by technology and voltage level for 2034 in TWh

Year	PV	Wind	Gas	BESS
LV	14	0	0	1
HV	3	3	0	0
EHV	3	13	0	1
132kV	2	6	5	1

Table 11: Counterfactual – Average wholesale market prices (£/MWh)

	2023	2028	2034
January	169	124	153
February	128	82	78
March	112	82	77
April	88	78	72
May	76	77	75
June	70	62	52
July	68	72	66
August	74	76	72
September	80	83	81
October	70	56	49
November	117	109	104
December	127	105	96

Table 12: Curtailments – Average wholesale market prices (£/MWh)

	2023	2028	2034
January	169	125	153
February	128	83	77
March	112	82	77
April	89	79	72
May	76	78	76
June	70	63	53
July	68	72	67
August	75	76	74
September	80	84	81
October	70	56	49
November	118	109	104
December	128	105	96

Table 13: Best-View – Emissions avoided in Mt

Year	20% Best View	40% Best View	60% Best View	80% Best View	Best View	120% Best View	140% Best View	160% Best View	180% Best View
2023	0.05	0.09	0.14	0.19	0.24	0.3	0.35	0.39	0.44
2024	0.04	0.08	0.13	0.18	0.22	0.28	0.33	0.36	0.41
2025	0.04	0.07	0.13	0.17	0.21	0.26	0.3	0.34	0.38
2026	0.03	0.07	0.12	0.16	0.2	0.24	0.28	0.31	0.36
2027	0.03	0.06	0.12	0.15	0.19	0.22	0.25	0.29	0.33
2028	0.03	0.06	0.12	0.14	0.18	0.2	0.23	0.27	0.31
2029	0.03	0.05	0.11	0.13	0.16	0.18	0.21	0.24	0.28
2030	0.03	0.05	0.1	0.12	0.14	0.17	0.19	0.22	0.25
2031	0.03	0.05	0.09	0.11	0.13	0.15	0.17	0.2	0.22
2032	0.02	0.04	0.08	0.09	0.11	0.13	0.15	0.18	0.19
2033	0.02	0.04	0.07	0.08	0.1	0.11	0.13	0.15	0.17
2034	0.02	0.04	0.06	0.07	0.08	0.1	0.12	0.13	0.14
Total	0.37	0.69	1.24	1.59	1.95	2.35	2.71	3.08	3.48

Table 14: Best-View – System Cost Benefit (wholesale markets) in £m

Year	20% Best View	40% Best View	60% Best View	80% Best View	Best View	120% Best View	140% Best View	160% Best View	180% Best View
2023	12	29	56	83	105	124	131	156	175
2024	18	39	63	92	117	138	150	176	200
2025	25	48	71	101	130	152	169	197	224
2026	31	57	78	110	143	167	187	218	248
2027	37	66	86	119	156	181	206	239	273
2028	44	76	93	128	169	195	224	259	297
2029	44	79	101	134	174	196	233	272	311
2030	45	83	109	140	178	197	242	285	325
2031	46	86	117	146	183	198	251	298	340
2032	47	89	125	152	187	199	260	312	354
2033	47	93	132	158	192	200	268	325	368
2034	48	96	140	164	197	201	277	338	382
Total	445	840	1171	1528	1931	2148	2598	3075	3497

Table 15: Best-View – System carbon Benefit (emissions) in £m

Year	20% Best View	40% Best View	60% Best View	80% Best View	Best View	120% Best View	140% Best View	160% Best View	180% Best View
2023	4	7	11	16	19	24	28	31	36
2024	4	7	12	16	19	24	28	31	35
2025	3	7	12	16	20	24	27	31	35
2026	3	7	12	16	20	24	27	31	35
2027	3	7	13	16	20	23	26	31	35
2028	3	6	13	16	20	23	26	30	35
2029	3	6	12	15	19	22	25	29	33
2030	3	6	12	14	18	21	24	27	31
2031	3	6	11	14	17	20	23	26	29
2032	4	6	10	13	15	18	21	25	27
2033	4	6	10	12	14	17	20	23	25
2034	4	6	9	12	13	16	19	22	23
Total	41	76	137	174	213	256	296	337	378

Table 16: Best-View – System Total Benefit (emissions + wholesale markets) in £m

Year	20% Best View	40% Best View	60% Best View	80% Best View	Best View	120% Best View	140% Best View	160% Best View	180% Best View
2023	16	36	67	98	124	148	160	187	211
2024	22	45	75	107	137	162	178	208	235
2025	28	55	83	116	150	176	196	228	259
2026	34	64	91	126	163	190	214	249	284
2027	41	73	99	135	176	204	232	269	308
2028	47	82	106	144	189	218	250	290	332
2029	48	85	113	149	192	218	258	301	344
2030	48	89	121	155	196	218	266	313	356
2031	49	92	128	160	199	218	273	324	368
2032	50	95	135	165	203	217	281	336	381
2033	51	98	142	171	206	217	289	348	393
2034	52	102	149	176	210	217	296	359	405
Total	486	917	1308	1702	2144	2405	2893	3412	3875

9.2 Results on the Voltage sensitivity analysis

Table 17: Best-View – Curtailments by voltage level in TWh

Year	LV	HV	EHV	132kV	Distribution
2023	0.23	0.02	0.03	0.81	1.08
2024	0.28	0.01	0.05	0.83	1.18
2025	0.34	0.01	0.07	0.86	1.28
2026	0.4	0.01	0.09	0.88	1.38
2027	0.46	0.00	0.11	0.91	1.48
2028	0.52	0.00	0.13	0.94	1.58
2029	0.69	0.01	0.14	0.88	1.73
2030	0.87	0.02	0.16	0.83	1.88
2031	1.05	0.03	0.17	0.77	2.03
2032	1.23	0.05	0.19	0.72	2.18
2033	1.41	0.06	0.20	0.66	2.33
2034	1.58	0.07	0.22	0.61	2.48
Total	9.06	0.29	1.56	9.70	20.61

Table 18: Best-View – Emissions avoided by voltage level in Mt

Year	LV	HV	EHV	132kV	Distribution
2023	0.03	0.00	0.00	0.21	0.24
2024	0.04	0.00	0.00	0.19	0.22
2025	0.04	0.00	0.00	0.17	0.21
2026	0.05	0.00	0.01	0.15	0.20
2027	0.05	0.00	0.01	0.13	0.19
2028	0.06	0.00	0.01	0.11	0.18
2029	0.05	0.00	0.01	0.10	0.16
2030	0.05	0.00	0.01	0.08	0.14
2031	0.05	0.00	0.01	0.07	0.13
2032	0.04	0.00	0.01	0.06	0.11
2033	0.04	0.00	0.01	0.05	0.1
2034	0.04	0.00	0.01	0.04	0.08
Total	0.53	0.00	0.08	1.34	1.95

Table 19: Best-View – System cost benefit (wholesale markets) by voltage level in £m

Year	LV	HV	EHV	132kV	Distribution
2023	10	0	8	86	105
2024	19	0	12	87	117
2025	26	0	16	88	130
2026	34	0	19	90	143
2027	41	0	23	93	156
2028	48	0	26	95	169
2029	58	0	25	91	174
2030	70	0	22	85	178
2031	84	0	20	79	183
2032	98	0	17	73	187
2033	114	0	14	65	192
2034	131	0	10	55	197
Total	732	0	212	987	1931

Table 20: Best-View – System carbon benefit (emissions) by voltage level in £m

Year	LV	HV	EHV	132kV	Distribution
2023	2	0	0	17	19
2024	3	0	0	16	19
2025	4	0	0	15	20
2026	5	0	1	14	20
2027	6	0	1	13	20
2028	7	0	1	12	20
2029	7	0	1	11	19
2030	6	0	1	10	18
2031	6	0	1	9	17
2032	6	0	1	8	15
2033	6	0	1	7	14
2034	6	0	1	6	13
Total	65	0	11	138	213

Table 21: Best-View – System total benefit by voltage level in £m

Year	LV	HV	EHV	132kV	Distribution
2023	13	0	8	103	124
2024	22	0	12	103	137
2025	30	0	16	103	150
2026	39	0	20	104	163
2027	46	0	24	106	176
2028	54	0	28	107	189
2029	65	0	26	102	192
2030	77	0	24	96	196
2031	90	0	21	88	199
2032	104	0	18	81	203
2033	119	0	15	72	206
2034	136	0	12	62	209
Total	795	0	224	1125	2144

Table 22: Monthly total system benefit by voltage level

	2023				2028				2034			
	LV	**HV**	**EHV**	**132kV**	**LV**	**HV**	**EHV**	**132kV**	**LV**	**HV**	**EHV**	**132kV**
January	2.20	0.00	1.33	17.50	5.82	0.00	2.99	11.56	7.92	0.00	0.68	3.58
February	0.77	0.00	0.47	6.14	2.69	0.00	1.38	5.34	7.86	0.00	0.68	3.55
March	1.24	0.00	0.75	9.85	7.16	0.00	3.67	14.22	15.90	0.00	1.37	7.18
April	0.73	0.00	0.44	5.78	7.73	0.00	3.97	15.35	10.67	0.00	0.92	4.82
May	0.53	0.00	0.32	4.20	5.05	0.00	2.59	10.03	8.20	0.00	0.70	3.70
June	1.29	0.00	0.78	10.24	12.30	0.00	6.31	24.42	19.31	0.00	1.66	8.72
July	0.59	0.00	0.36	4.67	2.20	0.00	1.13	4.37	14.98	0.00	1.29	6.77
August	1.11	0.00	0.67	8.84	1.15	0.00	0.59	2.28	40.09	0.00	3.45	18.10
September	0.43	0.00	0.26	3.38	1.94	0.00	0.99	3.85	2.36	0.00	0.20	1.06
October	0.94	0.00	0.57	7.47	1.89	0.00	0.97	3.76	1.18	0.00	0.10	0.53
November	1.94	0.00	1.18	15.44	3.78	0.00	1.94	7.50	5.86	0.00	0.50	2.65
December	1.18	0.00	0.72	9.40	2.33	0.00	1.20	4.63	1.91	0.00	0.16	0.86