LCPDelta

DER and CER visibility and control

Quantitative Benefits Assessment

JUNE 2025

Contents

Executive summary

This report quantifies some of the key benefits of increased visibility and control of DER and CER assets

Definitions of DER and CER

Distributed Energy Resources (DER)

DER are business-owned small-scale power generation, storage and demand devices connected to the distribution grid, located close to where energy is consumed.

- Assets considered in this analysis include wind, solar and batteries connected to the distribution network without existing visibility and control, as well as large scale demand such as fleet EV charging. We do not include other large-scale demand.
- Analysis by NESO suggests 37,500 DERs by 2035. (2,500 new DERs each year with 12,500 retrospective DERs)[1]

Consumer Energy Resources (CER)

CER are (residential) consumer-owned assets, that are connected to the distribution grid at the consumer premises.

- This analysis includes rooftop solar, EVs and batteries. We do not include heat pumps and white goods.
- Analysis by NESO suggests >40m Solar panels, batteries and EVs by 2035 and >60m by 2045[2]

Definitions of visibility and control

Visibility

Visibility is the awareness of assets and their expected input and output. This leads to better understanding of forecasts and system requirements.

Control (including Control and Access)

Control is the ability to provide dispatch instructions that change the input and output of the units, either directly (control) or through an intermediary (access).

[1] Based on annual Distribution Network Operator (DNO) submissions for each DNO from 2020 to estimate future numbers.
[2] Based on Office for National Statistics: 32.5m cars in June 2023; 26.4m dwellings in England and Wales in 2021;

Greater visibility and control of DER and CER could substantially reduce system and consumer costs, primarily by reducing imbalances

DER and CER visibility and control would lead to substantial quantifiable benefits by reducing the costs of managing the power system

- Greater visibility and control reduces energy imbalances, provides greater competition for energy actions and thermal constraint actions and could increase thermal limits on transmission boundaries.

These benefits could reduce system costs[1] by £222m-£243m pa and consumer costs by £270m-£292m pa (average 2025-35, real 2023)

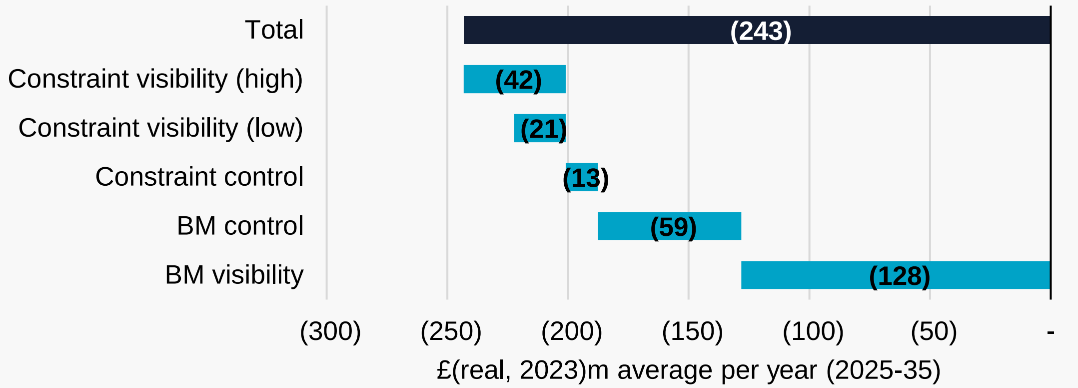
- The main sources of benefits are from the reduction of energy imbalance volumes through improved forecasting of renewable generation, and control to improve competition in energy balancing.
- Note that in our analysis, we have modelled independent and sequential actions to manage constraints and energy imbalances whereas, in practice, actions may achieve both. In that respect, this analysis overestimates the benefit.

There are additional benefits which should be explored further, in more detail than covered in the scope of this project

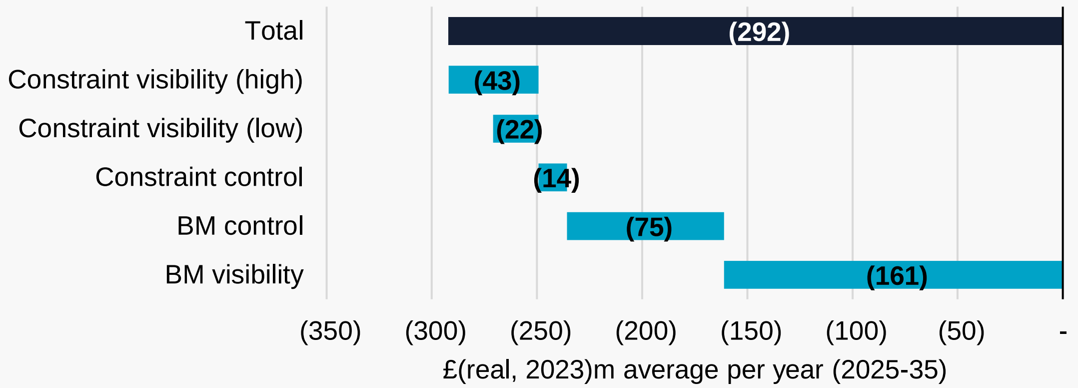
- We estimated in this analysis that there is an additional £7m pa (real 2023) benefit from reduced reserve and response service requirements. However, this analysis could be expanded.
- Benefits for distribution network operation and constraints were out of scope for this analysis.
- We did not quantify benefits for system security and resilience (e.g. Black Start) as they were out of scope for this analysis.

Given the scale of the quantified benefits and the potential for additional cost reductions, future work should be considered to evaluate the full benefits case.

System cost changes



Consumer cost changes



[1] Definitions of system and consumer cost metrics are provided in the methodology. Note that these are interrelated concepts, and the benefits are not additive as explained in the methodology.

Background from qualitative assessment

The qualitative analysis of use cases has identified categories of benefits to quantify

Improved forecasting of imbalances and constraints

Competition within balancing and ancillary services

Network reinforcement or constraint management costs avoided

System security and resilience

Scenarios for quantitative analysis

Counterfactual

- The qualitative analysis has produced a view of currently planned arrangements
- However, this is difficult to precisely replicate
- **We consider a counterfactual with no visibility and control to quantify the total potential benefits**

Factual

- **Consider full visibility and a high level of control across key forms of DER/CER.**
- Within this report, we disaggregate the benefits of visibility and control across these benefits and highlight where future work is required.

The earlier assessment of use cases identified several priority use case groups which can be mapped to quantifiable benefits

<table>
<tr><th>#</th><th>Priority use case group</th><th>Improved forecasting of imbalances and constraints</th><th>Competition within balancing and ancillary services</th><th>Network reinforcement costs avoided</th><th>System security and resilience</th></tr>
<tr><td>1</td><td>Monitoring DER/CERs to manage system operation and resilience</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>9</td><td>Improve data modelling interoperability e.g. between short/long-term forecasts or between ESO and DNOs</td><td colspan="2">Enables other use cases providing this benefit</td><td></td><td></td></tr>
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<tr><td>13</td><td>Improve accuracy of network reconfiguration – e.g. restoration following faults, network maintenance and fault management</td><td></td><td></td><td></td><td></td></tr>
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Methodology and assumptions

Background market scenario

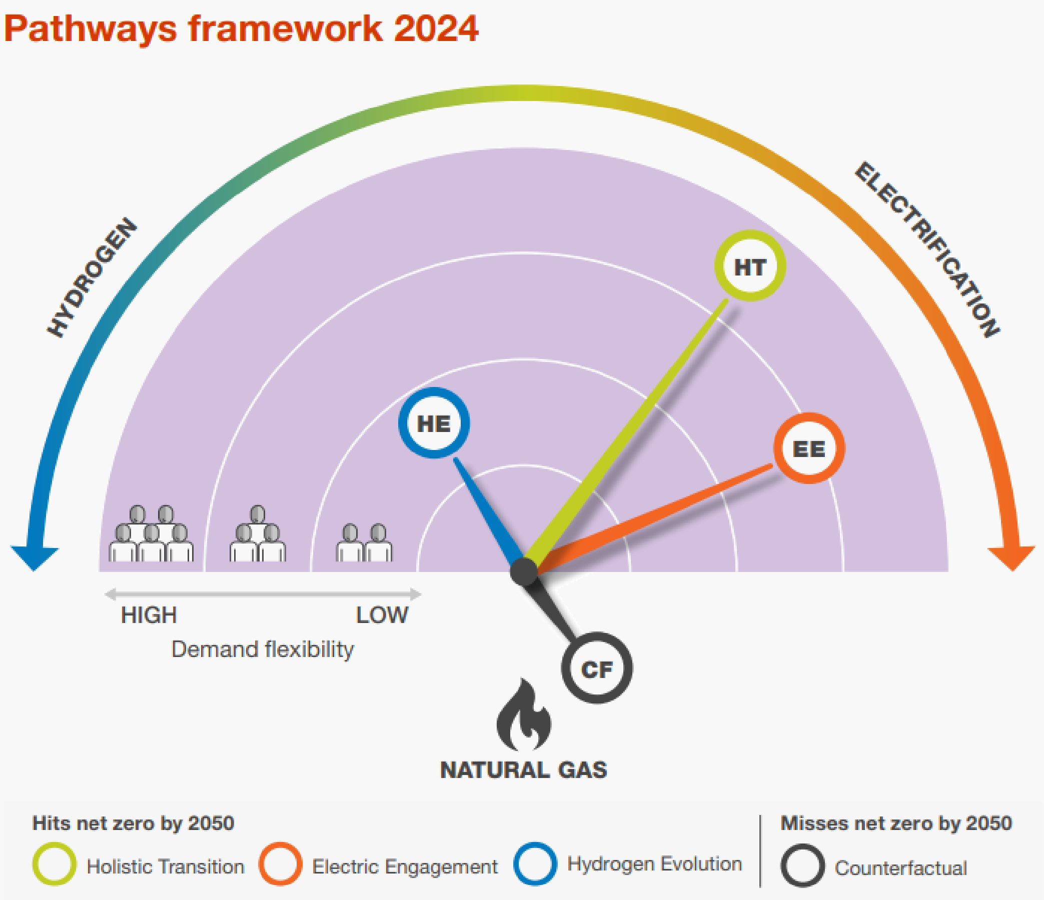
The market background we have selected is the Holistic Transition pathway from FES 2024

Key assumptions we use that feed into our analysis include:

- Capacity mix across technologies
- Peak and annual demand
- Commodity prices
- Detailed data on distribution level assets including renewables, storage, thermal and transport flexibility.

The reason for selecting Holistic Transition is that it **reflects a balanced pathway between electrification and hydrogen**. Selecting either of the other (Net Zero) pathways could bias the results of the analysis.

Note that while we have aligned the overall capacity and demand mix to NESO's Holistic Transition, we have applied our view of the locations for future generation capacity because this is not published in FES.



We evaluate DER/CER benefits by quantifying the impact on volumes and costs for the following services outside of wholesale markets

Wholesale market dispatch

For demand and each generation asset in GB, including DER/CER, the forecasted position against which the market dispatches.

This accounts for locations of generation, renewable availability and optimisation of flexibility against price signals e.g. batteries.

- Wholesale market dispatch is not the same as final dispatch because of uncertainty in the supply/demand balance.
- Variability in renewables and demand drives energy imbalances and costs of managing these imbalance in the balancing mechanism.
- Improved DER/CER visibility would reduce uncertainty of renewable generation and reduce the need for some system services.
- Greater control of DER/CER would increase competition to reduce costs.

We will quantify the benefits of DER/CER visibility and control on the following services outside of wholesale:

Imbalance volumes and BM actions

Generation and demand are not as expected, leading to redispatch through the balancing mechanism.

For example, renewable generation may be higher than expected, resulting in generation being turned down or demand turned up.

Transmission constraint management

Network constraints affect the ability of generation to reach demand.

As with imbalance volumes, actions are taken to resolve supply and demand imbalances on each side of constraints.

Reserve and response services

Some assets are procured at day-ahead stage to provide reserve and response services should they be required.

Benefits are typically assessed by evaluating consumer and system cost changes, which represent the change in consumer bills and underlying resource costs respectively

Consumer costs

The costs paid by consumers for their energy and for other services provided by producers and networks

Components

- Wholesale costs
- Policy costs
- Network costs
- Constraint costs
- Balancing costs

Further detail on consumer cost components can be found on page 28

System costs

The underlying costs of building, maintaining and operating infrastructure to provide energy and services

Components

- Generation costs
- Carbon costs
- CapEx costs
- Fixed OpEx costs
- Network costs
- Interconnector costs

Further detail on system cost components can be found on page 29

Note: These two cost definitions are interrelated and are not additive. Reducing the costs of running the system leads to benefits which are shared between consumers and producers. For example, consumers benefits may be smaller than system benefits when producers capture some of the reduced costs of providing services. Equally, consumers may save more than the system saving if profitability of producers decreases.

We have estimated the volume of generation and storage assets for which visibility and control could be improved

FES provides data on total Dx-connected capacity by technology

- We have focussed on renewables, BESS and thermal.

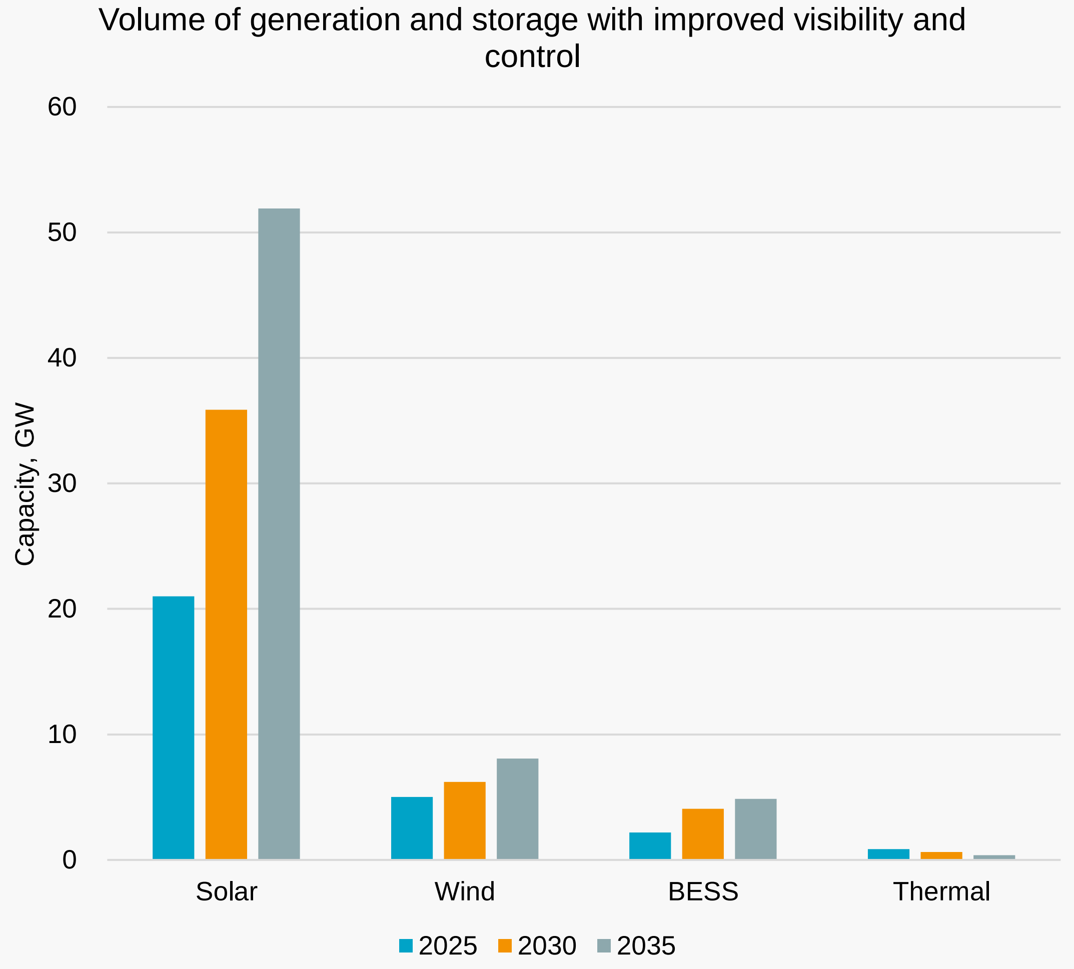
We used BMU data to identify the proportions without visibility and control[1] currently

- Those assets which were distribution connected but not BMUs were assumed to be those affected by this programme.
- This was calculated as a percentage of 2025 Dx-connected capacity.

Combining the two produces an estimate of affected capacities

- Assuming that the percentage without visibility and control remains fixed, we apply this percentage to future capacities from FES.

As expected, most of the volumes with increased visibility and control would be solar PV. Wind will have a large impact on variability and imbalances due to higher load factors while BESS control will reduce costs of balancing actions.



[1] Not visible and controllable to NESO, noting that some of these assets may be visible or controllable to DSOs.

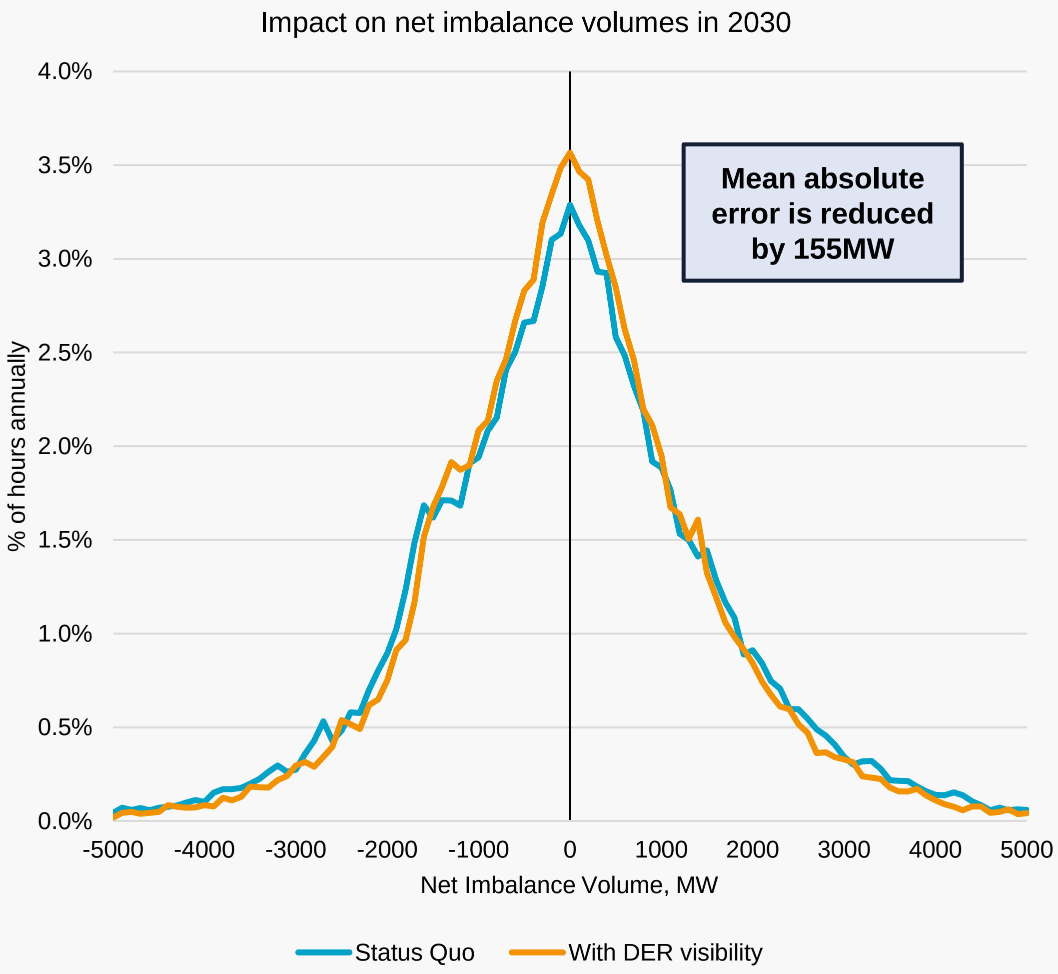
Quantitative benefits assessment

We consider each of the following impacts in turn, showing the additional benefit of each given the previous benefits have been realised.

- **Impact 1:** DER/CER visibility reduces energy imbalances in the BM
- **Impact 2:** DER/CER control reduces cost of resolving energy imbalances
- **Impact 3:** DER/CER control reduces cost of resolving thermal constraints
- **Impact 4:** DER/CER visibility increases thermal boundary limits (“high” sensitivity shown in detail)
- **Impact 5:** DER/CER visibility reduces reserve service costs

Impact 1: DER/CER visibility reduces energy imbalances in the BM

Imbalances based on historic forecast errors, accounting for changes in generation and demand, are reduced by DER/CER visibility



The key drivers of net imbalance volumes in the BM which could be reduced by DER/CER visibility are wind and solar forecast errors.

Currently, these appear as errors in demand forecasts. NESO forecasts the generation of these DER/CER to incorporate into their demand forecast.

Previous analysis on benefits of visibility as part of GC0117 quoted the relative accuracy of wind forecasts for BMU assets (4% mean absolute error) vs non-BMU assets (8% mean absolute error). This was based on analysis of outturn data from 2022. In the absence of similar data for solar, the GC0117[1] report assumed the same 50% improvement in errors.

In this analysis, we make the same assumption – that **improved visibility would reduce the mean absolute error of wind and solar forecasts by 50%**. This is incorporated this into our in-house simulations of imbalance.

We **apply this improvement to the volume of DER/CER assets assumed to have greater improved visibility** because of DER/CER Visibility. When taken together with other causes of imbalance (demand) this reduces the mean absolute error of the forecast by 155MW (12.7%).

The chart on the left shows how this affects the distribution of net imbalance volume in 2030, **reducing the volume of actions taken in the BM to resolve imbalances** and reducing costs for consumers. The total volume of actions is reduced from 10.7TWh to 9.3TWh in 2030.

[1] GC0117 Workgroup report, Annex 19.

Reducing the size of imbalances substantially reduces both the volume of balancing actions and the marginal price, avoiding gas generation

System costs are reduced by £128m pa (average 2025-35, real 2023), primarily through reduced use of unabated gas generation for balancing leading to fuel and carbon savings.

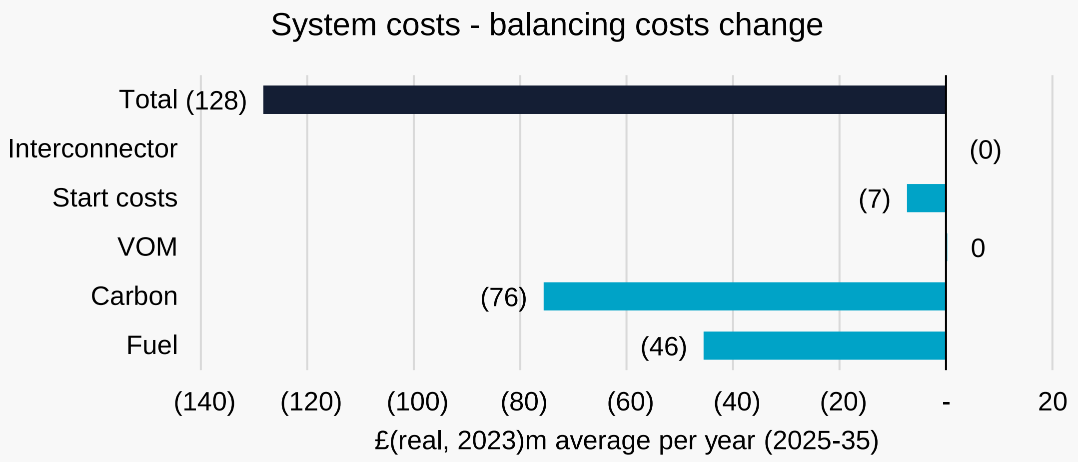
- The chart below shows the change by year in outturn generation by technology due to this change

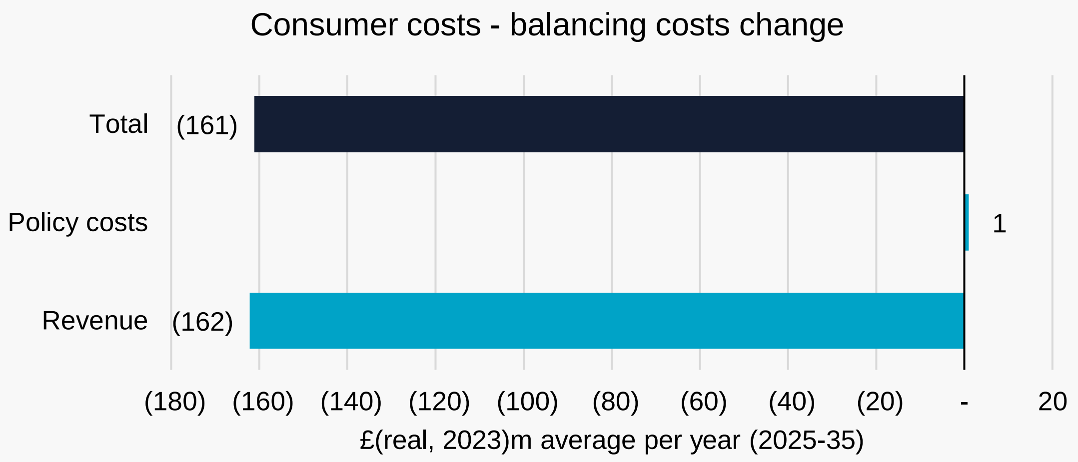
Consumer costs are reduced by £161m pa (average 2025-35, real 2023).

- The impact on consumer costs is larger, because not only are there fewer redispatch actions, but the cashout price in the BM is less extreme which means other actions are less expensive for consumers.

Notes

- Imbalances (as well as constraints in later sections) are typically resolved by flexible sources of generation or storage. These assets can quickly change their dispatch to resolve a mismatch between supply and demand.
- However, these assets are not necessarily the cheapest form of generation. If there were less forecasting error then it would be possible to use lower cost generation such as less flexible, more efficient thermal generation or interconnection. This would mean system costs, such as carbon and fuel costs, were lower.
- This is what the analysis is showing when greater visibility reduces the size of imbalances – the system is able to operate more efficiently and reduce system costs.
- Equally, consumers save money because cheaper forms of generation are utilised – leading to a consumer benefit by reducing generator revenues.





Impact 2: DER/CER control reduces cost of resolving energy imbalances

There are further significant benefits from increased control as battery storage arbitrages imbalances to produce profit and system benefits

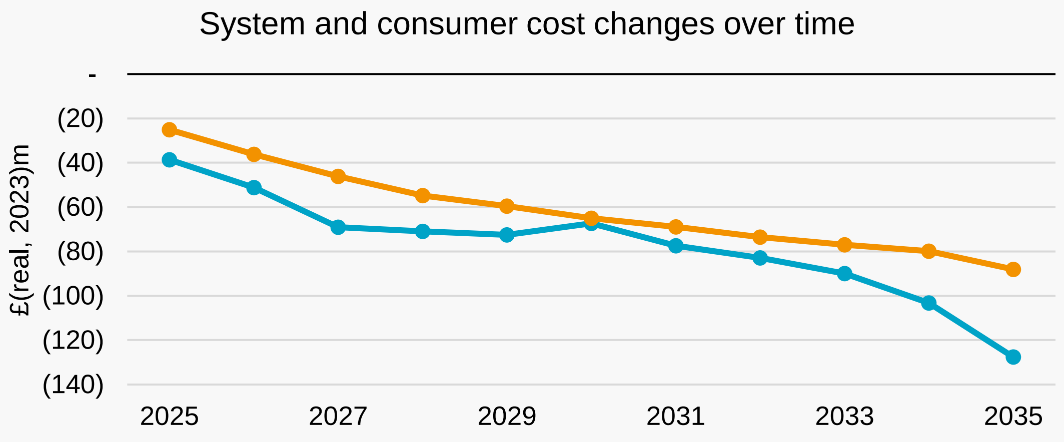
This scenario considers the additional benefit from DER/CER control in energy balancing, on top of the benefit from Impact 1 (increased visibility).

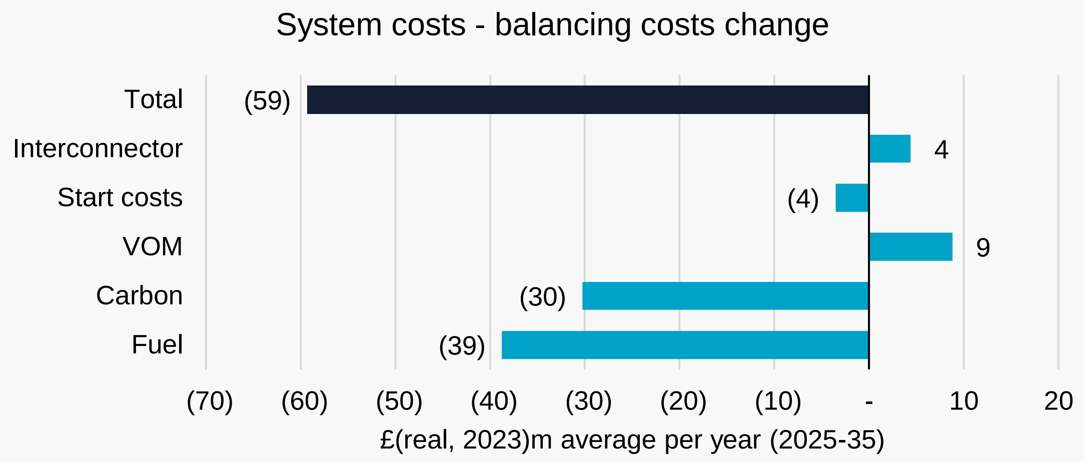
System costs are reduced by £59m pa (average 2025-35, real 2023).

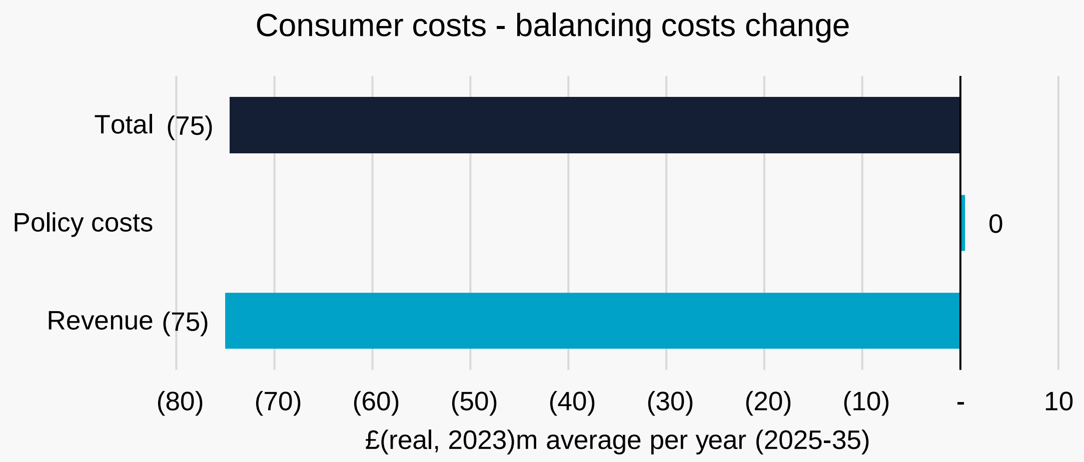
- Battery storage operating in the BM for energy imbalances charges during periods when the system is long and meets system needs when the system is short.
- In this way, it can displace higher cost thermal generation with lower cost generation.

Consumer costs are reduced by £75m pa (NPV 2025-35, real 2023).

- The chart below shows how this consumer and system benefit changes over time. The benefit grows over time as imbalance volumes increase with higher renewable capacity on the system.







Impact 3: DER/CER control reduces cost of resolving thermal constraints

The impact of DER/CER control on constraint costs is smaller than energy balancing due to lower volumes and frequency

This scenario considers the additional benefit from DER/CER control in managing thermal constraints, on top of the benefit from Impacts 1 & 2 (increased visibility and control in energy balancing).

Our modelling considers benefits for thermal constraints over the B2 and B6 boundaries.

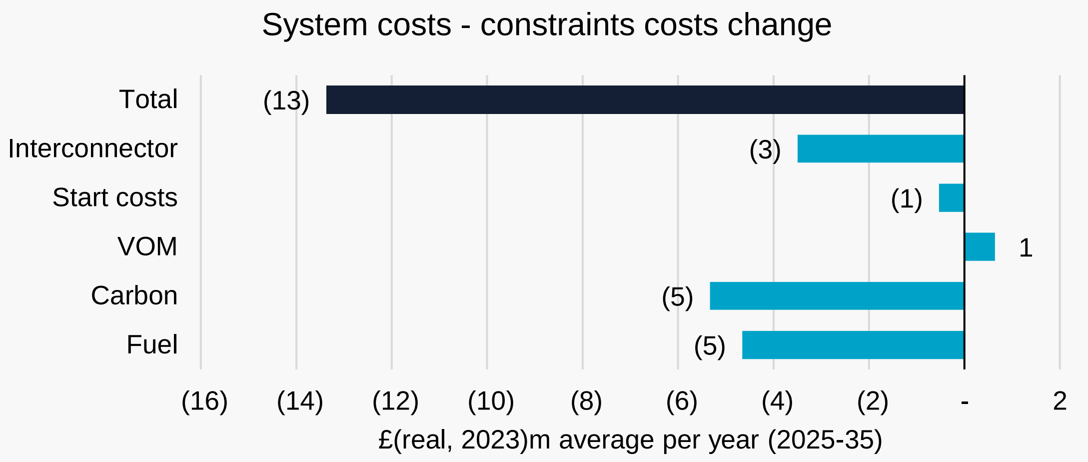
- These are the most heavily constrained boundaries in GB, between North and South Scotland (B2), and Scotland and England (B6).
- Additional benefits could be seen over other boundaries and further analysis should consider all network boundaries.

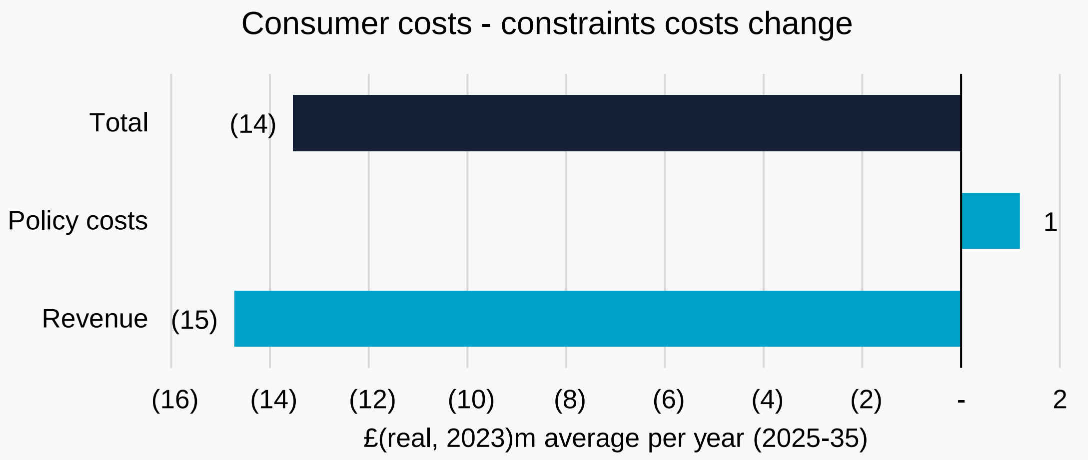
The benefits of DER/CER control with respect to constraint costs are lower than the benefits for energy balancing costs because actions are less frequent.

System costs are reduced by £13m pa (average 2025-35, real 2023).

- Control over DER/CER batteries provides additional competition for locational constraint actions, reducing costs.
- The result is reduced renewable curtailment due to locational constraints

Consumer costs are reduced by £14m pa (average 2025-35, real 2023).





Impact 4: DER/CER visibility increases thermal boundary limits

Uncertainty could also lead to more efficient setting of constraints due to lower risk, which we estimate in our modelling through sensitivity analysis

How might greater visibility improve network constraints?

- The system operator must take actions to level the supply/demand balance on each side of all network constraints.
- It tries to do so at least cost based on forecasts of required network flows before corrections are made.
- Since there are uncertainties around the mix of supply and demand on each side, it is reasonable to assume that some prudence is built into the management of constraints.
- This could mean that constraint limits are set lower.
- While this may exist, based on conversations with NESO it is challenging to quantify precisely.
- We have applied a methodology which explores how improvements in DER/CER visibility could affect network constraints
- We consider sensitivities as there is limited information on the extent of the impact.

Our modelling approach

Approximate the change in uncertainty on boundary flows due to DER/CER visibility

- Study the distribution of boundary flow forecast errors before and after DER/CER visibility improvements.
- That is, the distribution of the difference between expected boundary flow at day-ahead vs outturn boundary flow before constraint management.

Develop sensitivities in which different levels of risk are built into where constraints are set

- We assume that constraints are set with allowance for errors in boundary flows at different risk levels.
- E.g. assume that network constraints allow for 10th or 25th percentile of error, or assume no allowance at all (as is assumed in the analysis so far).

Run sensitivities where boundary capabilities are increased to reflect reduced risk

- We model this improvement by increasing network capability across boundaries in line with the improvement in these risk metrics.

The next slide shows how we calculate this improvement, based on the improvements in forecast uncertainty shown earlier in this report.

By simulating the error on each side of a boundary independently, we can estimate the distribution of boundary flow forecast errors

The distribution of boundary flow forecast errors could depend on the boundary considered. For example, if all renewable generation were concentrated on one side, this may have different implications for the boundary flow errors.

The chart on the right considers a range of hypothetical network boundaries, which split GB into two regions with a given percentage of uncertain generation/demand on each side e.g. in the 20% case, we assume a boundary with 20% of renewable generation on one side, and 80% on the other.

We simulate generation forecast errors on each side of the boundary independently and create a distribution for boundary flow error. From this, we measure percentiles as risk metrics and report how these change with improved visibility.

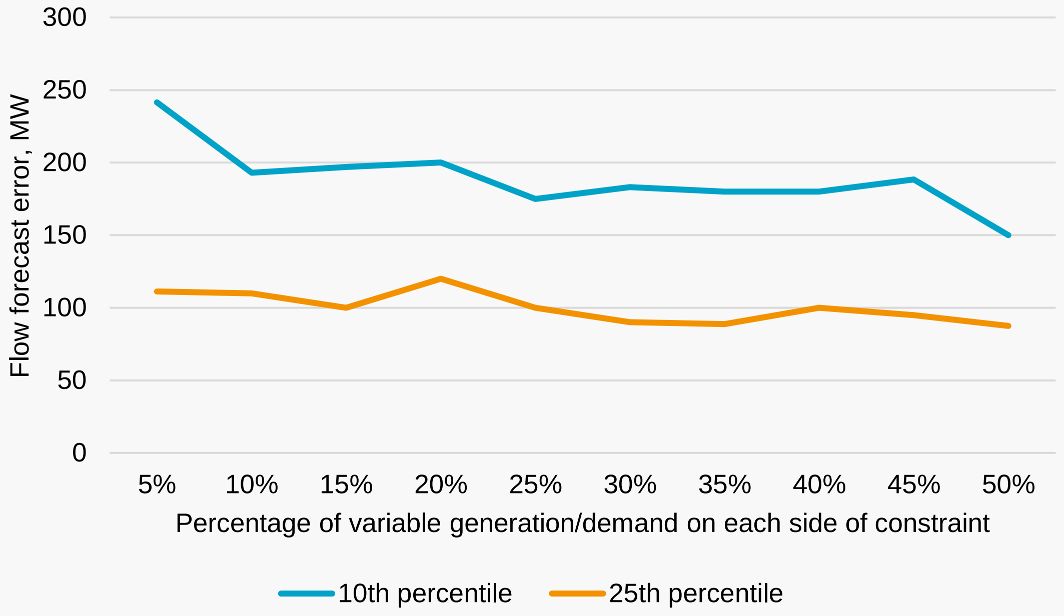
In the example of the 20% boundary in the chart, the 10^{th} percentile of network flow errors is 200MW lower after improvements in DER/CER visibility. The equivalent value for the 25^{th} percentile is lower at 120MW.

We then model sensitivities in which constraint limits on boundaries are increased in line with these reductions in risk.

Limitations of this approach are:

- Errors will not be truly independent either side of a constraint and will in practice depend also on the expected level of flow.
- This analysis looks at the uncertainty of boundary flow across all periods, not just those in which there are constraints (typically high wind). This would need to be on a boundary-specific basis depending on constraint limits.
- We do not know if there is a risk tolerance in constraint limits and how this is set.

Impact of reduced uncertainty on flow forecast error in a sample year



We consider sensitivities **in which DER/CER visibility increases constraint limits in line with the change in the 10^{th} percentile ("high") and the 25^{th} percentile ("low") as well as no impact.**

This change varies by year and is set based on the average over the range of values shown for different types of boundaries in the graph above.

The "High" sensitivity leads to additional savings which reduce over time as network reinforcements alleviate constraints

This scenario considers the sensitivity in which DER/CER visibility increases thermal boundary limits, using the "High" sensitivity.

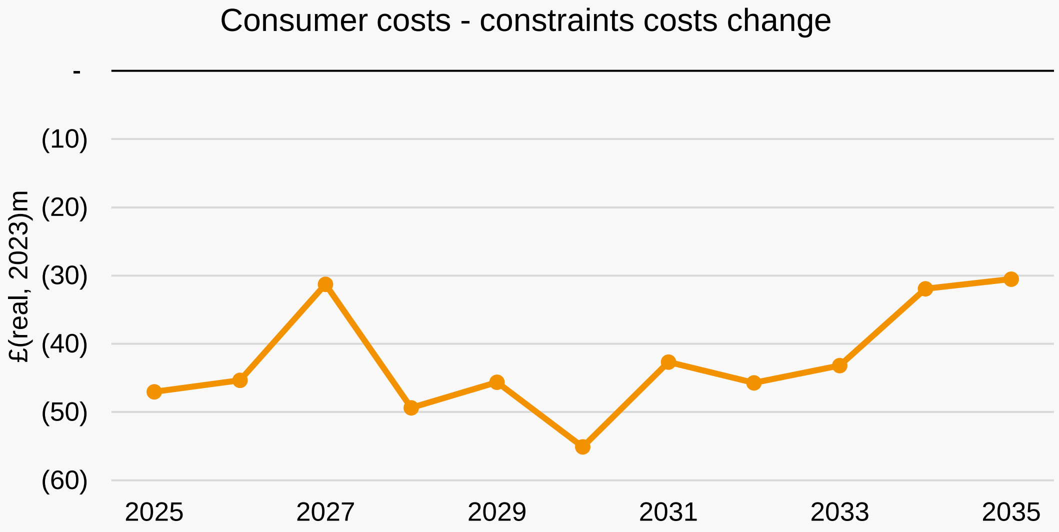
The increase in boundary capacity due to this sensitivity grows from 193MW in 2025 to 355MW in 2035.

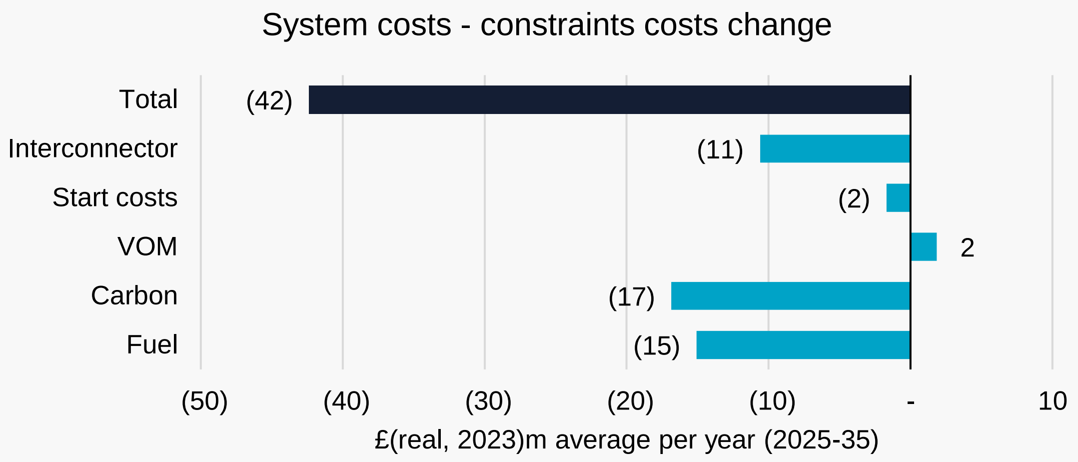
System costs are reduced by £42m pa (average 2025-35, real 2023).

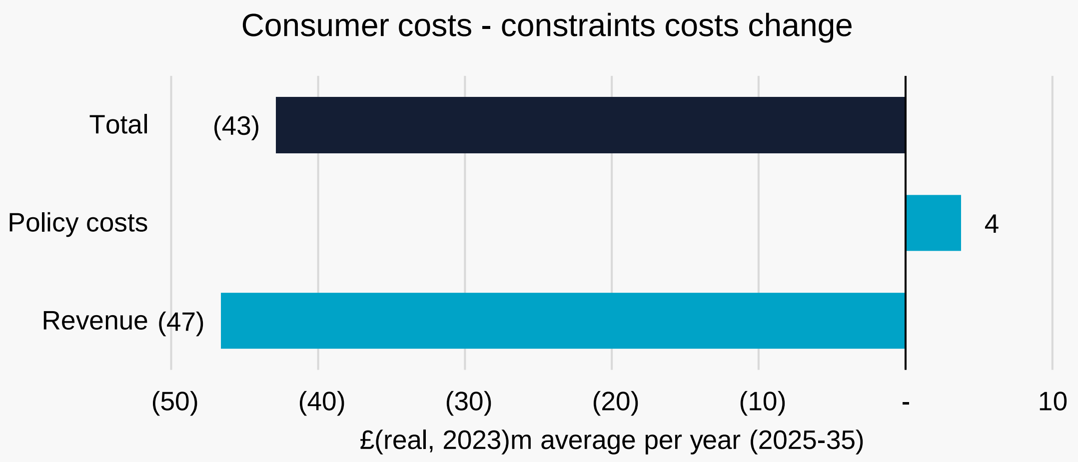
- Higher constraint limits reduce the need for actions to manage thermal constraints, reducing system and consumer costs. It could alternatively lead to reductions in network investment.

Consumer costs are reduced by £43m pa (average 2025-35, real 2023).

- Consumer benefits decrease over time, as shown in the graph below, because network boundaries are reinforced and so the background level of constraint costs decreases.







Impact 5: DER/CER visibility reduces reserve service costs

For reserve products, we focus on only those which are pre-fault and estimate cost-reductions off model based on renewable variability

Greater visibility of DER/CER will reduce the requirement for pre-fault frequency response and reserve products.

We assume that post-fault products will, largely, be determined by the largest in-feed loss which we assume is unchanged.

The chart on the right shows the total spend on pre-fault services over the year April 2024 to March 2025.

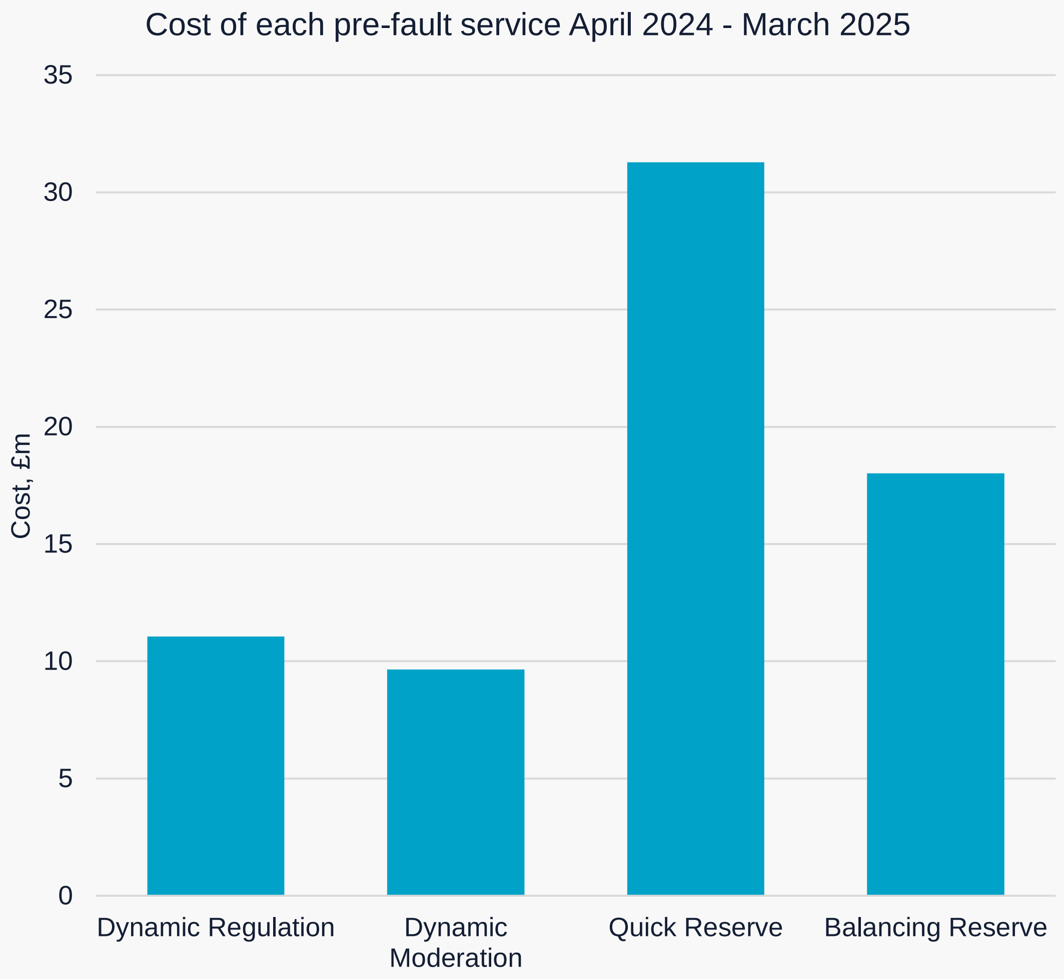
For each of these services, we approximate the impact of greater visibility on the volume of these services required based on uncertainty in renewable generation.

For example, for balancing reserve, we would expect that the Additional Positive Reserve requirement, linked to renewable generation, will be reduced proportionally to the change in mean absolute forecast error. Similarly, for the Dynamic Moderation/Regulation products, their requirement will increase with greater renewable variability.

However, the requirement for these services also depends on demand and inertia requirements, amongst other factors, and a more detailed assessment should clarify with NESO teams how requirements are set.

If we assume that all costs fall in line with mean absolute error in renewable generation, then we can estimate the benefit due to greater DER/CER visibility.

Using this approximation, the consumer **benefit of DER/CER visibility on response and reserve services is approximately £7m pa (real 2023)**.



Annex A: Limitations of this analysis and scope for further work

Benefits beyond the scope of this analysis

We set out additional benefits which we have not quantified in this analysis

Item	Additional benefit	Considerations for future analysis
Distribution level benefits	We have not quantified the impact of DER/CER on costs incurred at the distribution level e.g. reducing the volume and/or cost of DSO services or network investment, and connection costs. This has the potential to be a significant benefit given the level of network investment required to integrate both DER and CER into the distribution network.	• Quantifying these benefits is challenging given a small sample of historic data and challenges with understanding the scale of the future costs. • Such a model would need a comprehensive set of representative network archetypes and reliable data on the level of current network headroom down to LV level, which in our experience is not readily available and/or reliable. • This analysis would also need to consider interactions between the needs of DSOs and TSOs.
System resilience	An additional set of benefits identified by the qualitative work is the reduced cost of restoration services and other related network planning.	• This would require extensive engagement with NESO teams to estimate these benefits and would likely rely on high level approximations rather than detailed modelling.
Constraint cost reductions on other boundaries	This analysis focused on constraint costs over the B2 and B6 boundaries to reduce the complexity of the analysis and assumptions – which was proportionate given limited data on the impact of DER/CER on network constraint limits.	• Extend the analysis to consider all network boundary constraints. • The value of this analysis is contingent on developing a robust assumption for the impact of visibility on constraint limits.
Include other CER assets in scope	This analysis did not consider heat pumps and white goods in the analysis to reduce the complexity of the analysis.	• While we expect these benefits to be less material than the CER we considered (solar, batteries and EVs) their volumes are large enough that the benefit could still be material.

Other limitations and suggestions for future work

We set out key limitations of this analysis and suggestions for future analysis in projects with a larger scope

Item	Limitations of this analysis	Suggestions for future work
Market scenarios	This analysis uses the Holistic Transition pathway from FES 2024 together with network plans from the Beyond 2030 analysis. The results may vary under different scenarios e.g. under a more hydrogen-focused pathway.	• Replicate the analysis for other FES pathways or market scenarios, or with sensitivities for network deployment (e.g. if network is deployed more slowly than expected).
Market reform	The analysis does not consider the impact of ongoing proposals for market reform both within REMA (zonal pricing and CfD reform) and outside (e.g. P462). These reforms could materially affect constraint and balancing costs in the counterfactual, impacting the benefits case for DER/CER visibility and control.	• Repeat this analysis when future market design is more certain.
Constraint limits impacts	Engagement with NESO teams in this project did not find a clear method for quantifying the impact of DER/CER visibility on setting constraint limits more efficiently. We have carried out sensitivities on the potential impact, but the underlying assumptions could be improved.	• Engage further with NESO teams or others to provide a more reliable basis for the impact on constraint limits of DER/CER visibility. • The analysis should also consider the impact of not studying an intact network.
Simultaneous optimisation of constraints and imbalances	Our analysis assumes that energy imbalances and network constraints are managed independently and in sequence. In practice, actions are taken which resolve both simultaneously. This means our analysis may overstate the benefits estimated.	• Consider the impact of co-optimisation to manage network constraints and energy imbalances.
Trade off between network investment and constraint costs	This analysis assumes that all benefits from reduced constraints are realised through reduced constraint costs. In practice, larger savings may be achieved through a mix of reduced network investment and smaller constraint cost savings.	• Optimise this trade off to quantify the (larger) benefits of DER/CER visibility and control.

Annex B: Comparison to GC0117 analysis

The GC0117 analysis quantified a similar set of benefits for a smaller set of assets

The LCP Delta analysis estimates a larger benefit across comparable metrics than the GC0117 analysis.

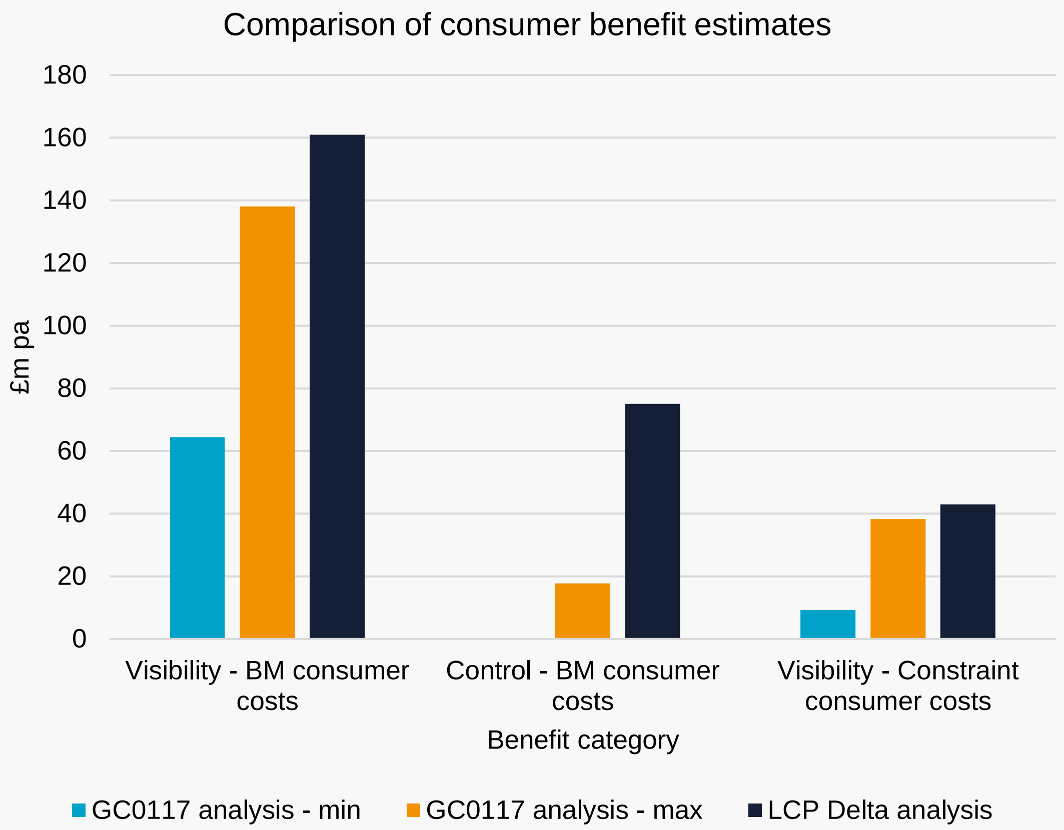
- This is expected as the scope of assets considered is larger. GC0117 only considered DER greater than 10MW.
- Other factors which could influence this include using more recent FES pathways for the LCP Delta analysis, which include more ambitious renewable deployment.
- On the other hand, scenarios from 2022 used for GC0117 will have used less ambitious network plans as well as higher commodity price forecasts, both of which lead to a higher level of consumer costs in the counterfactual.

GC0117 focused on consumer costs impacts while the LCP Delta analysis considered system cost impacts as well.

- In the graph on the right, we have compared the average annual benefit for different benefit categories. For the LCP Delta analysis, we are showing the comparable consumer cost impact.
- GC0117 considers a range of scenarios from FES 2022 – the graph shows the values for the highest (max) and lowest (min) scenarios (excluding Falling Short).

For each of these benefits, the underlying modelling approach is different. However, the overall level of alignment (allowing for the differences above) despite different modelling approaches suggests that the benefits are more robust.

- The GC0117 approaches focus on analysis of historic data. This analysis is more transparent but relies on historic data being applicable to the future market/system. It also leads to some counterintuitive results, such as zero benefit for control in the BM in all but one scenario.
- The LCP Delta approach is more dynamic as it models plant redispatch to meet system needs. Therefore, it capture how benefits change in a future market.



Notes:

- LCP Delta results are £2023 real as an average between 2025 and 2035. GC0117 analysis is an average between 2023 and 2030 and it is unclear if values are nominal or real.
- GC0117 considers a range of scenarios from FES 2022 – the graph shows the values for the highest (max) and lowest (min) scenarios (excluding Falling Short).

Annex C: Detailed description of cost metrics

Summary of consumer cost components

The costs paid by consumers for their energy and for other services provided by producers and networks

Consumer cost components		
Component	**Definition**	**Additional notes**
Wholesale Costs	The cost to consumers of paying generators the wholesale price, calculated as the local wholesale price multiplied by demand in each period.	- Unchanged in this analysis as modelled before balancing and constraint actions which are affected by DER/CER visibility and control.
Policy Support Cost	The payments made to generators as a result of having policy support contracts such as CfDs and ROCs.	- Changes in policy payments due to constraints are not reported in national market, as they as also not included in constraint costs below as per earlier slide.
Network Costs	The proportion of the cost of maintaining, reinforcing and extending the transmission network passed on to consumers.	- Assumed unchanged, as network benefit is related to the reduction in constraint costs which is modelled directly.
Constraint Costs	The payments made to generators as a result of being asked to turn-up or turn-down through the balancing mechanism to manage locational constraints.	- Constraint costs impacts include changes in policy revenue. - We do not consider distribution network constraints in this analysis.
Balancing costs	The payments made to generators as a result of being asked to turn-up or turn-down through the balancing mechanism to resolve energy imbalances due to fluctuations in demand and supply.	- Balancing costs impacts include changes in policy revenue.

Summary of system cost components

The underlying costs of building, maintaining and operating infrastructure to provide energy and services

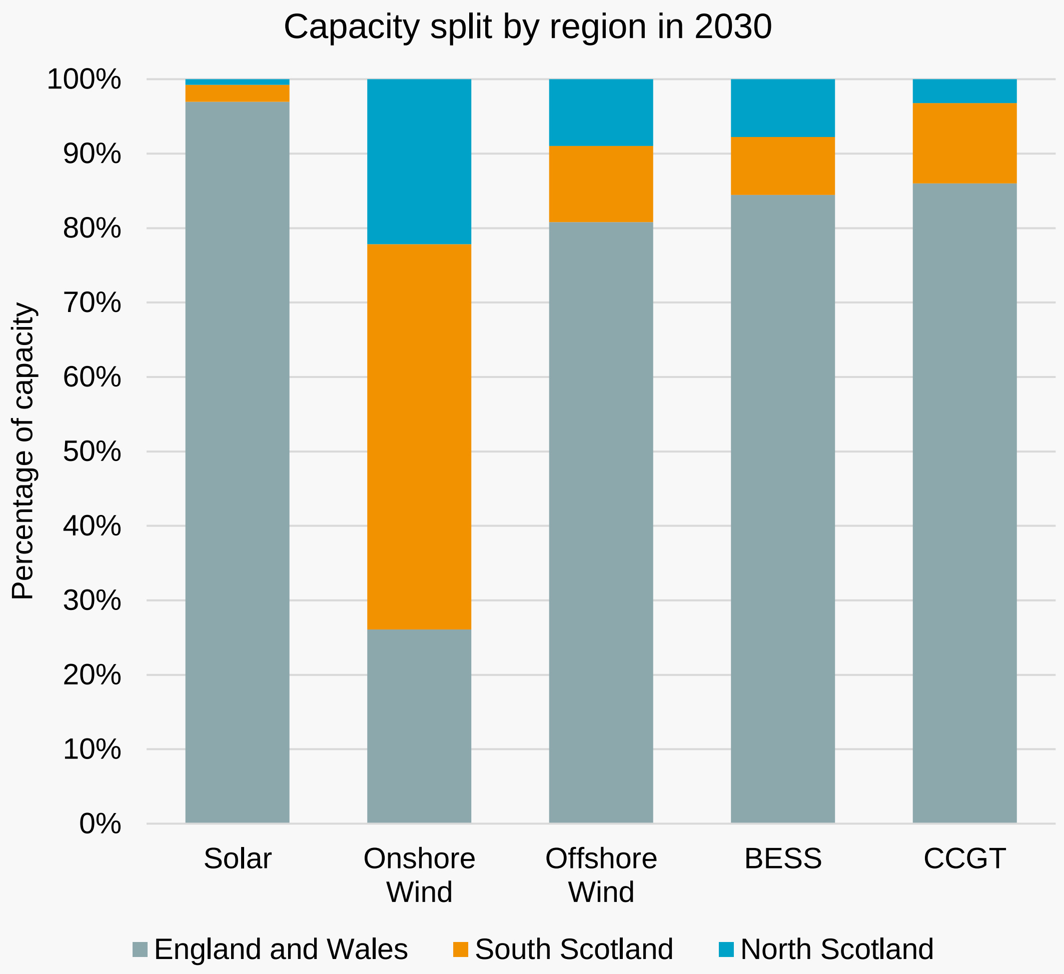
System cost components		
Component	**Definition**	**Additional notes**
Generation Costs	Fuel and variable operating and maintenance (VOM) costs of plants associated with meeting electricity demand hour to hour, i.e. final dispatch after balancing and constraint management	- Includes the net effect of actions taken for energy balancing and thermal constraint management
Carbon Cost	Carbon costs based on carbon emissions priced at social cost of carbon (i.e. DESNZ central appraisal price).	-
Capex Costs	Capital costs include pre-development, construction and infrastructure costs (all £/kW) for building plants, as well as financing costs.	- Assumed unchanged as plant build is unchanged
Fixed Opex Costs	Fixed operating costs of plants, any operating costs that do not vary with output, and represented in £/kW terms.	- Assumed unchanged as plant build is unchanged
Network Costs	Cost of maintaining, reinforcing and extending the transmission network. Distribution network costs are not directly included in our modelling.	- Assumed unchanged, as network benefit is related to reduction in generation costs after thermal constraint actions.
Interconnection Costs	Costs associated with building, maintain and operating interconnectors. Costs are calculated based on a 50:50 split between net imports priced at the domestic market price and at the foreign market price.	-

Annex D: Location assumptions for key technologies

To model constraints, we have used our internal assumptions on the location of capacity by technology

The graph illustrates the split of capacity across regions for each of five key technologies.

- As we have focussed on the B2 and B6 boundaries, we have only split capacity between North Scotland, South Scotland and England & Wales.
- These are the key technologies which affect the level of constraint costs in GB.



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