



Cost Benefit Analysis GC0117

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Aim

Provide a cost benefit analysis of the options: Original Proposal/WACM2 and WACM1 plus the status quo (i.e., no change in definitions). The status quo will be used as a baseline with any changes in cost presented relative to this level.

How?

We have identified three main workstreams each of which considers costs incurred by NGESO to balance the system which could be affected by the outcome of GC0117. These costs are collected by NGESO from the industry participants by the Balancing Services Use of System (BSUoS) charges.

- WP1 Balancing Mechanism price stack
- WP2 Constraint analysis
- WP3 Demand forecast errors

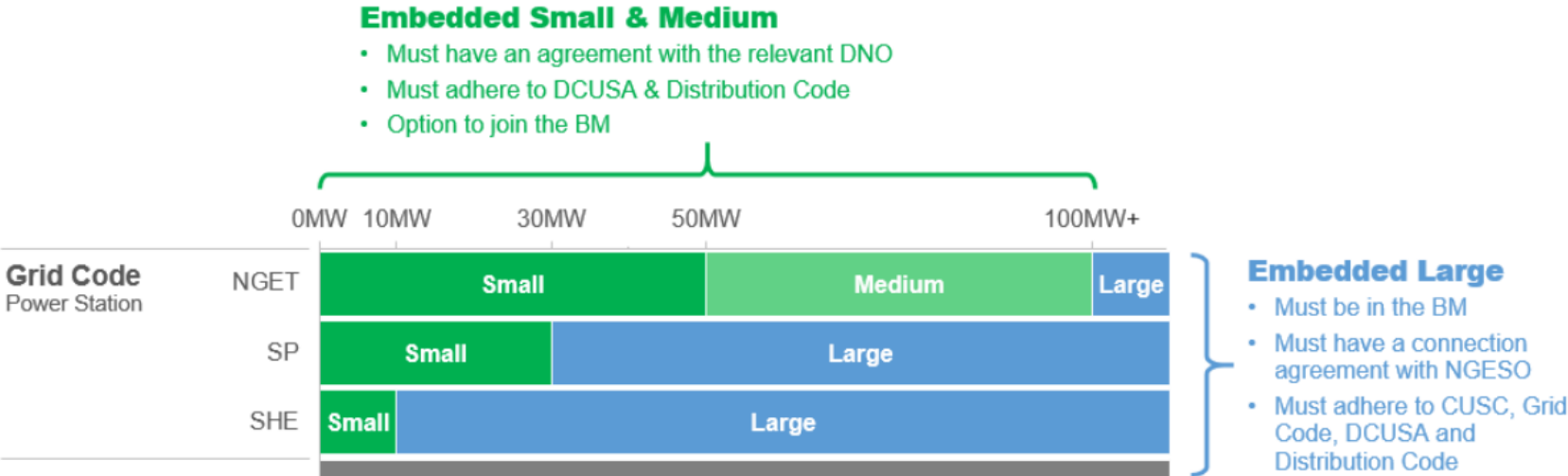
Key Assumptions



Implementation Year Assumptions

- The analysis relies on historic data and relationships around the costs of managing the power system, and so 2022 was used as a benchmark year throughout most of the analysis.
- Due to these data limitations, the impacts are calculated on the basis of this modification being implemented in 2022, even though the earliest implementation year is 2027.
- In each work package we have kept everything the same for future years but allowed generator installation capacities to increase in-line with FES (except for constraint costs in WP2 where a projection is used from NOA7).
- The results for the future years therefore provide a best view of the potential impact, but we acknowledge other factors may also change.

Capacity Assumptions



Original Proposal (OP):

- England & Wales (NGET) – embedded generators between 10-100MW become BMUs
- South Scotland (SP) – embedded generators between 10-30MW become BMUs
- North Scotland (SHE) – N/A as no change

WACM1:

- England & Wales (NGET) – N/A as no change
- South Scotland (SP) – BMU generators between 30-100MW become embedded
- North Scotland (SHE) – BMU generators between 10-100MW become embedded

Capacity Assumptions

The basis for our projected capacity estimates were the forecasts published as part of the 2022 Future Energy Scenarios (FES), which covers four scenarios.

For the Original Proposal, to estimate the proportion of the distributed FES capacities that might be affected, we use the embedded capacity register (published by DNOs). For WACM1, to estimate the proportion of the transmission FES capacities that might be affected, we use the capacities of currently live BMUs.

Generation Category	Proportion of new Capacity affected by GC0117 OP
Battery	85%
Biomass	84%
Fossil_Gas	74%
Non-Pump Hydro	53%
Other	70%
Solar	42%
Wind	65%

Generation Category	Proportion of new Capacity affected by GC0117 WACM1
Battery	0%
Biomass	0%
Fossil_Gas	0%
Non-Pump Hydro	78%
Other	13%
Solar	0%
Wind	20%

Work Package 1: BM



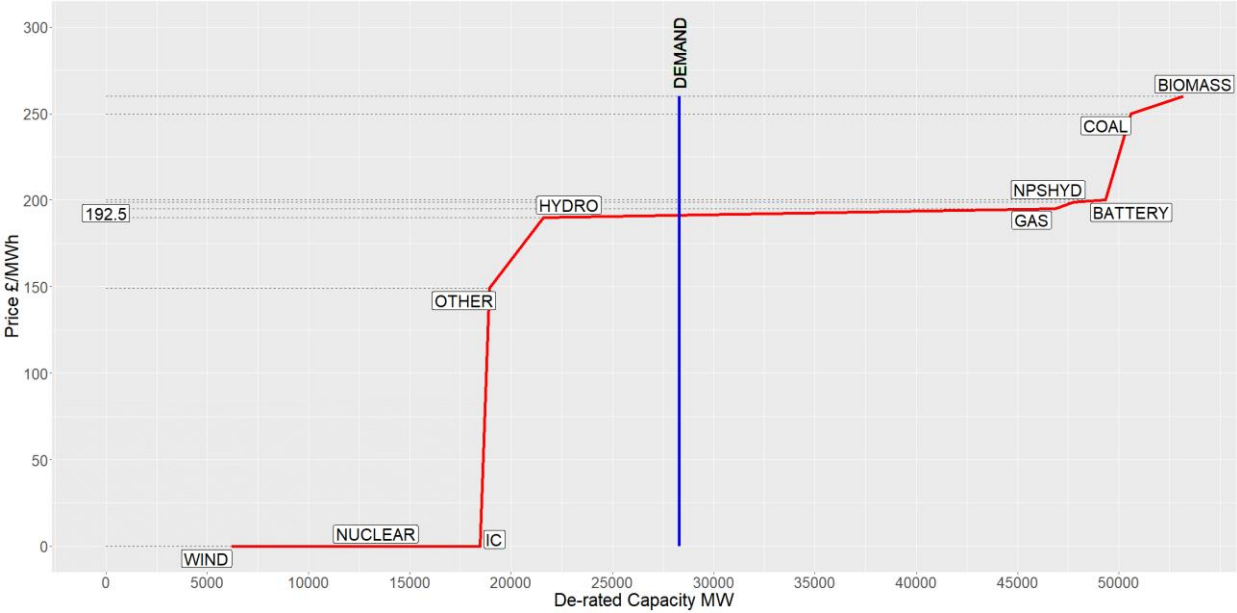
Work Package 1: Overview

BM Pricing:

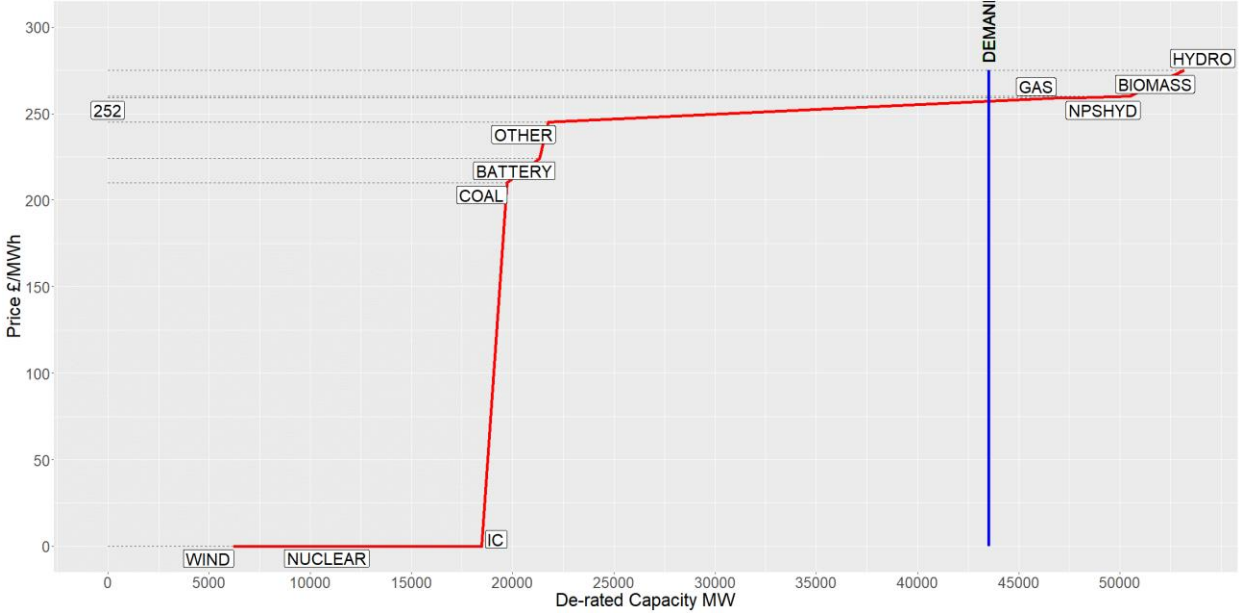
- To estimate the impact on the marginal BM price from new capacity entering the BM of a smaller size than today's arrangements.
- Estimate the impact on balancing costs

Price Stack Creation

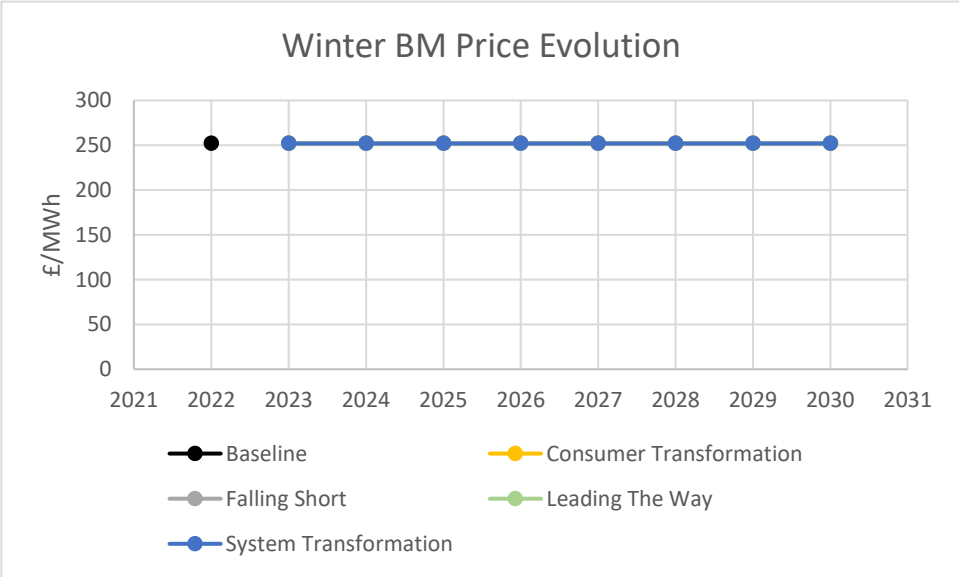
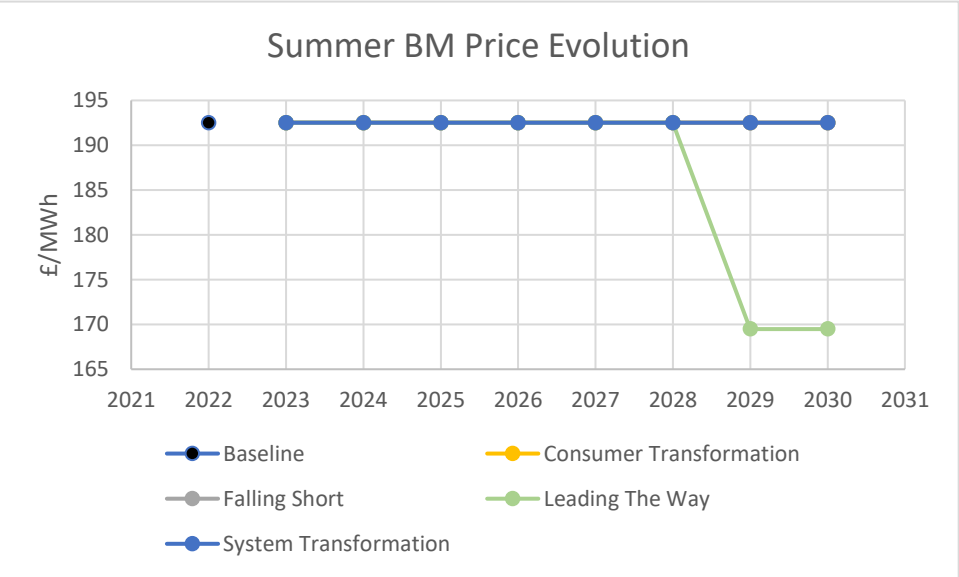
Summer Price Stack
Price (red line)+ Demand (blue line)



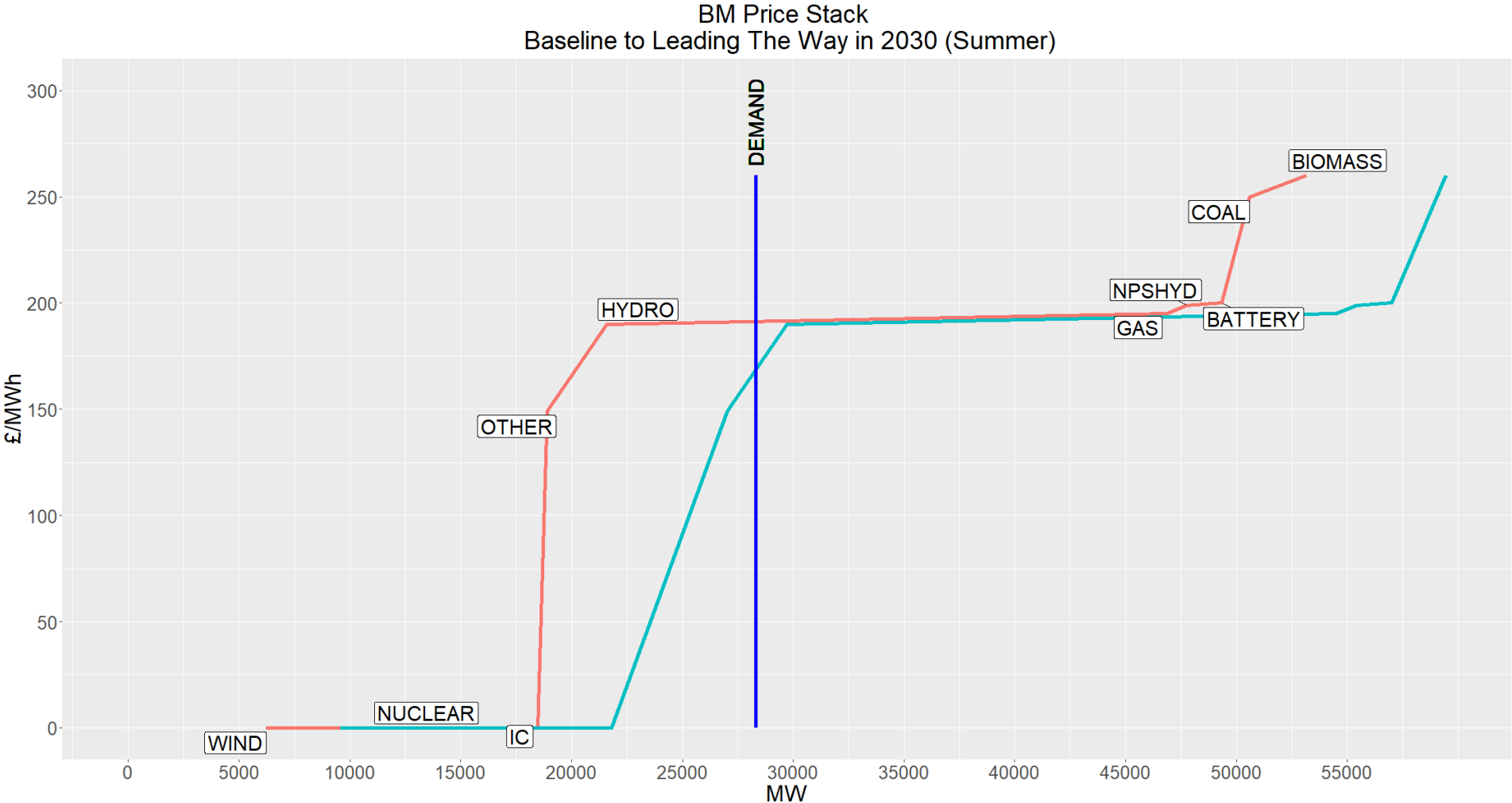
Winter Price Stack
Price (red line)+ Demand (blue line)



Impact on price



Impact on Price



Impact on BM costs

	Impact per Year £m							
	2023	2024	2025	2026	2027	2028	2029	2030
Consumer Transformation	£0	£0	£0	£0	£0	£0	£0	£0
Falling Short	£0	£0	£0	£0	£0	£0	£0	£0
Leading The Way	£0	£0	£0	£0	£0	£0	£71	£71
System Transformation	£0	£0	£0	£0	£0	£0	£0	£0

Work Package 2: Constraints



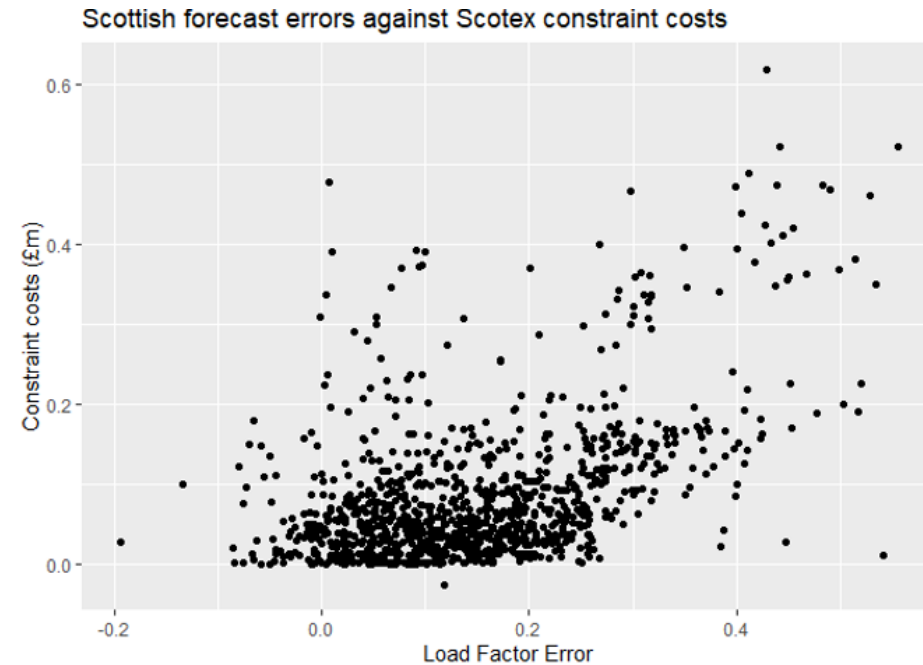
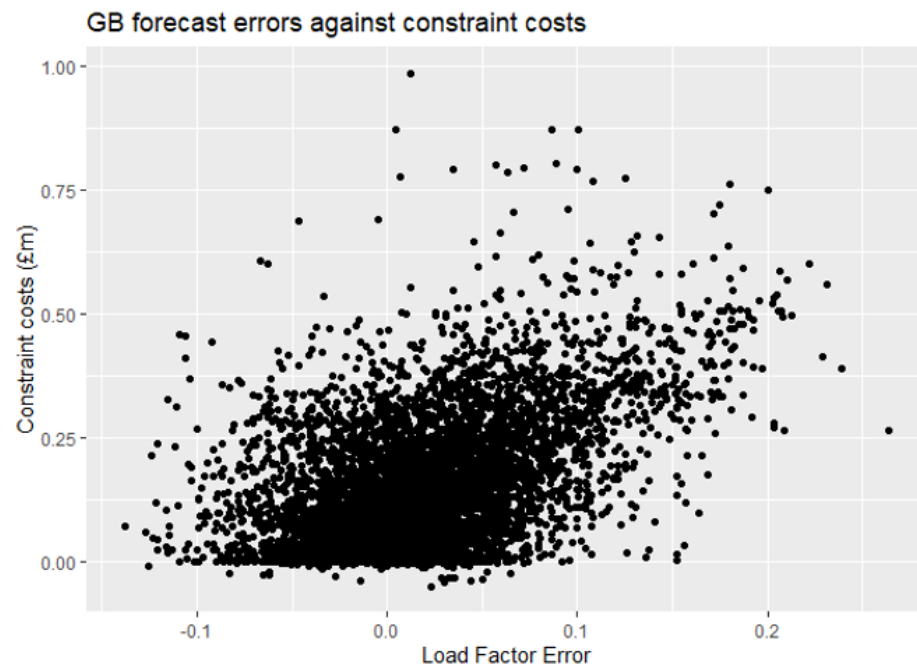
Work Package 2: Overview

To inform the decision-making regarding flows across constraint boundaries an understanding of the generation and demand behind the constraint is required. Each option (OP and WACM1) will result in a different level of visibility for NGESO.

Improved visibility of metering should enable better forecasting, which is estimated as part of the 'Demand Forecast Errors' workstream of this cost benefit analysis. This work package is focussed on translating a forecasting performance change into a constraint cost impact.

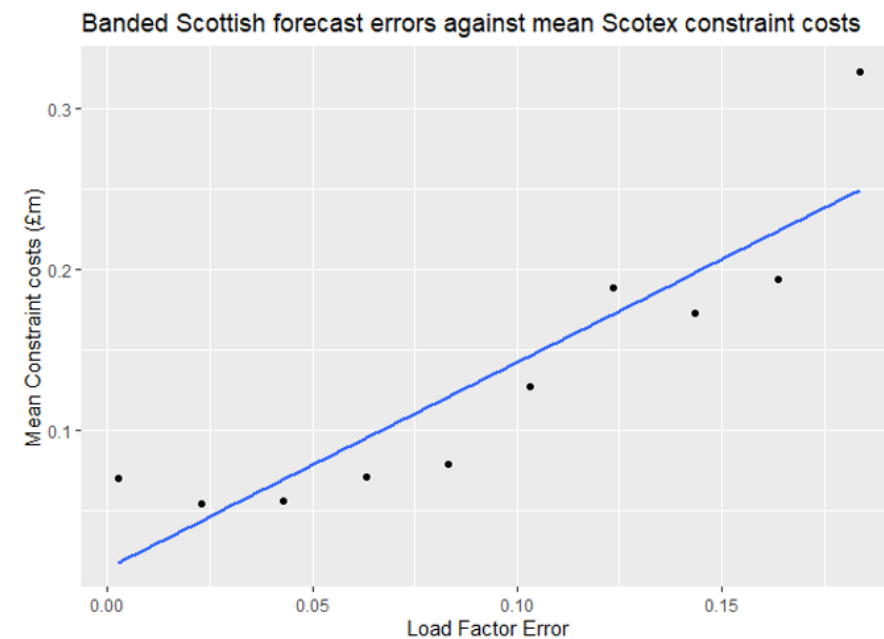
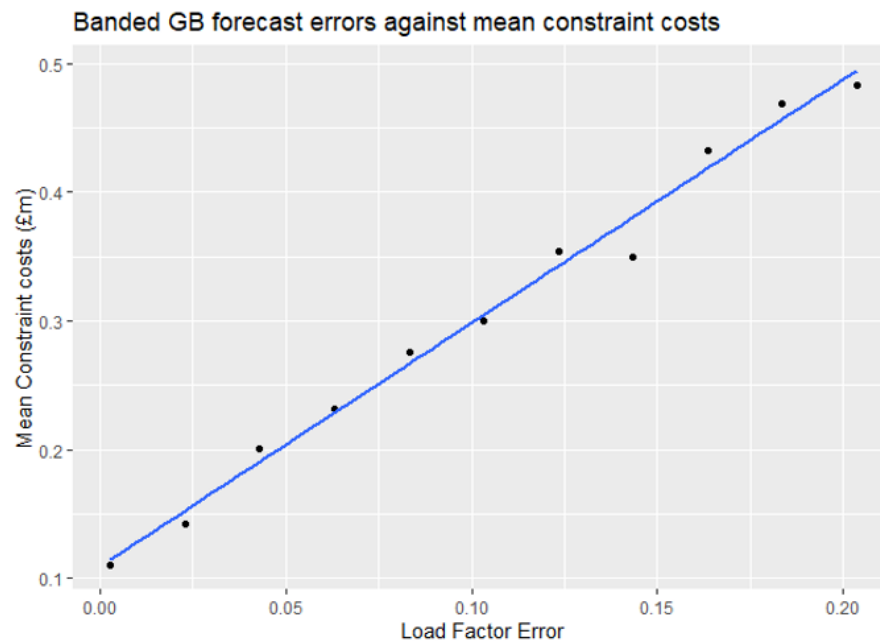
Relationship between Wind Forecast Error and Constraint Costs

- To calculate the constraint cost impact, the first step is to find the relationship between wind generation **forecast errors** (in terms of proportion of load factor) and constraint costs.
- For the OP, we use the relationship at the GB level, while for WACM1 just the **Scottish data** is used.



Relationship between Wind Forecast Error and Constraint Costs

- To make the underlying relationship clearer, the next step in the analysis is to split the errors into 20 groupings and calculate the mean constraint costs for each group.
- To calculate the final relationship linear regression is applied



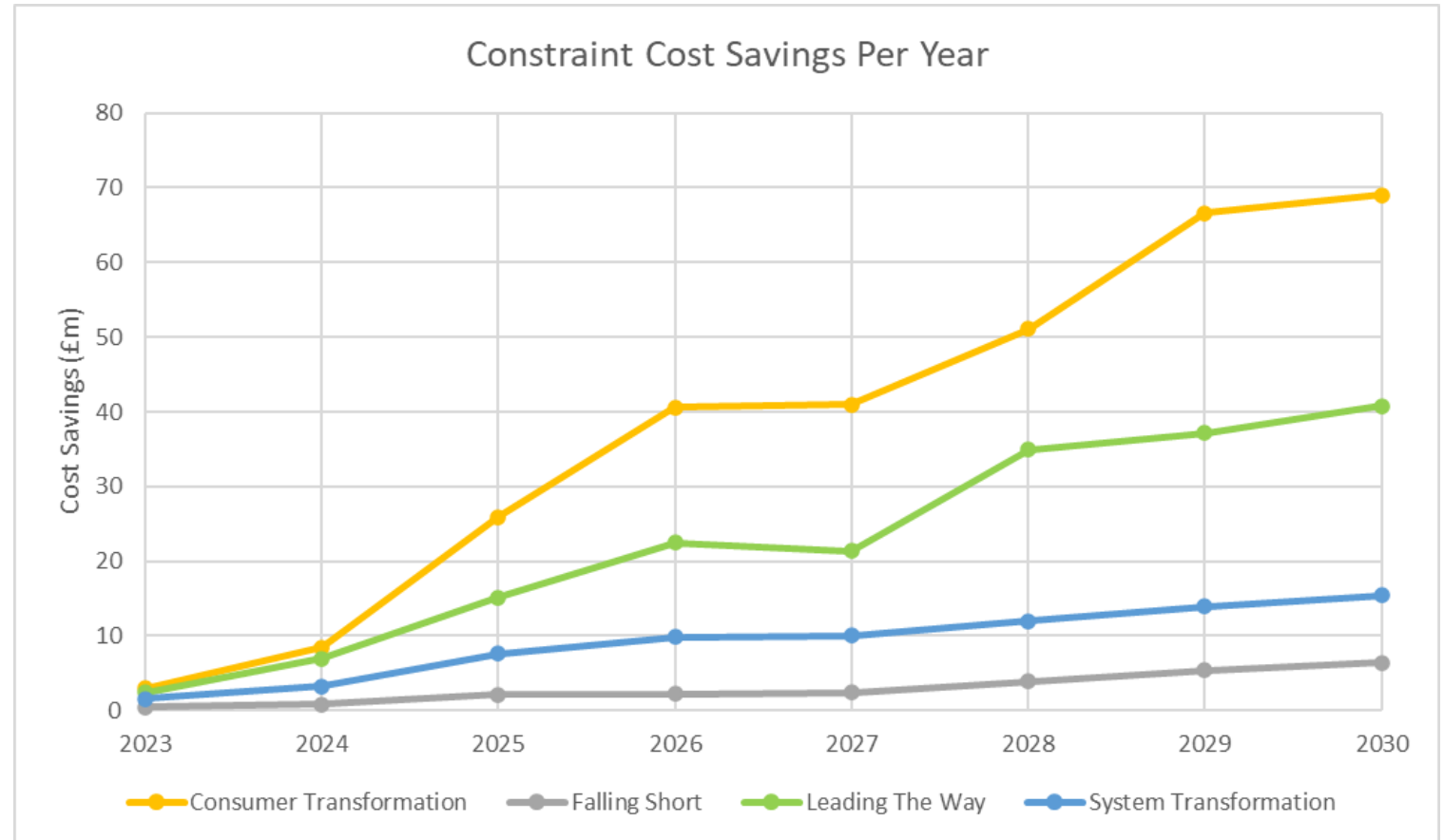
Other elements of the calculation for the impact on constraint costs

There are then a few extra processing steps to get to an annual figure relating to the impact of this modification:

- The performance difference is assumed to be 4% (based on analysis in the next section)
- NOA7 estimates are used to scale up the expected constraint costs for future years.
- The proportion of total BMU capacity that would be affected by GC0117 in each year is calculated, as described in the Capacity Assumptions section.
- For the original proposal we assume that there would be constraint costs incurred every hour (especially likely when renewable capacity increases). For the alternate proposal, the number of hours per year with constraint costs is based on the number of hours in 2022, scaled up using the NOA7 projections of costs.

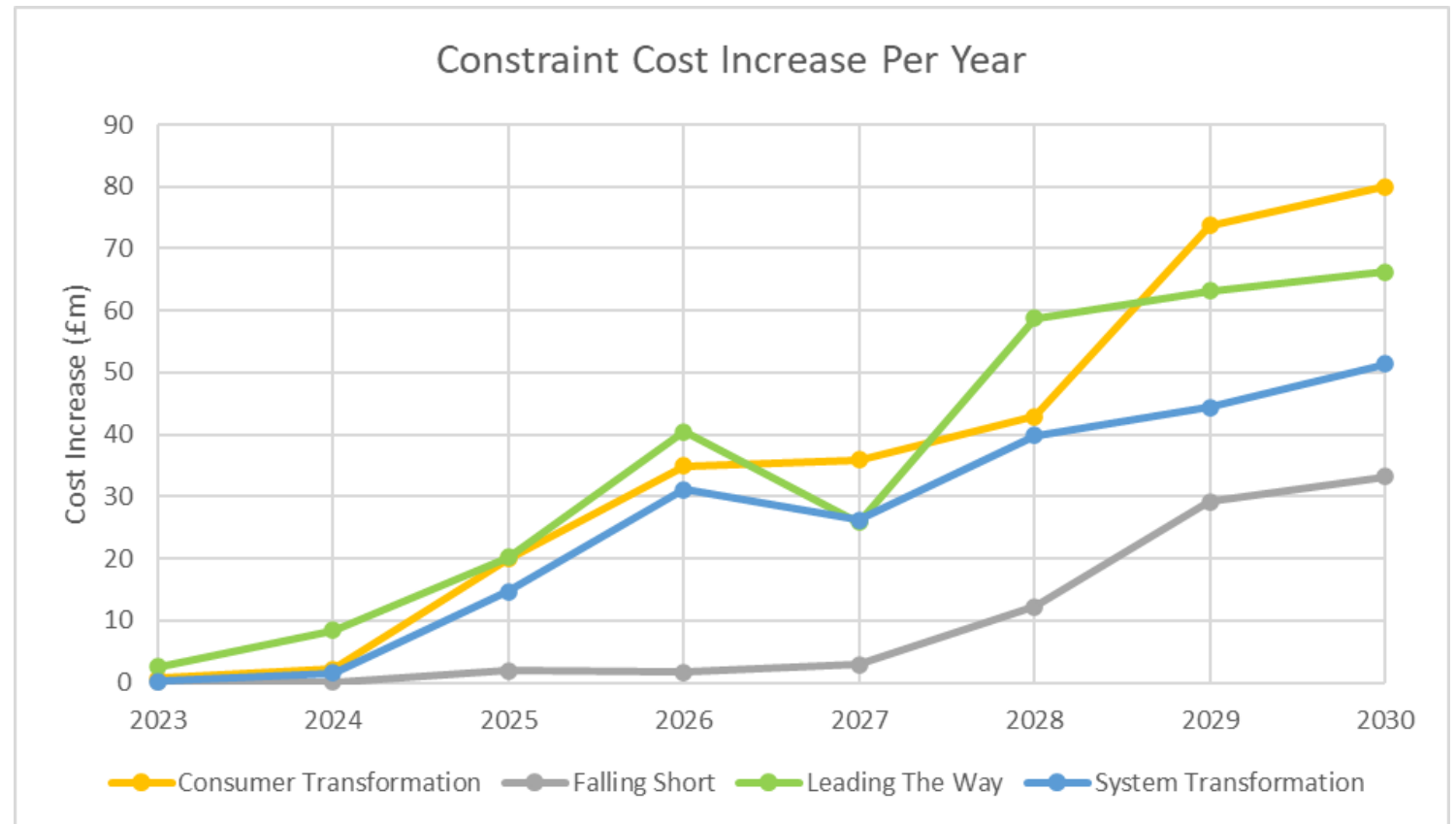
Original Proposal Results

- If this modification were implemented in 2022, benefits would grow to range between £6m and £70m in 2030.
- The benefits would be expected to gradually increase as more distributed capacity is installed and constraint costs are forecast to rise.
- The impact is so small for the 'Falling Short' scenario primarily because the projected installation of distributed wind generation is very small.



WACM1 Results

- If this option were implemented in 2022, the cost increases are estimated to range between £33m and £80m in 2030.
- This only covers the SCOTEX constraint. Others would likely also be impacted (e.g. SSE-SP2 and SSHARN3), so these estimates should be treated as a non-exhaustive low impact case.



Work Package 3: Forecasting Errors



Work Package 3 Demand forecast errors

National Demand (ND)

The amount of generation supplied by the Transmission Network to help meet the total GB Electricity Demand
Sum of BM generation (including Interconnector import). Based on National Grid operational metering

Embedded generators

Non-BMU generators connected to the Distribution Network act to suppress the National Demand

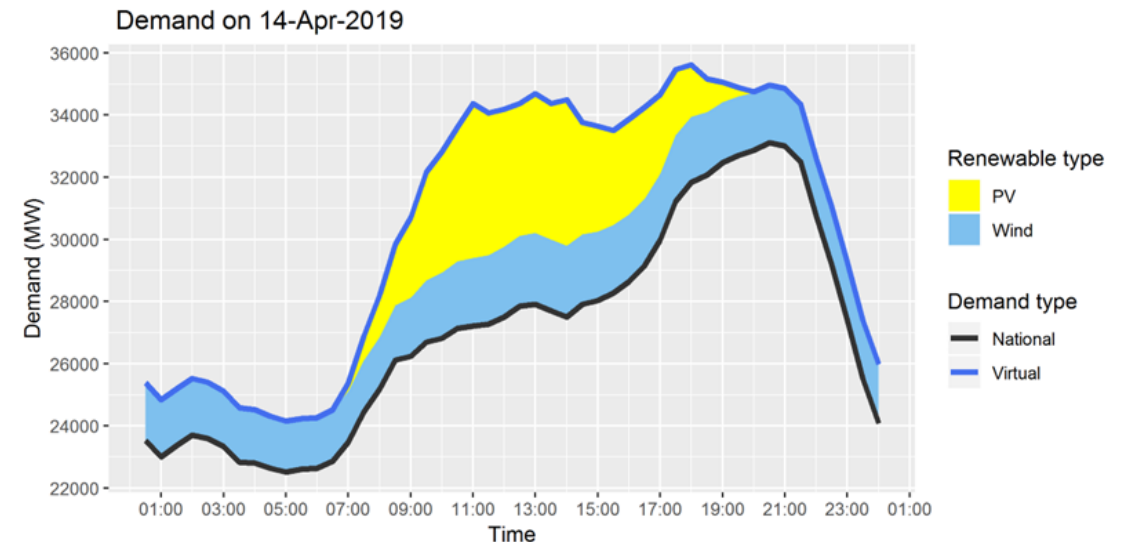
NGESO account for wind and solar PV explicitly in modelling:

Embedded wind ~ 6.5 GW

Embedded solar PV ~ 14.0 GW

Impact of other embedded generators hidden in National Demand

Other embedded generators capacity ~10 – 15 GW



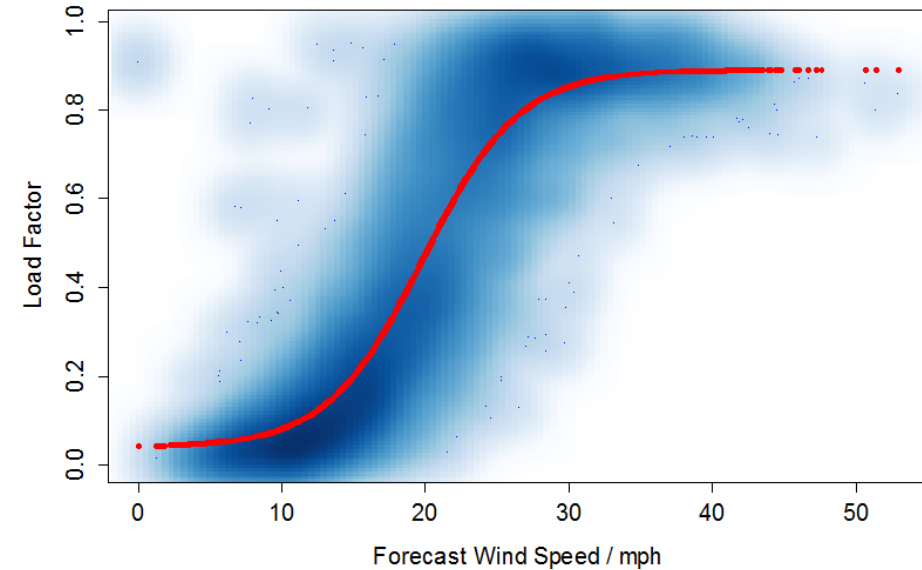
Wind power forecast

AIM

1. The difference in forecast accuracy for wind units which are registered as BMUs compared to those which are non-BMUs.
2. What is the financial cost of the errors and how do these change as a result of the code modification?

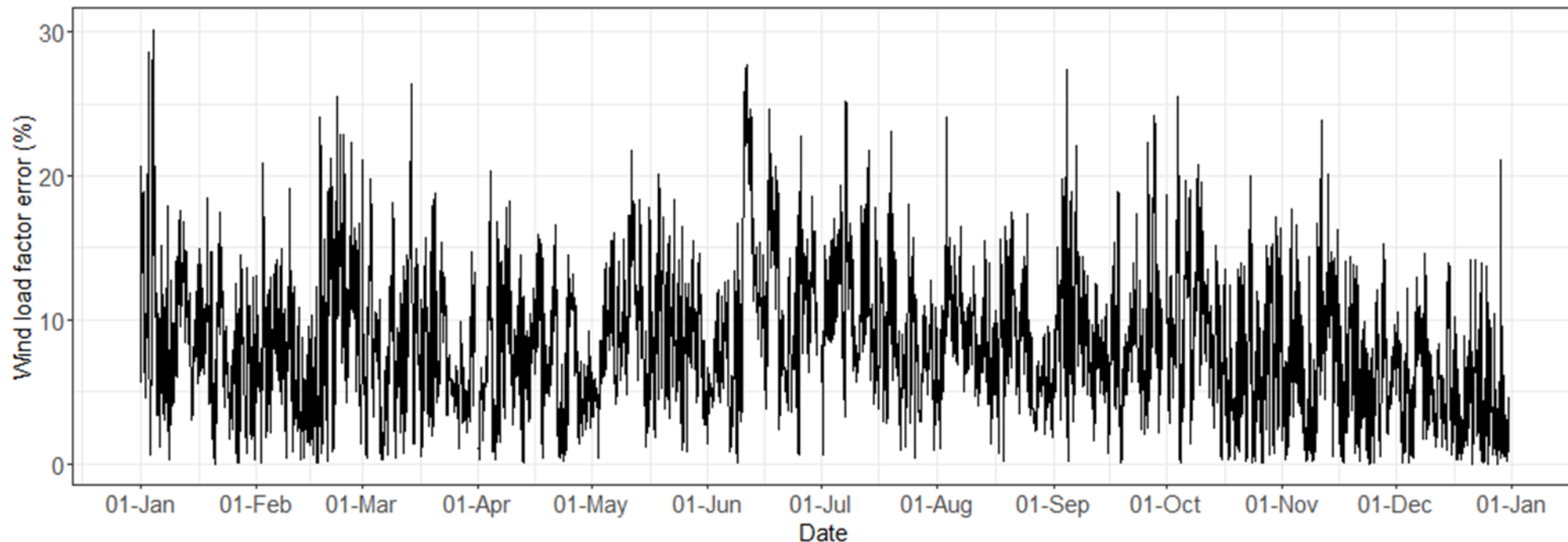
Wind power forecast

- Forecast metered & unmetered wind
- Metered wind:
 - Wind speed forecast at specific site of wind farm
 - Produce power curve with historic measured wind speeds and metered power output
 - Apply power curve to forecast wind speeds
 - Adjust farm capacity based on outage information
- Unmetered wind:
 - Capacity & location found from public databases.
 - Apply generic power conversion curve to wind speed forecast
 - Assume full capacity all the time



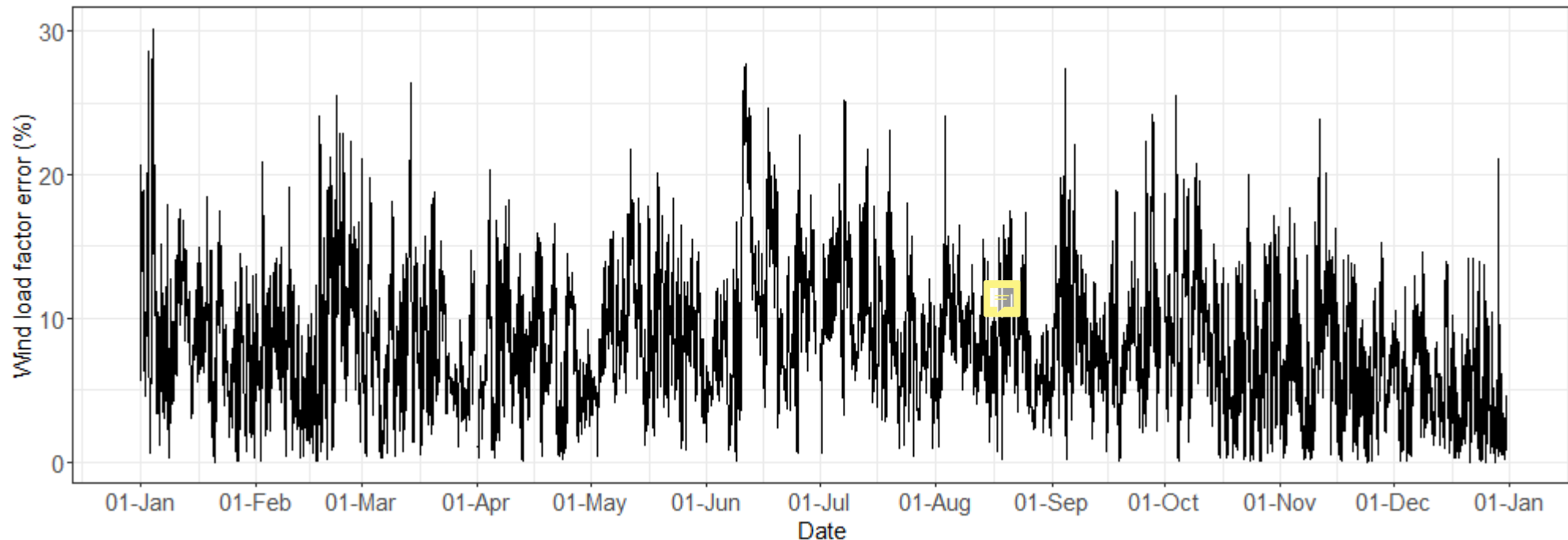
Embedded wind forecast error

- Do not have metering therefore embedded wind forecast error is unknown.
- To quantify the embedded wind forecast error, we have applied our embedded forecasting approach to the BMU wind units.
 1. Collect 1 year of forecast wind speed data for each BMU wind site (selected latest forecast)
 2. Apply generic power curve to estimate power output
 3. Aggregate forecast power across all wind farms
 4. Compare forecast load factor to metered load factor



Embedded wind forecast error

- Mean error across the year of 8% (current error ~540 MW)
- Largest error ~30% (~2 GW)
- Errors a combination of unknown availability and unknown power curve
- Error in MW will grow as capacity increases
- If modelled as a BMU the mean error = 4%.

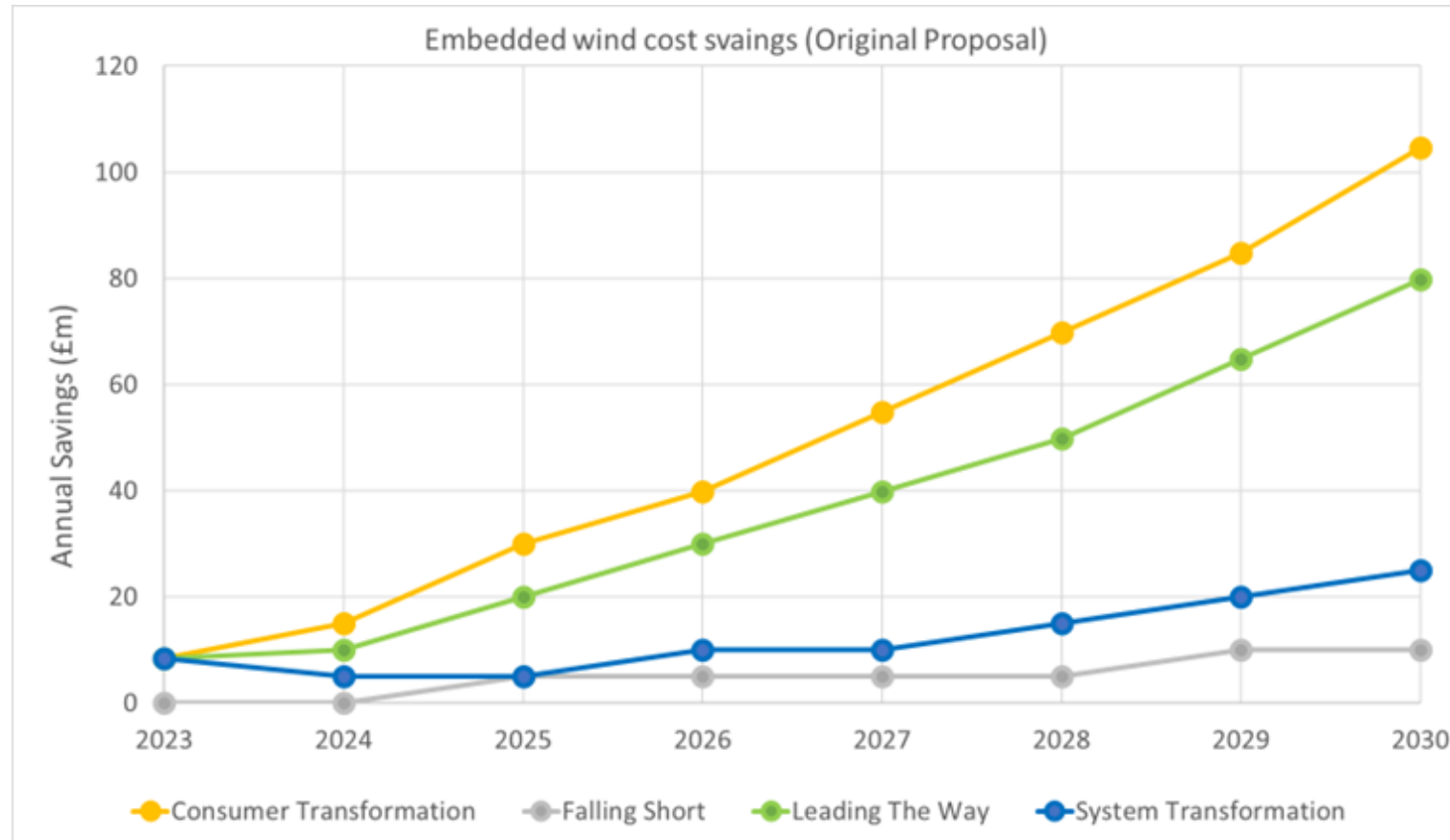


Impact of Original Proposal on embedded wind forecast errors

1. Find the capacity of wind affected by the original proposal for each year out to 2030.
2. Find the error in the wind forecast in MW for each settlement period if the units were to remain as non-BMU
3. Multiply the error for each settlement period by the system price and then sum to find the total annual cost of managing errors in embedded wind forecasts for the additional capacity.
4. Repeat the analysis but this time based on the error in the wind forecast in MW if the units were BMUs .

Original Proposal Results

- Increased visibility of embedded wind generators leads to annual savings for ESO.



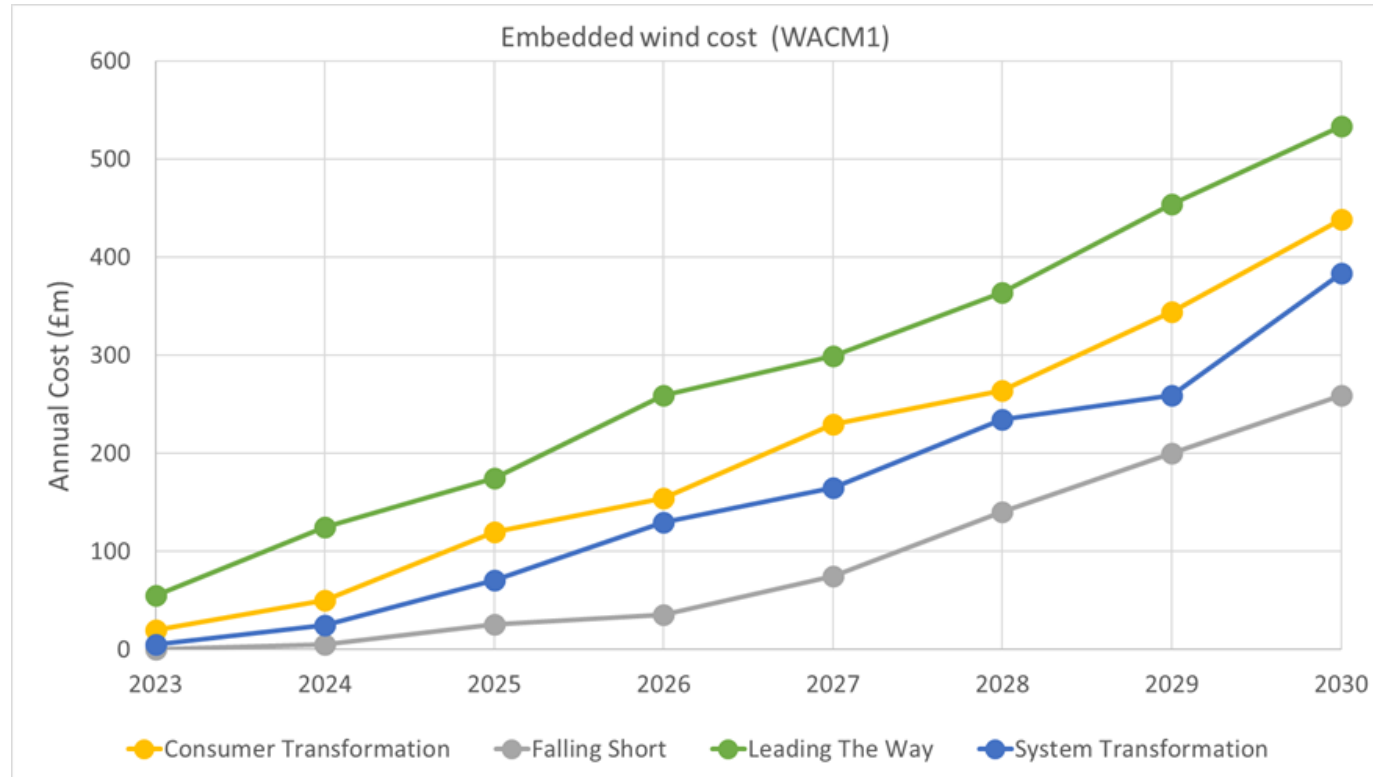
Impact of WACM1 on embedded wind forecast errors

We have followed the methodology of the Original Proposal, but with two key differences:

1. Find the capacity of wind affected by WACM1 for each year out to 2030. This relates to wind farms in Scotland with a capacity of 10-100 MW.
2. Assume these wind farms will be modelled as non-BMU generators rather than BMUs.

WACM1 Results

- Reduced visibility of embedded wind generators leads to a significant increase in the cost of managing demand forecast errors.



Impact of other embedded generators

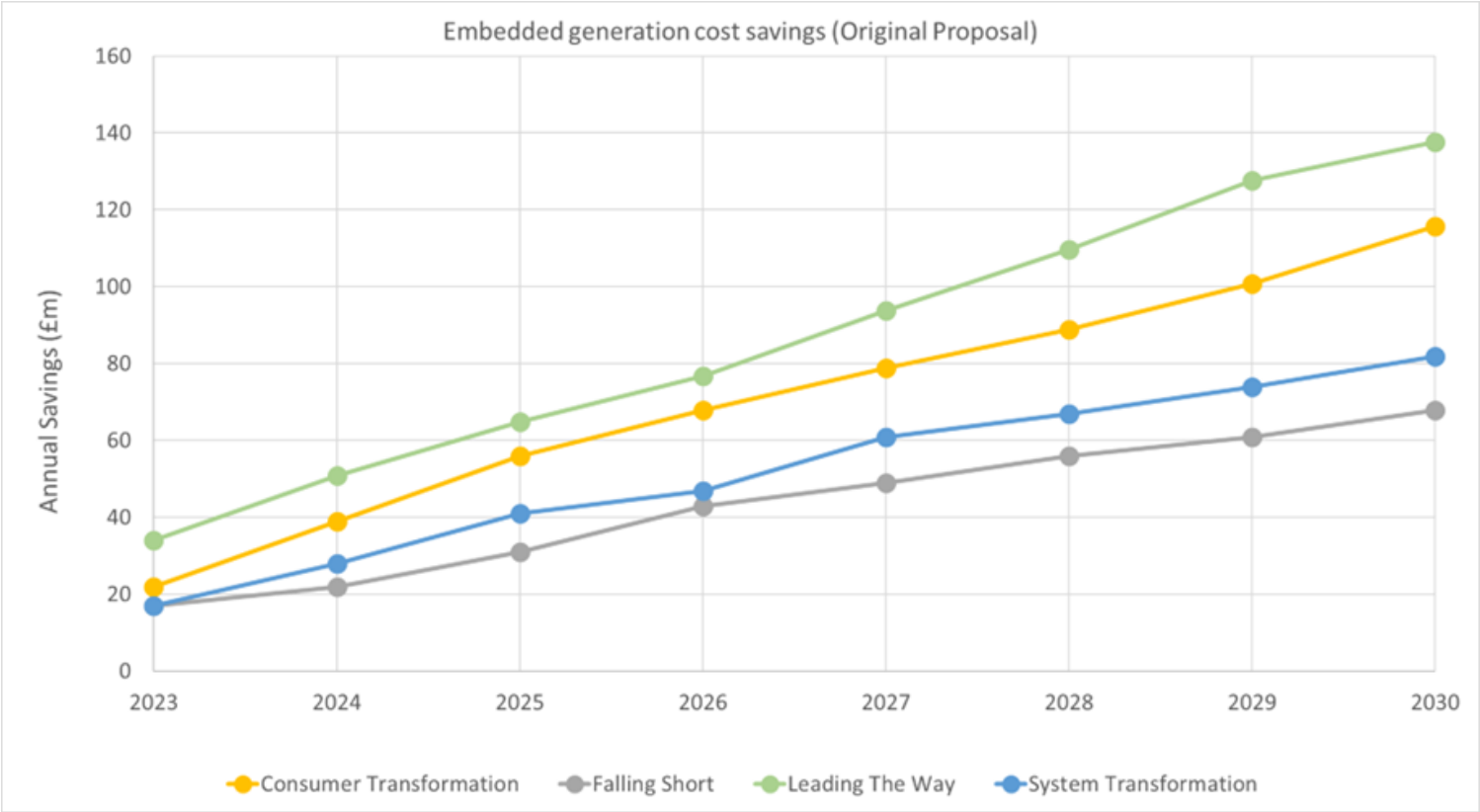
The aim of this section is to determine how the code modification would impact the demand forecast errors associated with non-BMU generators which are not wind generators (this includes batteries, diesel generators and solar PV).

However, unlike the wind generators, we do not have a similar BMU forecast to make the comparison against. We have therefore followed an adjusted method.

1. Find the capacity of generation affected by the original proposal for each year out to 2030.
2. For each settlement period in 2022, estimate the residual error in the latest forecast of the National Demand. This is the error which cannot be explained by weather errors or embedded wind errors.
3. Assume that 50% of the residual error is due to lack of visibility of non-BMU/non-wind generators.
4. For each of the capacity scenarios, scale the residual error by the capacity impacted by the Original Proposal.
5. Multiply the error for each settlement period by the system price and then sum to find the total annual savings.

Original Proposal Results

- Increased visibility of embedded generators leads to annual savings for ESO.



WACM1 Results


- Impact of WACM1 on visibility of non-wind generators is negligible (low levels of affected planned capacity in Scotland)

Conclusions





Results



WP1: Impact on price stack available in the BM.

- The Original Proposal could lead to a reduction in marginal BM price resulting in annual cost savings of balancing the system of up to approximately **£70m** 

WP2: Impact on constraint costs:

- The increased visibility of generators provided by the Original Proposal could lead to annual savings in constraint costs of up to approximately **£70m**. 
- The reduced visibility as a result of WACM1 could lead to an increase in constraint costs of up to **£80m** per year. 

WP3: Impact on demand forecast errors:

- The increased visibility of generators provided by the Original Proposal could lead to reduction in demand forecast errors and therefore cost savings of up to approximately **£220m** per year. 
- The reduced visibility of wind units in Scotland as a result of WACM1 could lead to a significant increase in demand forecast errors and therefore additional annual costs of up to approximately **£530m** per year. 

Questions & Discussion