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Grid Code Modification GC0117

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Context

GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Stations requirements. This modification will set out within the Grid Code the common GB obligations in the EU Connection Codes as they relate to the specification of certain items by certain obligated party or parties.

Options	Summary of Original Proposal and Alternatives
Original Proposal	Large/Small Power Station Threshold changed to 10MW
WACM1	Large/Medium/Small Power Station Thresholds in England and Wales applied in Scotland
Alternative 1	Large/Small Power Station Threshold changed to 100MW
Alternative 2	LEEMPS Plus – Medium Power Station Threshold changed to 10 – 100MW across GB. Applies LEEMPS arrangements with a Balancing Mechanism Component and hence becomes a hybrid of LEEMPS and BELLAs or BEGAs
Alternative 3	Apply Large/Medium/Small Power Station Threshold in England and Wales in Scotland (as per WACM1) but all embedded plant between 10 – 100MW would be required to participate in the BM and provide Ancillary Services through a control system which would take the Appendix G and Active Network Management processes behind each Grid Supply Point into account. National Grid ESO are developing several schemes using this approach using the Regional Development Platform (RDP)
Alternative 4	Hybrid solution of Alternative 2 & 3 RDP solution for Small Power Stations between 10 – 49.9MW and LEEMPS Plus solution for Medium Power Stations between 50 –100MW

Aim

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

1. Workstreams

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. These costs are not exhaustive, and there may be other smaller cost categories. For instance, if DNOs do not retain the majority of compliance processes there may be need for additional compliance resource in the ESO.

1. **Balancing Mechanism (BM) price stack:** Based on the last three years identify how the actions taken by NGESO would change based on the different price stacks of bids and offers
2. **Constraint analysis:** To inform the decision-making regarding flows across constraint boundaries an understanding of the generation and demand behind the constraint is required. Each option will result in a different level of visibility for NGESO.
3. **Demand forecast errors**: Generators which are not part of the BM and connected to the distribution network are not visible to NGESO and therefore they act to suppress the National Demand. Investigate how the accuracy on the demand forecast varies for each option.

2. Capacity Assumptions

All the workstreams require assumptions around how much capacity would be affected by the different proposals as part of this modification. Figure 1 shows the existing thresholds and obligations across the different GB regions.

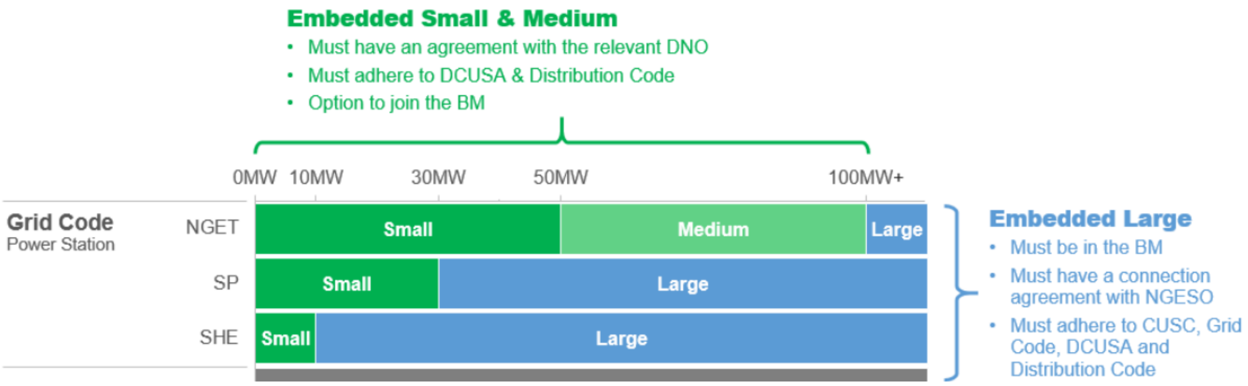

Figure 1 - Diagram showing the current thresholds and obligations

We focus on two main scenarios: the original proposal, and WACM1. The definition of affected capacity in these scenarios is as follows.

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

The basis for our projected capacity estimates were the forecasts published as part of Future Energy Scenarios (FES) in 2022, which cover four scenarios. However, this only gives a view of distributed and transmission capacities, and not how much of these capacities might fall under the two scenarios given above.

For the first scenario (OP) we use the Embedded Capacity Register published by each DNO. The register has been filtered to only look at sites newly connected in the past 10 years, and the above rules for capacity were applied.

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%

Table 1 - Estimates of the proportions of new capacity that would be affected by the Original Proposal

This provides proportions for how much newly connected capacity in the past 10 years would have been affected by the original proposal if it had been in place, shown in Table 1. Note that this therefore does not include upgraded connections that could still be affected by this modification, but as only the proportions are used from this source and not the final values, this is less of an issue.

For the second scenario (WACM1), to work out what proportion of FES Transmission capacity would be affected, we use the capacities of existing BM Units (from internal National Grid data). Applying the logic laid out above, and looking at existing capacities in Scotland, the proportions were calculated as shown in Table 2.

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%

Table 2 - Estimates of the proportions of new capacity that would be affected by WACM1

The proportions have been applied to the projections for distributed or transmission capacity in the FES 2022, as relevant for each work package. A baseline was applied against the current installations in the FES, where only future capacity over the capacity in the baseline year was considered (as existing generators will be unaffected by this modification). It should be noted that the FES projections only give the net change and so do not show any capacity that might replace existing generators. Therefore, these capacity estimations are likely to be underestimates of the real total affected capacity, and so the impact could be greater than that reported in the below assessments. Limiting the analysis to only cover until 2030 restricts the impact of this assumption, as after more years, more of the existing generation fleet is likely to have been retired and replaced.

The final estimated capacities based on the above methodology can be found in the Appendix.

3. Balancing Mechanism (BM) price stack

A simplified price stack has been constructed from submitted BM data over the last 3 years, grouped by Winter and Summer[1] (see Figure 2). These are comprised of key fuel types - gas, coal, hydro, non-pump storage hydro (NPSHYD), battery and other. For wind, interconnectors (IC) and nuclear sources of generation, prices were set to zero as they are low/zero cost. De-rated installed capacities have been used and the median price was calculated. A filter has been applied to remove all extreme high submissions. The most recent Winter average colds spell demand peak (43.5GW) and latest Summer demand (28.3GW) were used to calculate the marginal BM price. For Winter this is calculated to be £252/MWh and for Summer it is £192.5/MWh.

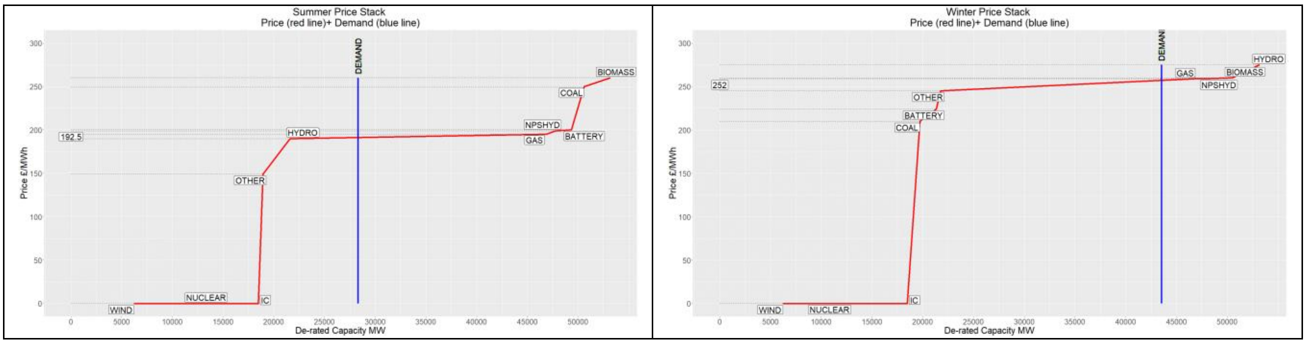

Figure 2 BM price stacks for Summer and Winter.

To assess the impact of additional small units being available in the BM (as outlined by the Original Proposal) we use the capacities outlined in Section 2. From the price stack we expand each fuel type retaining the current demand curve and dispatch order. The volume of additional capacity is added onto the existing de-rated installed capacity. Where the plant mix is directly mapped to the existing mix this is done, however, where new sources were expected to be available, they are assigned to the most appropriate existing fuel type. The results of the change in the BM marginal price (from the baseline) are in Figure 3 and Figure 4. The Original Proposal

[1] Summer is April to September and Winter is October to March.

does not lead to a reduction in the marginal price in Winter in any scenario however, for summer there is price reduction for the Leading the Way scenario in 2029 and 2030.

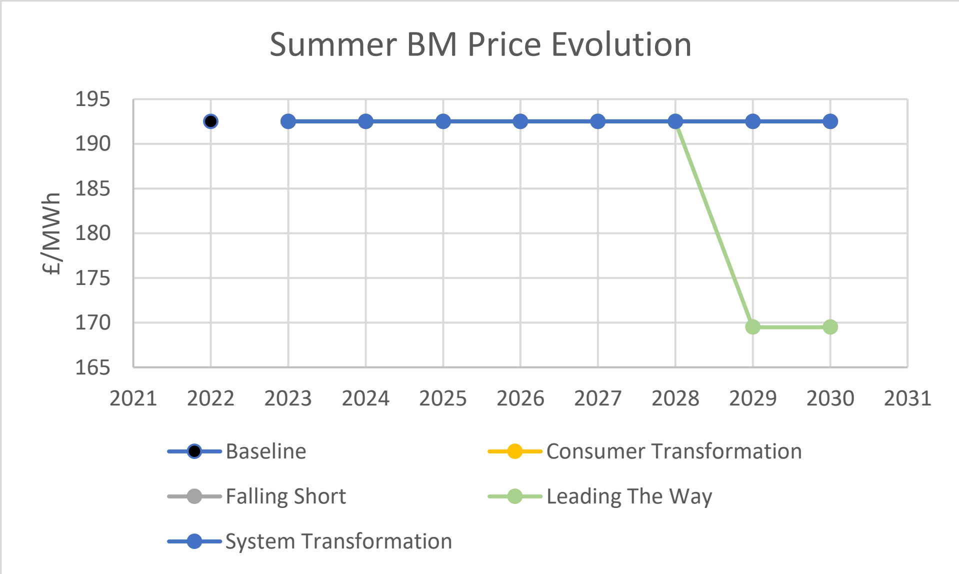

Figure 3 Summer BM Marginal price from the baseline for each scenario

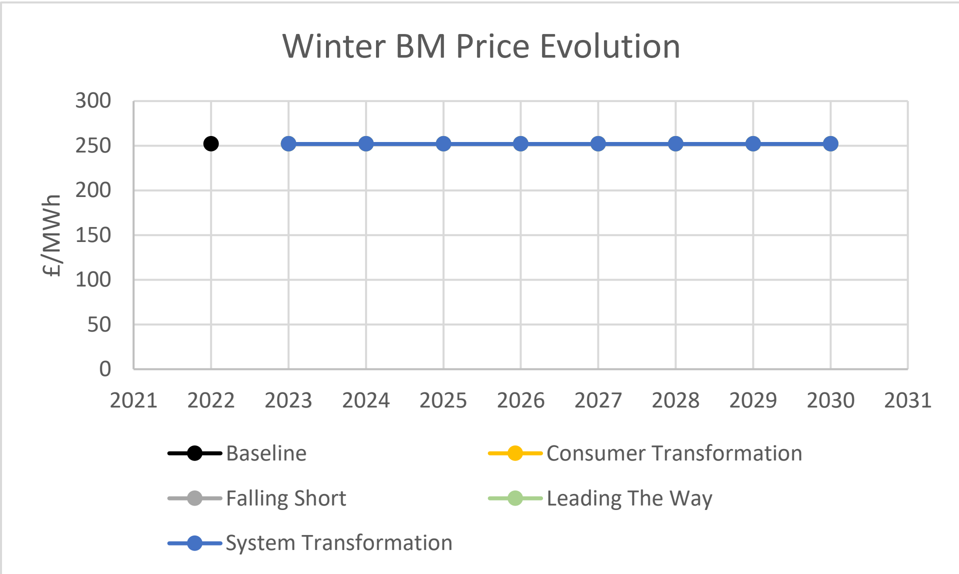

Figure 4 Winter BM Marginal price from the baseline for each scenario

Volumes of BM actions[2] from the Monthly Balancing Services Summary (MBSS) were taken to apply to the modelled price changes to derive a cost impact. An average volume for Summer and Winter was calculated for the last three seasons separately and applied to each of the future years. Given there was no change in price for Winter, the cost savings were zero for each FES scenario. For Summer, we see a range of cost savings of between £0-£71m across the 4 scenarios (see Figure 5). Taking both seasons together we have a savings range of £0-£71m across all four scenarios up to 2030 (see Table 3 and Figure 6).

[2] BM Operating Reserve & BM constrained Operating Reserve were used

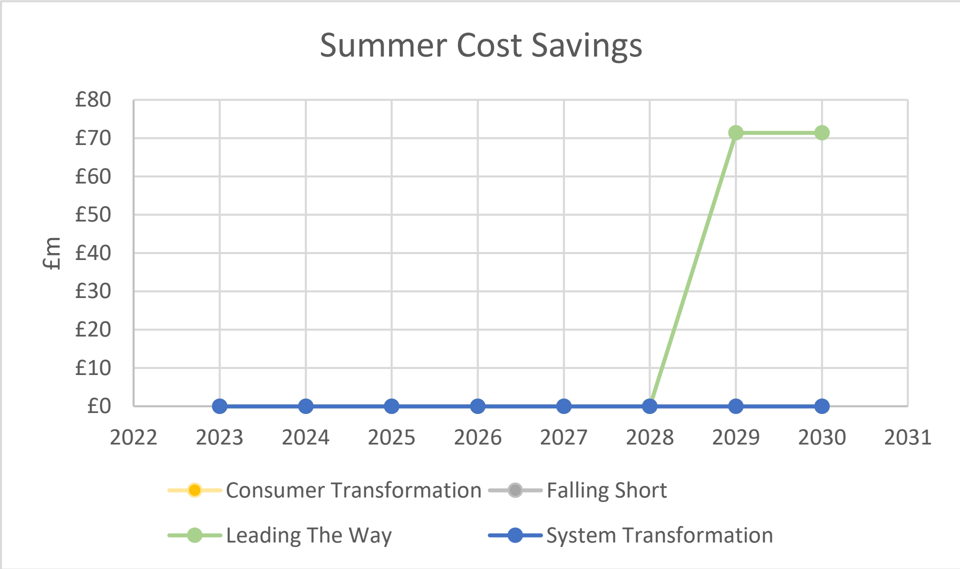

Figure 5 Original Proposal estimated cost savings in summer per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

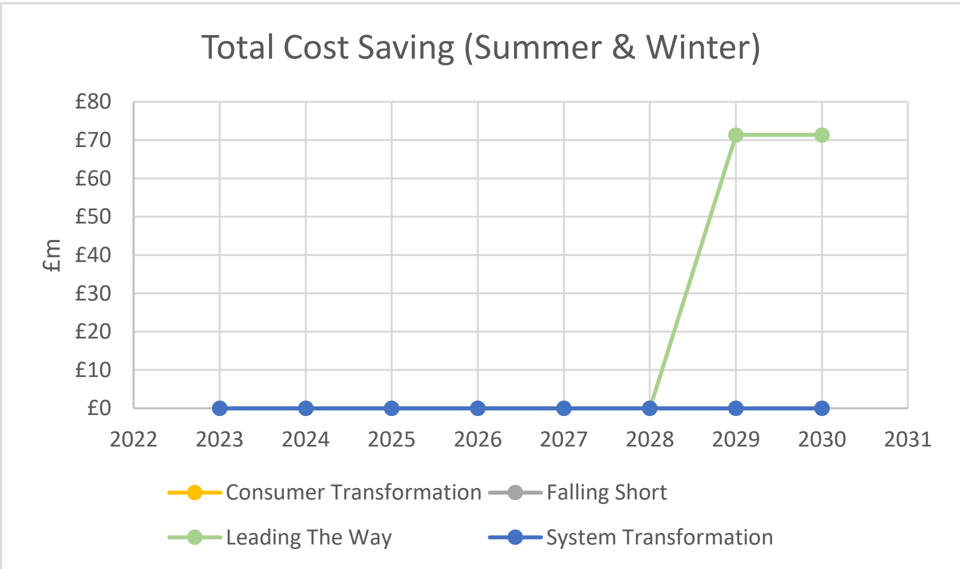

Figure 6 Original Proposal estimated cost savings per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

	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

Table 3 Original Proposal WP1 results showing the estimated cost savings per year in £m

Since the proposed modification would not be applied retrospectively, the existing levels of installed capacity would be unaffected. The rate of growth of generation from some sources would be slowed and therefore extend existing price points further than they would be in a more widely accessible BM.

There are two opposing affects for WACM1, the volume of capacity that does not enter the BM will still be installed but will be embedded. As today, embedded generation can appear as supressed demand itself lowering the BM marginal price. The lack of growth in some sources in the BM would maintain existing price points for longer. We have assumed these two effects cancel each other out therefore the cost impact of WACM1 is taken to be zero.

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4. Constraint analysis

Methodology

The principle behind this workstream is that with better understanding of the generation behind each constraint on the transmission network, constraints can be set in a more efficient way. Improved visibility of metering should enable better forecasting, which is estimated as part of the 'Demand Forecast Errors' workstream of this cost benefit analysis. For simplicity, this workstream is focussed on the impacts of wind generation only.

To calculate the constraint cost saving, the first step is to find the relationship between wind generation forecast errors (in terms of proportion of load factor) and constraint costs. Due to the lack of visibility of metering for embedded generation, this workstream focussed on the relationship between forecasting errors for existing BMU wind generators and historic constraint costs. This relationship is then applied to theoretical future forecast improvements for embedded wind, on the assumption that any uncertainty in generation will affect constraint management independent of source.

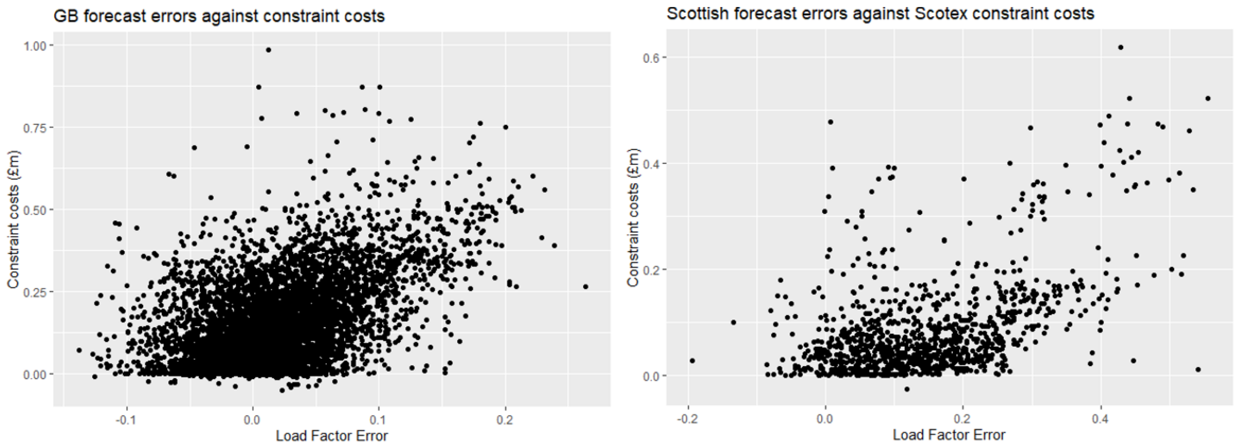

Figure 7 - Plots of hourly data from 2022 showing the relationships between forecasting errors of wind generation and constraint costs. LHS is on a national basis; RHS shows errors in Scottish generation and SCOTEX constraint costs.

This analysis is completed at both the national level (whole system constraint costs against all GB BMU wind generation) and focussed on the Scottish Wind Generation and SCOTEX constraint costs (see Figure 7). The first view is used for assessing the original proposal as the impact would be across much of GB, while the second view is used to assess the alternate (WACM1) proposal, which would only affect Scottish generation.

The raw relationship isn't very strong because there are a wide range of constraint costs in 2022 at each error level. There are also a lot more data points with a low level of error and 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.

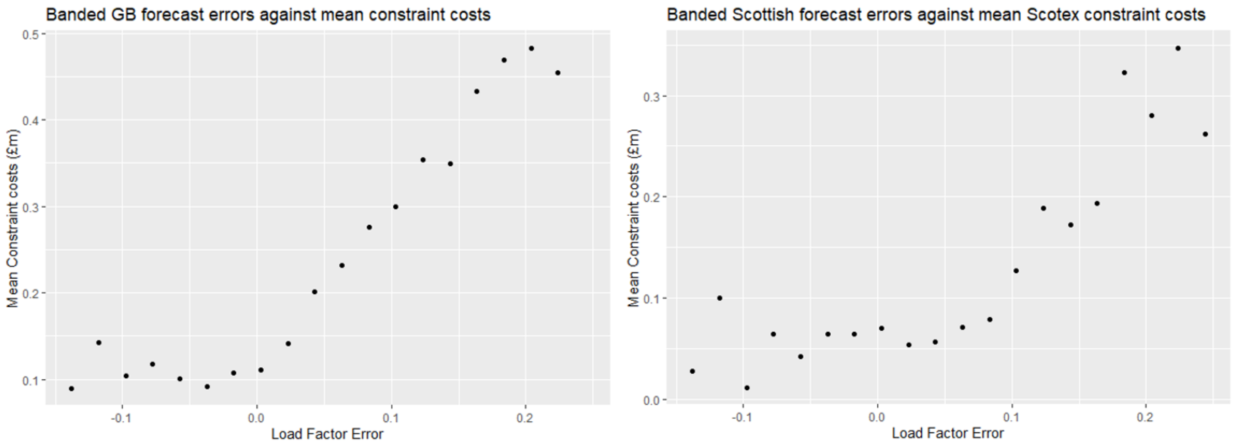

Figure 8 - Plots of the relationships between forecasting errors of wind generation and constraint costs, where the hourly data has been cut into 20 equal sections of load factor errors, with the mean costs calculated for each band. LHS is on a national basis; RHS shows errors in Scottish generation and SCOTEX constraint costs.

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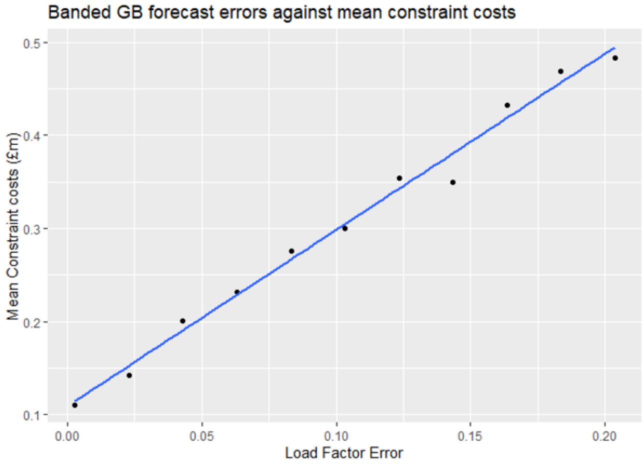
With this processing the underlying relationship is much easier to see, as shown in Figure 8. For negative load factor errors (where the forecast of generation was lower than the outturn), the costs do not seem to change with the magnitude of the error. However, for positive errors there is a clear positive relationship between the magnitude of the forecast error and the costs. This supports the hypothesis that when forecasts are higher than outturn wind, costs are higher, likely because more wind is constrained off than needed for system balancing.



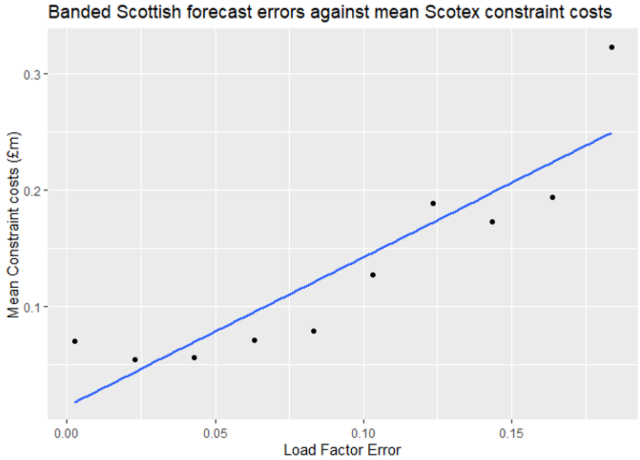


Figure 9- Plots of the relationships between forecasting errors of wind generation and constraint costs, processed as in Figure 8 except that only positive errors are included and groups with less than 10 data points were excluded. Linear Regression models fit on this data are shown in blue. LHS is on a national basis; RHS shows errors in Scottish generation and SCOTEX constraint costs.

To calculate the final relationship linear regression is applied, as shown in Figure 9. For fitting this relationship, only positive errors are considered, and any groups containing less than 10 data points were excluded.

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

- The performance improvement 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: the original proposal analysis uses the GB wide assumptions, and the alternate proposal analysis uses the values associated with Scotland only.
- 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.

It should be noted that this methodology assumes the modification was implemented in 2022, due to data availability and difficulty in making estimates with confidence at long lead times.

Results - Original Proposal

The analysis shows that, if this modification were implemented in 2022, benefits would grow to range between £6m and £70m in 2030, based on the different FES scenarios, as shown in Figure 10 and **Error! Reference source not found.**. The benefits would be expected to gradually increase (including beyond 2030) 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 (only 0.2GW above existing levels).

	Savings Per Year (£m)							
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Consumer Transformation	3	8	26	41	41	51	67	69
Falling Short	0	1	2	2	2	4	5	6
Leading The Way	2	7	15	23	21	35	37	41
System Transformation	2	3	8	10	10	12	14	15

Table 4 - Original Proposal WP2 results showing the estimated constraint cost savings per year in £m

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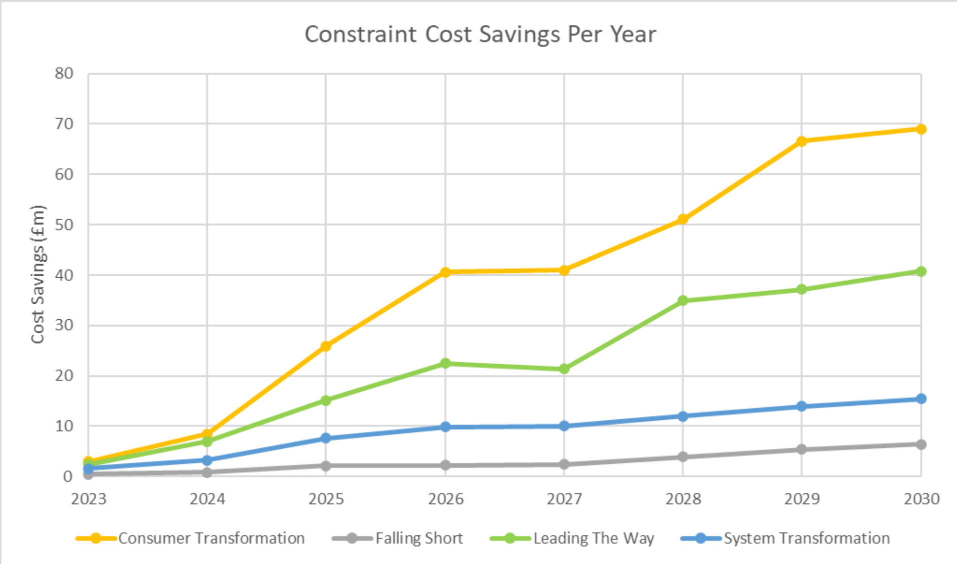

Figure 10 - Original Proposal WP2 results showing the estimated constraint cost savings per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

Results - WACM1

If WACM1 were implemented, this would result is less visibility of wind generation in Scotland for the ESO, and thus increases in wind forecasting errors and increases in constraint costs. Were this modification implemented in 2022, the cost increases are estimated to range between £33m and £80m in 2030, based on the different FES Scenarios, as shown in Table 5 and Figure 11. This analysis only covers the SCOTEX constraint, while others would likely also be impacted (SSE-SP2 and SSHARN3 in particular), so these estimates should be treated as a non-exhaustive low impact case.

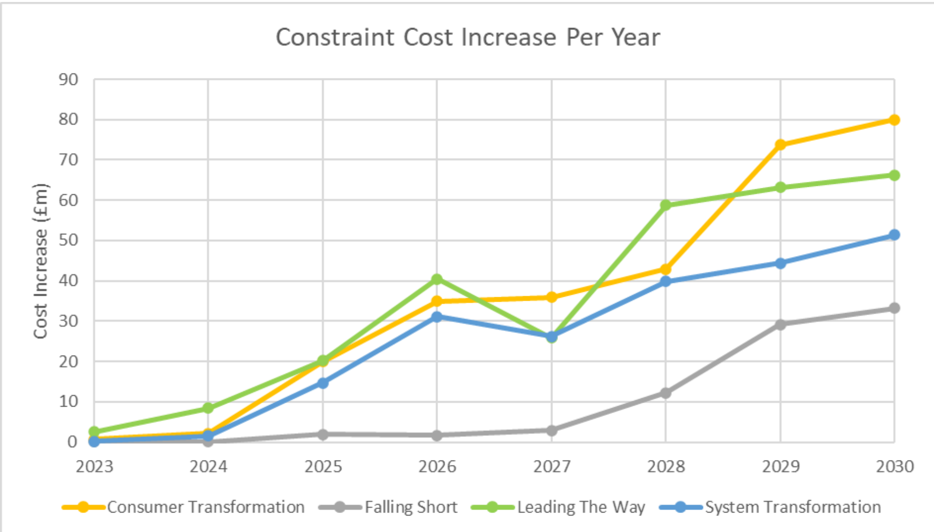

Figure 11 - WACM1 WP2 results showing the estimated constraint cost increases per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

	Impact Per Year (£m)							
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Consumer Transformation	1	2	20	35	36	43	74	80
Falling Short	0	0	2	2	3	12	29	33
Leading The Way	3	8	20	40	26	59	63	66
System Transformation	0	2	15	31	26	40	44	51

Table 5 - WACM1 WP2 results showing the estimated constraint cost increases per year in £m

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5. Demand Forecast Errors

National Grid ESO produces regular forecasts of National Demand which are published to the market and provided to the control room to enable them to manage the system in real time. National Demand is defined as the sum of generation on the transmission network required to maintain the system frequency at 50 Hz. Errors in the demand forecast therefore may lead to actions being taken in the balancing mechanism (BM) to maintain the balance between supply and demand.

Generators which are not part of the BM and connected to the distribution network are not visible to NGESO and therefore act to suppress the National Demand. The principle behind this workstream is that improved visibility of metering of the non-BM units should enable NGESO to produce more accurate forecasts of National Demand and therefore reduce the risk of unnecessary actions taken in the BM. For simplicity, this workstream has been split into two sections. The first looks at the impact of the code change on the accuracy of forecasts of wind generators and the second considers all other generation types.

Wind forecast errors

The aim of this section is to determine:

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?

To forecast the output of a BMU wind generator, NGESO first derive a power curve which describes the relationship between wind speed at the wind farm and its outturn. This is possible as metering data is provided by the generator and wind speed observations are available from a weather provider. When forecasting the output of the farm, the derived power curve is applied to forecast weather data to estimate load factor- which is then multiplied by the available capacity to produce a power forecast.

For non-BMU wind generators, NGESO applies the same approach but as metering data is not available, we have to assume a generic power curve (i.e., the relationship between the wind speed and outturn is assumed to be the same for multiple sites). Consequently, we see larger forecast errors for the non-BMU generators than BMU generators. Analysis of data for 2022 showed that for the latest forecast (i.e., closest to real-time), the mean error (across all settlement periods in the year) for BMU wind farms was 4%. However, if these units were non-BMU and therefore modelled with the generic power curve the error would have been 8%. Therefore the difference of 4% is attributable to non-BMU status.

To determine the financial implication of the change in forecast errors of wind units under the proposals outlined in GC0117, we have assumed that any errors will have to be managed by NGESO in the balancing market and therefore subject to the system price.

Original proposal

To find the financial impact of the original proposal the following methodology has been followed:

1. For each Scenario, find the capacity of wind affected by the original proposal for each year out to 2030 (see section 2).
2. For each settlement period in 2022, estimate the error in the latest forecast of the nationally aggregated non-BMU wind generation (expressed as a load factor).
3. For each of the capacity scenarios, determine the error in the wind forecast in MW for each settlement period if the units were to remain as non-BMU (i.e., multiply output from step 1 by output from step 2)
4. 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.
5. For the same time period, estimate the error in the latest forecast of the nationally aggregated non-BMU wind generation if it could be modelled in the same way as current BMUs (also expressed as a load factor).
6. For each of the capacity scenarios, determine the error in the wind forecast in MW for each settlement period if the units were a BMU (i.e., multiply output from step 1 by output from step 5).

7. 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.
8. The financial impact of the Original Proposal is therefore estimated by subtracting the output from step 7 from the output from step 4.

Based on the Original Proposal, the increased visibility of the wind units in the size range 10-100 MW would lead to significant savings. The magnitude of the savings varies, from £10 million per year for Falling Short to £105 million per year for the Consumer Transformation (see Figure 12 and Table 6).

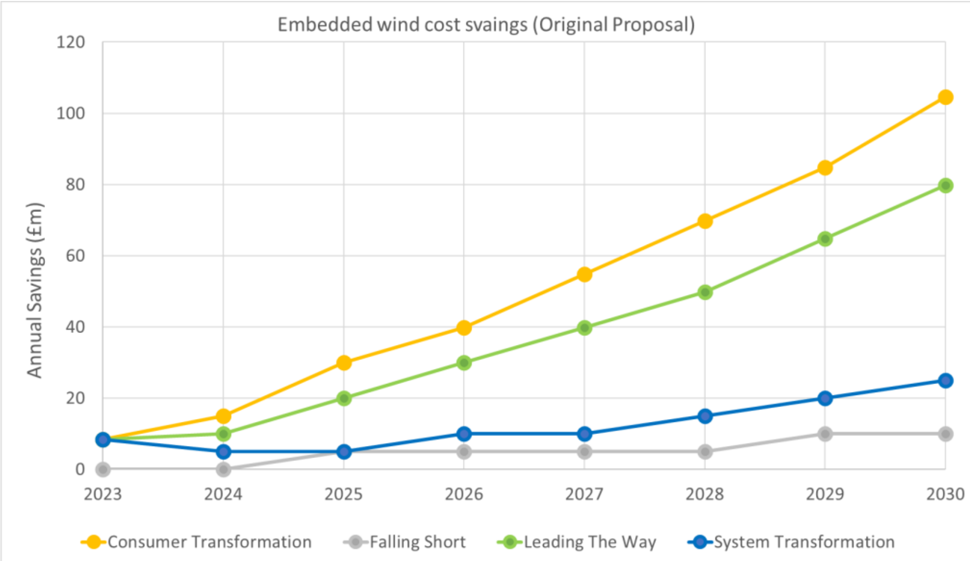

Figure 12 Original Proposal WP3 results showing the estimated demand forecast error cost savings per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

	Impact Per Year (£m)							
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Consumer Transformation	8	15	30	40	55	70	85	105
Falling Short	0	0	5	5	5	5	10	10
Leading The Way	8	10	20	30	40	50	65	80
System Transformation	8	5	5	10	10	15	20	25

Table 6 Original Proposal WP3 results showing the estimated demand forecast error cost savings per year in £m

WACM1

To find the financial impact of WACM1, we have followed the methodology of the Original Proposal, but with two key differences:

- For each Future Energy Scenario, find the capacity of wind affected by WACM1 for each year out to 2030 (see section 2). This relates to wind farms in Scotland with a capacity of 10-100 MW.
- Assume these wind farms will be modelled as non-BMU generators rather than BMUs.

Based on the WACM1, the decreased visibility of the wind units in the size range 10-100 MW would lead to significant extra costs in managing the power system (see Figure 13 and Table 7). These costs would be incurred due to an increase in the magnitude of forecast errors of embedded wind units. As with the original proposal, there is large variability across scenarios, but the magnitude of the costs is significantly higher than the Original Proposal. For example, for the Leading the Way scenario, the decreased visibility of wind farms in Scotland could lead to additional costs of over £500 million per year (based on the installation capacity for 2030).

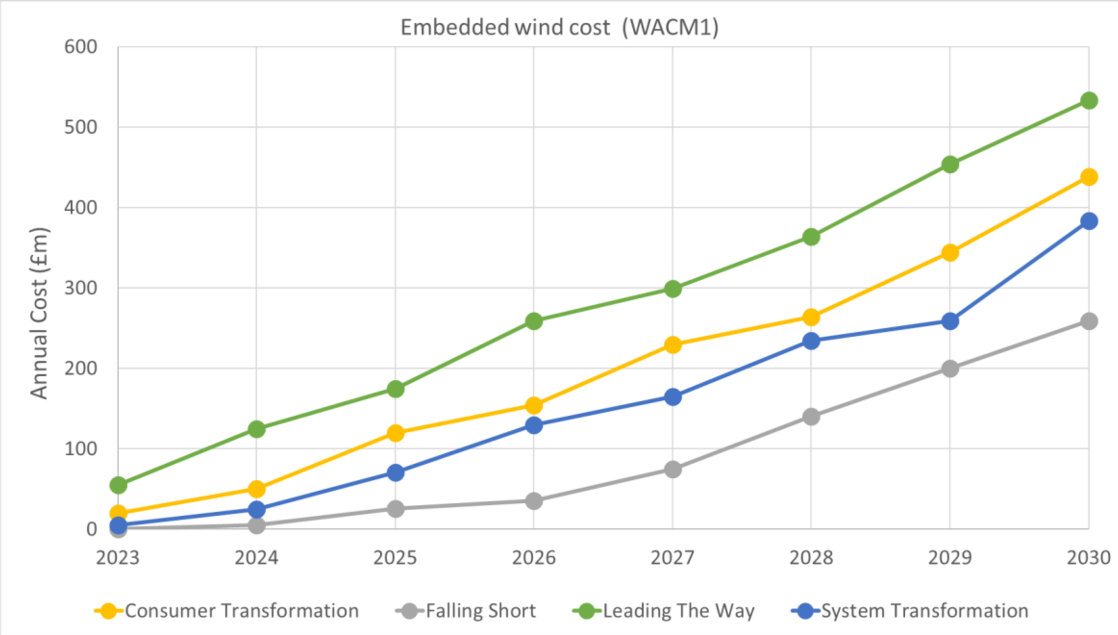

Figure 13 WACM1 WP3 results showing the estimated demand forecast error cost increases per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

	Impact Per Year (£m)							
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Consumer Transformation	20	50	119	154	229	264	344	438
Falling Short	0	5	25	35	75	140	200	259
Leading The Way	55	125	175	259	299	364	454	533
System Transformation	5	25	70	130	164	234	259	383

Table 7 WACM1 WP3 results showing the estimated demand forecast error cost increases per year in £m

Other generation type errors

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). The analysis has followed a similar principle to the wind forecast analysis, in that it is based on the premise that increased visibility of the generators to NGESO would lead to increased forecast accuracy. 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. For each Future Energy Scenario, find the capacity of generation affected by the original proposal for each year out to 2030 (see section 2). This is non-wind generators of size 10-100 MW.
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.

Based on the Original Proposal, the increased visibility of the generator units in the size range 10-100 MW would lead to significant savings. The magnitude of the savings varies from scenario to scenario, from £65 million per year for Falling Short to £140 million per year for Leading the Way (see Figure 14 and Table 8).

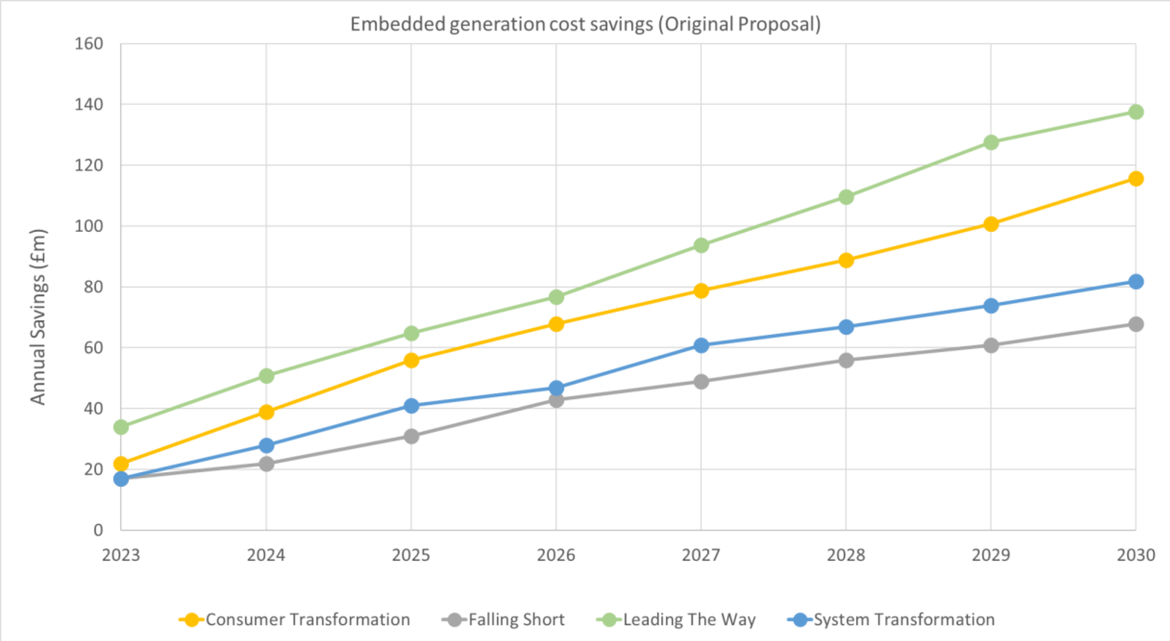

Figure 14 Original Proposal WP3 results showing the estimated demand forecast error cost per year (non-cumulative), based on if this modification were implemented in 2022, for each FES scenario.

	Impact Per Year (£m)							
Scenario	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Consumer Transformation	22	39	56	68	79	89	101	116
Falling Short	17	22	31	43	49	56	61	68
Leading The Way	34	51	65	77	94	110	128	138
System Transformation	17	28	41	47	61	67	74	82

Table 8 Original Proposal WP3 results showing the estimated demand forecast error cost savings per year in £m

The potential impact of WACM1 has also been explored and the potential economic impact for this aspect of the National Demand error was shown to be negligible. This is due to the lack of units which would be impacted by the WACM1 (i.e., non-wind units in Scotland in the size range 10-100 MW).

6. Conclusions

We have completed three main workstreams to estimate how the costs incurred by NGESO to balance the system could be affected by the outcome of GC0117. Given the uncertainty regarding the future installation of generators in Great Britain and therefore, the amount of capacity impacted by the modification, we have considered 4 scenarios (in line with NGESO Future Energy Scenario reports). The key results are:

- WP1: Impact on price stack available in the BM. There is evidence that the Original Proposal would lead to a reduction in marginal BM price resulting in annual cost savings of balancing the system of up to approximately £70 million.
- 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 £70 million. In contrast, the reduced visibility as a result of WACM1 could lead to an increase in constraint costs of up to £80 million 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 £220 million per year. In contrast, 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 approximately £530 million per year.

ESO

Appendix

Original Proposal estimated affected capacities:

Capacity in MW	2023	2024	2025	2026	2027	2028	2029	2030
BIOMASS								
Consumer Transformation	0	0	0	0	0	0	0	0
Falling Short	85	93	100	105	108	110	110	110
Leading The Way	0	0	0	0	0	0	0	0
System Transformation	85	89	92	97	102	43	48	19
GAS								
Consumer Transformation	225	532	780	945	1,144	1,275	1,372	1,384
Falling Short	691	1,062	1,355	1,711	2,012	2,346	2,620	2,867
Leading The Way	54	157	344	380	409	396	414	-481
System Transformation	225	532	780	945	1,144	1,275	1,372	1,384
NPSHYD								
Consumer Transformation	14	22	30	39	48	58	68	79
Falling Short	2	2	3	4	4	5	6	6
Leading The Way	5	8	11	14	16	19	22	24
System Transformation	5	8	11	14	16	19	22	24
OTHER								
Consumer Transformation	1,316	2,164	2,874	3,129	3,268	3,362	3,538	4,020
Falling Short	799	873	1,333	2,105	2,174	2,317	2,349	2,476
Leading The Way	2,030	2,608	2,632	2,590	3,071	3,535	4,107	4,774
System Transformation	842	1,269	1,928	1,916	2,562	2,581	2,526	2,634
WIND								
Consumer Transformation	115	318	573	821	1,083	1,391	1,717	2,093
Falling Short	20	39	58	78	98	119	139	192
Leading The Way	88	238	433	616	812	1,042	1,284	1,588
System Transformation	57	95	134	183	241	301	362	509
SOLAR								
Consumer Transformation	710	1,190	1,962	2,735	3,507	4,342	5,240	6,263
Falling Short	136	209	292	418	595	804	1,054	1,388
Leading The Way	1,378	2,317	3,528	4,739	5,950	7,161	8,372	9,582
System Transformation	526	856	1,273	1,733	2,234	2,797	3,424	4,175

WACM1 estimated affected capacities:

Capacity in MW	2023	2024	2025	2026	2027	2028	2029	2030
WIND								
Consumer Transformation	412	976	2,412	3,139	4,568	5,285	6,912	8,816
Falling Short	43	99	524	747	1,514	2,765	3,961	5,221
Leading The Way	1,072	2,468	3,513	5,231	5,956	7,311	9,095	10,708
System Transformation	78	503	1,371	2,636	3,347	4,686	5,244	7,683