CORNWALL INSIGHT

CREATING CLARITY

CUSC Modifications Analysis

Zenobe Energy Limited

23 August 2022

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Contents

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1. Executive summary

Zenobe Energy Limited ("Zenobe") commissioned Cornwall Insight ("we", "us", "our") to provide support to quantify the impact of two Connection and Use of System Code (CUSC) modification proposals which it was intending to progress through the open governance process. Those modifications have since been formally submitted as CUSC Modification Proposal (CMP) 393 *Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage* and CMP394 *Removing Generation Charges from Electricity Storage Operators in Positive TNUoS Zones*.

These aim to reform the Transmission Network Use of System (TNUoS) classifications (conventional carbon, conventional low carbon. Intermittent) to create cost-reflective tariffs for battery storage.

This report details the analysis we undertook prior to Zenobe formally proposing the modifications, as summarised in Annex 1 provided with both modification proposal submissions. It provides;

- An overview of our baseline TNUoS forecast over a 15 year period, and how this would change with the implementation of the two modifications
- An approximation of the impact of increased deployment on curtailment costs
- A brief assessment of how the modifications could impact on storage deployment

1.1. Impact on TNUoS

Neither of the proposed modifications will have a material impact on TNUoS for generation technologies other than battery storage. There will be slight increases in TNUoS charges for all generators in GB, but these are relatively small (typically ~£0.20/kW) and therefore are not expected to have a material impact on the context of most generators' total TNUoS charges.

The impacts on storage are more marked, with significant decreases in charges in the most northern transmission generation zones while typically maintaining the existing level of credits in southern zones.

1.2. Impact on curtailment costs

We have assessed the marginal impact of adding a 1MW/2MWh storage facility behind the B6 boundary, showing a reduction in constraint volumes of approximately 202MWh in 2025, reducing to 127MWh in 2035, with a greater impact in the winter given that wind speeds are the primary driver behind constraints.

The financial impact of this reduction in constrained volume falls over time as both the total constrained volume and volumetric costs of constraints fall. Our analysis of the financial impact in 2025 shows that the addition of the 1MW/2MWh storage facility behind the B6 boundary storage has a positive impact, reducing constraint costs by ~£35,000/MW in 2025.

1.3. Impact on storage deployment

While TNUoS is a significant consideration of storage developers, it is not the only material locational consideration, with other key factors including:

- The probability of constraint at key times impeding revenue options
- Large connection costs in some areas may be sufficient to stop projects being developed
- Sharing connection, development and operation costs between a storage and a co-located renewable asset will lead to cost savings - therefore the potential for co-location is an important consideration
- Participation in some ancillary services may carry more risk/be more difficult if the assets are unable to guarantee output in certain periods due to constraints being applicable

2. Introduction

Zenobe commissioned Cornwall Insight to provide analysis on the potential impact of two proposed Connection and Use of System Code (CUSC) modifications. The modifications are as follows:

- ***CMP393** Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage*
- ***CMP394** Removing Generation Charges from Electricity Storage Operators in Positive TNUoS Zones*

This report has been prepared for Zenobe to present to the CMP393 and CMP394 workgroups, setting out the analysis we undertook prior to Zenobe proposing the modifications. The analysis is summarised in Annex 1 to both CMP393 and CMP394.

We have addressed three main questions in relation to the modifications, summarised below:

- How would the proposed modifications impact TNUoS charges for storage and for other generation technologies?
- To what extent would the deployment of storage behind constraints reduce curtailment costs and network reinforcement costs?
- How would the proposed modifications impact the deployment of storage in generation-constrained regions?

The remainder of this report takes those three questions in turn, with the first two based on our in-house modelling and the latter qualitatively based on our interactions with storage developers. Modelling undertaken to quantify the second question was necessarily high level to enable outputs to be provided sufficiently quickly for the modifications to progress.

3. Impact of modifications on TNUoS

In this section we show the impact of the two proposed modifications on generator TNUoS, both for storage assets and for other assets. We first outline our approach, before showing the results under the existing TNUoS methodology.

3.1. Approach

We have used a combination of latest actual TNUoS, *National Grid Electricity System Operator*'s (NG ESO) five-year forecast and our own in-house TNUoS forecast to show the impact on TNUoS in four spot years:

- 2022-23 (i.e. what tariffs would have been had the modifications been in place this year)
- 2025-26 (using NG ESO's five-year forecast)
- 2030-31 (using our in-house forecast)
- 2035-36 (using our in-house forecast)

Our in-house forecast enacts the requirements of the CUSC for the calculation of TNUoS, using our demand and generation forecasts for each year to determine a forecast of TNUoS charges under that methodology. We have used NG ESO's forecast for the early years as it is a standard publication used by industry, with our in-house forecast used for later years as NG ESO's publication only runs to 2027-28.

We have shown the impacts on five archetype generators in different locations, and on storage in all zones. The five archetypes are shown in Figure 1.

Figure 1 – Archetype generators

Archetype number	Description	TNUoS classification	TNUoS generation zone	Reason for inclusion
#1	North Scotland – onshore wind	Intermittent	Zone 1	Typical Scottish wind generator – currently the highest charges
#2	South Scotland – onshore wind	Intermittent	Zone 11	Wind located at the most southerly point north of the B6 boundary
#3	Northern England – CCGT	Conventional Carbon	Zone 13	CCGT in northern England
#4	South East England – solar	Intermittent	Zone 24	Typical location for solar generation
#5	South West England – CCGT	Conventional Carbon	Zone 26	Currently highest credits for CCGT in this zone

Source: Cornwall Insight

Zones have been selected to give a representative spread, including generators currently facing the highest charges and those currently receiving the greatest credits. Technologies have been selected to give a spread of technologies, and also to provide representative locations for that technology (e.g. wind in the far north, solar in the far south).

3.1.1. Impact of modifications

We have overlayed CMP393 and CMP394 onto our baseline TNUoS model. This is based on static assumptions on the generation mix and so the locational elements (Peak Security, Year Round Shared and Year Round Not Shared) are not impacted for any generators.

However, the modifications result in lower TNUoS revenue from storage, so impact the EU Adjustment Factor which is used to ensure average generator TNUoS charges fall within €0-2.50/MWh. It is currently a negative adjustment, used to bring the average generator charge down from above €2.50/MWh. By reducing the average charge from the locational elements, the modifications result in a smaller negative adjustment being required, so increase TNUoS charges for all other generators.

For both modifications, we have calculated the reduction in revenue from storage which arises from applying the modifications based on our forecast of storage capacity in each generation zone. Site specific Annual Load Factors (ALF) have been used where available (e.g. for existing pumped hydro) and the generic pumped hydro ALF (9%) used for the remainder.

CMP393 requires a change to the ALF calculation for storage, to be based on "net" network use rather than gross generation. The two ALF calculations are shown below.

$$Baseline\ ALF = \frac{Gross\ Generation\ Volume\ (MWh)}{TEC\ \times 24 \times 365}$$

$$Modification\ 1\ ALF = \frac{Gross\ Demand\ Volume\ (MWh) - Gross\ Generation\ Volume\ (MWh)}{TEC\ \times 24 \times 365}$$

For standalone storage, demand volumes are larger than generation volumes due to battery inefficiency which results in some power taken from the network being lost. We have used an assumption of 85% efficiency (based on our experience of working with storage asset developers) to determine the ALF under CMP393. Compared to the generic ALF of 9%, this reduces the storage ALF in CMP393 to 1.6%.

We have calculated the difference in TNUoS revenue using baseline ALFs vs CMP393 ALFs to determine the change in the EU Adjustment Factor driven by CMP393.

CMP394 is similar in that it reduces storage revenues. Each zone has been identified as either TNUoS positive or not in each year based on whether the £/kW rate for storage with the generic ALF would be positive in that zone. This includes the negative EU Adjustment Factor. Revenue from storage in TNUoS positive zones has been set to zero and the EU Adjustment Factor recalculated.

We note that there is a circularity in this approach, with the change to the EU Adjustment Factor potentially pushing marginal zones from TNUoS positive to TNUoS negative. However, this is not considered material as changes to the EU Adjustment Factor are small, with our analysis showing a change of less than £0.50/kW.

3.2. Results

The impacts of the modifications vary over time, but are reasonably consistent across the two early spot years (2022-23 and 2025-26) and two later spot years (2030-31 and 2035-36).

3.2.1. Early spot years

The impacts of the modifications on non-storage generation technologies are relatively modest, as shown for 2022-23 in Figure 2.

Figure 2 – Impact on archetype generators in 2022-23

2022-23 (£/kW)	Baseline	CMP393	CMP394	Impact of CMP393	Impact of CMP394
North Scotland (zone 1) Wind	23.977	24.007	24.206	0.029	0.229
Borders (zone 11) Wind	10.179	10.209	10.408	0.029	0.229
North East (zone 13) CCGT	9.442	9.472	9.671	0.029	0.229
South East (zone 24) Solar	0.107	0.136	0.336	0.029	0.229
South West (Zone 26) CCGT	-4.768	-4.739	-4.539	0.029	0.229

Source: Cornwall Insight

These modest impacts are driven by the relatively small TNUoS revenues associated with storage. For example, in 2022-23 the revenue reduction derived from removing TNUoS from storage in positive zones (i.e. CMP394) is ~£15mn, with that reduction resulting in the EU Adjustment Factor increasing from a negative adjustment of £0.229/kW to zero, as average generator revenue already falls within the allowable range without adjustment.

The outcomes for 2025-26 is very similar, albeit with the EU Adjustment Factor still being required under CMP394, increasing from a baseline of (-)£2.545 to (-)£2.234 (in 2022-23 prices) as shown in Figure 3

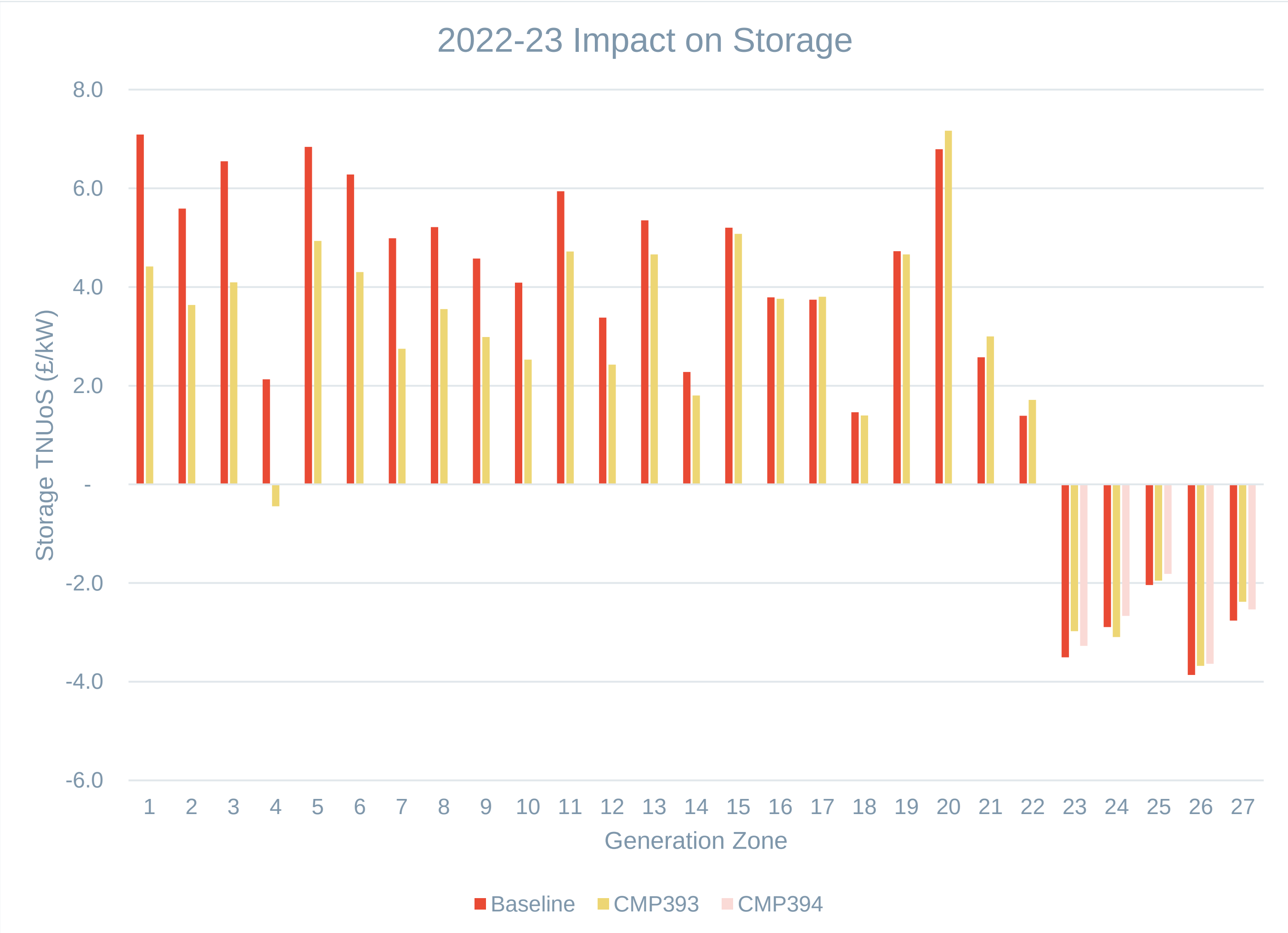
Figure 3 – Impact on archetype generators in 2025-26

2025-26 (£/kW)	Baseline	CMP393	CMP394	Impact of CMP393	Impact of CMP394
North Scotland (zone 1) Wind	25.813	25.874	26.034	0.062	0.221
Borders (zone 11) Wind	9.954	10.015	10.175	0.062	0.221
North East (zone 13) CCGT	6.121	6.183	6.342	0.062	0.221
South East (zone 24) Solar	-2.199	-2.137	-1.978	0.062	0.221
South West (Zone 26) CCGT	-7.840	-7.778	-7.619	0.062	0.221

Source: Cornwall Insight

The impact on storage is more marked, as shown for all zones for 2022-23 in Figure 4.

Figure 4 – Impact on storage in 2022-23



Source: Cornwall Insight

For CMP393, zones broadly fall into three types:

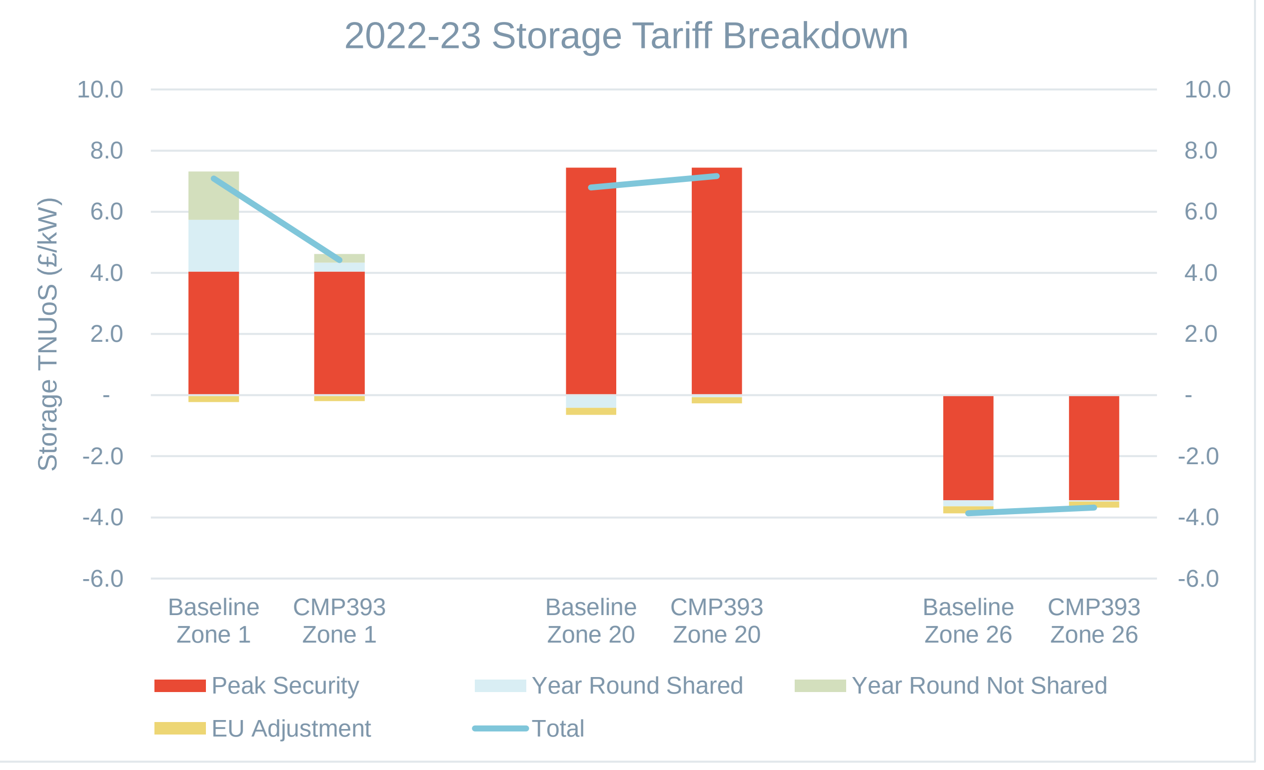
- Those in Scotland and northern England (zones 1-14) in which the Year Round elements are significant. Those elements are scaled by ALF in the calculation of storage TNUoS. The reduction in

ALF drives a reduction in tariffs for storage

- Those in the Midlands and Wales (zones 15-22) in which charges are dominated by the Peak Security element which is not scaled by ALF in the calculation of storage TNUoS. The reduction in ALF therefore does not drive a significant reduction, and in some instances (e.g. zone 20) the slight increase in the EU Adjustment Factor drives an overall increase
- Those in southern England (zones 23-27) in which storage receives credits. There are some small decreases in credits for storage in these zones as the Year Round elements are scaled by the lower ALF resulting in lower overall credits

The varying dominance of different tariff elements is shown in Figure 5 for zones 1 (North Scotland), 20 (Pembrokeshire) and 26 (Somerset and Wessex) in 2022-23, showing the impact of CMP393 on each element.

Figure 5 – 2022-23 tariff breakdown



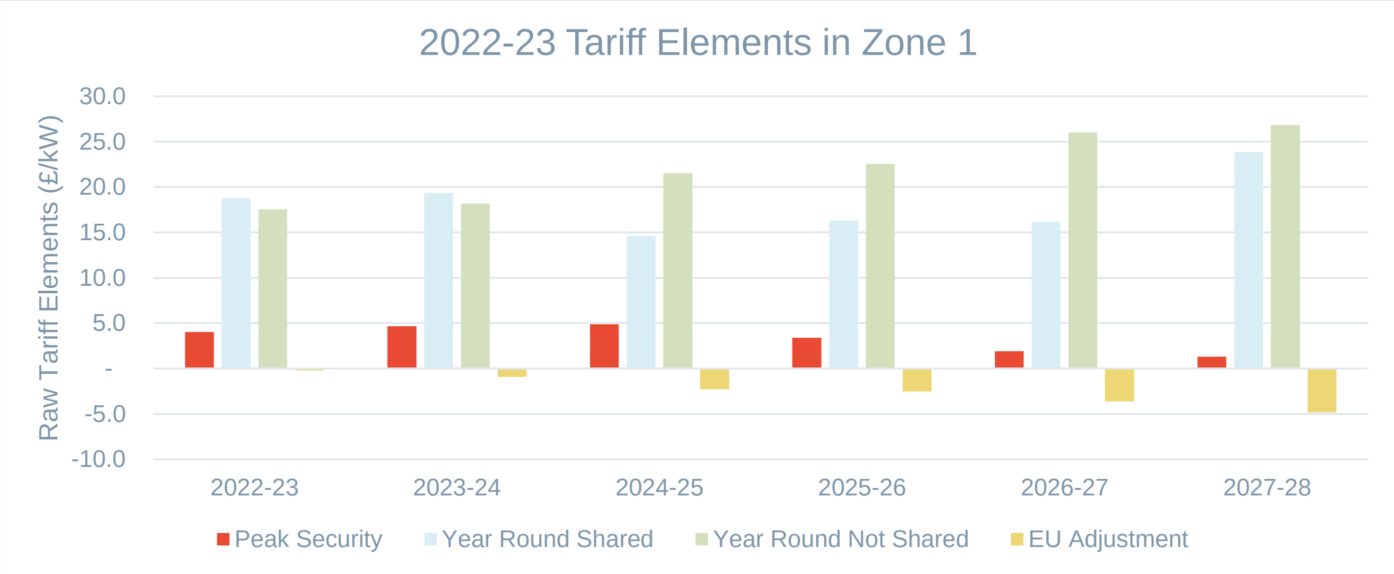
Source: Cornwall Insight

CMP394 has a bigger impact, with charges removed for storage in the majority of zones. In those where the charge is not removed (zones 23-27) the credits reduce slightly due to the smaller negative residual, which is in line with the impact on all other technologies in all zones.

3.2.2. Later spot years

The balance between Year Round and Peak Security elements shifts significantly over the analysis period, as shown in Figure 6 for zone 1 from 2022-23 to 2027-28. Notably, there is a significant step up in the Year Round element in 2027-28 driven by the introduction of the Torness to Hawthorn Pit High Voltage Direct Current (HVDC) link. This is followed by the Peterhead to Drax HVDC link in 2029-30. Hence by 2030-31, the Year Round elements in Scotland are much more material. This in turn results in higher overall revenue from generation, so requires a larger negative EU Adjustment to bring the average charge back to €2.50/MWh.

Figure 6 – 2022-23 tariff breakdown



Source: NG ESO Five Year Forecast, compiled by Cornwall

The Year Round elements are scaled by ALF in the calculation of storage TNUoS – therefore even without the modifications the decrease in Peak Security charges more than offsets higher Year Round charges for Scottish storage. Coupled with a larger EU Adjustment, this results in many more zones having credits for storage in the baseline, and so smaller impacts from the modifications as shown for a subset of zones in Figure 7.

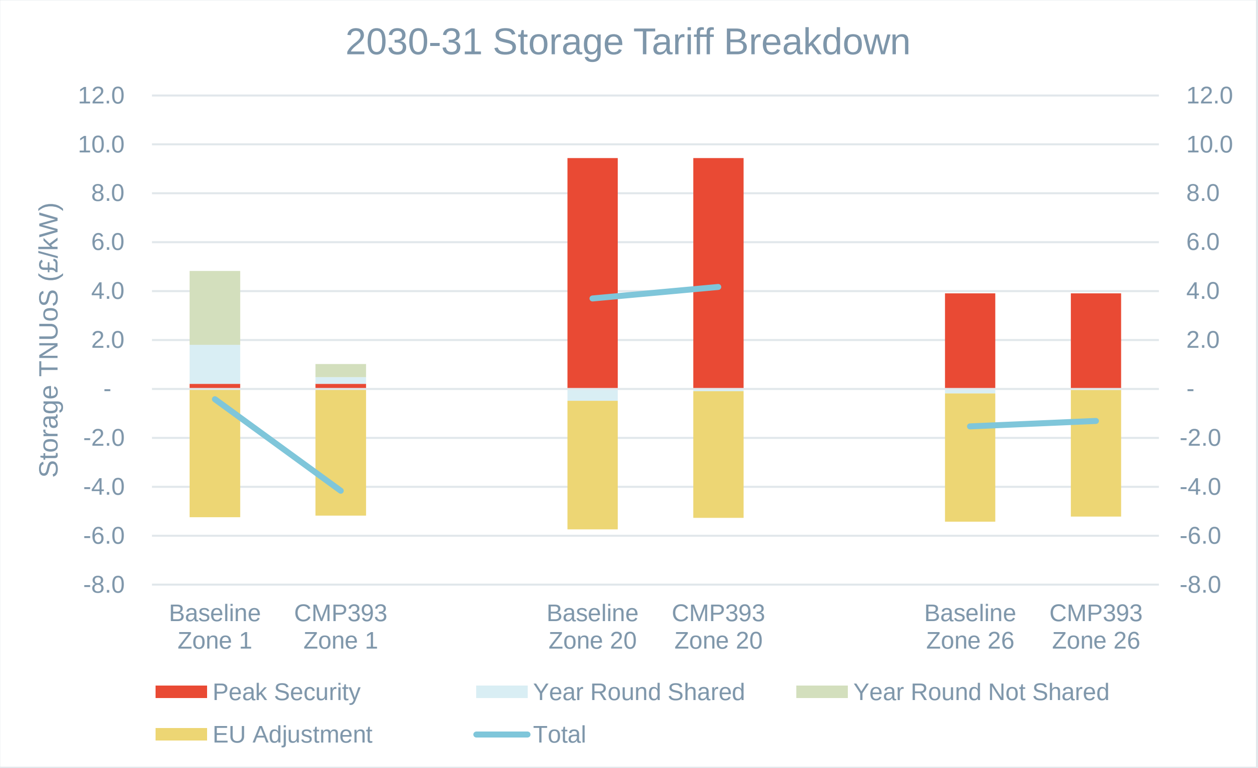
Figure 7 – Impact on storage in 2030-31

Source: Cornwall Insight

CMP393 now drives larger credits. The Year Round elements are sufficiently high that a shift from a 9% load factor to 1.6% has a material impact. The same pattern seen in 2022-23 is shown thereafter, with zones in the Midlands seeing relatively small impacts due to the higher Peak Security elements in those regions. Zone 20 is an outlier due to a high Peak Security charge and Year Round credit – storage remains exposed to the Peak Security charge but sees a smaller offsetting reduction from the Year Round credit (due to being scaled by a smaller ALF), hence the overall increase. Zones in the South continue to be dominated by Peak Security so there are relatively small impacts.

A breakdown by tariff element for zones 1, 20 and 26 is shown in Figure 8.

Figure 8 – 2030-31 tariff breakdown



Source: Cornwall Insight

As there are a limited number of TNUoS positive zones, CMP394 has a minimal impact with only zones 3 and 20 affected. As a result, CMP393 drives a bigger impact on other technologies with the revenue change from storage from CMP394 no longer driving any impact on the EU Adjustment, as shown in Figure 9.

Figure 9 – Impact on archetype generators in 2030-31

2030-31 (£/kW)	Baseline	CMP393	CMP394	Impact of CMP393	Impact of CMP394
North Scotland (zone 1) Wind	34.529	34.592	34.529	0.063	0.000
Borders (zone 11) Wind	14.865	14.928	14.865	0.063	0.000
North East (zone 13) CCGT	-0.369	-0.307	-0.369	0.063	0.000
South East (zone 24) Solar	-3.264	-3.201	-3.264	0.063	0.000
South West (Zone 26) CCGT	-2.394	-2.331	-2.394	0.063	0.000

Source: Cornwall Insight

The impacts seen on storage in 2030-31 become even more marked in 2035-36, but with similar impacts on other technologies as shown in Figure 10.

Figure 10 – Impact on archetype generators in 2035-36

2035-36 (£/kW)	Baseline	CMP393	CMP394	Impact of CMP393	Impact of CMP394
North Scotland (zone 1) Wind	35.753	35.812	35.753	0.058	0.000
Borders (zone 11) Wind	14.793	14.851	14.793	0.058	0.000
North East (zone 13) CCGT	-1.691	-1.632	-1.691	0.058	0.000
South East (zone 24) Solar	-4.919	-4.861	-4.919	0.058	0.000
South West (Zone 26) CCGT	-4.249	-4.191	-4.249	0.058	0.000

Source: Cornwall Insight

3.3. Summary

Both modifications have relatively minor impacts on non-storage technologies in all years, with no impact seen at all under CMP394 in 2030-31 and 2035-36. However, they do have a material impact on storage in early years, with significant decreases in the high TNUoS seen in north Scotland zones under both modifications, most notably under CMP394. In a small number of outlying zones, storage assets experience higher charges as a result of CMP393, but these increases are much smaller than the decreases seen elsewhere.

4. Curtailment and network reinforcement costs

We have taken a simplified approach to estimating the impact of additional storage behind a constraint on the volume of generation curtailed and resultant costs to NG ESO of alleviating that constraint. We have then used the impact on curtailment costs to approximate the benefits derived from reducing the need for additional network assets by increasing the deployment of storage. This provides an indication of the potential benefit if the modifications increase battery deployment.

4.1. Key simplifications

Due to time constraints on producing model outputs, we have made necessary simplifications to our model including:

- Only modelling the B6 boundary rather than the full set of inter-related transmission constraints
- Simplified view on output from controllable generators behind the constraint – most notably Peterhead (CCGT) and Torness (nuclear)
- Simplified view on the behaviour of interconnectors, with NorthConnect (1.4GW to Norway) assumed to import and Moyle (500MW to Northern Ireland) assumed to export. However, we have considered a sensitivity under which NorthConnect operates in line with our power market modelling
- Storage dispatch is significantly simplified to use the constraint as its main dispatch signal, choosing to charge at times of constraint and discharge at times of no constraint

4.2. Curtailment volumes

We have provided a high-level analysis of the impact of battery storage on constraint costs. To do so, we have modelled constraints on the B6 boundary – which follows border between Scotland and England and is one of the main constraints on the transmission system – over a 15-year time horizon as follows:

- Modelling of the volume (MWh) constrained in each half hour under a baseline with our forecast generation mix. For context, we have modelled both a scenario with no storage and a scenario with our forecast of storage capacity behind the B6 boundary (1.7GW/3.4GWh in 2025) to show the value of existing (and planned) storage capacity for relieving constraints
- Modelling of the equivalent volume constrained under a scenario with an additional 1MW of storage behind the constraint
- Forecasting of the estimated cost per MWh of constraints to derive the cost saving on curtailment costs derived from the additional 1MW of storage.

4.2.1. Volume constrained – baseline

As we are modelling the B6 boundary which sits on the Scotland to England border, we first determined the volume constrained based on expected generation in Scotland less expected demand in Scotland, compared to the network transfer capacity available on the B6 boundary.

Scottish generation was determined based on our forecast of generation capacity in Scotland using our Benchmark Power Curve power market model, with that generation assumed to dispatch as follows:

- The load factor for the Peterhead CCGT has been set at 35% and for the Torness nuclear power station has been set at 85%. Those stations are assumed to output a flat output shape at 35% and 85% of capacity respectively. This is a significant modelling simplification, particularly for the CCGT, but was necessary to enable delivery within the required timescales
- Output from intermittent renewables in each half hour is based on 64 stochastic samples with a Monte Carlo simulation used to evaluate the likely outcome across all samples

- Storage dispatch is based on a simple algorithm:
  - Available storage is dispatched to reduce constraints at £0/MWh. This is because the Transmission Constraint Licence Condition requires Balancing Mechanism participants behind a constraint to bid their marginal cost of reducing generation/increasing demand – which in the case of storage is £0/MWh
  - Storage then discharges whenever there is volume available in the storage and there is no constraint on the boundary
  - Interconnector flows are assumed to be import from Norway (across the NorthConnect interconnector) at full capacity, 1400MW and export to Northern Ireland (across the Moyle interconnector) at full capacity, 500MW. As with Peterhead and Torness, this is a significant but necessary assumption

Scottish demand has been estimated based on our view of the GB demand shape and locational demand data from *National Grid's Future Energy Scenarios (FES)* 2021. As with generation, 64 independent samples are also produced for demand.

Network transfer capacity has been derived from NG ESO's data portal which includes available transfer capacity. That data has also been used to estimate the probability of outages. Network transfer capacity increases faster than generation capacity in the long-term. 2025 sees the biggest over-capacity of generation to network transfer capacity which then decreases. The addition of the Eastern HVDC links in the late 2020s results in network transfer capacity exceeding de-rated generation capacity. So, much high constraint volumes were expected to be observed in early years.

4.2.2. Volume constrained

We have first determined the constrained volume in each year with no storage connected. We have then determined the value of existing and planned storage by overlaying our current forecast of storage capacity in each year. Finally, we have determined the reduction in constrained volumes from additional storage by adding an additional 1MW/2MWh storage asset to the Scottish generation mix and rerunning the model. This allows us to model the change in constrained volumes from that additional 1MW, which can then be used as a proxy for the £/kW benefit of **additional** storage behind the constraint.

This results in three scenarios having been run within the analysis:

- **No storage scenario**, which models the volume and costs of constraints at the B6 boundary in 2025, 2030 and 2035 based on the inputs discussed in Section 4.2.1 with no storage behind the B6 boundary
- **Baseline scenario**, which models the volume and cost of constraints at the B6 boundary in each year with our forecast of storage capacity in each year included
- **Marginal scenario**, which mirrors the Baseline scenario but includes an additional 1MW/2MWh storage asset

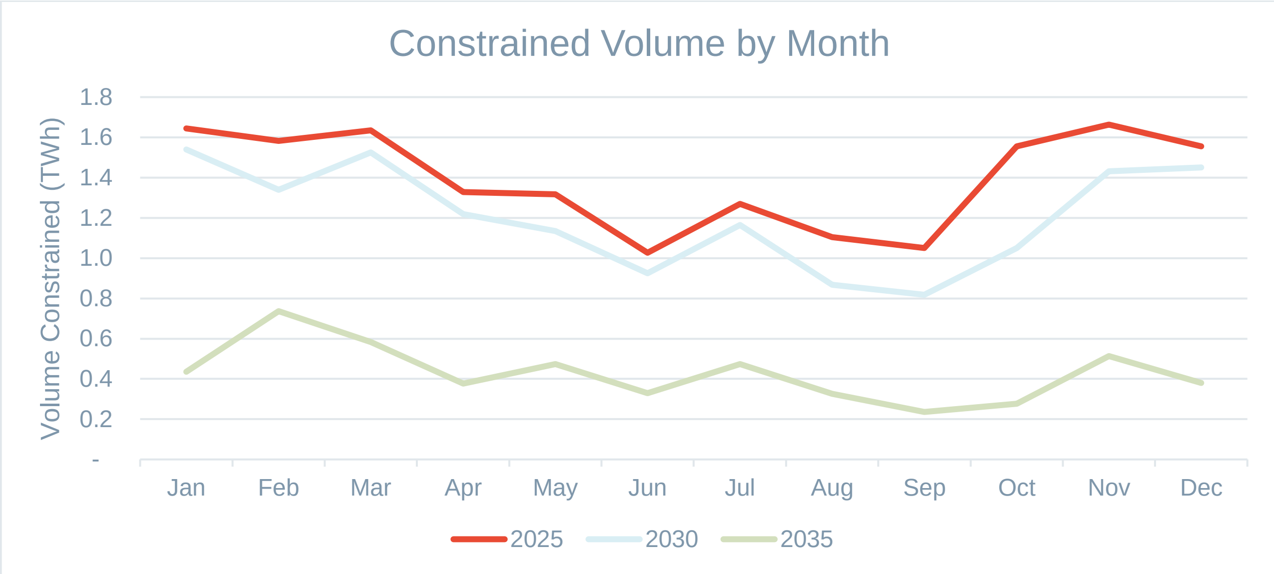
4.2.3. Results – no storage

The volume of constraints seen without any storage behind the B6 boundary averages ~17.1TWh in the year across samples in 2025.

On a monthly basis there is a pattern of constrained volumes being higher in winter than summer in 2025 when the constraint is the greatest – the reason for which being that although boundary capacity and Scottish demand are lower in the summer months, winter load factors for onshore and offshore wind capacity are one of the driving factors behind constraints across the B6 boundary, and wind speeds are higher in the winter.

Constrained volumes decrease significantly over time out to 2035. This is because the network transfer capacity on the B6 boundary increases at a faster rate than the generation capacity, and electrification drives an increase in demand in Scotland. These two factors combined result in lower constrained volumes.

Figure 11 – Monthly volume of constraint (2025, 2030 and 2035) – Baseline scenario



Source: Cornwall Insight

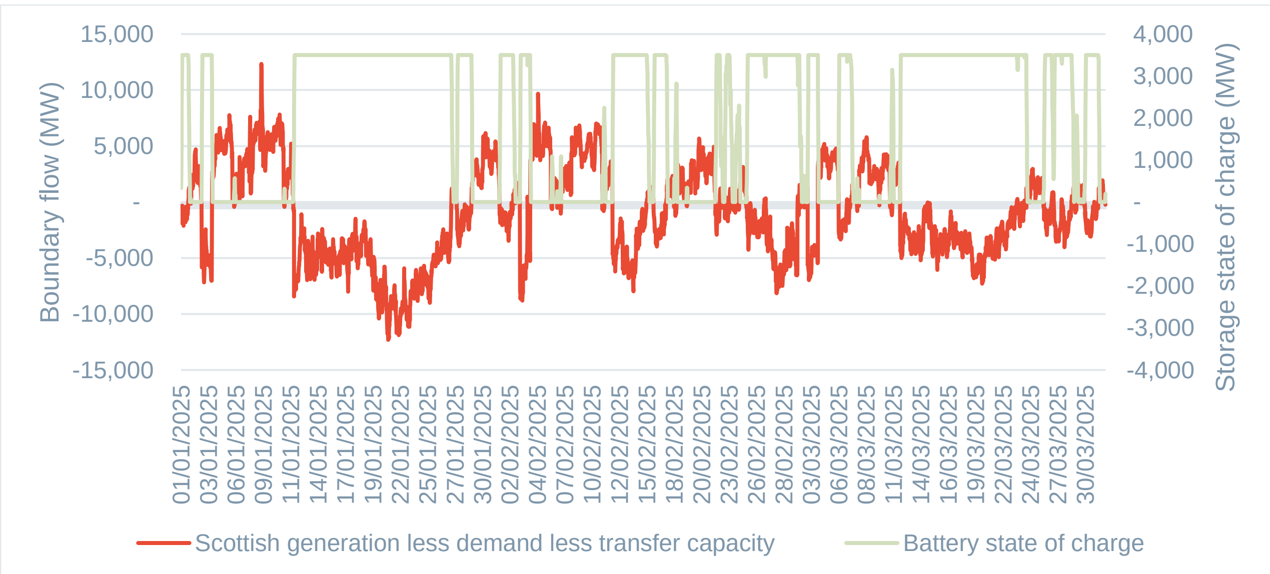
4.2.1. Results – baseline storage

The volume of constraints is significantly lower with storage included, at 16.7TWh in 2025, a reduction of ~400GWh compared to the no storage scenario.

On a per MW basis, 2 hour storage alleviates ~223MWh of constraint per MW of storage. This corresponds to ~0.3 cycles per day. This is relatively low compared to the typical operating pattern of storage assets, driven by the duration of constrained and unconstraintED periods. For example, in all samples there are periods of several days with no constraint and periods of several days with continuous constraint. During those periods, our simplified approach to deployment of storage results in assets being empty, with no option to import; or full, with no option to export, respectively.

This is illustrated in Figure 12 which shows the outputs for the first quarter of 2025 for a single sample. Flows across the B6 boundary are shown relative to the transfer capacity, i.e. negative values are those which would be constrained, alongside the state of charge of the 3.4GWh of storage assumed in the baseline scenario.

Figure 12 – illustrative storage activity



Source: Cornwall Insight

As an example, there is a long period in the second half of January in this sample where the constraint is active. Storage charges fully at the start of this period and is then unable to discharge until late January when the constraint is no longer active. In reality, storage would likely operate in a more nuanced manner, potentially discharging at times of lower constraint or coordinating with other generators in order to be available to charge at times of higher constraint.

Figure 13 shows the total volumes constrained for each year in the no storage and baseline scenarios, along with volume of storage assumed behind the B6 boundary in each year.

Figure 13 – Annual constraint volumes and impact of storage, No storage and Baseline scenarios

Year	No storage Total Constraint (TWh)	Baseline storage Total Constraint (TWh)	Difference (GWh)	MW of storage capacity behind B6 boundary	Difference (MWh per MW of storage capacity)
2025	17.1	16.7	390.4	1,749.8	223.1
2030	14.9	14.5	415.0	1,749.8	237.2
2035	5.6	5.1	428.9	2,857.3	150.1

Source: Cornwall Insight

4.2.1. Results – incremental additional storage

The volume of constraints is again lower with an incremental additional 1MW of storage. The value of incremental storage decreases as storage volumes increase (smaller constraints are alleviated by storage volumes so additional storage has an increasingly lower impact). However, there is still a significant benefit from an incremental 1MW of storage in 2025.

Figure 14 shows the total for each year in the Baseline and Marginal scenarios.

Figure 14 – Annual constraint volumes and impact of storage, Baseline and Marginal scenarios

Year	Baseline Total Constraint (TWh)	Marginal Total Constraint (TWh)	Difference (MWh)
2025	16.7	16.7	201.9
2030	14.5	14.5	223.4
2035	5.1	5.1	126.8

Source: Cornwall Insight

The constrained volume avoided by the additional 1MW/2MWh battery shows the impact that storage has on the overall constraint considerations on the B6 boundary. This is significant in relation to the modifications, as it means that any increase in potential storage asset deployment in constrained areas is likely to reduce the amount of action the system operator needs to take. Any increased deployment of storage assets as a result of the modifications is therefore likely to be beneficial.

4.3. Curtailment costs

The value associated with these constraint actions has also been forecast, based upon the modelling of the impact of additional storage on the volumes of generation constrained. In order to alleviate a constraint, NG ESO will typically instruct a generator behind the constraint to reduce output and another generator in front of the constraint to increase output. We have identified the likely marginal unit on each side of the constraint (i.e. the units which will be required to reduce/increase output to alleviate the constraint) and their likely bid/offer costs to NG ESO.

4.3.1. Marginal generators and costs

In all years (2025, 2030 and 2035), we have assumed that the marginal unit behind the B6 boundary will be a wind asset and the marginal unit in front of the B6 boundary will be a gas generator.

Wind behind the constraint will be required to bid at its marginal cost in line with the Transmission Constraint

Licence Condition. In each year we have estimated the costs as follows:

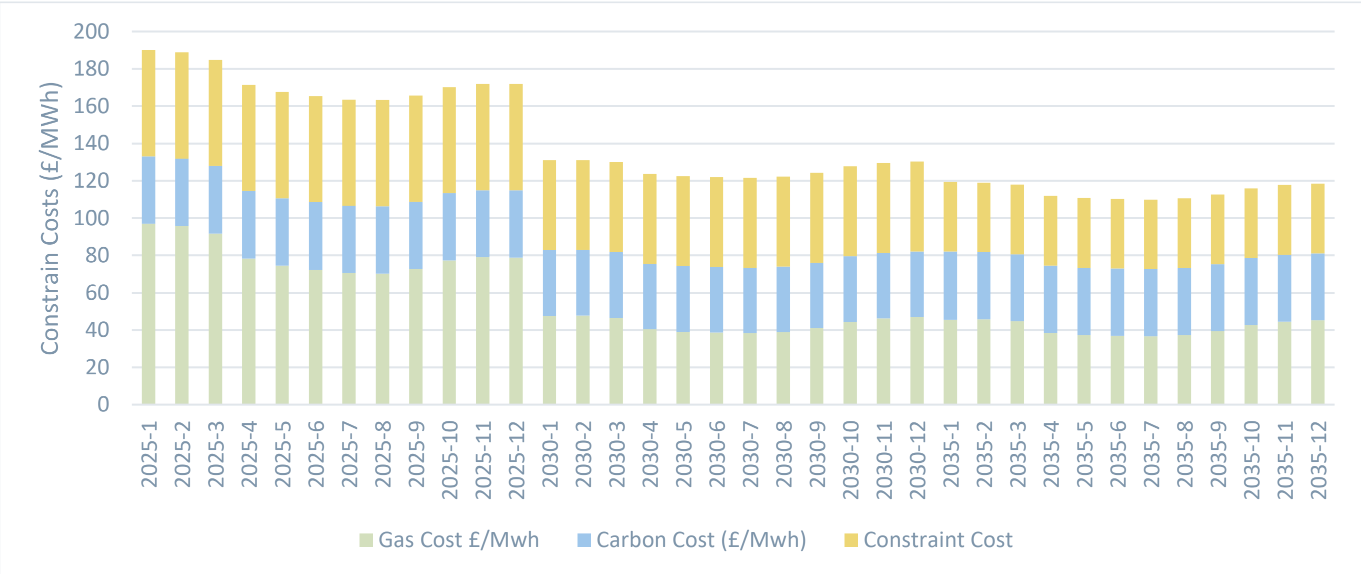
- 2025: marginal wind generator likely to be a Renewables Obligation Certified generator, so its bid will be set to recover its lost Renewables Obligation Certificate (ROC) value and ROC recycle value. We have set the bid price as our estimate of the ROC price (£52.88/MWh), ROC recycle price (£5.22/MWh) and the proportion of that value which a generator would typically retain under a Power Purchase Agreement (PPA) at 98%.
- 2030: marginal wind generator likely to be a Contracts for Difference (CfD) asset from Allocation Round (AR) 3, which we have set based on Forthwind at £48.21/MWh.
- 2035: marginal wind generator likely to be a CfD asset which has not yet been allocated. We have estimated the bid price based on our forecast of the Levelised Cost of Energy (LCOE) of new build offshore wind in 2030 at £37.38/MWh.

Gas generation in front of the constraint is not bound by the Transmission Constraint Licence Condition. Nonetheless, we have continued to assume its BM offer price is based on its marginal cost of generation. In reality, gas assets will have complex bid/offer strategies so there may be higher costs to NG ESO. The marginal cost of generation for gas is based on the cost of gas, carbon and the carbon price support.

We have assumed the gas fired generator being dispatched is 50% efficient in 2025 and 2030 to represent the efficiency of a CCGT and 48% efficient in 2035 to represent the efficiency of a reciprocating gas engine. This reflects our view of the relative importance in the capacity mix of each type of technology in the timeframe.

The monthly costs are shown in Figure 15; the yellow bar is the cost to the renewables generator being dispatched down, the green bar is the gas cost to the gas-fired generator of being dispatched upwards and the blue bar is the total carbon cost to the gas-fired generator of being dispatched upwards. The sum of all three bars is the total constraint cost.

Figure 15 – Monthly average constraint costs



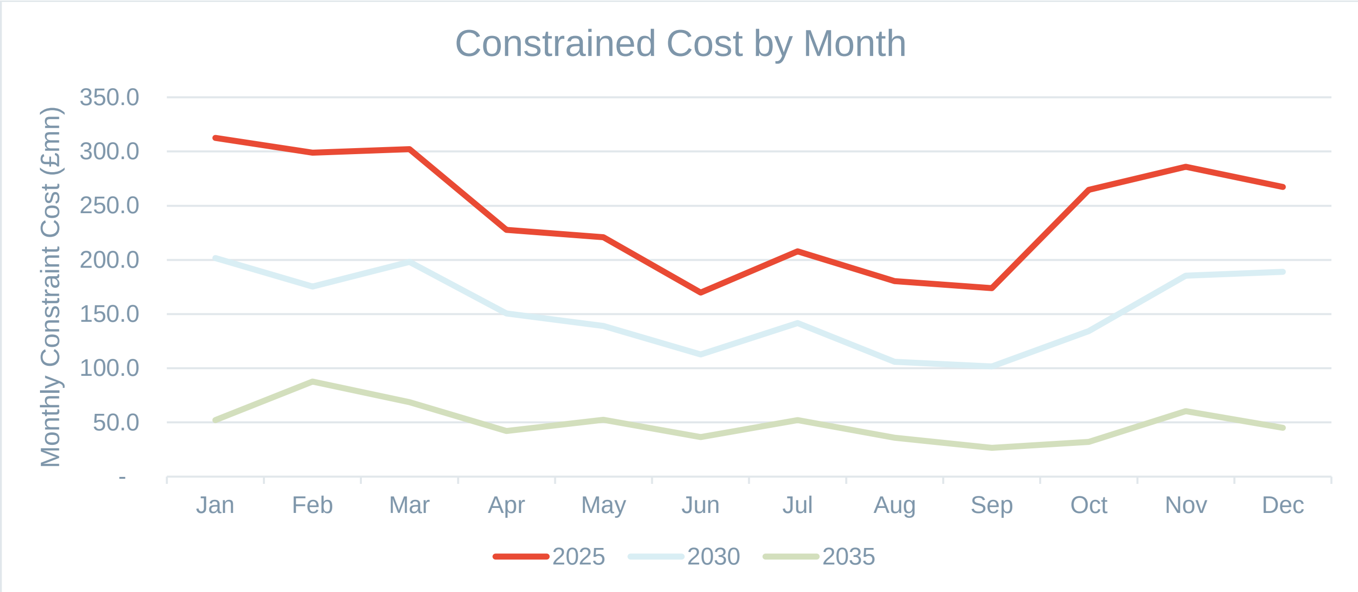
Source: Cornwall Insight

4.3.2. Impact of storage on curtailment costs

Within the Baseline scenario, the costs of the constraint actions are forecast to be around £2.9bn in 2025. The effect of the marginal 1MW of 2-hour storage is to reduce constrained costs paid by the system operator by £35k in 2025.

A similar monthly pattern to that seen for the forecast volumes is observed in the cost, which is exacerbated by higher gas prices in the winter. This is shown in Figure 16, which demonstrates the cost of constrained volumes within the Baseline scenario.

Figure 16 – Monthly cost of constraint (2025, 2030 and 2035) – Baseline scenario



Source: Cornwall Insight

Figure 17 below provides the constraint costs for the three years covered, outlining the total costs in the Baseline and Marginal scenarios. The table also shows, on a £/MW of storage capacity basis, the difference between the two scenarios.

Figure 17 – Annual cost of constraint and effect of storage

Year	Baseline - Total Constraint Cost (£mn)	Marginal - Total Constraint Cost (£mn)	Difference (£/MW)
2025	2,912.0	2,912.0	34,978.6
2030	1,835.5	1,835.4	28,245.9
2035	591.7	591.7	14,486.3

Source: Cornwall Insight

As with the volume of constraint, this analysis shows that there is savings for the system operator by storage assets being placed to alleviate constraints, with a saving of £35,000 in 2025 for every MW of 2-hour duration battery storage added. This demonstrates the potential benefit CMP393 and CMP394 could have on network costs if they encourage new assets to be deployed. The reduction in constraint volumes in the forecast scenarios in 2030 and 2035 means that the costs also reduce in these years, dropping to £592mn in 2035 in the Baseline scenario and only reducing from this by ~£14,000/MW in the Marginal scenario.

4.3.3. Sensitivity – interconnectors high exports

We anticipate that the Norwegian interconnector will import into GB the majority of the time as the marginal cost in GB is higher than Norway due to high gas penetration, the Carbon Price Support additional tax on GB generators and GB ETS prices clearing above EU ETS. However, we note that the increasing deployment of offshore wind in line with the UK's net zero targets means that there are likely to be increasing periods of exports from GB to continental markets including Norway.

To address this possibility, we have looked at a sensitivity where hourly exports are based on the flows across the Norwegian interconnectors in our Benchmark Power Curve model which looks at available capacity between different European markets and relative capacity mixes and demand in each market to determine cross border flows.

This results in more exports to Norway in periods of high wind output, which reduce the constraints across the B6 boundary by increasing demand above the constraint. Total constraint costs are reduced from £2.9bn in the baseline scenario in 2025 to £1.7bn under the interconnector high export sensitivity. However, despite reducing the total level of constraints, there is a synergy between storage and interconnectors meaning the £/MW effect of marginal storage in 2025 increases from the £35,000/MW calculated under the baseline to £38,500/MW under the interconnector high export sensitivity. This is because increased demand from Norway allows the storage to reduce volumes stored more often and is therefore more available to increase demand to alleviate constraints when they occur.

Figure 18 shows the total constraint costs under the baseline and marginal storage scenarios and the £/MW benefit of storage under both the “core” scenario (as detailed in Section 4.3.2) and the interconnector high exports sensitivity.

Figure 18 – comparison of curtailment costs under core scenario and interconnector high exports sensitivity

Scenario	Baseline - Total Constraint Cost (£mn)	Marginal - Total Constraint Cost (£mn)	Difference (£/MW)
2025 – Core	2,912.0	2,912.0	34,978.6
2025 – interconnector high exports	1,742.1	1,742.0	38,516.6
Variance	-1,169.9	-1170.0	3,538.0

Source: Cornwall Insight

There is potential for additional benefit from storage assets in the short term compared to the analysis assessed in Section 4.2.2. However, it also demonstrates that longer term benefits from storage assets may reduce if interconnector flows begin to change.

4.4. Network reinforcement costs

An alternative to using storage to resolve constraints would be to increase network capacity across the B6 boundary. We have compared the net present value (NPV) of 1MW of new network to the NPV of 1MW of storage being used to alleviate the B6 constraint, using a consistent discount rate of 3.5%.

Our calculation of the NPV of new network is based on the expected costs of the proposed Eastern HVDC links – £3.4bn for 4GW of network capacity[1], or £850,000/MW along with a notional operation and maintenance (O&M) percentage of 0.67% of capital costs annually. We have determined the MWh of constraint which an additional MW of new line will alleviate per year based on the proportion of time the constraint is expected to be active, being 56% in 2025 falling to 18% in 2035. As we have only modelled 2025, 2030 and 2035, the intervening years have been extrapolated, with 2025-2029 using the 2025 value and so on. The avoided curtailment cost of the MWh volume of constraint avoided is based on the same constraint cost as used for determining the impact of storage on curtailment costs. The NPV over 30 years is £5.6mn.

For storage, the NPV calculation uses Capital Expenditure (CAPEX) of £650/kW, repowering cost of £200/kW in year 15. The avoided curtailment cost is as described in Section 4.3. We have also assumed capacity market revenue of £45/kW with a de-rating factor of 39%. As with new line, 2025-2029 use the 2025 modelled value and so on. The NPV over 30 years is £53,924.

We have not assumed any annual TNUoS costs in the NPV calculation of the storage and have determined that with these parameters an annual TNUoS cost of £3.03/kW would reduce the NPV over 30 years to £0.

As expected, the NPV of new network is very high. The frequency and cost of constraints drives very high NPV for new network. But the NPV of storage is also positive, indicating that there is customer benefit of new storage. The key difference is the speed with which they can be deployed. As evidenced by the Eastern HVDC links, which have been in design for several years and are not expected to come online until at least 2027. Those links are already factored into this analysis. It is likely that any further new network will take at least ten years to deliver. Conversely, storage has much quicker deployment times and so has the potential to alleviate constraints and deliver consumer benefit much more quickly than new network.

[1] https://www.ofgem.gov.uk/sites/default/files/2022-03/EHVDC%20FNC%20final.pdf

5. Impact on storage deployment

In this section we provide a qualitative overview of the likely impact on storage deployment based on our experience of storage investment decisions and the impact of network costs on the returns available to storage operators.

5.1. Locational considerations for storage developers

Currently, when developing and financing storage assets, TNUoS is one of the major locational considerations for developers, particularly for transmission-connected assets. The difference between credits in southern TNUoS regions and high charges in northern regions is significant. There is a small locational signal for distribution connected assets if they discharge during the three half hours of peak demand (Triads) and have a positive Embedded Export Tariff (EET), but all northern/Scottish locations have an EET of £0/kW giving no locational signal.

There are also a number of wider considerations which are likely to have a significant impact on the location of deployment of storage assets. These include:

- The probability of constraint – elements such as Active Network Management (ANM) schemes or other approaches which impose restrictions on when a storage asset can charge/discharge will be a significant concern to developers when organising grid connections.
- Connection costs – large connection costs in some areas, particularly for distribution-connected assets, may be sufficient to stop projects being developed, albeit Ofgem's final decision on the Network Access and Forward Looking Charges review is likely to result in lower connection costs for distribution connected assets from April 2023.
- Potential for co-location – sharing connection, development and operation costs between a storage and renewable asset will lead to cost savings. Co-locating storage with a pre-existing site will also potentially make other elements of development (such as obtaining lease rights) easier.
- The Transmission Constraint Licence Condition (TCLC) places restrictions on how assets can sell power in the Balancing Mechanism (BM) to turn down generation/increase demand during constraint events on their part of the network. This may limit the optionality for a battery asset in charging under the BM by restricting the lowest price they pay to charge.
- Participation in some ancillary services may carry more risk or be more difficult if the assets are unable to guarantee output in certain periods due to constraints, such as under the Dynamic Containment service which requires the asset to be able to deliver when required at any point during the relevant delivery window.

These limitations may not hamper storage assets significantly but may mean they are unable to access certain revenue streams or charging markets and, in turn, the assets may be less economically viable. Developers may struggle to achieve financial close on a storage project for which a constraint is in place.

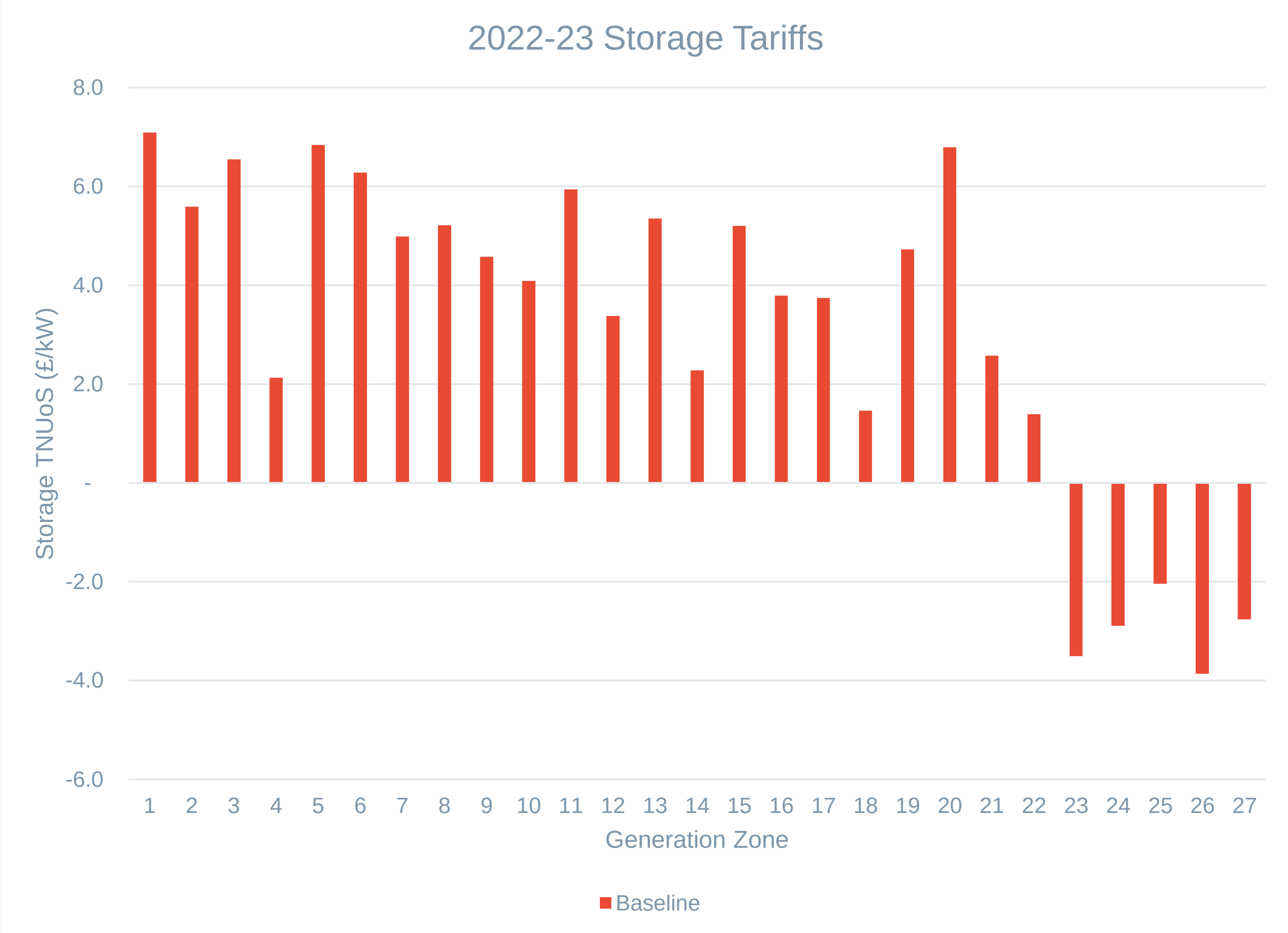
While many of these factors are also likely to be more favourable for southern locations in GB (due to large amount of generation in the north) they are likely to be seen as more important for determining the location of new storage assets.

5.2. Magnitude of TNUoS costs

As detailed in Section 2, TNUoS costs for storage in Scotland in the near term are expected to be high. Figure 19 shows the TNUoS charge for storage in 2022-23 using the generic ALF of 9%, with charges as high as £7/kW in many zones.

We typically see annual revenues for battery assets of between £50/kW and £80/kW for one-hour storage projects. Hence annual TNUoS costs of £7/kW immediately introduce a cost of up to 15% of the annual revenue expected.

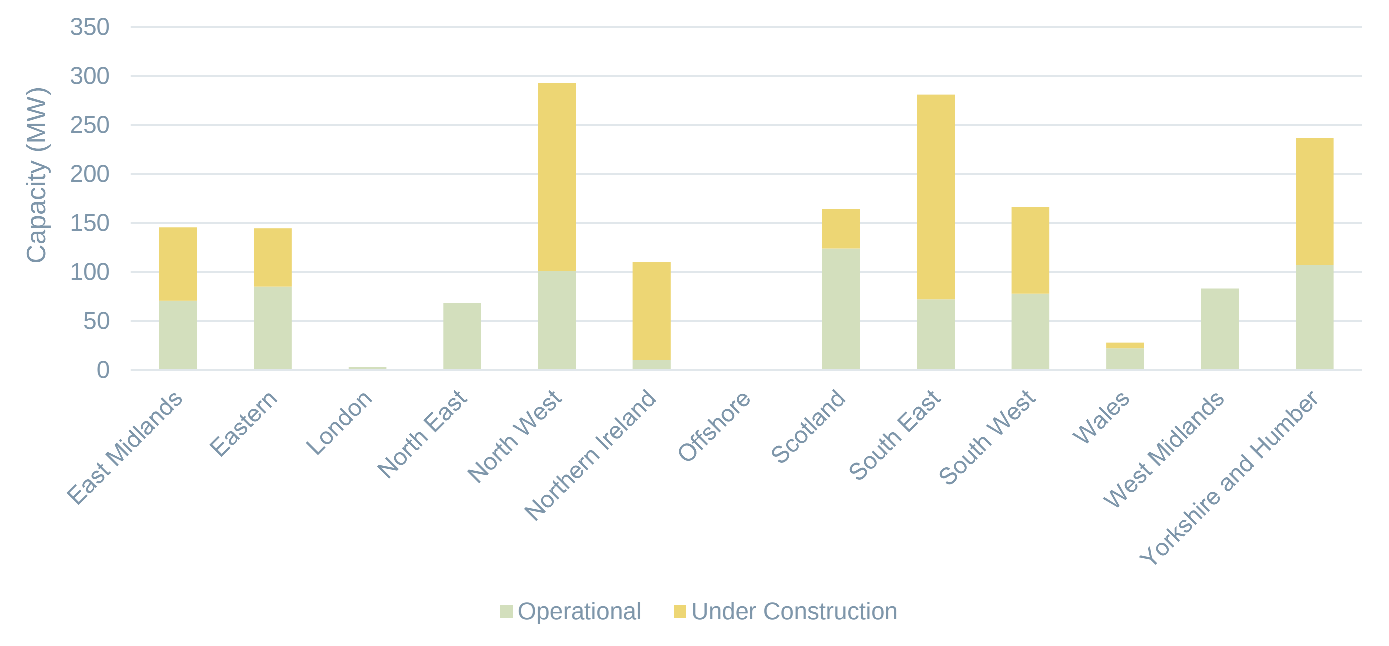
Figure 19 – Storage tariffs in 2022-23



Source: Cornwall Insight analysis of NG ESO published charges

However, while TNUoS costs in Scotland are significant, is it not a complete barrier to projects, as shown in the number of assets which have been developed in GB already. Figure 20 provides an overview of the capacity of storage assets which are operational or under construction according to the Renewable Energy Planning Database, split by region.

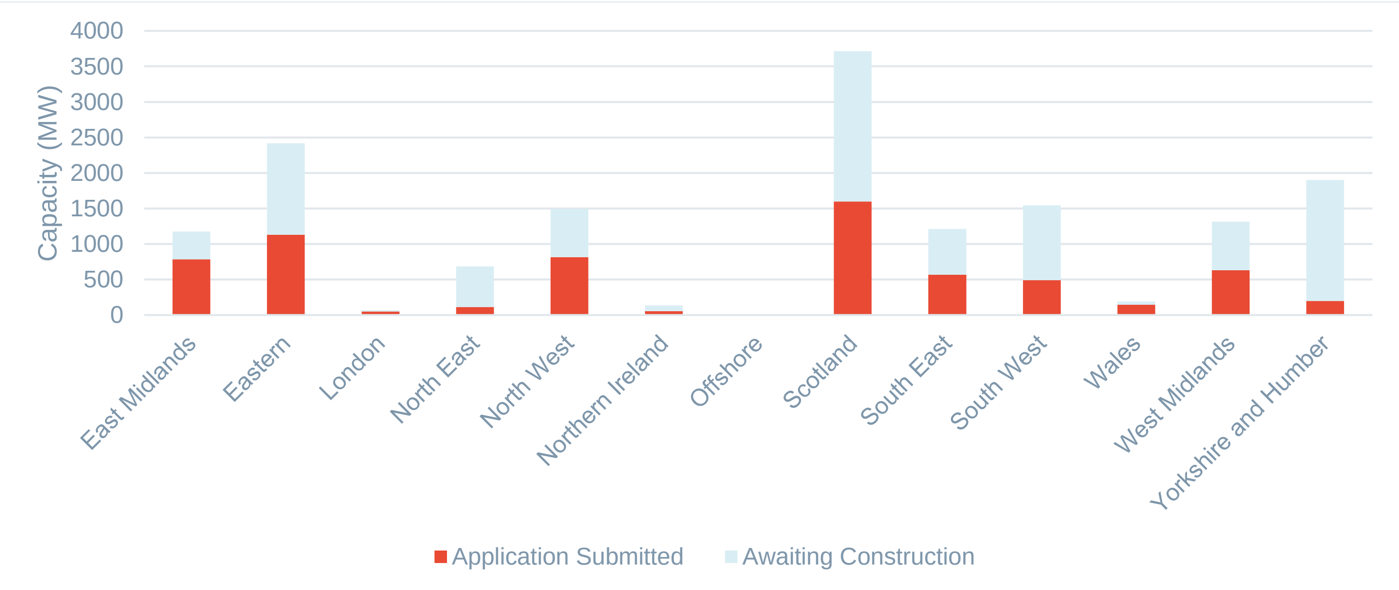
Figure 20 – Capacity of current operational and under construction storage assets in GB, by region



Source: April 2022 REPD

Whilst there is considerable capacity that has been or will be developed in the South East and South West of England, there are a large number of projects seen in the North West, Yorkshire and Humber, as well as Scotland. This demonstrates that high TNUoS costs in these regions have not deterred storage developers from developing assets in these regions. This is supported by the analysis of the number of projects which are currently going through the planning and financing process, as shown in Figure 21. Scotland has the largest number of assets in the planning process and awaiting construction.

Figure 21 - Capacity of application submitted and awaiting construction storage assets in GB, by region



Source: April 2022 REPD

This analysis shows there is a considerable cost which could be applicable for TNUoS in relation to northern storage assets. However, this has not, to date, been seen as a key driver for preventing development. Lack of long-term certainty of TNUoS charges is likely to remain a concern, and the uncertainty on how rates will change means that developers have to try and factor these risks into their financial models, which can be difficult.

5.3. Impact of modifications

CMP393 and CMP394 would both reduce the costs associated with storage assets in northern regions of GB. This is likely to encourage development in these areas. However, the wider alternative drivers for deployment for storage assets discussed previously are still likely to be more significant than TNUoS in determining the location in which to develop a storage asset.

The scale of this benefit will be site-specific and is unlikely to be significant enough to have material impact on deployment figures on a national scale. As discussed above, TNUoS is a key locational driven for storage assets, but not the only driver.

5.4. Wider considerations

The potential introduction of nodal pricing (in which assets in different parts of the country will achieve a different market price) will be a key consideration for storage developers, bringing uncertainty on wholesale power prices achievable for storage. This will have a considerable impact on battery storage assets in the future, as it may mean that some regions become unviable for storage assets due to sustained low power prices. The uncertainty in relation to nodal pricing, which is currently in the very early stages of being developed, may put off some storage developers. As a result, changes to TNUoS will not impact deployment as it does not alleviate concerns on returns achievable under nodal pricing.

Co-located assets may also be impacted by the modifications. Currently, co-located storage and renewables sites have TNUoS rates calculated using the methodology applicable for the larger generation technology (i.e. whichever of the storage or renewables has the largest capacity). This is under review under *CMP316 TNUoS Arrangements for Co-located Generation Sites* which is seeking to introduce a “pro-rata” approach. The removal of TNUoS for storage assets could therefore have an impact on deployment on co-located assets and, in turn, the deployment of renewables. The results of the impact will depend on how the co-located TNUoS is calculated under both CMP316 and CMP393/CMP394, but it is an important consideration as it may encourage more co-location and renewable assets to be deployed.

5.5. Summary

In conclusion, the removal of positive TNUoS charges is likely to benefit battery deployment, creating less charges for batteries assets, and increasing the options they have for locations in which they can develop. However, the wider considerations for location selection discussed previously (such as optionality for co-location or constraint risks) are likely to continue to be significant factors in choosing the location for developing an asset. Future changes, such as nodal prices, may make the impact of removing TNUoS more significant, but this is difficult to determine at this time. CMP393 and CMP394 will likely benefit battery storage deployment, but the significance of this benefit may be limited.

6. Conclusions

There are a number of key conclusions which can be drawn from the analysis undertaken within the report.

6.1. Impact on TNUoS

CMP393 and CMP394 will reduce costs for storage assets with minimal downside for other generating assets.

- Our analysis indicates that there would be a slight increase in TNUoS charges for all generators in GB as a result of both CMP393 and CMP394
  - However, this increase is expected to be relatively small (typically ~£0.20/kW) in both modifications
  - It is therefore anticipated that the impact will not be material in the context of most generators' total TNUoS charges
- The impacts on storage are more marked, with significant decreases in charges in the most northern generation zones while typically maintaining the existing level of credits in southern zones

6.2. Impact on curtailment costs

Our modelling shows a benefit for the network operator in having storage assets behind constraints on the network, both in regards to the volume of assets which need to be constrained and the ultimate costs which are passed to consumers.

- The marginal impact of adding a 1MW/2MWh storage facility behind the B6 boundary is significant, showing a reduction in constraint volumes of approximately 127MWh in 2035 and 202MWh in 2025, with a greater impact in the winter given that wind speeds are the primary driver behind constraints.
  - This equates to a saving of around £35,000/MW of battery capacity by 2025
- These benefits are forecast to reduce over time but still remain beneficial, with the saving for the 1MW/2MWh marginal storage facility falling to £14,500/MW in 2035

6.3. Impact on storage deployment

Whilst the modifications will improve operating costs for storage assets, the impact the modifications will have on encouraging deployment of storage in specific locations may be limited. TNUoS is a significant consideration of storage developers, but it is not the only material locational consideration, with other key factors including:

- The probability of constraint at key times impeding revenue options
- Large connection costs in some areas may be sufficient to stop projects being developed
- Sharing connection, development and operation costs between a storage and a co-located renewable asset will lead to cost savings - therefore the potential for co-location is an important consideration
- Participation in some ancillary services may carry more risk/be more difficult if the assets are unable to guarantee output in certain periods due to constraints being applicable

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