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DER Technical Forum

27 January 2025
1400-1545

Welcome, Housekeeping and Introductions

Agenda

14:00	Welcome, Introductions and Acceptance of Agenda
14:05	Actions from previous meeting
14:10	Minor Technical Changes to G99 – progress
14:15	SAF Update
14:25	New Issues • P28 & G5 assessment/compliance for generation on IDNO networks
14:40	Draft EREP P28 – “ Guide to the Application of Engineering Recommendation P28 Issue 2”
15:00	Existing Issues update • Fault current limiters • G100 • Registered Capacity and maximum export
15:15	GC0117
15:20	EU Update
15:25	AOB
15:30	Next Meeting

Actions from previous meeting

None that are not on the Agenda

Updates on G99 and SAF

Updates on G99 and SAF

EREC G99 Issue 2 was sent to Ofgem for approval on 07/10/24

Approval expected 25/01/24

SAF v 1.12 published early January. It can be downloaded from here.

V1.12 makes more detailed information mandatory at the time of first application and is designed to support the changes to the connexion queue process which the Government, NESO and the DNOs are making.

It also updates the language/terminology around the security of connexions to the network, reflecting the language of the Access SCR changes to DCUSA, as well as the ENA's tactical solutions guidance for BESS.

SAF – new requirements for new projects

Heads of Terms for access to the relevant site for the generation project

Need to be signed by the relevant grantor

Site Drawings

Showing boundaries, connexion point, site area and key infrastructure

Single line diagram

Includes all key generation equipment, protection, metering, cabling, earthing, switchgear, transformers etc.

Preliminary project timeline

Key dates, including the new requirements for the queue, Gate 2 compliance declaration date; expected planning consent dates, plant ordering and delivery dates, construction, energising, commissioning etc.

These requirements are waived for existing sites which are applying for modifications.

New Issues

New Issues

P28 and G5 compliance responsibilities for IDNO connexions.

There is some guidance for G5 in ETR122 and EREC G97.

Draft EREP P28
Summary for the DER Technical Forum

Background to EREP 28

EREP 28 is a new engineering report

- Intended to be an application guide for EREC P28 Issue 2

The document has been prepared by the P28 Working Group

- WG established under the governance of the Distribution Code Review Panel in early 2023

The requirement for guidance on how to assess BESS from a P28 requirement was the key driver

- The revision of EREC P28 predated large uptake in BESS connections; and
- Newer frequency response services(DM, DC and DR)

A draft report has been approved by the P28 WG for consultation

- It is not intended to be published as an Annex 1 or 2 standard to the Distribution Code given its guidance nature

Purpose & Scope

- Provides guidance on the application of EREC P28 Issue 2 in particular for assessment of BESS.
- It does not replace or override any existing requirements in EREC P28 Issue 2.
- Scope was based around initial consultation and feedback from stakeholders undertaken in 2023/2024.
- It incorporates the findings to date from the NPg NIA project title ‘BESS P28’ (NPG_NIA_046).
- Section 9 covers commentary and examples on how to assess BESS for: Flicker, RVC and Step Voltage Change.
- Includes guidance on assessing reductions in system inertia.

Key Contents

- Guidance of how long slow ramps should be assessed, i.e. not in steady state.
- Validity of 3% step voltage change for BESS power swings.
- Application of shape factors for simplified flicker assessment.
- Guidance on impact of frequency response services, BM, wholesale market and arbitrage fluctuations.
- BESS control modes and power factor considerations.
- Addresses guidance on modelling and link to commissioning (reference to EREC G99).
- Some new definitions relating to batteries such as:
  power rating, ramp rate etc.
- Some worked examples for BESS
  (including simplified assessment of power changes and ramp rates)

Next Steps

Consultation on Draft EREP (version 4) – February 2025

- DER Technical Forum
- DCRP

P28 WG to review comments and respond – March 2025

Finalise Draft EREP for publication – April/May 2025

Previous Issues

Outstanding Issues – see appendix 1:

Registered Capacity – 112

BESS connexions – issues 113, 114

Delays associated with DNOs being able to submit Mod Apps to NGESO because of inadequate SAF data – 126 – As above, the DNOs have updated the SAF – can be closed.

Initial P28 assessments for generation tripping and/or load rejection etc. – 127 – should be picked up in the guidance on P28 being developed by the ENA.

IONs for Type B and Type C – 129 – now included in the proposed G99 update.

Various issues from BPA – 130 – can now be closed.

G100 issues from 07/10 DER TF

No additional issues with G100 have been received.

DNOs agree that there is some minor terminology related to HV connected sites that could be improved.

As suggested at the last DER TF some of the other issues discussed at the 07/10 DER TF might benefit from inclusion in the G100 guidance note. It is now intended to try to create a draft by Easter.

There are a couple of other points raised, particularly the mandatory requirement for back-up protection at HV which DNOs are still considering.

Registered Capacity and Maximum Export Capacity

DNOs in general express the site export limits in kVA and power factor terms.

There is not intended to be a limit on PGMs producing more active power than the PGM's registered capacity.

Instances where the Maximum Export Capacity would seem to limit the PGM output, when operating at high power factors should be, be discussed with the DNO.

Fault Current Interrupters

Some DNOs are actively considering fault current interrupters.

There are issues which remain to be resolved in that interrupting generation during a transmission fault is not allowed: fault ride through and fast fault current injection are required.

DNOs are engaging with NESO to try to resolve these issues.

GC0117

GC0117 – alignment of Large, Medium and Small across GB

This was submitted to Ofgem on 14 May 2024

The three main options are:

- The baseline (ie existing arrangements unchanged)
- The original proposal (ie Large starts at 10MW in all of GB)
- WAGCM1 – extending the E&W arrangements (including Medium PSs) to GB

A majority of the Workgroup voted for the baseline.

The Grid Code Review Panel members' votes on the proposals were split, with no consensus.

Although Ofgem initially suggested they would rule by mid August, they have now announced that they will run a six week consultation starting in January 2025, although this is probably now going to be starting in February.

EU Update

EU Update

Progress with the NC RfG 2.0 and NC DC 2.0 is slowing down.

The Commission seem to accept that for heat pumps and EVs it would make sense to add the new requirements, especially compliance verification, to the existing CE/Ecodesign and vehicle homologation regulations respectively.

The underlying technical requirements are unlikely to change, and when they are enacted, will drive the EU market for heat pumps and EVs to implement these technical requirements.

The ENA expects to have some discussions soon with NESO about the implications for GB.

AOB and next meeting

Appendix – historic Forum issues

Outstanding Issues – 1

No	Issue	Assumed Status
112	A common issue that keeps coming up is Registered Capacity vs design install and grid agreements. I have a specific case where the G99 and connection agreement is for 9MW, the developer undersized the inverters slightly. So it can only produce 8.5MW (in round numbers) whilst operating in the 0.95 lag/lead range. This is what is shown when we do the G99 study, and we noted this shortfall. So the question arises, of what happens to the site now and what can it do. Specifically, 1) Is it's new official RC 9MW or 8.5MW ie do they retain their original agreed capacity, or is this list back to the DNO? This is a common sticking point, taking the above example it cannot meet the 9MW required, but they may upgrade an inverter later to give them more MVAr headroom and it could then operate at 9MW. 2) If the DNO doesn't want/need them to operate across the 0.95 lag/lead range can they then operate at 9MW active power and say unity or 0.98pf. In this case they are producing their official R, but their system design does not meet the required G99 standard for a 9MW site.	This is an issue that does re-appear from time to time. We have attempted to deal with it in the past in issues 40, 80 and 83. We went through it with slides at the 7 June 2022 DER TF. DNOs have summarized how they specify maximum capacities and power factors in their connexion agreements. We propose that we incorporate the material from the 7 June 2022 meeting into the next version of the DG guides

Outstanding Issues – 2

No	Issue	Assumed Status
113	P28 has the usual classifications of frequent events, infrequent events (4 per month) and very infrequent events (1 per 3 month)…. what should we be assessing a storage system performing a dynamic containment service as? The UK grid is reasonably stable, at the moment, but with more conventional plant dropping out, the power swings are going to get a bit more sever, and the DC type services will be getting worked more often. Classing it as a very infrequent event probably isn't realistic, but what about infrequent events? I could see that it is possible that you could get to around the 4 events per month, although probably not at the full power swing.	This is a good point, and one that probably would benefit from a consistent consideration by DNOs. It might be sensible to base the frequency on the observed incidence of frequency excursions, over the last 18 months say, that trigger a specific level of response from such services. The response level might be set locally, and the P28 "frequency of event" set by the historic track of frequency excursions triggering that level of response. This can be calculated from the information NGESO publish monthly. This should be picked up as part of ongoing work to develop a common approach to BESSs between the DNOs. However, note that in the BESS discussions on 18/11 it was pointed out that the 3% limit essentially applies at any time once the transients have died away, so for BESS power swings the 3% probably applies in all cases, irrespective of frequency of event. The DNOs work on reviewing customers' issues with P28 should pick thi

Outstanding Issues – 3

No	Issue	Assumed Status
114	We have concerns relating the voltage step change for Battery Energy Storage Systems (BESS) when the systems are designated for fast frequency response. A number of network operators define step change to be full declared export to full declared import for real power P and for reactive power Q. The FFR contracts do not have a contracted obligation to reverse the direction of reactive power flow and no obligation to match the fast MW response with a MVAr response. When importing, there is no obligation to operate at a particular power factor only to operate within a +/-0.95 range. If a full MW ramp has occurred, it is reasonable to assume the system is under stress. To reverse Q at this point would be the worst of all strategies at it would exacerbate the stress of the system by introducing an unnecessary voltage step. It is likely that EFR or FFR BESS is located at a point with a high X/R ratio (close to a BSP or GSP). Therefore a unit change in Q would have at least 10x the impact on at the voltage step that of a unit change in P. This Q reversal condition appears to be based on a false assumption about the default behaviour of inverters under FFR. We believe it is a matter for the customer to demonstrate through simulation the voltage step change under power reversal. It is a matter for the customer to produce a reactive power strategy that meets the constraints of the D Code and the connection offer. Confirmation of the simulation can be done via commissioning tests with frequency injection for smaller steps. The imposition of this requirement distorts the market by essentially limiting the capacity of a BESS scheme to around half the capacity of other technologies thus creating hidden barrier to the penetration of the technology. The customer should demonstrate how they meet the voltage step change challenge through modelling and if necessary to verify through commissioning demonstration, not for the network operator to impose a control philosophy.	To be picked up in the BESS sessions

Outstanding Issues – 4

No	Issue	Current Status
126	Customers are still seeing very long delays for DNOs to submit a Modification Application to National Grid for the appropriate GSP. A developer accepted a scheme Sept 2020 and only had the Mod App response back August 2022 (even with pushing for a Mod App to be done with escalation). This is not an isolated experience. One part of the delay occurred as the DNO informed us they are allowing customers to only fill in sections 1 -3 before receiving a distribution offer, but required customers to fill in section 4 before they were able to submit the Mod App. Whilst the customer UBGC represented had filled in Part 4 when the scheme was applied for, others which accepted before had not and a Mod App was further delayed, to allow customers who accepted ahead to fill in the form. This would have been 14+ months after they had initially accepted their offers. If Part 4 is a requirement for a Mod App but the DNO feels comfortable making a distribution offer without part 4, can it be agreed that part 4 it is filled in within a set period, I.e. 2-3 months of acceptance to prevent further delays in Modification Applications in the future or that the Mod App is submitted based only on the information within parts 1-3.	The timing of the provision of data is prescribed in DPC1 of the Distribution Code – needs review to see how this suggestion might be accommodated. Need to set up some discussions with appropriate DNO experts as soon as possible. Following a meeting between Philip and DNO experts from NGED and Electricity North West it is suggested that Part 4 of the SAF becomes mandatory.

Outstanding Issues – 5

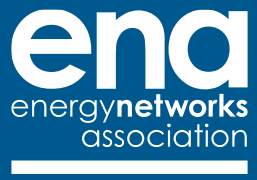
No	Issue	Current Status
127	There is a requirement in ENA P28/2 (Although fairly sketchily defined) that we are supposed to consider what happens if a generator trips under full load conditions at different power factors ie 0.95 lag, unity and 0.95 lead. We have had a fairly large number of these sites come up that have a problem on them, and when we carry out the studies, we get a fail (ie the SVC is greater than +/-3%). When we hit this point there isn't really much we can do to help, as the SVC results are really just a function of the MW, MVAr flow and system strength – the only option is to constrain the generator MW output if it is at a problem PF – this causes headaches for developers Some general thoughts would be • A generator tripping on full load conditions would be relatively unusual – although with G99 LoM protection I guess it can and does happen, so I can see why its there. • Is it really realistic to consider it against minimum (outage) fault condition? • Should the developer really be doing this and finding problems - it is such a simple assessment the DNO should really do this, and check before issuing an offer. In reality just a simple loadflow of before and after.	DNOs broadly agree that the DNO should undertake these checks early in the application process. It is appropriate (and necessary in P28) to consider outages. To be investigated further as part of the refinement of BESS processes.

Outstanding Issues – 6

No	Issue	Current Status
129	Our issue is specifically regarding Type C PPMs. We have a number of Type C (solar) sites across different DNOs. Looking at G99 section 18.2 there is no EON or ION in the connection process for Type C PPMs, and to achieve FON we need to complete tests that require at least 65% (full voltage control) or 85% (reactive power and frequency response tests) of the maximum export capacity to be generated. For solar sites that energise over the winter months, it is unlikely that they would have such irradiation needed to achieve the required export to complete those tests until spring/summer the following year. For Type D PPMs there is the ION to cover this type of situation and allow export during this period until testing can be completed and FON achieved. Having discussed this with other developers there seems to be a consistent inconsistency. We have had varying processes for achieving FON from different DNOs as well as confusion and variance within the DNOs. I outline two examples: 1. DNO A issues a Nil Export Connection Agreement (export allowed for testing purposes only) and following all the tests that could be completed at the time, issued an ION and vary the Connection Agreement to allow full export. Following successful completion of the outstanding compliance tests the FON is then issued. This approach seems a pragmatic approach. 2. DNO B have stated that they require FON to be completed before they will counter sign the Connection Agreement and allow full export. This leads to a lot of confusion and questions over how we are going to be able to complete the testing which requires connection to the network and export without a Connection Agreement in place – they won't offer a Nil Export initially but only the final Connection Agreement with the full requested Export Capacity. Further, this will result in our site that is due to energise in December, not being able to export until March/April when we have the required irradiation to complete the remaining testing and achieve FON.	Suggested that a new clause is introduced into 17.3.6 and 18.3.6: "To aid completing the necessary tests, and to allow the interim export of energy for the Generator's commercial purposes, at the discretion of the DNO, the DNO and the Generator may agree an interim operating regime, including issuing and Interim Operational Notification, pending completion of all the necessary tests and data submission. In such cases the provisions of Section 18.4 shall be respected and Section 19.3 shall be used as a guide to the formality required."

Outstanding Issues – 7

No	Issue	Current Status
130	1. Do DNOs have any advice on how to challenge the current CUSC wording in relation to the criteria determining when a SoW is required? Are there any other forums where these issues could be discussed and progressed? 2. Diversity assessment of complex sites Does the company (DNO) have a formal policy on how to assess the diversity of demands and generation on complex sites when assessing new applications for that site? If so, is it published? Where? 3. Generation/Site curtailment Under what circumstances do you install equipment that can trip either a customer's generation? Or the customer's whole site? Under what circumstances could the latter apply? Is this approach published? Where? Where the company use the facilities installed in accordance with G99 11.1.3 or 12.1.3, or if the site is intetripped, what are the rules the determine which sites are affected and in which order? Are these published? What information does the company have to produce to the customer in relation to the likely volume and incidence of use of any of the above curtailment? 4. Combination of applications – under what circumstances does the company combine applications for quotations from different, or even from the same, customer? Can customers provide their own P28 and G5 studies and assessments? Are there published rules on this? If so, where? 5. Fault levels Fault level problems can lead to very long lead times for connexion. What is your company doing about this? Are there any technology solutions that can be deployed? On the DNO side, is your company considering Industrial Internet of Things (IIoT) technologies similar to export limiting and ANM requested from customers to monitor and control activities in your substations? What technologies could be adopted by customers to reduce fault current contribution from generation and storage assets? 6. Batteries Possibly an extension of 2a above, but does the company always treat generation and storage output as 100% additive when usually they will be substitutional? What mitigations exist to avoid treating the output as additive? Would an approach where customers would commit to storage trading strategies linked to site's demand, generation and potentially fault current levels enable faster transition to net zero? Such strategies could be subject to witness tests as export limiting and ANM solutions are. Storage would in essence be relying on the same type of technology as export limiting/ANM/intertripping to ensure reliability. 7. How can your company signal to developers etc where there are beneficial sites for siting or co-locating storage?	Issues raised with DNOs.



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