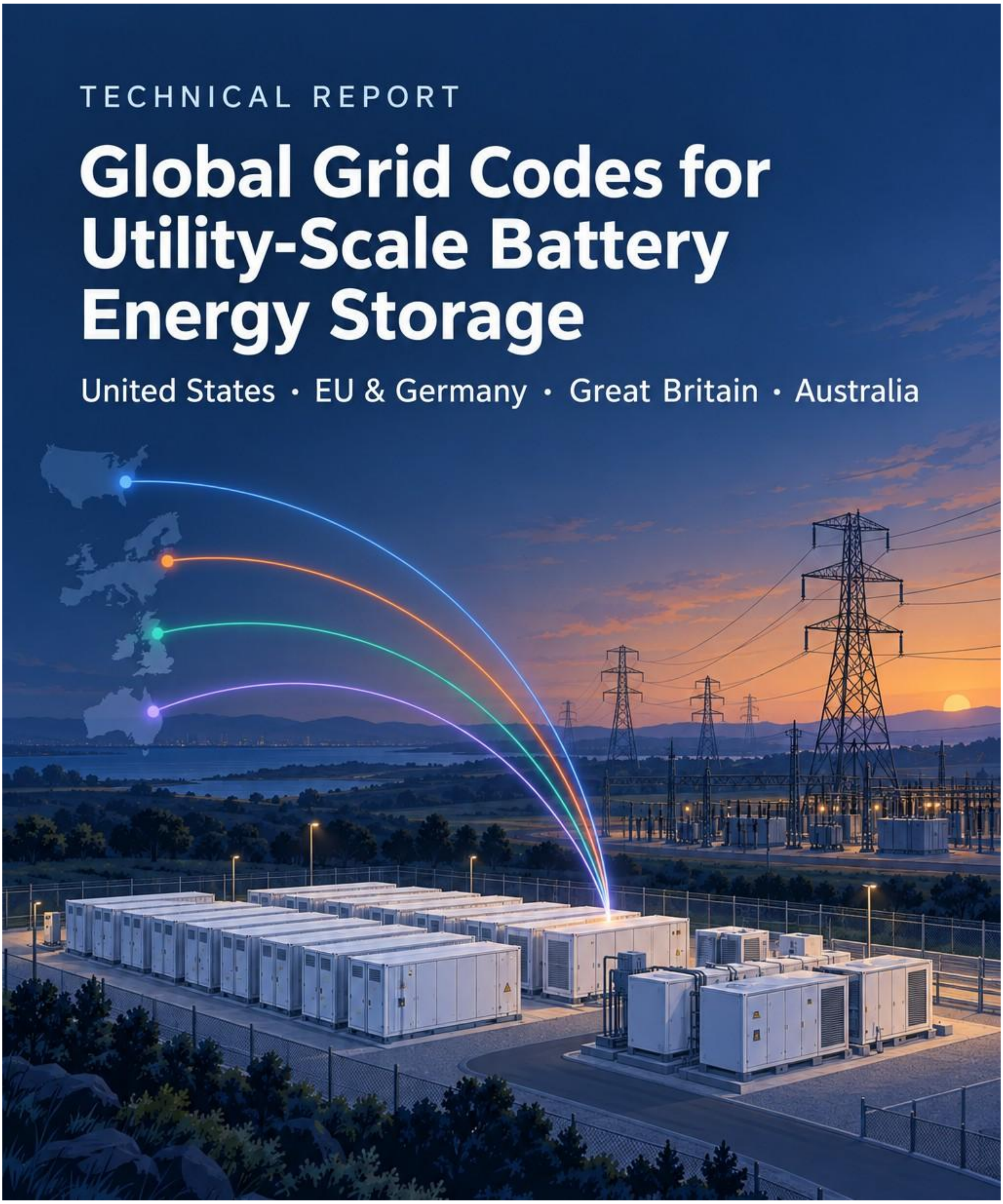

Fred Yang

Director, Univers · Author of 'The Complete Picture of Energy' · yangyulong.com

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Compiled from public grid codes, standards and operator guidelines listed in Works Cited. Parameters are summarised for orientation; always confirm against the current edition of the applicable code before design or compliance decisions.

Executive Summary

Most grid codes were written for a system of synchronous machines. That system is disappearing. Every coal or gas unit that retires takes some inertia, some short-circuit current and some voltage support with it, and the inverter-based plant replacing it does none of those things unless its controls are told to. Utility-scale batteries are now the main asset system operators reach for to fill the gap, which is why the connection rules for batteries have tightened so quickly in the last four years.

This report sets the battery connection rules of four systems side by side: the United States (FERC, NERC, IEEE 2800, ERCOT), the European Union and Germany (NC RfG, the stalled RfG 2.0 revision, VDE-AR-N 4110/4120/4130 and the FGW certification guidelines), Great Britain (the Grid Code, GC0137, EREC G99 and NESO's dynamic services) and Australia (NER Chapter 5, the Generator Performance Standards as amended in August 2025, and AEMO's system strength framework). Sections 3 to 6 cover each regime; Section 7 puts the numbers that decide PCS selection and plant controller design in comparable tables; Section 8 covers the modelling, hardware-in-the-loop and commissioning work that now stands between a signed connection agreement and energisation.

Five things are worth taking away.

- Riding through a fault used to mean surviving it. It now means helping. IEEE 2800-2022, NERC PRC-029-1 (in force from 1 October 2026), ERCOT NOGRR 245 and VDE-AR-N 4120 all forbid momentary cessation inside the mandatory ride-through zone, and IEEE 2800, the German codes and Australia's new clause S5.2.5.5A go further and require negative-sequence current during unbalanced faults.[68,69,77,93]
- Grid-forming capability is being written into the rules, but not at the same speed everywhere. In Great Britain GC0137 is an open specification that a plant may choose to meet. In the EU the ACER-recommended RfG 2.0 would make it compulsory for storage of 1 MW and above, but the Commission has not adopted it and has given no date. Germany opened a market for instantaneous reserve in January 2026 and has consulted on a draft amendment that would require it of new HV-connected batteries. In Australia AEMO's specification is voluntary, but a grid-forming battery can use it to discharge its own system strength obligation.[74,75,78,84,97]
- The clock has moved from seconds to milliseconds. A grid-forming plant in GB must respond inherently within 5 ms; Australia's automatic access standard now wants reactive current to start within 10 ms; Germany wants 90% of it within 30 ms; NESO's Dynamic Containment wants full active power within a second.[77,83,85,86,93]
- Weak-grid physics is now written into the rules rather than argued about afterwards. Australia relaxed its minimum reactive current standard in 2023 because rigid fast injection was tipping inverters into instability at high-impedance sites, and its system strength framework charges a connecting plant unless it fixes the problem itself.[94,96]
- Desk studies no longer get a plant connected. Operators want EMT models compiled from the production firmware, controller hardware-in-the-loop tests, certified unit and plant models (FGW TR3/TR4/TR8) and staged hold-point tests on site (AEMO R1/R2). In the US, IEEE 2800.2-2026 now describes how the performance is to be tested.[72,79,99]

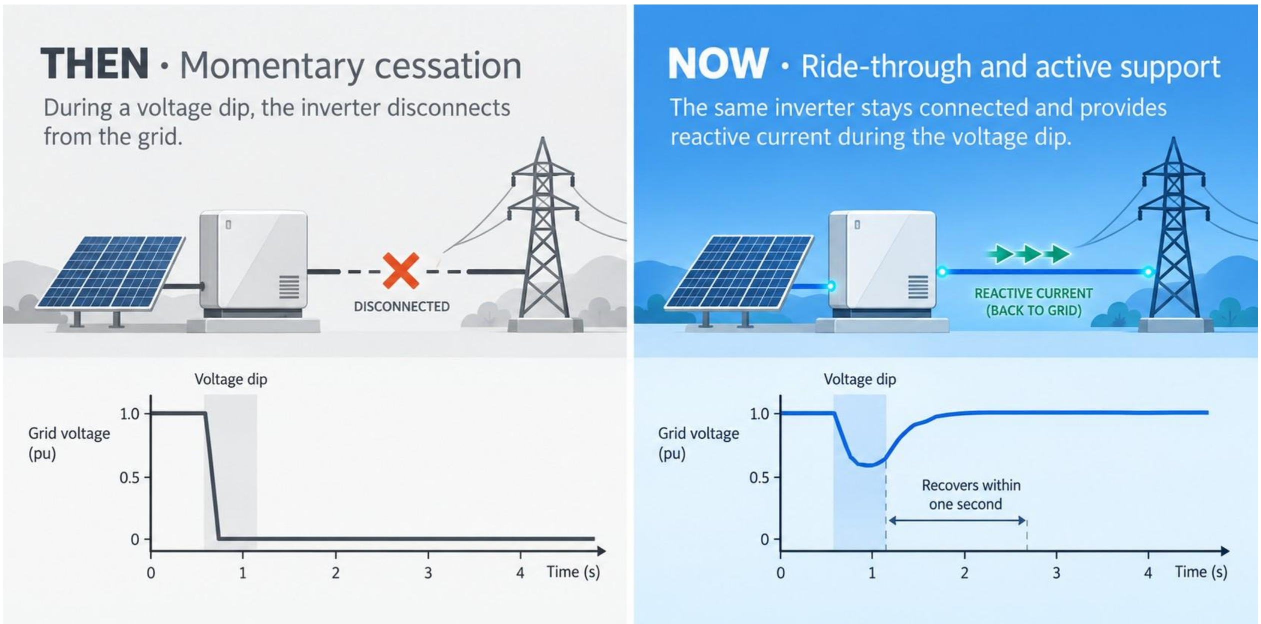

Figure 1. Then and now. An inverter that blocked during a voltage dip was protecting itself; the current codes require it to stay connected, inject reactive current and be back at full active power within about a second.

The consequence for anyone developing, supplying or integrating a battery is simple to state and hard to live with: the grid code is a design input, not a compliance step. Which PCS you buy, how the plant controller is built, how good the model is and how commissioning is staged all follow from the regime the project sits in, and from which of the instruments in this report is actually in force on the day the connection agreement is signed. Table 6 in Section 9 records that status for each of them.

Contents

1. Introduction: Why BESS Grid Codes Have Tightened

A synchronous generator helps the grid whether or not anyone asks it to. Its rotor stores energy, so frequency cannot change instantly; its field winding keeps pushing current into a fault, so protection can see the fault and voltage does not collapse. An inverter does none of this by nature. A power conversion system (PCS) is a set of semiconductor switches driven by software, and during a disturbance it will do exactly what its control loops tell it to, which for many early designs meant blocking and waiting for the disturbance to pass.

That difference is the whole reason battery grid codes exist. As synchronous plant retires, inertia and short-circuit levels fall, and the utility-scale battery is the cheapest asset available to put some of that behaviour back, provided the rules say what behaviour is wanted. So the rules have grown: how fast the plant must respond to frequency, how much reactive current it must push into a fault and how quickly, what it must ride through without tripping, how it must damp oscillations, and what evidence, from laboratory tests to EMT models to site measurements, it must produce to prove all of this.

The rules are not the same everywhere, and the differences are physical before they are political. North America and Continental Europe are large synchronous systems with, for now, plenty of inertia; Great Britain is an island that lost its coal fleet early; the Australian NEM is a 5,000 km radial corridor where the strongest renewable resources sit furthest from the load. Each system has written the rules its own geography demanded. This report is an attempt to put those rules next to each other so that an engineer moving between them, or a supplier selling into all four, can see what actually changes.

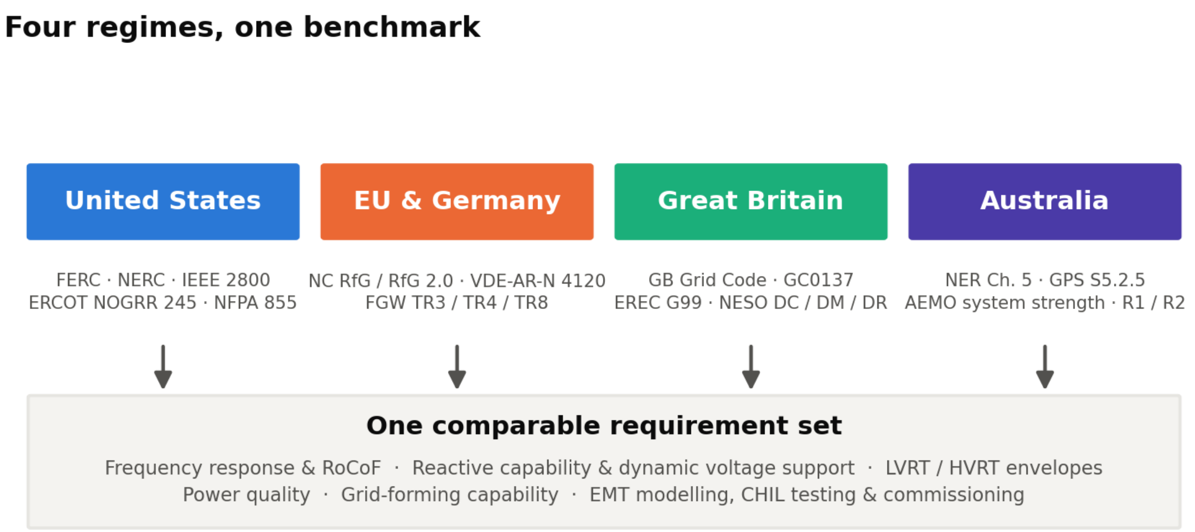

Figure 2. Four regimes, compared on the same set of requirements.

A note on the numbers

Three kinds of number appear in this report and they should not be read the same way: values in rules that bind today, values in published drafts, and values in voluntary or market specifications. Table 6 in Section 9 says which is which for every instrument, as at September 2026. I have checked the figures against the rule text, the standard or the operator's guidance note wherever those are public. Some are not (IEEE 2800, VDE-AR-N 4120 and the IEC 61000 series are paywalled), and in those cases the figure comes from an operator summary or an accredited certifier's documentation and is marked as such in Works Cited. I have also kept each code's own name for the point where compliance is measured, because they are not interchangeable: the reference point of applicability in IEEE 2800, the network connection point in Germany, the grid entry point in GB, the connection point in Australia. None of this replaces reading the current edition of the code before a design or contract decision.

2. Global Governance Architecture

In each of the four systems the rules come from four layers: a statutory regulator, a reliability authority or network code, the system or market operator, and the technical standards bodies whose documents the operator points to. Who sits in each layer, and which document carries the requirement, differs from one system to the next, and a good deal of confusion in cross-border projects comes from assuming that a body in one system has the same role as its namesake in another. Table 1 lays the layers out, and Figure 3 shows how all four land on the same battery.

Table 1. Governance architecture and primary instruments by jurisdiction

Jurisdiction	Statutory regulator	System / market operators	Primary grid code and statutory instruments	Core standards and technical guides
United States	Federal Energy Regulatory Commission (FERC); state commissions (e.g. PUCT for ERCOT)	CAISO, ERCOT, PJM, MISO, SPP, NYISO, ISO-NE	FERC Orders 841, 2023 and 901; NERC Reliability Standards (PRC-024-4, PRC-028-1, PRC-029-1, PRC-030-1); RTO/ISO tariffs and operating guides	IEEE 2800-2022 and IEEE 2800.2-2026; IEEE 1547-2018; IEEE 519-2022; UL 9540 / 9540A; NFPA 855
European Union and Germany	Agency for the Cooperation of Energy Regulators (ACER); Bundesnetzagentur (BNetzA)	ENTSO-E; German TSOs (TenneT, 50Hertz, Amprion, TransnetBW)	Commission Regulation (EU) 2016/631 (NC RfG); ACER-recommended NC RfG 2.0 (not adopted); German EnWG; VDE-AR-N 4110 / 4120 / 4130	FGW Technical Guidelines TR3, TR4, TR8; VDE FNN Hinweis on grid-forming properties (v2.0, 2025)
Great Britain	Office of Gas and Electricity Markets (Ofgem)	National Energy System Operator (NESO, from 1 October 2024)	GB Grid Code (European Connection Conditions incl. GC0111 FFCI and GC0137 grid-forming); EREC G99 Issue 2 (2025)	ENA Engineering Recommendations; NESO Grid Forming Guidance Note; NESO dynamic services (DC/DM/DR)
Australia	Australian Energy Market Commission (AEMC); Australian Energy Regulator (AER)	Australian Energy Market Operator (AEMO); TNSPs (Transgrid, Powerlink, ElectraNet, AusNet, TasNetworks)	National Electricity Rules (NER) Chapter 5, Schedule 5.2 (GPS), as amended by ERC0393 (in force 21 August 2025)	AEMO Power System Model Guidelines v3.0 (2025); AEMO Voluntary Specification for Grid-forming Inverters (2023) and Core Requirements Test Framework (2024); Frequency Operating Standard (2023)

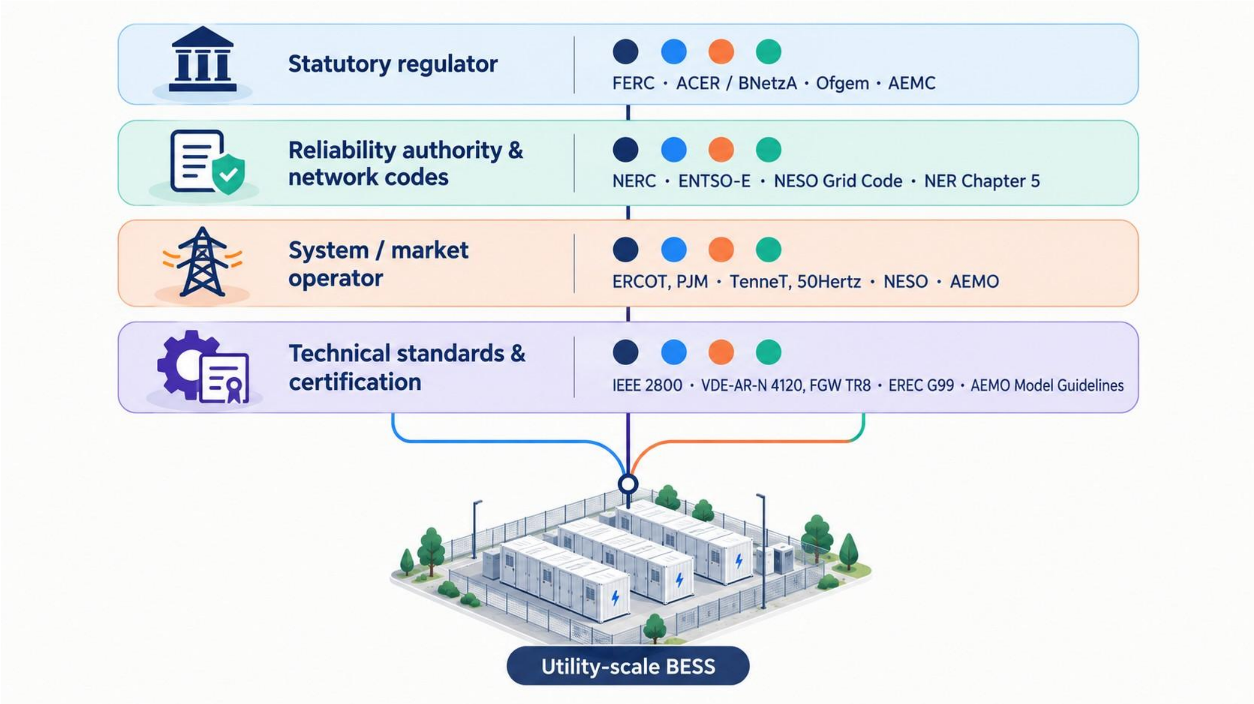

Figure 3. Four layers of rule-making, one plant.

3. United States: Federal Mandates, IEEE 2800 and Safety Codes

A US battery answers to four separate authorities: FERC and the regional operator for market access and the interconnection queue, NERC for enforceable reliability performance, the IEEE standard that the operator's tariff points to for the engineering detail, and the local fire authority for the installation itself. None of them defers to the others, so all four have to be planned for (Figure 4).

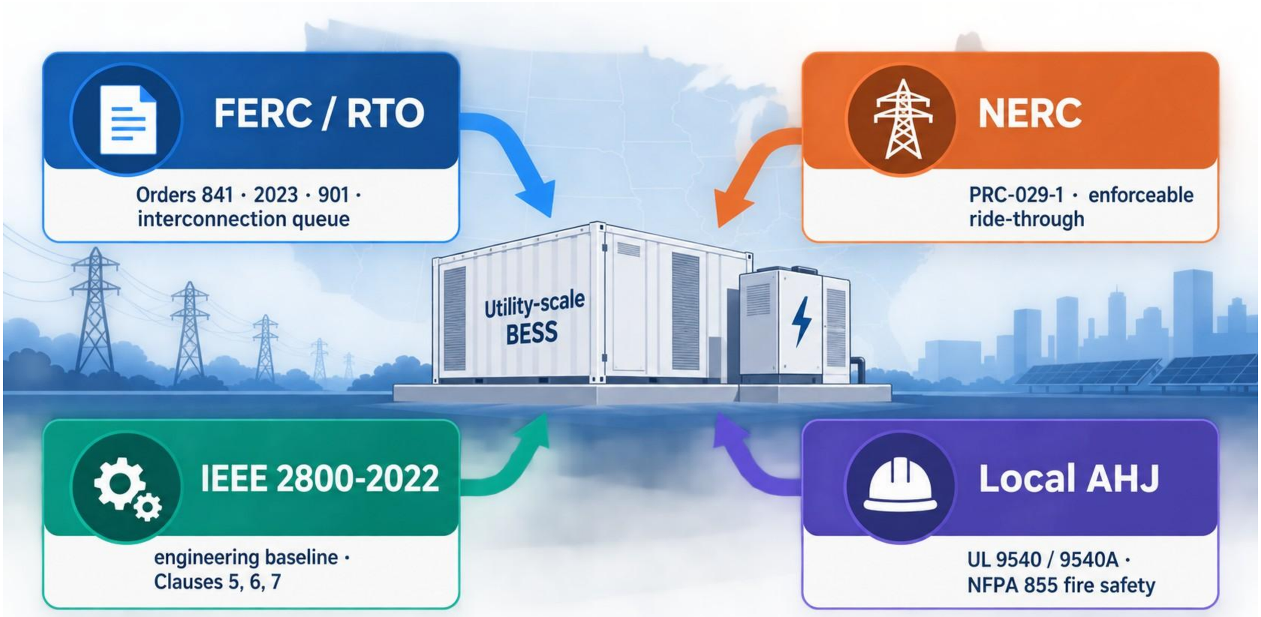

Figure 4. The four authorities a US battery project must satisfy.

3.1 Federal Regulatory Rulemaking

FERC Order 841 (February 2018) established the regulatory treatment of storage in wholesale markets by requiring every RTO and ISO to create an Electric Storage Resource (ESR) participation model.[65] The order recognised the continuous bidirectional operation of BESS as both generation and wholesale load without subjecting the facility to duplicative retail tariffs. Market operators were required to accept bidding parameters that reflect physical constraints, including state of charge (SOC), minimum and maximum charge and discharge limits, run-times and ramp rates, with a minimum participation size of 100 kW, allowing storage to provide energy, capacity and ancillary services on an equal footing with conventional generators.[65]

FERC Order 2023 (July 2023) restructured the interconnection queue from a serial, first-come-first-served process into a first-ready-first-served cluster study framework, with withdrawal penalties, study and commercial-readiness deposits, and 90% to 100% site-control requirements to clear non-viable projects.[66] For storage the useful change is quieter: transmission providers must study the plant on the charging behaviour it actually proposes, instead of assuming it charges at full power during the system peak and discharges without limit at minimum load.[66]

FERC Order 901 (October 2023) is the order that turned a series of embarrassing disturbance reports into enforceable rules.[1,2] From 2016 onward NERC had documented event after event in which hundreds of megawatts of solar and storage tripped or stopped injecting current during ordinary transmission faults that a synchronous plant would have ridden through without comment. Order 901 directed NERC to develop enforceable reliability standards across four domains: data sharing, model validation, planning and operational assessments, and physical performance.[1,67] NERC's roadmap runs through four milestones: a work plan (January 2024), the ride-through and disturbance-monitoring standards PRC-028-1, PRC-029-1 and PRC-030-1 (November 2024), the modelling standards MOD-026-2, MOD-032-2 and MOD-033-3 (November 2025, approved by FERC in February 2026), and the planning and operational study standards due on 4 November 2026.[67]

3.2 Engineering Standards and Reliability Mandates

IEEE 2800-2022, approved in February 2022 and published that April, is the first standard to set out in one place what a transmission-connected inverter plant must do.[5,68] Its premise is the opposite of the older disconnection-first practice: the plant stays on and supports the grid.

- **Clause 5 (reactive power and voltage control).** A BESS must be capable of injecting and absorbing reactive power of at least 0.3287 p.u. of its continuous rating (equivalent to a 0.95 power factor at rated power) at the reference point of applicability, across the full active power range.[5,68] Voltage control is the default closed-loop mode, with a minimum damping ratio of 0.3 and a reaction time under 200 ms.[5]
- **Clause 6 (primary frequency response).** The default deadband is ±0.036 Hz (adjustable from ±0.015 Hz to ±0.96 Hz) and the default droop is 5%, adjustable between 2% and 5%.[7] Dynamic response is specified as a reaction time of 0.5 s (adjustable 0.2 to 1.0 s), a rise time of 4 s and a settling time of 10 s by default.[7] Fast frequency response, where required, must reach full output within 1.5 s, adjustable to 1 s.[7]
- **Clause 7 (ride-through).** Performance is defined across distinct operating zones.[5] The standard distinguishes installations with auxiliary-equipment constraints (Table 11, typically Type 3 wind turbines) from those without (Table 12); utility-scale BESS and PV fall under Table 12.[8,69] Table 12 sets minimum ride-through durations as cumulative time below each voltage threshold: 0.32 s below 0.10 p.u. (permissive operation, in which current may be limited but the unit must not trip), 0.32 s between 0.10 and 0.25 p.u., 1.2 s between 0.25 and 0.50 p.u., 3.0 s between 0.50 and 0.70 p.u. and 6.0 s between 0.70 and 0.90 p.u.[9,69] Assets must also withstand rate-of-change-of-frequency (RoCoF) up to 5.0 Hz/s averaged over at least 0.1 s, and positive-sequence phase-angle jumps of up to 25 electrical degrees, without protective disconnection.[8] Test and verification procedures are set out in **IEEE 2800.2-2026**, a recommended practice published in June 2026.[72]

In response to Order 901, NERC developed **PRC-029-1** (Frequency and Voltage Ride-Through Requirements for Inverter-Based Resources) alongside companion standards PRC-028-1 (disturbance monitoring) and PRC-030-1 (unexpected performance analysis).[1,69] PRC-029-1 translates the IEEE 2800 ride-through zones into enforceable obligations on Generator Owners.[10,69] It prohibits momentary cessation within the must-ride-through zones, requires active power to be restored to the pre-disturbance or available level within one second of voltage returning to the continuous-operation region, and requires the unit to exchange current on the affected phases to support voltage during unbalanced faults.[69] FERC approved PRC-029-1 in **Order 909** (July 2025), and it becomes effective on 1 October 2026.[70] To address the Commission's clarifying directives on hardware limitations and long-lead projects, NERC developed a successor, PRC-029-2, and filed it with FERC for approval on 28 August 2026 (Docket RD26-10); at the time of writing it is pending regulatory approval and, once approved, is intended to replace PRC-029-1.[70,111]

IEEE 2800 binds nobody by itself; it becomes binding when a regional operator writes it into its tariff or operating guide, and ERCOT went first.[5] **NOGRR 245**, in force since 1 October 2024 after approval by the Public Utility Commission of Texas, requires all IBRs to maximise voltage and frequency ride-through capability and applies IEEE 2800 Clauses 5, 7 and 9 to projects with interconnection agreements executed from 1 June 2024.[14,71] Existing units had to maximise capability by 31 December 2025 or file extension or exemption requests with engineering justification; extensions are capped at 31 December 2027 for frequency ride-through and 31 December 2028 for voltage ride-through.[71] New projects document compliance through the Resource Integration and Ongoing Operations (RIOO) platform, and ERCOT screens submitted PSS/E and

PSCAD models with its automated Model Quality Test suite.[12,16] MISO and New York have adopted IEEE 2800 through their own processes.[5,7]

3.3 Life-Safety, Product Listing and Installation Codes

The fourth authority is the local fire official, the Authority Having Jurisdiction (AHJ), who enforces the product listing and installation codes. This layer has nothing to do with grid performance and everything to do with whether the site can be built as drawn.

UL 9540 (Standard for Energy Storage Systems and Equipment) is the foundational listing standard. It assesses the integrated assembly of battery modules, battery management system (BMS), PCS, cooling loops and internal balance-of-plant switchgear, evaluating thermal behaviour, structural integrity, containment boundaries and protective interlocking. Component inverters must be listed to **UL 1741**, including Supplement SB, which covers the IEEE 1547-2018 interconnection and interoperability functions of smart inverters, so that autonomous control firmware behaves predictably during disturbances.

NFPA 855 (Standard for the Installation of Stationary Energy Storage Systems) governs fire protection and physical layout.[18,101] Under the 2023 edition, lithium-ion storage is arranged in groups of no more than 50 kWh, with at least 3 ft (0.91 m) between groups and to walls; in buildings that are not dedicated to storage the aggregate per fire area is capped at 600 kWh, while dedicated-use buildings and remote outdoor sites are exempt from that cap.[101] Outdoor units must maintain at least 10 ft (3.05 m) from lot lines, public ways, buildings and combustible materials; this can be reduced to 3 ft with a fire barrier or on the basis of UL 9540A large-scale fire test data accepted by the AHJ.[19,101] The 2026 edition replaces the maximum-quantity table with a hazard mitigation analysis (HMA) as the default route.

The **UL 9540A** test method evaluates thermal runaway fire and gas propagation at four scales:[19]

- **Cell level.** Quantifies thermal runaway onset temperature, gas generation volume and composition (including H_2, CO and light hydrocarbons) and lower flammability limit (LFL) parameters.[19]
- **Module level.** Determines whether thermal runaway initiated in a single target cell cascades to adjacent cells, measuring internal heat flux and cell surface temperatures.
- **Unit level.** Evaluates fire propagation across a full-scale enclosure: total heat release rate (HRR), deflagration potential, radiant heat flux at the exterior and external flaming.
- **Installation level.** Evaluates unit-to-unit spacing and suppression effectiveness in representative multi-rack configurations, generating the documentation AHJs need to approve setback reductions and deflagration venting designs under NFPA 68 and NFPA 69.[19]

> **For US projects**
>
> The two long-lead items are the models and the fire test data, and they are owned by different teams who rarely talk to each other. The PSS/E and PSCAD models have to pass the operator's screening before the queue moves; the UL 9540A data decides the NFPA 855 separations and therefore the site layout. Start both early and in parallel.

4. European Union and Germany: Network Codes, Dynamic Voltage Support and Certification

Europe works in two layers: a Commission regulation that sets the frame, and national connection codes that fill in the numbers. Germany has the most fully worked-out national layer, and the one most often copied elsewhere, so it is the example used here.

4.1 The EU Network Code Framework and NC RfG 2.0

Interconnection requirements across the internal electricity market are grounded in **Commission Regulation (EU) 2016/631**, the Network Code on Requirements for Grid Connection of Generators (NC RfG).[73] RfG establishes functional capabilities across four categories, Type A through Type D, based on voltage level and maximum capacity. In the Continental Europe synchronous area the maximum thresholds are 1 MW (Type B), 50 MW (Type C) and 75 MW or a connection point at 110 kV or above (Type D); TSOs may set lower national thresholds, and Germany does.[73]

Article 3(2)(d) of RfG excludes storage devices other than pumped-storage units from its scope.[73] In practice, Member States and TSOs applied RfG-derived Power Park Module (PPM) requirements to BESS in infeed mode and demand-side rules in charging mode, and the German connection rules addressed storage and mixed installations explicitly. ACER's Recommendation 03/2023 of December 2023, which forwarded the draft **NC RfG 2.0** to the European Commission, would close this gap by defining an "electricity storage module" and applying requirements in both directions of power flow.[74]

The proposal that matters most for batteries is **mandatory grid-forming capability**: for all Type C and Type D power park modules, for Type B modules where the relevant system operator requires it, and for electricity storage modules of 1 MW and above in both infeed and consumption mode, with a three-year implementation period after entry into force.[74,75] ENTSO-E's technical basis for the grid-forming requirement, published in its Phase II report of November 2025, specifies voltage-source behaviour behind an effective impedance, an active current response reaching 50% of its theoretical peak within 10 ms of a phase jump, reactive current reaching 90% within 30 ms and settling within 60 ms after a voltage step, synthetic inertia expressed as a mechanical starting time T_M (equal to 2H), a damping ratio of at least 5% across 0.1 to 10 Hz, and tolerance of current clipping for no more than 40 ms.[75]

None of this is law. As at September 2026 the Commission has not adopted RfG 2.0, has said that the connection code revision is not a near-term priority, and has given no date; ENTSO-E has been reduced to urging TSOs to put the content into national codes on their own.[76] A developer should read the grid-forming clause as a statement of where Europe intends to go, and look at the national code to find out what applies today.

4.2 German Technical Connection Codes: VDE-AR-N 4110, 4120 and 4130

In Germany, the statutory mandates of the Energy Industry Act (EnWG) and EU RfG are executed through technical connection rules (TAR) developed by the Forum for Network Technology/Network Operation in the VDE (VDE FNN). Medium-voltage connections above 1 kV and below 60 kV fall under **VDE-AR-N 4110**; the 110 kV high-voltage level (60 kV to below 150 kV) is governed by **VDE-AR-N 4120**; and extra-high-voltage connections at 220 kV and 380 kV are covered by **VDE-AR-N 4130**.[77] Utility-scale BESS connect under 4120 or 4130 depending on size and location.

VDE-AR-N 4120 asks for reactive capability across the whole active power range, in the form of a Q/P envelope whose variant the network operator picks. The two standard variants correspond to a power factor of about 0.95 under-excited to 0.925 over-excited (Q equal to 0.33 and 0.41 of installed active power respectively), or the mirror image; below roughly 10% active power the required capability is reduced.[77] Three autonomous control modes must be supported: continuous voltage control Q(U), reactive power control to a schedule Q(P) or Q(t), and fixed power factor.[77]

Dynamic reactive current injection (VDE-AR-N 4120)

$$\Delta I_B / I_N = k \cdot (\Delta U / U_N) = k \cdot (U - U_0) / U_N$$

Gain $2 \le k \le 6$ (default $k = 2$, operator-specified) · Deadband operator-specified, up to ±10% U_N · Rise time (90%) ≤ 30 ms · Settling time ≤ 60 ms

During balanced and unbalanced voltage excursions outside the operator-specified deadband, VDE-AR-N 4120 mandates dynamic reactive current injection to support grid voltage.[32,77] The magnitude is governed by the adjustable **k-factor** equation, where k must be configurable between 2 and 6, with 2 as the default and some network operators prescribing higher values.[77] The response must reach 90% within 30 ms and settle within 60 ms of the initiating event.[77] For unbalanced faults the code additionally requires negative-sequence reactive current in proportion to the negative-sequence voltage, so that the injected current suppresses phase-voltage unbalance rather than aggravating it; this requires separate positive- and negative-sequence current control in the PCS, and the German codes are among the few that require it explicitly.[34,77]

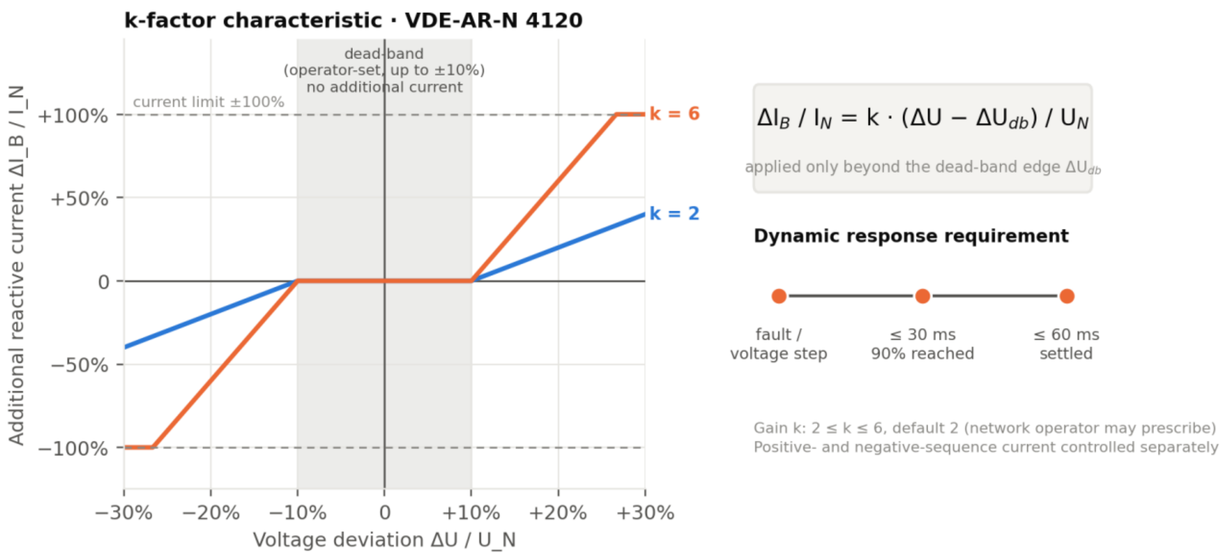

Figure 5. The k-factor characteristic in VDE-AR-N 4120. Nothing happens inside the operator-set dead-band; beyond it, reactive current rises in proportion to the voltage deviation measured from the dead-band edge, k = 2 by default and up to 6, until the PCS runs out of current. The response must be 90% complete within 30 ms and settled within 60 ms.

4.3 The FGW TR3 / TR4 / TR8 Certification Framework

What sets Germany apart is not the numbers but the proof. No plant is energised without a certificate from an independent body, accredited by DAkkS under ISO/IEC 17065, working to the technical guidelines of the FGW (Fördergesellschaft Windenergie und andere Dezentrale Energien).[30,79] Three guidelines carry the process.

- **FGW TR3 (Determination of Electrical Characteristics).** Test methodologies executed at specialised test fields to measure the physical performance of production PCS hardware: low- and high-voltage ride-through (LVRT/HVRT), reactive power delivery, harmonic emissions and switching operations.[30]
- **FGW TR4 (Modelling and Model Validation).** Procedures for validating digital simulation models against the physical TR3 measurements.[30] Modellers build representations in DIgSILENT PowerFactory or PSCAD that match the exact laboratory setup.[31] TR4 defines mathematical acceptance criteria, including

normalised RMS errors and maximum absolute errors for active, reactive and total currents across all disturbance phases.[30] A model with a formal TR4 validation report becomes the authorised digital twin of the inverter.[30]

- **FGW TR8 (Certification of Electrical Characteristics).** Governs certification in stages.[30,79] First, an accredited body issues a **unit certificate (Einheitenzertifikat, EZE)** for the PCS based on TR3 test records and the TR4-validated model.[30] Second, developers combine the validated PCS model with site-specific transformer parameters, park cabling and the power plant controller (EZA-Regler) software to simulate behaviour at the network connection point (Netzanschlusspunkt).[30] On verification, the body issues the **plant certificate (Anlagenzertifikat, EZA)**, required before commissioning for all HV connections and for MV plants above 950 kW (a simplified certificate applies to smaller MV plants).[79] Third, and often overlooked, after commissioning the certification body checks the as-built plant against the certified design and issues a **conformity declaration (Konformitätserklärung)**, which completes the process.[79]

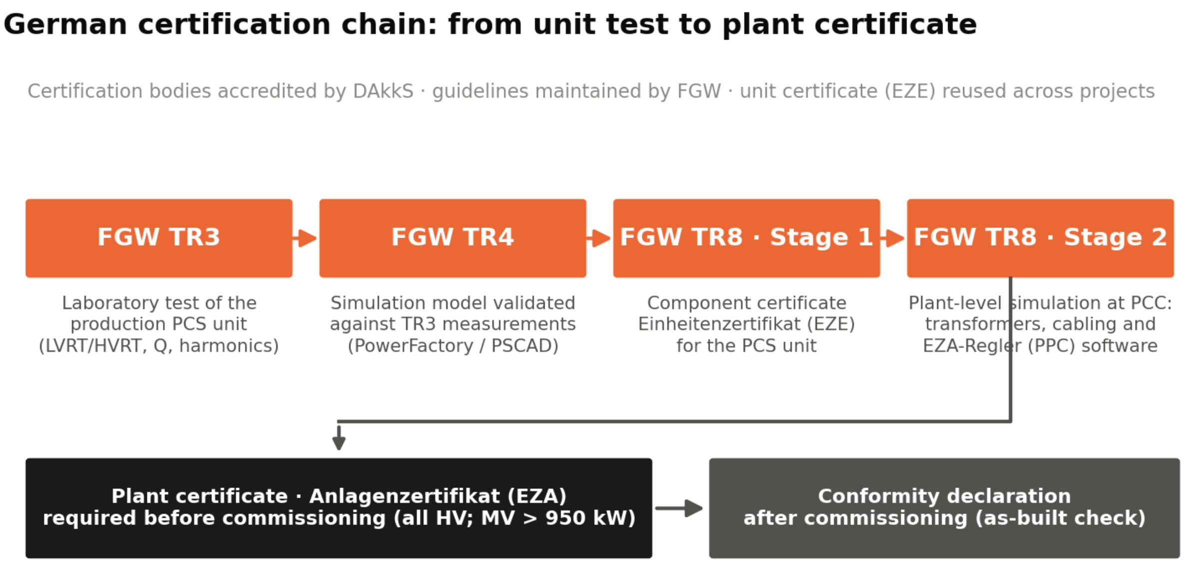

Figure 6. The German certification chain. Laboratory tests (TR3) validate the model (TR4); the model earns the unit certificate, the unit certificate and the site design earn the plant certificate, and the as-built check closes the loop (TR8).

4.4 Recent Developments in Germany

Germany has not waited for Brussels. VDE FNN issued version 2.0 of its guidance note on grid-forming properties and instantaneous reserve in May 2025; it characterises grid-forming behaviour with a starting-time constant T_A and a damping factor rather than the ENTSO-E parameters.[78] On 22 January 2026 the four TSOs opened a market for instantaneous reserve (Momentanreserve), four products in which converter-based plant and batteries can bid, so grid-forming capability in Germany now earns money as well as satisfying a code.[80] And a draft amendment to VDE-AR-N 4120, consulted in April and May 2026, would make grid-forming behaviour a requirement for new HV-connected batteries.[108] Two legal decisions round out the picture: the Federal Court of Justice upheld capacity-based connection cost contributions (Baukostenzuschuss) for batteries in July 2025, and BNetzA narrowed in March 2026 the grounds on which a network operator may refuse a storage connection.[106,107]

5. Great Britain: The GB Grid Code, GC0137 and Dynamic Services

Great Britain runs its own frequency. The island is linked to Continental Europe and Ireland only by HVDC cables, so none of the continent's inertia helps it, and with the coal fleet gone and offshore wind growing it has had to buy fast frequency response and stability services rather than assume them. That is why GB has the most developed battery service markets in this report and why its system operator was first to publish an open grid-forming specification. The operator has been the National Energy System Operator (NESO) since 1 October 2024, when it took over from National Grid ESO.

5.1 The GB Grid Code and EREC G99

Transmission connections are managed by NESO under the GB Grid Code, whose European Connection Conditions (ECC) implement RfG for new plant; distribution-connected systems fall under the Energy Networks Association (ENA) Engineering Recommendation **G99**, now at Issue 2 (2025).[81,82]

G99 categorises plant from Type A (below 1 MW) through Type B (1 to below 10 MW) and Type C (10 to below 50 MW) to Type D (50 MW and above, or connected at 110 kV and above, which in GB practice means 132 kV).[81] Under the Grid Code, transmission-connected power park modules and storage must ride through a zero-voltage fault at the grid entry point for 140 ms, the main-protection clearance time on the transmission system, with the required voltage-time boundary then rising linearly to 0.85 p.u. at 2.2 s; active power must be restored to at least 90% of its pre-fault value within 1 s of the voltage recovering to 0.9 p.u.[82]

Fast Fault Current Injection (FFCI), specified in ECC.6.3.16 under modification GC0111, is triggered when voltage at the grid entry point falls below 0.9 p.u. Reactive current must be at least the pre-fault value and increase with the depth of the dip according to a gain k (default 2.5, adjustable 2 to 7), capped at 1.0 p.u.; a delay of no more than 20 ms from fault inception is permitted, and the envelope requires, for deep dips, about 0.65 p.u. reactive current within 60 ms and full delivery by roughly 120 ms, sustained through fault clearance.[83] The requirement is defined on positive-sequence quantities; for unbalanced faults the plant must inject maximum reactive current within its transient rating without over-voltage on the healthy phases, but no independent negative-sequence control is mandated.[83]

5.2 GC0137: Grid-Forming Capability

Grid Code modification **GC0137 (Grid Forming Requirements)**, approved by Ofgem in January 2022 and in force from February 2022 as ECC.6.3.19, was the first open, published specification anywhere for what a grid-forming inverter must do.[84,85] It is optional. A plant that wants to be recognised as grid-forming (GBGF-I) has to meet it; a plant that does not can still connect as grid-following.[84]

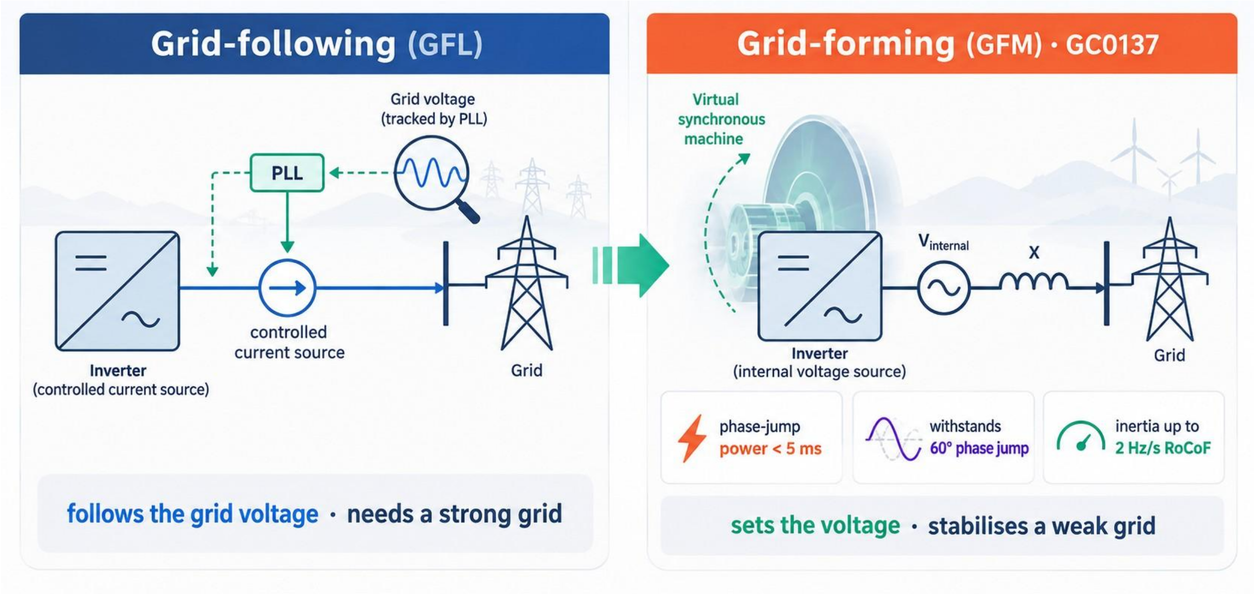

Figure 7. Grid-following and grid-forming control. The first follows a voltage it measures through a PLL; the second sets a voltage of its own behind a reactance and behaves, to the grid, like a small synchronous machine. GC0137 figures shown.

A GC0137-compliant grid-forming BESS operates as an internal voltage source behind an effective transient reactance, maintaining an internal voltage vector that resists instantaneous deviations in external phase and frequency.[28] It must supply:

- **Active phase-jump power.** An inherent response starting within 5 ms of a phase shift, with a phase-jump angle withstand of at least 60 electrical degrees and a linear response region of at least 5 degrees.[85]
- **Active inertia power.** Instantaneous active power proportional to system RoCoF, delivered without current limiting for RoCoF up to 1 Hz/s, with a withstand requirement of 2 Hz/s measured over a rolling 500 ms window (twice the 1 Hz/s applied to other plant).[85]
- **Damping and control bandwidth.** The control-based part of the response must have a bandwidth below 5 Hz to avoid resonance, and damping is demonstrated with test signals and an equivalent damping factor between 0.2 and 5.[85] Modification GC0163 (July 2024) allows virtual impedance in the grid-forming implementation.

The first grid-forming battery procured under the Stability Pathfinder, Blackhillock in Scotland, went live in March 2025.[102] It has not started a rush. In the second round of NESO's Stability Market in March 2026 every contract went to synchronous condensers or to gas turbines running as synchronous compensators; grid-forming batteries bid and lost on price.[109]

5.3 Frequency Ranges and NESO Dynamic Balancing Services

The Grid Code normal control range is 49.5 to 50.5 Hz; continuous operation is required from 49 to 51 Hz, with 47.5 to 49 Hz and 51 to 51.5 Hz for at least 90 min, 51.5 to 52 Hz for 15 min and 47 to 47.5 Hz for 20 s.[82] Primary response uses a droop of 3% to 5% with combined deadband and insensitivity no wider than 0.03 Hz (±0.015 Hz).[82] RoCoF withstand for conventional plant is 1 Hz/s over a rolling 500 ms, matching the loss-of-mains protection settings in G99.[82]

To procure fast frequency response from batteries, NESO operates three dynamic services, all with a ±0.015 Hz deadband:[86]

- **Dynamic Containment (DC).** Designed for severe post-fault generation or interconnector trips. Delivery follows a knee at 5% of contracted volume at ±0.2 Hz and reaches 100% at ±0.5 Hz; the ramp must start within 0.5 s and full delivery is required within 1 s.[86] Leading providers deliver within 150 to 200 ms, arresting the initial RoCoF.[47]

- **Dynamic Moderation (DM).** Addresses intermediate imbalances, with the 5% knee at ±0.1 Hz and full delivery at ±0.2 Hz, again within 0.5 s to start and 1 s to complete.[86]
- **Dynamic Regulation (DR).** Continuous small-signal response, ramping to full delivery at ±0.2 Hz with initiation within 2 s and full delivery within 10 s.[86]

The three NESO services in one line each

Dynamic Containment catches the big post-fault excursion: full delivery at ±0.5 Hz within 1 s, and the best batteries do it in under 200 ms. Dynamic Moderation stops a smaller excursion becoming a big one: full delivery at ±0.2 Hz within 1 s. Dynamic Regulation does the continuous housekeeping: full delivery at ±0.2 Hz within 10 s. All three share a ±0.015 Hz dead-band and have been dispatched through NESO's Open Balancing Platform since January 2026.

6. Australia: The NEM, AEMO Generator Performance Standards and System Strength

The NEM is a line, not a mesh. It runs about 5,000 km from Port Douglas in Queensland to Port Lincoln in South Australia, and the four mainland regions (Queensland, New South Wales with the ACT, Victoria and South Australia) form one synchronous system along it; Tasmania is a separate synchronous area hanging off the Basslink HVDC cable. The best solar and wind sites are at the far ends of the line, where the network is weakest, and as coal has closed the system has become short of fault current and prone to phase-angle jumps that grid-following inverters handle badly. The Australian response has been the most detailed and technically demanding set of connection standards in this report, most recently revised by the "Improving the NEM access standards, Package 1" rule (ERC0393), in force since 21 August 2025.[95]

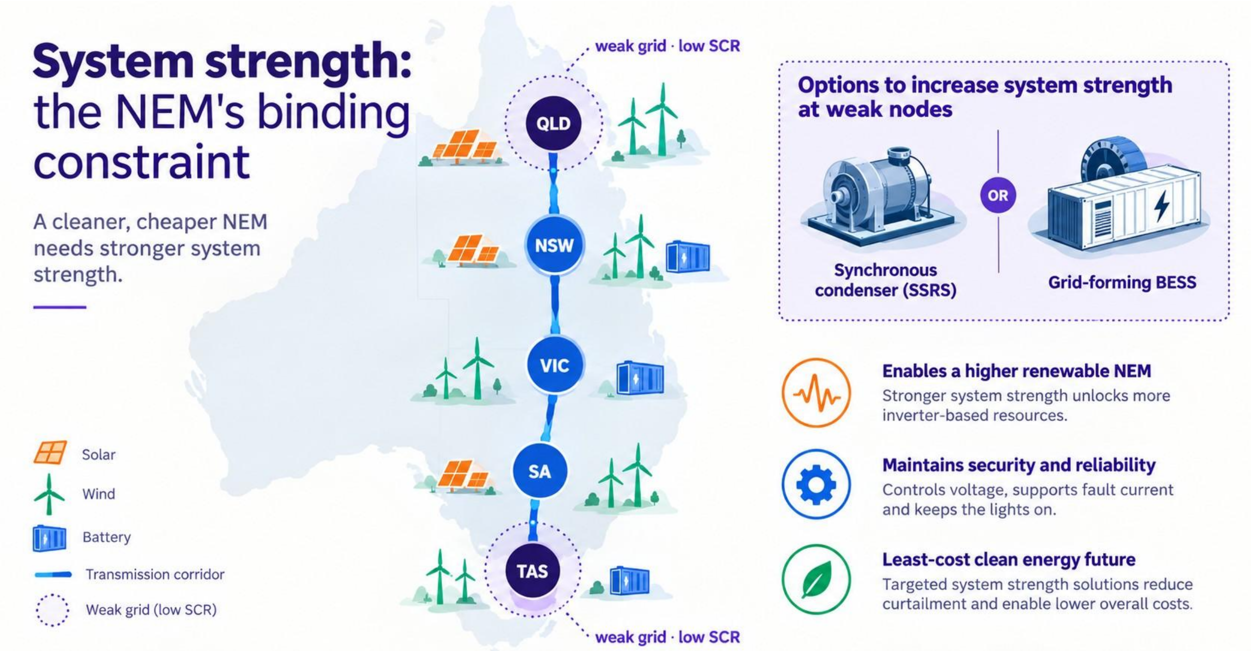

Figure 8. Why system strength binds in the NEM: a long radial corridor with its weakest nodes at the ends, and the two routes a connecting plant can take. The two routes are not yet equivalent; see Section 6.3.

6.1 NER Chapter 5 and the Generator Performance Standards

Connection negotiations are structured under Chapter 5 of the National Electricity Rules (NER), centred on Schedule 5.2.[52,54] The historical separation between generation (Schedule 5.2) and contestable load (Schedule 5.3) forced bidirectional storage into dual registration.[49] The AEMC's **Integrating Energy Storage Systems** rule, made in December 2021 and effective from 3 June 2024, created the Integrated Resource Provider (IRP) category, under which a battery is an "integrated resource system" of "bidirectional units" and is assessed under a single set of Generator Performance Standards (GPS).[88]

The GPS framework uses a dual-threshold negotiation structure:[50]

- **Automatic Access Standard (AAS).** A benchmark that, if demonstrated through simulation and plant design, must be accepted by the Network Service Provider (NSP) and AEMO for that requirement.[51]
- **Minimum Access Standard (MAS).** The floor; a proposal below the MAS is rejected.[51]
- **Negotiated Access Standard (NAS).** An intermediate level agreed with the NSP and AEMO; it must be no less onerous than the MAS, must not adversely affect system security or other users' supply quality, and the applicant must propose a level as close as practicable to the AAS.[52,53]

6.2 Schedule 5.2 Electrical Clauses after the 2023 and 2025 Reforms

Schedule 5.2 sets the specific technical parameters for BESS in the NEM. The values below reflect the rules as amended on 21 August 2025.[89,90,91,92,93]

- **S5.2.5.1 (reactive power capability).** AAS: supply and absorb reactive power of at least 0.395 times maximum active power (a power factor of about 0.93) at any active power level, within a ±5% band around an NSP-specified mid-point voltage, tapering outside that band.[89] MAS: no reactive capability is required, but the plant must not cause more than a 1% voltage change when out of service.[89]
- **S5.2.5.3 (response to frequency disturbances).** AAS: continuous uninterrupted operation across the ranges defined in the Frequency Operating Standard, which on the mainland means indefinitely within the normal operating band (49.85 to 50.15 Hz), across the operational tolerance band (49.5 to 50.5 Hz, 49 to 51 Hz after network events) and out to the extreme excursion limits of 47 to 52 Hz (47 to 55 Hz in Tasmania).[90,100] RoCoF: the AAS requires ride-through unless RoCoF exceeds ±4 Hz/s for more than 0.25 s or ±3 Hz/s for more than 1 s; the MAS thresholds are ±2 Hz/s and ±1 Hz/s respectively.[90]
- **S5.2.5.4 (response to voltage disturbances).** AAS: continuous operation between 0.90 and 1.10 p.u., and withstand of over-voltage bands of 1.10 to 1.15 p.u. for 20 minutes, 1.15 to 1.20 p.u. for 20 s, 1.20 to 1.25 p.u. for 2 s, 1.25 to 1.30 p.u. for 0.2 s and above 1.30 p.u. for 0.02 s, together with under-voltage bands of 0.80 to 0.90 p.u. for 10 s and 0.70 to 0.80 p.u. for 2 s.[91]
- **S5.2.5.5 (disturbance ride-through).** AAS: ride through three-phase transmission faults cleared by primary protection, and single- and two-phase faults cleared in breaker-fail time (430 ms where no scheme is specified, per Table S5.1a.2 for the 100 to 250 kV level), plus up to 15 disturbances in any five-minute period, with no more than six below 50% voltage.[92,103] MAS: asymmetrical faults cleared by primary protection and up to six disturbances in five minutes.[92]
- **S5.2.5.5A (responses to disturbances, new in 2025).** AAS: capacitive reactive current of at least 4% and inductive current of at least 6% of maximum continuous current per 1% positive-sequence voltage deviation, commencing within 10 ms of the initiating condition (85% or 115% voltage) with a rise time of no more than 40 ms and an "adequately controlled" response, negative-sequence current in proportion to the negative-sequence voltage, and active power restored to at least 95% within 100 ms of the disturbance ending.[93] MAS: any positive contribution ("do no harm"), initiating at 80% or 120% voltage, commencing within 40 ms with a rise time of no more than 80 ms.[93]

How Australia arrived at these numbers is worth a paragraph, because it shows a regulator learning from the physics. Before 2023 the minimum standard required at least 2% additional reactive current for every 1% of voltage deviation, up to the plant's current limit, which for a deep fault meant close to full rated reactive current from every inverter in the area at once. At weak, high-impedance sites that produced transient over-voltages and set neighbouring inverters against each other. The AEMC's **Efficient Reactive Current Access Standards** rule (ERC0272, final determination 20 April 2023) pulled the minimum standard back to "do no harm", added a 40 ms limit on how quickly the response must start, stretched the permitted rise time from 40 ms to 80 ms, dropped the settling-time test and replaced "adequately damped" with "adequately controlled". The automatic standard was left alone.[94] Two years later, Package 1 rebuilt the automatic standard around a 10 ms start, explicit negative-sequence injection and a 100 ms active-power recovery, which is the AEMC saying that the equipment has caught up and the fast response can now be demanded, provided it is controlled.[95]

6.3 System Strength Framework and Grid-Forming Incentives

The AEMC's **Efficient Management of System Strength** rule (ERC0300, final determination October 2021) restructured how system strength is provided.[48,96] Transmission network service providers were designated

System Strength Service Providers (SSSPs), with a system strength standard binding from 2 December 2025. Under NER clause 5.3.4B and Schedule 5.2.5.15, a connecting plant must either pay the SSSP's **system strength charge** or self-remediate through a **System Strength Remediation Scheme (SSRS)**, and the election is irrevocable; the minimum access standard for asynchronous plant is stable operation at an SCR of 3.0 at the connection point, assessed with full EMT simulation.[96]

A grid-forming battery is now the usual way to self-remediate. AEMO's **Voluntary Specification for Grid-forming Inverters** (May 2023) and the **Core Requirements Test Framework** that followed in January 2024 set out the tests, among them stable operation with a fault applied as the SCR is stepped down to 1.25 (1.0 is informative).[97,98] A plant that passes is treated as inherently capable of providing system strength, and if it demonstrates stable operation at an SCR of 1.2 or below (the system strength framework uses a slightly stricter figure than the test framework) the available-fault-level component of its system strength impact falls to zero.[96] What has not been settled is whether a grid-forming battery can also supply the minimum fault level that protection relays need. A fault-current trial is running, and a proposal to replace about 900 MW of planned synchronous condensers in New South Wales with grid-forming batteries was still pending when this was written. So a grid-forming battery can discharge its own obligation today; whether it can replace a synchronous condenser at network level is being tested, not assumed.

7. Technical Parameter Benchmarking

This section puts the numbers next to each other. The choice of parameters is deliberate: these are the ones that, in my experience, decide which PCS a project can use and how the plant controller has to be built. Where a code leaves a value to negotiation or to the network operator, the table says so and gives the usual range instead of inventing a single figure.

7.1 Active Power Regulation and Frequency Response

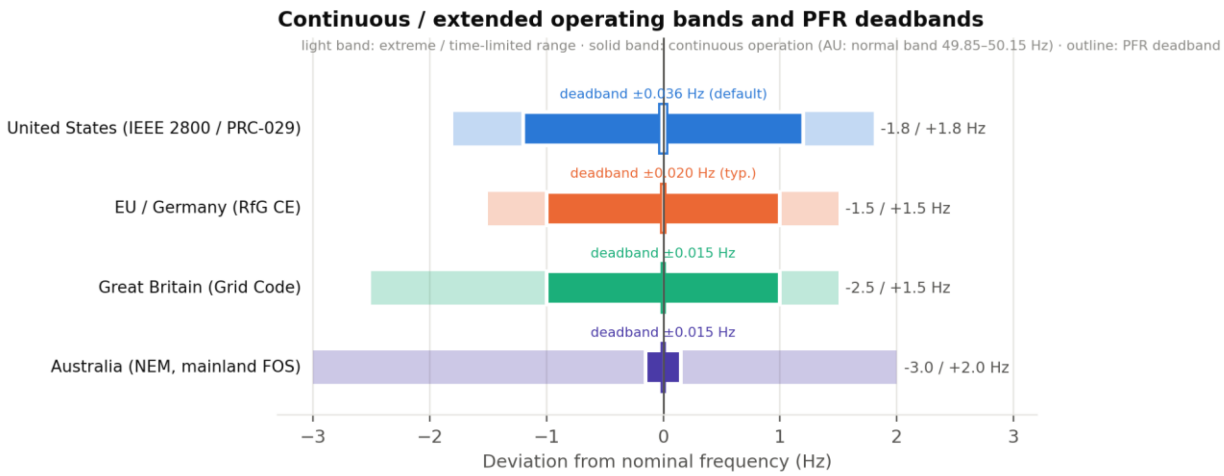

Figure 9. Frequency operating ranges and primary-response dead-bands, as deviation from nominal.

Table 2. Active power and frequency response requirements

Performance metric	United States (IEEE 2800 / NERC PRC-029)	EU and Germany (RfG / VDE-AR-N 4120)	Great Britain (Grid Code / NESO)	Australia (NEM S5.2.5.3 / FOS)
Nominal frequency (f_N)	60 Hz	50 Hz	50 Hz	50 Hz
Continuous operation range	58.8 to 61.2 Hz; mandatory ride-through 57.0 to 58.8 Hz and 61.2 to 61.8 Hz for at least 299 s[69]	49.0 to 51.0 Hz unlimited; 47.5 to 49.0 Hz and 51.0 to 51.5 Hz for at least 30 min[73]	49.0 to 51.0 Hz continuous (normal control 49.5 to 50.5 Hz); 47.5 to 49.0 and 51.0 to 51.5 Hz for 90 min; 47.0 to 47.5 Hz for 20 s[82]	Normal band 49.85 to 50.15 Hz; operational band 49.5 to 50.5 Hz (49 to 51 Hz after network events); extreme limits 47 to 52 Hz (mainland)[100]
Primary frequency deadband	±0.036 Hz default; adjustable ±0.015 to ±0.96 Hz[7]	0 to ±0.5 Hz permitted by RfG;[73] ±0.010 to ±0.020 Hz typical in German practice[77]	≤ 0.03 Hz combined deadband and insensitivity (±0.015 Hz)[82]	±0.015 Hz typical (AEMO primary frequency response requirements)
Active power droop	5% default; adjustable 2% to 5%[7]	2% to 12% (FSM and LFSM); 4% to 5% typical[73]	3% to 5%[82]	Typically 2% to 5% (a negotiated access standard agreed per plant under S5.2.5.11)
Primary response dynamics	Reaction ≤ 0.5 s; rise 4 s; settling 10 s (defaults); FFR full output within 1.5 s (1 s adjustable)[7]	FSM: initial delay ≤ 2 s, full activation ≤ 30 s[73]	Grid Code primary response fully delivered within 10 s and secondary within 30 s;[82] Dynamic Containment (market service): start ≤ 0.5 s, full delivery ≤ 1 s[86]	Mandatory primary frequency response under S5.2.5.11 and AEMO's PFR requirements; response times agreed in the GPS

Performance metric	United States (IEEE 2800 / NERC PRC-029)	EU and Germany (RfG / VDE-AR-N 4120)	Great Britain (Grid Code / NESO)	Australia (NEM S5.2.5.3 / FOS)
RoCoF withstand	≥ 5.0 Hz/s averaged over ≥ 0.1 s[8]	Set by the TSO under RfG;[73] ENTSO-E guidance and the German TAR: 2.0 Hz/s over 0.5 s, 1.5 Hz/s over 1 s, 1.25 Hz/s over 2 s[77]	1.0 Hz/s over 500 ms (2.0 Hz/s for grid-forming plant)[82,85]	AAS: ±4.0 Hz/s for 0.25 s and ±3.0 Hz/s for 1 s; MAS: ±2.0 Hz/s and ±1.0 Hz/s[90]

7.2 Reactive Power Capability and Dynamic Voltage Support

Table 3. Reactive capability, control modes and fault response

Jurisdiction and standard	Continuous reactive capability	Steady-state operating modes	Dynamic voltage support / fault response	Asymmetrical fault behaviour
United States (IEEE 2800 / PRC-029-1)	≥ 0.3287 p.u. inject and absorb (PF 0.95 at rated power) across the active power range[68]	Closed-loop voltage control (damping ≥ 0.3, reaction < 200 ms), reactive power, or fixed PF[5]	Dynamic current injection in the ride-through zones; momentary cessation prohibited[69]	IEEE 2800 requires negative-sequence current; PRC-029-1 requires current exchange on the affected phases[8,69]
Germany (VDE-AR-N 4120)	Operator-selected variant, typically cos ϕ 0.95 under-excited to 0.925 over-excited (Q = 0.33 to 0.41 P_{inst})[77]	Q(U) characteristic, Q(P) or Q(t) schedule, or constant cos ϕ[77]	k-factor injection (2 ≤ k ≤ 6, default 2); 90% within 30 ms, settled within 60 ms[77]	Explicit positive- and negative-sequence current control[34]
Great Britain (GB Grid Code ECC)	PF 0.95 lagging to 0.95 leading at the grid entry point at rated MW[82]	Continuous voltage control with slope 2% to 7% (0.5% steps)[82]	FFCI: gain k default 2.5 (2 to 7); delay ≤ 20 ms; ~0.65 p.u. within 60 ms for deep dips; grid-forming plant responds inherently within 5 ms[83,85]	Positive-sequence specification; maximum reactive current within transient rating on unbalanced faults, no negative-sequence control mandated[83]
Australia (NEM S5.2.5.1 / S5.2.5.5A)	AAS: ±0.395 P_{max} (PF ≈ 0.93) within ±5% of mid-point voltage; MAS: none required[89]	Closed-loop voltage control with droop, direct reactive power, or PF[58]	AAS: 4% capacitive / 6% inductive per 1% ΔV, commence ≤ 10 ms, rise ≤ 40 ms; MAS: "do no harm", commence ≤ 40 ms, rise ≤ 80 ms[93]	AAS requires negative-sequence current proportional to negative-sequence voltage[93]

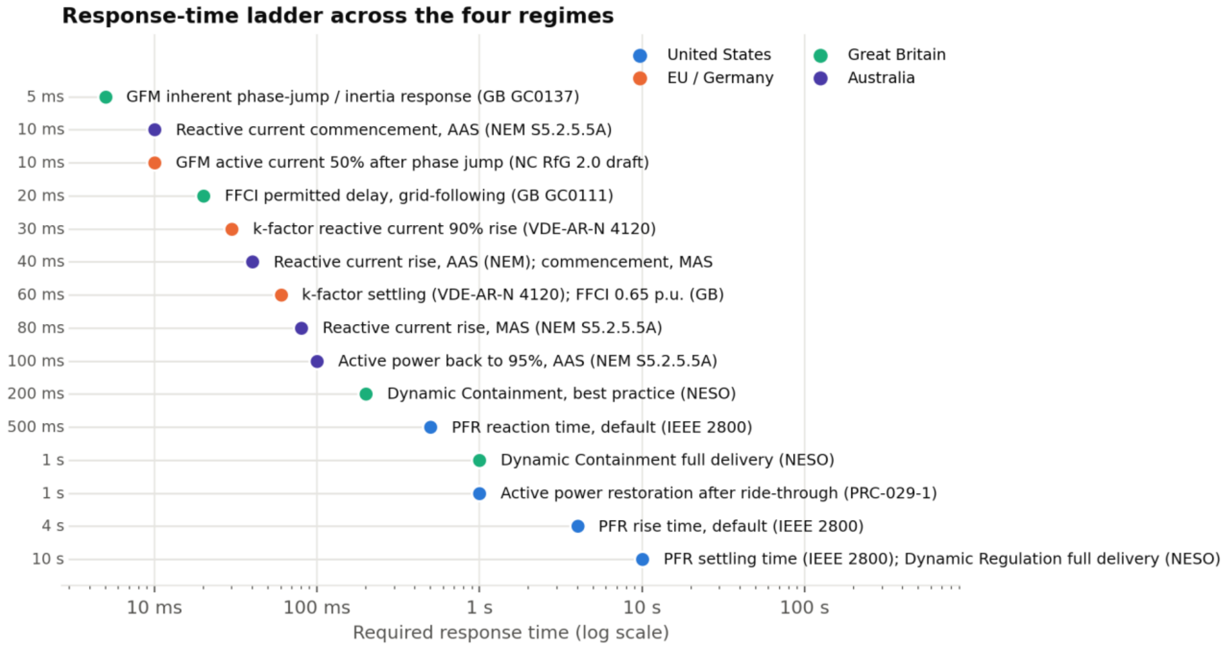

Figure 10. Response times required by the four regimes, from 5 ms to 10 s on a log scale.

7.3 Voltage Fault Ride-Through (LVRT / HVRT) Envelopes

A ride-through envelope is a promise: below this voltage, for this long, the plant will not trip. The low-voltage side is set by fault clearance times and the high-voltage side by what the network does after a fault clears or a line is switched. Figure 11 draws the four envelopes on one time axis so the differences are visible.

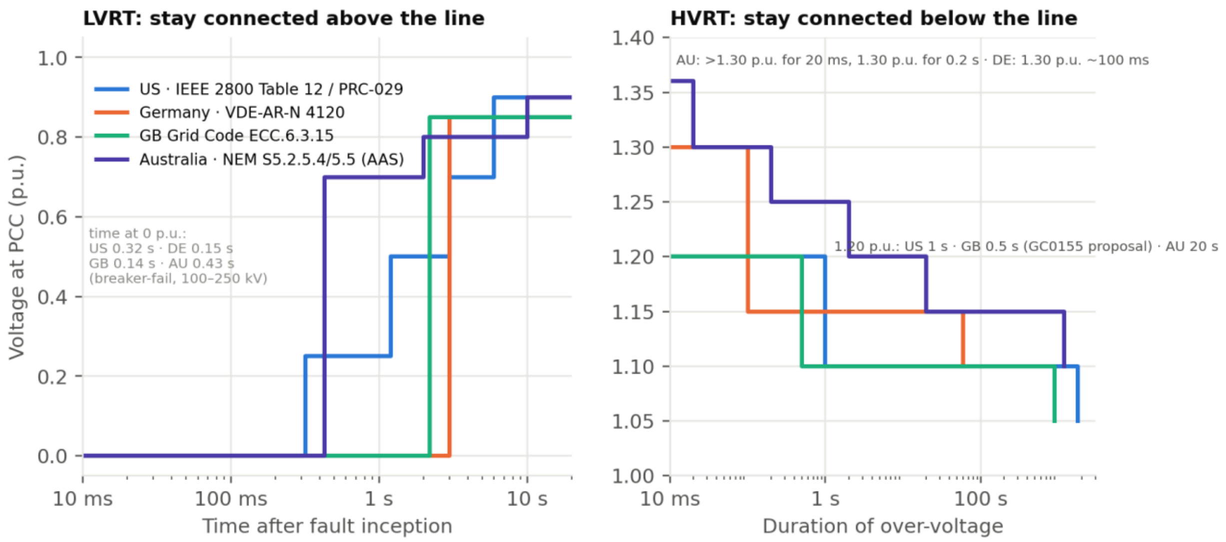

Figure 11. Ride-through envelopes compared, log time axis. Stay connected above the left-hand lines and below the right-hand lines. GB's temporary over-voltage withstand is bilateral; the GC0155 proposal is drawn.

- **United States (IEEE 2800-2022 Table 12 / PRC-029-1).** LVRT durations as in Section 3.2 (0.32 s below 0.25 p.u., rising to 6.0 s at 0.70 to 0.90 p.u.).[9,69] HVRT: 1.0 s between 1.10 and 1.20 p.u., 1,800 s between 1.05 and 1.10 p.u., and continuous operation from 0.90 to 1.05 p.u.; above 1.20 p.u. the unit may trip.[8,69] Momentary cessation is prohibited within these bands.[69] Multiple-fault withstand: the unit must ride through four deviations in 10 s, six in 120 s and ten in 30 min, and may only trip beyond those counts; for deep deviations below 0.50 p.u. it must ride through two in 10 s and three in 120 s.[8]

- **Germany (VDE-AR-N 4120).** Remains connected at 0 p.u. for 150 ms, with the lower boundary then rising to 0.85 p.u. within about 3 s.[77] The HVRT boundary begins at 1.30 p.u. for about 100 ms and steps down to 1.15 p.u., which must be sustained for 60 s at the HV level, so that multi-phase auto-reclosure cycles are survived without tripping.[77]
- **Great Britain (GB Grid Code ECC.6.3.15).** Zero voltage at the grid entry point for 140 ms, followed by a linear boundary reaching 0.85 p.u. at 2.2 s, with active power restored to 90% within 1 s of recovery.[82] Steady-state voltage ranges are 0.90 to 1.10 p.u. at 275 kV and 132 kV and 0.90 to 1.05 p.u. at 400 kV (1.05 to 1.10 p.u. for up to 15 minutes); temporary over-voltage withstand is set in the bilateral agreement, and modification GC0155, still at workgroup stage, proposes a code-wide 1.20 p.u. for 0.5 s.[82,87]
- **Australia (NEM S5.2.5.4 and S5.2.5.5).** Ride-through of faults cleared in primary and breaker-fail times per Table S5.1a.2 (80 to 120 ms primary and 175 to 430 ms breaker-fail depending on voltage level), with up to 15 disturbances in five minutes under the AAS.[92,103] Over-voltage withstand per S5.2.5.4: 20 min up to 1.15 p.u., 20 s up to 1.20 p.u., 2 s up to 1.25 p.u., 0.2 s up to 1.30 p.u. and 0.02 s above 1.30 p.u.; under-voltage 10 s down to 0.80 p.u. and 2 s down to 0.70 p.u.[91]

7.4 Power Quality Tolerances

A PCS makes harmonics, inter-harmonics and switching noise, and in a weak network those can find a resonance. The codes handle this by planning levels for the network as a whole and an emission allocation for each connection. Table 4 gives the planning levels and standard limits; the allocation a particular plant receives is always some fraction of them and is set by the network operator, so nobody should design to the table values directly.

Table 4. Power quality planning levels and standard limits

Power quality metric	North America (IEEE 519-2022)	Continental Europe (IEC/TR 61000-3-6, -3-7, -3-13; VDE TAR)	Great Britain (ENA EREC G5/5, P28, P29)	Australia (NER S5.1a, referencing IEC/TR 61000.3.6 and 61000.3.7)
Total harmonic voltage distortion (THD)	Above 161 kV: THD ≤ 1.5%; 69 to 161 kV: ≤ 2.5%; 1 to 69 kV: ≤ 5.0%; ≤ 1 kV: ≤ 8.0%	Planning levels: HV and EHV 3%; MV 6.5%; allocation to a single customer typically 1.5% to 2% at HV	G5/5 planning levels: 3% at 132 kV and above; 4% at 33/66 kV; 5% at LV; connection assessed by staged emission limits	NSP-allocated emission limits derived from IEC/TR 61000.3.6 planning levels (S5.1a.6, S5.2.5.2)[104,105]
Individual harmonic voltage (IHD)	Above 161 kV: ≤ 1.0%; 69 to 161 kV: ≤ 1.5%; 1 to 69 kV: ≤ 3.0%	Allocated per IEC/TR 61000-3-6 (e.g. 5th and 7th at HV-EHV: 2%)	G5/5 individual harmonic planning levels by voltage level and order	Individual allocation factors per IEC/TR 61000.3.6[104]
Voltage unbalance (V_2/V_1)	Steady-state typically ≤ 1% to 2% (ANSI C84.1 / utility practice); short-term ≤ 3%	Planning levels: HV 1.4%; EHV 0.8%; compatibility level 2%	P29: negative-sequence voltage ≤ 1% at 132 kV and above (≤ 2% for short periods)	Table S5.1a.1, above 100 kV: 0.5% (30 min), 0.7% (credible contingency), 1.0% (10 min), 2.0% (1 min)[104]
Short-term flicker (P_{st})	Planning per IEEE 1453 / IEC 61000-3-7 (HV: 0.8)	Planning level HV-EHV P_{st} ≤ 0.8 (MV 0.9)	P28 Issue 2 planning levels aligned with IEC 61000-3-7 (HV: 0.8)	IEC/TR 61000.3.7 planning levels applied by the NSP (HV: 0.8) (S5.1a.5)[104]
Long-term flicker (P_{lt})	Planning per IEEE 1453 (HV: 0.6)	Planning level HV-EHV P_{lt} ≤ 0.6 (MV 0.7)	P28 Issue 2 planning levels (HV: 0.6)	IEC/TR 61000.3.7 planning levels (HV: 0.6) (S5.1a.5)[104]

Power quality metric	North America (IEEE 519-2022)	Continental Europe (IEC/TR 61000-3-6, -3-7, -3-13; VDE TAR)	Great Britain (ENA EREC G5/5, P28, P29)	Australia (NER S5.1a, referencing IEC/TR 61000.3.6 and 61000.3.7)
Rapid voltage change (RVC)	Typically ≤ 3% per step (utility practice)	Customer-caused Δu typically limited to about 2% under the German TAR; IEC/TR 61000-3-7 allows 2.5% to 5% depending on event frequency	P28 Issue 2: step-change limits by frequency of occurrence (typically 3% for infrequent events at HV)	S5.1a.5: NSP-set limits per IEC/TR 61000.3.7; ≤ 3% common for switching steps[104]

8. Simulation, Hardware-in-the-Loop and Field Commissioning

A battery's behaviour during a fault is decided by control code running in a few hundred microseconds, and a positive-sequence RMS model, which was built to represent rotating machines a few cycles at a time, cannot see that. Operators learned this the hard way, from plants that passed their RMS studies and then tripped in the field. The result is a chain of evidence (Figure 12) that now runs from the OEM's compiled firmware through a hardware-in-the-loop bench to measurements on site; Figure 13 shows its four stages.

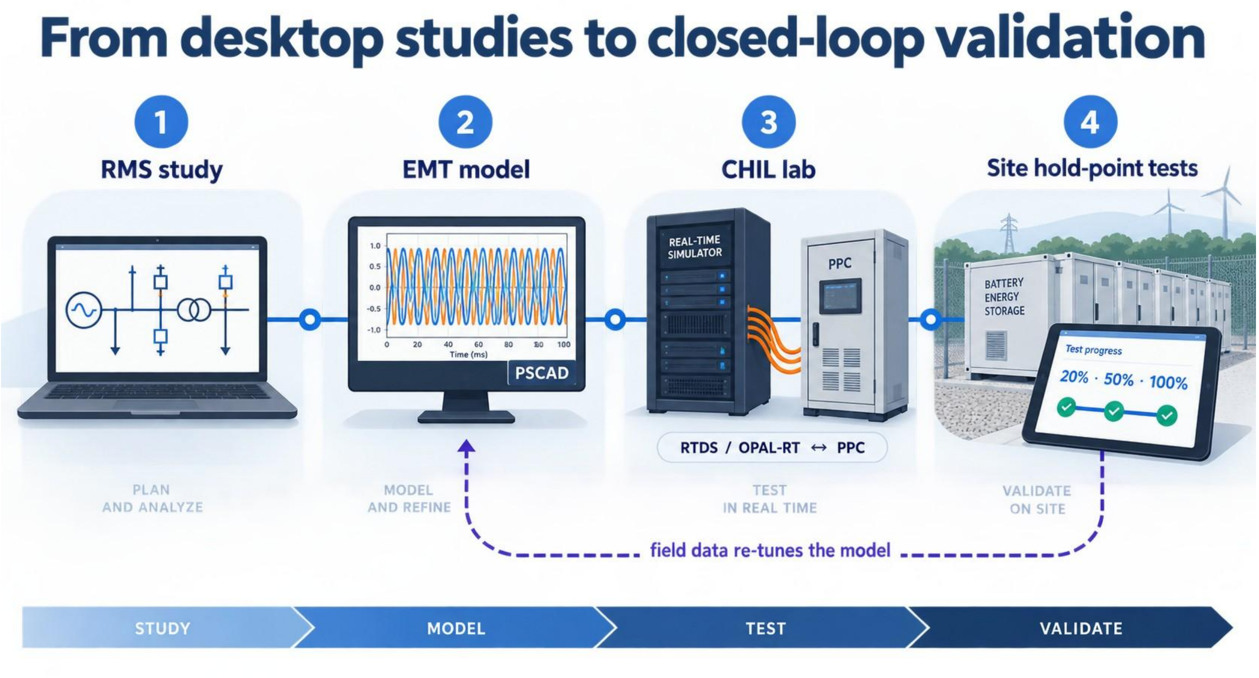

Figure 12. The evidence chain: RMS study, EMT model, controller hardware-in-the-loop bench, staged site tests, and field data going back into the model.

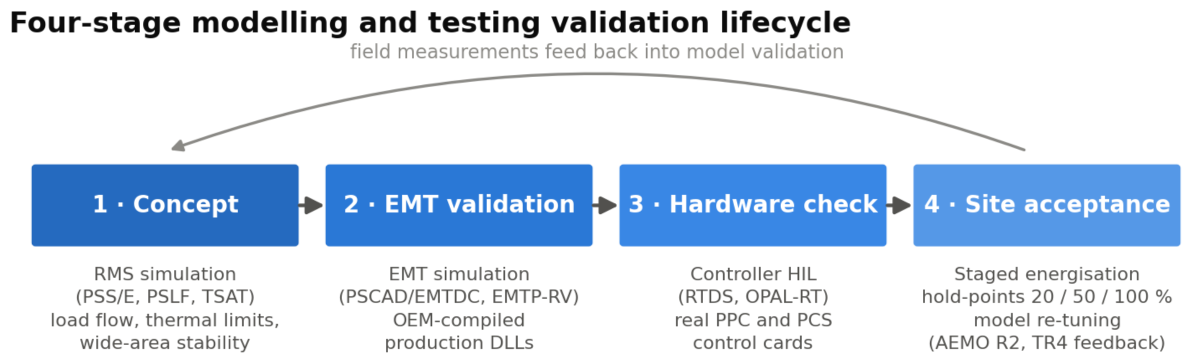

Figure 13. The four stages, and what each one uses.

8.1 From RMS to High-Fidelity EMT Modelling

RMS tools such as Siemens PTI PSS/E, GE Vernova PSLF and PowerWorld represent the network as balanced, fundamental-frequency phasors. They are still the right tool for wide-area studies: inter-area oscillations, thermal flows, long-term stability across an interconnection.

What they cannot do is represent a converter controller honestly. The inner current loops, the PLL, the current limiter and the switching itself are all reduced to algebra, and in a weak network with a low SCR and low X/R that algebra will often report a stable plant where the real one would oscillate or trip.

So operators now ask for electromagnetic transient (EMT) models, usually in PSCAD/EMTDC or EMTP-RV.[3] An EMT model solves the three-phase differential equations point on wave, at microsecond steps, and can therefore represent:

- PLL tracking dynamics during steep phase-angle jumps and weak-grid faults;[1]
- non-linear saturation of PCS magnetics and collector transformers;
- sub-synchronous control interactions (SSCI) between fast inverter voltage loops, nearby power electronics and series-compensated corridors;[28]
- positive- and negative-sequence current control transitions during asymmetrical faults.

8.2 Modelling Requirements by Jurisdiction

- **United States.** Under FERC Order 901, NERC's Milestone 3 modelling standards (MOD-026-2, MOD-032-2, MOD-033-3, approved February 2026) require verified dynamic models, including EMT models where the planning coordinator requires them, and Milestone 4 will add planning and operational study obligations in November 2026.[67] ERCOT runs an automated Model Quality Test (MQT) suite that evaluates vendor PSS/E and PSCAD models against dozens of standardised parameter steps, phase jumps and low-SCR conditions before queue progression.[12]
- **Australia (AEMO).** The *Power System Model Guidelines* (v3.0, September 2025) require fully validated PSS/E and PSCAD/EMTDC models that match the firmware programmed into the site PCS and power plant controller (PPC).[99] The R1 package (registered data and model) is due at least three months before commissioning; AEMO and the NSP then simulate the project within a wide-area EMT model of the NEM. After energisation the plant proceeds through agreed hold points, staged by MW level and set according to the plant's expected system impact, and delivers an R2 package, with the model re-validated against commissioning measurements, within three months of completing commissioning.[99] AEMO's Commissioning Guideline (effective January 2026) and R1 Capability Assessment Guideline (2025) formalise this under the Connections Reform Initiative.
- **Germany (FGW TR4).** Software models must be validated against measurements from TR3 hardware testing.[30] TR4 mandates error evaluations comparing simulated active power, reactive power and dynamic current traces against laboratory records, qualifying the model for full-plant TR8 compliance simulations.[30]

8.3 Controller Hardware-in-the-Loop (CHIL) Testing

An EMT model is still a model of the controller. To test the controller itself before it reaches site, developers, OEMs and network operators use a Controller Hardware-in-the-Loop (CHIL) bench.[62]

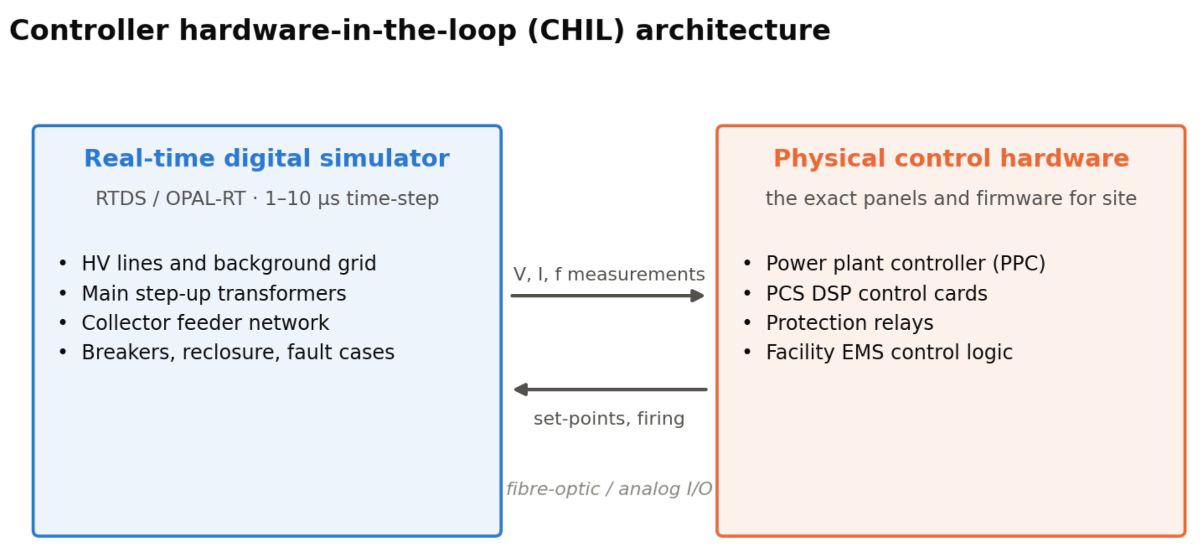

Figure 14. Controller hardware-in-the-loop. The network is simulated in real time; the controller under test is the real one.

CHIL integrates physical control hardware directly into a real-time simulation loop. The network, including lines, transformers, breakers and surrounding generation, is modelled in a digital real-time simulator (RTDS or OPAL-RT), typically at a network time-step of around 50 µs with converter sub-networks solved at 1 to 3 µs, and interfaced with the physical controllers through high-speed analogue and digital I/O and fibre-optic links.

The controller is no longer approximated; the plant and the network still are. Within that limit CHIL is the best tool available for:

- evaluating high-density multi-inverter interactions, identifying localised control instabilities and high-frequency resonances between PCS units on a common collector bus;
- assessing trip boundaries and transient withstand under zero-voltage conditions and complex auto-reclosure sequences, verifying that real hardware will not enter momentary cessation or trip on internal over-current;[10]
- tuning and testing black-start and islanding for grid-forming BESS, verifying control loop stability through transformer inrush, unenergised line charging and sudden block-load pickup.

8.4 Field Commissioning and Operational Compliance Testing

The last stage is the site itself, where the question is whether the plant behaves the way the models said it would:

- **Pre-energisation static checks.** Protection relay settings, insulation resistance, polarity and phasing, and communications links between field controllers, local SCADA and the system operator.
- **Harmonic and background power quality audits.** Baseline background distortion is captured before breaker closure, followed by post-energisation monitoring to verify emissions remain within allocated limits.[63]
- **Step-response tuning.** Closed-loop PPC response is tested by injecting stepped set-points for active power, reactive power and terminal voltage to measure rise time, settling time and damping.[5]
- **Dynamic disturbance verification.** Facilities are equipped with digital fault recorders (DFRs) and sequence-of-events (SOE) loggers; high-end installations sample at 10 kHz or more, and in the US NERC PRC-028-1 sets minimum requirements for fault recording (at least 16 samples per cycle) and dynamic

disturbance recording (at least 30 samples per second) at large IBR facilities.[5,110] When grid disturbances occur, recorded high-speed data are cross-referenced with the pre-interconnection models to confirm compliance with ride-through profiles and dynamic support mandates.[5]

9. Cross-Jurisdictional Standards Comparison

Table 5 collects the instruments, their scope and their main technical demands in one place. Table 6, which I regard as the more useful of the two, records what each instrument's legal status actually was in September 2026, because several of the requirements that get quoted most often in this field are drafts or options rather than rules.

Table 5. Consolidated comparison of BESS interconnection standards

Jurisdiction	Standard and title	Regulatory / standards body	Scope and applicability	Core technical mandates	Compliance and validation process
United States	**IEEE 2800-2022**: Standard for Interconnection and Interoperability of IBRs Interconnecting with Associated Transmission Electric Power Systems[68]	IEEE Standards Association; adopted by ERCOT, MISO, NYISO and others through tariffs[5]	Transmission and sub-transmission connected IBRs and BESS[5]	Reactive capability 0.3287 p.u. (PF 0.95);[68] Table 12 ride-through (0.32 s below 0.10 p.u., 6 s to 0.90 p.u.);[69] PFR droop 2% to 5%, deadband ±0.036 Hz default;[7] RoCoF 5.0 Hz/s;[8] momentary cessation prohibited[69]	Test and verification per IEEE 2800.2-2026;[72] NERC Reliability Standards; RTO model acceptance criteria[5]
United States	**NERC PRC-029-1**: Frequency and Voltage Ride-Through Requirements for Inverter-Based Resources[69]	North American Electric Reliability Corporation; approved by FERC Order 909[70]	Bulk Electric System generator owners of IBRs[69]	Binding ride-through within the IEEE 2800-derived zones; no momentary cessation; current exchange on affected phases; active power restoration within 1.0 s[69]	Effective 1 October 2026; regional compliance monitoring; successor PRC-029-2 filed with FERC 28 August 2026, pending approval[70,111]
United States	**ERCOT NOGRR 245**: IBR Ride-Through Requirements[14]	ERCOT / Public Utility Commission of Texas[14]	All transmission-connected IBRs and BESS in ERCOT[11]	Maximum ride-through capability; IEEE 2800 Clauses 5, 7, 9 for agreements from 1 June 2024;[71] elimination of phase-jump and transient over-voltage nuisance trips[11]	Effective 1 October 2024; existing units by 31 December 2025 with extensions to 2027/2028; RIOO submissions and Model Quality Tests[12,71]
United States	**NFPA 855-2023**: Standard for the Installation of Stationary Energy Storage Systems[18]	National Fire Protection Association[18]	All commercial and utility-scale stationary storage[18]	50 kWh groups; 600 kWh per fire area in non-dedicated buildings;[101] 3 ft / 10 ft separations;[19] deflagration venting (NFPA 68) and gas detection[18]	AHJ submittals supported by UL 9540 listing and UL 9540A propagation testing;[19] HMA route in the 2026 edition
European Union	**NC RfG (EU) 2016/631** and the ACER-recommended **NC RfG 2.0** (not adopted)[73,74]	European Commission / ENTSO-E / ACER[74]	RfG: generation Types A to D; RfG 2.0 would add electricity storage modules ≥ 1 MW[74]	RfG: FSM droop 2% to 12%, deadband ≤ 0.5 Hz, TSO-set RoCoF;[73] RfG 2.0: grid-forming for Type C/D PPMs and storage ≥ 1 MW, 10 ms phase-jump response, damping ≥ 5%[75]	RfG: directly applicable, with non-exhaustive requirements set nationally; Power Generating Module Documents and operational notification;[35] RfG 2.0: no adoption timeline[76]

Jurisdiction	Standard and title	Regulatory / standards body	Scope and applicability	Core technical mandates	Compliance and validation process
Germany	**VDE-AR-N 4120:2018-11** (HV, 110 kV) and **VDE-AR-N 4130** (EHV)[77]	VDE / FNN[29]	60 kV to below 150 kV (4120); 220 and 380 kV (4130)[77]	Reactive envelope cos ϕ 0.95 to 0.925 (variant);[77] k-factor injection (k = 2 to 6), 90% in 30 ms;[77] explicit negative-sequence support;[34] draft 4120/A1 adds grid-forming for HV BESS	Three-tier certification: FGW TR3 (unit testing), TR4 (model validation), TR8 (EZE, EZA, conformity declaration)[30,79]
Great Britain	**GB Grid Code (European Connection Conditions incl. GC0111 and GC0137)**[82,83,84]	National Energy System Operator[82]	Transmission-connected generation and storage (275 kV and 400 kV; 132 kV in Scotland)	FRT 0 p.u. for 140 ms, 0.85 p.u. at 2.2 s;[82] FFCI delay ≤ 20 ms, k = 2.5;[83] grid-forming (optional): 5 ms inherent response, 60° phase jump, 2 Hz/s RoCoF[85]	Validated EMT/RMS model submission; compliance testing; dynamic service qualification (DC/DM/DR)[86]
Great Britain	**ENA Engineering Recommendation G99 Issue 2 (2025)**[81]	Energy Networks Association[40]	Generation and storage connected in parallel with public distribution systems[40]	Type A to D categories (Type D ≥ 50 MW or ≥ 110 kV); LVRT through 140 ms zero-voltage events; loss-of-mains RoCoF 1 Hz/s over 0.5 s[81]	Equipment registration and type certification via ENA; distribution network impact assessments
Australia	**NER Schedule 5.2 (GPS)** as amended by ERC0393 (in force 21 August 2025)[95]	AEMC / AEMO[50]	NEM generating, integrated resource and synchronous condenser systems[49]	AAS: ±0.395 P_{max} reactive;[89] RoCoF ±4 Hz/s for 0.25 s;[90] 15 disturbances in 5 min;[92] S5.2.5.5A: 4%/6% per 1% ΔV, commence ≤ 10 ms, negative sequence, P to 95% in 100 ms;[93] system strength charge or SSRS[96]	R1 pre-connection models and wide-area PSCAD studies, staged hold-point commissioning, R2 model validation within 3 months[99]

Table 6. Legal status of the principal instruments as at September 2026

Jurisdiction	Instrument	Status	What it means for a project
United States	IEEE 2800-2022 (standard) / IEEE 2800.2-2026 (recommended practice)	Voluntary consensus documents; IEEE 2800 is binding where adopted in RTO tariffs (ERCOT, MISO, NYISO)	Apply the RTO's adoption date and scope, not the standard's publication date
United States	NERC PRC-029-1	Approved (FERC Order 909, July 2025); effective 1 October 2026; successor PRC-029-2 filed with FERC (Docket RD26-10, August 2026), pending approval	Ride-through obligations become enforceable on BES generator owners from October 2026
United States	ERCOT NOGRR 245	In force since 1 October 2024	Existing units had until 31 December 2025; extensions to 2027 (frequency) and 2028 (voltage)
United States	NFPA 855	Binding where adopted by the state or local code; 2023 edition widely adopted, 2026 edition published	Check which edition the AHJ has adopted; the HMA route differs materially
European Union	NC RfG (EU) 2016/631	Directly applicable Commission Regulation; non-exhaustive requirements set nationally by TSO proposals approved by regulators	Storage is outside RfG scope; national codes govern
European Union	NC RfG 2.0 (ACER Recommendation 03/2023)	Draft with the Commission; not adopted; no timeline	Grid-forming mandate is a direction signal, not a requirement
Germany	VDE-AR-N 4110 / 4120 / 4130	Binding technical connection rules; draft 4120/A1 consulted April to May 2026	Certification through FGW TR3/TR4/TR8 is a precondition of energisation
Germany	Momentanreserve market	Live since 22 January 2026	Grid-forming capability has a revenue line
Great Britain	GB Grid Code ECC (incl. GC0111 FFCI)	Binding for transmission connections	FFCI and FRT profiles apply to all new PPMs and storage
Great Britain	GC0137 grid-forming (ECC.6.3.19)	In force since February 2022; non-mandatory	Required only if the plant is to be recognised as grid-forming
Great Britain	GC0155 FRT clarification	Workgroup stage (2026)	Proposed 1.20 p.u. / 0.5 s over-voltage withstand is not yet in the code

Jurisdiction	Instrument	Status	What it means for a project
Australia	NER Schedule 5.2 as amended by ERC0393	In force since 21 August 2025 (grandfathering for earlier enquiries)	S5.2.5.5A and the revised S5.2.5.1 apply to new applications
Australia	AEMO grid-forming specification and test framework	Voluntary	Route to self-remediate system strength; not yet a substitute for minimum fault level
Australia	System strength standard (ERC0300)	SSSP obligations binding from 2 December 2025	Pay the system strength charge or commit to an SSRS; the election is irrevocable

10. Technical Trajectories and Implications

Read together, the four regimes are moving in the same three directions, at different speeds.

10.1 From Grid-Following to Grid-Forming

A grid-following inverter is a current source that needs a voltage to follow. It finds that voltage with a PLL, and in a weak network, after a large phase jump, with little inertia around it, the PLL can lose its grip, and when several inverters lose their grip together the result is the wide-area oscillation and tripping that started this whole regulatory cycle.[1] A grid-forming inverter sets its own voltage and lets the grid pull current from it, which is what a synchronous machine does, and which is why every operator in this report wants more of it.[23]

The rules differ in how hard they push. GB offers an open specification and market contracts (GC0137, the Stability Pathfinder); Australia offers a voluntary specification with a financial reason to meet it (system strength self-remediation); Germany has a market for instantaneous reserve and a draft rule that would require the behaviour of new HV batteries; the EU has a proposal to require it of all storage from 1 MW upward, waiting for adoption.[74,78,84,97] The plant the codes are converging on is one that holds its own voltage and frequency, delivers inertia without being asked and damps rather than feeds sub-synchronous oscillations.[75]

10.2 From Passive Self-Protection to Active System Support

Momentary cessation was a sensible design choice for a small inverter on a strong grid: block the switches during a voltage dip, protect the silicon, come back when the voltage does.[10] It became a system problem when gigawatts of plant did it at the same moment during faults the grid was designed to survive.[1] The current codes forbid it inside the ride-through zone (IEEE 2800-2022, NERC PRC-029-1, ERCOT NOGRR 245, VDE-AR-N 4120) and ask instead for fast, controlled reactive current in both sequences, tolerance of phase-angle jumps, and active power back within a defined time after the fault clears (IEEE 2800, VDE-AR-N 4120, Australia's S5.2.5.5A).[69,77,93] Australia's sequence, loosening the minimum standard in 2023 and tightening the automatic standard in 2025, is the clearest statement of what the operators want: fast, but under control.

10.3 From Desktop Studies to Closed-Loop Validation

Nobody accepts a load-flow and a positive-sequence stability run as proof any more.[12] The operator wants an EMT model compiled from the firmware that will actually run on site,[3] wants it screened (ERCOT's model quality tests, AEMO's R1 review), and wants it re-validated against what the plant did during commissioning (AEMO's R2, Germany's conformity declaration).[67,99] IEEE 2800.2-2026 now gives the US a written procedure for the tests.[72] Add a hardware-in-the-loop bench and the FGW laboratory measurements, and the evidence for a battery today runs unbroken from the OEM's compiler to the grid connection.[30]

10.4 What I Would Do With This

Six habits for project teams

Check the status of an instrument before its content. The requirements most often quoted in this field (RfG 2.0 grid-forming, PRC-029-1, GC0155, VDE-AR-N 4120/A1) are at four different stages of legal force, which is the reason Table 6 exists. Write the connection agreement against the version in force on the signing date and decide who carries the risk of a later change.

Ask the PCS vendor for the paper, not the datasheet. A TR8 unit certificate in Germany, an IEEE 2800 attestation and a PSCAD model that has passed ERCOT's screening, GC0137 evidence if grid-forming status is wanted in GB, a model built to AEMO's guidelines in Australia. If the vendor cannot produce it, the schedule problem is already yours.

Treat the model as a long-lead item. A model rejected at ERCOT's quality test or AEMO's R1 review costs months, and the delay lands after the site is built. Budget time for tuning, and for a hardware-in-the-loop bench if the site is weak.

Design to the tightest regime you might sell into. A PCS that starts reactive current in 10 ms (Australia's automatic standard) and reaches 90% in 30 ms (Germany) can be detuned for an easier market; the reverse is not possible.

In the US, get the fire test data before the layout. UL 9540A results set the NFPA 855 separations, and the separations set the land take. This is a feasibility question, not a permitting one.

Price grid-forming as revenue, not cost. In Australia it discharges the system strength obligation; in Germany it can now be sold as instantaneous reserve; in GB it competes for stability contracts. In the EU it would become a condition of connection for storage of 1 MW and above if RfG 2.0 is adopted, and there is no date for that.

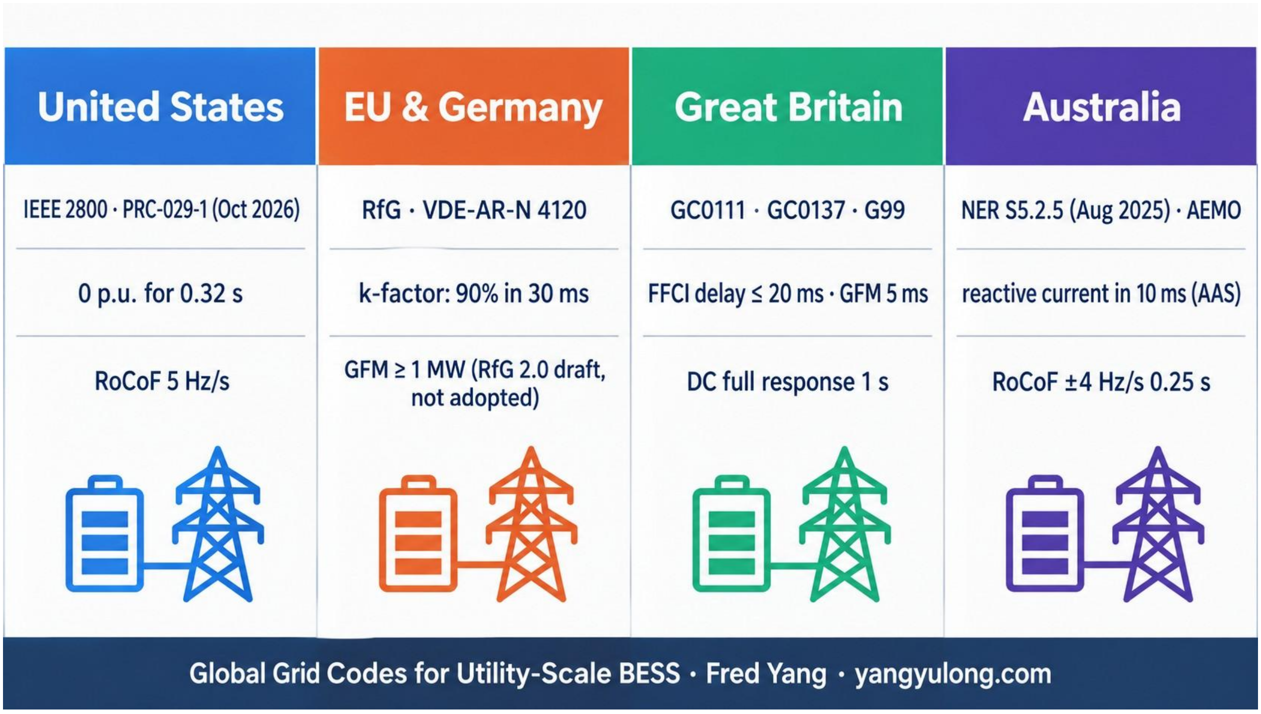

Figure 15. The four regimes on one card. Headline figures from Sections 3 to 7; legal status in Table 6.

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Sources 1 to 64 come from the first research pass and are kept so that every statement can be traced; several are secondary summaries and a few are weak. Sources 65 onward are the rule texts, standards and operator documents used to check the figures from Edition 1.1 onward. Where the two disagree, the later source is the one to trust.

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