i2X Forum for the Implementation of Reliability Standards for Transmission (FIRST) Summary Notes

Interconnection Innovation e-Xchange (i2X)

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Working Draft

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Disclaimers

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Executive Summary

The DOE i2X Forum for the Implementation of Reliability Standards for Transmission (FIRST) established an open industry forum to facilitate discussion, brainstorming, and information sharing regarding the supports the adoption of new standards and test procedures for inverter-based resources (IBRs)[1] connecting to the transmission and subtransmission electric system. Building on the 2024 *Transmission Interconnection Roadmap*, i2X FIRST convenes industry stakeholders to share practices on standard implementation of IEEE 2800-2022 and the upcoming IEEE P2800.2 recommended practices through webinars and workshops. Topics include IBR ride-through, modeling, monitoring, frequency and voltage support, and evolving technologies like grid forming inverters. Discussions also align with FERC directive and ongoing NERC standards revisions.

Season 1 of the i2X FIRST initiative provided a foundational exploration of IEEE 2800-2022, its core requirements, and early industry experiences with implementation. Meeting recordings, presentations and full synopsis and the brief recap summary from Season 1 are available here. Season 2 is continuing these efforts, with a focus on IBR plant design evaluations, change management during the interconnection process, IBR plant commissioning best practices, and emerging standards developments and technology adoption. Sign up for Season 2 i2X FIRST meetings here.

[1] Such as solar photovoltaic (PV), wind, and battery energy storage systems (BESS), and hybrid plants comprised of these technologies.

List of Technical Acronyms

AC	Alternating Current
ACE	Area Control Error
AGIR	Authority Governing Interconnection Requirements
AVR	Automatic Voltage Regulator
BOP	Balance of Plant
BPS	Bulk Power System
CHIL	Control Hardware in the Loop
COD	Commercial Operation Date
CPR	Duke Capability and Performance Report
DC	Direct Current
DER	Distributed Energy Resource
DFR	Digital Fault Recorder
DFT	Discrete Fourier Transform
DLL	Dynamic Link Library
EMT	Electromagnetic Transient
ESR	Energy Storage Resource
FAT	Factory Acceptance Testing
FFR	Fast Frequency Response
FRT	Frequency Ride-Through
GFL	Grid Following
GFM	Grid Forming
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Procedure
GO	Generator Owner
GOP	Generator Operator
HIL	Hardware in the Loop
HVDC	High Voltage Direct Current
IBR	Inverter-Based Resource
IFRO	Interconnection Frequency Response Obligation
IPID	IBR Plant Information Database
IRR	Intermittent Renewable Resource
ISO	Independent System Operator
LSL	Low Sustained Limit
OEM	Original Equipment Manufacturer
OLTC	On-Load Tap Changer
PC	Planning Coordinator
PCS	Power Conversion System
PDT	Phasor Domain Transient
PFR	Primary Frequency Response
PLL	Phase Lock Loop

PMU	Phasor Measurement Unit
POC	Point of Connection
POI	Point of Interconnection
POM	Point of Measurement
PPC	Power Plant Controller
RFI	Request for Information
ROCOF	Rate of Change of Frequency
RMS	Root Mean Square
ROI	Return on Investment
RPA	Reference Point of Applicability
RTO	Regional Transmission Organization
RVC	Rapid Voltage Change
SAT	Site Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SFTP	Secure File Transfer Protocol
SSCI	Subsynchronous Control Interactions
SCR	Short Circuit Ratio
SIL	Software in the Loop
SMIB	Single Machine Infinite Bus
SSR	Subsynchronous Resonance
TOV	Transient Overvoltage
TP	Transmission Planner
TS	Transmission System
TSO	Transmission System Operator
UDM	User-Defined Model
UFLS	Underfrequency Load Shedding
VRT	Voltage Ride-Through
VSC	Voltage Source Converter
WSCR	Weighted Short Circuit Ratio
WTG	Wind Turbine Generator

* Generally not including names of organizations, institutions, or initiatives.

May 27, 2025 Virtual Meeting

Season 2 Kickoff (~200 attendees)

Presentation recording and slides are available to download here. Figure 1 shows the makeup of meeting attendees by industry sector:

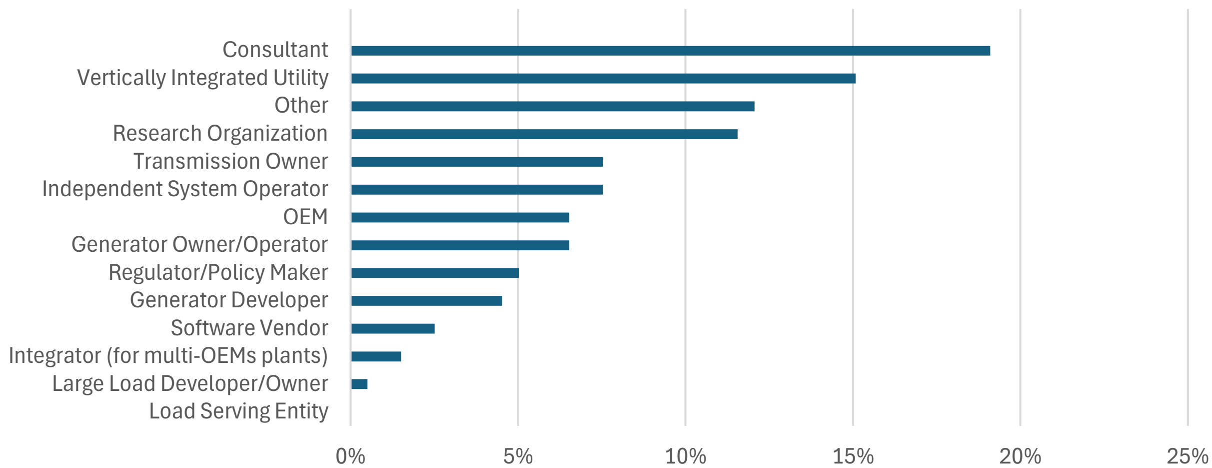


Figure 1: Meeting attendees by industry sector

This first meeting of Season 2 of the DOE i2X FIRST initiative provided a recap of Season 1 highlights and key takeaways, and status updates regarding IEEE 2800-2022 adoption, IEEE P2800.2 progress, and NERC Milestone 2 and 3 standards development efforts. Presentations included the following:

Julia Matevosyan, ESIG

Julia gave an overview of Season 1 topics and shared highlights from the initiate thus far. Season 1 monthly webinars and hybrid workshops were attended by over 1,225 unique participants across a diverse set of stakeholder groups including developers, utilities, system operators, OEMs, and consultants. Consultants comprised the highest percentage of attendees, and this is somewhat to be expected as this group is often supporting generator owner/operators or even independent system operators and utilities through the interconnection process. Season 1 materials can be downloaded on the ESIG i2X FIRST webpage. High-level key takeaways from Season 1 include:

- Harmonizing IBR requirements and enhancing conformity assessments, leveraging IEEE 2800-2022 and IEEE P2800.2, are vital for streamlining the interconnection process while supporting grid reliability.

- NERC or FERC adoption of IEEE 2800-2022 could lead to uniformity and consistency across entities and regions. Coordination with regulatory requirements at the FERC and NERC levels is critical to avoid overlaps, redundancy, and most importantly conflicting requirements. Industry participation in NERC standards development efforts is essential to align with IEEE 2800-2022 and to avoid duplication of effort.
- OEMs are advancing IBR ride-through capabilities and preparing for IEEE 2800-2022 implementation. Guidance is needed from transmission providers on configuration and setting parameters.
- Increased education, engagement, and collaboration is needed between OEMs, transmission providers, IBR plant developers and owners, to enable a streamlined process.
- Accurate IBR unit and IBR plant modeling is a foundational aspect of IEEE 2800-2022 performance conformity assessments. This includes IBR unit model validation based on type testing, IBR plant modeling including in EMT domain, verification of model structures and parameter values, model benchmarking between simulation tools and modeling domains, IBR plant design and as-built/as-left evaluations, commissioning tests, post-commissioning plant-level model validation, and other aspects.
- Retroactively applying advanced requirements to the existing fleet has proven to be difficult, costly, and burdensome on industry overall. Some improvements of IBR plant capability and performance can be achieved with software updates at a minimal cost, these are encouraged.
- Mandatory hardware upgrades have notable risks for existing assets, should be carefully considered.
- Enhancing standards on a regular basis to keep pace with technological advancements, and pro-active requirements for emerging capabilities (prior to their utilization) could minimize the need for retroactivity and ensure continuous improvement of IBR plant performance.

Julia also introduced the agenda for Season 2 which will focus on IBR plant design evaluations, change management during the interconnection process, IBR plant commissioning best practices, and emerging standards developments and technology adoption. Lastly, a brief industry survey conducted at the end of Season 1 also recommended other topics of interest including real-world examples of challenges in overcoming issues to get the most benefit from resources (i.e., tariffs or market limitations), impacts of large loads on transmission grids, oscillations due to changes in load and IBR interactions, and minimum modeling requirements needed for system studies.

Jens Boemer, EPRI

Jens described industry progress towards adoption of IEEE 2800-2022 and the various adoption methods for the standard. He described four generally recognized methods of adoption:

- General reference
- Detailed reference and customization
- Hybrid reference, customization, and specification
- Full specification and customization.

Each method has benefits and challenges yet the hybrid integration approach and the detailed reference approach appear to be widely adopted by industry stakeholders depending on their unique circumstances. Figure 2 shows a recap of an ongoing assessment that EPRI is conducting that shows how industry is adopting the standard. While Clause 7 (ride-through requirements) are widely adopted by most entities, power quality and protection requirements are much less widely adopted. The front matter clauses of IEEE 2800-2022 (Clauses 1-3) are often not referenced, or generally referenced (without customization).

The following are a few adoption methods and approaches used by entities across the country:

- SPP has used a phased adoption strategy with detailed reference to IEEE 2800-2022, and is applying this to the SPP 2025 DISIS queue and beyond. This approach appears to be following the successful adoption strategy used by MISO, with planned additions for grid forming (GFM) inverters.
- ERCOT has also used a phased adoption strategy with NOGRR 245, NOGRR 255, and NOGRR 272 and PGRR 121 nodal operating guide and planning guide revision requests (with additions for GFM batteries). This effort is using a hybrid reference, customization, and specification approach. Phase 1 efforts with NOGRR 245 were delayed three years, mainly due to the fact that ERCOT applied these rules retroactively to existing resources.
- ISO-NE has also adopted IEEE 2800-2022 via planning procedure changes using a detailed reference approach for Clauses 3 to 7, with only 3 succinct pages of material. This applies to new IBRs on or after February 2, 2024.
- NERC has used a full specification approach and is not adopting IEEE 2800-2022 directly or by reference; rather, requirements are individually being aligned with the standard through stakeholder efforts. IEEE 2800-2022 also conflicts with some aspects of the FERC Generator Interconnection Agreement (GIA) such as reactive power capability requirements.

Company	Phase (if applicable)	Adoption Approach (End)	Retroactive Application on Legacy IBRs	Reference Point of Applicability (RPA)	Performance and Capability?	Clause 1: Overview	Clause 2: Normative references	Clause 3: Definitions, acronyms, abbreviatio	Clause 4: General requirements	Clause 5: Reactive power—voltag e contro	Clause 6: Active power—freque ncy respon	Clause 7: Response to TS abnormal condition	Clause 8: Power quality	Clause 9: Protection	Clause 10: Modeling data	Clause 11: Measurement data	Clause 12: Test and verification	Grid-forming Requirements
Ameren IL		Hybrid Reference Customization &	✗	POI	✓	○	○	○	○	◑	○	○	○	○	○	○	○	○
Ameren Transmission Company of Illinois (ATXI)	Interim Phase 1 (ahead of MISO)	Detailed Reference & Customization	✗	POI	✓	○	○	○	○	○	○	◕	○	○	●	○		
	Phase 1 (aligned with MISO)	Hybrid Reference Customization &	✗	POI	✓	○	○	○	●	○	○	◕	○	○	○	○		
Bonneville Power Administration (BPA)		Detailed Reference & Customization	✗	POI	✓	○	○	◑	●	●	●	●	◑	◑	●	◑		
Duke Energy		Hybrid Reference Customization &	✗	POI	✓	○	○	◑	◕	●	●	●	◕ (red)	●	●	●	◑ (red)	○
ERCOT	Phase 1	Hybrid Reference Customization &	✓	POI	✓	○	○	○	◔	●	○	●	○	●	◔ (red)	◔ (red)	◔ (red)	
	Phase 2	Hybrid Reference Customization &	✓	POI	✗	○	○	○	○	○	○	○	○	○	○	◑	○	○
HECO	Stage 3 Hawaii RFP	Hybrid Reference Customization &	✗	POI	✓	○	○	○	◔	●	◕	◑	●	●	●	●	○	
ISO-NE		Detailed Reference & Customization	✗	POM	✓	○	○	●	◕	◕	◕	◕	○	○	○	○	○	○
MISO	Phase 1	Detailed Reference & Customization	✗	POM	✓	○	○	○	◑	○	○	◕	○	○	◔ (red)	○	○	
	Phase 2	Detailed Reference & Customization	✗	POM	✓	○	○	○	◑	◕ (red)	◕	◕	○	○	◔ (red)	◕	○	
NYSRC		Detailed Reference & Customization	✗	POI	✓													
North American Electric Reliability Corporation (NERC)	Milestone 2	Full Specification & Customization	✓	POM	✓	○	○	◔	○	○	○	◕ PRC-029	○		○	◕ PRC-028	◔ PRC-030	○
Natural Resources Department of Canada	SREPs Program	General Reference	✗	POI	✓	○	○	○	○	○	◑	○	○	○	○	○	○	○
San Diego Gas & Electric Co.		Hybrid Reference Customization &	✗	POI	✓	○	○	○	○	◑ (red)	◑ (red)	◑	◔	◑ (red)	◑ (red)	◕	◔	○
SaskPower		Hybrid Reference Customization &	✗	POI	✓	○	○	○	○	◕ (red)	●	◕	○	○	○	○	○	○
Southern California Edison (SCE)	Phase 1	Detailed Reference & Customization	✗	POI	✓	●	●	●	●	◑	◑	● (red)	●	●	○	○		
Southern Company	Phase 1	Detailed Reference & Customization	✗	POI	✓	○	○	○	◑	●	●	●	◑ (red)	●		◕		○
	Phase 2	Detailed Reference & Customization	✗	POI	✓	○	○	◕	◑	●	●	●	◑ (red)	●	●	◕	◔ (red)	○
	Phase 3	Detailed Reference & Customization	✗	POI	✗	○	○	◕	○	○	○	○	○	○	●	○	◕ (red)	○
SPP	Phase1	Detailed Reference & Customization	✗	POM	✓	○	○	○	◑	○	○	◕	○	○	○	●	○	
SRP	Phase 1	Hybrid Reference Customization &	✗	POI	✓	○	○	●	●	●	●	◕	◕ (red)	●	●	●	●	○
Tennessee Valley Authority (TVA)	Phase 1	Hybrid Reference Customization &	✗	POM	✓	●	○	●	●	●	◕	●	◕ (red)	●	●	●	○	○

Legend: ○ – not adopted | ◔ , ◑ , ◕ , ● – various adoption degrees | ◔ (red) , ◑ (red) , ◕ (red) , ● (red) – various degrees of own specs

Figure 2: Recap of Ongoing Assessment of Industry Adoption of IEEE 2800-2022 [Source: EPRI]

The following lessons learned were emphasized:

- Adoption of IEEE 2800-2022 for new IBRs with specified transition period is relatively easy; adoption for legacy IBR is challenging.
- Reference to IEEE 2800-2022 or its specific clauses increases harmonization and clarity.
- Include a table listing exceptions for clauses or sub-clauses of IEEE 2800-2022.
- Some sub-clauses of IEEE 2800-2022 require specified decisions by the Transmission System (TS) owner/operator or Authority Governing Interconnection Requirements (AGIR).
- Drafting new language may trigger significant stakeholder discussions and debate, as well as inadvertent loss of specific details of IEEE 2800-2022 language (footnotes in IEEE 2800-2022 contain important clarifying details but are often overlooked while drafting new language).
- Some requirements or language in IEEE 2800-2022 likely needs to be revised such as addressing challenging requirements or removing implied barriers for GFM technology.

Lastly, Jens discussed the future plans for IEEE 2800-2022 and what EPRI considers to be the "preferred" approach (see Figure 3). This includes near-term revisions to the standard and IEEE 2800.1/.3 recommended practices for GFM equipment as well as longer term incremental changes to the standard to keep pace with technology.

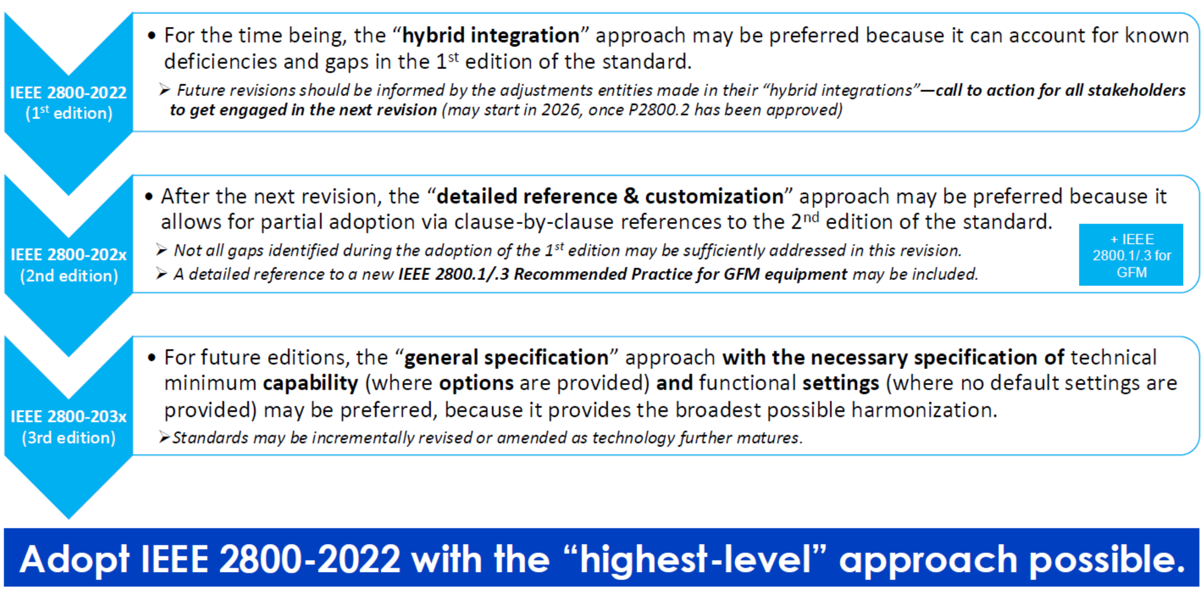


Figure 3: IEEE 2800-2022 Adoption and Revision Roadmap [Source: EPRI]

Andy Hoke, NREL

Andy provided an overview of IEEE P2800.2 content and an update on drafting progress. The requirements of IEEE 2800-2022 each have a Reference Point of Applicability (RPA) – they point where the requirements apply – and almost all requirements have the RPA at the Point of Measurement (POM) of the IBR plant (see Figure 4). Thus, IEEE 2800-2022 requirements are mostly applicable to the entire IBR plant, not to specific devices or components within the plant.

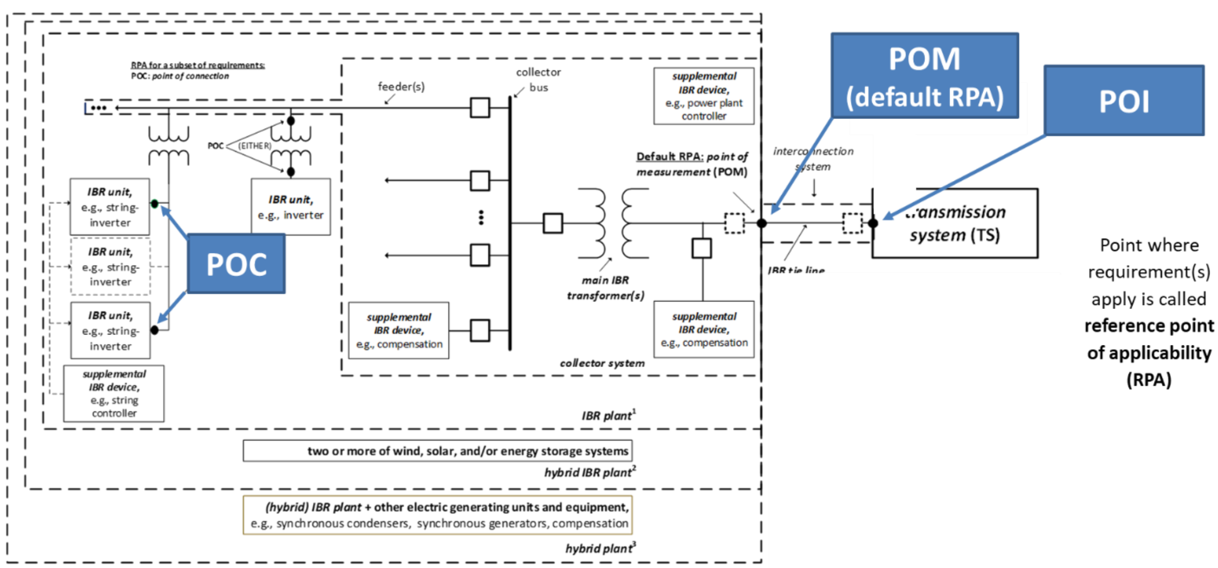


Figure 4: Visualization of IEEE 2800-2022 Reference Points of Applicability [Source: IEEE]

IEEE P2800.2 includes recommended practices regarding the test and verification methods and practices that ensure IBR plant conformity with the standard requirements. The drafting team is compiling and seeking consensus on industry recommended practices and producing them in a consolidated way in IEEE P2800.2. Note that IEEE P2800.2 includes recommended practices; therefore, it primarily uses "should" language rather than "shall" language.

The document will include a framework and procedures for IBR plant standards conformity assessment including the following (see Figure 5) steps that cross multiple stakeholders:

- IBR unit-level type tests (results used for unit-level model validation)
- Design evaluation using verified IBR plant model (including procedures to validate the IBR plant model)
- As-built evaluations
- Commissioning tests
- Post-commissioning model validation, monitoring, periodic tests, and verifications

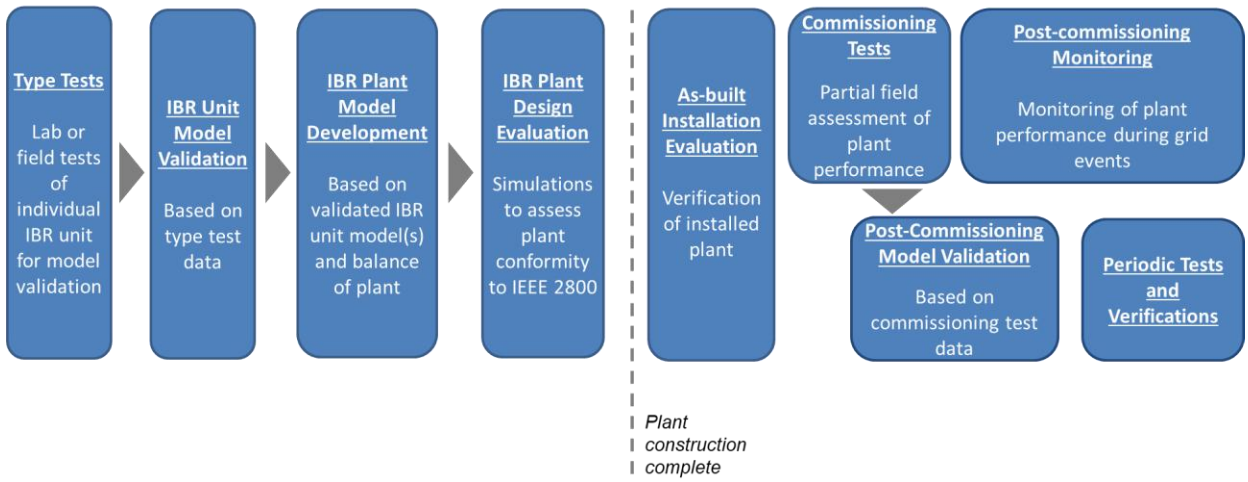


Figure 5: Overview of Conformity Assessment Steps in IEEE P2800.2 [Source: IEEE]

The recommended practices are not intended to define (or redefine) the interconnection process for new generators – this is specifically out of the scope of IEEE P2800.2. The procedures are intended to be used as a part of the interconnection process – particularly around designing, evaluating, verifying, and validating the performance of an IBR plant.

As almost all requirements in IEEE 2800-2022 apply to the IBR plant and not individual inverters/turbines, certification of inverters/turbines is not applicable because conformity is assessed at the plant level. Additionally, the type tests in IEEE P2800.2 do not generally include pass/fail criteria and instead provide data to be used in unit-level model validation. This concept differs from the IEEE 1547/1547.1 and UL 1741 paradigm used on the distribution system.

Andy emphasized that adoption of IEEE 2800 is not necessarily contingent upon publication of IEEE P2800.2. In the absence of IEEE P2800.2, IBR owners, TS owners/operators, original equipment manufacturers (OEMs), etc., can develop their own conformity assessment procedures or use existing procedures. For systems experiencing IBR ride-through events/problems, some requirements may be higher priority than others (e.g., ride-through, transient overvoltage (TOV), rate-of-change-of-frequency (ROCOF), and phase jump).

The IEEE P2800.2 working group continues to develop the recommended practices and test procedures following the proposed schedule shown in Figure 6. The group has been working on IEEE P2800.2 for over three years, and 94% of members agreed to send the draft recommended practice to ballot. The ballot pool has been established and SA initial ballot is open presently; public comments can be submitted through July 7, 2025, here. The group expects to gather useful feedback to move the draft towards completion with a tentative publication time of around Q1/Q2 2026 if everything remains on track.

Figure 6: IEEE P2800.2 Working Group Timeline [Source: IEEE]

After IEEE P2800.2 is approved, revisions to IEEE 2800-2022 will likely start in 2026. Various industry efforts are working towards a standard for GFM IBR equipment or plants (with an initial focus on battery energy storage systems (BESS)) connected to the bulk power system (BPS).

Alex Shattuck, ESIG

Alex provided a refresher on FERC Order 901 directives to NERC to enhance or develop new NERC Reliability Standards to address IBR-related reliability risk in data sharing, model validation, planning and operational studies, and performance requirements. Milestone 2, submitted to FERC in Q4 2024, focused on IBR disturbance monitoring (PRC-028-1), ride-through performance (PRC-029-1), and post-event performance validation (PRC-030-1). PRC-028-1 and PRC-030-1 are approved by FERC and industry is awaiting next steps regarding PRC-029-1.

NERC is presently working on its Milestone 3 efforts with four standards projects underway:

- Project 2020-06 – Verifications of Models and Data for Generators (MOD-026, MOD-027, FAC-002)
- Project 2021-01 – System Model Validation with IBRs (MOD-033)
- Project 2022-02 – Uniform Model Framework for IBR (MOD-032, TOP-003, IRO-010)
- Project 2022-04 - Electromagnetic Transient Modeling (MOD-032, FAC-001, FAC-002)[2]

Alex shared some keys for success for these projects such as learning from Milestone 2 experience; leveraging industry consensus through efforts like IEEE P2800-2022 and P2800.2; using existing best practices such as the NERC dynamic modeling recommendations, NERC

[2] Related but not technically a Milestone 3 project.

alerts, and disturbance reports; gathering input from OEMs; carefully handling retroactivity; and recognizing that FERC directive can have flexibility in interpretation with sufficient technical justification.

Interactive Group Discussion

The MOD-033 drafting team is making minimal revisions to the standard and stating this will meet the FERC Order 901 directives. Any thoughts on how FERC will respond or what actions FERC or NERC may take?

When a drafting team comes to this conclusion, the team needs to have technical justification and rationale for why they believe that this decision meets the FERC directive. The more technical basis possible, the more likely that FERC will accept their perspective. Part of the last drafting team ballot asked these questions to the industry. If NERC or FERC has issues with these perspectives, then FERC will likely respond to NERC's submittal of the standard revisions accordingly later in 2025.

What is the most efficient way to adopt IEEE 2800 as part of enforceable standards?

There are varying ways to adopt IEEE 2800-2022 ranging from general reference to full customization. Most entities are using a detailed reference or hybrid integration approach where the standard (or specific clauses) are adopted, and specific details are provided to help aid in effective implementation. This minimizes rework, enables adoption with minimal additional language in requirements documents while also providing the technical details that interconnection customers need throughout the process. Pros and cons of various adoption methods are covered in ESIG's Brief for Decision-makers: IBR Interconnection Requirements, Status and Needs posted here.

Are there any pertinent updates on IEEE P2800.2 drafting efforts?

The type testing section is nearly complete and in "good shape" according to the team. The plant-level design evaluation materials are likely where most the technical work is still needed. This is one of the last steps in the design process. The team has lots of content and work, but the content needs further refining. Portions of the commissioning and post-commissioning steps are relatively mature. Refer to above link to submit public comments by early July 2025.

Will it be possible for OEMs to state that they tested according to IEEE P2800.2 recommended practices and can prove it has capabilities?

OEMs will be expected to provide type test results and data for IBR unit model validation efforts to demonstrate the model matches reality. IBR developers should be requesting from OEMs documentation and information regarding these reports. This will also tie in with the revisions to NERC MOD-026-2 underway. OEMs may be able to provide information about the "compatibility" of their equipment with IEEE 2800-2022, including a list of equipment capabilities that can support IBR plant conformity with the standard—the draft P2800.2 currently does not include procedures to verify such OEM self-declarations.

Were there any situations where test and verification methods could not be created to demonstrate conformity with IEEE 2800-2022 requirements?

Some requirements have proven challenging to develop test and verification procedures such as transient overvoltage. These can be tested but they are probabilistic in nature and thus make testing very difficult and burdensome. Some of these findings may help inform future revisions to standard but could also—for the time being—be a requirement that is not assessed pre-commissioning yet could be monitored during operations if sufficiently accurate measurement devices were used.

Does it make sense to have hardware-in-the-loop (HIL) testing and certification to a certain "typical" plant setup?

IEEE P2800.2 does not provide options for using a typical or generic plant setup. This concept may be used for some of the inverter-level requirements, but the IBR plant-level requirements should be tested on a site-specific basis.[3]

What are lessons learned from ERCOT NOGRR 245 and IBR ride-through maximization?

ERCOT embarked on NOGRR 245, which adopted portions of IEEE 2800-2022 requirements. Resource Entities are required to "maximize" IBR ride-through capability within equipment limitations (up to hardware-based limits). IBR ride-through maximization has proven an effective way to improve IBR performance and grid reliability; however, the process and methods for doing so should be carefully implemented. Various ride-through issues have been uncovered through this process; however, working with the OEMs to make changes to equipment and to update the models is a long and arduous (and costly) process. See recent presentation on this topic here.

Key Themes

- **Season 1 Recap:** Over 1,225 unique stakeholders participated in Season 1, with consultants making up the largest group. Key takeaways emphasized harmonizing IBR requirements, improving model quality, and the importance of coordination across NERC, FERC, and IEEE efforts.
- **Modeling and Conformity Linkage:** Accurate IBR plant-level modeling and validation—including type testing, commissioning, and post-commissioning verification—are essential for assessing IEEE 2800-2022 conformity.

[3] IEEE 2004-2025 provides a Recommended Practice for Hardware-in-the-Loop (HIL) Simulation Based Testing of Electric Power Apparatus and Controls.

- **Industry Collaboration and Transparency Needs:** Stronger collaboration between OEMs, developers, and transmission providers is needed to improve modeling quality, clarify expectations, and support streamlined interconnection processes.
- **IEEE 2800-2022 Adoption Methods and Lessons Learned:** Four adoption methods (general reference to full specification) are used across ISOs/RTOs; hybrid and detailed reference approaches are most common. Adoption is easier for new IBRs, but legacy retrofits are more complex and costly.
- **Transmission Provider Implementation Examples:** SPP, ERCOT, and ISO-NE are applying IEEE 2800-2022 using phased and customized strategies. ERCOT's experience with NOGRR 245 highlights the benefits of IBR plant ride-through maximization up to hardware limits but also the challenges of retroactive application.
- **Need for Clarification and Flexibility in Standards:** Some IEEE 2800-2022 requirements may need revision or clarification—particularly those that create challenges for grid-forming inverters or that imply barriers to implementation. Flexibility and coordination are key for practical adoption.
- **IEEE P2800.2 Drafting and Scope:** IEEE P2800.2 provides recommended practices for conformity assessment of IBR plants, including type testing, model validation, commissioning, and post-commissioning steps. It uses "should" language and is not intended to redefine interconnection processes.
- **Plant-Level Conformity Emphasis:** IEEE 2800-2022 applies to the full IBR plant, not individual devices, meaning that model validation and testing must occur at the plant level. Inverter-level certification is not sufficient.
- **NERC Standards and FERC Order 901 Response:** PRC-028, -029, and -030 standards address IBR monitoring, ride-through, and post-event validation. NERC Milestone 3 includes ongoing standards updates that build on IEEE 2800-2022 and require industry consensus, best practice integration, and careful retroactivity planning.
- **Future of IEEE 2800 and GFM Capabilities:** Revisions to IEEE 2800 are expected post-2026, along with additional IEEE recommended practices focused on GFM IBRs, with the first edition focused on battery energy storage systems (BESS) connected to the bulk power system.

June 24, 2025 Virtual Meeting

NERC Milestone 3 Update (~230 attendees)

Presentation recording and slides are available to download here. Figure 7 shows the makeup of attendees by industry sector:

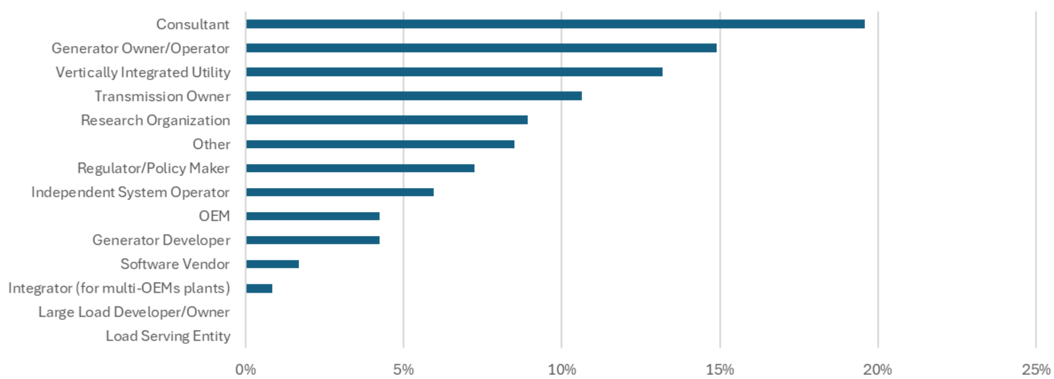


Figure 7: Meeting attendees by industry sector

This second meeting of Season 2 of the DOE i2X FIRST initiative focused on the North American Electric Reliability Corporation (NERC) Milestone 3 standards projects, the current state of IBR modeling in North America, and legacy IBR plant modeling practices. Presentations included the following:

Sandhya Madan, NERC

Sandhya provided an overview of NERC standards revisions underway related to FERC Order 901. NERC has implemented a four-part milestone plan spanning several years (see Figure 8).

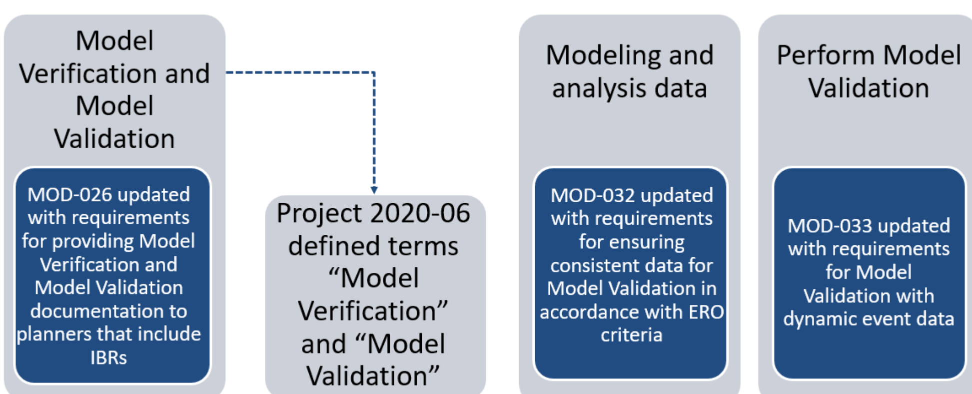
Figure 8: NERC Work Plan Milestones for FERC Order 901 [Source: NERC]

Milestone 1 involved NERC submitting its Order 901 work plan to FERC. Milestone 2 included standards development efforts to address IBR disturbance monitoring (PRC-028), disturbance ride-through and performance requirements (PRC-029), and post-event performance validation (PRC-030). Those standards were submitted by NERC to FERC before the November 2024 deadline. In February 2025, FERC approved the new IBR definition (see below) and proposed Reliability Standards PRC-028-1, PRC-002-5 (for synchronous generators), and PRC-030-1.[4] The implementation plans for each standard were also approved.

> ***NERC Definition of Inverter-Based Resource:*** *A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as an inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. Examples include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.*

Current standards drafting efforts are now focused on Milestone 3 standards revisions, which relate to data sharing and model validation for all applicable IBRs. Figure 9 illustrates the various standards revision efforts underway presently targeting model verification and validation, a uniform modeling framework, and system model validation. The related standards projects include:

- **Project 2020-06 Verifications of Models and Data for Generators:** This project is revising MOD-026 (and consolidating MOD-026 and MOD-027) and has also developed "Model Verification" and "Model Validation" terms for the NERC Glossary of Terms.
- **Project 2021-01 System Model Validation with IBRs:** This project is revising MOD-033 with minor editorial and technical revisions.
- **Project 2022-02 Uniform Modeling Framework for IBR:** This project is revising MOD-032, IRO-010, and TOP-003, as well as developed a definition for "Distributed Energy Resource" for the NERC Glossary of Terms.



[4] At the time of writing, FERC has not made any statement regarding PRC-029-1 approval.

Figure 9: NERC Milestone 3 Summary [Source: NERC]

All three standards projects have now completed their initial ballots. Table 1 provides an overview of the results of those initial ballots. The drafting teams are currently responding to industry comments and feedback provided, making revisions to the standards and implementation plans, and will be re-posting the standards for a next round of balloting in July/August timeframe. The standards must be submitted to FERC by the November 2025 deadline.

Table 1: Initial Ballots for Milestone 3 Standards

Project	Standard	Standard Ballot Results	Implementation Plan Ballot Results
Project 2020-06	MOD-026-2	32.47% (Fail)	40.22% (Fail)
Project 2021-01	MOD-033-2	57.06% (Fail)	59.43% (Fail)
Project 2022-02	MOD-032-2	39.05% (Fail)	39.46% (Fail)
	IRO-010-6	41.62% (Fail)	
	TOP-003-8	34.70% (Fail)	

NERC is also ramping up initial efforts related to Milestone 4 activities. The Milestone 4 SARs will be published around August timeframe for industry comment. NERC is seeking nominations for Milestone 4 drafting team members – specifically looking for individuals from utilities, Regional Entities, and vendors with expertise in planning and operational studies with IBRs. These projects will focus on the NERC TOP, IRO, FAC, PRC, and TPL standards as well as revise the definitions for Real-Time Assessment, Operational Planning Analysis, and Balancing Contingency Event to include IBR performance and sudden IBR output reduction.

Miguel Cova Acosta, Vestas

Miguel presented on the current state of IBR modeling in North America, particularly from Vestas' perspective. Accurate IBR modeling is essential for grid reliability, project stability, and long-term success throughout the lifecycle of the asset. Standard library models are widespread due to their simplicity, ease of use, and ease of review; they are mandated across many regions and used widely in both interconnection studies and planning cases. This can pose a challenge because these models may give the illusion of compliance. The models may appear to provide a smooth and compliant response; however, they may not reflect the dynamic characteristics of the asset under varying system operating conditions, curtailments, etc. This can result in misleading study results that introduce reliability risks. Miguel emphasized the need for IBR developers to raise internal standards in terms of model quality and fidelity, particularly with the use of user-defined models (UDMs).

During the interconnection process, IBR plant design evolves as equipment is selected, plant and protection systems are designed, and site controls are tuned. After the interconnection process, an IBR plant may have further changes due to firmware updates, plant upgrades, and further parameter tuning. Thus, the models must also evolve and refine as the site specifications change. However, current requirements and practices tend to discourage model updates because they may result in interconnection delays and restudies. Up through energization, industry needs a framework that encourages model updates to reflect latest changes rather than punishing entities for making improvements to the models. Additionally, once the resource enters commercial operation, it is imperative that the models reflect the actual installed equipment to support accurate reliability studies.

Use of standard library models, instead of OEM-validated UDMs, may create a false sense of grid code compliance for the IBR developer. Where available, OEM-supplied UDMs with verified site-specific model parameters should be used during interconnection studies and IBR plant performance conformity tests since they are the most accurate representation of the actual controls, protections, and overall representation of the asset. Use of models that do not have all the key controls features of the physical asset may lead to a disconnect between the model and actual performance, introducing reliability risks. Leaning towards model simplicity rather than model accuracy is a prevalent issue across various systems in North America, relying on standard library model representations and not considering UDMs.

Miguel also described the efficacy of different types of supplemental modeling documentation to aid in ensuring model quality. Figure 10 illustrates effective and less effective options. Parameter verification reports, model quality test results and reports, and site-specific verification and validation reports are all effective options; however, OEM attestations, model compliance checklists, and generic requests for information (RFIs) can result in complications or generic information provided if not issued or delivered with clear instructions and understanding of their use.

Figure 10: Effective and Less Effective Supplemental Documentation to Ensure IBR Model Quality [Source: Vestas]

Miguel recommended that the model development process should always follow a source code integration concept, which should mirror parameterization and performance of the IBR plant as built in the field. Industry standards should focus on interfacing source code-integrated models rather than standardizing control structures for IBR plant models generically.

Andrew Isaacs, Electranix

Andrew presented on legacy (i.e., existing) IBR plant modeling practices and challenges, primarily focused on EMT modeling. When an IBR plant model is needed for a legacy asset for the purposes of conducting a study, there is often no satisfactory solution. Hence, this is why it is very important to ask for high-quality models prior to interconnection whether or not those models will be used immediately in a study. Sufficiently detailed and specific modeling requirements are important, if not necessary to ensure that the right questions are asked, appropriate tests/model reviews are conducted, and that accurate models are supplied. These concepts apply to both IBR plants and power electronic loads such as data centers, and should be a major priority for all regions across North America.

If an EMT model is needed for an existing asset, there are a few guiding questions that can be asked:

- Is the model needed for posterity/requirements, or is there a study being conducted?
- If a study is being conducted, how impactful is the plant to the study area?
- Is it the main device being studied?
- Is it electrically very close or impactful under key contingencies?

- What phenomena are the key areas of focus (e.g., subsynchronous control interactions (SSCI), fault ride-through (FRT), voltage impacts, other transients, etc.)?
- Is the plant large or small relative to the other plants and study area?

These questions help determine the level of effort needed to ensure accuracy of the missing model. If an EMT model is not available and cannot be acquired through requirements, regulations, or other mandatory and enforceable ways, there are a few options that can be considered (from best to worst):

- Best approaches:
- Collect a model from the interconnection customer/GO that meets the requirements established.
- Find engineers involved from the original OEM and ask (or pay) them to create a model using their best information.
- Proxy model approach:
- Learn as much as possible about the equipment, and configure a proxy model using a similar vintage and type of model from the *same* OEM.
- If possible, test the hardware in a lab and configure an appropriately parameterized generic model to match the performance.
- Learn as much as possible about the equipment, and configure a proxy model using a similar vintage and type of model from a *different* OEM.
- Generic model approach (not recommended):
- Learn as much as possible about the equipment and configure a generic model to match key settings to the extent possible.
- Use a completely generic model.

Deviations from accurate implementation of phase lock loop (PLL), protection circuits, and inner controls will cause misrepresentations of SSCI damping, ride-through performance, and voltage control response. Deviations from accurate implementation of delays, power plant controllers (PPCs), outer loop controls, etc., can cause important errors depending on the study being performed. If a device is important to the study, proxy modeling is not recommended and it may be best not to conduct a study at all.

Anything other than a fully-tested, verified, and validated EMT model will degrade the benefit obtained from the EMT study in terms of accuracy and the ability to make business decisions using the results obtained (i.e., accuracy requirements exist for a reason). If the model quality is degraded too far, and the plant is critical in the study being performed, it may not be possible to drive useful results from the EMT study.

Additionally, all models will require maintenance and updating throughout the lifecycle of a plant. Effective data organization procedures, documentation, and change management practices help ensure the model remains accurate as compared with the actual equipment. Furthermore, as requirements change, older models may become noncompliant and require updates; thus, it is important to have robust requirements to start with and also for IBR developers to have strong contract language for ongoing support from OEMs.

Dynamic link library (DLL) wrapper real code model writing processes are helpful to maintain compatibility across tool and compiler revisions. Models should be written to support these techniques.[5]

Q&A and Interactive Group Discussion

What are the initial ballot results for MOD-026-2 and what is the current status for Project 2020-06?

The initial ballot for MOD-026-2 recently closed as of late June 2025. The standard and implementation plan received a 32.5% and 40.2% weighted ballot score, respectively. The drafting team is currently reviewing comments received and working on addressing those comments in a revised version that is planned for another ballot in late July or August.

With the next ballots for the Milestone 3 projects scheduled for late July (and subsequent review in August/September), how is NERC expecting to meet the November 4 FERC deadline particularly given that the NERC Board meeting is scheduled for October? Will NERC expect to leverage its Rules of Procedure Section 321 process again for these standards?

NERC and the drafting teams are working towards revised standards that meet the concerns raised by industry commenters as part of the ballot process. NERC is conducting informational webinars to share updates along the way. However, the deadlines are fast-approaching, and NERC may need to take alternate paths (e.g., NERC Section 321 process) to expedite meeting the November deadlines set by FERC if the standards do not pass the next ballot.

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[5] Cigre B4.82 "Guidelines for Use of Real-Code in EMT Models for HVDC, FACTS and Inverter based generators in Power Systems Analysis" Available here.

What are the pertinent updates regarding approval and effective dates for NERC Milestone 2 projects including PRC-028-1, PRC-029-1, and PRC-030-1?

FERC approved both NERC PRC-028-1 and NERC PRC-030-1. FERC also issued a Notice of Proposed Rulemaking (NOPR) to gather additional information and industry feedback on NERC PRC-029-1 and has not yet ruled on this standard as of June 2025. With the NOPR, FERC sought comments on all aspects of the proposed PRC-029-1, but was particularly interested in comments and supporting materials on concerns regarding: "(1) the IBR performance requirement set forth in Requirement R1; (2) the absolute RoCoF in Requirement R3; and (3) the adequacy of NERC's proposed exemption provision in Requirement R4 as it pertains to both projects in service and those under contract, but not yet in-service as of the effective date of Reliability Standard PRC-029-1."[6]

Regarding effective dates, NERC PRC-028 became effective on April 1, 2025. FERC did not establish an effective date for PRC-030-1 since it relies on NERC PRC-029-1. Thus, industry expects that once FERC rules on PRC-029-1, it will also include an effective date for PRC-030-1 in that ruling.

The proposed NERC MOD-026-2 leaves establishing a model verification and validation procedure up to each Transmission Planner (TP) and Planning Coordinator (PC). This may lead to widely disparate requirements and lack of harmonization across North America, creating additional obstacles and barriers for IBR asset owners. What is NERC doing to address this concern, which has been raised in industry stakeholders numerous times?

Sandhya stated that NERC Reliability Standards explicitly do not define how a standard must be implemented and only focus on what must be implemented. Thus, to handle the need for regional or transmission entity-specific differences, the NERC Project 2020-06 drafting team has left these considerations up to the TP and PC to determine. It was acknowledged that this could lead to disparity across TPs and PCs, which could create complications for GOs.

How can entities effectively commission an IBR plant when the OEM does not have a mapping between PSCAD and their actual equipment settings, parameters, and controls?

IBR commissioning has been identified by the NERC Inverter-Based Resource Performance Subcommittee and other organizations as an area for improvement for IBR integration. IBR plants may be commissioning in a way that does not match the modeling and studies conducted during the interconnection process. This is further exacerbated when the IBR plant model parameters are obfuscated by the OEM and thus the Generator Owner is unable to discern whether what is being commissioned matches expectations. Improvements in IBR model

[6] https://www.ferc.gov/media/e-10-rm25-3-000

transparency, regardless of model type, are needed to map actual equipment to models and their respective parameters.

ISOs may emphasize overlaying simulation plots and lack attention to how controls, protections, etc., are implemented in the IBR plant. Any recommendations for this can change?

Much of the interaction between the interconnection customer and the TP/PC is related to ensuring that the models are verified to match the actual equipment, meet certain model quality test requirements, and are suitable for transmission system impact studies. Transmission entities should adopt modeling requirements that ensure model verification – the model matches the proposed and actual equipment – as well as model quality and performance tests that ensure the IBR plant meets a certain performance, and the models are adequate for use in studies.

The concepts of 1) "the IBR plant passes the model quality tests" and 2) "the IBR plant operates reliably under all credible contingencies" are almost entirely orthogonal to each other; yet, almost all simulation time and effort between the IBR developer/owner and TP/PC is devoted to the former. How can this be overcome?

These different types of tests are intended to analyze the IBR plant models in different ways. Model quality tests are intended to check that the model is suitable for studies and is a reasonable reflection of the actual equipment planned or installed at the facility. These test may consider varying system conditions such as voltage and frequency fault ride-through or system strength. Once the models pass the necessary single machine infinite bus (SMIB) type modeling tests, then they are integrated into the system model for system-level performance evaluations. Significant time between the IBR developer/owner and the TP/PC needs to be devoted to ensuring models are accurate and of high quality to help aid in preparations for effective systems studies, which are the responsibility of the TP/PC.

For the current state of IBR modeling, why was the option for OEMs to more actively participate in the standard library model building process not included?

OEMs should still engage in standard library model building processes, particularly since the use of these models is mandated by FERC for use in interconnection-wide base cases. Industry cannot simply forego these efforts as they are mandated by federal law presently. Thus, as observed by the NERC modeling recommendations and other guidelines, both types of models are needed and OEMs need to actively be engaged in creating high-quality UDMs as well as sufficiently reflective standard library models for their equipment.

If models across simulation domains are to only be real code models, does industry thus have to trust the OEMs if a model cannot accurately represent a feature in the actual equipment? This may introduce significant reliance on OEMs on intellectual property concerns regarding information sharing.

Focus needs to turn toward effective collaboration between the interconnection customer/GO and the OEM to ensure that the currently-used models are reflective of the actual product (make, model, version, etc.), rather than artificially tuning standard library models which are not reflective of the actual equipment. OEMs will need to be transparent about what is and is not modeled, and should provide IBR unit (single inverter or wind turbine) model validation reports to demonstrate that the model adequately reflects actual product across a range of operating conditions. Note that "real code" models remain black boxed models (i.e., the real code is not accessible to the end user of the model).[7,8]

What is the difference between UDMs and standard library models regarding IBR plant commissioning? Intuition is that UDMs would also be subject to "manual tuning, patchwork fixes, and late-stage overrides" to reflect as-built conditions but the slides implied otherwise.

Regardless of model type, it is important to ensure that the commissioned IBR matches the models used during study, and that any discrepancies are identified, updated in the models, and shared with the transmission provider for evaluation. Commissioning tests may subject the site to small disturbance events that can then be used to conduct post-commissioning model validation. It should be noted that these tests likely will not subject the site to large disturbance events that initiate ride-through modes of operation. Hence, post-conditioning event monitoring and model validation is important to also ensure accuracy of the models upon commissioning.

It was mentioned that EMT modeling concerns raised regarding IBRs may also apply to data center load modeling efforts – can you elaborate on those issues and give some examples?

Many of the issues pertaining to IBR modeling today – model transparency, model verification versus actual equipment, model quality testing, and post-event model validates – all translate to large power electronic load (e.g., data center) modeling. Ensuring that the models used to represent data centers are adequate representations of the actual facility, particularly for rather large load sites, is imperative to ensure reliability of the bulk power system.

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[7] https://www.e-cigre.org/publications/detail/gb-16-power-system-dynamic-modelling-and-analysis-in-evolving-networks.html

[8] https://www.e-cigre.org/publications/detail/881-electromagnetic-transient-simulation-models-for-large-scale-system-impact-studies-in-power-systems-having-a-high-penetration-of-inverter-connected-generation.html

Why do so many organizations push for creating and running generic models in studies? Seems like a lot of research effort is going into creating generic models for use in real world studies and this may not be the recommended approach. Thoughts?

Generic model may have a place for exploratory studies or research and development activities; however, these models are not adequate for making utility decisions such as determining reliability impacts of a specific IBR plant seeking interconnection, establishing operating limits, or determining the need for transmission network upgrades. This is particularly relevant for those conditions that invoke instability risks. Further, the generic models may inappropriately show stable operating conditions whereas the more detailed UDMs in phasor domain or EMT studies may uncover reliability risks. Thus, general industry consensus, as recommended by NERC and required in FERC Order 2023, is to gather both UDMs for local reliability studies and appropriately parameterized standard library models for interconnection-wide base case development.

Key Themes

- **NERC Milestone 3 Standards Development and Balloting Challenges:** The current NERC Milestone 3 efforts are addressing data sharing, model verification, and system model validation including IBRs. Initial ballots for the three Milestone 3 projects did not reach passing scores; current drafting team efforts are focused on addressing industry concerns. NERC is aiming for re-ballots by late summer to meet a tight FERC submission deadline in November 2025. If needed, NERC may need to use its Section 321 procedures to meet the FERC timelines. The challenges underscore ongoing industry tension between compliance needs and implementation feasibility.
- **Upcoming Milestone 4 Work and Expanding IBR Reliability Focus:** NERC is preparing to launch Milestone 4 projects, which will examine broader reliability standards including TOP, IRO, PRC, and TPL, and revise key definitions. Draft SARs will be released in August 2025, and NERC is actively seeking drafting team members with experience in planning and operational studies involving IBRs. The goal is to integrate IBR-specific considerations into operational and planning assessments.
- **Legacy Modeling Practices and the Importance of Accurate EMT Models:** Modeling legacy IBR plants presents unique challenges, especially when EMT models are needed post-interconnection and were never initially required. Without high-fidelity models, studies may yield unreliable or misleading decisions. Proxy models and generic models offer limited accuracy and should only be used when absolutely necessary. Upfront modeling requirements and OEM-supplied, validated models are essential, particularly for high-impact assets. Ongoing model maintenance, including change management and source code compatibility, is equally critical over a plant’s lifecycle.

- **UDMs vs. Standard Library Models:** Standard library models, though easy to use and review, often present a simplified and misleading picture of IBR performance. Reliance on these models may give a false sense of compliance with applicable interconnection requirements, as they often omit the nuanced dynamics of actual equipment. UDMs provided and validated by OEMs offer a more faithful representation and should be preferred, especially during interconnection studies and plant commissioning. Industry's current tendency toward simplicity over accuracy introduces reliability risks that grow as grid complexity increases. More OEM collaboration, transparency, and use of supplemental documentation can help ensure IBR model quality.
- **Commissioning Gaps and Model Fidelity Concerns:** The commissioning process for IBR plants often lacks alignment with the models used during interconnection studies. Discrepancies between installed equipment and model parameters—especially when OEMs obscure model details—can result in mismatches that degrade reliability. While commissioning tests help validate models through small-signal disturbances, they may miss crucial behaviors activated during grid faults or instability events. This highlights the need for robust model validation post-commissioning, and for utilities to require transparency and ongoing model support from OEMs. Accurate commissioning models are essential to uphold both compliance and operational integrity.
- **Model Quality and Use in Planning vs. Operational Studies:** The industry tends to over-emphasize verifying model quality while under-investing in ensuring reliable system-level performance of IBRs under real-world contingencies. While SMIB-type tests verify models against equipment, they do not guarantee that a plant will behave reliably under stressed grid conditions. Transmission planners must adopt dual objectives: ensuring models are technically valid and conforming with applicable interconnection requirements, while also verifying actual plant performance through contingency simulations as part of system impact studies.
- **Modeling Challenges Shared by IBRs and Data Centers:** The challenges with IBR modeling—model transparency, verification, lifecycle accuracy, and event-driven validation—are now also surfacing in modeling large data center loads. As with IBRs, inaccurate or generic data center models can misrepresent impacts on the grid. Industry must recognize that reliability risks are not limited to generation but also apply to increasingly complex, inverter-dominated loads. Robust model requirements and validation protocols for both generation and load are essential for ensuring bulk power system reliability.
- **Limitations of Generic Models in Decision-Making:** Generic models may be useful for early-stage research or exploratory studies, but they are generally not sufficient for decision-making such as setting operating limits or approving transmission upgrades. These models often miss critical OEM-specific control behaviors, potentially masking

underlying reliability risks. As such, NERC, FERC, and OEMs all stress the need for UDMs in phasor domain and EMT for reliability-critical studies. Interconnection-wide base cases may still require standard library models, but local reliability studies should rely on detailed, OEM-supplied, site-specific models to ensure accuracy. The industry must evolve from a generic-first mindset toward a precision-first approach to grid modeling.

July 22, 2025 Virtual Meeting

IBR Plant Design Evaluation with Applicable Requirements I (~200 attendees)

Presentation recording and slides are available to download here. Figure 11 shows the makeup of meeting attendees by industry sector:

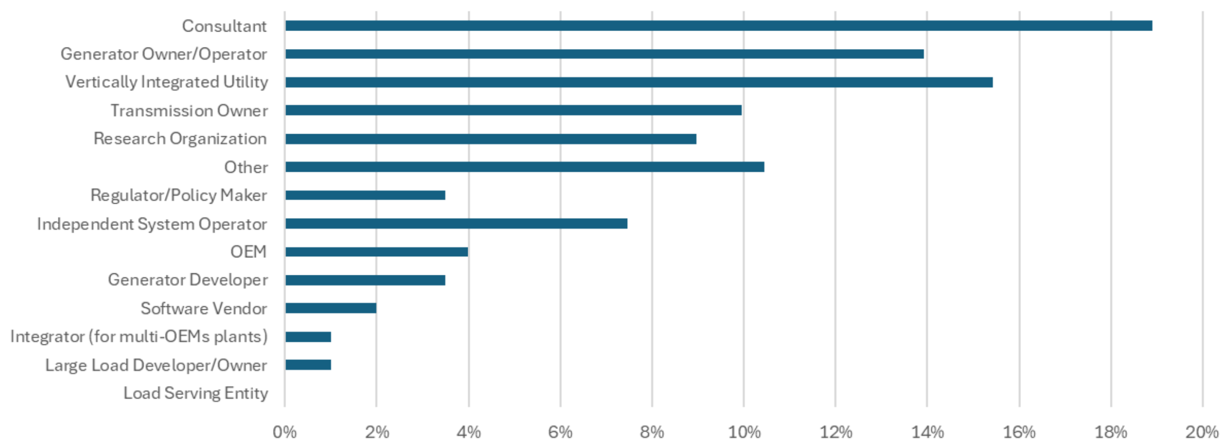

Figure 11: Meeting attendees by industry sector

This third meeting of Season 2 of the DOE i2X FIRST initiative focused on IBR plant design evaluation with applicable IEEE 2800-2022 requirements, providing an overview of IEEE P2800.2 IBR plant design evaluation clauses and sharing perspectives from both an IBR plant developer and owner/operator as well as engineering, procurement, and construction (EPC) provider. Presentations included the following:

Jens Boemer, EPRI

Jens provided an overview of IBR plant design evaluation and related topics. These IBR plant design evaluations are a continuum of IBR scrutiny in terms of conformance against established requirements (see Figure 12). In the past, little to no performance specifications were established and this may have resulted in abnormal performance (e.g., tripping). More recently, transmission providers have established performance specifications (including adoption of IEEE 2800-2022 requirements and other regional requirements). In some instances, such as on the distribution system with IEEE 1547-2018, unit-level certifications are used; however, this approach is not being used by IEEE 2800-2022. Rather, IBR plant-level conformity is assessed using power system models, model quality and verification tests, and performance conformity simulations.

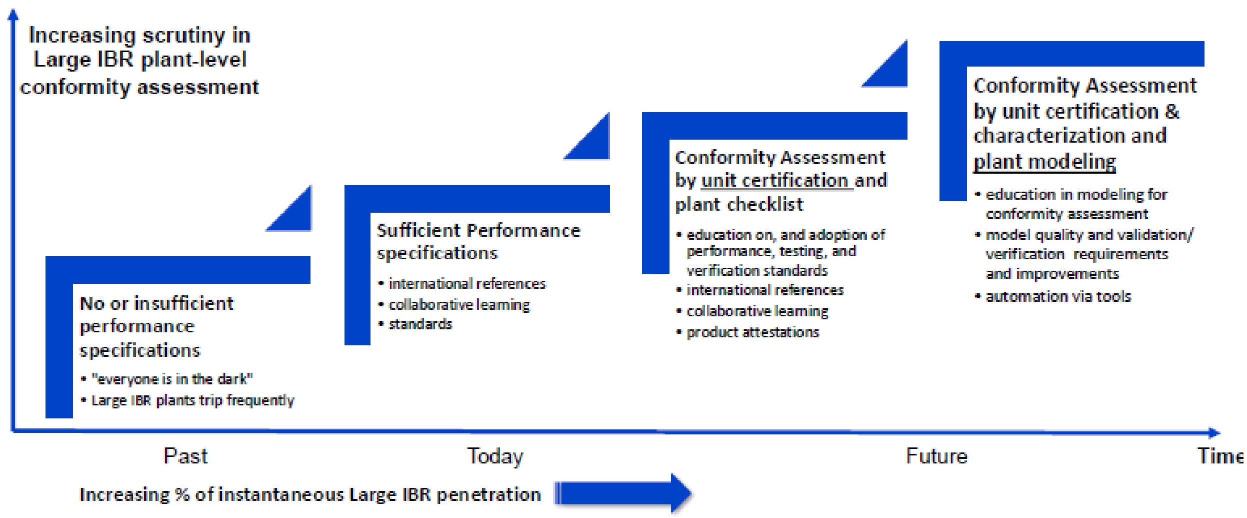

Figure 12: Large IBR Plant Interconnection Reliability Roadmap [Source: EPRI]

It is important to acknowledge and recognize the meaning of different terms used in this space, including:

- **Compatibility:** Design equipment to support conformity or compliance of a complex system (e.g., IBR plant) – equipment level.
- **Conformity:** Adherence to certain voluntary industry standards or procedures (e.g., IEEE P2800.2) – plant level.
- **Compliance:** Meeting mandatory and enforceable legal and regulatory obligations (e.g., NERC standards or interconnection requirements) – plant level.

Nonconformity with IEEE 2800-2022 requirements can be assessed, and there are historical examples such as the large NERC disturbance reports that illustrate failures to meet specific requirements.

Additionally, conformity with requirements can be assessed and tested as part of the interconnection process. For example, MISO is currently proposing to implement IBR modeling requirements that also include performance tests that can be used to test the IBR plant conformity against established requirements, to some extent. While the tests may not mirror IEEE 2800-2022, MISO is starting with a set of test procedures that can be effectively implemented by interconnection customers.

The IBR plant design evaluation uses the complete IBR plant model once it is fully developed. This model includes the validated IBR unit model(s), the verified IBR plant model components, and verified balance of plant protection elements as well. With this model, simulations are conducted to assess plant conformity with IEEE 2800-2022 requirements (see Figure 13). In these tests, it is important to remember that the requirements regarding current injection during abnormal voltage conditions apply at the POC whereas the other requirements apply at the POM.

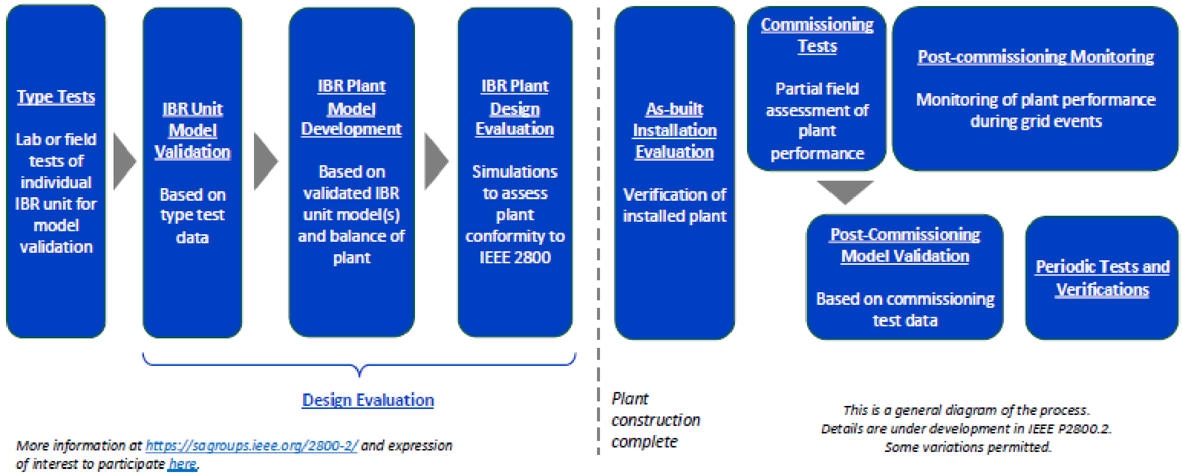

Figure 13: IEEE P2800.2 IBR Plant Conformity Assessment Framework [Source: IEEE]

An IBR plant design evaluation and performance conformity assessment is notably different from a system impact or reliability study. The IBR plant design evaluation ensures that the IBR plant meets the minimum requirements established whereas the system impact study ensures that the IBR plant reliably operates when connected to the grid. The IBR plant design evaluation includes both documentation checks (verification) and modeling and simulations. The documentation checks focus on reviewing capabilities, settings, and equipment model validation reports; modeling and simulations focus on model quality checks, plant model development and verification, and simulations of capability and performance.

The simulation tests can be set up with a controllable AC source connected to the POM through an impedance (see Figure 14). The controllable source induces POM grid conditions which are used to invoke a response from the IBR plant model, which can be assessed. The adjustable impedance is used to simulate different grid strength conditions.

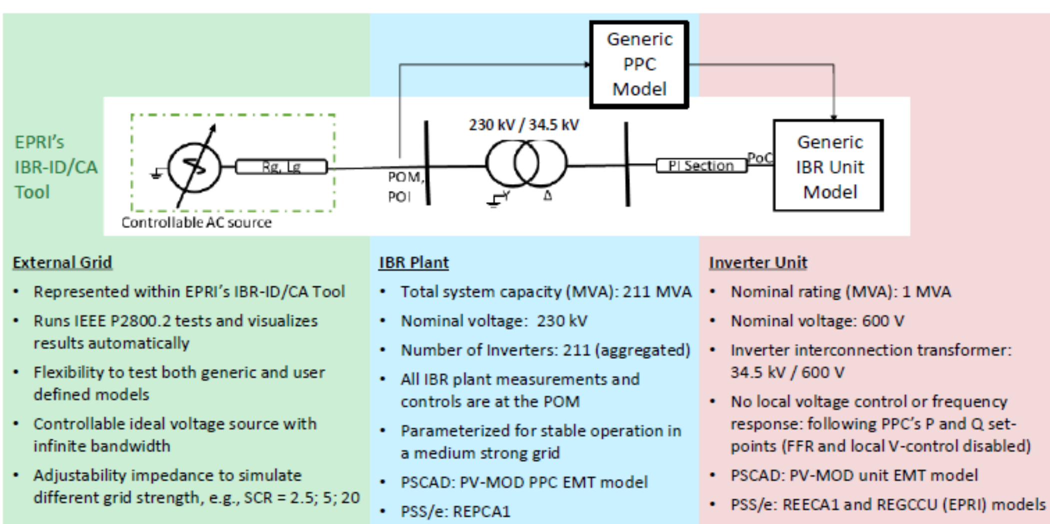

Figure 14: Example of IBR Plant Design Evaluation Simulation Setup [Source: EPRI]

Rishi Maharaj, Engie

Rishi shared practical experience from an IBR plant developer and generator owner/operator pertaining to IBR plant conformity assessment gaps and opportunities. Development and operation of a new IBR plant is often perceived as involving two primary categories of entities: the developer or generator owner/operator (before and after commercial operation date (COD), respectively) and the transmission entities such as Transmission owner/operators, transmission planners, RTO, etc. While the IBR plant developer/owner has obligation to comply with applicable interconnection requirements, in some organizations nearly all work upon which the performance and conformity of the plant depends will be performed by the following third parties (see Figure 15):

- OEMs
- Engineering consultants
- EPC contractors who may subcontract either of the above

Therefore, achieving conformity with technical requirements (NERC, ISO, Transmission Planner, etc.) requires coordination and communication between many parties through the project phases from interconnection application to commercial operation. The primary tool for a developer to obtain any technical deliverable is to write it into the contractual scope of work of a consultant, EPC, or OEM. Gaps in these scopes of work, and limited coordination between parties, are often where problems and eventual non-conformity originate.

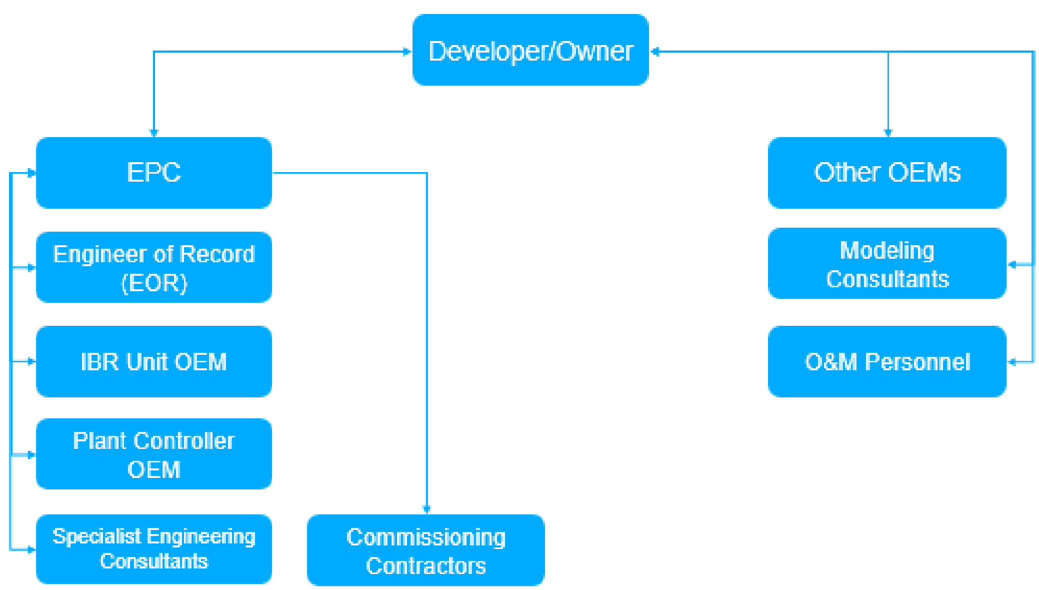

Figure 15: Simplified IBR Plant Project Hierarchy of Organizations [Source: Engie]

With this structure, an IBR plant developer/owner is therefore responsible for a tremendous number of activities that lead to eventual conformity, such as:

- Map out required scopes of work from each project participant to achieve the new requirement; and
- Negotiate with each party to include that scope in their respective contracts; and
- Monitor each party's delivery of their component from their respective subcontractors at the correct time; and
- Perform an overall plant conformity assessment to the new requirement considering the entire project holistically (perhaps by assigning it to yet another consultant); and
- If possible, verify performance with commissioning tests.

This is a lot for a non-expert IBR plant developer who may have very limited or no internal power systems expertise. Achieving and assessing conformity with a requirement that is relatively simple from a technical point of view can still be quite complex from a project execution perspective, requiring a consistent effort from the IBR plant developer/owner to coordinate all parties.

Rishi also explained that there is a basic conflict between the desire of IBR plant developers/owners to contract out technical work and the fact that only the owner has visibility of the entire project and the ability to deliver the required technical coordination.

The definition of conformity assessment is "demonstration that specified requirements are fulfilled."[9] However, to an IBR plant developer, it is unclear which requirements. Interconnection requirements applicable to a particular transmission-connected IBR plant in North America can originate from multiple sources:

- NERC Standards – uniform, but largely do not address IBR performance (especially prior to Order 901 standards)
- ISO Rules that apply uniformly to all facilities meeting certain thresholds (e.g., ERCOT Nodal Protocols and Operating Guides)
- ISO, RTO, or TO requirements that are specific to a particular GIA

A non-trivial amount of work is required simply to identify all applicable requirements. Writing "comply with all interconnection requirements" into a contract is largely useless. Without both parties being aware of the specific requirements in sufficient detail to enumerate them, it is very difficult to deliver and validate conformity. Since most requirements apply at the IBR plant level and require coordination between multiple parties, trying to write IBR plant-level conformity obligations into any one party's contract is not practically workable. Thus, in many projects, a comprehensive understanding of "all applicable interconnection requirements" does not exist.

[9] IEEE P2800.2 referencing ISO/IEC 17000:2020.

Comprehensive, proactive "grid code compliance" studies addressing all applicable requirements are not typically done by IBR plant developers. The extent to which engineering studies (i.e., IBR plant design evaluations) are done to assess conformity with applicable interconnection requirements is almost entirely driven by processes formally mandated by the transmission provider or other authority governing interconnection requirements (AGIR). Reactive power studies, stability studies, subsynchronous oscillation (SSO), etc., are all examples of IBR plant studies that are on a mandatory path to COD. However, mandatory studies only address a relatively small subset of interconnection requirements.

Further, various mandatory studies may be done by different project participants without coordination with each other, resulting in conflicting, inaccurate, or wrong models being used by different entities to study the same plant. The items specifically verified or checked by the AGIR to grant commercial operation are the core focuses of the IBR developer; everything else is, for practical purposes, optional. The net result is passive or inadvertent non-conformity with a significant fraction of the presently enforceable requirements.

Power plant controllers (PPCs) are also an under-appreciated risk in IBR plant design evaluations. The current trend of procuring PPCs from EPCs, which cannot be accurately simulated until very late in the project (if at all), limits the ability to perform IBR plant design evaluations for certain requirements earlier in the interconnection process. Design evaluation is only one aspect of conformity assessment. Even when design evaluation is done, gaps exist in feeding required changes back into the IBR plant design and implementing them in the field. Most AGIRs in North America have no enforced requirement for verification of IBR plant parameters and settings. Consultants may tune model parameters without OEM involvement, resulting in a plant model that "passes" assessments but cannot be implemented in the field. OEMs may be willing to update EMT models to provide favorable results in ways that do not accurately reflect their actual product as deployed in the field. The lack of a standardized format for exchanging IBR unit and plant controller parameters causes inadvertent errors. Again, Rishi emphasized that what is mandatory is what gets done.

Fortunately, many of the pain points and pitfalls mentioned above are directly addressed in IEEE P2800.2, which comprehensively maps how conformity assessments should take place. It does not (and cannot) define exactly how IBR plant owners/developers, TS owners, operators and planners execute that process in actual projects. The 2024 NERC Alert on IBR Model Quality Deficiencies results show that many IBR plant owners do not have basic facility information available to them. Layering new, more comprehensive and more complex requirements with current and future adoption of IEEE 2800-2022 by AGIRs requires process improvement to successfully attain conformity. IBR plant developers/owners will need to devote significant resources to building internal expertise to successfully build plants that conform with IEEE 2800-2022.

Patrick Hart, Mortenson

Patric shared EPC perspectives on IBR plant design and commissioning. EPCs may span different portions of the IBR plant design and commissioning processes (see Figure 16).

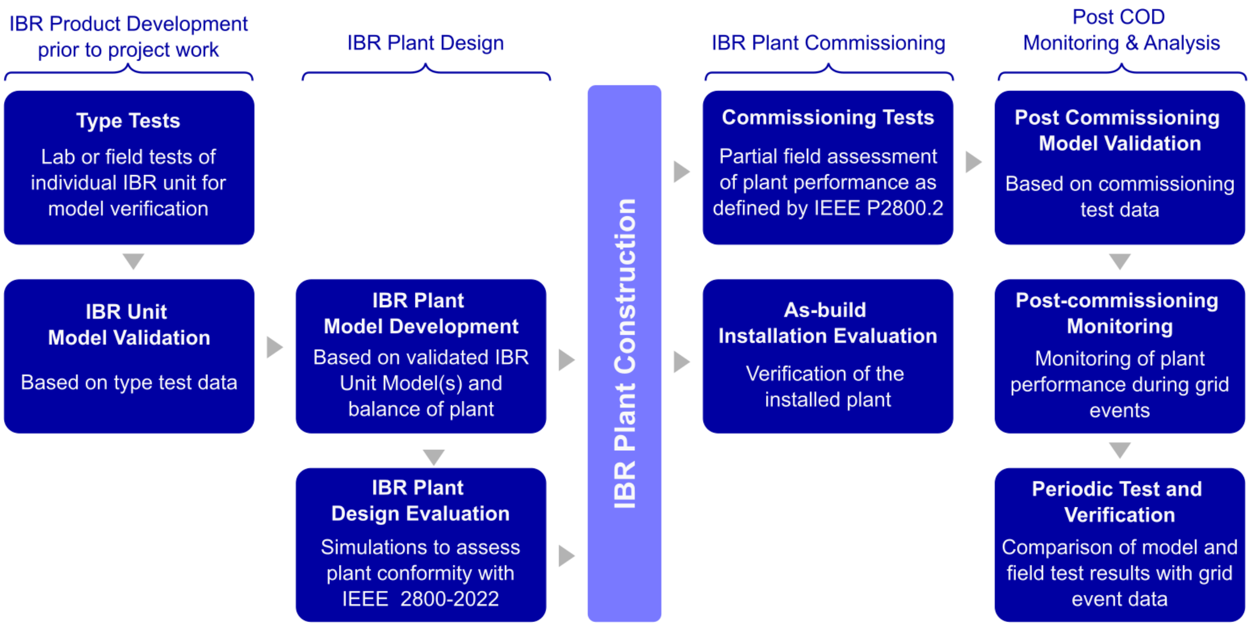

Figure 16: EPC Scope Focused Around Construction [Source: Mortenson]

Standard work is critical for effective deployment of IBR projects. Missing the COD can lead to significant losses for IBR developers, owners, and operators. Product design is centered around test requirements; project design and commissioning are also centered around test requirements. In both cases, if the product or plant are not tested, they likely will not operate as expected. OEM equipment may be capable but must be configured correctly. OEMs serve many markets, and IBR equipment must be inherently designed for that variability. More market variability means more configuration settings, which means more opportunity for errors and failures.

Some of the pain points faced today with IEEE 2800-2022 requirements P2800.2 conformity assessments include:

- IBR plant reaction time less than 200 ms – more difficult to meet with multiple vendors (power conversion system OEM plus PPC OEM(s) plus inverter OEM(s) and challenging for hybrid power plants; leveraging Modbus protocol is a challenge in meeting this requirement, which is common industry practice.
- Data recording requirements – OEMs yet to implement functionality required to log data (e.g., IBR fault codes and oscillography); perceived as “not my problem” by the OEMs.

- Time synchronization – very difficult and expensive to meet at the IBR unit level; IRIG-B, PTP, and NTP protocols[10] all have challenges and costs; can equate to added cost of $200k+ per project just to meet stringent time synchronization costs.
- As-left control settings – control settings often controlled by the OEM engineers; limited visibility into these parameters and settings; hundreds or thousands of parameters, most associated with enabling/disabling features to shape response.

IBR plant developers and owner/operators are including compliance with IEEE 2800-2022 as a contractual requirement. OEMs are working towards compatibility at the unit level; however, plant-wide coordination is still a major hurdle. Industry players continue to get more knowledgeable about specific requirements and how to verify, test, or assess conformity.

Q&A and Interactive Group Discussion

Is IEEE P2800.2 proposing too many tests and is that level of testing necessary?
Some stakeholders believe the volume of proposed tests—spanning various operating conditions, SCR levels, and modeling tools—is impractical for implementation. However, rigorous testing is critical for ensuring grid reliability. Reliability is a shared responsibility among IBR developers, OEMs, and transmission entities to ensure models are accurate and reliable, even if that means conducting a significant number of tests. The key challenge is finding a feasible, coordinated, and efficient approach—some suggest that frameworks like MISO's may offer a manageable path forward. The true challenge lies in coordinating across multiple stakeholders—developers, OEMs, EPCs—to produce a unified and verified model.

Can we automate these tests to reduce the burden?

Standardized test procedures enable automation and incentivize OEMs to build testing features into their equipment. Without standardization, fragmentation reduces the return on investment (ROI) on automation investments. Many of the plant-level tests can be automated (with a human engineer in the loop), especially during IBR plant design evaluation and commissioning. Automation helps reduce effort and improves consistency, particularly with the level of tests required.

What is the distinction between commissioning tests and simulation tests?

Commissioning tests verify performance post-installation, while simulation tests earlier in the project are used to ensure expected behavior. Both are critical but serve different purposes.

[10] These are various protocols used to synchronize time across different systems and devices.

How do we make testing more efficient to avoid project delays?

The goal is not to overload projects with tests but to focus on tests that evaluate the behavior ahead of time—through type testing, design evaluation, and smart scheduling—to avoid surprises later in the process.

Doesn't the cost of testing pale in comparison to the total project cost?

Yes, testing costs are relatively minor in the context of a $100M+ project. The bigger issue is doing it efficiently to avoid delays and errors, which can be far more costly.

When in the project lifecycle should these studies and tests occur?

They should happen "all along the way"—design, iteration, and adjustment should be embedded throughout the project lifecycle to avoid late-stage surprises.

How should contract language address changing regional requirements and evolving standards?

Don't just meet the minimum. Adopt a forward-looking, high-bar standard that integrates upcoming or likely requirements into the EPC contract. This avoids costly retrofits later.

How can developers handle evolving technical deliverables in long project timelines?

Since standards may change mid-development (e.g., NERC PRC-024 to PRC-029), contracts should include flexible language that anticipates new requirements and ensures compliance by COD.

How are HIL/CHIL simulations being used in IBR projects, and what is their value—particularly for PPCs?

While HIL use on the EPC side is limited due to equipment variation and complexity, it's increasingly recognized as essential for large or hybrid plants. CHIL is especially valuable for PPC validation, allowing testing with actual hardware and firmware to reduce reliance on potentially inaccurate models. This is critical, as PPCs are often under-validated and pose significant modeling risks.

How can industry improve PPC validation and reduce project-by-project inefficiencies?

One solution is to shift PPC procurement outside of EPC scope and rely on high-quality OEMs that offer pre-validated, certified products. Certification is most effective at the product level, with version-controlled, configurable designs. However, integration risks remain, especially between PPCs and inverters, highlighting the importance of system-level testing such as HIL to catch issues like firmware mismatches and configuration errors.

What are key focus areas for improving IBR design evaluation over the next six months to a year?

- **Jens:** Finalize and resolve comments on P2800.2, engage industry to promote adoption.
- **Rishi:** Standardize information exchange formats (e.g., IBR Plant Information Database (IPID) or .IBR file).
- **Patrick:** Focus on areas not covered in typical studies, especially documentation quality and completeness.

What are best practices for contractual language with OEMs and EPCs, particularly when the inverter or turbine OEM is different from the PPC OEM and not all equipment is procured under the EPC contract?

It is important to ensure that contractual language addresses configuring the equipment in alignment with the model accepted by the transmission provider, at least as reasonably close as possible, and providing proof upon commissioning or upon request that the as-left settings accurately reflect the model that has been provided by the OEM. This is particularly important for IBR unit and PPC models in EMT and positive sequence UDMs. The contractual language should also address troubleshooting of modeling issues by the OEM to support IBR plant-level modeling and studies by the IBR developer or third-party consultant. OEMs should also be obligated to provide field parameter mapping/parameter verification reports of as-left settings any time a change is made to the facility to ensure the model remains accurate.

Key Themes

- Achieving conformity with IEEE 2800-2022 requires coordination across IBR plant developers, OEMs, EPCs, and consultants. Misaligned scopes of work and fragmented responsibilities often lead to non-conformity, even when the technical requirements are achievable.
- Relying solely on the minimum path to commercial operation often results in missed or misunderstood requirements. A proactive, high-bar approach—baked into contracts and internal processes—is needed to future-proof projects and avoid compliance failures down the line.
- Without consistent data formats, simulation procedures, or model verification practices, IBR projects face recurring issues like poor model fidelity, redundant work, and errors in implementation. Standardization is essential to enable automation and reduce risk.
- PPCs are often delivered late, poorly modeled, and disconnected from overall plant validation efforts. They pose high modeling risk and are rarely validated early, making them a weak link unless product-level certification and integration practices improve.

- Design evaluations and testing should occur continuously—from early design through commissioning. Simulation-based assessments and field commissioning tests serve different purposes but are both essential to verifying plant behavior and performance.
- Conformity assessments will not be widely adopted unless AGIRs enforce them—requiring IBR plant design evaluations prior to energization and as-built verification before final commissioning is essential for meaningful implementation.
- IBR developers and owner/operators need to build internal capabilities to execute on IBR plant design evaluations effectively. As interconnection standards become more performance-driven, in-house expertise will be critical and can still be supplemented by external support.

August 26, 2025 Virtual Meeting

IBR Plant Design Evaluation with Applicable Requirements II (~225 attendees)

Presentation recording and slides are available to download here. Figure 17 shows the makeup of meeting attendees by industry sector:

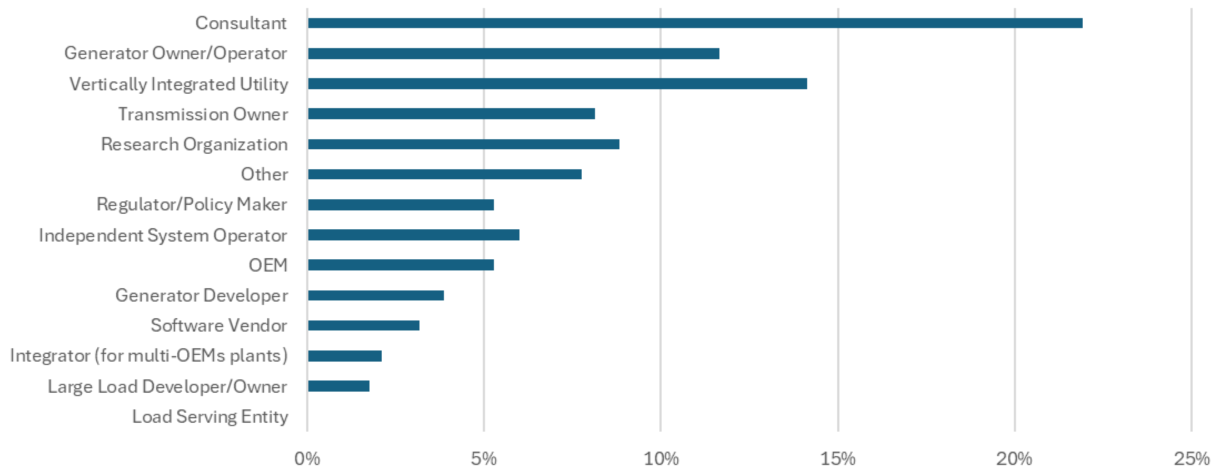

Figure 17: Meeting attendees by industry sector

This fourth meeting of Season 2 of the DOE i2X FIRST initiative focused on IBR plant design evaluation with applicable IEEE 2800-2022 requirements, providing an overview of IEEE P2800.2 IBR plant design evaluation clauses and sharing system operator and utility perspectives on IBR design evaluation requirements. IBR plant design evaluations based on model testing and on review of equipment type tests and other available documentation were discussed. A full picture of how these requirements fit together to ensure grid reliability was presented as well as potential pathways to process automation were discussed. Presentations included the following:

Alan Urban, MISO

Alan shared MISO's proposed IBR modeling requirements currently under development and finalization. MISO proposed updates that will be used in the interconnection process as part of a new BPM-015 appendix. The requirements focus on evaluations that would be performed during the interconnection process and are generally aligned with the high priority performance capabilities MISO is seeking from its adoption of relevant clauses from IEEE 2800-2022.

MISO is requiring the submission of four types of models to align with FERC Order 2023 directives and to meet simulation platform compatibility needs. These include:

- PSS/E standard library model
- PSCAD model

- TSAT user-defined model (UDM)
- PSS/E UDM

PSS/E UDM is required only at the time of signing the GIA; the other models are required at the initial interconnection application. The requirements also include 17 model quality performance tests, and all models must be benchmarked against that test. Results must be submitted in a report that documents acceptable performance.

Alan recognized that MISO's intended goal was to strike a balance in their enhancements to modeling requirements. On one hand, no IBR modeling requirements would lead to inadequate quality checks and performance conformity testing and higher reliability risk. On the other hand, exhaustive modeling requirements fully aligned with IEEE 2800-2022 would require significant work from interconnection customers and MISO and result is slowdown of the interconnection process. Hence, MISO selected a subset of simulation tests that closely align with IEEE 2800-2022 clauses and the IBR plant design evaluation proposed in the draft IEEE P2800.2 (see Figure 18).

Test	MISO Test #	IEEE 2800 Clause	Model Applicability
Initialization Tests	5.1.1	5.1 Reactive Power Capability	Generic, UDM, EMT
Balanced Fault Ride-Through Tests	5.1.2	7.2.2.5 Dynamic voltage support 7.2.2.6 Resetore output after voltage ride-through	Generic, UDM, EMT
Small Voltage Disturbance (SVD) Tests	5.1.3	7.2.2.2 Voltage disturbances within continuous operation	Generic, UDM, EMT
Small Frequency Distrubance (SFD) Tests	5.1.4	6.1 Primary Frequency Response	Generic, UDM, EMT
High-Voltage Ride-Through (HVRT) Tests	5.1.5	5.2 Voltage and Reactive Power Modes 7.2.2.1 Voltage distrubance ride-through: General 7.2.2.3 Low- and high-voltage ride-through 7.2.2.5 Dynamic voltage support	Generic, UDM, EMT
Low-Voltage Ride-Through (LVRT) Tests	5.1.6	5.2 Voltage and Reactive Power Modes 7.2.2.1 Voltage distrubance ride-through: General 7.2.2.3 Low- and high-voltage ride-through 7.2.2.5 Dynamic voltage support	Generic, UDM, EMT
High-Frequency Ride-Through (HFRT) Tests	5.1.7	7.3.2 Frequency disturbance ride-through	Generic, UDM, EMT
Low-Frequency Ride-Through (LFRT) Tests	5.1.8	7.3.2 Frequency disturbance ride-through	Generic, UDM, EMT
Protection Verification Tests	5.1.9	7.2.2.1 Voltage distrubance ride-through: General 7.2.2.3 Low- and high-voltage ride-through 7.3.2 Frequency distrubance ride-through	Generic, UDM, EMT
Short Circuit Ratio SCR Tests	5.1.10	Common industry test	Generic, UDM, EMT
Phase Angle Change Tests	5.2.1	7.3.2.4 Votlage phase angle changes ride-through	EMT

Figure 18: Mapping MISO Tests to IEEE 2800-2022 Clauses [Source: MISO]

For all the tests, active power, reactive power, and voltage values must reasonably match between the models when measured at the POM. Acceptable damping ratios are considered 0.3 or greater. All tests are performed on a single-machine-infinite-bus (SMIB) system with a controllable voltage source. SCR is specified as 3 for initial tests, with SCR being updated to reflect actual interconnection conditions later in the process as needed.

Test	Model	IEEE Clause(s)	MISO Test No	Disturbance	IBR Plant Initial Conditions			Grid Initial Condition	
					Active Power at POM	Reactive power at POM	Voltage at POM	Infinite Bus Voltage	SCR
Small Voltage Disturbance (SVD) Tests	Generic, UDM, EMT	7.2.2.2 Voltage disturbances within continu	5.1.3-1	Small voltage disturbance	Pmax	0	Figure 3	N/A	3

Pass/Fail Criteria

The models pass these tests if all the following conditions are met:

1. The plant shall not trip.
2. The plant shall have a stable and well-damped response. An acceptable damping ratio is 0.3 or greater [5].
3. The plant shall not enter momentary cessation (current blocking) mode.
4. Appropriate reactive power response shall be observed based on control settings.
5. Active, reactive, and voltage values shall reasonably match between standard library, PSS®E/TSAT™ UDM, and PSCAD™ models at the POM.

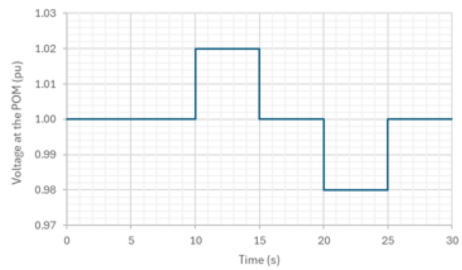

Figure 19: Example of Small Voltage Disturbance (SVD) Tests [Source: MISO]

In terms of next steps, MISO is bringing draft requirements to their Planning Advisory Committee stakeholder meeting and intends to publish the requirements in Q4 2025. The requirements would go into effect in 2026. MISO is also exploring tooling options to automate tests, benchmarking, and reports.

Jens Boemer, EPRI

Jens presented IBR design evaluation steps that focus mostly on documentation review such as type tests, IBR unit model validation, IBR plant model development, and IBR plant design evaluation steps of the IEEE P2800.2 conformity framework. Clause 7.3.3 of IEEE P2800.2 describes design evaluation practices based on review of OEM and IBR plant documentation. Some IEEE 2800-2022 specifications are not suited for simulation test evaluations such as consecutive voltage deviation ride-through capability and transient AC overvoltage ride-through capability. Similarly, conformity with other types of requirements is best verified by reviewing IBR plant documentation such as prioritization of IBR response, control capability requirements, measurement accuracy, enter service performance, protection settings, etc.

Jens described that IBR documentation-based verification can be conducted at various stages of the interconnection process (see Figure 20). Early verification may focus on OEM documentation of anticipated IBR equipment, IBR plant design considerations, overall conformity approach with the requirements, etc. Later-stage verifications can focus on changes made to equipment, IBR plant design, settings, and other features that may adversely affect conformity with the requirements.

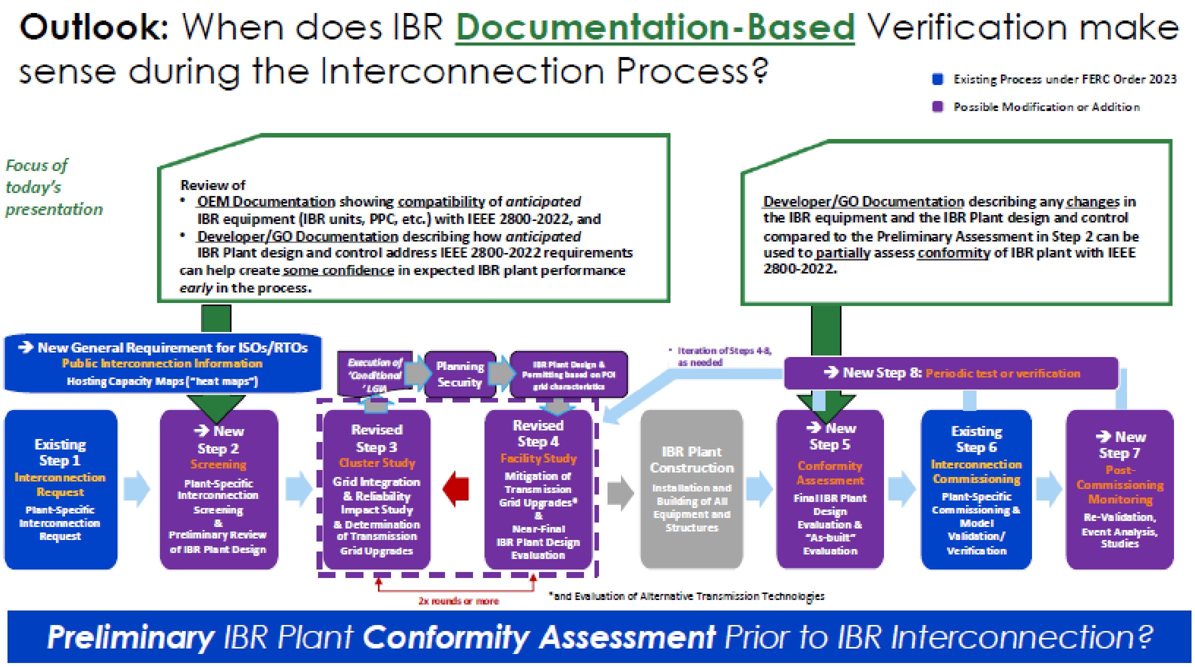

Figure 20: Documentation Verification during Interconnection Process [Source: EPRI]

Jens also mentioned a concept regarding an EPRI IBR Performance Identification and Conformity Assessment (ID/CA) Tool which may be funded at a later time.

Anthony Williams, Duke Energy

Anthony shared Duke Energy's IBR design evaluation process and ongoing efforts in this area. Duke pilot project regarding IBR design evaluation and commissioning align with past presentations in the i2X FIRST discussions regarding number of partners and players during IBR plant design, coordination issues among parties, difficulty of developers identifying and conveying technical information, aligning roles and responsibilities, and ineffective requirements/practices to ensure adequate work is completed. Industry collectively knows there are IBR configuration and performance issues and most understand the benefits of IBR plant design reviews, yet implementing a formal (or informal) design review is a difficult and complicated process.

Duke has established a Capability and Performance Review (CPR) process between the Interconnection Agreement and Commissioning stages of the interconnection process for IBR plants. This process includes 4 distinct stages – CPR.1 (initial design), CPR.2 (intermediate design), CPR.3 (final design/integration), and CPR.4 (pre-commissioning and pre-verification). Duke is changing processes to be more involved throughout this process, and developers are subsequently changing processes to include reviews as part of interconnection. Some key goals for the Duke CPR include:

- Identify and discuss design requirements early so there is opportunity to make changes with minimal impact to project cost and schedule
- Provide supplemental guidance on information that helps the IBR developer know how to comply with the interconnection requirements
- Allow for multiple reviews rather than one lumped review at the end
- Allow reviews to align with the Developer's / EPC's normal design process
- Have reviews prior to critical tasks to minimize the possibility of equipment specification or IBR plant design that does not meet requirements

The core goal is to ensure the IBR plant is designed to meet the established requirements, to verify the design ahead of commissioning, and to have the actual design accurately represented in the IBR plant models.

Duke has evolved their transmission-connected IBR requirements and documentation (see Figure 21). Today there are three core documents:

- **IBR Technical Interconnection Requirements (TIR):** establishes the defined interconnection requirements that the interconnection customer must comply with.
- **Coordination Document:** describes what is required to be submitted (e.g., plant documents, OEM documents, inverter and PPC narratives, plant studies, models), with fields for interconnection customer responses and Duke review responses; transparent and consistent for both parties involved.
- **Design Evaluation Checklist:** describes what the design should include and how to demonstrate compliance with the requirements; includes a checklist of items to submit as well as expected time of submittal (event-based, not date-based).

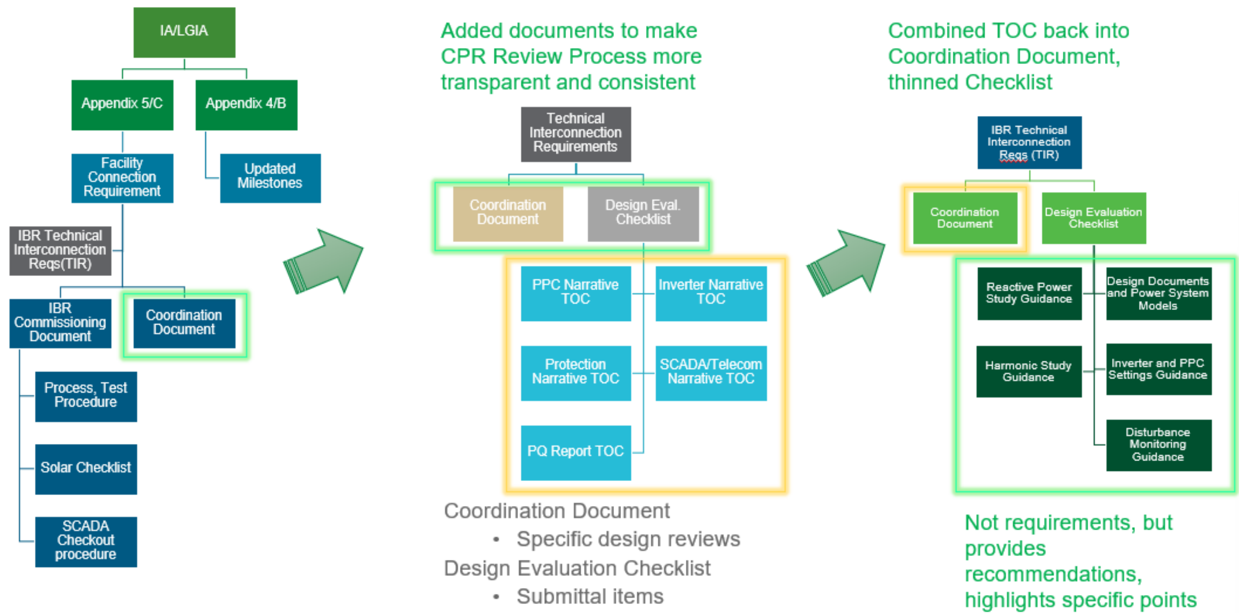

Figure 21: Evolution of Transmission-Connected IBR Documents [Source: Duke Energy]

Anthony highlighted that there are dependencies between work products, and the order of IBR developer work may cause repeat work needed, which Duke is seeking to avoid. A dependency diagram was developed based on a thorough review of work products and dependencies (see Figure 22).

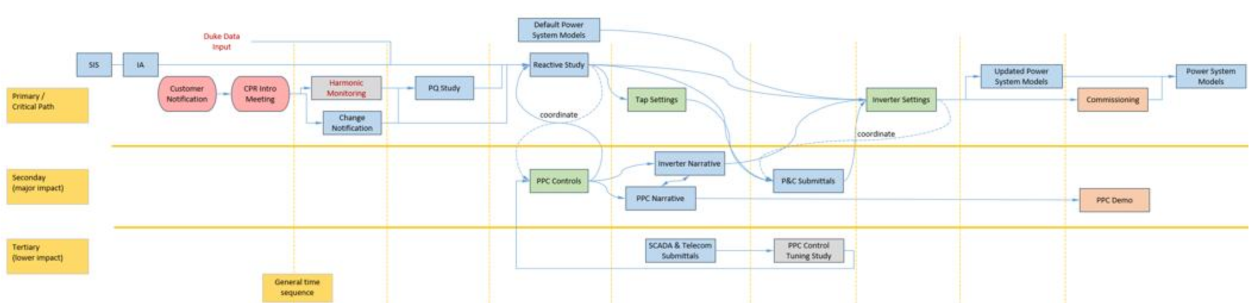

Figure 22: Work Products and Dependencies during Duke CPR Process [Source: Duke Energy]

Duke expects several iterations of this CPR process to improve review documents and is exploring ways to subdivide information between proper contractors, consultants, and OEMs. Balancing the right level of specificity – clear versus overly detailed – is a challenge. They expect that the review process will help ensure proper IBR plant configuration, providing the required performance and updated IBR plant models.

Ryan Quint, Elevate Energy Consulting

Ryan presented practical considerations and approaches for putting IEEE P2800.2 concepts into action following adoption of IEEE 2800-2022 requirements. The presentation highlighted moving away from focusing only on IEEE 2800-2022 requirements and focusing more holistically on IBR plant design, performance requirements, modeling requirements, and verification methods in a coordinated manner. While industry has made progress defining expectations, actual implementation across transmission providers, developers, and OEMs remains uneven and may be insufficient moving forward. Ryan emphasized that several efforts at NERC, including standards development work and recent Alerts, are making some aspects of IEEE 2800-2022 and IEEE P2800.2 mandatory in terms of modeling requirements, model verification, possibly commissioning, and post-commissioning.

The first step in these endeavors is to adopt IEEE 2800-2022 in interconnection requirements, and there are multiple industry references that emphasize this recommended practice. Once the transmission provider codifies the specific capability and performance requirements for newly connecting IBRs, then IBR developers can build processes around the overall steps of the conformity framework in IEEE P2800.2. However, in many cases, those steps also need to be codified in the requirements themselves; otherwise, IBR developers are unlikely to adopt them voluntarily. Examples include, but are not limited to, the following:

- Type test documentation and IBR unit model validation reports should be required with interconnection applications and after any updates.
- IBR plant model development and model verification documentation should be provided with the IBR plant models.
- IBR plant design evaluations using either documentation or simulation tests need to be defined to demonstrate the IBR plants conformity with the requirements.
- IBR plant commissioning checks and documentation should be provided that verify the site is configured as expected.
- IBR plant commissioning test data can be used for subsequent dynamic model validation and submittals.

The next step in the process is for the IBR developer to build processes that comply with the requirements set forth. IBR plant documentation management and version control are critical at this stage. IBR plant information repositories are key to handling the large volume of data from many entities involved in the IBR plant design, construction, and commissioning steps. Examples of documentation that need to be retained include the following:

- Contractual language in OEM equipment procurements
- Coordination with EPCs and third parties

- IBR plant design considerations
- Documentation collection and vetting
- Model(s) development, version control, and verification
- Model performance testing
- Interconnection application completeness and process alignment
- As-planned/as-left settings verification
- Increased visibility across departments and collaborators

The development of IBR modeling requirements by the transmission provider should be combined with the concepts of the IBR plant design evaluation (see Figure 23). Interconnection customers can automate much of the simulation model testing that checks whether the IBR plant model meets quality checks and whether the as-designed IBR plant complies with the requirements established. There are various categories of tests being developed such as those presented by MISO (see presentation from Alan Urban above) as well as Southern Company, ISO-NE, ERCOT, and others. At a high level, the categories of tests may include:

- Initialization and model functionality
- Balanced and unbalanced fault ride-through
- Small voltage and frequency disturbances
- Voltage control and reactive power capability
- High and low voltage and frequency ride-through
- Short circuit strength performance
- Protection verification

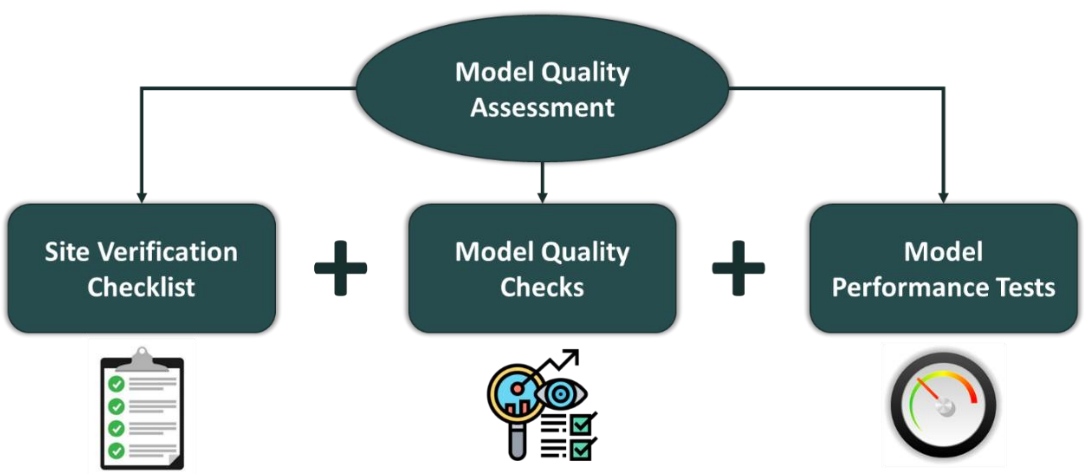

Figure 23: Work Products and Dependencies during Duke CPR Process [Source: Duke Energy]

Ryan also noted that there is an apparent gap in industry practices in terms of coordination between the transmission provider and the interconnection customer post-GIA up to COD. At this stage, the project design has been solidified, and the project will eventually be constructed and operated. Transmission providers need to develop processes, tools, and resources to support oversight and verification that the IBR plant is commissioned to match the IBR plant design used in studies, address any discrepancies, and ensure the as-left settings are documented and verified. This requires dedicated and educated staff on these topics.

IBR requirements must cover not only performance and capability but also robust modeling, documentation, and process-oriented elements, with compliance verification being just as important as the requirements themselves. By embedding IEEE P2800.2 conformity assessments, using documentation repositories, and automating model performance checks, transmission providers can adopt a "trust but verify" approach that streamlines interconnection while ensuring reliability.

Q&A and Interactive Group Discussion

Would it be more efficient to shift the requirement for UDM benchmarking from the application phase to the pre-sync validation phase for the new MISO process? Benchmarking a standard library model to PSCAD should allow MISO to run a comprehensive interconnection study, while still aligning with Order 2023.

MISO did not believe this aligned with its interpretation of the Order 2023 directives and does not recommend deferring all UDM delivery and benchmarking to a later phase. MISO must collect UDMs during the study phase, and the tests/report validation are materially easier and more efficient to perform at application. While benchmarking a standard library model to PSCAD can enable base-case creation, it may not satisfy the detailed studies needs for local interconnection applications and thus the UDM is needed. This also aligns with NERC's recommendations and guidance on this topic. This preserves study fidelity and schedule discipline without pushing critical work into the already time-compressed interconnection periods.

How are developers meant to navigate the unavailability of OEM models across platforms? For example, if TSAT UDMs are unavailable at interconnection request phase, will a project be kicked from the queue?

MISO flagged platform readiness in June 2025 with an expectation that OEMs be "up to speed" by June 2026. TSAT is a major platform, and projects should plan to have TSAT UDMs by that effective date. Under some case-by-case instances, if a TSAT UDM is missing at interconnection application, the interconnection customer may consider submitting a standard library model benchmarked to PSCAD and provide a dated OEM letter of commitment with a delivery plan for TSAT UDMs ahead of the June 2026 applicability. This reduces queue risk while acknowledging current supply-chain/model-release realities. However, developers should assume MISO will not accept prolonged gaps and may tie study progress or milestones to delivery of the missing UDM.

In MISO LVRT/HVRT tests, what is the requirement for reactive power injection? The term 'appropriate reactive current injection' is very general.

The term is intentionally non-prescriptive to accommodate OEM design diversity and system conditions. MISO may clarify without over-constraining OEMs by specifying expectations. Ranges of acceptability could be considered for additional guidance to interconnection customers; however, this is a difficult and contentious topic of IEEE P2800.2 efforts and thus was not intended to limit or preclude technologies seeking interconnection. The requirements for "appropriate" response are intended to flag gross errors or discrepancies, where needed.

Is there a reason why the balanced phase jump test is only in the EMT domain?

The requirement is tied to sub-cycle response (IEEE P2800.2 Clause 7.3). Certain control and protection behaviors (e.g., phase-locked loop and fast protection latching) are not captured accurately in phasor-domain models, so EMT is preferred to ensure fidelity.

Has MISO considered developing a change management process detailing when model re-testing is required after commercial operation due to model updates or plant changes? Particularly IBR unit or PPC software/firmware updates.

MISO already uses material modification reviews; many firmware/setting changes will fall under facility modifications that still require model updates. A clear, written change-control matrix helps. Changes that affect the electrical behavior of the IBR facility require model updates and resubmittal of the model performance tests and benchmarking.

For some documentation-based design evaluation steps, is PPC verification included?

The PPC should not be overlooked in verification steps, as it is often a source of error and late-stage tuning is rather common. Requiring a function map showing prioritization (voltage control, VRT/FRT, P/Hz, Q/V, ride-through logic), timing artifacts (delays, ramps, latches, fault-mode transitions), plant-level Q/P dispatch coordination across units, and as-planned/as-left settings with traceability are all key. IEEE P2800.2 explicitly calls out PPC prioritization and model-based tests—leverage that to make PPC evidence mandatory in the submission and to anchor IBR plant-level performance in both positive-sequence and EMT domains.

Does MISO perform consecutive voltage ride-through testing?

Not today. This did not rank as a high-priority requirement in MISO's internal prioritization. If adopted later, a risk-based approach makes sense: require it where short-circuit strength is low, where back-to-back contingencies are plausible, or where historical oscillography indicates multi-dip exposure.

As MISO collects UDMs at the generator interconnection level, do those same UDMs enter the Eastern Interconnection base case?

For EI-wide case creation, PSS®E standard library models are typically preferred for portability and model useability. PSS®E UDMs may be used where supported, but broad guidance tends toward standard library models for base cases.

For MISO, if relay voltage/protection settings change in operation, are all benchmarking tests required?

Not necessarily. The scope depends on what was changed and any downstream impacts on IBR plant performance. For example, a VRT threshold change warrants at least the VRT/HVRT suite, protection coordination checks, and any coupled PPC behaviors (e.g., current-limit transitions). Provide old vs. new comparisons and rerun the affected test groups, and this likely will suffice.

Please touch on a global perspective. Are all regions aligned in following and using IEEE P2800.2 as the preferred process? Or are there differences?

Broadly yes, there is general high-level alignment with the concepts outlined in IEE P2800.2. The concept set—unit-model validation, plant model build/verification, and a conformity assessment at point of interconnection—aligns with practices in Australia, the EU, and parts of South America. Regional differences in implementation exist, particularly for more detailed and sensitive requirements such as transient overvoltage or consecutive VRT requirements. Overall, the direction of requirements + evidence + testing matches international norms. Various recommended practices in IEEE P2800.2 can be adopted or integrated into existing practices, where needed, to improve IBR integration.

How common is IBR plant design evaluation and conformity framework internationally?

In parts of Europe (e.g., Germany), this has existed for more than a decade; although, historically, with less emphasis on grid reliability studies given their more meshed grids. As IBR plants scale, penetration levels rise, and other characteristics of different grids evolve, regions are extending from "design-meets-code" to "design + validated performance + selective impact studies," which mirrors the P2800.2 philosophy.

Staffing gaps have been an issue on both the transmission and generation side. Now, even OEMs are overloaded and understaffed with modeling queries. How do you envision this staffing issue being resolved?

Pair people with process and tools. Having clear and concise requirements that are easily understood creates streamlined processes and submissions. Deploying automation tools for asset management, model management, documentation management, and simulations can also expedite delivery of information and results. Standardized artifacts such as settings databases, test documentation, model benchmarking reports, etc., can help as well. Training and resourcing to bridge interconnection support, modeling/studies, protection and control, commissioning, etc., can also help minimize rework.

When will final version of IEEE 2800.2 be published?

The working timeline targets the first half of 2026 for publication.

Key Themes

- MISO is moving to a balanced, risk-informed modeling framework that requires four model types (PSS®E Standard Library, PSCAD, TSAT UDM, and PSS®E UDM) and a subset of tests mapped to IEEE 2800-2022/P2800.2. Draft requirements are slated for Q4 2025 publication with 2026 effectiveness, and MISO is exploring automation to run tests, benchmarking, and reporting efficiently. The MISO model performance tests and benchmarking center on 17 model quality performance tests with cross-model consistency at the point of interconnection (active/reactive power and voltage).

- Conformity assessment is both simulation- and documentation-driven: some IEEE 2800-2022 specifications (e.g., consecutive VRT, TOV) are best verified via documentation, not studies. Verification needs to cover the entire plant (inverter, PPC, balance of plant, etc.) must be sufficiently evidenced for traceability.

- Shifting models submittals later in the interconnection process can cause complications for transmission providers conducting studies. Model benchmarking is critical to ensure accuracy of models across platforms. Collecting UDMs and validating reports at application preserves study fidelity, enables early error detection, and avoids compressing critical work into late project windows.

- Platform readiness and tooling may be a near-term execution risk. Various tools, practices, processes, etc., are all being developed to support IEEE P2800.2 conformity assessments and verifications throughout the IBR interconnection process. However, industry may need to staff up to handle increased workloads.

- Post-COD change management should distinguish material modifications from facility modifications yet still require targeted re-tests when electrical behavior changes. A change-control matrix, delta reports (old vs. new settings), and scoped re-execution of only the affected benchmarks reduce burden while maintaining confidence.

- Utilities are operationalizing design evaluation through staged processes (e.g., Duke's CPR.1–.4) and clearer artifacts (TIR, Coordination Document, Design Evaluation Checklist), but staffing remains a constraint across TSOs, developers, and OEMs. Standardized repositories, version control, and automated test/report pipelines enable a "trust-but-verify" approach that aligns with emerging international practice and positions stakeholders for IEEE P2800.2's anticipated 2026 publication.

September 23, 2025 Virtual Meeting

IBR Plant Modeling Requirements and Best Practices (~225 attendees)

Presentation recording and slides are available to download here. Figure 24 shows the makeup of meeting attendees by industry sector:

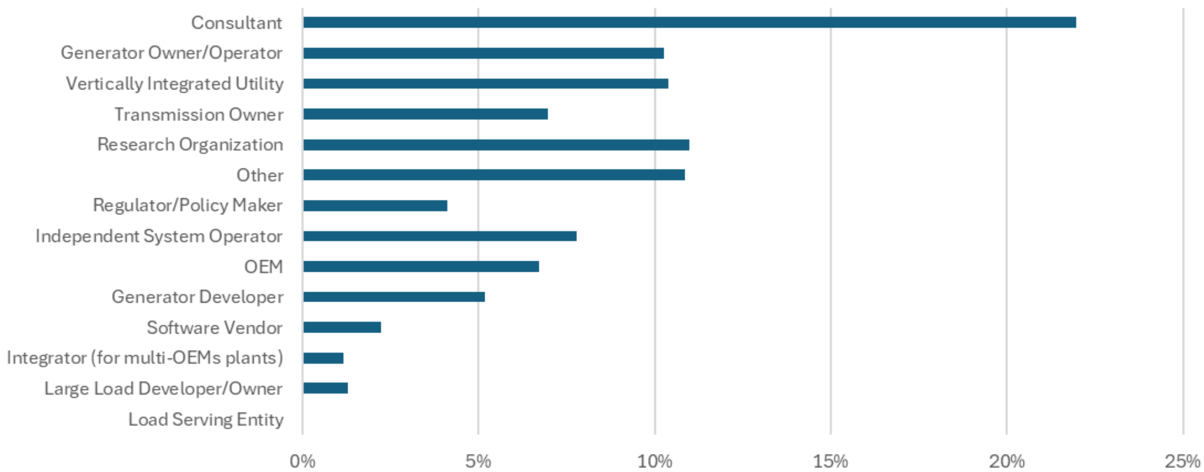

Figure 24: Meeting attendees by industry sector

This fifth meeting of Season 2 of the DOE i2X FIRST initiative focused on IBR plant modeling requirements and best practices, sharing experience from an ISO/RTO, developer/consultant, and perspectives looking forward in this area. Presentations included the following:

Bruno Leonardi, New York Independent System Operator (NYISO)

Bruno shared recent updates, initiatives, and perspectives from the NYISO. FERC Order 901 and New York State Reliability Council (NYSRC) Reliability Rule B5 (effective since February 9, 2024) have been some of the key drivers for NYISO to enhance their modeling requirements, and NYISO believes its IBR modeling requirements are in alignment with NERC's vision in this area (see Figure 25). While enhanced modeling and performance validation requirements can improve reliability and increase the accuracy and trust in models used for studies and decision making, these requirements can also affect timely commercial operation dates which can affect resource adequacy and reduction of security margins. In particular, Bruno mentioned that the NERC recommendations use the following statement (emphasis added):

> *"Performance testing processes should include sufficient tests necessary to show conformity with published performance expectations without adding undue study burden"*

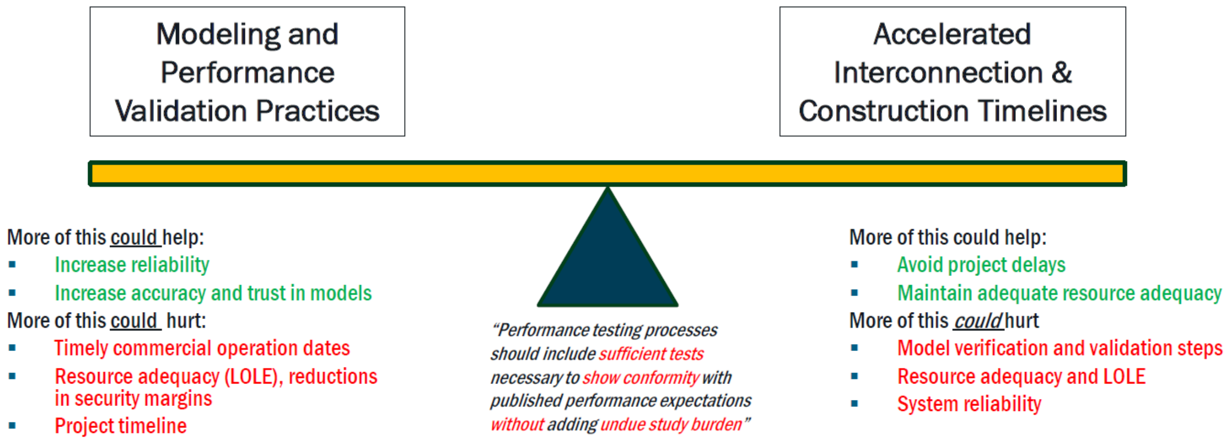

Figure 25: NYISO Perspectives on IBR Modeling Requirements and NERC Vision [Source: NYISO]

NYISO has established some core practices regarding IBR plant modeling, as shown in Figure 26. These include:

- Requiring models to accurately represent the as-planned and as-installed equipment.
- Clear equipment and model performance requirements
- Aggregate plant representation
- Benchmarked and aligned phasor domain transient (PDT) and EMT models
- Preference for standard library models but accepting all types of models
- Performing EMT studies later in the interconnection study process rather than earlier

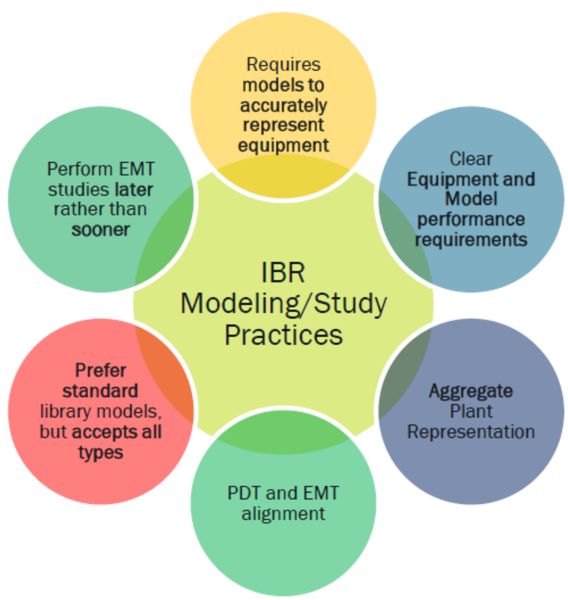

Figure 26: NYISO IBR Plant Modeling Practices [Source: NYISO]

Regarding EMT modeling and studies, Bruno shared some ongoing efforts and requirements that NYISO has implemented. EMT models are required for all IBR plants in the New York system including existing plants, plants under construction, and future IBR plants. Most EMT studies are only performed on a small area of the network, and NYISO is developing screening methods and processes to determine which IBRs must undergo more extensive EMT studies. NYISO is also thinking about the EMT study process as more of a "cycle" rather than a snapshot of the interconnection process, where EMT studies may be redone during plant construction or prior to COD once settings are confirmed/verified. The EMT study efforts have been moved later in the study process, once project details are solidified. This includes gathering EMT models *after* the cluster system impact studies prior to/during plant construction and then conducting studies as needed leading up to plant COD.

In terms of IBR modeling requirements, NYISO has established a set of tests that are similar to those specified in IEEE 2800-2022. NYISO opted not to specify quantitative pass/fail criteria; clear deviations off of baseline performance will generate questions during reviews. NYSRC Rule B5 adopted IEEE 2800 requirements (see Figure 27).

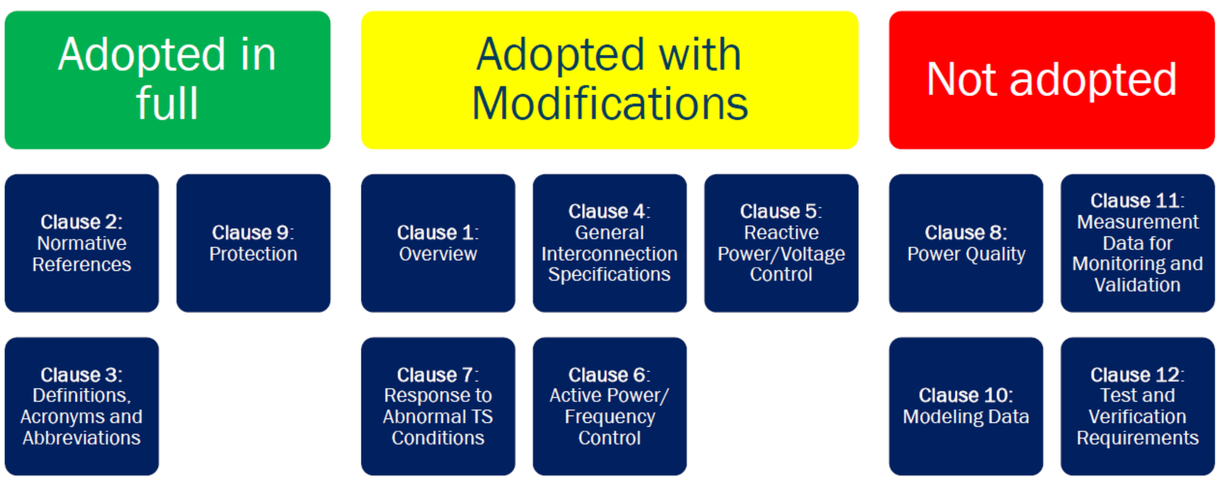

Figure 27: NYSRC Rule B5 Adoption of IEEE 2800-2022 [Source: NYISO]

Kasun Samarasekera, Elevate Energy Consulting

Kasun shared three recent case studies of IBR modeling and related those efforts to many of the IBR modeling and performance issues described in the i2X initiative. The first case involves a recent PSCAD model validation effort that revealed discrepancies between what was assumed to be a verified EMT model and actual behavior of the equipment in the field during an event. Somewhat abnormal response in the field was observed and the team attempted to recreate this performance in the model. To do so, the team needed to extract the inverter as-left settings, review the PSCAD model documentation, and review the actual PSCAD model. Inconsistencies in naming conventions across these three domains resulted in challenges interpreting what is installed in the field versus in the model (see Figure 28). Findings showed that the model performed very well to simulated disturbances and that model was used to pass ISO/RTO modeling tests whereas the actual equipment in the field had abnormal performance issues that needed further analysis. This highlighted the need for model verification (i.e., comparing "as-built" equipment and settings with the submitted model) during commissioning as well as ongoing model validation efforts to ensure the model matches the actual performance.

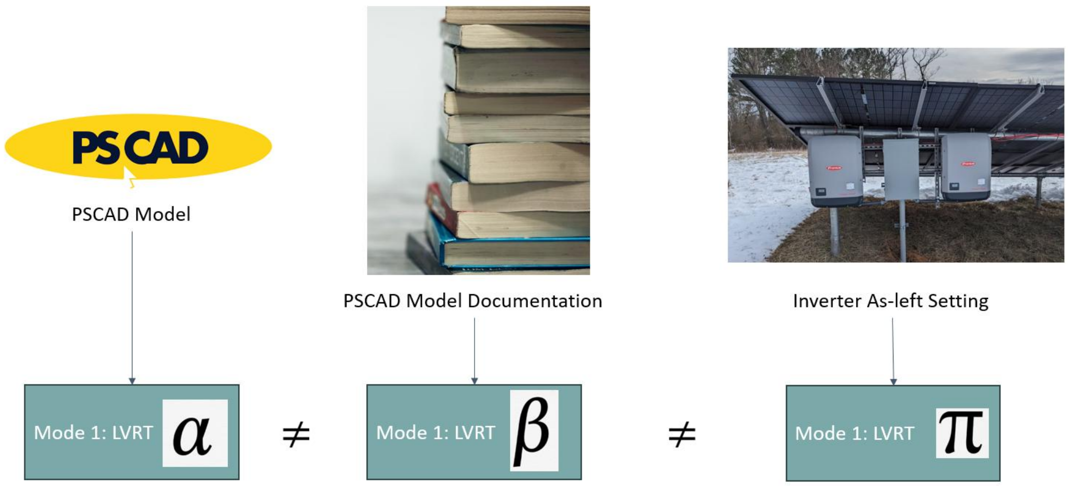

Figure 28: Discrepancies between Model, Documentation, and As-Left Settings [Source: Elevate Energy Consulting]

The next case study focused on a PPC OEM's generic model that may not meet the new ERCOT requirements related to PPC accuracy and validation as well as ongoing challenges interpreting what qualifies as "generic" versus actual control hardware in the loop (CHIL) testing and model validation. Generic PPC models based on, for example, the standard library "REPC" control block diagrams are no longer allowed in ERCOT. CHIL validation has become increasingly common for IBR units (i.e., turbines and inverters) but not necessarily for PPCs. Unrealistic PPC models (i.e., high gains, no communications delay, etc.) are rather common to achieve desired performance required by the system operator and these models are often used as defaults during the interconnection process.

Kasun highlighted the importance of accurate PPC model validation, which can include two options:

- .DLL "real code" wrapper where the actual control code is used and masked by a .DLL in the simulation models[11]
- PSCAD block model with CHIL validation to prove that the model matches actual performance

[11] CHIL testing is still recommended even when using these types of models to validate that the model matches the actual performance of the equipment.

The last case study described working with an OEM PSCAD model in the HECO region where model updates by the OEM to pass certain tests resulted in failed results for other tests that previously passed, which highlights the need for comprehensive model testing approaches. In this situation, the OEM-specific models were provided with default parameter values and may not meet all grid code requirements under all necessary conditions. Thus, model tuning is necessary. This required close collaboration between the OEM, the project developer, and the consultants supporting the project to ensure inverter compliance with the applicable rules. The OEM made changes to the model based on a new version that enabled the plant to improve its ride-through capability; however, the plant then exhibited unacceptable damping following some disturbances. Conducting all required tests to ensure the model wholly passes all requirements prior to submission can help lead to a successful submission. Ensuring some degree of verification of the model against the field equipment/proposed settings helps ensure accuracy throughout the process.

Lastly, Kasun highlighted a recent concept and framework developed by Elevate to create more consistency and standardization between models and as-left settings across OEMs. Some OEMs have adopted a process where a mapping file can be used to extract as-left settings and port them to the models, and vice versa. However, these mapping files are not standard and require significant time to understand and refer to for project engineers. The exercise of extracting as-left settings and understanding how they map to the models should be a 5-minute exercise that can be quickly checked; however, this is not the case presently on a widespread basis. Thus, the concept of a ".IBR" file could be used to convert OEM mapping of their parameters (models and as-lefts) such that a standardized reporting tool could be used to extract parameters and settings when needed.

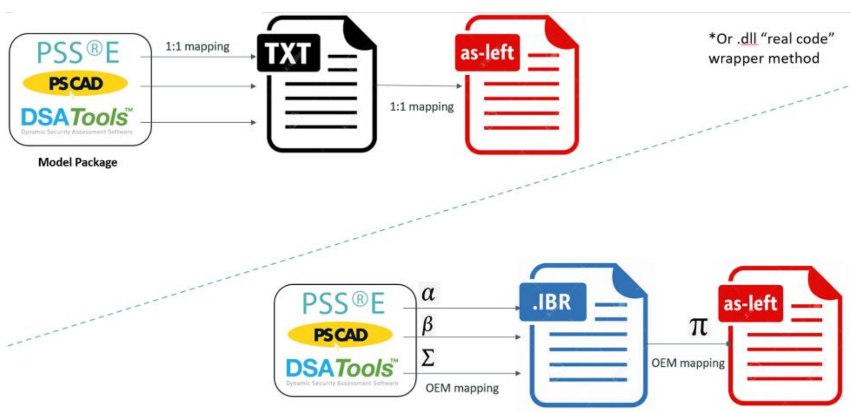

Figure 29: Concept of ".IBR" Standardized Mapping File between Model and As-Lefts [Source: Elevate Energy Consulting]

<u>Andrew Isaacs and Lukas Unruh, Electranix</u>

Andrew and Lukas highlighted that industry has made good progress in the area of IBR performance and modeling including publication of an IEEE standard that raises the performance bar, the prevalence of IBR modeling requirements, development of automations and processes to gather and review models, and understanding of GFM technology. These efforts have hopefully led to meaningful reliability benefits and the reduction of risks to the bulk power system. However, more work is needed moving forward to improve model accuracy such as:

- Requirements and guidance regarding unit-level model validation reporting and inclusion of type testing from IEEE P2800.2
- Improved IBR commissioning, testing, and verifications around COD
- As-built confirmations (i.e., verification) to ensure control firmware, parameters, etc.
- Adoption of .dll standards (i.e., real code models)
- Improved PPC modeling, modeling of plant communications delays, DC-side protections and controllers, etc.

OEMs may be providing a general purpose model that must be parameterized for specific projects and conditions yet the OEMs do not have sufficient resources to create and maintain as-left models that continually reflect the equipment in the field. OEMs are apprehensive to share "proprietary" information with project developers and consultants supporting the modeling efforts throughout the interconnection process. Some equipment protections may be disabled by default, leaving errors or omissions in the models if not carefully reviewed.

Data management is also becoming a challenge as more model iterations are required during the interconnection process as changes occur to the IBR plant design and equipment selection. Documentation and models need to reflect these changes and be reported accordingly. Code management, version control, etc., are all key to enabling this more effectively. Data repositories where models are "fetched" can play a key role here.

Improvements and maturity in screening tools and automations are also key for EMT studies. This includes screening for weak systems, SSO risks, etc., using high-quality, commercial-grade tools rather than one-off scripts. Clean and effective automation tools for building cases and conducting studies is needed so that the everyday study engineer does not need to be an expert in EMT modeling, similar to how PDT tools are used today.

Andrew and Lukas also highlighted that expanding study capabilities will also improve informed decision making, and this is applicable not only to IBRs but also to large load interconnection analysis as well.

<u>Q&A and Interactive Group Discussion</u>

What requirements, checks, verifications, etc., does NYISO have in place to ensure the models match the proposed equipment, particularly early in the interconnection process?

Some requirements exist for PDT models but no requirements around verification exist for EMT models yet. NYISO recently started their EMT implementation strategy and are working through when to request models, the level of detail in the models, and how those models will be used in studies. NYISO has not gotten to the point of requiring verification steps but did highlight that the NERC alert included recommendations regarding verification and validation of models.

Did NYISO send a request to all GOs for EMT model submissions from existing plants? Did it include model quality testing or benchmarking?

All existing IBR plants have been asked to submit an EMT model in accordance with the EMT modeling guidelines NYISO has published and were given six months to prepare and submit the model. There are several tests in the guideline to evaluate model performance and usability, and those tests are not pass/fail but rather are meant to be informational. If significant discrepancies from the "baseline response" are observed, additional discussions to understand why the models deviate may ensue. This should lead to better, usable models. Benchmarking between the PDT and EMT models is only requested for selected tests. NYISO recognizes that this is a fluid topic with IEEE 2800.2 and the recent NERC alert proposing test procedures to help facilitate conformity evaluation, so new processes to address that may emerge in the future.

Is Rule B5 applicable from Calendar Year 2023 onwards? What is the expectation from IBR projects submitted before that time? Does NYISO still expect an EMT model?

Correct, if you read Rule B5, it says it is applicable to projects in the interconnection studies process. Plants already in commercial operation are not asked to comply with it. The expectation for existing IBR plants remains unchanged and guided by the NYISO Tariff and manuals, local TO requirements, and applicable NERC, Northeast Power Coordinating Council (NPCC) and NYSRC rules and standards. The NYISO tariff grants NYISO the ability to request EMT models (or studies) from any market participant. EMT models were not requested until recently but given the significant volume of new IBR plants interconnecting to the system, having accurate EMT models of existing IBR plants is important. Those models are useful not only for system reliability studies, but also when there is a need to study new IBR plants connecting near existing ones.

Please elaborate on how NYISO enforces changes/upgrades to the IBR plant or network when the studies are occurring post-GIA? The developer has a signed GIA, so how do you enforce requiring changes at this late phase?

NYISO has requirements that every time a change occurs at the facility, a new model must be provided and additional studies may be needed. NYISO recognizes that settings changes do occur throughout the interconnection process. Things are likely to change, so it is hard to set a firm date on when changes can no longer occur. The requirements in the NYISO manuals and tariff require developers to report changes and a new study cycle may be initiated.

NYISO has not adopted IEEE 2800-2022, Clause 10 (Modeling Data). Does NYISO intend to adopt this clause in the future along with tests specified in IEEE P2800.2? If not, what

would need to change in IEEE 2800-2022 or IEEE P2800.2 for NYISO to be more inclined to adopt the 2800/.x framework and tests?

NYSRC Rule B5 adopts most of IEEE 2800-2022 and made modifications to clauses that NYSRC thought needed adjustment. Clause 10 has not been adopted as part of Rule B5. NYISO has started collecting EMT models so, to an extent, is already doing part of what Clause 10 asks. Complete adoption of Clause 10 remains a topic of discussion. Adoption of IEEE P2800.2 (or a slightly modified version of it) seems like a natural step for NYISO given that NYISO/NYSRC adopted most of IEEE 2800-2022 requirements through rule B5. Currently NYISO is not asking for model validation steps to be performed, and this is a critical step in ensuring models capture actual equipment behaviors. This remains a fluid topic of discussion. NYISO will issue public statements when more details can be shared.

There appears to be a lot of focus on "validation" but not nearly as much focus on "verification". What do the presenters think about this?

The state of the art IBR modeling is rather good, particularly model validation at the IBR unit level when done correctly (e.g., using DLL real code wrapper standards). It is useful to do validation both at the IBR unit and IBR plant level to identify issues, fix modeling or site errors, etc. However, the much larger gap is verification right now. There are many instances where the models simply do not match the as-left settings, configuration, controls, protections, etc., at the site. This completely invalidates the model and makes validation efforts meaningless and/or much more difficult. The process of verification is not straightforward and standardization in this area is needed. Verification should be a 5-minute exercise, but it presently is a spiderweb across settings, models, and documentation. Industry harmonization and ideally standardization would be very impactful for industry practitioners.

Regarding identifying weak system, what is the main advantage and features of the mentioned commercial software over various SCR-based methods?

Traditional SCR based metrics become unreliable in medium-to-high penetration IBR scenarios. SCR does not consider the impacts of nearby IBRs. Weighted SCR (WSCR) can consider nearby IBRs but 1) assumes they are all interacting in unison (overly conservative), and 2) requires discrete selection of which IBRs to include in the calculation which can arbitrarily skew the metric one way or another. New tools are a highly-scalable implementation of SCR with Injection Factors (SCRIF) (see Cigre WG B4.62 *Connection of wind farms to weak AC networks* (2016)), with the modification of setting device-dependent source impedances to distinguish between short-term voltage control ability of various resources. It accounts for nearby IBRs according to the voltage coupling between POIs, which can also be defined as off-diagonal impedance elements in the equivalent reduced impedance matrix.

Key Themes

- NYISO continues to evolve and enhance its IBR modeling requirements in response to FERC Order 901 and NYSRC Rule B5, emphasizing alignment with NERC's broader vision. The approach seeks to balance improved model fidelity and reliability benefits against potential delays in achieving commercial operation dates, which directly affect resource adequacy and system security margins.
- EMT modeling is becoming a core requirement for all new and existing IBR plants in New York, but NYISO is treating EMT studies as a cyclical process rather than a one-time step. Studies are being conducted later in the interconnection process, with screening tools developed to identify which IBRs require more detailed analysis and ongoing updates through construction and prior to COD.
- Case studies highlight gaps between verified EMT models and actual equipment behavior, underscoring the importance of commissioning-based model verification and ongoing validation. Challenges such as inconsistent naming conventions, unrealistic generic PPC models, and OEM tuning that resolves one test but breaks another all point to the need for more comprehensive and standardized validation frameworks.
- Verification of models against as-left settings remains a significant industry gap compared to validation. Without ensuring that models truly reflect installed equipment, protections, and settings, validation efforts become far less meaningful. Efforts like the conceptualized framework of the standardized ".IBR" mapping file aim to streamline and harmonize this process, making verification efficient and practical across OEMs.
- Industry progress includes adoption of IEEE 2800-2022, growing use of DLL "real code" wrappers, and increased reliance on CHIL validation, but OEMs face resourcing and proprietary-data barriers that limit the availability of accurate, project-specific models. Data management and version control are increasingly critical as models evolve through plant design changes, highlighting the need for structured repositories and automation.
- Looking forward, automation and improved screening tools are viewed as essential to making EMT studies more accessible and less expert-dependent. Enhancing PPC modeling, incorporating plant communication delays, and applying commercial-grade screening methods for weak systems and SSO risks will elevate study quality and help ensure that BPS decision-making reflects the real performance of IBRs under diverse operating conditions.

October 21, 2025 Virtual Meeting

Challenges with IEEE2800-2022, Planned Revisions (~215 attendees)

Presentation recording and slides are available to download here. Figure 30 shows the makeup of meeting attendees by industry sector:

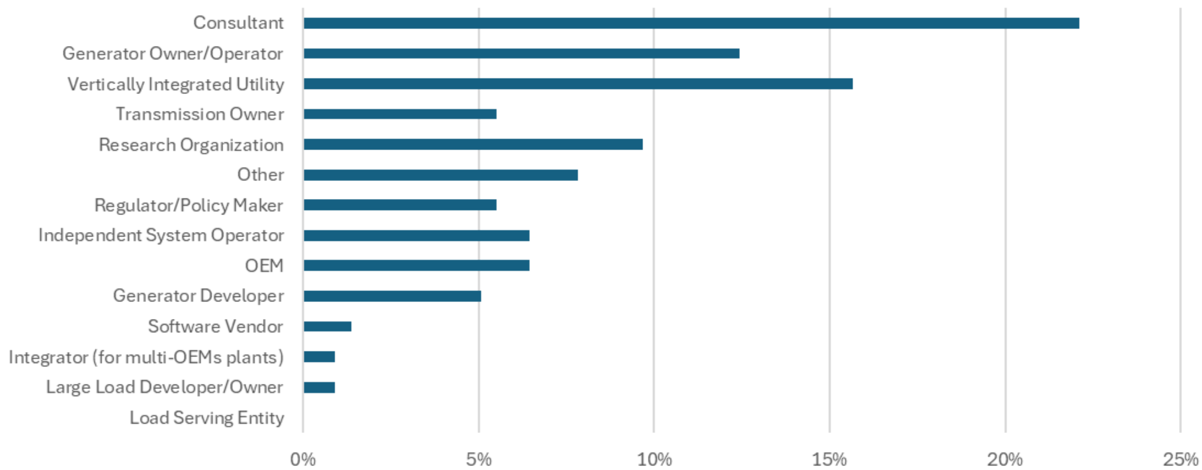

Figure 30: Meeting attendees by industry sector

This sixth meeting of Season 2 of the DOE i2X FIRST initiative focused on challenges with IEEE 2800-2022, ongoing IEEE P2800.2 recommended practice developments, and new efforts starting to revise IEEE 2800-2022 and initiate new projects related to grid forming (GFM) inverter technology as it relates to the standard. Presentations included the following:

Andy Hoke, National Renewable Energy Laboratory (NREL)

Andy provided an overview of the evolution, technical content, and implementation status of IEEE P2800.2, which provides recommended practices for test and verification procedures for inverter-based resources (IBRs) connecting to the transmission and sub-transmission system. The draft set of practices are closely tied to the foundational standard IEEE 2800-2022, which defines the minimum performance and capability requirements for applicable IBRs.

IEEE P2800.2 is current in the IEEE Standards Association (SA) ballot process and is expected to finish in late 2025 with publication in early 2026. The P2800.2 working group has over 170 voting members and over 50 non-voting members, with all major stakeholder groups represented (see Figure 31). The ballot group represents all key stakeholder groups and is not dominated by any one group. Initial ballot results back in June had an 87% approval rate, which exceeds the 75% threshold to pass. However, the working group continues to refine and improve the standard based on the comments received.

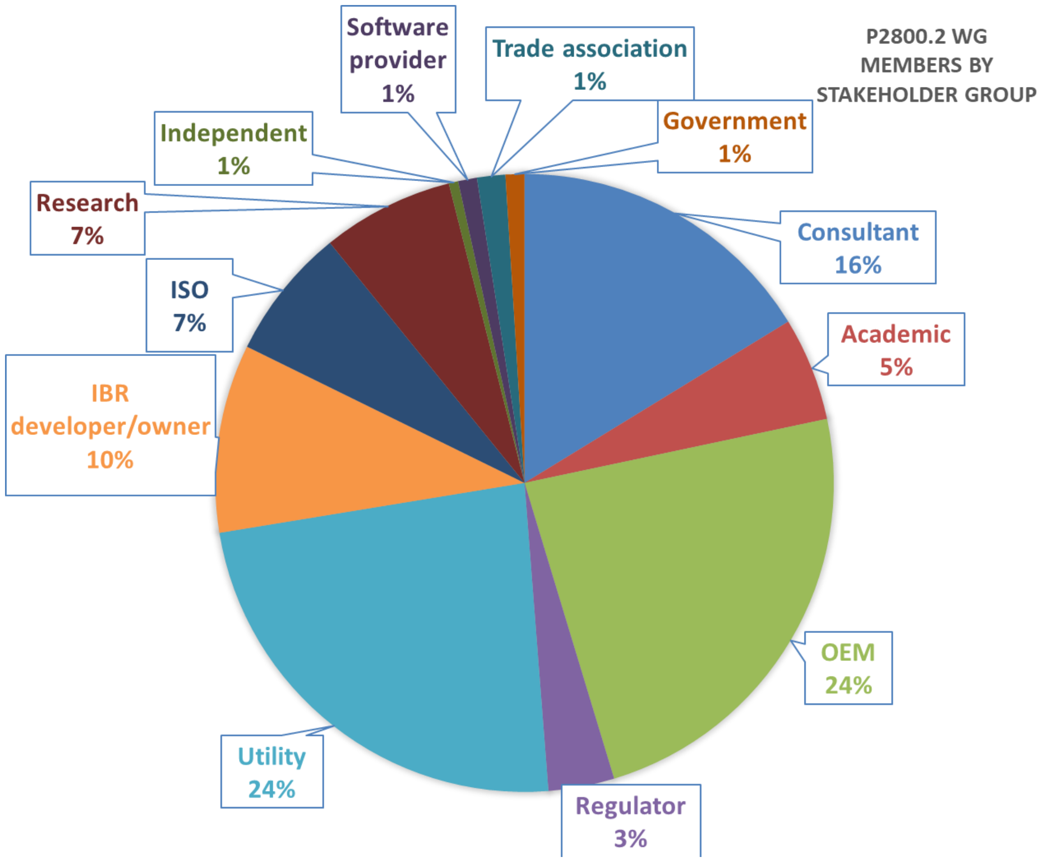

Figure 31: IEEE P2800.2 Working Group Members by Stakeholder Group (Source: IEEE)

The working group received 778 comments during the initial ballot and the Comment Resolution Group (CRG) of the working group – a group of 33 industry experts (the IEEE P2800.2 leadership team plus 13 additional invited subject matter experts) – has completed their review to address those comments. Most comments focused on type testing and IBR plant design evaluations, with a few notable themes:

- **Prescriptiveness vs. Flexibility:** The working group debated whether type tests and IBR plant design evaluation tests should be prescriptive for uniformity and efficiency or flexible for user interpretation; Draft 4.0 of the standard is now somewhat more prescriptive than the prior draft following comment resolution.
- **Type Tests:** Expanded detail and clarity with new tables, figures, and more rigorous frequency and ROCOF ride-through testing, while retaining general flexibility.
- **Design Evaluation:** Slightly lowered model validation rigor, and removed the partial framework for quantitative IBR unit model validation – model validation is only qualitative in Draft 4.0 now. The guidance regarding non-aggregated models was moved to an annex and the draft retained the option to use either a simple test system or detailed real-grid test system.

- **Commissioning Tests:** Broadened scope with added voltage feedback, reactive power control, and power factor control tests, but maintained adaptability and declined alignment with specific regulatory frameworks.

The working group is expecting the timeline to publication as shown in Figure 32.

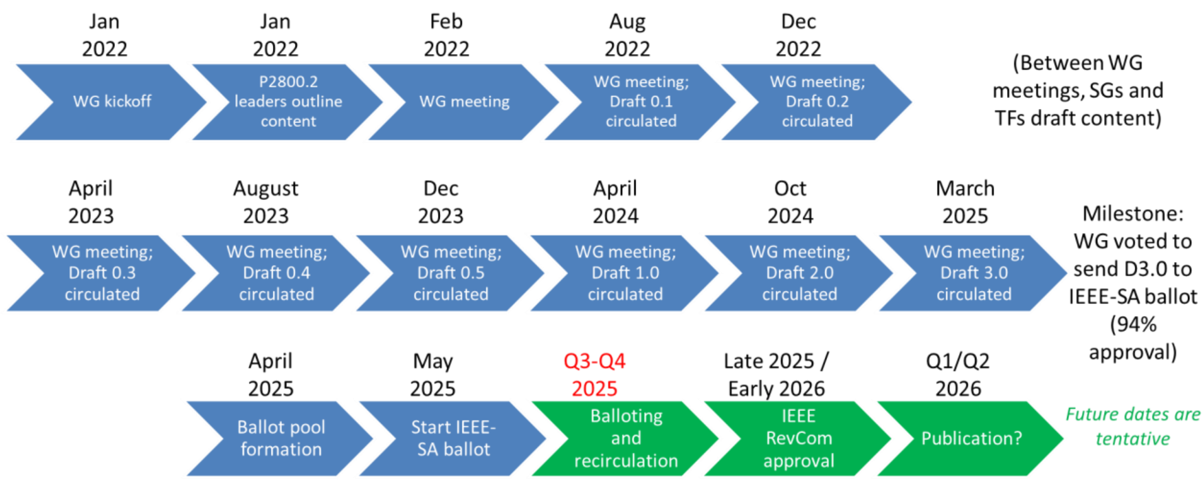

Figure 32: IEEE P2800.2 Working Group Timeline to Publication (Source: IEEE)

Manish Patel, Silicon Ranch

Manish provided a detailed review of potential areas of concern and issues to consider for a future revision of IEEE 2800-2022, including:

- Reactive power capability requirements (Clause 5.1)
- Voltage and reactive power control mode (Clause 5.2)
- Voltage ride-through capability requirements (Clause 7.2.2.1)
- Transient overvoltage ride-through requirements (Clause 7.2.3)
- Consecutive voltage deviation ride-through capability requirements (Clause 7.2.2.4)

Regarding reactive power capability (Clause 5.1), the clause states that the IBR units shall have the capability to provide reactive power support when the primary energy source is available and not available. It is recognized that this should likely be a requirement on the IBR plant, and not the IBR units directly (as the standard language currently seems to suggest). Further, the IBR plant is not required to operate at zero reactive power when voltage is greater than V4; however, the IBR plant is required to operate at zero reactive power when voltage is less than 0.95 pu (see Figure 33). Thus, additional considerations and adjustments may be needed to the capability curve.

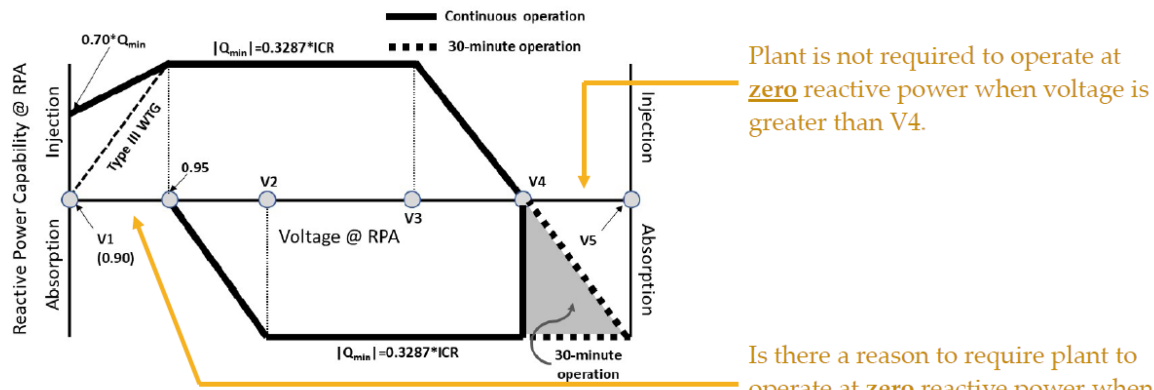

Table 4—RPA voltage range[a]

TS nominal voltage at the RPA	V1 (p.u.)	V2 (p.u.)	V3 (p.u.)	V4 (p.u.)	V5 (p.u.)
< 200 kV	0.90	0.99	1.03	1.05	1.10
≥ 200 kV except 500 kV and 735 kV as below	0.90	1.00	1.04	1.05	1.10
500 kV	0.90	1.02	1.06	1.10	1.10
735 kV[b]	0.90	1.02	1.06	1.088	1.10

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Figure 33: Annotated IEEE 2800-2022 Clause 5.1 Reactive Power Capability Curve (Source: IEEE)

Regarding voltage and reactive power control modes, Clause 5.2.2 includes confusing use of “reference value” and “RPA voltage set point” that may lead to the inability to meet the requirements depending on voltage droop and pre-event reactive power output. Additionally, the clause also uses the term “reactive power droop” whereas some Transmission Planners require voltage droop control and the standard may want to consider allowing this. Lastly, Table 5 of IEEE 2800-2022 includes a reaction time requirement and some individuals have argued that this time may need further clarification regarding if the measurement time is included or not in the reaction time requirement.

In Clause 7.2.2.1 regarding voltage disturbance ride-through requirements, the voltage versus cumulative time curve and table may be misunderstood by some and may need additional clarification. It is the intent of the working group that this requirement be interpreted as a voltage versus time curve wherein for a given voltage, the IBR plant shall not trip until the duration at this voltage exceeds the ride-through curve capability. Based on this understanding, one interpretation of the voltage ride-through requirement is that a wind plant, for example, must withstand a single voltage disturbance event where the voltage drops to zero at time t=0 and then gradually recovers following the curve steps. Additionally, there are some differences between IEEE 2800-2022 Clause 7.2.2.1 and NERC PRC-029 Attachment 1 Item #7. For a voltage that remains below 0.7 pu for 2.0 seconds and below 0.9 pu for 3.5 seconds, the IBR plant is allowed to trip per IEEE 2800-2022 but not allowed to trip per NERC PRC-029-1 based on the interpretation of the requirements. This may cause inconsistencies and difficulties meeting both distinct standards in situations where both apply.

Regarding transient AC overvoltage (TOV) requirements in Clause 7.2.3, the requirement applies at the point of measurement (POM); however, TOV protection is not applied at the POM and is usually included in IBR units (at the point of connection (POC)) to protect their power electronics. Hence, it is important to understand how TOV at the POM is reflected down to the POC. It is unclear whether an aggregate model is sufficient to study this or if a detailed non-aggregated model would be needed. Regardless, the IBR plant is allowed to trip if TOV is above the specified threshold for a duration longer than specified even if the fundamental frequency phasor component of the applicable voltage is within the mandatory or continuous operation region. One of the key challenges to this requirement is how to demonstrate conformance with the TOV ride-through requirements.

Some individuals have articulated that the consecutive voltage deviation ride-through capability requirement in Clause 7.2.2.4 is too complicated and impractical to test so many different scenarios. Furthermore, the consideration of energy displacement during faults and post-fault active power recovery is key for certain technologies. There are challenges with voltage source converter (VSC) high voltage DC (HVDC) connected IBRs typically used for offshore wind plants and certain Type 4 wind turbine generators (WTGs). IEEE 2800-2022 includes an exception only for IBRs connected via VSC HVDC due to limitations of the DC chopper to absorb energy, which can affect ride-through behavior, the balance of active/reactive current during the fault, and post-fault active power recovery.

All these issues are being documented in various ways and are planned to be included in the subsequent revision of IEEE 2800-2022.

Jens Boemer, Electric Power Research Institute (EPRI)

Jens shared forthcoming revisions to IEEE 2800-2022 and the development of a new IBR recommended practice for GFM equipment. The IEEE Power and Energy Society (PES) Wind and Solar Power Plant Interconnection and Design Subcommittee (WSPPID-SC), under the Energy Development and Power Generation (EDPG) Committee, is the parent subcommittee of the Inverter-Based Resources Interconnection Working Group (IBRI-WG), which houses the IEEE 2800-2022 standard efforts and IEEE P2800.2 recommended practice developments. As the IBRI-WG begins to embark on revisions to IEEE 2800-2022, they are encouraging anyone interested in participating to sign up if they are not currently part of the IEEE P2800.2 effort (those individuals part of IEEE P2800.2 efforts will automatically be included in the subsequent efforts). A direct link to express interest in the IBRI-WG in IEEE myProject is here.

Stakeholders have asked for a revision cycle in the following areas:

- IEEE P2800a: IEEE 2800-2022 will be modified to reduce potential barriers to GFM technology adoption through an amendment process, and this topic has been identified as the most urgent.

- IEEE P2800.1: Specifications for optional GFM equipment capability and standardized performance will be established in a Recommended Practice document,[12] which will be deemed the IEEE P2800.1.
- IEEE P2800: A full revision effort to IEEE 2800-2022 will commence based on industry learnings during adoption thus far.

The IEEE P2800.1 project on GFM IBR equipment will also need to align with the other IEEE 2800/.x series of documents and thus the main standard will also need to be revised so as not to preclude the technology from being unable to meet the requirements applicable to all IBRs. This effort will need to evaluate the grid services provided by varying types of GFM technology as the future GFM recommended practices are developed. Additionally, a list of various clauses have been identified as a starting point for alignment between the IEEE P2800a, IEEE P2800.1 and IEEE P2800 efforts. There are also some plans to align with the IEC (International Electrotechnical Commission) and its efforts, where possible.

For the time being, adoption of IEEE 2800-2022 is still strongly encouraged as it establishes a solid baseline of IBR plant capability and performance requirements. After the forthcoming revisions are complete, industry may need to update their requirements to reflect the new version(s) of the standard. It is expected that the IEEE 2800 series of standards will undergo continuous learning and improvements, which should not deter any transmission provider or other authority governing interconnection requirements (AGIR) from adopting the latest version of the standard.

Q&A and Interactive Group Discussion

In addition to type testing of IBR units, is type testing of PPCs included in IEEE 2800.2? How do the considerations/type tests differ in that case?

IEEE P2800.2 includes type tests for IBR units (i.e., turbines/inverters) and PPCs. The same general concepts apply to validate these models.

ERCOT now requires type test results (control hardware in the loop (CHIL)) of PPCs or real code models of PPCs. What does IEEE P2800.2 say about this? And how should industry think about this for legacy and new projects?

CHIL testing and/or real code models are recommended. IEEE 2800-2022 is designed as a forward-looking standard and not intended to be applied retroactively to existing facilities. Industry may be adopting portions of the standard differently, which may result in challenges and obstacles.

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[12] IEEE Standards are documents that specify mandatory requirements (i.e., “shall) whereas Recommended Practices are documents in which procedures and position preferred by the IEEE are presented (i.e., “should”).

How many individuals submitted comments to the IEEE P2800.2 initial ballot?

About 40 people submitted comments (most people voted without commenting). As the working group moves into recirculation ballot, the group will look for ways to wrap up the work and try to avoid making major changes.

The original IEEE P2800.1 was the entity-based test and verification effort. Did that effort get replaced with this new effort? What are the processes/procedures?

Yes, the original IEEE P2800.1 entity-based project expired and no progress was made. Thus the.1 came available again, and the working group decided to use the opportunity to apply the .1 for the forthcoming GFM recommended practice effort.

ERCOT, MISO, and others already published GFM requirements. How does the working group envision the new IEEE requirements aligning with existing ones?

The idea is that the GFM task force under the IBRI-WG will review all requirements in North America and some internationally and to the extent that the group agrees on equipment-level requirements or recommended practices, they can be published as such. However, note that what will be published are recommended practices and entities can adopt as they see fit.

Please explain the benefits of harmonization between IEEE and IEC standards.

This is an aspirational goal by the IBRI-WG to coordinate with IEC. One of main drivers is that IBRs are a global market and OEMs design products for all markets and build in capabilities to design for regional configurations. These IBR often use the same hardware platform with different software versions. So, to the extent possible, such interconnection requirements should be globally coordinated and enable a more streamlined set of product offerings across markets.

Other regions around the world have already developed significant experience with GFM and how the technology can be utilized. Breaking down requirements for capability and performance and sorting out what are capability versus utilization requirements is essential.

When will the recirculation ballot for IEEE P2800.2 start and for how long will it be open?

The recirculation is expected to start the last week of October 2025 and will last 21 days.

How is the IBRI-WG deciding to make changes to IEEE 2800-2022?

The group has an informal list of potential items to change or fix in IEEE 2800-2022 based on feedback from industry thus far, including feedback from the i2X FIRST forum. Ultimately, what gets changed will be decided by the working group.

What is the rationale for different reactive power requirements for Type 3 and Type 4 wind turbines? There are type 4 wind turbines without any reactive power capability below cut-in wind speed.

The presenters noted that the justification was that Type 4 wind can easily be designed to provide reactive power at zero active power, just like a solar PV or BESS. In contrast, it is more difficult to design a Type 3 WTG to provide reactive power at very low active power. However, this is one of the requirements that some want to change in the revision to IEEE 2800-2022. Some of the currently available Type 4 wind turbines do not offer any reactive capability at zero wind.

Describe the term "utilization requirement" (in the context of GFM).

IEEE 2800-2022 front matter has informative notes describing differences between capability requirement, performance requirement, and utilization. Utilization is outside the scope of IEEE 2800-2022. However, it can relate to GFM performance and capabilities; for example, a GFM-capable inverter that provides response to voltage phase angle jump may require the inverter to adjust active power instantaneously. Inverter may be capable of this design, but it may not be able to deliver this active power if it is already operating at its maximum active power level. So, it is hard to differentiate what is about design of equipment and what is about utilization of equipment to deliver specific services. Utilization is outside scope of the IEEE 2800 series but may need further clarification in the context of GFM.

How can we better educate Utility Regulators on evolving IBR technology capabilities, requirements developments, and how changes are being made to address these?

The presenters talked about alignment, education, information sharing, etc. ESIG serves as a forum to provide such education, and there may be opportunities to coordinate with the National Association of Regulatory Utility Commissioners (NARUC).

Key Themes

- **IEEE P2800.2 Toward Publication:** The IEEE P2800.2 Working Group is nearing completion of recommended practice for testing and verification of applicable IBRs. The initial draft received 87% ballot approval and nearly 800 comments—most centered on type testing and design evaluation. The group continues refining the document, targeting publication in early 2026 following recirculation.
- **Balancing Prescriptiveness and Flexibility in Testing and Design:** A central theme throughout the P2800.2 development is the balance between standardized, prescriptive testing for uniformity and flexible approaches that accommodate diverse technologies. The latest draft (D4.0) modestly increases prescriptiveness for type testing while keeping space for user interpretation in design and commissioning evaluations.

- **Emerging Lessons and Gaps in IEEE 2800-2022 Implementation:** Experience with IEEE 2800-2022 has surfaced areas needing clarification—particularly in reactive power capability, voltage and reactive control modes, and ride-through requirement definitions. Misinterpretations of key clauses, complexity of other clauses, and alignment issues with NERC PRC-029 have revealed inconsistencies that can complicate compliance. These insights are shaping the next revision cycle to make the standard more practical and consistent with system operator expectations.
- **Upcoming Revisions and New Efforts on GFM Technology:** Parallel to the P2800.2 ballot, IEEE is launching three new efforts that will continue to refine and reshape the IEEE 2800 series of standards: P2800a to reduce barriers for GFM adoption, P2800.1 to define equipment-level requirements for GFM equipment, and a full revision of IEEE 2800-2022 to align all related standards.
- **Importance of Global Harmonization and Regulatory Education:** IEEE and IEC are attempting to coordinate efforts, although noted as "aspirational." IBR technology and manufacturing are global efforts. Thus, aligning international standards reduces cost, complexity, and regional divergence in product design. Participants also emphasized the need to better educate regulators and policymakers about evolving technical standards.
- **Industry Participation and Continuous Improvement:** The IEEE IBRI-WG is encouraging broad participation in ongoing and future projects. Stakeholders were reminded that adoption of IEEE 2800-2022 should continue even as revisions are underway, since each iteration builds on lessons learned. The evolving IEEE 2800 series is intended to be a "living framework," continuously refined to reflect advancements in technology, modeling, and system reliability practices.

November 25, 2025 Virtual Meeting

Change of Management during IBR Plant Interconnection Process and Commissioning, How to Maintain Conformity (~175 attendees)

Presentation recording and slides are available to download here. Figure 34 shows the makeup of meeting attendees by industry sector:

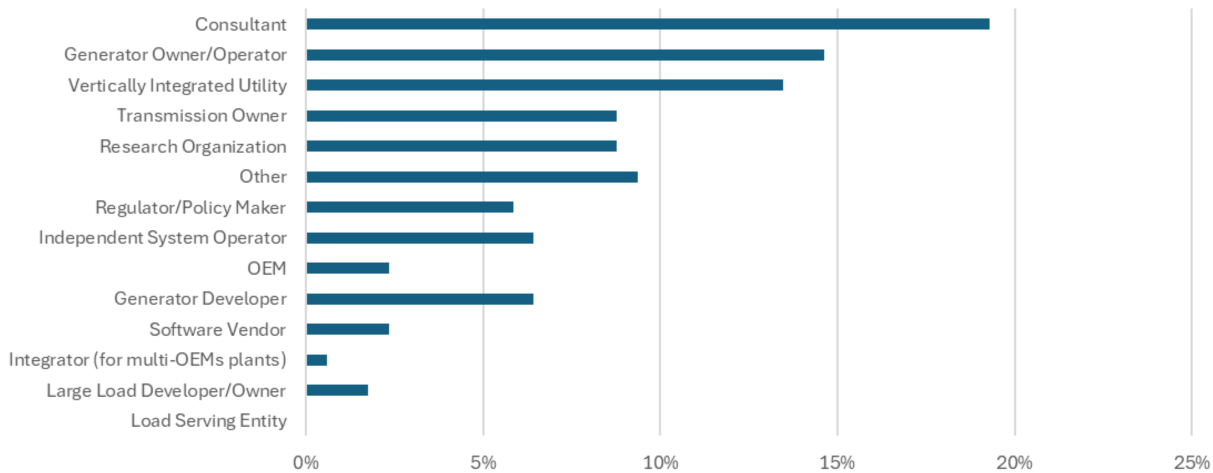


Figure 34: Meeting attendees by industry sector

This seventh meeting of Season 2 of the DOE i2X FIRST initiative focused on IBR plant change management during the interconnection process and commissioning and how to maintain conformity throughout that process. Presentations included the following:

Katie Iversen, Joseph Parry, Andrew Lopez, AES

The AES team shared their perspectives regarding the importance of verifying inverter and PPC settings, alignment of models and field implementation, and how standardized processes can reduce friction across OEMs, contractors, and internal teams. They highlighted that this effort supports grid reliability, helps IBR plant developers achieve project success for commercial operation, supports operational performance and regulatory compliance, and improves productivity and resource management.

The "as studied" models need to match the "as commissioned" configuration of the site for many reasons and this can be an overlooked area during commissioning activity; thus, focused attention during commissioning to ensure site parameterization matches the studied models, and that any discrepancies are addressed effectively, helps meet utility and regulatory obligations. Allowing these discrepancies to persist can be costly, lead to risks during commercial operations, and may undermine compliance efforts.

While standard library models are still widely used, they often deviate significantly from actual equipment behavior. They do not have a close correlation to actual equipment settings (controls and protection). On the other hand, EMT and UDMs more closely match the actual inverter/PPC settings and make verification efforts easier so long as those settings are made available to the user/IBR plant developer. It is important to have requirements for IBR plant performance and model/simulation requirements and reviews.

Inverter settings have a lifecycle (see Figure 35) that evolves from the early-stage equipment selection, equipment capabilities, and site-specific project needs. These settings may change to reflect the IBR plant performance requirements for a specific region. This involves working with the OEMs to iterate and tune the inverter settings. Those settings (model and actual) get approved by the utility/ISO and serve as the baseline for commissioning efforts. However, those settings may change during commissioning and also may change during commercial operations intentionally or unintentionally.

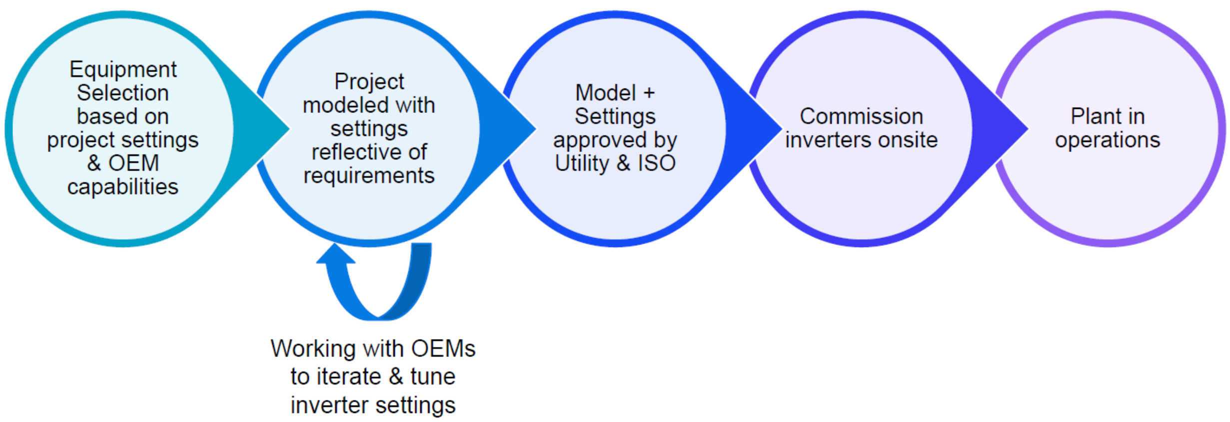


Figure 35: Inverter Setting Lifecycle (Source: AES)

The AES team recognized that the inverter setting lifecycle is not a linear process prior to equipment selection, which may include parts of the interconnection process. Prior to equipment selection, best efforts should be made to gather reasonable information about the project; however, this information may not exist, and more generic information is often used. Once equipment has been selected, settings should not deviate from the selected and approved values; otherwise, this may pose risks to project success.

To address variability across OEMs' models, platforms, file types, etc., AES requests deliverables from inverter OEMs that include documentation of, approval of, and visibility into inverter parameters (see Figure 36). This includes an inverter settings statement after the model is studied and approved which converts the model and inverter settings into a digestible list that is used for commissioning efforts. It also includes an on-site parameter verification process that verifies the approved parameters are uploaded on the actual equipment. Lastly, it includes

SCADA integration to capture some of these settings into the SCADA alarming and historian for improved visibility, compliance support, and traceability of settings.

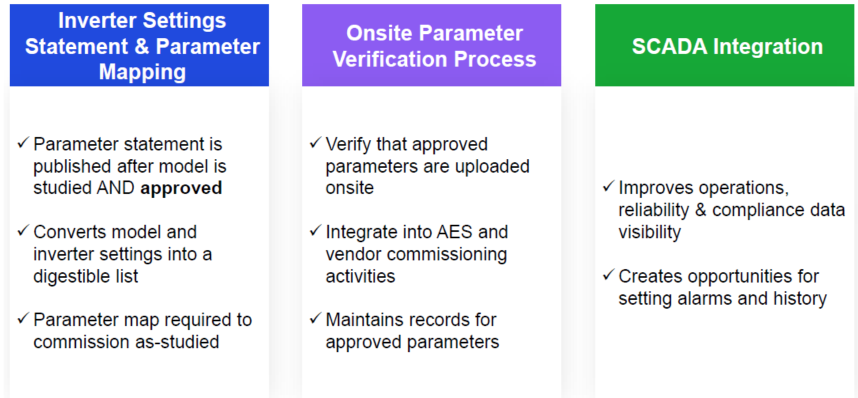


Figure 36: Deliverables for Inverter OEMs (Source: AES)

AES is focusing on ensuring modeling accuracy throughout the commissioning process and has developed a timeline to reduce commissioning friction by identifying critical checkpoints for parameter upload, verification, and onsite download (see Figure 37). This approach creates a division of responsibilities between the internal modeling team, OEM(s), commissioning engineers, and project engineers. The goal is to maintain alignment between the approved models and what gets implemented in the field. At the beginning of the process, the verified parameter list is uploaded to the equipment and then immediately downloaded for verification. Furthermore, at inverter hot commissioning[13] and IBR plant testing phases, the settings are again downloaded and re-verified.

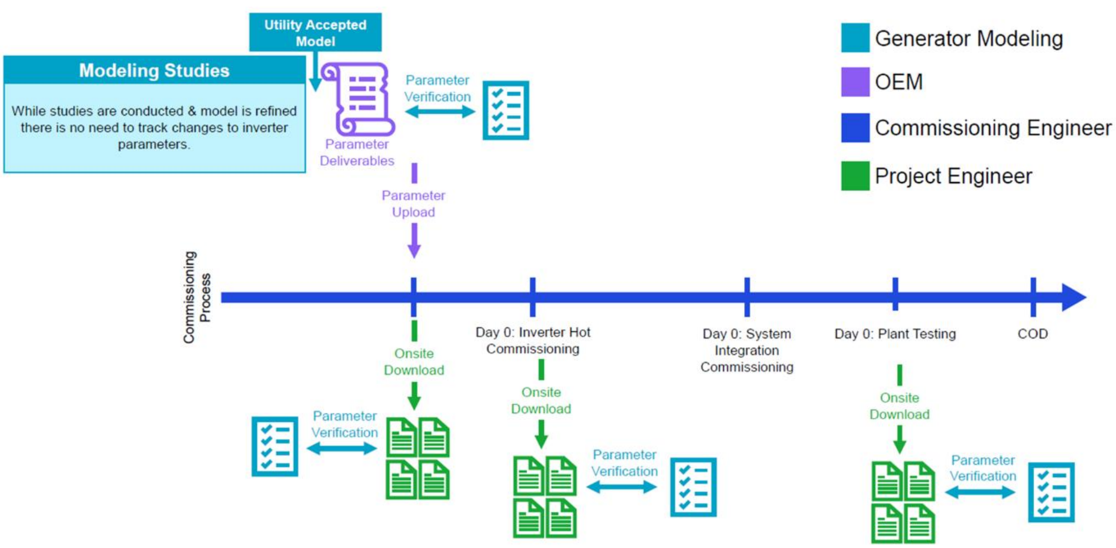


Figure 37: Key Milestones for Modeling and As-Left Setting Verification (Source: AES)

[13] Phase of commissioning where an inverter is tested while energized and connected to its DC source or the grid.

AES has had experience with this approach, identifying situations where parameters were inconsistently pushed to inverters at an IBR plant. Most inverters had the correct settings, but one set of inverters was configured with different settings unexpectedly. Their IBR plant verification practices and systems were able to help them quickly identify and address this issue on-site.

The presentation concluded with key takeaways for IBR plant developers, owners, and operators:

- Standardize grid reliability settings such as ride-through parameters and voltage/frequency control settings, and file types (OEMs, industry groups, developers)
- Improve interconnection processes and IBR plant model reviews (transmission planners)
- Standardize access to inverter settings and settings change alerts (OEMs, industry groups)
- Focus on change management for inverter/PPC firmware and software updates (OEMs, developers/owners)

Miguel Cova Acosta, Vestas

Miguel shared OEM perspectives regarding change management during the IBR interconnection process. Changes in personnel, ownership, and project management during the interconnection and commissioning of IBR plants can jeopardize grid code conformity, which is not a single milestone. Rather, maintaining grid code compliance is a responsibility spanning early development, contracting, engineering, construction, commissioning, and commercial operation (see Figure 38). Each phase introduces players including sales teams, project developers, EPCs, OEM engineering groups, grid operators, and service teams. Handoffs create potential for misalignment or misinformation, yet a successful project maintains continuity through these transitions.

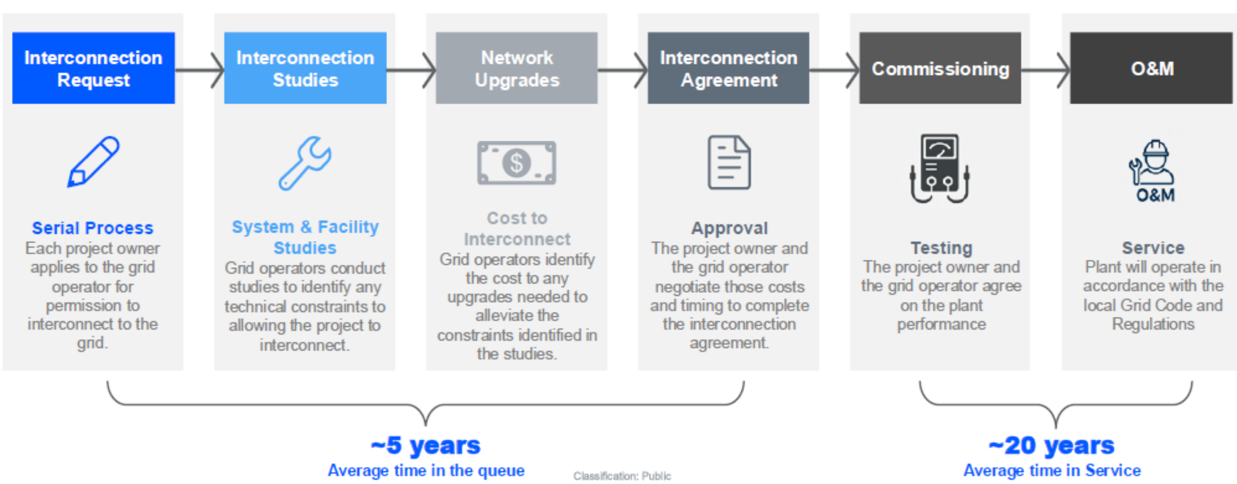


Figure 38: Interconnection Process Overview from OEM Perspective (Source: Vestas)

One challenge in maintaining grid code compliance is that the grid code often applies at the IBR plant POI rather than individual turbines/inverters and thus the OEM is generally not directly responsible for grid code compliance. Meeting requirements at the IBR unit-level does not guarantee compliance at the point of common coupling for the inverters because of the collector system and other design decisions. Long feeders, weak grid conditions, low system inertia, series compensation, control interactions, and other factors can significantly affect the electrical response at the POI and thus the IBR plant must be evaluated as an entire resource connecting to the grid.

There are several areas where change management can go wrong, as illustrated in Figure 39. Early-stage design decisions and specification misalignment can result in equipment selections and/or configurations that do not match the actual grid code requirements or grid needs. These may be based on commercial urgency rather than technical reality and have long-term consequences that resurface later in the process. Drift between the actual product decisions and the models used for grid code evaluation and reliability studies can also create conflicts or issues during commissioning or with the transmission provider. Deviations of as-sold or as-left settings from the approved models can result in noncompliance. Communication and handoff challenges exist between teams and entities. Lastly, human factors such as turnover, lack of training, misinterpretation or misunderstanding of equipment capabilities, and other factors all lead to areas of concern. Clear and effective OEM deliverables throughout the full IBR plant lifecycle help overcome these challenges.

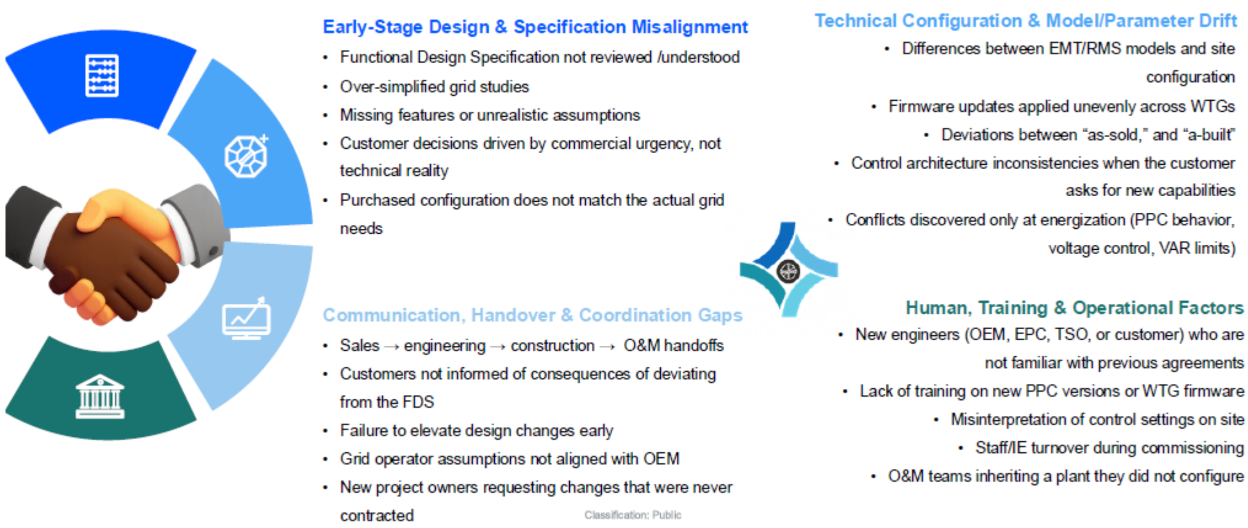


Figure 39: Areas Where Change Management Can Go Wrong (Source: Vestas)

Rigorous early-stage electrical design and well-developed foundational documents are critical because later-stage issues often stem from gaps or misunderstandings early in the process. Maintaining consistency between models and as-built plant configuration/settings is essential for grid code conformity as even small deviations in controls, parameters, or firmware can compromise commissioning. In practice, challenges arise from coordination breakdowns across

EPCs, OEMs, owners, and grid operators. Continuity and competency across all involved teams have a major influence on project success. Strong OEM involvement across the entire lifecycle helps preserve design integrity and long-term grid compliance requires ongoing verification to keep documentation, models, and field settings aligned.

Patrick Hart, Mortenson

Patrick shared EPC perspectives on managing change during the interconnection and commissioning of IBR plants and emphasized that changes occurring throughout the process (before or after commercial operation) can affect compliance, performance, and long-term project viability. The EPC must play an active role in design, coordination, and compliance to ensure projects stay aligned with evolving grid code requirements. Prior to COD, transitions bring more work and higher timeline risk but offer greater flexibility to address early. For example, changes in IBR plant configuration, metering locations, communication protocols, settings, control modes, etc., can be reconsidered and ensure that the equipment is physically capable of such changes. After COD, however, changes are more challenging and may not be practical with the equipment installed. In either case, detailed documentation, knowledge of interconnection requirements, and understanding of exemptions or other practical design considerations are essential.

Post-COD owners should never assume a project is compliant; instead, they should independently review and verify commissioning test results, assess operational data, and verify whether warranties, service agreements, and OEM support are intact. Patrick shared recommended practices for maintaining compliance through transitions:

- **OEM Compliance:**
    - Verify NERC compliance such as ride-through capability and operation, reactive power capability, active power performance, recording capabilities, protective relays, and other features.
    - Ensure equipment capability and performance meets NERC and utility interconnection requirements.
- **Operational Compliance:**
    - Understand operation of the facility, particularly for hybrids, multi-phase projects, and co-located sites.
    - Verify critical documentation such as control narratives, commissioning test plans and results, operational manuals, maintenance manuals, and cybersecurity plans and protections.

- **Financial Performance:**
  - Verify ratings, degradation estimations, capacity factors; determine storage energy/power overbuild, expected derating conditions, augmentation options.
  - Analyze operational data and equipment performance such as fault performance, serial defects, offending unit(s), etc.

From an IBR plant buyer perspective, conduct rigorous compliance gap analysis against NERC and IEEE standards to compare facility design with compliance obligations. Ensure stricter cybersecurity requirements are met. Ensure OEM and EPC engagement throughout the process. Plan for any necessary upgrades in situations where gaps may exist.

Q&A and Interactive Group Discussion

Equipment selection may come well after dynamic models are required by the utility/ISO. Can you elaborate on how this should be handled from an IBR developer perspective?

This is a complex issue, and a truly linear process only begins once the inverter selection is finalized, but the early design stage carries significant variability. Iterative reviews are unavoidable—early-stage iterations simply help ensure the IBR plant developer presents the strongest initial case while later iterations refine project settings and validate them through testing. When equipment selection is still open, the IBR plant developer coordinates closely with the development team to narrow options to IBR technologies that can pass interconnection model acceptance tests and other requirements. Once the equipment is locked in during execution, the IBR plant developer repeats those tests with actual design data.

A common misconception is that early-stage projects lack sufficient detail to justify meaningful analysis, so the effort seems premature. In practice, early analytical discipline sets the project up for success during execution by clarifying what questions must be answered and what model information is required across stakeholders. As noted, a linear approach cannot fully capture the interplay between equipment selection and settings validation. The reality is that iterative analysis is unavoidable as early design details mature. Above all, the execution team and the interconnection team must stay tightly aligned for the process to work.

What specific interoperability protocols and data formats are used to integrate inverter settings with the SCADA system? How is data being extracted out of the inverter and how is that communicated to SCADA? Is there opportunity to identify situations where firmware updates are causing inadvertent settings changes?

Secure File Transfer Protocol (SFTP) is being evaluated since it's already used for other functions like data reporting to the ISO. Inadvertent changes are exactly the type of situation the IBR owner is looking to identify proactively along with regular downloads of inverter settings and timely notifications from OEMs about updates. SCADA values can be verified before and after changes occur. Alarms can be programmed to flag setting changes without relying on OEM notifications, though those are still preferred.

When a firmware update requires inverter setting changes, the OEM must communicate those updates to the developer. Once a change is identified, the IBR owner confirms the changes meet the requirement, coordinates with the modeling team to update the model(s), revalidates performance to ensure it still passes applicable tests, and then communicates the changes back to the utility. Increasing on-site verification can improve visibility into errors, erroneous settings, etc., and corrections can be made before they lead to grid events.

Is there more convergence toward standardized parameters or standardized approaches to extracting information?

Standardizing actual parameter values is challenging because they depend on equipment capabilities, but standardizing *which* parameters must be exposed for grid reliability (without compromising OEM intellectual property) is essential. Protective relays use ANSI numbers to clearly identify specific settings; the IBR community should consider a similar approach to IBR control functions like ride-through, PFR, and voltage control. Even a manual but consistent, standardized method for extracting these parameters would be a meaningful step forward. Ultimately, visibility across all stakeholders is key.

When should the OEM provide dynamic models during the interconnection process?

The IBR developer is requesting dynamic models from OEMs once they know what IBR unit they are submitting to be used in the interconnection process. This establishes the latest and greatest validated unit model at that point in time to use for model quality tests as required by the utility, and it gets updated throughout the interconnection process as required and as known.

What specific studies are performed to obtain the inverter settings? Say, for instance, in ride-through settings, what specific study is done to get the setting after the model has been validated to work?

There are a few tests that are considered: 1) Model Quality Tests required by the utility for the IBR plant to meet, 2) NERC PRC-029 ride-through evaluation tests, and 3) upcoming IEEE P2800.2 conformity assessment practices. Some tests may not be a requirement to get through the interconnection process; however, they support commercial operations.

Requirements are defined at the POI but equipment components (PPC or inverter) need to support meeting these. How does this practically work together, especially for equipment bought earlier than new requirements? Who has the onus to solve the problem of taking nonconformant equipment and making it work? What can be done to solve this dilemma?

It depends heavily on the nature of the issue. Much of this comes back to how well the IBR developer structured the OEM contracts. If the requirements were clearly captured, the OEM may still be responsible for meeting them. Often, these details are overlooked, or the IBR developer references IEEE 2800-2022 when it does not apply to the OEM directly. If the issue is a firmware or parameter update, it can typically be handled through a change order that compensates the OEM for implementing the update. Some changes may be physically infeasible; in those cases, the applicable requirements may include exemption or exception provisions that need to be invoked.

The OEMs generally stress that grid code compliance does not directly apply to them as many of the requirements are established at the IBR plant POI or POM; thus, an OEM cannot singularly state that their product complies with a specific requirement. IBR developers and utilities must ensure that the OEM product(s) used support compliance with the requirements, requiring additional design evaluation testing and verification.

How are PPC OEMs providing tuned parameters sufficient for utility model approval that will not change during commissioning? Specifically gain values for AVR or PFR.

Some OEMs emphasize that they do not make unilateral changes to PPC settings; updates are only implemented with explicit owner approval and follow a defined checks-and-balances process. From an EPC perspective, experiences vary—during commissioning, they often work closely with the controller vendor to tune the plant to meet required reaction and response times. This frequently results in setting adjustments that differ from the original study models due to real-world factors such as metering, filtering, and communication delays. Since communication delays are often not represented in models, the plant's actual performance can diverge from expectations, raising the question of why these delays are not routinely modeled. Developers and owners value detailed model reviews and as-left verification, but there is a clear need for greater standardization across the industry.

As an OEM, do you have a standardized settings file that seamlessly translates model and as-left settings?

Approaches have changed throughout the years. In the US, external companies often conduct model testing and studies and thus the OEM obfuscates many parameters out of fear of intellectual property risks. For PPCs, there is much more transparency to the customer because there is less IP concern in the PPC. But in the inverters, there are thousands of parameters, and it can be "overwhelming" to customers or third parties using the models. Tools have been developed by, for example Vestas, for correctly parameterizing an as-built/as-left model within hours. A model is generated that matches the site, and this is somewhat automatic. However, for legacy sites, this may not be possible since they tools have been focused on newer vintages of inverters/turbines only.

Key Themes

- **Maintaining Alignment Between Models and Field Implementation:** There is a mission-critical need to ensure that the "as-studied" models match the "as-commissioned" and "as-left" inverter and PPC configuration and settings. Deviations between model and field settings directly affect grid code compliance, regulatory compliance, operational performance, and grid reliability. Standardized processes, repeated parameter verification, and coordinated checks among developers, OEMs, and commissioning teams are essential to prevent costly discrepancies.
- **Change Management as a Continuous Lifecycle Responsibility:** Grid code conformity is not a single milestone; rather, it is a lifecycle obligation that spans development, engineering, construction, commissioning, and decades of operation. Changes in personnel, ownership, equipment selection, or design assumptions introduce risk, especially when documentation is incomplete or knowledge transfer is weak.
- **Early-Stage Design Quality Drives Downstream Success:** Many downstream issues trace back to early-stage design gaps, incomplete interconnection requirements or IBR developer specifications to OEMs, overly generic studies, or assumptions made before equipment selection. Iterative analysis helps IBR developers identify feasible technology options, understand model requirements, and avoid surprises during execution.
- **Standardization and Transparency Are Increasingly Necessary:** Across developers, OEMs, EPCs, and utilities, there is growing recognition that lack of standardization—whether in parameter naming, data formats, settings access, or model deliverables—creates friction and risk. Stakeholders called for clearer exposure of essential reliability parameters without compromising intellectual property, like the ANSI standardization approaches used in protective relays. Consistent, repeatable methods for extracting and verifying settings would improve visibility, reduce errors, and strengthen confidence in model accuracy.
- **Commissioning Requires Iteration and Collaboration:** Commissioning can be a valuable opportunity to identify grid code compliance risks that may not show up beforehand such as communication delays, filtering effects, metering locations, or hardware limitations. EPCs and IBR developers routinely work with controller vendors to tune response times and adjust parameters, often revealing gaps that models did not capture. Sustained OEM engagement, routine downloads and as-left verification, and strong coordination between interconnection and execution teams are crucial for ensuring that the plant performs as required and remains compliant over time.

December 16, 2025 Virtual Meeting

IBR Plant Commissioning Best Practices II (~180 attendees)

Presentation recording and slides are available to download here. Figure 40 shows the makeup of meeting attendees by industry sector:

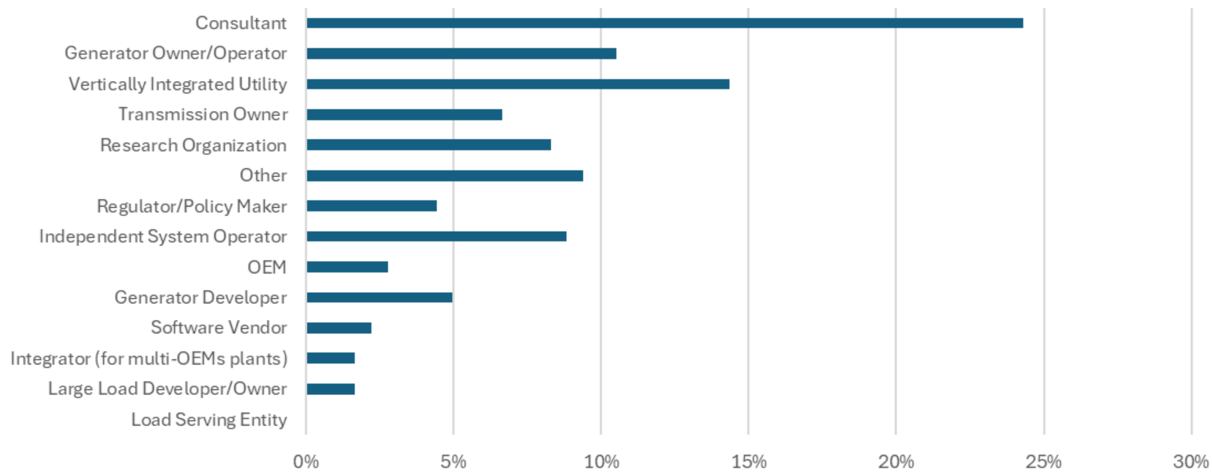


Figure 40: Meeting attendees by industry sector

This eighth meeting of Season 2 of the DOE i2X FIRST initiative focused on IBR plant commissioning best practices and experience from developers, OEMs, and system operators. IBR plant commissioning is the process configuring, integrating, testing, verifying, and validating that the equipment is installed correctly performs as required when connected to the grid. Its purpose is to demonstrate safe, reliable, and compliant operation before commercial operation is declared. Commissioning consists of a sequence of events that occur over a relatively short time period following construction and prior to COD. The process involves multiple parties and integrates prior interconnection process phases such as interconnection requirements, interconnection and modeling study results, OEM equipment acceptance testing, etc.

Once equipment is installed, site commissioning begins and is usually performed in a staggered manner for large IBR facilities. Initial activities may occur prior to energization such as "cold commissioning" which focuses on controls, communications, protection, and telemetry. As portions of the plant are energized, additional grid-connected "hot" testing is performed at increasing power levels. Plant-wide testing and final validation typically involve coordination with, and sometimes formal acceptance by, the transmission owner or grid operator.

Commercial operation occurs only after commissioning is complete and required performance has been demonstrated. The time between initial testing and commercial operation can range from weeks to months depending on project size, complexity, and regulatory requirements.

Presentations from this session included the following:

Zach Hammond and Rishi Maharaj, Engie

Zach and Rishi shared typical mandatory field commissioning tests for IBR plants in North America as well as observations, experience, and recommendations regarding these tests. IBR plant commissioning plays a critical role in determining whether a facility will perform reliably once it enters commercial operation. Although commissioning occurs late in the development lifecycle, it represents the final opportunity to verify and validate plant controls, protection systems, and operational behavior align with interconnection requirements and system reliability needs. Despite its importance, Zach and Rishi highlighted that commissioning practices across North America remain highly inconsistent.

Mandatory commissioning requirements vary widely by region and applicable grid authority. Some regions impose detailed test definitions, review procedures, and approval processes, while others have minimal or no formal commissioning requirements at all. A lack of mandatory requirements should not be interpreted as an indication that robust commissioning is unnecessary. Levels of oversight also vary significantly, ranging from active review and approval of test plans and results to simple receipt of a declaration that testing has been completed. Since NERC registration and compliance obligations for Generator Owners are only triggered at commercial operation, attention to demonstrating compliance with NERC standards is often overlooked during commissioning. This means that IBR plants are often commissioned without the rigor later expected under the NERC MOD and PRC standards.

Typical commissioning tests for IBR plants include automatic voltage regulator (AVR) testing, primary frequency response (PFR), active power control and curtailment capability, and capacity testing for BESS. While these tests are commonly referenced, test methodologies, scopes, and acceptance criteria differ substantially across transmission entities. This variability leads to inconsistent expectations and plant behavior, even for similar technologies.

The following are brief explanations of some of the common tests performed:

- **AVR testing** is often performed using voltage reference set point step changes to confirm that voltage control within the continuous operation region is enabled and that reactive power responds in the correct direction. More comprehensive testing evaluates whether the plant can deliver its full reactive capability at the POI under specified conditions and within required response times. However, important operating modes such as voltage support at zero active power generation (e.g., night VARs for solar plants) or idle operation for BESS are rarely tested despite their relevance to real-world grid conditions.
- **PFR testing** is typically conducted by injecting or simulating frequency offsets within the PPC and observing the IBR plant's response. Deadbands, droop settings, and performance criteria are usually defined, and wind or solar IBR plants are often required

to demonstrate overfrequency response only (i.e., underfrequency response from curtailed state is usually not tested) while BESS are expected to respond to both under- and overfrequency events.

Other less common tests such as in-plant contingencies, hardware and communication failures, large disturbance behavior testing, etc., are not often performed but can help provide useful insights into how the IBR plant will respond to these abnormal conditions.

The fundamental objective of IBR plant commissioning should be to understand how the facility behaves under grid events, not merely to demonstrate compliance with minimum requirements. Wherever possible, IBR plants should be subjected to challenging but safe test conditions to uncover failure modes and unintended interactions. Many scenarios cannot be fully evaluated through simulation testing alone. These include hardware failures, communications failures, invalid command handling, controller redundancy and fallback behavior, and system re-initialization following abnormal conditions. Grid operator requirements should be viewed as complementary to owner-driven testing, not as a substitute for it.

Care must be taken to coordinate tests with the transmission operator, but limiting testing to narrow scenarios increases the risk of unanticipated behavior during real grid events. Additional areas that warrant attention include validation of external measurement devices, testing of night-mode voltage regulation for solar plants, and evaluation of frequency response from curtailed state and using realistic, time-varying frequency signals.

Many modern IBR plants are supported by EMT models developed prior to commissioning, yet significant challenges remain in using these models to replicate field behavior. Measurement devices and associated time delays are often simplified or omitted. On load tap changer (OLTC) logic and shunt switching behavior are rarely represented accurately in the models and require measurement-based validation. Aggregation of collector systems can obscure terminal voltage behavior at individual inverters, and PPC models may not fully represent limiters, fallback logic, or priority schemes implemented in the field. As a result, models may satisfy interconnection study requirements while failing to demonstrate the as-left, commissioned configuration. EMT models are most valuable when they are actively used to inform commissioning rather than treated as static interconnection artifacts.

Differences between modeling assumptions and field implementations are often most evident during parameter verification. Reactive power limits are a common example. Models may use fixed gross MVAR limits, while PPCs apply MW-dependent, net-of-loss limits at the POI. Direct translation of parameters between these frameworks can result in unintended behavior and discrepancies between simulated and measured performance. Active power limits present similar challenges. Gross inverter capability represented in EMT models must be translated to net power at the POI after accounting for collector system and transformer losses. Failure to understand these distinctions can lead to unexpected results during commissioning, even when parameters appear to be “approved.”

Minimum commissioning requirements should be treated as a baseline rather than a target. The effort and cost required to correct deficiencies increase dramatically as a project progresses, and commissioning represents the last relatively straightforward opportunity to address design and control issues. Accelerating commissioning by reducing test scope often results in costly rework during commercial operations, additional operational risk to the IBR plant owner/operator, and long-term reliability challenges. Detailed commissioning plans are essential for understanding plant behavior, even when individual components have been extensively validated, and is especially critical when they have not.

Lars Johnson, Merit Controls

Lars shared perspectives of a PPC manufacturer that also touched on SCADA integration and networking considerations. He highlighted that effective commissioning of IBR plants extends well beyond inverter controls and system performance requirements. Reliable IBR plant operation depends on the successful integration of PPCs, SCADA systems, communications networks, and various field equipment. From initial scoping through long-term operations, commissioning must be treated as an end-to-end process that validates not only electrical behavior, but also data integrity, control pathways, cybersecurity, and operational readiness (see Figure 41).

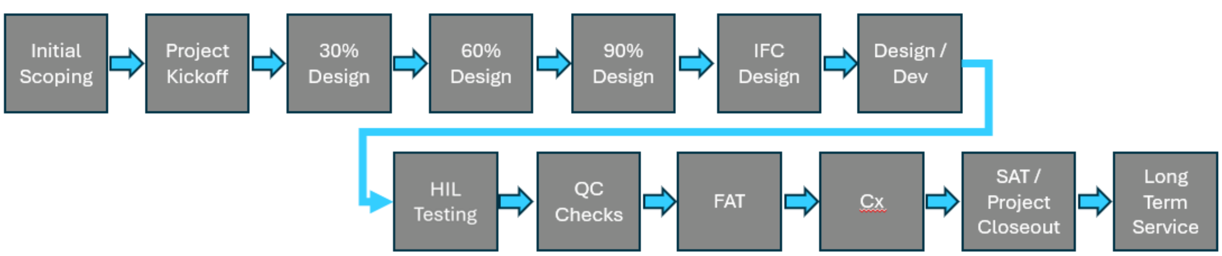


Figure 41: Overall Project Flow for IBR Plant PPC Design [Source: Merit]

A structured project lifecycle begins with initial scoping, during which project requirements are defined based on interconnection obligations, grid code requirements, equipment selections, functional features, and schedule constraints. These requirements flow into progressive design stages, typically at 30%, 60%, 90%, and Issued-For-Construction (IFC) levels, which serve as the foundation for system development and configuration. Design documentation captures control narratives, system architectures, data flows, network layouts, and test plans, providing a common reference for owners, integrators, and equipment vendors.

Early in the project lifecycle, integration meetings with inverter OEMs and other equipment suppliers are essential to clarify interfaces, communications protocols, data mappings, and control requirements. For new or unfamiliar vendors, additional qualification activities are often required. These may include laboratory testing at the vendor's facility, point-to-point communications verification, setpoint and control testing, and characterization of inverter behavior through tests and emulator-based environments. These efforts reduce integration risk later in the project, including at commissioning.

System configuration builds upon standardized templates and automation, allowing project-specific parameters to be applied consistently across PPC logic, SCADA tag databases, network devices, and server infrastructure. Configuration activities include development of SCADA displays, I/O mappings, communication drivers, PPC parameter sets, and networking equipment configuration. Template-based approaches improve repeatability while allowing for site-specific customization.

Hardware-in-the-loop (HIL) testing is often used as additional quality assurance. Real-time simulation environments combining grid models, inverter models, and control system logic allow verification and validation of IBR plant response, particularly for scenarios that are not practical to test in the field (e.g., voltage and frequency ride-through events, faults, etc.). HIL testing supports early tuning of control parameters and validation of edge-case behavior prior to site deployment. EMT models of the PPC and master controller logic are maintained and updated throughout the project. These models are validated and benchmarked against phasor domain transient models and used to confirm consistent response to voltage, frequency, and setpoint changes.

Before equipment is shipped to the site, factory acceptance testing (FAT) is performed following internal quality control checks. FAT environments replicate the site architecture as closely as possible including SCADA servers, PPC hardware, network switches, firewalls, fiber networks, and plant emulators representing meters, inverters, trackers, etc. FAT validates networking and cybersecurity configuration and serves as a customer-witness activity confirming readiness rather than discovering new issues. Equipment is then shipped as fully integrated, pre-tested systems intended for quick field deployment.

Site commissioning proceeds in phases including, but not limited to, the following:

- **SCADA rack installation**
- **Field fiber network enclosure installation**
- **Cold commissioning** prior to energization to verify networking configurations, telemetry, data integrations with the utility and ISO(s), meter data quality and scaling, time synchronization, control point confirmation, etc. (see Figure 42)

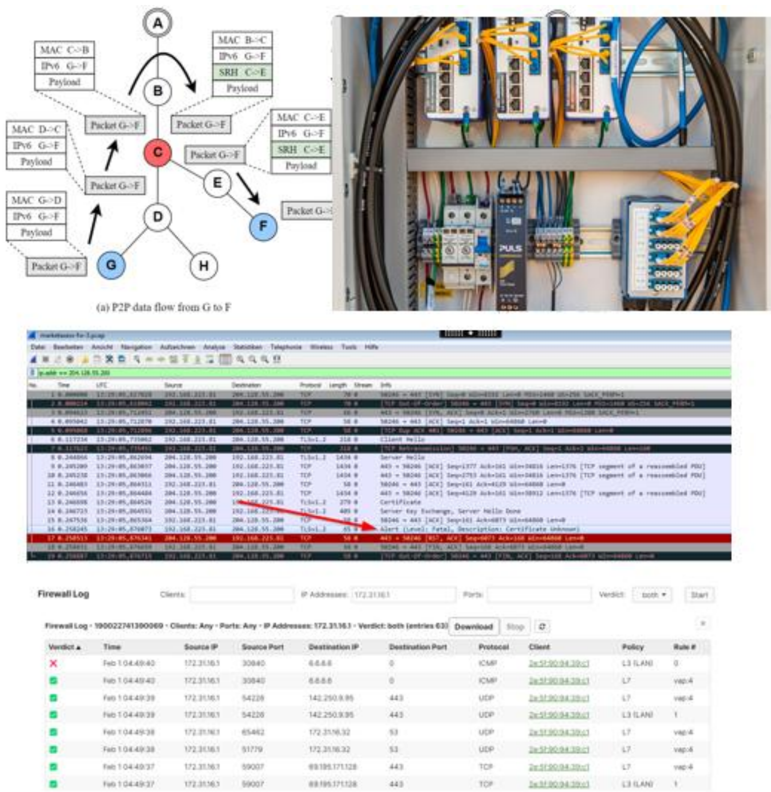


Figure 42: Visualization of Cold Commissioning Checks [Source: Merit]

- **Hot commissioning** once initial test energy is available (typically less than 20 MVA connected to grid) including initial synchronization, live data verification, communications checks, validation of inverter and other auxiliary data, etc. Functional testing progresses from manual start/stop commands and active and reactive power set points to closed-loop automatic control within defined limits. Plant metrics, counters, aggregation logic, and high sustained limit (HSL) calculations are verified, along with telemetry delivery to external entities. Data logging functions required for standards and reliability reporting are confirmed.
- **Site acceptance testing (SAT)** is performed once confidence in the integrated system has been established. SAT validates plant-wide manual and automatic controls, capacitor bank integration, aggregate active and reactive power performance, and overall system stability. Response tests against established performance requirements are often performed at this phase. SAT is a contractual milestone and precedes, rather than replaces, ISO or utility commissioning tests, though overlap may occur.
- **Coordination with the transmission operator, ISOs, and site commissioning managers** is often needed for large power changes and full capability testing. These tests may include full-power and zero-power operation, ramp rate verification, PFR response, power factor capability testing, four-quadrant operation for BESS, and automatic voltage

control. Voltage step tests may be initiated through controller setpoints, simulated measurements, or utility-driven network changes. Remote control and telemetry tests are often conducted concurrently to validate external commands.

- **Retesting** may be needed if grid conditions are restrictive and limit testing procedures – this is sometimes unavoidable. Grid voltage conditions, equipment outages, unavailable capacitor banks, insufficient inverter availability, telemetry errors, or misunderstandings of utility acceptance criteria can all necessitate additional (re)testing. Weak grid conditions further increase the likelihood that tests will not pass on the first attempt, requiring tuning or other workarounds.
- Formal handoff to operations involves delivering final documentation, SAT reports, model validation data, and recording of final “as-left” parameters. Training is provided for operators and operations and maintenance teams, and remote access arrangements are transitioned to long-term service providers.

Several recurring challenges have emerged across IBR plants. Scheduling disruptions caused by construction delays, weather, and shifting priorities can complicate resource planning and coordination. Compressed timelines with fixed commercial operation dates increase risk. Issues outside the PPC or SCADA scope (often related to third-party equipment or site infrastructure) frequently surface during commissioning and must be resolved before progress can continue. Weak grid conditions, late-emerging requirements, and discovery of design gaps late in the project further increase complexity.

Experience consistently shows that early preparation, thorough requirements gathering, extensive pre-deployment testing, and disciplined commissioning practices are essential for success. Addressing integration, controls, and network challenges early in the project lifecycle significantly reduces rework, delays, and operational risk once the IBR plant enters service.

Phillip Hiusser, Independent Electricity System Operator (IESO)

Phillip shared ISO perspectives regarding IBR plant commissioning and checks that the transmission provider can do to verify and validate the performance of newly connecting IBR plants. Commissioning IBR plants is a critical component of the connection assessment and approval process in Ontario and designed to ensure that new IBRs enter service without introducing reliability risks to the grid. Growing levels of IBRs in Ontario are increasing the importance of robust commissioning processes that verify performance, validate models, and confirm operability before facilities are approved to connect.

Figure 43 illustrates a high-level connection review process used by IESO. The connection process begins with preliminary assessments based on proposed equipment ratings, capabilities, and models. At this stage, models are often hypothetical or based on typical parameters, and numerous assumptions are required to assess compliance with technical requirements. As a result, conclusions drawn during early studies are inherently tentative, and approval to connect is conditional on successfully demonstrating performance during commissioning.

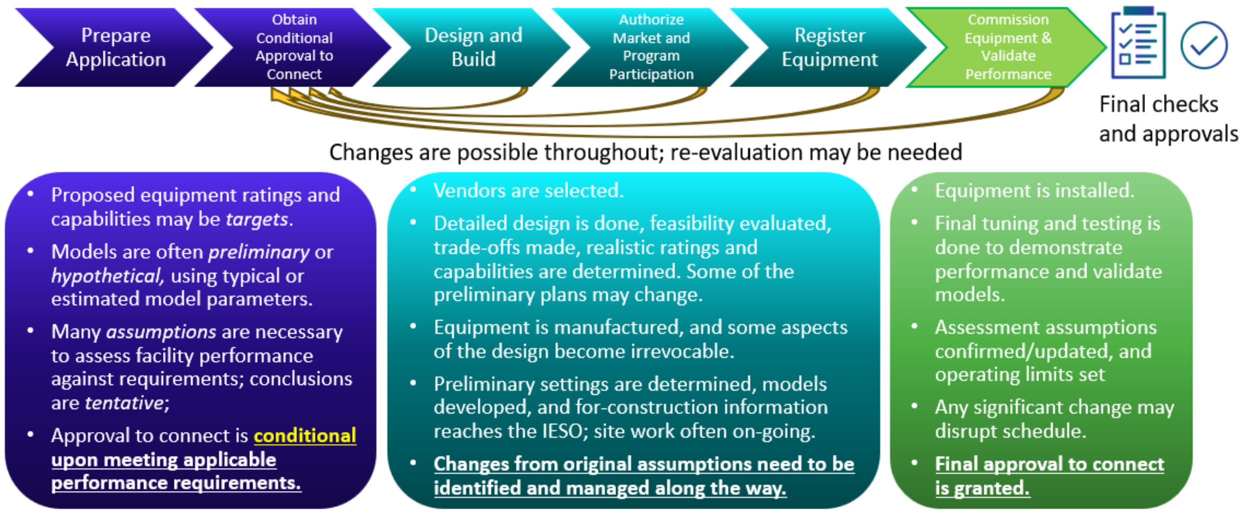


Figure 43: Connection Process and Conformity Checks in Ontario [Source: IESO]

As projects progress, vendors are selected and detailed designs are finalized. Equipment capabilities are refined, trade-offs are evaluated, and realistic ratings are established. Some aspects of the design become fixed once equipment is manufactured, while others remain adjustable through configuration and tuning. Preliminary settings are developed, models are updated, and for-construction information is submitted. Throughout this phase, deviations from original assumptions must be identified, tracked, and managed to avoid late surprises.

Once equipment is installed, commissioning activities focus on final tuning, testing, and demonstration of performance. Test results are used to confirm or update earlier assumptions, establish operating limits, and validate models. Significant changes at this stage can disrupt schedules, underscoring the importance of early alignment between studies, design, and expected field behavior. Successful completion of commissioning leads to final approval to connect.

Commissioning workflows involve coordinated responsibilities between applicants and the system operator (see Figure 44). Commissioning guidelines are used to demonstrate compliance with applicable NERC, Northeast Power Coordinating Council (NPCC), and market rule requirements, while project-specific requirements may be identified during interconnection studies and carried forward into IBR plant commissioning. Because IBR plants are complex, additional testing or data submissions may be required to confirm operational behaviors such as switching sequences, start-up and shut-down behavior, and responses to equipment failures.

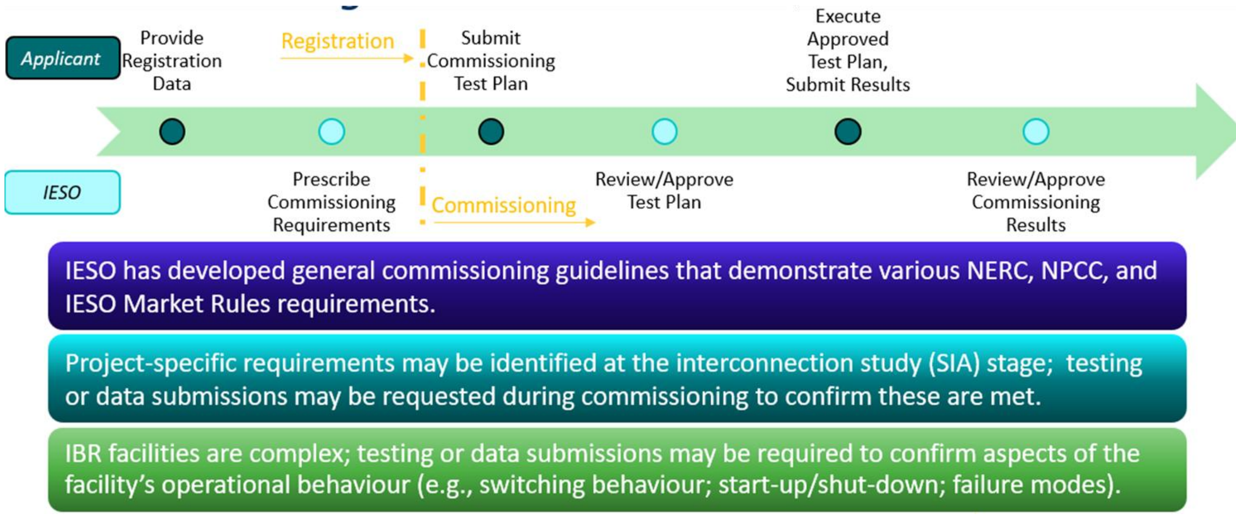


Figure 44: Commissioning Workflow in Ontario [Source: IESO]

The overarching objective of commissioning is to 1) ensure equipment connected to the grid has the performance required to maintain reliability (meet applicable requirements and not exhibit objectionable behavior), and 2) show the models and other data provided to IESO accurately reflect the site and support IESO planning and operations decision making processes. Both objectives are equally important, as accurate models are essential for anticipating system behavior beyond the specific conditions tested in the field.

Performance and model confirmation rely on a combination of benchmarking, verification, and validation. Benchmarking compares positive-sequence dynamic models (generic and user-defined) against validated EMT models. Verification focuses on ensuring that final "as-left" configurations and settings are accurately reflected in models, using evidence such as configuration files, screenshots, photographs, and documented parameter values (see for verification check examples). Validation involves direct comparison of measured responses from staged tests or ambient operation against simulated responses to confirm acceptable agreement.

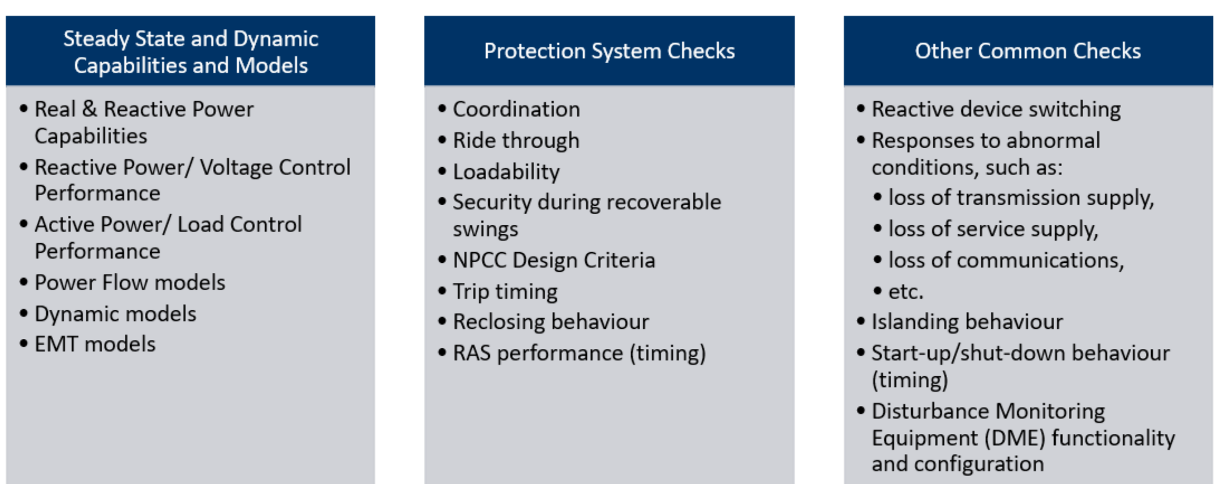


Figure 45: Examples of IBR plant Verification Checks [Source: IESO]

Key observations and recommendations IESO has collected over the years include the following:

- **Managing requirements is a recurring challenge.** Applicable obligations arise from numerous sources, including reliability standards, market rules, interconnection studies, protection requirements, and transmission-specific criteria. These requirements are often complex and region-specific. Process complexity should be minimized where possible, and developers benefit from clear guidance on expectations and common pitfalls. Successful projects typically employ systematic processes to track requirements to completion, engage experienced vendors and service providers, and maintain frequent, clear communication with relevant authorities.
- **Project scoping and scheduling present additional challenges.** Ambitious commercial operation dates often conflict with the sequential nature of interconnection and commissioning processes. Site construction is rarely the final step before commercial operation, and failure to account for remaining dependencies can result in unrealistic schedules, time pressure, rework, or compromised technical scope. Clear articulation of process steps and timelines, combined with realistic scheduling and active management of schedule changes, improves project outcomes.
- **Change is inevitable during commissioning.** Unforeseen issues frequently arise, particularly in weak or complex grid conditions or under unusual operating scenarios. While digital control systems offer flexibility to address such issues, changes can invalidate prior assumptions and introduce unintended consequences. EMT studies are especially valuable for identifying potential oscillations or performance problems under reasonably foreseeable conditions. Effective change management requires clear documentation, defined communication protocols, and guidance on which changes necessitate re-studies. Ensuring resources are available to update analyses when needed can significantly reduce delays.
- **Fundamental engineering discipline plays a critical role in commissioning success, particularly with respect to base values and unit consistency.** Power system analysis relies on numerous per unit base quantities, including those embedded in controllers, relays, transformers, facility ratings, and simulation models. Mixing quantities on different per unit bases is common and can easily lead to errors. Best practices include explicitly documenting per unit bases, listing values in engineering units as well as per-unit or percentage form, confirming the reference base for all normalized values, and minimizing manual calculations through automation. Attention to related pitfalls such as primary versus secondary measurement quantities and phase versus phase-to-phase measurements is equally important.

Together these practices reinforce the role of IBR plant commissioning as a critical reliability stage gate. Thorough performance testing, disciplined model validation, proactive change management, and strong engineering fundamentals are essential to ensuring that IBR facilities integrate successfully into Ontario's evolving power system without introducing avoidable operational or reliability risks.

Q&A and Interactive Group Discussion

How common is it that the studied/modeled parameters used during the interconnection process get implemented in the field during commissioning without any modification? Is it more common that generic PPC/IBR unit parameters are installed and models need to be updated?

This issue does occur quite often, and it is important to test the entire IBR plant as a whole system. OLTC settings, capacitor bank switching logic, hybrid plant configuration and controls, communications network latencies and delays, etc., all require additional testing during IBR plant commissioning. Capacitor banks are very commonly custom-implemented for the specific site and thus lack standardized design and settings. Thus, this becomes an integration challenge with the OLTC and PPC in terms of deadbands, dwell times, and other settings. Sometimes, the IBR plant must be detuned to handle these considerations.

In general, some model updates are almost always required. This is especially true once the IBR plant is connected to the actual grid. Fundamental limitations of simulation models prevent 100% accuracy. However, it is important not to "start from zero" in this effort. Maintaining models as accurately as possible throughout the interconnection process can help ensure that the starting point for commissioning-based true-up is closer to the actual and therefore less likely to cause delays in commercial operation.

Can you share the process of getting models updated around commissioning and COD? What happens when models do not match reality? Is COD delayed? Or are models updated after COD? How is this managed during this crunch time?

IESO shared that commissioning is completed once fully verified and validated models (based on commissioning testing) are attained. At least the settings and expectations for the IBR plant models should be agreed to at this point. There may be some lingering paperwork to true up documentation after COD. It is rather common for last-minute re-studies to be performed with the updated parameters/settings, and these are required before COD is achieved for the IBR plant. Changes need to be evaluated before COD; however, IESO allows for some documentation to be updated later.

Lars shared that escalations with very fast timeframes near the end of commissioning are quite common but did recognize that the changes are usually rather small in terms of impact to the site and models.

Engie agreed that the timelines are quite compressed and that updates often do occur after COD, if at all. In jurisdictions where a parameter verification report is not required, it is most common that anything that changed during commissioning will not be reflected back into the models. The models get submitted but no changes are reflected. Often times, the "as-built model" is just resubmitting the old model and the checks completed on the transmission owner/operator side are inadequate to flag these issues.

Updating the models during commissioning may be very challenging and cause long delays; however, getting accurate and verified models is important. If no one is overseeing this aspect of commissioning, it is often overlooked in the interest of reaching commercial operation on time. The closer the pre-commissioning model can be to reality, the easier it is to work through this process of change effectively.

It was mentioned that overfrequency response for wind/solar IBRs is checked (operating with no headroom) but should underfrequency be checked for wind/solar to ensure it behaves correctly to max available power? What about curtailed operation to verify performance if ever curtailed?

It is good practice to test PFR across all operating conditions and in both directions, including PFR behavior during curtailment. This should also be tested at different active power operating conditions for wind resources, in particular. It can be rather difficult to get a conclusive response from OEMs on this topic and thus should be adequately tested.

It is important to ensure that the EMS system is operating correctly. ERCOT published resources regarding issues with the HSL, and transition between curtailed and non-curtailed operations can also be problematic with the PPC. These are rather easy things to test in the field, but difficult to test in a laboratory environment.

For AVR testing, what tests should be conducted to verify the combined response of the PPC, shunt devices, and OLTC, as this equipment does not activate at the same time?

This can include a combination of static and dynamic tests. In terms of static tests, this can include reactive power capability testing of the IBR plant at the POI, exercising equipment at various voltage levels, moving OLTC tap positions across a range of voltages, etc. From a dynamic test perspective, this includes voltage reference step changes, switching shunt devices in and out of service, measuring stability, overshoot, damping, etc. In some cases, the OLTC settings may be slow and coordination with the PPC may not be a factor; in other cases, the OLTC may operate in more dynamic timeframes and need closer coordination.

Longer-term testing of changes in terminal conditions can watch the overall longer dynamics of the IBR plant move to new set point values, which may not be reflected in the dynamic models but is good to understand from an operational perspective. The AVR testing can be done using lower resolution SCADA data (1-2 second resolution). This may not capture fast transients, overshoot, response time, and other characteristics. PMU or DFR data is generally required for validating these faster dynamics in the phasor domain and EMT models.

Can you share guidance on types of data for various commissioning tests for IBR plants?

The IESO asks for 1 sample per cycle data (e.g., PMU-type data) for dynamic tests, and some tests require this resolution of data. PMU-type monitoring data is required at the high-side of the main power transformers and recommended at the low side as well. The IESO also sees that it is relatively common for high-speed recording devices to be able to be configured to capture collector system measurements and also possibly IBR unit-level data, and this is now common practice in IESO footprint.

For evaluating AVR tests where a step change to the voltage reference is initiated, should the plant's response times be evaluated based on MVAR or voltage? Are there specific settling bands that the plant should maintain?

The IBR plant is not solely responsible for establishing voltage at the POI; rather, the PPC is commanding a MVAR set point value and this is used as the evaluation measurement to a change in reference signal. There are not universal requirements for settling time across all IBR plants and this may be evaluated on a case-by-case basis. This test can be helpful in uncovering site issues that affect operational performance.

Are there any recommendations you have for shaping contractual agreements with OEMs that ensure developers capability to execute rigorous testing during commissioning

The "gold standard" is to define precisely what you need as an IBR plant developer in terms of what you want tested, how to test it, and what the pass/fail criteria is. And then take that information to the OEM(s) and add that as a contractual obligation around commissioning. The key point here is to bring this to the OEM as early as possible. If these details show up later in the process (e.g., right before commissioning), it is very unlikely that they will get implemented. As an IBR developer/owner, you need to know exactly what the requirements/expectations need to be and communicate that early.

Key Themes

- **Commissioning as a Critical Reliability Stage Gate:** Commissioning is the last practical opportunity to confirm that an IBR plant will operate reliably once it enters service. Issues discovered after commercial operation are significantly more difficult and costly to correct. Treating commissioning as a formality rather than a reliability stage gate increases both operational and grid reliability risk.
- **Inconsistent Requirements Drive Uneven Commissioning Rigor:** Commissioning requirements and oversight vary widely across regions and transmission providers, leading to inconsistent testing practices and expectations. In some cases, minimal

requirements result in insufficient verification and validation of IBR plant configuration, settings, capabilities, and operational performance. The absence of mandatory NERC requirements does not reduce the need for robust IBR plant commissioning as comprehensive verification and validation efforts at commissioning set the IBR plant up for compliance once COD is attained.

- **Standard Tests Alone Do Not Capture Real-World Plant Behavior:** Common commissioning tests such as AVR, PFR, and curtailment are necessary but often insufficient to fully understand plant performance. Important operating conditions such as zero-power operation, communications system failures, and other failure scenarios are frequently under-tested. Expanding test scope to include realistic and challenging scenarios provides far greater confidence in plant behavior.
- **Models Must Be Actively Aligned with As-Commissioned Reality:** While EMT and phasor domain models are widely used during the interconnection study process, they often diverge from actual field implementation. This is partly attributed to a lack of model verification and validation around the time of commissioning. Models provide the most value when they are treated as living tools that inform commissioning and reflect the final "as-left" configuration, and should be maintained throughout the lifecycle of the facility.
- **End-to-End Integration Is Essential for Successful Commissioning:** Reliable IBR operation depends on the coordinated performance of controls, SCADA, communications networks, telemetry, and supporting infrastructure. Commissioning must therefore be approached as an end-to-end process, beginning early in the project lifecycle and continuing through handoff to operations. Early preparation, clear requirements, comprehensive contractual agreements, disciplined testing, and proactive change management consistently reduce risk, delays, and rework.

January 27, 2026 Virtual Meeting

NERC PRC-029 Implementation, Experience, and Recommended Practices (~280 attendees)

Presentation recording and slides are available to download here. Figure 46 shows the makeup of meeting attendees by industry sector:

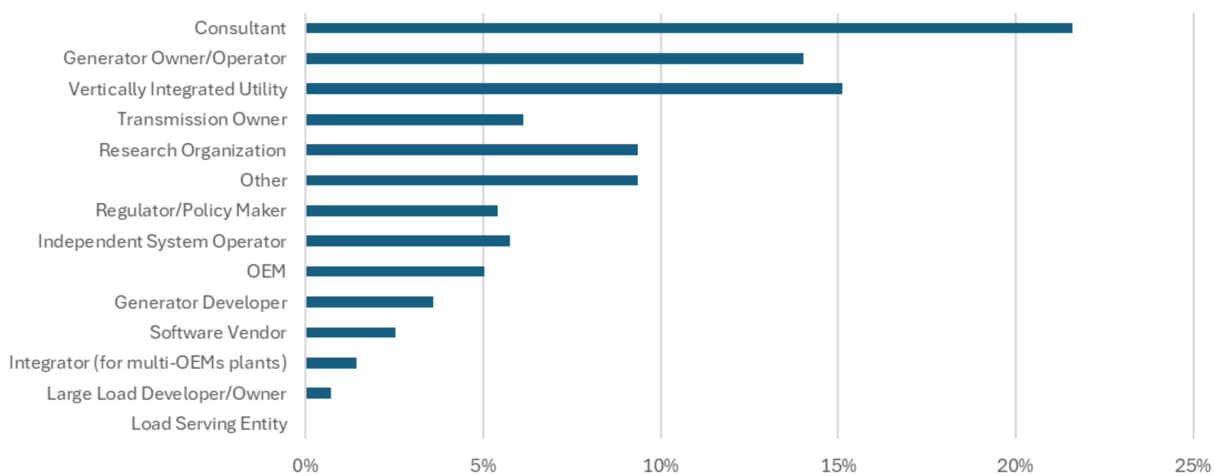


Figure 46: Meeting attendees by industry sector

This ninth meeting of Season 2 of the DOE i2X FIRST initiative focused on NERC PRC-029 implementation, experience, and recommended practices. With initial IBR plant ride-through design evaluations due by October 2026, this session served as an opportunity to hear from NERC and early experience from industry experts supporting these evaluations.

JP Skeath, NERC

JP shared an overview of NERC PRC-029-1 and FERC Order 909. NERC PRC-029-1 was developed as part of NERC implementation plan to meet the directives in FERC Order 901. The NERC Milestone 2 standards include NERC PRC-028-1, PRC-029-1, and PRC-030-1 (see Figure 47); NERC PRC-029-1 establishes performance-based ride-through criteria as well as capability-based ride-through criteria. FERC Order 901 directed NERC to "develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." IBR plants must "continue to inject current and perform frequency support" within ride-through conditions.

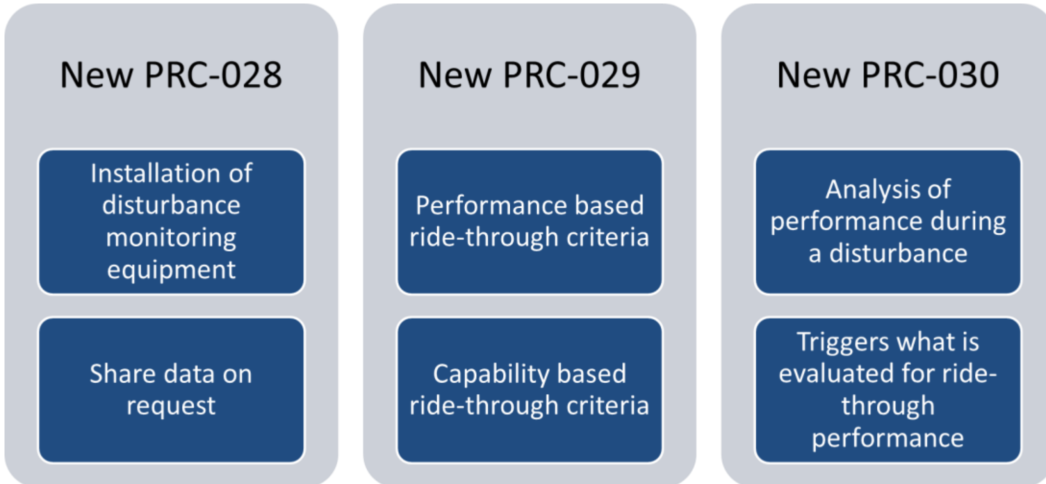


Figure 47: Overview of NERC Milestone 2 Projects [Source: NERC]

NERC was also directed to determine whether PRC-029-1 should allow for limited and documented exemptions for certain registered IBRs for voltage ride-through performance requirements. Subsequent stakeholder workshops and feedback justified that frequency exemptions are also credible and should be considered and were subsequently addressed in the proposed standard.

NERC PRC-029-1 includes four requirements. Requirements R1–R3 establish frequency and voltage ride-through capability and performance requirements for IBRs (see Figure 48) and include performance criteria regarding IBR plant dynamic performance during ride-through conditions. Requirement R4 defines the limited exemptions applicable to IBRs in service by the effective date of NERC PRC-029-1 (October 1, 2026). The exemptions are limited to known hardware limitations that prevent the IBR plant from meeting documented frequency and voltage ride-through criteria. Exemptions are to be submitted to the Compliance Enforcement Authority (CEA), Planning Coordinator, Transmission Planner, Transmission Operator, and Reliability Coordinator. IBR owners are expected to follow-up on requests for additional information, and IBR owners are also expected to notify the applicable entities within 90 days of CEA acceptance of hardware limitation.

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

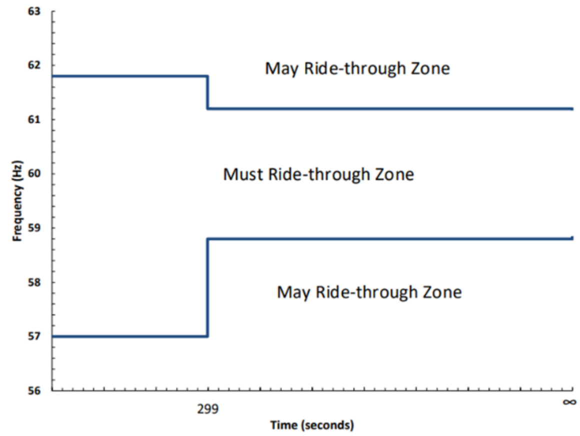


Figure 1: PRC-029 Frequency Ride-through Requirements

Figure 48: NERC PRC-029-1 Voltage and Frequency Ride-Through Criteria [Source: NERC]

FERC subsequently issued Order 909 on July 24, 2025, to approve PRC-029-1 and PRC-024-4,[14] and also issued several directives to NERC including addressing the following topics through its standards development process:

- Address the issues raised in the rulemaking proceeding regarding HVDC-connected IBRs with choppers and long-lead time equipment and submit its determination within 12 months
- Address concerns about absent documentation for legacy IBR units (e.g., modify requirement, expand Measures to include non-exhaustive list of acceptable evidence) within 12 months
- Following full implementation of the standard, submit an informational filing to FERC including certain data and an assessment of the reliability impacts of the exemption process.

FERC subsequently issued Order 909-A on Sept 25, 2025, denying a request for clarification of Order 909. The request raised concerns about potential timing mismatch between NERC's anticipated filing of a modified standard in August 2026 and the standard's effective date of October 1, 2026. Specifically, the concern was that some registered entities could be placed in a noncompliant status on the effective date while simultaneously seeking exemptions related to the issues raised in Order 909. In denying the request, the Commission stated that NERC retains "the flexibility to address the Energy Trades' timing concern whether through the implementation plan for a modified Standard, NERC's enforcement discretion, or some other means."

[14] NERC PRC-024-4 is the revised generator voltage and frequency protection settings standard for synchronous generators, Type 1 and Type 2 wind resources, and synchronous condensers.

NERC held a virtual workshop on Order 909 to address the topics describe above. Lastly, also received an industry Standard Authorization Request (SAR) from the American Clean Power Association (ACPA) and initiated Project 2025-05. The SAR was posted for comment, ending December 18, 2025. The scope of the SAR seeks to extend PRC-029-1 Requirement R4 exemption eligibility to include long lead-time IBR projects in active development, extend exemption eligibility to include chopper limitations, and to clarify the non-exhaustive acceptable evidence to aid entities. The SAR has not been approved as of this meeting, and the drafting team is responding to solicited comments first.

Yaw Akpaloo and Lukas Sales, GE Vernova

Yaw and Lukas shared GE Vernova's perspectives with onshore wind equipment regarding PRC-029-1 implementation. GE has over 75 GW of double-fed induction generator (DFIG) wind turbine generators (WTGs) installed in the North American market. This includes the new and active 2.X-127, 3.X, and 6.X platforms. All newly delivered and currently active products are designed to meet NERC PRC-029-1 and IEEE 2800-2022 requirements. Software-based upgrades enable full alignment with the applicable requirements for some legacy models. This includes the legacy 1.X-10Y, 2.X, and early 1.X platforms which can meet most of the PRC-029-1 requirements through targeted software upgrades, unlocking enhanced ride-through and recovery capability. Older variants have meaningful capability expansion opportunities, with performance aligned to turbine design and plant configuration. Achievable outcomes are upgrade-enabled and turbine-specific, which allows customers to "pursue practical, value-driven capability pathways" across their fleets.

GE Vernova has supported its customers with the following:

- **Position Papers & Technical Capability Reports:** These papers have been shared with applicable generator owners to explain turbine-level capabilities and upgrade options, support exemption evaluations where applicable, and enable informed compliance strategies.
- **Validated WTG Simulation Models:** Turbine models (e.g. PSS®E, PSCAD) with current capability and upgraded controls are created on a case-by-case basis for customers. These IBR unit models are intended to be incorporated into the full IBR plant models for subsequent compliance evaluation studies.
- **Software-Based Upgrade Development & Deployment:** Software upgrades are delivered through a structured, platform-based roadmap, aligned with fleet needs and regulatory priorities. Each upgrade undergoes validation to ensure performance and deployment is planned with customers to align with site access and outage windows, operational priorities, and regulatory milestones.

GE Vernova elaborated on observations and questions raised by customers, including:

- Some customers have mixed interpretation of whether NERC PRC-029-1 R1–R3 enforcement aligns with PRC-028-1 implementation dates and deadlines.
- Maximization requirements in the NERC requirements are less prescriptive and in some ways unclear.
- Continued alignment discussions around exemptions for in-kind replacements and partial repowering where hardware changes are limited as well as uncertainty on specifics for demonstrating achievable capability including justification where physical constraints exist.
- Process for wind plant upgrade and simulation models updates, particularly with respect to how ISOs and utilities use different processes for plant upgrades, model updates, and validation, which reinforces establishing an upgrade pathway and gathering OEM-supported documentation to streamline multi-region deployment.

GE Vernova stated that they remain committed to engaging with their customers, ISOs, utilities, and other industry stakeholders as implementation efforts continue. Early coordination across GOs, OEMs, consultants, and regulators helps unlock clarity, alignment, and efficient execution at scale.

Amin Banaie, Elevate Energy Consulting

Amin shared recommended practices and experience conducting IBR ride-through evaluations on IBR plants pursuant to NERC PRC-029-1 requirements. Amin shared the compliance deadlines for both Bulk Electric System (BES) IBRs as well as registered Category 2 IBRs (see Figure 49) and described the assessment methodology and lessons learned from conducting evaluations on various IBR plants and technology types.

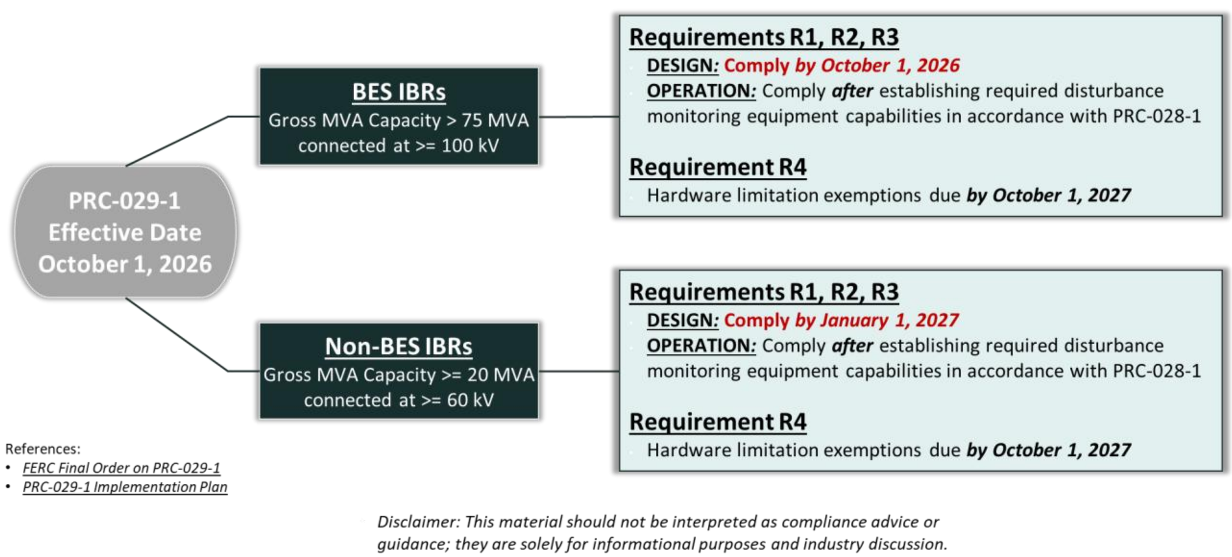


Figure 49: NERC PRC-029-1 Compliance Deadlines [Source: Elevate Energy Consulting]

The IBR plant ride-through design evaluation methodology involves a multi-step process to assess IBR plant protection, controls, and settings to ensure the overall IBR plant meets the requirements set forth in NERC PRC-029-1. This includes the following steps (see Figure 50):

- **As-Left Site Data Collection:** The IBR plant as-left settings and data are collected and verified to ensure that the latest on-site configuration is represented and documented. This is often an overlooked step that can result in errors that progress through the entire process if not carefully reviewed.
- **Verification with OEMs (as needed):** In many cases, gathering the necessary protection and control information, particularly for the IBR units, requires requesting access to data and information from the OEMs. This information is not always (or even often) readily available to the end-user/owner and must be requested. Additionally, there are protection and control settings that may not be visible to the owner that are hard-coded by the OEM and warrant careful attention. In many cases, multiple iterations with the OEM are required to gather the necessary information to verify site details.
- **Protection and Control Verification:** Once all data has been collected, a desktop evaluation of protection and control settings occurs. This includes the frequency and voltage ride-through settings of the IBR units, the PPC (if applicable), and the balance of plant relays. Additionally, protections such as phase jump, ROCOF, anti-islanding, DC-side protections, and other protections are also evaluated, particularly since they are often not represented in the dynamic models.
- **Site Configuration, Model Verification, and Simulation Ride-Through Testing:** Once the site as-left settings, protections, and controls are verified, then the IBR plant dynamic model(s) can be verified. This step involves ensuring that the dynamic models do not have any errors or omissions. Again, not all protections are reflected in the dynamic models, and older sites may not have access to EMT models. Thus, careful evaluation of protection and control settings may be more accurate and sufficient than simulation tests. Regardless, these tests provide additional assurance that the IBR plant is able to ride through specific events and provide the appropriate dynamic response (active and reactive current/power) as specified in the sub-requirements.
- **IBR Plant Updates, Corrective Actions:** Once the evaluation is complete, any corrective actions to get the plant into compliance with the requirements are identified, where applicable. This may involve additional coordination with the OEM(s).
- **Exemption Request Documentation Preparation:** In some cases, all applicable software-based updates may not be sufficient for legacy assets to meet the established requirements. In these cases, careful collection of exemption documentation and additional coordination with the OEM is needed. These materials are to be shared with the CEA and applicable entities for evaluation.

- **Compliance Documentation and Evidence Tracking:** Upon completing the evaluation, all documentation, models, and evidence are tracked and retained for ongoing compliance purposes.

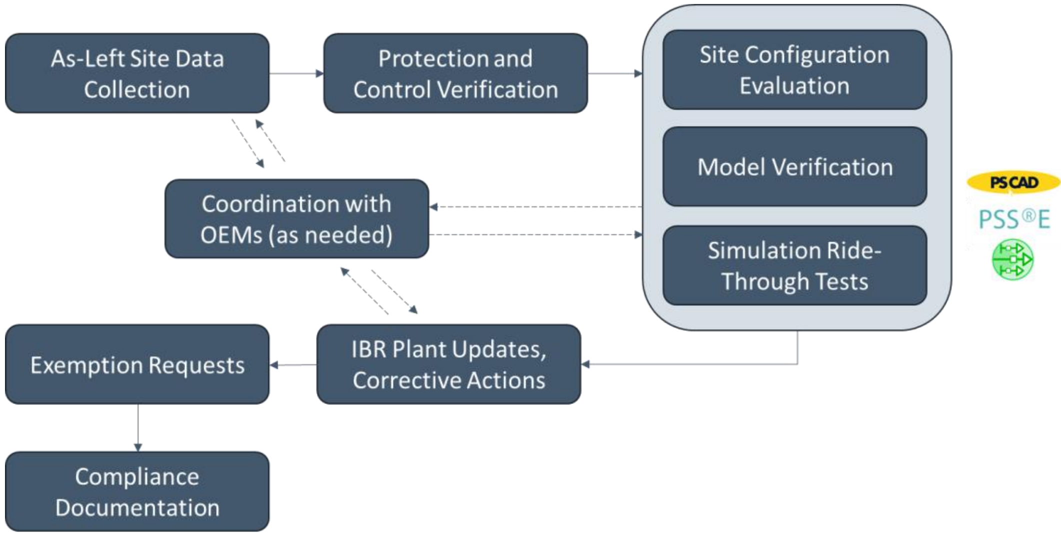


Figure 50: Elevate IBR Plant Ride-Through Design Evaluation Methodology [Source: Elevate Energy Consulting]

As mentioned, careful consideration of all the sub-requirements in Requirements R1–R3 is needed during the evaluations. Some of these require careful analysis of simulation results under defined operating conditions, such as speed of active power recovery, active versus reactive current priority during ride-through modes of operation, maintaining active power during continuous operation, etc. Figure 51shows an example of a simulation result evaluating the post-fault recovery of active power per the sub-requirement.

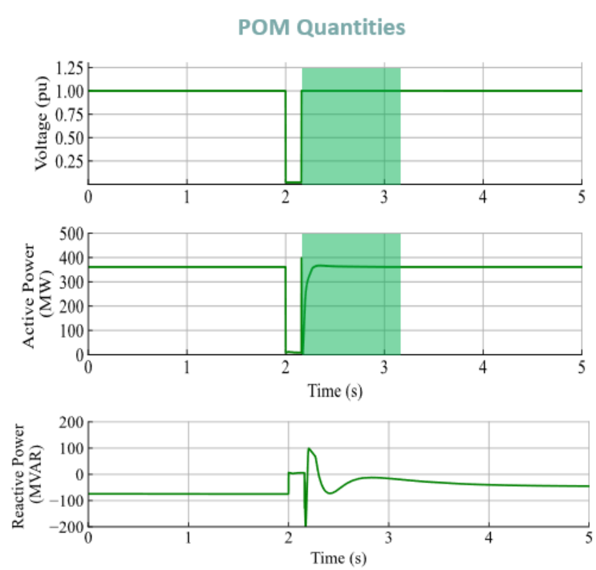


Figure 51: Illustration of Evaluating Simulation Results Against Sub-Requirements of PRC-029-1 [Source: Elevate Energy Consulting]

Some requirements cannot be adequately assessed using simulation results. For example, it is very rare for simulation models to represent consecutive voltage ride-through thresholds as they may often involve mechanical impacts that are not included in the electrical models. Thus, desktop evaluations are key to ensuring an adequate and comprehensive evaluation is conducted. Simulation results should not be overly relied upon to justify ride-through, as this could result in a false sense of acceptable performance. Further, both EMT and phasor domain positive sequence models can be effective for conducting IBR plant ride-through design evaluations; it is first and foremost important that accurate models reflective of the actual as-left settings are used for the studies and careful use of the models and understanding their limitations is key.

Q&A and Interactive Group Discussion

Where do the requirements of NERC PRC-029-1 apply?

The requirements apply at the point of measurement (POM) of the IBR plant, which is the high side of the main power transformer(s).

How can the IBR plant ride-through design evaluation be completed to meet compliance by 10/1/2026 yet the exemptions are due by 10/1/2027? It seems that the exemptions would be due by 10/1/2026. Please clarify.

Prior to the October 1, 2026, cut-off date, resources are considered legacy and follow the legacy rules. If exemption documents are available, the 12-month window is used to bridge between the effective date of PRC-029-1 and the last date to seek exemption being on October 1, 2027.

PRC-029-1 Requirement R4 lists "known hardware" but what about older inverters that do not have documentation of sufficient detail and could have "unknown" limitations?

JP stated that if the IBR unit preventing the IBR plant from meeting Requirement R4 is getting replaced, then there are no issues. For older inverters with unknown limitations, JP noted that the NERC team is still identifying the specific requirements, so the formal process is in development. If equipment data is not available to necessary parties, OEMs are encouraged to participate, which was mentioned in the FERC Order 909 virtual conference.

Regarding exemptions for Requirement R4, there is no template. The standard is also under revision with Project 2025-05. Entities are encouraged to reach out to their applicable CEA. There are no published recommendation documents at this time. NERC does not write compliance guidance materials for industry. Since PRC-029-1 has no guidance, it is up to entities to find the evidence to present against the standard. Comments and feedback can be brought to Project 2025-05 and entities are encouraged to reach out with concerns.

Is there any mandate that PRC-029-1 should only be performed using EMT models? Are RMS models acceptable? Some jurisdictions do not have EMT modeling requirements during generator interconnection and thus those models are not available. Are standard library PSSE/PSLF models effective to perform evaluations? What will NERC accept / expect in the evaluation? Is a standard library model sufficient or is a UDM required?

Amin highlighted that both EMT and phasor domain models should be considered acceptable by the regulatory bodies, and the best available model and information should be used for all evaluations. Many existing IBR plants do not have an EMT model available or constructed, and it is extremely time-intensive and costly to build these models from scratch in coordination with the OEMs. Thus, for these types of sites, a phasor domain model should be deemed adequate and additional desktop evaluation efforts can be performed to ensure a thorough evaluation of ride-through is conducted. Symmetrical faults do not strictly require EMT for PRC-029-1 IBR ride-through evaluations, although phasor software may be an inferior representation than EMT in many ways. Generally, if a high quality EMT model is available, it should be used for the PRC-029-1 evaluation.

NERC recommended to use the currently available information about the site. There is no defined requirement regarding which models to use, but NERC does recommend that the most accurate model available be used, which is generally a UDM rather than generic and an EMT model over a phasor domain model.

GE Vernova highlighted that momentary cessation is not captured in the phasor domain models that they release for their wind fleet. Thus, EMT models are encouraged; however, not all sites have an EMT model.

It was mentioned that voltages within the IBR plant are important to consider when setting up a power flow case. How is this done with an aggregated model? Do you suggest detailed IBR plant models for PRC-029-1 evaluations?

Amin explained that an aggregate model is sufficient and generally the only model of the IBR plant available; it is relatively uncommon for a detailed, disaggregated dynamic model of the IBR plant to be readily available and verified. Regardless, aggregate representation is adequate to capture worst-case assumptions of voltage drop across the collector system and PRC-029-1 is at an IBR plant-level rather than an inverter-level so aggregate models are again useful here.

Voltage ride-through is specified at the high side of the main power transformer(s). Is there recommended guidance for translating the high side values to the inverter settings at the inverter terminal voltage base? Transformer taps and power flow conditions have a large impact on the voltage difference.

Amin recommended that simulations be performed to verify the settings and establish stressed operating conditions to verify ride-through performance. Using playback-based approaches, the

POM voltages can be controlled and the IBR plant components, protections, and controls can be evaluated via simulation.

Who will evaluate the IBR plant model compliance?

JP stressed that the IBR plant ride-through design evaluation is the responsibility of the generator owner, including modeling performance tests. The IBR plant owner will report any exemptions to the CEA and other entities; otherwise, they must have evidence of the evaluation to meet compliance and then the IBR plant must also perform to these capabilities operationally. The Reliability Coordinator or Transmission Operator may identify ride-through failures and the IBR owner may also detect failures, both of which may require performance evaluation per NERC PRC-030.

Is there a need for disaggregated models of the IBR plant to assess PRC-029-1 compliance or are aggregate models sufficient?

Aggregate models should be considered sufficient for conducting these ride-through design evaluations.

How should PRC-029 findings be addressed if the OEM is no longer in business to support remediation?

This is still a relatively rare occurrence where the OEM is no longer in business, but it does exist for some facilities. In these cases, careful evaluation of the site should be addressed on a case-by-case basis based on the data, information, and models available. If a relatively accurate model is available, and can be used for the evaluation, then there are likely no additional software updates to make. However, some OEMs have transferred support services to a third party and thus software-based updates may still be viable. Acquiring accurate EMT models and phasor domain UDMs will be very challenging in these cases, so standard library models may be required for the simulation portion of the evaluation.

The grid is evolving rapidly, and current stability margins are being reduced by the current IBR interconnection and planning processes. What are the main updates in WTG Type 3 and 4 in this area?

All GE Vernova platforms are grid following inverter technology. Although new controls enable meeting new requirements, low voltage leads to torque loss and later recovery, causing electrical power fluctuation. Mechanical implications may damage equipment, so these must be addressed to mitigate mechanical load. With other stringent power recovery rates, they are evaluating more than just the electrical aspect.

With much more stringent requirements in PRC-029-1 as compared with NERC PRC-024-3, as OEM are you pushing limits or identifying limits?

GE Vernova stated that for turbine models being produced, EMT simulations and sub-component tests are conducted in the lab. For simultaneous events, they are doing lab tests for the next level requirements, specifically turbine-level validation. They are executing voltage ride-through testing on the 3.8 type turbine right now. However, the level of validation for lab tests on legacy turbines is limited, so they rely a lot on simulations.

Can GE Vernova share their PRC-029 evaluation documents with the whole industry so other OEMs can see and consider applying the same approach?

GE Vernova stated that they must respect customer confidentiality. Limitations on GE Vernova's equipment do not apply to other OEMs and they may have their own limitations. GE Vernova plans to publish a report for a group of turbines for their ride-through capabilities. Most of the requirements are at the POM but the ride-through capabilities are defined at the WTG terminals.

Is it required to simulate the 1800sec period for the 1.05-1.1 voltage range?

EMT models take a relatively long time to run an 1800-second simulation; phasor domain software is designed to run 60-100s. Thus, these dynamic models are not intended to run simulations for this long and are not accurate at this time scale. IBR plant settings can be reviewed to verify the performance with this sub-requirement beyond 60-100 second simulation timeframe.

How can phasor domain simulation programs be used to prove functions such as DC bus tripping or PLL trips are not occurring? Are EMT models therefore required?

Amin stated that this is a concept that requires careful consideration by the subject matter expert conducting the evaluation. Not all inverters have DC-side protection; however, some may have instantaneous protections that require careful consideration against the requirements. If they do have these protections, they are not generally represented in the phasor domain models and are often not even modeled in the EMT models adequately. Desktop evaluations may prove just as effective in assuring ride-through performance in these cases.

How are transformer on load tap changer settings evaluated for PRC-029-1?

Amin articulated that tap changer settings impacts the power flow base case setup and the voltage on the feeders when setting up the 0.95 lagging and leading power factor cases. If the taps are not reset before solving each power flow case, one might see unreal over- or under-voltage on the feeders. Thus, careful attention to the tap changer settings and treatment in the simulations is key.

In the PRC-029 assessment, is an infinite short-circuit level at the POI assumed or do you consider the prevailing short-circuit levels at the POI (max, min, and eventually absolute min)?

Generally, a single machine infinite bus (SMIB) system is used to control the POM voltage conditions and test ride-through performance under defined voltage profiles.

How is automation of dynamic simulations handled, particularly for large quantities of simulation tests? Are multiple Python scripts used? How is this broken up?

This can depend on how long and how many simulations are performed. If the run time is long, the "Parallel Dynamic Module" of PSS®E could be used which allows running multiple simulations at the same time on different CPU cores. This can significantly improve the overall evaluation simulation speed.

Are asymmetrical voltage disturbances required for simulation in Requirement R2.2? What methods need to be used?

It is generally not necessary to conduct an asymmetrical fault because the symmetrical fault captures the worst-case scenario and pushes the IBR to its limits. Phasor domain tools cannot adequately test asymmetrical faults. However, if an EMT model is available, then additional simulations could be conducted to test asymmetrical faults, but again this may not be necessary.

Key Themes

- **Transition to Performance-Based Ride-Through Requirements:** The implementation of PRC-029-1 represents a shift from a settings-based relay standard to a comprehensive performance-based standard for applicable IBRs. The standard focuses on ride-through capability and performance, as well as the dynamic performance of the IBR plant during ride-through events. Initial compliance deadlines are approaching in October 2026, and all applicable IBR owners are strongly encouraged to start compliance assessment efforts and IBR plant ride-through design evaluations as soon as possible to meet regulatory deadlines.
- **Regulatory Evolution, Exemptions, and Unresolved Gaps:** Directives stemming from FERC Orders 901 and 909 highlight that PRC-029-1 continues to evolve and additional topics are being addressed by a current drafting team. This is particularly with respect to exemptions for legacy equipment, long lead-time projects, and HVDC-connected IBRs with choppers. The exemption process is also still somewhat unclear and entities should ensure they conduct ample due diligence to prepare for these exemption requests fleet-wide. Significant uncertainty remains around documentation sufficiency and timing alignment.
- **OEM Capability Pathways and Fleet-Specific Solutions:** OEM perspectives highlighted that compliance is technology- and platform-specific, particularly for legacy assets. Software-based upgrades can improve ride-through capability and performance for older sites, however, must be acquired by the OEM and implemented. Ride-through evaluations will need to be re-conducted for post-implementation outcomes. Physical

hardware-based design limits exist and should be considered carefully in coordination with the OEM.

- **Importance of Accurate As-Left Data and Desktop Verification:** A recurring theme was that ride-through evaluations are only as credible as the underlying site data and settings used in the assessment. Verifying as-left configurations, hidden protections, and hard-coded OEM logic is often more critical than running extensive simulations. Desktop reviews of protection and control behavior are essential, particularly where dynamic models could fail to represent key trip functions or mechanical constraints.
- **Model Fidelity Over Model Type:** The discussions reinforced that PRC-029-1 does not mandate a specific modeling approach; rather, it expects use of the most accurate model reasonably available. EMT models provide greater visibility into phenomena such as momentary cessation and DC-side protection yet phasor domain models, when paired with careful engineering judgment, are generally sufficient for many evaluations. Over-reliance on simulations without understanding model limitations can lead to false confidence in ride-through capability.
- **Need for Early Coordination and Scalable Processes:** Effective PRC-029-1 implementation depends on early and sustained coordination across generator owners, OEMs, consultants, and compliance authorities. Differences in regional processes for upgrades, model validation, and evidence review can create friction that must be managed proactively. Establishing repeatable methodologies, documentation procedures, and shared expectations is critical to effectively achieving compliance at-scale.

February 24, 2026 Virtual Meeting

IBR Standards – How to Make Sense of it All? (204 attendees)

Presentation recording and slides are available to download here. Figure 52 shows the makeup of meeting attendees by industry sector:

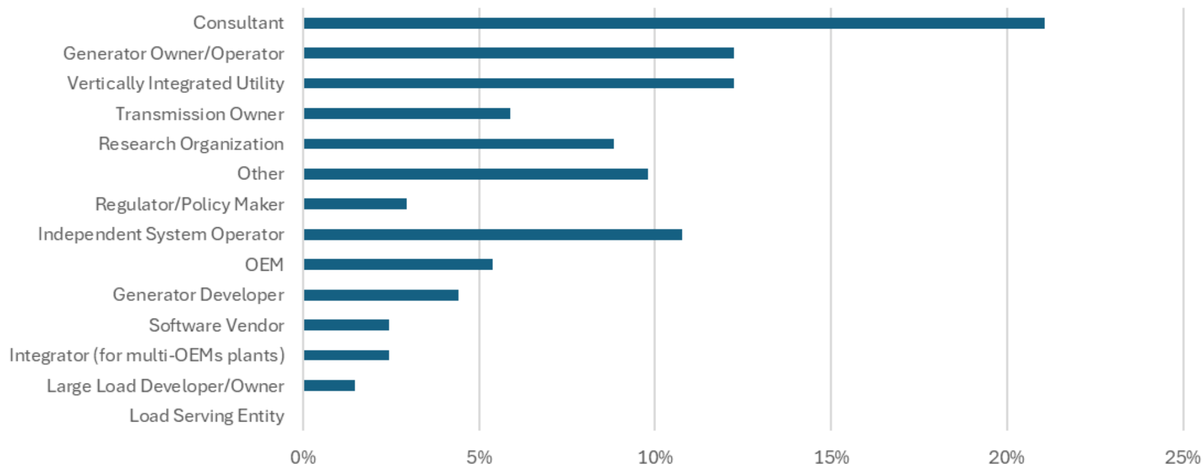


Figure 52: Meeting attendees by industry sector

The tenth meeting of Season 2 of the DOE i2X FIRST initiative focused on lessons learned developing IBR requirements, integration into existing processes, experience bringing new IBRs online, and ensuring they conform with applicable standards and requirements. The session focused on adoption of IEEE 2800-2022, recently approved NERC standards from FERC Order 901, the upcoming publication of IEEE P2800.2, and future updates to these standards.

Jens Boemer, EPRI

Jens Boemer presented on the evolving landscape of IBR standards and their implications for BPS reliability. He provided historical context regarding past NERC disturbance report findings, noting that unexpected IBR tripping, misapplication of IEEE 1547 standard to transmission-connected IBRs, lack of standardized IBR performance, modeling, and verification are all key contributors to reliability risks. He emphasized the importance of not just trusting IBR plant designs but also verifying that they are implemented correctly through as-built verification.

Jens outlined the relationship between voluntary and mandatory standards, particularly in the U.S., highlighting FERC Order 901 as a key driver for developing NERC Reliability Standards applicable to IBRs (see Figure 53). While NERC standards have been inspired by IEEE standards, IEEE standards have not been directly adopted by NERC. Thus, implementation of IEEE 2800-2022 relies heavily on ISO/RTOs, transmission providers, and other authorities governing interconnection requirements as well as IBR plant developers, OEMs, and other stakeholders to adopt the principles within the standard.

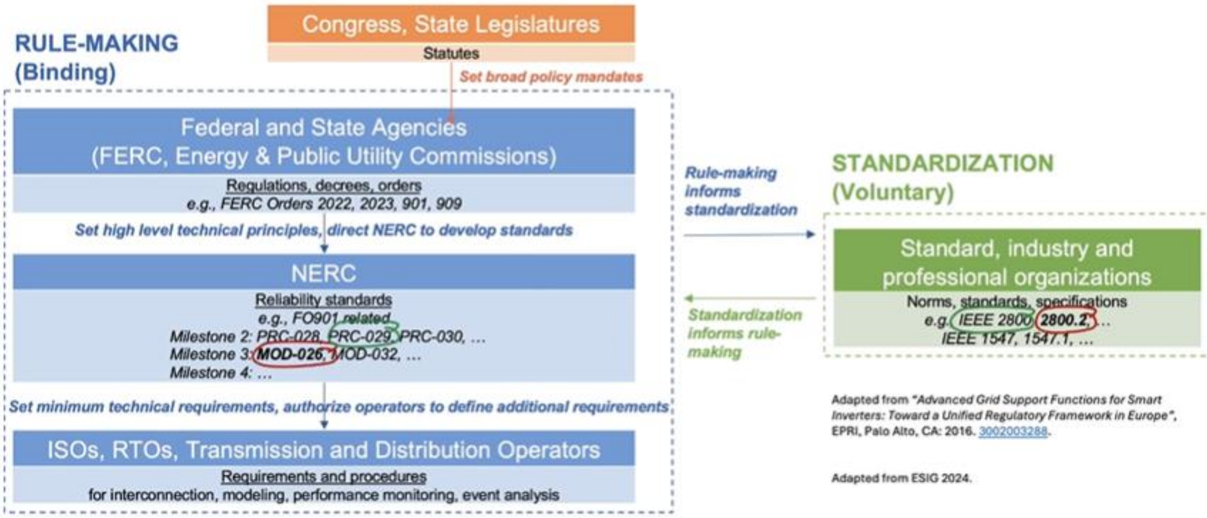


Figure 53: Relationships between voluntary and mandatory IBR standards in the United States [Source: EPRI]

Many Category 2 IBRs (i.e., between 20 MVA and 75 MVA connected at 60 kV and above) that have not been subject to mandatory NERC Reliability Standards will soon be through NERC IBR registration initiatives. Over 650 Category 2 IBRs have been identified by NERC, with expectations this number could rise to 700 or 800. These IBRs will now be required to meet standards like NERC PRC-029-1 for ride-through capability and performance, which is a significant shift for many existing facilities that previously had no mandatory reliability requirements.

Jens highlighted the difference between capability and utilization, advocating for early incorporation of capabilities into designs, even if they are not immediately required and utilized (see Figure 54). This is one way to mitigate grid reliability risks as the prevalence of IBRs grows.

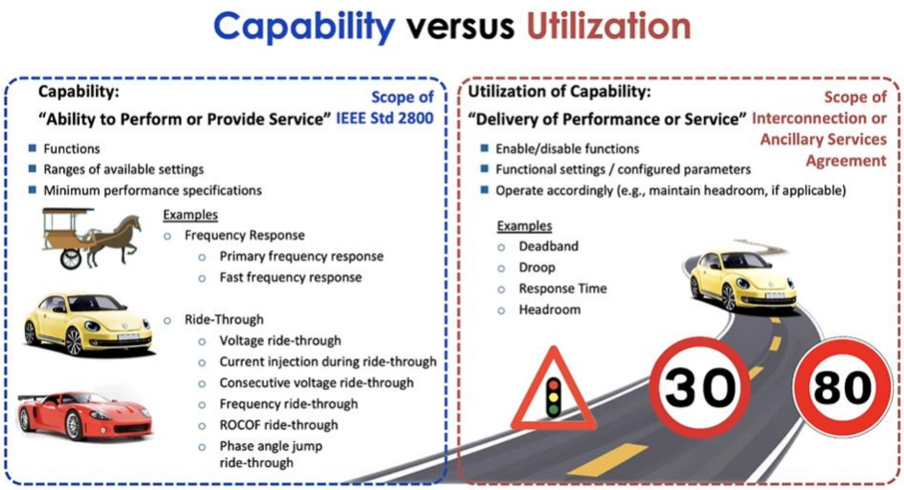


Figure 54: Relationships Between Capability and Utilization [Source: EPRI]

He also discussed the upcoming publication of IEEE P2800.2, which is expected to be published in April 2026 and aims to provide a coherent framework for verifying IBR capabilities and assessing conformity with IEEE 2800-2022. While modeling is a critical tool for assessing conformity, it is not the only method; evaluating design documentation is equally important.

Industry collaboration to update existing IBR modeling and performance requirements is critical to address known and future reliability risks, given the evolving nature of the grid. Many procedures in IEEE P2800.2 are not new and are being adopted by various entities already. However, these procedures were developed in a short timeframe and leave opportunities for improvement through industry engagement. Passing down knowledge and engaging the future workforce in standards development is also key to ensure ongoing improvements in IBR performance and reliability. Through industry collaboration, IEEE 2800 standards will move from a "hybrid integration" adoption approach to a "general reference" approach as the standard and its implementation continue to mature.

Scott Anderson, Salt River Project

Scott Anderson provided a detailed look at the Operational Readiness (OpR) program at Salt River Project (SRP) and how the utility is adapting to increasing levels of IBRs. SRP is one of the largest public power utilities in the U.S., based in Phoenix, AZ, with a historical focus on thermal generation, and a more recent focus on IBRs, particularly large-scale solar PV and BESS – most of these assets are under a power purchase agreement arrangement. SRP OpR initiative reflects SRP's commitment to operate future grids safely, reliably, and cost-effectively, emphasizing a strategic approach to managing a grid with higher IBR penetration.

The development of SRP's OpR strategy involved extensive data collection, surveys, and stakeholder engagement, including a "think tank" with over a hundred participants across the organization as well as external subject matter experts. This process led to a gap analysis that highlighted key areas for improvement across generation, tools, and people—specifically, understanding solar variability and battery storage technology, updating forecasting and situational awareness systems, and enhancing training and expertise in IBR technology. To address these gaps, SRP initiated 30+ projects across six thematic areas, with completed projects summarized and shared across relevant departments to ensure alignment and knowledge transfer. They are now in the fourth year of implementing the OpR strategy and have added nine new IBRs totaling 2.6 GW (1500 MW of solar and 1100 MW of BESS).

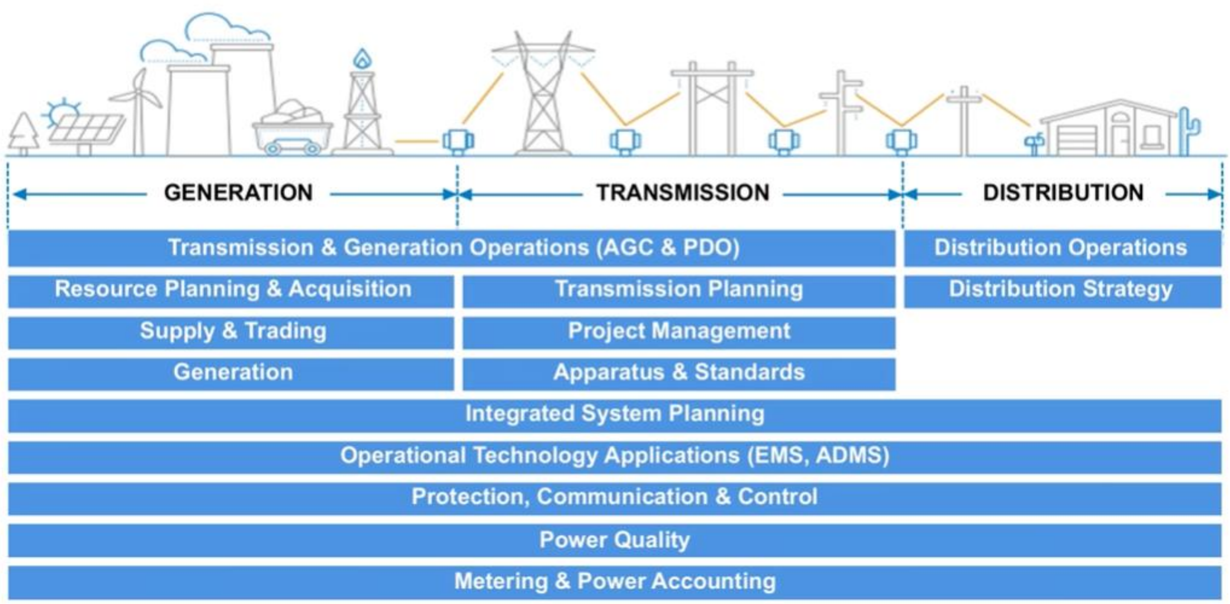


Figure 55: SRP OpR Enterprise Stakeholders [Source: SRP]

Collaboration is a central theme of the OpR program, which engages multiple departments across transmission, generation, and distribution to ensure a coordinated approach to integrating IBRs (see Figure 55). SRP has evolved its technical requirements for IBRs, informed by IEEE 2800-2022, NERC Order 901 standards efforts, and other industry reports. These requirements were structured around power purchase agreements (PPAs) and then moved to SRP's Facility Connection Requirements, with improvements including provisions for plant dispatch, data and telemetry responsibilities, forecasting obligations, and refined modeling and performance requirements. SRP leveraged the "hybrid integration" approach for IEEE 2800-2022 adoption (see Figure 56).

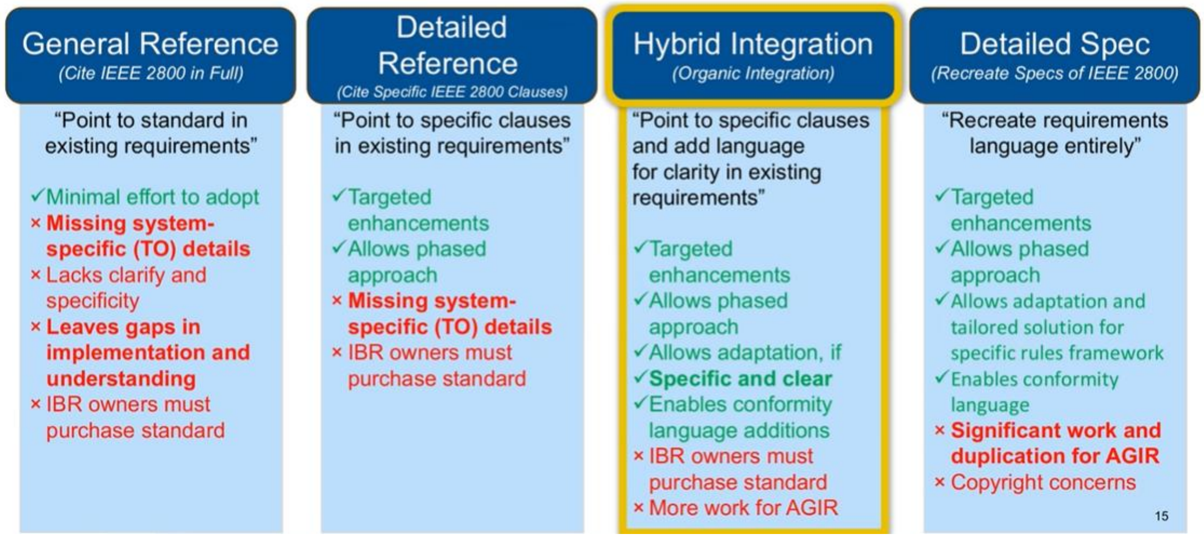


Figure 56: SRPs "Hybrid Integration" Approach to IEEE 2800-2022 [Source: SRP, adapted from ESIG]

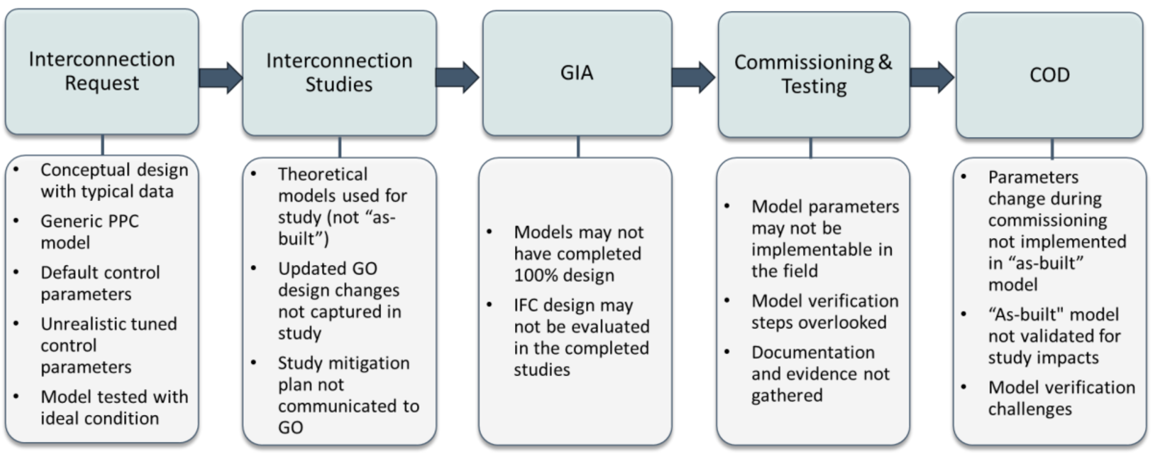
Scott shared real-world examples including sharing data from IBR sites that demonstrated SRP's success in integrating solar and BESS projects, highlighting measurable gains in cost effectiveness, reliability, and operational efficiency. Looking ahead, SRP recognizes the importance of proactively preparing for continued IBR growth and maintaining a focus on continuous improvement and strategic planning. SRP's collaborative, forward-looking approach to facing IBR-related challenges has proved an effective tool for the organization and a model for other industry stakeholders.

Ryan Quint, Elevate Energy Consulting

Ryan focused on the need to establish clear, harmonized interconnection performance and modeling requirements for IBRs as a foundational step toward improving grid reliability and streamlining the interconnection process. He also highlighted the numerous reliability events reported by NERC involving IBRs, noting these incidents point to broader, systemic challenges rather than isolated failures, which can be overcome with improvements to IBR plant conformity assessments during the interconnection process. The 2022 Odessa disturbance report was a tipping point that underscored this need, and stressed at the federal level the need for action both in the NERC Reliability Standards and in the FERC Generator Interconnection Procedures (GIP).

Ryan highlighted the importance of defining performance expectations early in the process. The first step is establishing clear, consistent performance requirements for newly connecting IBRs before projects move too far into development. Harmonizing these requirements based on learnings domestically and internationally can help avoid costly retrofits and redesigns later. By setting expectations upfront, utilities and developers can reduce uncertainty and ensure new IBRs are designed and operationally perform to meet performance expectations and requirements.

Ensuring accuracy and alignment between IBR plant model, IBR plant design, and performance requirements is central to achieving reliability objectives. IBR plants must be designed to meet established performance standards, and the models used in reliability studies must accurately reflect the actual project configuration. When models diverge from as-built designs, the integrity of planning studies and operational decision-making can be significantly compromised. This can be the result of the constant changes occurring to IBR plant designs throughout the interconnection process and IBR plant lifecycle (see Figure 57). Default model parameters, early-stage designs used in cluster studies, IBR plant equipment changes later in the process, and gaps in IBR plant commissioning all create opportunities for misalignment and systemic risks to be introduced.



* IFC = Issued for Construction; GIA = Generator Interconnection Agreement; COD = Commercial Operation Date

Figure 57: Potential Challenges with Current Interconnection Process [Source: Elevate Energy Consulting]

Without national-level requirements in place, industry has developed somewhat harmonized but notably different implementation of IEEE 2800-2022, IBR modeling requirements, performance conformity assessment processes, etc. Ryan stressed that harmonization can enhance reliability but also enable faster and more predictable interconnections by minimizing errors and rework. This requires sequential alignment throughout the interconnection lifecycle, with clear checkpoints to ensure that projects remain consistent with established requirements at each stage. Without such checks and balances, misalignment between study assumptions and actual plant capabilities can introduce reliability risks and delay project timelines.

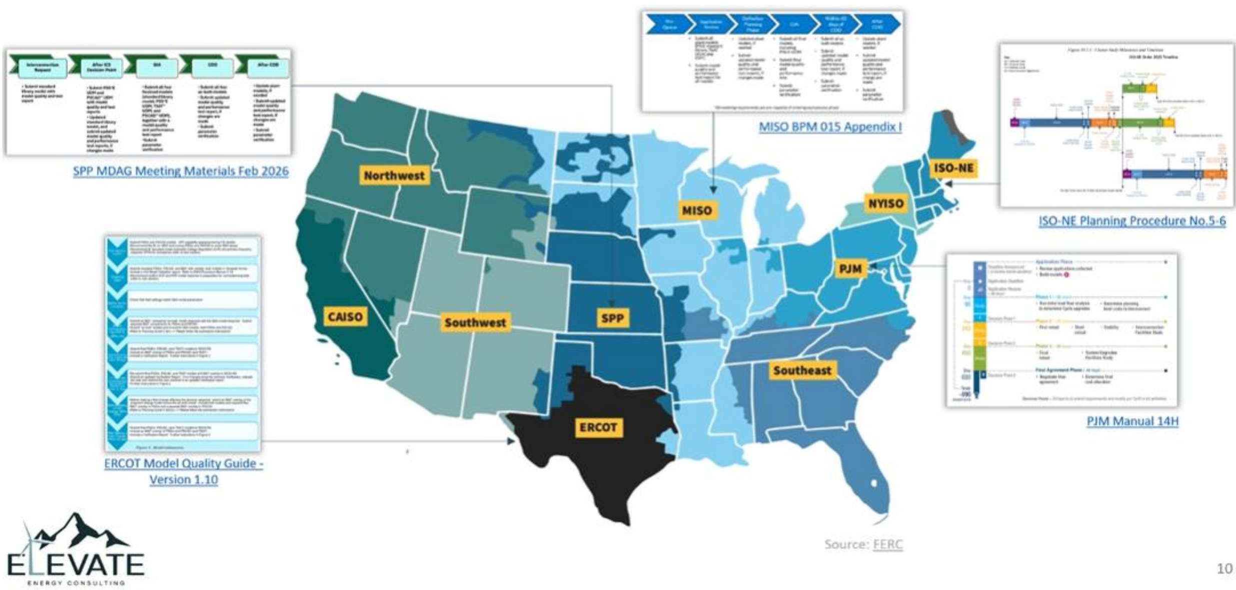


Figure 58: Regional IEEE 2800 Implementation Varies [Source: Elevate Energy Consulting]

Looking ahead, Ryan pointed to the implementation of the upcoming IEEE P2800.2 standard as a key opportunity to strengthen and modernize the interconnection process overall. He encouraged ongoing collaboration among utilities, IBR developers, OEMs, and regulators to ensure that performance requirements are consistently applied and effectively integrated in practice. He also emphasized that portions of IEEE P2800.2 need to be codified and put into action for effective change to occur. Industry is experiencing some implementation changes and improvements across regions (see Figure 58), but there are still key differences across the U.S. that need to be harmonized. He specifically cited MISO and ERCOT as adding in more model quality and performance testing requirements that are more in line with IEEE P2800.2. However, the challenge is that the current process is set up to fit these checks into a relatively short period of time between the cluster study and the final agreements. Overall, harmonized, clearly defined performance standards with checks at more frequent milestones and transmission provider involvement in the IBR plant commissioning and testing process are a strategic necessity for addressing the known IBR systemic risks.

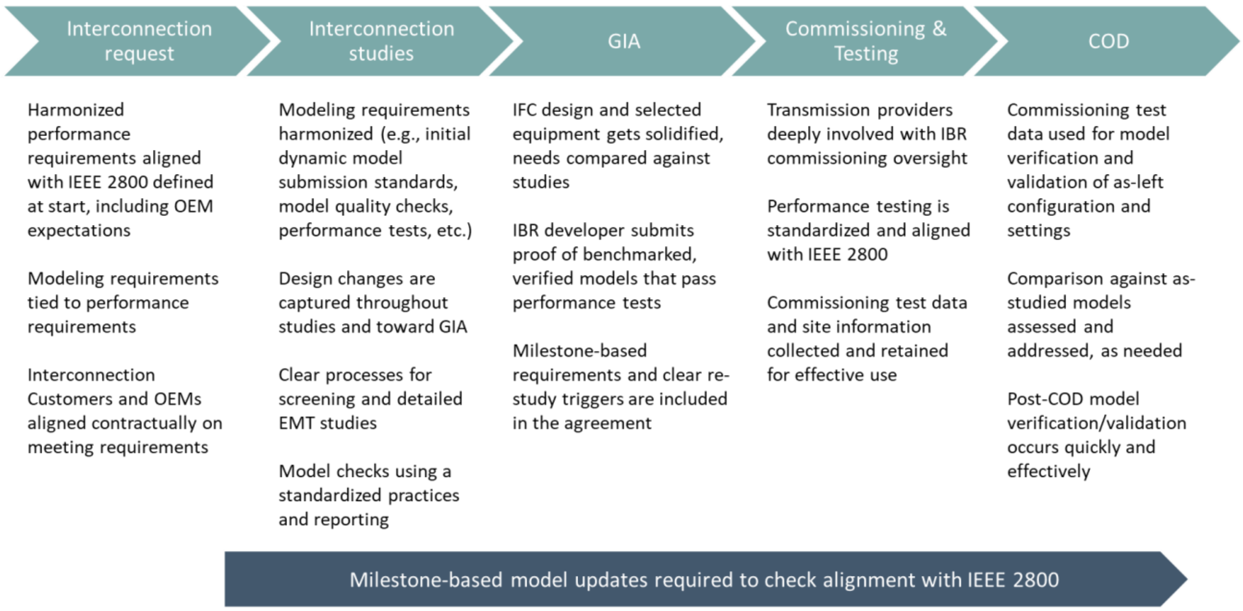


Figure 59: Recommended path forward to improve the IBR lifecycle [Source: Elevate Energy Consulting]

Q&A and Interactive Group Discussion

Is it beneficial for the grid to have IBRs injecting short-circuit current larger than nominal for five or more seconds?

Jens responded that there is no simple or generic answer to this question. Whether sustained fault current injection is beneficial depends on multiple factors, including grid conditions, the number and type of IBRs in the study area and beyond, and the protection systems in place, including legacy protection. In some cases, higher short circuit current contribution may be helpful; in others, it may introduce risk. IEEE 2800-2022 includes concepts related to overrating, though these are primarily focused on power rather than sustained current injection. He also indicated that EPRI has conducted research in this area and that further study is needed before drawing firm conclusions.

Ryan added that on the BPS, five seconds is already a very long fault duration. In his experience, even extreme cases tend to be significantly shorter, reinforcing that system context is critical when evaluating such scenarios.

Scott emphasized the importance of understanding both current system assumptions and future conditions, including how resource mix may evolve over the next decade. He noted that modeling assumptions and study expectations play a significant role in determining whether additional fault current is necessary or beneficial. Ryan further observed that traditional utility practices such as assuming all resources are online in short circuit analyses may create unrealistic assumptions that lead to costly upgrades.

Is a standalone STATCOM considered an IBR? If so, does this make sense considering the fundamental differences between generation and transmission assets?

Under IEEE 2800-2022, a standalone STATCOM does not meet the definition of an IBR because it is not "capable of exporting active power" as required by the standard's definition, (see Clause 3.1). However, STATCOMs may be used as "supplemental IBR devices" within an IBR plant to help the plant meet IEEE 2800-2022 performance requirements. In that context, the STATCOM becomes part of the overall IBR plant design. This distinction does not apply to transmission-connected STATCOMs operating independently of generation resources. The NERC construct is similar in that an IBR is defined as a generating asset whereas a standalone STATCOM is considered a dynamic reactive power resource.

What is a phasor model? Is it the same as a positive-sequence model?

Phasor models are based on fundamental frequency representations of the grid and the controls of IBR plants. While many phasor-domain models used in typical U.S. transmission planning practice are positive-sequence models, not all phasor models are strictly limited to positive-sequence representation. Positive-sequence models are a subset of phasor-domain models and depending on configuration, phasor models may produce negative- or zero-sequence components.

What does it mean for a regulatory body to adopt or enforce IEEE P2800.2 when it is written as a recommended practice (largely "should" and "may" language) rather than mandatory "shall" requirements?

IEEE 2800-2022 primarily uses "shall" language in the requirements but must be enforced by a regulatory body or other entity. The language in the requirements is written in a manner intended for use in enforceable requirements. IEEE P2800.2 is a voluntary set of recommended practices and thus intentionally leverages mostly "should" language.

Enforcement mechanisms are important for utilities and system operators to understand as they adopt both IEEE 2800-2022 and IEEE P2800.2. The adopting authority could choose to convert "should" statements to "shall" requirements. Jens suggested that during adoption, stakeholders should review each "should" statement and determine whether it is appropriate to make it mandatory.

Ryan added that IEEE 2800-2022 was developed through strong industry consensus, with extensive debate behind each requirement. Because IEEE P2800.2 is written entirely as a recommended practice, effective implementation may require a structured effort to review and potentially replace "should" language with enforceable "shall" requirements where appropriate. Jens also noted that initial adoption as guidance, without immediately introducing legal enforcement, may facilitate collaboration and smoother implementation.

It was mentioned that IEEE P2800.2 does not fully verify the model. What are some things that might get missed?

IEEE P2800.2 Clause 7.3 addresses procedures for IBR plant capability and performance assessment and specifies that "for each equipment model within a plant (for example, aggregated IBR unit model, power plant controller models, and supplemental IBR device models), controls and their parameter values should be configured such that they represent the overall IBR plant configuration and represent the utilization of capability as specified by the TS owner/TS operator."

In SRP's Iberian Peninsula workshop, one of the top concerns was difficulties coordinating with IBR plant developers, owners, and operators. Can you elaborate on that and any changes being implemented?

Scott explained that as the volume of new IBR projects increases, SRP has recognized the need for highly specific internal procedures that clearly define roles and responsibilities and how staff engage with IBR developers and owner/operators. This includes clarifying who is responsible for obtaining accurate IBR plant information and models and establishing enforcement mechanisms if requirements are not met. The coordination challenge stems in part from the pace of development now that they are adding numerous resources each year.

What is meant by "harmonized" requirements? Does harmonization refer to alignment across IBR technologies, across deployment stages, or something else?

Harmonization refers to establishing consistent, forward-looking technical minimum functional and performance requirements for IBR plants across entities. By defining clear baseline capabilities, system operators can better manage risk and decide when and how to utilize those capabilities to manage risk.

Key Themes

- **Voluntary Guidance and Mandatory IBR Reliability Standards:** The transition from largely voluntary guidance to mandatory NERC Reliability Standards and IEEE 2800-2022 adoption for IBRs is occurring rapidly, in an attempt to address known systemic risks that may stem from the interconnection process. Significant work is focused on effective implementation efforts to comply with these standards including meeting NERC standards, adopting requirements from IEEE 2800-2022, and incorporating recommended practices from IEEE P2800.2. IEEE P2800.2 implementation will require careful coordination among ISOs/RTOs, utilities, IBR developers, OEMs, third parties, and regulatory bodies.
- **Operational Readiness as an Organizational Initiative:** Utility operational readiness programs that bring together diverse stakeholders can help accelerate utility and system operator preparedness for rapidly rising IBR levels. Data gathering, internal surveys,

cross-departmental engagement, and proactive risk mitigation have helped SRP accelerate solutions to manage higher IBR penetrations today and ahead. The utility has launched more than 30 projects across multiple themes to strengthen forecasting, situational awareness, training, modeling practices, IBR performance requirements, and interdepartmental coordination.

- **Challenges with current interconnection lifecycle:** There remain challenges throughout the interconnection process regarding model verification and accuracy, and IBR plant conformity assessments. Default or generic models, generalized assumptions, early-stage design used for cluster system impact studies, and lack of milestones later in the interconnection process are all contributors to these challenges. Final as-built designs may not be adequately checked and lack of oversight during IBR plant commissioning may underutilize the data available for model verification and validation. This introduces risks that can be fixed with improvements to the process and may lead to systemic risks persisting unless addressed.
- **National Harmonization of Technical Requirements to Reduce Reliability Risk:** The discussion continued to emphasize greater national consistency in how interconnection processes, IBR plant performance requirements, and IBR modeling requirements are defined and implemented. ISOs and utilities are developing somewhat similar yet notably different processes and requirements that create significant complications for IBR developers operating in different regions. The web of rules, requirements, milestones, etc., creates room for error and slowdown of the process. A more unified approach would reduce regional fragmentation, lower retrofit risk, and increase confidence that IBRs are designed to meet necessary technical minimum requirements.
- **Accountability Throughout the Interconnection Lifecycle:** Structured, milestone-based implementation of IEEE P2800.2, IBR modeling requirements, IBR plant performance conformity assessments, and commissioning practices can help address many of the challenges outlined. Alignment with IEEE P2800.2 between the authority governing interconnection requirements, the IBR developer, OEMs, and third parties can help streamline the process and reduce risk. More closely tracking design changes throughout the interconnection process and conducting IBR plant design evaluations (including checking as-studied and as-built configurations) are key. Commissioning test data should be systematically collected and used to validate final plant settings, with transmission providers actively involved in oversight and model verification.

March 16, 2026 (Hybrid event at ESIG Spring Workshop)

Grid Forming IBR Specifications, Testing Requirements, and Lessons Learned (~50 in-person attendees and ~100 virtual attendees)

Presentation recording and slides are available to download here. (Breakdown of attendee by sector was not available for this event.)

The eleventh and final meeting of Season 2 of the DOE i2X FIRST initiative involved a hybrid (in-person and online) workshop in conjunction with the ESIG Spring Workshop. This session focused on grid forming (GFM) inverter technology including basics of the technology, system needs that drive GFM utilization, evolving grid code requirements, and global landscape and trends.

Introduction, Julia Matevosyan, ESIG; Cynthia Bothwell, DOE (Contractor)

Julia welcomed in-person and online participants to the workshop, provided a recap of the i2X FIRST Season 2 efforts, and gave an overview of the workshop agenda for the day. Julia also highlighted some new updates regarding DOE i2X and related topics, including the following:

- **i2X FIRST Season 3**, which will include four meetings from June 2026 to January 2027 covering emerging topics including NERC PRC-029 implementation process updates, NERC Milestone 4 projects and the NERC Project 2022-04 EMT Modeling drafting efforts, IEEE P2800.2 deep dive and adoption pathways, and updates on new IEEE 2800 series efforts (including GFM requirements).
- **i2X STITCH** "Studies, Tools, and InTerconnection Consistency & Harmonization," which will include nine meetings from May 2026 to March 2027 and summarize current interconnection studies approaches across ISOs, strive for opportunities to standardize and harmonize interconnection study methods, identify industry recommended practices, and discuss possible gaps and ways to overcome these challenges.
- **Interconnection Technical Assistance Office Hours** where industry stakeholders can meet with ESIG and the Elevate Energy Consulting team to discuss specific technical issues related to understanding, implementation, adoption of harmonized and/or comprehensive interconnection requirements or standards for generators, as well as conformity assessment approaches for new standards.
- An encore round of upcoming in-person and online trainings being planned for 2026 focused on interconnection and EMT modeling/studies based on successes from both trainings in 2025.

Cynthia provided an overview of the i2X initiative, its mission, and some of its recent successes. The i2X effort is focused on enabling a simple, fast, and affordable generator interconnection process while enhancing reliability and security of the electric grid. It is focused on strategic solutions, stakeholder engagement, data and analytics, and research and development efforts. Some recent 2026 highlights are listed in Figure 60.

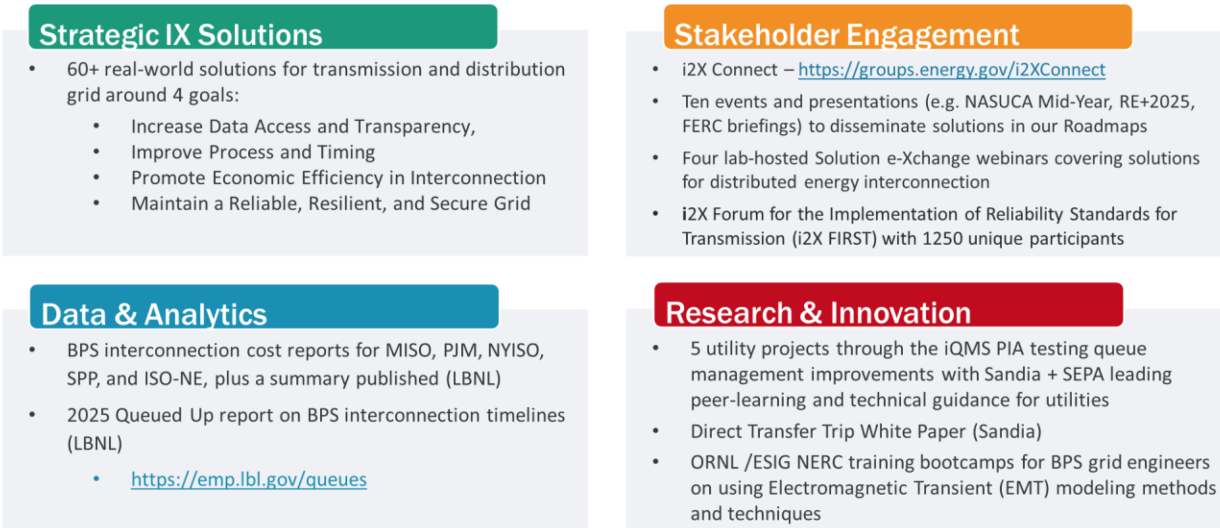


Figure 60: i2X Focus Areas and 2025 Activity Highlights

Cynthia also shared details regarding the upcoming Interconnection Cost Reduction Solutions (iCRS) Program opportunities for transmission (iCRS-T) and distribution (iCRS-D). The iCRS-D effort will be funding local, state, or regional partnerships to execute a "Lighthouse Project" to develop and demonstrate new technologies and effective solutions to increase data access and transparency, streamline and expedite interconnection services, and maximize economic efficiency. The iCRS-T effort will facilitate matchmaking between US transmission providers and organizations with specialized expertise in advanced grid modeling and interconnection studies in an effort to pursue cost-reducing technologies in interconnection studies.

Session 1, Part I – Basics of Grid Forming IBRs, Andrew Isaacs, Electranix

Andrew provided a brief tutorial about the fundamentals of GFM technology, controls, and applications. GFM has evolved and matured significantly as a technology over the past decade and today the engineering community generally agrees on fundamental principles, definitions, and integration techniques of the technology. It has been proven and tested extensively in the field in many applications around the world and industry continues to develop and enhance requirements that have led to grid reliability improvements and effective utilization of the technology.

There are numerous definitions of GFM proposed by NERC, UNIFI, MISO, AEMO, NESO, and others. Many of these definitions align on the core principle that GFM technology seeks to "maintain an internal voltage phasor (magnitude and angle) that is constant or nearly constant in the subtransient to transient timeframe." There are minor terminology differences among the definitions, but nearly all of them align on this fundamental concept. Some entities have chosen to use alternative definitions to GFM that focus more on the performance and services provided, such as ERCOT's Advanced Grid Support (AGS) concept. **Ultimately, one can think about GFM as simply another type of converter control that has inherent grid-stabilizing properties. These general properties seek to resist changes occurring in the system rather than quickly try to follow those changes.** This core concept is fundamental to differentiating GFM and GFL IBR technologies and how they get defined and applied on the BPS.

The high-level concept of GFM versus GFL can be illustrated with a simple test system as shown in Figure 61. A change in system bus/node phase angle (θ_2) occurs. The GFL BESS seeks to hold its active power constant and thus rapidly changes its internal phase angle (θ_1) to "follow" the system phase angle θ_2 (some variations in active power will occur due to physical properties, measurement delays, and other factors). On the other hand, the GFM BESS seeks to keep its internal phase angle θ_1 constant and thus a change in active power occurs within the "inertial" timeframe. These same concepts also apply to the voltage (V) change / reactive power (Q) response, which is useful and applicable to GFM resources with little or no active power availability such as GFM STATCOM and VSC-HVDC systems.

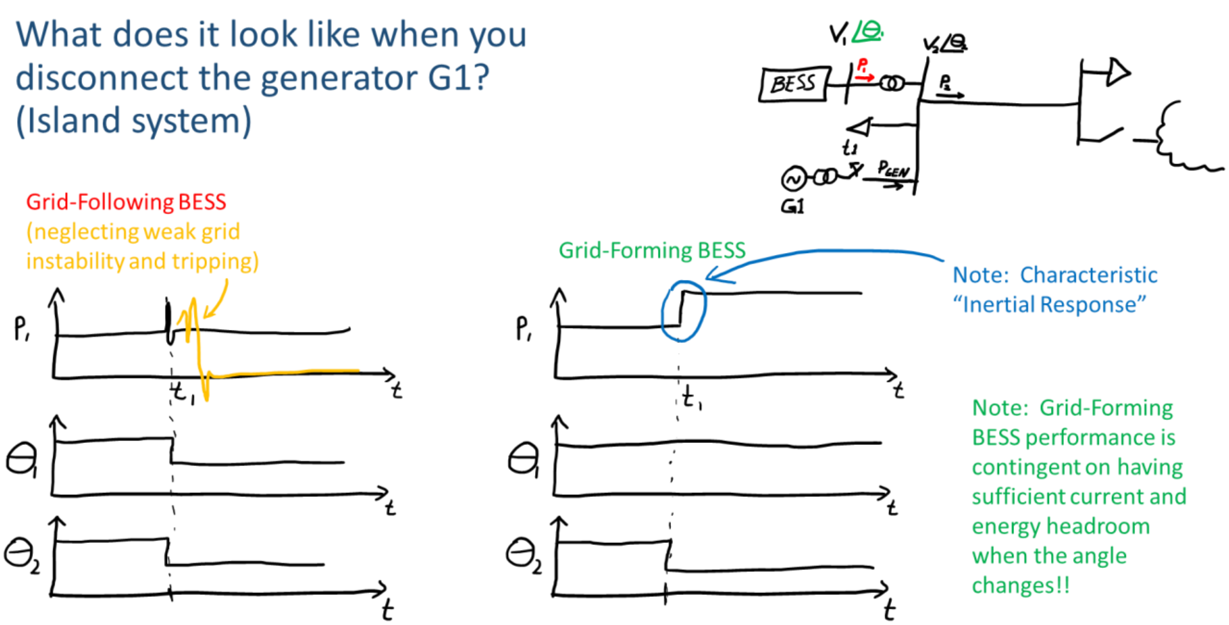


Figure 61: Conceptual Core Response of GFM and GFL in Simple Test System [Source: Electranix]

The reaction of the GFM versus GFL inverter controls are defined within the inner controls of the IBR units and are dependent on many factors such as available headroom,[15] equipment ratings, etc. Additionally, more conventional IBR controls that do not occur within the

[15] For GFM resources with energy and current headroom (like batteries) the hardware between GFM and GFL are generally quite similar; there are unique challenges that limit commercial viability for applying GFM to other IBR technologies such as wind and solar, although those are also under development by some vendors.

subtransient to transient timeframe can also be layered on to the GFM controls. For example, a GFM IBR can also provide steady-state reactive power-voltage control or active power-frequency control similar to a GFL IBR. **Generally, all the control features and benefits a GFL inverter can provide should also be expected from a typical GFM inverter.**

Furthermore, there are multiple GFM control strategies such as virtual synchronous machine or droop-based GFM controls; these various control topologies are analogous to the variations of synchronous generator excitation system and turbine-governor controls that have evolved over time and each have unique benefits, drawbacks, and operational considerations for tuning and utilization.

GFM can also fundamentally be described in terms of how GFM (versus GFL) resources affect system strength and stability. Conventional SCR-based system strength metrics are no longer relevant with the introduction of GFM IBRs. Conventional GFL IBRs reduce SCR whereas adding a GFM IBR improves SCR; therefore, one can consider GFM as increasing the numerator rather than increasing the denominator of the conventional SCR equation, as shown in Figure 62.

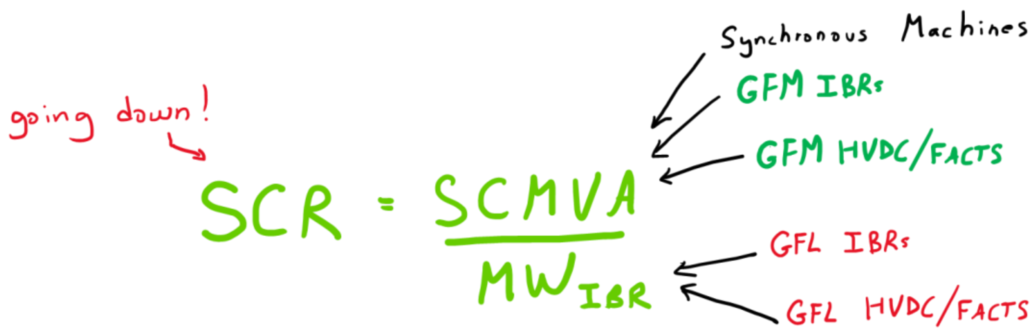


Figure 62: Conventional SCR Calculation and the Impacts of GFM versus GFL on the Calculation [Source: Electranix]

Briefly put, there are multiple key applications where GFM can provide a cost-effective solution to known reliability challenges including:

- **Strengthening** weak local IBR interconnections
- **Adding inertial response** to large interconnections
- **Increasing passive damping** at sub-synchronous frequencies, unlocking renewables in series-compensated networks
- Automatic **injection of negative sequence currents** to help balance the system
- Providing **very fast frequency response**
- **Transferring system strength** from one region to another, particularly with respect to GFM HVDC applications

- **Improving response times** and stability for reactive power devices such as GFM STATCOMs
- Reducing active power fluctuation impacts, **enabling data center load growth**

GFM technology in newly connecting BESS is commercially available across multiple vendors and has been deployed around the world. GFM technology in wind and solar is not yet commercially available but is under exploration and development by some manufacturers. Existing GFL BESS may or may not be able to be upgraded to GFM at a future date, depending on vendor-specific details; there are increased costs associated with retrofits in some cases that should not be overlooked.

Session 1, Part II – Basics of Grid Forming IBRs, Deepak Ramasubramanian, EPRI

Deepak provided a complementary view of GFM technology to explain the fundamentals and basics of GFM control. Industry often describes GFM as "acting like a voltage source" and GFL as "acting like a current source"; however, this should not be conflated with *ideal* voltage and current sources. All inverters used in power generation are inherently voltage source converters as they generate a dc voltage that is converted into an AC voltage waveform using power electronic switches. The control objectives of the inverter, however, then decide how that AC voltage waveform is created including the magnitude, phase angle, frequency, and response to grid events.

In power systems, AC voltage is an independent quantity whereas AC current and AC power are dependent quantities. The flow of AC current is dependent on the voltage (magnitude and phase) difference between two nodes; power is calculated as the multiplication of current and voltage. Inverter control objectives that use dependent quantities as their references can be less grid-friendly. Figure 63 illustrates broad families of inverter control objectives. The left two examples try to maintain active and reactive power by (quickly or slowly) changing AC voltage. The right example tries to maintain voltage and frequency (angle) and therefore responds to grid events slowly. The left-hand examples are illustrative of GFL controls whereas the right-hand example is illustrative of GFM controls.

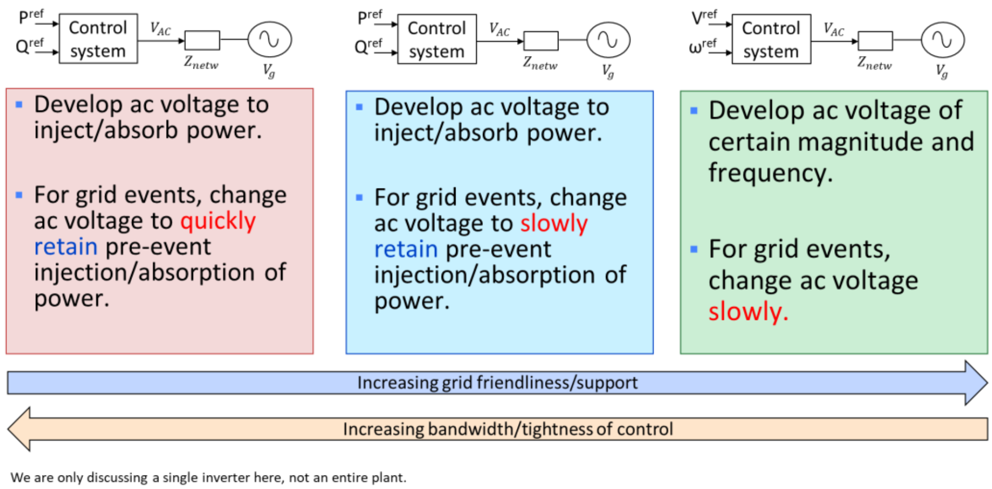


Figure 63: Broad Families of Inverter Control Objectives [Source: EPRI]

Deepak also described how the concepts of GFM and GFL are mainly applicable to a relatively tight bandwidth of controls that affect response times from around a few milliseconds to around 100 ms (see Figure 64).

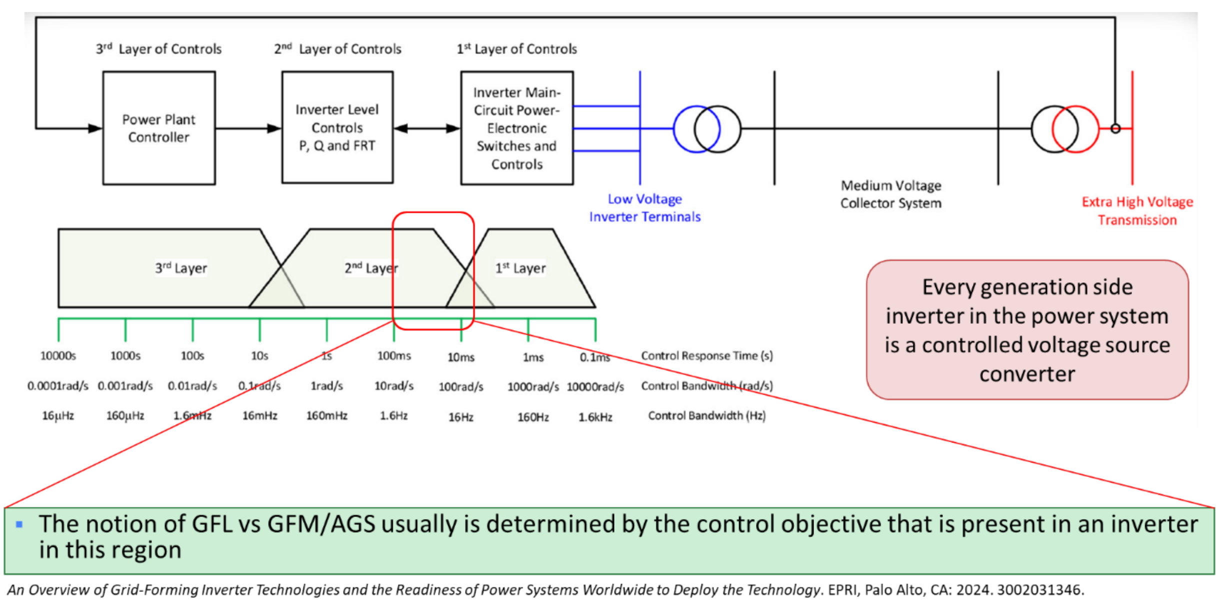


Figure 64: Hierarchy of Controls within an IBR Plant [Source: EPRI]

Figure 65 shows a summary of the key attributes of GFM and non-GFM (i.e., GFL) controls in the various timeframes, which provides a good summary of the key differences between technology options.

Time scale	Non-Grid Forming (non-GFM)	Grid Forming (GFM)
Sub-transient	Prioritizes current to meet fixed P/Q	Prioritizes current to meet fixed V/f control
Transient	Prioritizes P/Q control	Prioritizes V/f control
Steady – State	May have droop characteristics for controlled V/f response	

Figure 65: Summary of Attributes for GFM and non-GFM (i.e., GFL) [Source: EPRI]

Deepak also shared research on the topic of frequency domain characterization of GFM controls. Frequency scanning approaches can characterize and explain GFM as compared with GFL controls that capture key attributes differently than typical time domain tests. Figure 66 illustrates the key checks used as part of frequency domain analysis, which will be covered in more detail in other sessions.

(i) an increase in grid voltage magnitude should result in decrease in Q injection from device and vice versa (ii) this behavior should occur even for fast voltage changes (< 1 cycle)

(i) an increase in reactive power injection should result in decrease in V generated from device and vice versa (ii) the feedback loop should remain passive and a sink for oscillations

(i) an increase in active power injection should result in decrease in ω generated from device and vice versa (ii) the feedback loop should remain passive and a sink for oscillations

Figure 66: Key Checks in for Frequency Domain Characterization of GFM [Source: EPRI]

There are additional considerations for GFM (and GFL) IBRs that deserve careful attention and additional research. Some of these areas include blackstart capability utilizing GFM capabilities, transformer energization, motor pickup, benefits of GFM providing subsynchronous damping, and BPS protection system impacts with high IBR penetration levels that include GFM technology.

Deepak closed the discussion reiterating that as long as an IBR can prove to deliver interconnection requirement performance expectations in a stable, reliable manner, it is less important whether than OEM defines the specific control as GFM or some other designation. **The concept of GFM may just be "a fancy suit" on what is already a stabilizing control architecture that provides grid benefits and should not be discouraged because of terminology alone. Interconnection requirements should be focused on specific performance needs rather than designation of GFM or not.**

Session 1 Q&A

It was noted that SCR-based metrics may not be useful in the future; some new tools include injection factor metrics. Are these useful for screening?

Unit interaction factor metrics are overall a good metric and similar to SCR-based metrics should be carefully leveraged to screen for potential IBR reliability risks in the future.

With an HVDC tie line connecting two transmission systems, can you use both converters as GFM?

HVDC systems can be operated with one converter in GFM and one in GFL and this takes advantage of the strong side for the benefit of the weaker side that has GFM implemented. One can also use GFM on both sides but must be careful with active power balancing. If both ends are GFM and HVDC connects two separate systems, then it may not be sufficient for one end to have a requirement; both systems should be considered.

When can industry apply GFM to hybrid systems or other types of IBRs?

BESS can be GFM today and this is widely commercially available. However, other portions of IBR plants may not have commercially available technology. The BESS side of a hybrid plant can be GFM with technology today. Other aspects need to be addressed for hybrid systems such as requirements, operating procedures, etc.

SPP adopted IEEE 2800, and in the ride-through requirements it talks about reactive current priority during ride-through. With GFM, this is less applicable, so how do we handle this?

A subgroup of IEEE 2800 is now looking at GFM and non-GFM technology and what language needs to be adjusted. Requirements language will evolve at the IEEE level and then can be adopted by entities who have integrated the IEEE 2800 language into their requirements.

We collectively need to simplify all these technical details down to executives and decisionmakers. What is missing here?

That sentiment is well understood by many in the GFM community, and those practitioners continue to share messages that appeal to less technical audiences that GFM is simply an evolution of IBR controls and nothing entirely new. It has been proven effective around the world and is widely commercially available. For policy people and people thinking about GFM as this new complicated thing, experience recommend "stop panicking" and try out the new technology as it is not a significant deviation from GFL controls in most ways. Start early before problems arise rather than wait until serious issues show up on the system. Add more testing to make sure it is robust and that performance is validated.

Can you articulate system versus local requirements and needs for GFM?

When thinking of regional requirements or system requirements, it is important to recognize holistically that synchronous generation levels are declining rapidly and IBRs are replacing those resources under operating conditions throughout the day and year. GFM is part of a solution to that problem that can *add* system strength rather than drain it.

Regional requirements are seeking a base level response of GFM to avoid the larger system-wide problem, and the specific rules are applicable to those assets (e.g., BESS) related to models, tests, performance, commissioning, etc. Local grid issues can then leverage GFM as a solution to specific needs, if required, for stability and controls tuning.

Any good examples doing model validation of IBRs for real world events?

There are many good examples of GFM specifically performing well to grid events as well as highly accurate models that reflect those GFM responses. The concept of validation using real world event model validation applies to both GFL and GFM equally. Hawaiian Electric, for example, has put DFRs at all IBRs and an event occurs they conduct model validation. They take recordings and compare against PSCAD models to gain experience and do model comparisons.

Session 2 – System Needs for Grid Forming Capabilities

Session 2 included a facilitator-led, interactive discussion among the following panelists:

- Alex Shattuck, ESIG (moderator)
- Weiqing Jiang, MISO
- Mostafa Sedighizadeh, SPP
- Scott Anderson, SRP
- Bin Wang, ISO-NE

Question: In your region, do you have a need or foresee a need for GFM capabilities and facilities?

SRP: Looking to the future, SRP is seeing a rapid growth of instantaneous IBR penetration and sees GFM as a cost-effective solution option worth pursuing. There are no glaring reliability issues or risks that SRP has identified, but does see a very different BPS in the years ahead than what it has experienced in the past. SRP is focused mainly on GFM BESS given its commercial maturity and availability, particularly for new resources. Some differences of opinion exist within the organization but overall SRP is pursuing GFM as one of multiple solutions to grid stability issues in the future.

SPP: SPP is facing a 110 GW queue and 75% of that queue is IBR technology. Thus, SPP expects very high penetration of IBRs in the years ahead and has already hit operating conditions upwards of 90% instantaneous penetration back in 2022. This raised concerns about what if a fault occurred during that time and whether the grid would remain stable under those conditions. SPP believes that more grid-stabilizing options are needed to assure reliability and minimize risk.

MISO: MISO conducted a comprehensive engineering study and identified an inflection point around 30-40% penetration level, which is nearing very rapidly. Issues included weak grids, voltage issues, etc. At 50-60% penetration levels, frequency issues also arose. In 2024, MISO implemented GFM requirements focused on "core" GFM capabilities and attributes, applicable to all BESS entering the 2023 interconnection queue and ahead. Looking forward, MISO wants to observe operational performance and explore additional GFM benefits.

ISO-NE: At the moment, ISO-NE has not identified a specific need for GFM and has not developed any requirements related to GFM technology. In the future, they are looking at multiple solution options but need more information to make these decisions. They are undertaking research endeavors with universities to explore this topic further, and developing a "systematic approach" with those partners.

Question: Are there other additional drivers your organization is tracking or wishes to track beyond IBR penetration levels?

SRP: SRP is expecting rapid instantaneous penetration growth in the next few years, upwards of 60-70%. SRP is also seeking to leverage the full capabilities of GFL IBRs today and into the future and monitoring their performance, but do lack dashboards and reporting at a granular level. SRP is also focused on variable large loads and sees GFM as an effective, multi-value solution to support these efforts as well. They are looking at cost-effectiveness across multiple solutions, and see GFM as one of the least-cost options, particularly for new projects.

SPP: SPP is focused on the very high IBR penetrations expected in the years ahead, but is also monitoring the NERC guidance, MISO efforts, other ISO and industry efforts, etc. SPP made the decision to take action to minimize risk, added language to their tariff regarding modeling, but is mainly looking at broad industry indicators and consensus from key trade organizations and regulatory bodies.

MISO: MISO has observed trends in resource adequacy studies and the growth of IBRs that have presented risks to MISO system reliability. MISO does see locational impacts, system strength issues, and other challenges beyond just broad IBR penetration levels. The MISO strategic approach is to observe trends, identify needs, and determine cost-effective solutions. GFM is one solution that can be provided by IBRs that provide a missing grid-stabilizing need.

ISO-NE: Main driver of identifying risk is the ISO-NE Needs Assessment for its various portions of the system. These studies focus on violations of voltage, frequency, thermal, etc. Then the assessments explore solutions to those needs in the planning horizon, of which GFM may be considered among other solutions. ISO-NE aims to deploy whichever solution is most effective and economic rather than pursuing one specific technology. Some recent research has illustrated that inertia and ROCOF are not issues for ISO-NE so long as FFR/PFR with sufficient droop is enabled in the region. ISO-NE also recognizes that they need to ensure that conventional GFL IBRs are parameterized and performing to meet system needs, in addition to potential additional technologies like GFM, synchronous condensers, and other solutions.

Question: For those that have formally determined a need for GFM integration (3 out 4 panelist organizations), what decision-making process was undertaken to accomplish this?

SRP: SRP has been tracking the multiple industry and regulatory papers and recommendations that strongly advocate for leveraging GFM technology, particularly for new IBRs. SRP underwent a cross-departmental decision-making process to pursue GFM enhancements to an existing site and to business practices. No specific studies were run identifying a need for GFM solely, but general operational readiness trends point toward leveraging the solution as a viable solution among others. SRP sees GFM as a low-cost solution that provides value to its stakeholders and customers. SRP has taken the approach of requiring capability of GFM for new BESS, which may or may not be enabled operationally at specific sites depending on SRP needs in the future.

SPP: SPP recognized a need to have requirements for GFM for energy storage resources (ESR) to ensure technology readiness. This process started in 2024, and SPP presented background, learnings, industry efforts, and proposed new requirements for modeling and testing of GFM ESR to its members. SPP received significant pushback from its generator owner/developer members, which slowed the process overall. Roughly 80% of the language presented was similar or identical to that used by MISO, and still resistance was rather extensive. The requirements focus on four model-based tests: loss of last synchronous generator, phase angle jump, changing SCR, etc. The final language is pending approval by FERC, but is generally expected sometime in 2026. Due to pushback from generator owner/developers, SPP had to focus only on new interconnection requests and not pursue any retroactivity of existing BESS.

MISO: MISO requires standalone BESS starting in the MISO 2023 interconnection queue to be operationally in GFM mode. MISO conducted its comprehensive engineering study to identify the inflection point where stability risks are identified and worked backward to realize they need to take action quickly. MISO conducted an extensive stakeholder outreach effort to ensure minimized costs, no oversizing obligations, and other key factors. MISO focused specifically on "core" GFM capabilities and a limited number of modeling tests to prove capability. Other tests were included (ROCOF, phase jump, system strength) to demonstrate normal performance expectations and that GFM was not harming performance expectations in any way. The goal was to utilize low hanging fruit capabilities of GFM to support system reliability as soon as possible.

Question: ISO-NE has not identified a need for GFM and has not adopted any requirements for GFM thus far. How was that determined?

The ISO-NE Needs Assessments study various system conditions against a range of contingencies and identify system performance violations (voltage, frequency, thermal, etc.). Voltage violations have been observed but frequency violations do not widely show up. So, as IBR penetration rises, some additional voltage-related issues may arise locally. ISO-NE is exploring solutions broadly and not focused specifically on GFM adoption.

Question: In the ISO-NE Needs Assessments, GFM may be a possible solution; however, GFM is mainly focused on supporting stability-related risks such as system strength, controller stability, etc. How is this explored in the Needs Assessment?

ISO-NE is focused on screening metrics to help scope the work needed on these specific topics. More advancements in this area are needed, but based on the studies being performed today, ISO-NE does not observe these issues in the planning horizon.

Question: Do you believe that GFM technology is mature enough to trust, implement, and utilize on the BPS today?

SRP: Yes, especially for BESS. The hardware is basically the same and the controls have been proven in many parts of the world. Lots of room for continuous improvement, but no notable drawbacks.

SPP: Yes, especially for ESR.

MISO: Yes, GFM BESS technology is commercially ready and has been proven and should be utilized. MISO plans to work closely with OEMs to stay updated on trends and evolving GFM technology for future adoption.

ISO-NE: From a device-level perspective, GFM technology readiness is high; there have been lots of improvements and advancements recently. Focus also needs to include identifying what the system needs, to develop good quantification of system needs metrics, to determine how GFM can contribute to these needs, and then to how GFM can be compared side-by-side along with other solution options.

Question: NERC recommends that new IBRs come with test and verification reports (i.e., model validation reports) from OEMs. In your experience, have OEMs supplied such documentation for GFM projects? Or what other information or data are you seeing for GFM projects?

MISO: The MISO GIA and Business Practice Manuals require IBR modeling requirements and milestones throughout the interconnection process; however, OEM test and verification (model validation) reports are not included. PMUs are also required at specified sampling rates, which may help provide data for model validation against actual grid events.

Question: For the entities that have determined a need for GFM, what is next in terms of implementation?

SRP: SRP has developed a Business Practice on OASIS, which is referenced in the recent 2025 All-Source RFP for new resources being procured by SRP. SRP then evaluated the different sites, developed a comprehensive scoring matrix, and has identified a couple sites where GFM is being pursued operationally. All sites are required to have GFM capability in case it is ever needed in the future. SRP is still fairly early in this process since these sites are not expected until around 2030. SRP is also pursuing a retrofit of an existing GFL BESS to convert it to GFM; this work is collaboratively underway with the IBR owner presently. SRP noted that some IBR developers are quite familiar with GFM and welcome its adoption and utilization while other are less familiar and are trying to get up to speed on new requirements.

SPP: SPP's proposed requirement are pending FERC approval, and SPP is expecting a determination around May 2026 timeframe. GFM ESR would be part of SPP's Business Practice, and mandated for new applicable interconnection customers starting in the 2027 cluster queue.

MISO: Requirement based on high-level studies, and driving system-wide operational requirement. Not focused on determining specific "availability" numbers. See broad need to move on this to maintain grid stability. For new resources, very minimal cost. Thus, requirement put in place based on trend and very minimal or no incremental costs for new assets. Very difficult to quantify "how much do we need" and thus want to see reliability assurance rather than get lost in research endeavors/studies.

Question: All panelists highlighted that your respective entities have put GFM requirements into Business Practice documents. Why was this approach used rather than in the tariff?

SRP: This is a common question explored within SRP, as they have evolved requirements from power purchase agreements to facility connection requirements, business practices, and some tariff revisions. Generally, the level of specificity and detail combined with the need to continuously adapt and update drive these types of requirements more toward the facility connection requirements and business practices. Regardless of tariff, business practice, or other requirements, relatively the same level of internal review and scrutiny occurs.

SPP: High-level requirement fall into the tariff generally but this is very challenging and lengthy to get updated. More detailed specifications fall into business practices.

MISO: High-level revisions to tariff have occurred, but generally all the details remain in business practices and go through a rigorous stakeholder process for approval. Business practices can be changed quicker and more effectively, which is needed for topics that are evolving such as GFM.

All: Generally, the tariff is not the optimal place for detailed requirements. Additionally, much more extensive regulatory requirements are required for tariff revisions, which slow down flexibility and speed to adopt requirements as they evolve, which have been recognized for IBR-specific topics. Business practices are binding and must be met by applicable entities and also require thorough approval processes. It is good practice to ensure that the tariff revisions align with the other requirements so they have ample “hooks” such that they are adequately enforceable.

Question: How did you engage stakeholders and inform them about the direction taken related to GFM, particularly in terms of articulating needs, determining specific details of adoption, and developing requirements?

SRP: SRP teams shared key messages and findings coming out of NERC, ESIG, EPRI, and other efforts to help build momentum and explain the benefits and needs broadly. Additionally, SRP Operational Readiness efforts followed their established governance processes to educate senior leadership and get their buy-in.

SPP: SPP initiated its typical stakeholder process for rule changes. This started with an introduction to GFM and its benefits in 2024. Every month, the SPP team presented fundamentals, learnings, industry reports (NERC, ESIG, AEMO, MISO, etc.) across four SPP working groups. This resulted in over 60 industry engagements through the stakeholder groups, and SPP received more than 100 unique comments throughout the process. All comments were resolved and then stakeholder committees approved the rule modifications before the updated tariff was sent to FERC.

MISO: Overall, MISO had a similar experience to SPP following its stakeholder process. OEMs were engaged as well as generation developers and policymakers to ensure the technology was commercially available and feedback was received.

Question: For ISO-NE, in addition to tracking the needs assessments, were any other sensitivities, studies, or efforts off-cycle pursued to inform possible needs?

Nothing specifically was, or is currently, planned off-cycle, and the main direction is periodic needs assessments. There is some discussion regarding whether GFM BESS would be a generation asset or more of a transmission asset.

Question: What other solutions beyond GFM has your organization evaluated in support of grid-stabilizing system needs?

SRP: SRP is focused on ensuring that all its generators (including GFL IBRs) are providing essential reliability services such as voltage and frequency control. SRP does not have any STATCOMs and does have a large HVDC connecting into their system soon. They are considering a re-evaluation of their voltage control strategy. There are many options on the table and being explored in terms of system reliability and costs and value to customers.

SPP: Some areas of focus include HVDC with dynamic performance studies, SSO screening studies, etc. Lots of studies focused on HVDC growth as well as large load requirements.

MISO: MISO continues to explore model validation to ensure models are accurate and conduct event analysis on any abnormal performance events for continuous improvement.

ISO-NE: ISO-NE is also looking at technologies such as synchronous condensers, STATCOMs, grid-enhancing technologies like dynamic line rating, HVDC, and others.

Question: During the GFM evaluation process, how useful have IEEE 2800-2022 and IEEE P2800.2 been either as a starting point or a framework for IBR capabilities and performance? How were they used?

SRP: They have been useful and were adopted by SRP; however, they are not specifically focused on GFM.

SPP: SPP has adopted clauses of IEEE 2800-2022 clauses with careful consideration but focused on how to adopt test/modeling requirements, which is challenging to implement for developers. Some exceptions with IEEE 2800-2022 requirements were considered and adopted, enabling some flexibility in implementation which has been positive.

MISO: IEEE 2800-2022 was adopted to redefine IBR performance requirements, and MISO focused on ride-through, frequency and voltage support, etc. Regarding GFM, MISO included GFM exceptions to IEEE 2800-2022 implementation with the goal of maintaining the core characteristic of GFM as acceptable.

ISO-NE: ISO-NE adopted IEEE 2800-2022 using the "detailed reference" approach for specific clauses. They have recognized exemptions to IEEE 2800-2022 for GFM and are actively participating in IEEE P2800.1 efforts.

Question: What type and extent of model verification and model validation testing do you believe is required for a GFM BESS going into commercial operation and during commercial operation?

SRP: Both PSLF and PSCAD models need to be validated to build trust in the installed equipment and its performance. SRP is exploring ways to do this better with data available to it.

SPP: The new Business Practice defines specific tests for GFM performance testing in PSCAD, but nothing is established regarding commissioning.

MISO: MISO included measurement requirements in its IBR requirements enhancements, which can be used for model validation.

Session 3: Grid Forming Requirements

This session focused on the development and adherence to GFM requirements around the world.

"GFM Requirements at HECO, AEMO, ERCOT, MISO, etc." – Andrew Isaacs, Electranix

Andrew shared an overview of various GFM requirements across multiple regions and described some of the history and reasoning for those requirements. Figure 67 shows how GFM requirements can be developed for different assets (or groups of asset types) and then can either be descriptive or test-based in nature. Then one must determine if these requirements are broad or if they are intended to be implemented within a specific region or area. One must also then determine if they are implemented at the equipment level or IBR plant level. It is also important to determine if these requirements will be comprehensive of all IBR performance or if they are intended to work in tandem with existing IBR requirements. Lastly, there are time domain testing techniques that have generally been well established and there are novel frequency domain testing techniques being explored (discussed in more detail below). ***Many of the existing requirements, specifically in the United States have focused on time domain testing of performance characteristics for GFM BESS assets.***

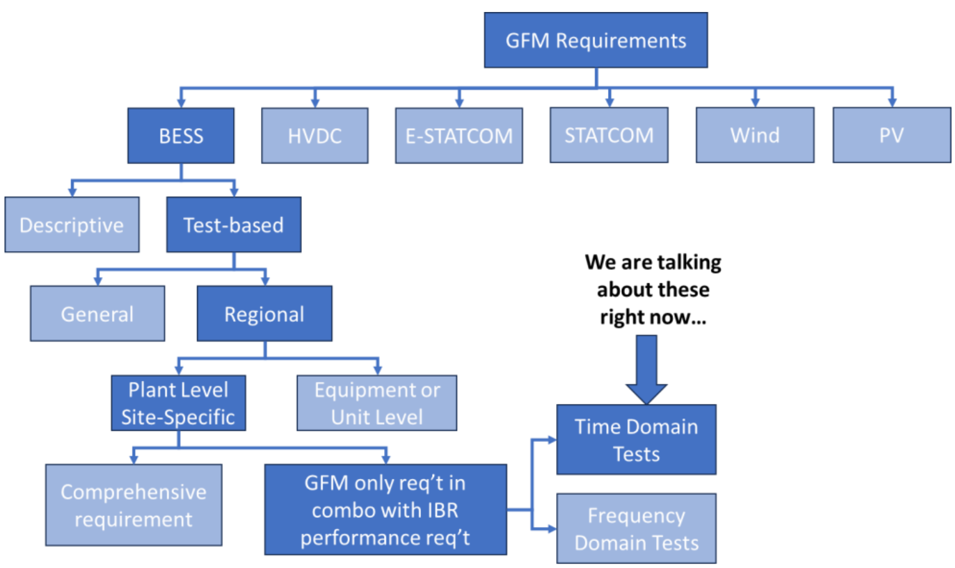
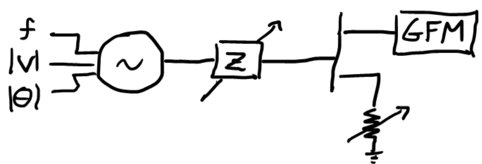


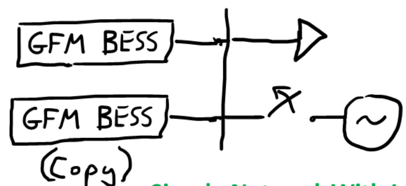
Figure 67: Categorization of GFM Requirements [Source: Electranix]

Time domain, regional, plant-level requirements have been utilized to-date because they are directly written for a specific TO/ISO and can be tailored to specific system needs. They can also be written relatively quickly and can be rather explicit in terms of acceptable and unacceptable performance criteria. Broader OEM-based equipment standards for GFM can be valuable but require a much broader stakeholder process and take significantly longer. Thus, transmission providers in some areas have adopted time domain plant-level requirements to move much quicker and leverage the technology for newly connecting resources where possible.

A common set of tests have been adopted by multiple entities, as shown in Figure 68, that stem from a couple test bench system configurations. A simple network with load involving GFM BESS assets is used to test GFM core functionality. A single machine variable impedance system is also used to test response to grid events to ensure overall stability and favorable response. A few tests have been defined as informational whereas most of the tests have a clear pass/fail criteria associated with them.



Single Machine Variable Impedance (SMVI)



Simple Network With Load

Test #	Test Name	Testing for:	Test Type	Testbench System	AEMO	ERCOT	Fingrid	HECO	MISO	NERC	UNIFI
1	Loss of synchronous machine - discharging	GFM core functions (BESS only)	Pass / Fail	2 - SNWL	■	■	■	■		■	■
2	Loss of synchronous machine - charging	GFM core functions (BESS only)	Pass / Fail	2 - SNWL	■	■		■	■	■	■
3	Loss of synchronous machine - limit test	GFM core functions, limits (BESS only)	Pass / Fail	2 - SNWL	■	■		■	■	■	■
4	Loss of synchronous machine - power balance	GFM core functions	Pass / Fail	2 - SNWL	■				■		
5	Large ROCOF up and down	Control stability	Pass / Fail	1 - SMVI	■	■	■	■	■		■
6	SCR step-down with fault	Control stability	Pass / Fail	1 - SMVI	■	■		■	■		■
7	Angle step change	GFM core functions	Pass / Fail	1 - SMVI	■	■	■	■	■		■
8	Special severe fault scenarios	Extreme disturbance stability	Pass / Fail	1 - SMVI				■			
9	Voltage step up and down	GFM core functions	Pass / Fail	1 - SMVI		■	■	■			■
10	Energy response test	Transient energy response	Informational	1 - SMVI		■					■
11	Frequency scan	Damping, impedance trend	Informational	4 - PVS	■		■				

Figure 68: Categorization of GFM Requirements [Source: Electranix]

Andrew warned that each test must be intentionally created, have a defined purpose, and have a clear set of success criteria for ease of implementation by all stakeholders involved. Time domain tests are vulnerable to "gaming" where a set of arbitrary controls parameters may be able to pass the tests but have other adverse consequences. For example, a ROCOF stability test may offset an incentive to use very high inertia for an energy response test. The creation of simulation tests should always be extensively tested against multiple varieties of equipment, where possible.

Andrew briefly shared additional details to the various tests listed above, including:

- **Loss of Last Synchronous Machine:** These are the tests proposed in the NERC GFM specification white paper, which focus on the core GFM functions under different operating conditions.

- **SCR Step Down with Fault:** Decrease in system strength occurs after a fault, and GFM response should generally be better as compared with GFL, down to an SCR of about 1.25.
- **Angle Step Change:** Phase angle step changes are applied to ensure GFM response is provided quickly enough and sustained for a sufficient duration.
- **Voltage Magnitude Step Response:** Voltage magnitude step changes are applied to ensure GFM response is provided quickly enough and sustained for a sufficient duration.
- **Energy Response Test:** Quantifies short-term (first 0.5 seconds) energy provided by GFM for frequency events. System frequency ramps up and down at 1 Hz/second, and the IBR plant is configured with headroom. The energy constant can be calculated by the area under the active power curve within the defined time period.

"UNIFI GFM Requirements" – Shahil Shah, National Laboratory of the Rockies & Dominic Groß, University of Madison–Wisconsin

Shahil presented on frequency domain specifications for GFM resources and perspectives and insights from testing experience. Unlike time domain testing, frequency-domain specifications can be defined relatively independently of the operating conditions (power output and grid strength). They directly and quantitatively show system strength contribution provided by GFM resources and are strongly correlated to time domain tests but provide greater insights regarding GFM performance. The main drawback is that frequency domain specifications focus only on the small signal behavior. Large disturbance behavior is also important to verify, particularly important during operation of GFM near their ratings.

Shahil shared two practical considerations for frequency domain specifications. Firstly, avoid duplication; limited new information is obtained from defining frequency-domain specifications for a performance characteristic of a GFM resource that is effectively captured by time domain specifications. Secondly, avoid complication; keep frequency domain specifications as simple as possible.

An ESIG report (see webinar here) was recently released related to testing performance of GFM resources and included details on frequency domain specifications. Tests and performance metrics for quantifying voltage source behavior are included, with frequency domain tests defined and pass/fail criteria specified. The frequency domain tests include:

- Impedance or V/I scan (equivalent Thevenin impedance)
- Q/V scan (related to voltage magnitude step test)
- P/θ scan (related to phase angle step test)

The tests are specifically analyzing the voltage source behavior of the resources. Figure 69 illustrates the characteristics of a voltage source behind a reactor up to the POI in time domain and frequency domain. In the frequency domain, for example, you can develop a transfer function relationship from voltage to reactive power (or from angle and to active power). The gain (in pu/pu) gives the equivalent SCR, which establishes a path to define the dynamic SCR (*d*SCR).

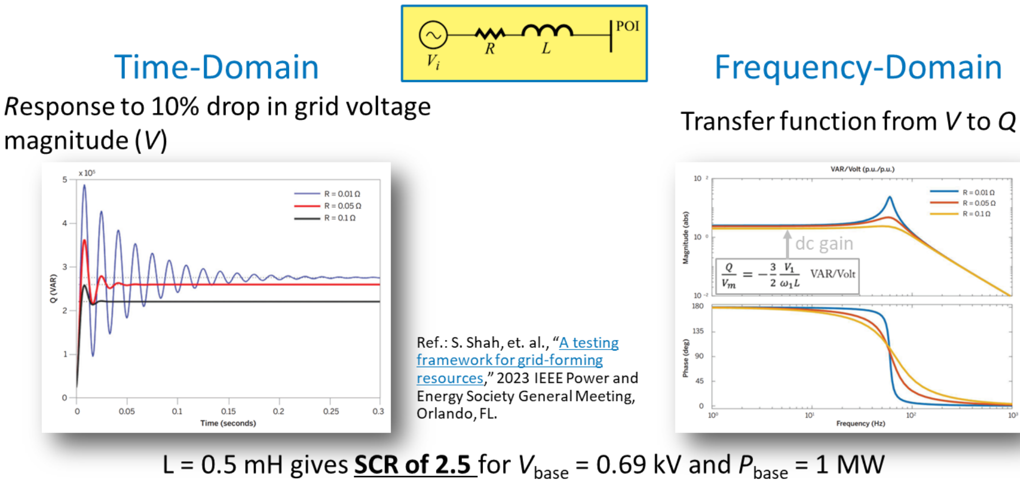


Figure 69: Characteristics of a Voltage Source Behind a Reactor [Source: NLR]

NLR has tested OEM-supplied models for a synchronous condenser and three GFM BESS to estimate their *d*SCR and impedance (Z = 1/*d*SCR) – results are provided in Figure 70. The black trace shows the synchronous condenser and the other plots are the GFM BESS. The results show the voltage source behavior for all resources, and the gains show the contribution to system strength (higher means more contribution).

Resource	dSCR	Z
SynCon	6.5	0.15
GFM BESS #1	3.9	0.25
GFM BESS #2	3	0.33
GFM BESS #3	2.6	0.38

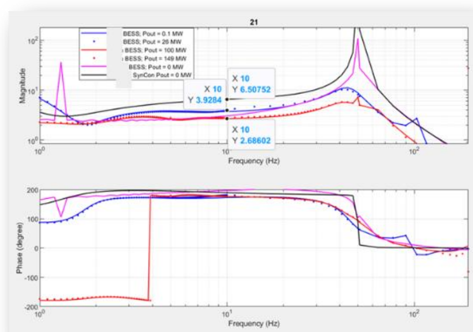


Figure 70: Frequency Domain Characterization of Synchronous Condenser and Three GF BESS [Source: NLR]

Performance metrics for each test can be developed. For example, for the Q/V frequency scan test, the magnitude of Q/V frequency scan should be higher than 2 p.u./p.u. within the frequency range of 4 to 40 Hz. The phase of the Q/V frequency scan should be ±180° within the frequency range 4 to 40 Hz. The error between the actual phase and ±180° should be smaller than 20°. Note that the specific frequency ranges and gains should be changed based on system needs.

Resonance or mechanical considerations might require deviation from this specification around certain narrow frequency ranges. The performance metrics for P/θ frequency scan are similar to that of Q/V frequency scan test.

Shahil also highlighted that frequency domain tests can also be helpful in sizing necessary amount of GFM. Once the amount of system strength contribution needed is defined, then the deficit can be provided by adequately sized GFM resources.

Dominic shared updates on dynamic droop specifications for GFM IBRs, which is being pursued by the UNIFI Consortium. UNIFI recently released Version 3 of its Specifications for GFM IBRs, which includes an approach to dynamic response specifications with the goal of quantitative and verifiable specifications of key grid support functions and quantitative specifications for two "flavors" of GFM control.

Dominic shared some examples of GFM and GFL resources responding to a frequency perturbation across frequency ranges (both with frequency droop configured). Figure 71 shows results from testing. The figure on the left shows time domain response at a 0.1 Hz and a 30 Hz frequency deviation from nominal. At lower frequency (0.1 Hz), both the GFL and GFM respond following the droop curve. As frequency increases (figure at 30 Hz), phase shift results in portions of the waveform where droop response is in the opposite direction than desired, thus destabilizing the response at that frequency. The figure on the right shows the gain and phase shift drifting away between the GFL and GFM resource.

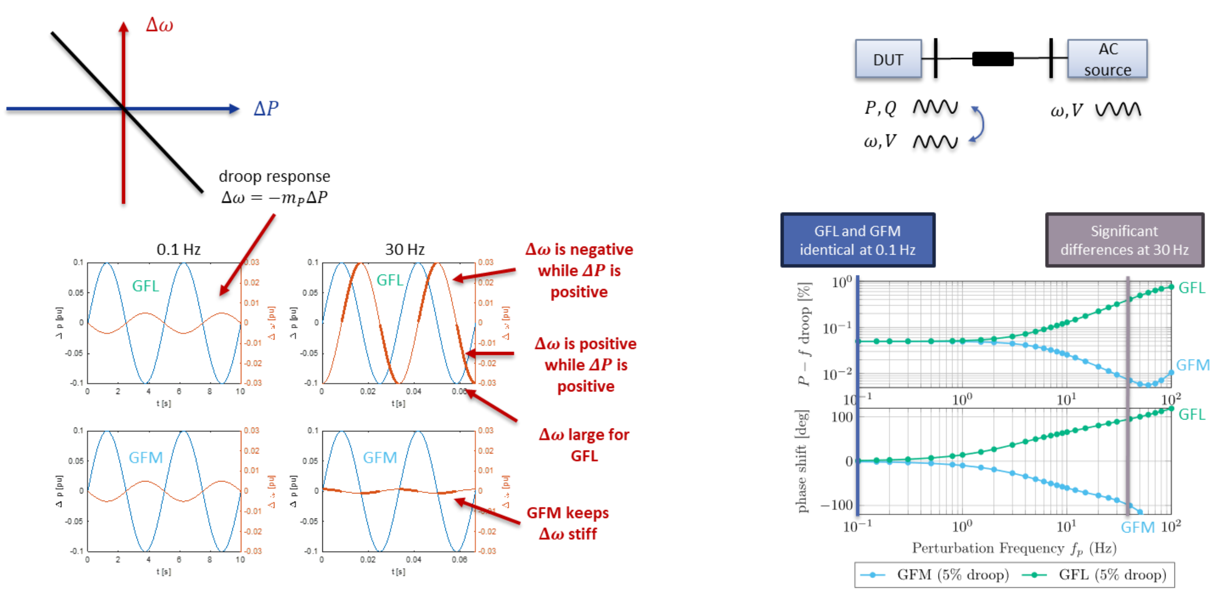


Figure 71: Dynamic Droop Results over Frequency Ranges [Source: UNIFI]

From the work conducted, Dominic described two GFM IBR "flavors". Figure 72 includes 1) power synchronization and passive high-frequency voltage phasor stiffness (left), and 2) power synchronization and low-gain high-frequency voltage phasor stiffness. Power synchronization encodes requirement for GFM IBR to synchronize through power, which allows for frequency synchronization without steady-state droop. Passive "high-frequency" response includes a requirement to remain in phase with droop specifications for at least half a cycle. Low-gain "high-frequency" response refers to negligible droop (thus frequency stiff). Bounds can be placed on these characteristics related to core GFM functions. Virtual synchronous machine (VSM)-type GFM may have increasing gain at higher frequency but phase remains within tighter bounds. On the other hand, if you have a lower gain, then phase limits can be relaxed. The UNIFI specifications include both types and do not show preference to one or the other.

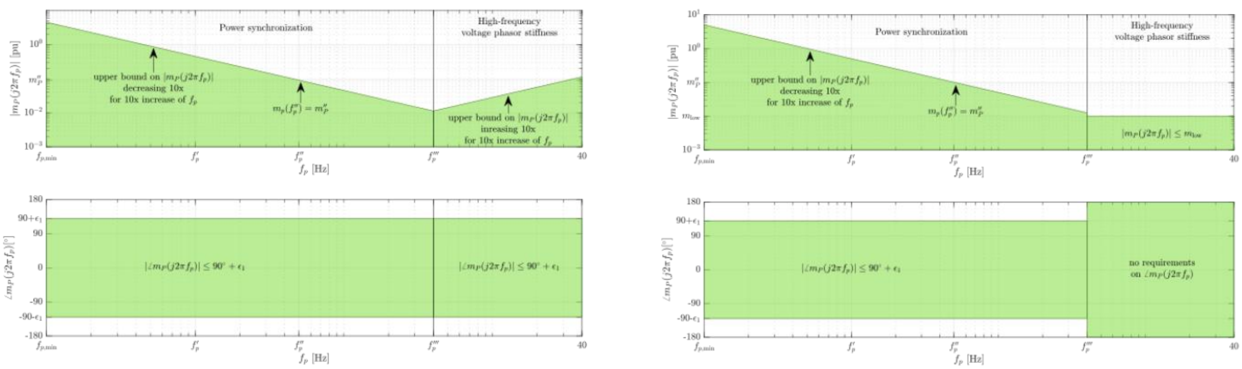


Figure 72: GFM IBR Flavors. (Left: Power synchronization and passive high-frequency voltage phasor stiffness. Right: Power synchronization and low-gain high-frequency voltage phasor stiffness) [Source: UNIFI]

Future work for UNIFI and IEEE P2800.1 will focus on P–V and Q–*f* cross coupling and how a GFM IBR should respond when limits are reached. UNIFI v3 specifications are being considered as a starting point for IEEE P2800.1 efforts.

"IEEE/IEC New GFM Requirements Efforts" – Alex Shattuck, ESIG

Alex shared an update on the IEC and IEEE GFM standardization efforts underway. He shared an update on the joint effort between IEC PWI 8A-26 and IEEE P2800.1, which are working collaboratively to create a framework for GFM requirements at the equipment-level. There are strengths, weaknesses, opportunities, and threats with this approach, as listed in Figure 73.

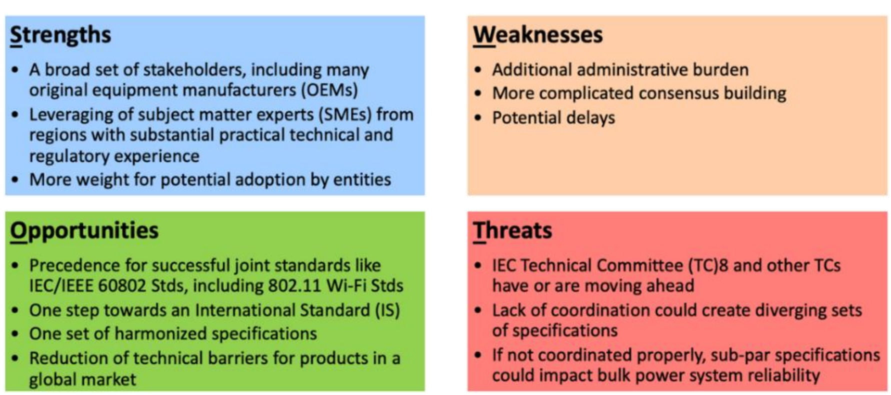


Figure 73: SWOT of IEEE/IEC Effort for GFM Standardization [Source: IEEE/IEC]

The IEC and IEEE frameworks are well aligned and a joint standard would have to adequately balance specificity with flexibility and align on terminology. The contributors to this effort are international members from both IEC and IEEE drafting teams, who are meeting regularly to coordinate their work. Figure 74 shows the joint standardization effort among IEC and IEEE committee structures.

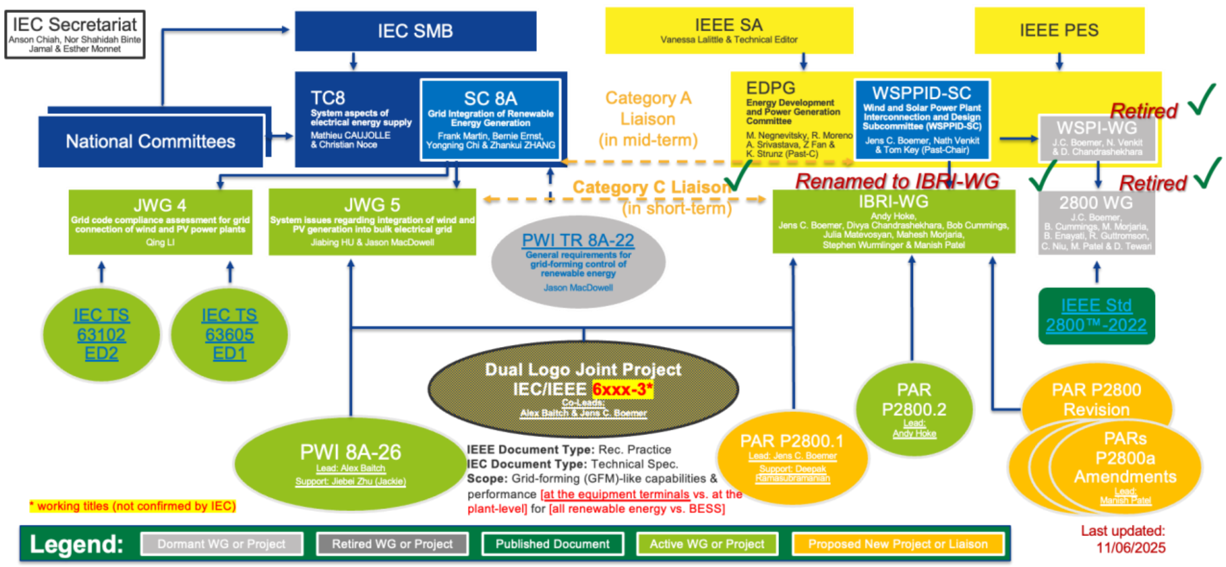


Figure 74: Visual Organizational Mapping of IEEE/IEC GFM Effort [Source: IEEE/IEC]

"VDE FNN GFM Requirements" – Roland Singer, Fraunhofer

Roland provided an update on the VDE-FNN GFM technical requirements for GFM capabilities including the provision of inertia, which have been adopted in Germany. In 2023, the German government approved the "Roadmap System Stability," defining milestones and processes toward a path to 100% renewable energy. German Transmission System Operators (TSOs) must show the needs and ways to fulfill them in their development plans. The needs are based on: TSO assets (HVDC, STATCOM, etc.), market-based procurement, and minimum requirements.

The German regulatory authority published the regulatory framework for procurement of local inertia in the middle of 2025, and procurement started in January 2026. The VDE-FNN is responsible for the definition of technical requirements, defined in the FNN-guideline "Technical requirements for grid-forming capabilities incl. provision of inertia." The third version (2.1) was published in January 2026, and is an addition to the Technical Connection Rules VDE AR-N-41XX.

The third pillar, definition of minimum requirements, is planned to be implemented via the European law via the update of the "regulation for generators" (RfG). The European energy regulator, ACER, proposed the amendment of the RfG to enable system operators to require

GFM capabilities from all generation and storage. An ENTSO-E technical group published a report proposing the technical requirements for national implementation.

The VDE-FNN requirements are applicable to synchronous generators as well as inverter-based generators (including controllable loads), and include a framework for verification of electrical properties of GFM units including principles of the verification process, prototype certificates of GFM units and systems, transferability of measurements to other units, tests and validation for synchronous units, and tests and validation for converter-based units.

The requirements for inverter-based units focus on the permanent behavior of a GFM unit as an "inertial voltage source behind a mainly inductive impedance" where a voltage amplitude change leads to a mainly reactive current change and a phase angle change leads to a mainly active current change. The following specifications are included:

- Effective impedance must be partly physical and may be controller-based. Effective impedance (without current limitation) shall be smaller than 0.27 pu without the unit transformer (low voltage side) or 0.35 pu including the unit transformer (medium voltage side). In normal operation, the negative sequence impedance must be the same as the positive sequence impedance.
- Voltages source behavior must be a general behavior, and during limitations:
  - During disturbances (step-wise changes of voltage angle or amplitude) for 40 ms, current clipping is acceptable. Current can be limited to 95% of the current that leads to current clipping
- Active current response within current capabilities to a voltage phase angle jump must be:
  - For at least 50% of the change in current in the procured direction, the power change may be limited to $\geq$ 45% P_{Emax}
  - For at least 5% of the change in current in the procured direction, the power change may be limited to $\geq$5% P_{Emax}
- Behavior in the sub- and super synchronous frequency range must dampen oscillations in frequency range of 3–50 Hz in the rotating reference frame
- Behavior in the harmonic frequency range must act passively in the frequency range of 100 Hz–2.5 kHz in the stationary reference frame
- Behavior must dampen power-frequency oscillations in the frequency range of 0.05–10 Hz in the rotating reference frame. Damping ratio must be $D \geq 0.5$ for SCR values of 3 and higher.
- Stable parallel operation of GFM units with synchronous, GFM non-synchronous, and GFL non-synchronous units at SCR values of 1.0, 3.0 and 25.0.

- Reactive power provision must follow control modes defined in the applicable VDE AR-N-41XX requirements, and behavior must follow a first order system defined in the requirements. Damping must be within defined tolerances for SCR between 10 to 50.
- Voltage control must be based on voltage source behavior for a controlled voltage source behind an impedance with linear proportional behavior for voltage amplitude steps (e.g., double step size of the amplitude change must lead to double the current reaction). Dynamic response time to set point change must be ≤ 1 s. For a change in grid voltage, control must have a response time (90%) ≤ 10 ms, settling time ≤ 60 ms, and damping ≥ 0.3. Stability of the voltage source behavior must be maintained, and the R/X ratio shall not change.
- Robustness to over- and under-voltage follows the applicable VDE AR-N-41XX requirements. Current limitations must be based on an amplitude limitation, and prioritizing between active and reactive current is not allowed. Active power needs to return within 1 second.
- There are additional requirements defined for connection in medium voltage systems.

The market-based procurement allows unidirectional inertia provision to enable the participation of renewable generation and controllable loads, and products are defined for:

- Positive inertia provision (power increase during negative RoCoF)
- Negative inertia provision (dower reduction during positive RoCoF)

For both directions, a “Premium” (>90% availability) and a “Basic” (>30% availability) product are defined. The inertial contribution is calculated and after the supply of inertia, the unit can recharge the internal storage. The energy for recharging must be smaller than 1.5x the supplied inertial energy. Within current limits, the GFM device needs to supply inertia over the whole operation range, and the OEM must specify the power range for which provision of inertia is possible.

Session 3 Q&A

From a verification and validation perspective, what changes between GFL and GFM?

In IEEE 2800-2022 and IEEE P2800.2, requirements exist for commissioning and post-commissioning behavior, what should be monitored and recorded, and how model validation can be conducted. This is a challenging job for any IBR, and that does not change for GFM. However, it is critically important to conduct these model validation efforts to ensure understanding of the technology and its dynamic performance and also to ensure accurate models.

How were the theories of GFM specifications derived?

There are multiple approaches to developing GFM specifications, including: 1) specifying the specific controls for GFM technology and trying to quantify them or 2) starting with performance attributes and specifying what performance is required (not focused on controls). The latter has historically been used to avoid defining specific GFM control architectures.

This is not necessarily a GFM-specific question or topic. Any IBR can be tuned to poorly perform on the grid or degrade stability and reliability. Rather we should be focusing on how to configure a GFM so that it is tuned to provide the right functions for a specific system.

Once the grid needs and desired attributes are defined, you can build tests against those, which is mostly what we have today in terms of specifications.

What is your experience of mandatory versus market-based?

Regardless of answer, very few entities will follow recommended practices unless they are mandatory because adherence to the recommended practices costs more. This is a general issue for the industry and not specific to GFM.

There are also concerns with tuning models to pass specific tests and then failing to implement controls aligned with those models. This again is not a GFM-specific issue and should be addressed with model verification and validation checks at IBR plant commissioning.

Session 4 – Global Landscape of Grid Forming Projects

This session focused on the global landscape of GFM requirements, developments, and commercial projects. Julia started the session by sharing relevant links to ESIG literature and webpages that provide details regarding the landscape of GFM projects around the world, including:

Julia shared the GFM webpage:

- GFM Landscape: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/
- Installed and Planned GFM Projects: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/installed-and-planned-gfm-projects/
- GFM Specifications and Interconnection Requirements: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/specifications-and-interconnection-requirements/
- GFM Modeling and Model Verification Efforts: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/modeling-and-model-verification-efforts/

- GFM Performance in Real-Time: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/grid-forming-performance-in-real-time/
- GFM Studies Evaluating Benefits of GFM: https://www.esig.energy/working-groups/reliability/grid-forming-landscape/studies-evaluating-benefits-of-gfm/

The session continued with short introductory presentations from each panelist followed by a facilitator-led Q&A.

Sarah Walinga, Tesla

Sarah shared experience with GFM deployments and operational experience globally. One of the key challenges of integration is translating IBR plant-level requirements down to GFM inverter specifications and management of reference and command signals and such. Generally, Tesla has lots of operational GFM experience with 3.21 GW and 7.52 GWh of operational assets as of March 2026, including some recent projects in the US.

All projects generally followed a similar pattern. The sites were designed in GFL mode and eventually ran into stability-related issues (e.g., low SCR/controls instability) and conversion to GFM was pursued. This has included some quite large BESS installations with lots of solar PV nearby or co-located facilities as well. In some cases, issues with oscillations were uncovered during commissioning and then the site was converted to GFM to achieve commercial operation. In one case, the facility is undergoing official approval since studies were not conducted in GFM mode.

The key message articulated by Sarah was that multiple utility-scale GFM projects are already operational in the continental US and around the world, and have been successfully integrated to address grid stability issues.

Jayanth Ranganathan Ramamurthy, AEMO

AEMO has numerous GFM Projects in service today in the AEMO NEM and WEM regions, and these have been highlighted in AEMO's Transition Plan for System Security. Refer to this document for numerous publications and references pertaining to GFM technology, integration, requirements, and utilization. The pipeline for GFM projects in Australia is very aggressive. ARENA has funded eight GFM projects constituting 100s of MWs of GFM. Jay highlighted that from an operational perspective, the best use case today is GFM used to enable IBR integration and support reliable operation in low system strength grids. GFM BESS has proved very efficient and reliable, and there are lots of studies supporting GFM providing FFR in AEMO.

Laurence Copson, Zenobe

Laurence shared a case study in the UK of the 200 MW Blackhillock GFM BESS, one of the world's first and largest GFM BESS installations, which provides stability services (inertia and system strength contribution) to the UK grid. Multiple large grid events involving generator tripping, pumped storage units tripping, HVDC circuits tripping, and other events have been used to test the performance operationally, and overall, the response is very positive. Figure 75 shows the expected versus actual response of the BESS over a time window, with very close match.

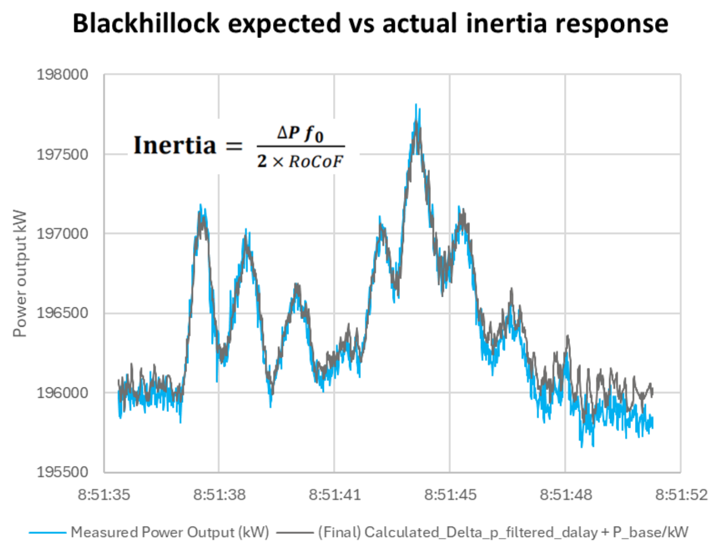


Figure 75. Blackhillock Expected vs. Actual Inertia Response [Source: Zenobe]

Overall, Laurence highlighted that GFM is a proven technology able to provide grid-stabilizing services. Grid planners need to model the capabilities of these resources and identify where GFM can benefit the grid, and either incentives or requirements can be put in place to drive the performance.

Ken Aramaki (for Li Yu), Hawaiian Electric Company (HECO)

Ken described GFM resources that have successfully been integrated in the HECO system across Hawaii. HECO is on a pathway to achieving net zero carbon emissions by 2045 and thus requires innovative solutions to ensure grid stability. Multiple existing projects have provided valuable grid-stabilizing benefits such as Kapolei Energy Storage (135 MW/540 MWh with 50 MW/25 MWh FFR) and Kupono Solar + BESS project. Multiple projects will be commissioned in the near future including Mountain View and Waiawa Phase 2 DC-coupled PV/BESS projects. On the Maui island, Waena BESS will also be coming online. The Stage 3 RFP awarded GFM projects of 126 MW, 60 MW, and 86 MW on Oahu, Maui, and Hawaii Island, respectively.

Benjamin Braun, Fluence

Benjamin shared international experience integrating over 3000 MVA of GFM projects worldwide, highlighting three key drivers for GFM BESS as shown in Figure 76 – physical and operating risk posed by grid conditions, regulatory response and standards evolutions, and economic value. However, disparate requirements around the world have led to challenges effectively deploying solutions for different sets of standards and specifications. For example, short-term overcurrent capability, inertia constant versus ROCOF and time duration, phase angle response, and damping across frequency ranges all pose technical challenges designing an optimal product across all markets. Battery system design, power conversion system (PCS) and PPC design and tuning, hardware in the loop testing, factory testing, and careful project execution – all are key to successful project and technology deployment. It was also noted that short-term overload capability is essentially mandatory for stable GFM controls, regardless of whether it is specified in grid codes.

Figure 76. Key Drivers for GFM BESS [Source: Fluence]

Session 4 Q&A:

What has motivated GFM projects that are in commercial operation today?

Key drivers often include system strength or low SCR conditions, addressing controls instability issues, existing GFM requirements, or incentives/market opportunities. As requirements are developed around the world for key markets, the OEMs play a significant role in trying to ensure those requirements are developed in a suitable way that enables product integration. It has become rather challenging for OEMs when an authority developing requirements picks and chooses stringent sub-requirements from different regions and pieces them together without much consideration for the impacts and costs this may have. Realizing these complications after requirements have been solidified can create serious obstacles during modeling, studies, and commissioning. Additionally, some GFM projects came to existence due to challenges observed and identified during commissioning that required GFM capabilities to improve stability. Situations where the transmission provider does not allow for GFM are withholding valuable grid-stabilizing features and contribution of system strength for the grid.

In HECO, system studies showed a significantly weakening grid strength that warranted improved inverter stability beyond conventional GFL controls and the need for grid strength contributions from GFM, particularly from BESS. This has allowed HECO to minimize the need for other large-scale transmission infrastructure on the islands.

In AEMO, GFM is not mandatory but there are GFM specifications being developed. AEMO currently has voluntary specifications but strong incentives for adoption due to system strength "do no harm" requirements for IBRs that have driven aggressive growth of GFM across the system. AEMO has also been studying the need, for example, of overcurrent for certain durations to support specific network providers and their primary fault current needs for relaying. These topics are not yet part of the basic GFM requirements.

The only equipment-level requirements for GFM are being developed by IEEE P2800.1. All other GFM specifications are plant-level requirements. How do OEMs translate plant-level requirements to equipment and how do you make sure the equipment is able to support the plant-level obligations? How do system operators and developers also handle/manage this?

Tesla described that a significant amount of time and effort goes into product design, site design, controls design and tuning, testing, modeling, etc. There are lots of stages of development for GFM projects. Once into commissioning, hold point testing occurs in phases to ensure product performance meets expectations. Julia noted that these perspectives sound very similar to a developer rather than an OEM. Sarah highlighted that as more IBRs come online, there is not enough verification and validation work going on throughout the project lifecycle to ensure models and performance match, which leaves significant risk on the table. More entities should be raising the alarms about these topics, "especially when an OEM is requesting more verification and more validation." Tesla in particular is very concerned with the lack of checks by developers and transmission providers, and thus takes it upon themselves to ensure performance of the site, to the extent possible.

Fluence described that they are developing their own converter with their own controls in-house. Past experience proved extremely costly trying to work with multiple vendors, which was not sustainable nor supportable. They are trying to streamline everything between the PCS up to the POI for successful controls performance. Developers then have one point of contact to engage across the entire stack from a controls perspective, which has led to greater success.

Zenobe highlighted that just 5 years ago, GFM was a much less mature space. Contracts have also matured significantly, with penalties for suppliers and OEM-backed products and delivery expectations.

What are the checkpoints that system operators require during design and development stage during an IBR project development and lifecycle to make sure GFM requirements are met? What is desired?

HECO does not have a formal process for testing IBR plants during ride-through/fault events. Once in service, they check performance against model. This has led to post-commissioning changes working with OEMs to address discrepancies between performance and model. Some issues are harder to get addressed but overall it has been a positive experience.

AEMO noted that their hold point tests (i.e., commissioning checkpoints) and registration process are working well and result in adequate checks that need to be completed ahead of commercial operation. Models, site information, test data, etc., particularly from the developer and OEM, have been adequate. Anyone registering in the AEMO NEM must meet all stages in this process, which has become very streamlined. AEMO also has conducted model validation for severe real-world events and seen very accurate models of GFM sites.

What are you seeing in terms of measurements and model validation for GFM compared with GFL projects?

There is not much difference between technologies regarding model validation using measurements for real-world events. In AEMO, plants come online and are waiting for a grid event. If possible, within 90-days, they need to demonstrate plant behavior matches the model. For example, Figure 77 shows a very good match of performance between model and actual equipment for a large event. Tesla stated that "intense enforcement of requirements is what results in this type of match."

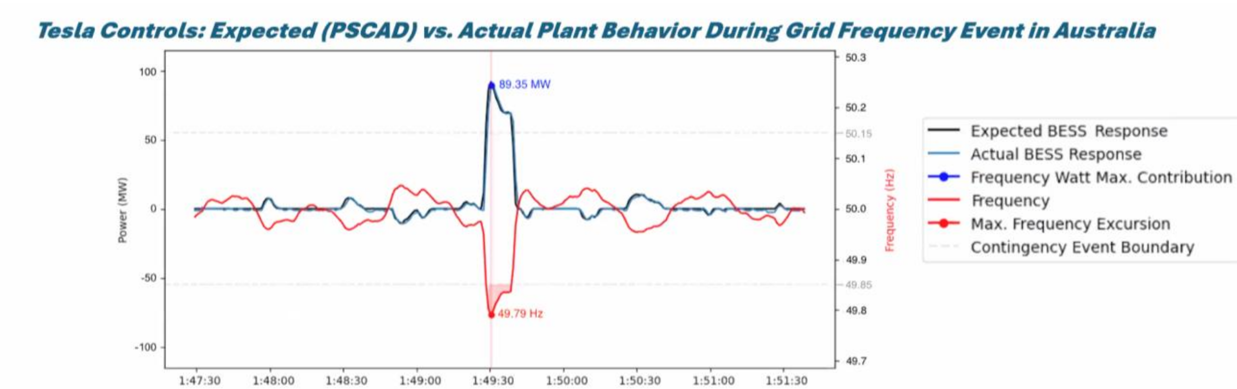


Figure 77. Example of Model Validation Experience for Real Event [Source: Tesla]

In the US, it is rather common to have a site-level PPC overlaid on top of an OEM-specific PPC, particularly for co-located and hybrid sites. These controls have a higher likelihood of not being modeled correctly as they are often configured and tuned during commissioning and never trued up. These issues are typically underenforced by the transmission provider and therefore go unnoticed until a performance issue occurs.

In some areas, however, these types of modeling issues are tested onerously both in the modeling phase and during site commissioning. In those cases, models generally have much higher quality and accuracy (i.e., match the as-left site settings). Some dynamic performance issues depend on field events and thus post-commissioning model validation based on real events is extremely valuable and should be conducted using on-site disturbance monitoring data.

What lessons can you share based on GFM experience thus far?

There are numerous older BESS projects that would ideally like to be converted to GFM such as sites with PPC issues, controls instability issues, weak grid problems, etc. However, the level of complexity for conversion of some of those sites is significant and creates financial strains.

As requirements change over time, new products must adapt to those new requirements and this must be done carefully and with attention to implementation timelines. If requirements are not developed carefully, complications can arise during implementation between IBR plant developers/owners and transmission providers. Situations have arisen where the IBR plant developer believes the site passes based on OEM-supplied documentation but the transmission provider states that the site fails performance tests. This leaves the IBR developer "stuck in the middle" in many ways, and they need guidance as to how to get out of this situation.

OEMs are testing and improving their controls all the time, including HIL testing and real world event validation. GFM products are already highly reliable and continue improving robustness to all sorts of grid events. However, GFM is not a "magic solution" that solves all problems – it is a complement to other types of grid solutions and can provide enhanced grid stability in situations with high IBR penetrations. Continued review and evaluation of models, performance, studies, etc., will all help the system overall become more reliable.

What are future issues we should be thinking about in terms of GFM deployment?

Speed of response, aggressiveness of controls, stiffness of GFM controls, and other issues beyond "inertia" all need to be considered and explored further. Post-fault overvoltage is another challenging area for GFM controls that OEMs are paying close attention to. Minimum and maximum current at various SOC points and temperature points are other areas of focus for OEMs. Energy and DC current limits can also trip the PCS if not carefully managed so these are a focus for OEMs and must be built into the controls. Lastly, OEMs need to ensure GFM controls are not overly degrading BESS battery lifespans. All these issues are OEM-centric challenges currently being explored and should be considered by all applicable parties.

How are you thinking about sizing GFM solutions in the future?

Entities are considering future scenarios and identifying worst case conditions under those scenarios. This may require an iterative process to review response of the grid and IBR plants and identify issues, then seek solutions to address those issues. This can help inform how much GFM (or other solutions) may be needed to solve those reliability issues. AEMO has used similar approaches to determine synchronous condenser sizing based on EMT simulations and results, looking at the contribution of stability benefits.

Sizing of GFM depends somewhat on the amount of GFL plants nearby, particularly from a system strength perspective. A simple ratio of how much GFM is needed for a specific level of GFL is not always straightforward and is site- and location-specific.

What part of revenue would you ideally see come from stability services/GFM aspects?

In the UK experience, one specific project contract for stability services is 1 million pounds per year for a 200 MW project, so this equates to about 5-10% of revenues and that was deemed "enough" by the developer to pursue it. Developers expect more monetization of these services in the future. If a developer is building a battery, for example, and there is no impact on how that BESS is trading energy or granted a certain capacity, then it is a matter of how much more cost burden occurs to procure GFM and developers want to see about 10% of the revenue stack from these additional services.

For a "premium" product and availability (in Germany) for a 500 MW BESS, you're looking at $5-10 million in fixed revenue for about 5-10 years. Having that fixed revenue and not volatile is very attractive for developers and financiers.

Key Themes

- GFM has matured from an emerging concept to a deployable, field-proven IBR technology. Over the past decade, GFM controls have matured to the point where fundamental principles are broadly agreed upon and validated through real-world deployments across multiple regions globally. Operational experience from large-scale BESS installations demonstrates that GFM is actively resolving stability challenges today. The industry is increasingly treating GFM as a practical extension of IBR control philosophy rather than a novel or experimental solution.
- The primary driver for GFM adoption is the rapid erosion of traditional system strength. High instantaneous penetrations of IBRs are exposing limits in conventional GFL IBR behavior, particularly under weak grid and disturbance conditions. System operators are observing inflection points (often in the 30–60% IBR penetration range) where stability, frequency response, and control interactions become more difficult to manage. GFM is a scalable, cost-effective mechanism to restore stabilizing characteristics historically provided by synchronous machines.
- Industry implementation is proceeding pragmatically, often ahead of complete analytical certainty. Several ISOs and utilities are adopting GFM requirements based on system-level trends and low incremental cost for new assets rather than waiting for perfect quantification of need. This reflects a shift toward risk-informed engineering judgment, where early deployment is viewed as preferable to delayed action in the face of evolving

system conditions and rapid deployment of BESS.[16] In practice, requirements are focusing on "core capabilities" with iterative refinement based on operational experience.

- Performance-based specifications are generally the preferred framework over prescriptive control definitions. Rather than mandating specific GFM control architectures, the leading approaches define measurable system behaviors through time-domain (and possibly frequency-domain in the future) tests that GFM resources must meet. This allows flexibility for OEM innovation while ensuring grid needs are met in a verifiable manner. Care must be taken to avoid poorly constructed tests that can be "gamed" or that fail to capture broader system interactions.
- Modeling, validation, and commissioning remain critical (and currently underdeveloped, even for GFL IBRs) risk areas. Across multiple stakeholders, there is consistent concern that model fidelity and as-built performance are not sufficiently aligned, particularly at the IBR plant and IBR controls integration level. While GFM itself is not uniquely problematic, the complexity of layered controls (e.g., PPCs, hybrid systems) increases the likelihood of discrepancies. Stronger enforcement of model validation, including use of PMU/DFR data and post-event performance evaluation and model validation, is essential to realizing the full reliability benefits of GFM.
- GFM is best understood as an IBR controls technology advancement, not a completely different solution, with broad grid-stabilizing attributes. System operators consistently emphasize that GFM complements, not replaces, other technologies such as synchronous condensers, STATCOMs, HVDC, and improved GFL performance. The optimal solution set remains highly location-specific, driven by system topology, resource mix, and operational objectives. As such, planning frameworks are evolving toward comparative, multi-technology evaluations rather than single-solution mandates.
- Standardization is accelerating but remains fragmented across regions and organizations. Parallel efforts across IEEE, IEC, UNIFI, and ISOs are converging on common principles yet differences in terminology, testing methods, and performance thresholds persist. Lack of harmonization introduces complexity for OEMs and developers attempting to design globally deployable solutions. The next phase of industry progress will depend heavily on aligning these frameworks into coherent, interoperable standards.
- Economic signals and policy structures are beginning to reinforce technical adoption. Market-based mechanisms for inertia and stability services, along with requirements embedded in business practices and interconnection processes, are creating revenue streams and compliance drivers for GFM deployment. Developers are increasingly willing to incorporate GFM when it represents a modest cost increment paired with

[16] It was noted that ERCOT may be a prime example of this delayed action where they expect upwards of 50 GW of BESS that are *not* required to be GFM due to delays in deploying requirements.

predictable value. This alignment of engineering need with economic incentive is likely to be a decisive factor in scaling adoption across the bulk power system.

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