NATF Inverter-Based Resource Interconnection Lifecycle: Interconnection Agreements and Requirements Practices

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Versioning

Version History

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08/14/2025	1.0	Initial version
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Review and Update Requirements

- Review: every 5 years
- Update: as necessary

Contents

1. Purpose

The electric utility industry is experiencing the highest volume of generator interconnections in history as a reaction to climate change and local, state, and federal initiatives. The North American Electric Reliability Corporation (NERC) has issued a recommendation to establish and improve clear and consistent interconnection requirements for bulk power system (BPS) connected inverter-based resources (IBR) [1]. Additionally, the Federal Energy Regulatory Commission (FERC) has issued Order No. 2023 regarding significant overhaul of the interconnection process, as well as Order No. 901 regarding changes to NERC Reliability Standards [2] [3].

The Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA) facilitate the relations between the interconnection parties. Each utility has specific requirements based on their system topology and practices, however, the LGIP and LGIA are pro forma per FERC rule. Additionally, state or local governments may have established LGIP and LGIA. The utility should establish supporting documentation to accompany the LGIP and LGIA to ensure an effective relation between the IBR and the bulk electric system (BES). Examples of supporting documentation include business practices, operating requirements, performance standards, interconnection technical specifications, facility connection requirements, etc. However, arriving at said supporting documentation presents its own challenges. There are numerous industry references and requirements to consider when developing this documentation. The utility should evaluate all references and discern their requirements for the optimal outcome of the pro forma LGIP and LGIA.

This document does not create, replace, or change any requirements in the NERC Reliability Standards or other applicable criteria, nor does it create binding norms by which compliance with NERC Reliability Standards is monitored or enforced. Implementation of NATF practices does not ensure compliance with the NERC Reliability Standards. In addition, this document is not intended to take precedence over any company or regional procedure. It is recognized that individual companies may use alternative and/or more specific approaches that they deem more appropriate.

2. Scope

This practice applies to all functions that are involved in executing or supporting interconnection requests. That may include, but is not limited to, the following functions: transmission planners, system protection, operations planning, transmission support, and tariff administration.

This document focuses on the second step, Interconnection Agreements and Requirements, of the IBR interconnection lifecycle (Figure 1). The document describes the LGIA, the importance of LGIA supporting documentation, cost allocation, accounting structure, examples of how to implement industry standards, and interactions with stakeholders during the process.

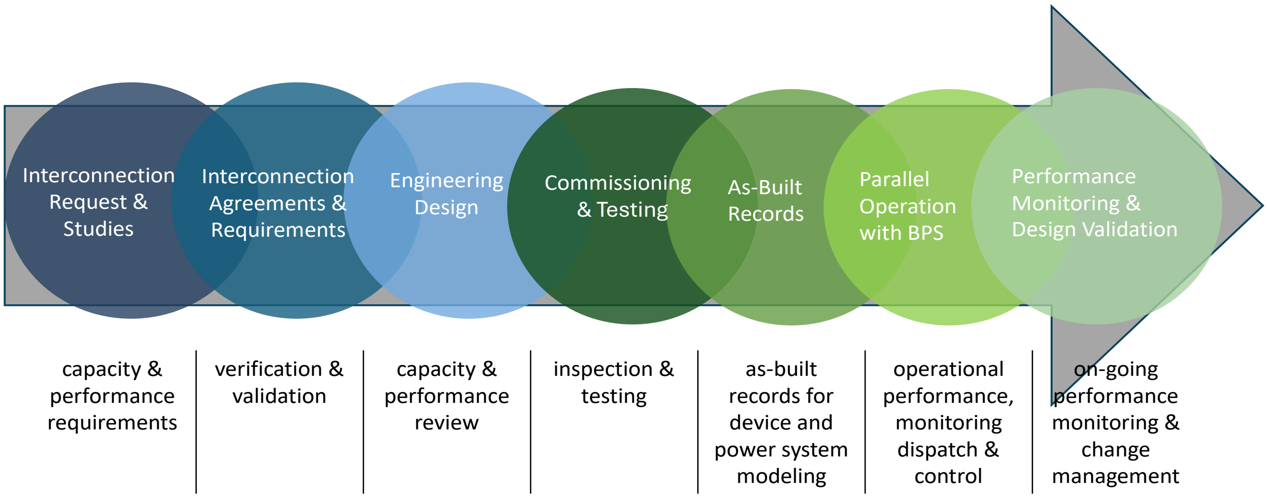

Figure 1. Inverter-based resource interconnection lifecycle

3. Definitions

NATF Practice

A documented method for performing a process, under the same or similar circumstances, in a safe, effective manner where the requisite skills, diligence, prudence, and foresight are those that are reasonably expected from skilled and experienced industry organizations.

NATF Superior Practice

A leading industry practice that can be consistently applied under a range of circumstances and that is a safe, effective, and efficient process or activity for achieving near-optimal industry results in terms of quality, reliability, and maintainability.

Interconnection Facilities

Facilities and equipment between the generating facility and the POI, including any modifications, additions or upgrades that are necessary to physically and electrically interconnect the generating facility to the Transmission Owner's transmission system. Interconnection Facilities are sole use facilities and shall not include distribution upgrades, stand along network upgrades or Network Upgrades [4].

Network Upgrades

Additions, modifications, and upgrades to the Transmission Owner's transmission system required at or beyond the point at which the Interconnection Facilities connect to the transmission system [4].

Reference Point of Applicability (RPA)

Location proximate to the IBR connection where the interconnection and interoperability performance requirements are specified [5].

Point of Measurement (POM)

A point between the high-side bus of the IBR and the interconnection system [5].

Point of Interconnection (POI)

A point where the interconnection system connects an IBR to the transmission system [5].

Inverter-Based Resource (IBR)

Generation resources that connect to the electric power system using power electronic devices to change direct current (DC) power produced by the resource to alternating current (AC) power compatible with distribution and transmission grids. IBR may refer to solar photovoltaic (PV), wind, fuel cell, battery storage, and renewable resources [6].

Per Unit (p.u.)

Quantity expressed as a fraction of a defined base unit quantity.

Co-located Plant

Two or more generation or storage resources that are operated and controlled as separate entities yet connected behind a single point of interconnection [5].

Facilities Study

An engineering study conducted by the Transmission Planner, based on and including Interconnection Facilities and Network Upgrades identified in the cluster study, that details modifications to the Transmission Provider's transmission system required to provide the requested transmission service, including the cost and scheduled completion date for such modifications.

Transmission Operator (TOP)

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities [7].

Transmission Owner (TO)

The entity that owns and maintains transmission facilities [7].

Transmission Planner (TP)

The entity that develops a long-term (generally one year and beyond) plan for reliability (adequacy) of the interconnected bulk electric transmission system within its portion of the planning authority area [7].

Transmission Provider

The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the tariff. The term Transmission Provider should be read to include the transmission owner when the transmission owner is separate from the Transmission Provider [4].

Transmission Service Provider (TSP)

The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements [7].

Interconnection Customer (IC)

Any entity, including the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect with the Transmission Owner's transmission system [4].

4. Generator Interconnection Agreements

The LGIA is a contract that delineates the responsibilities, procedures, and requirements for the Transmission Provider, the Interconnection Customer (IC), and the independent system operator, where applicable. It is intended to ensure a uniform and transparent process for interconnecting generators to the BES.

FERC Pro Forma LGIA

FERC has established a standardized framework for the interconnection of large generators to the transmission system through the pro forma LGIA [4]. The pro forma LGIA serves as a foundational template for interconnection agreements and details essential components such as:

- Interconnection service definitions
- Construction responsibilities
- Operating requirements
- Cost allocation and financial terms
- Milestones and scheduling
- Insurance and liability
- Dispute resolution and legal provisions

Evolution of the FERC Pro Forma LGIA

FERC Order 2003 [8] established the original LGIA.

FERC Order 845 [9] added flexibility in the form of Surplus Interconnection, Provisional Service, and improved information access.

FERC Order 2023 [3] enforced the use of cluster studies by the Transmission Provider, increased readiness requirements on the IC, and placed more strict study timelines on the Transmission Provider.

Importance of the LGIA

The LGIA provides legal certainty, regulatory consistency, and non-discriminatory access to the BES for ICs, while also assisting the Transmission Provider and the IC in managing the complexities of integrating renewable resources such as solar, wind, and energy storage.

The LGIA's appendices are necessary for detailing the project information, schedule of the project, and the Transmission Provider's operating criteria amongst other essential information about the project. The appendices are subject to modification by mutual agreement between all parties of the LGIA. When mutual agreement cannot be reached the IC or Transmission Provider can request that the LGIA be filed unexecuted at FERC.

Non-Jurisdictional Utilities

Adoption of the FERC pro forma LGIA is voluntary for non-jurisdictional utilities. However, many non-jurisdictional utilities have neighboring jurisdictional utilities, and maintaining consistency can help facilitate regional planning and generator interconnection. Non-jurisdictional utilities do have the ability and authority to make modifications to the pro forma LGIA to best fit their unique environments.

NATF Practices

4.1 Develop and maintain an LGIA either consistent with the pro forma LGIA or with allowable modifications.

Allowable Modifications

FERC does not have direct regulatory oversight for non-jurisdictional utilities such as cooperatives and municipalities. Therefore, modifications to meet operational and policy needs are permitted if they are non-discriminatory, maintain consistency with reliability and safety standards, and are transparent to prospective ICs.

Modification Examples

The following modifications to the LGIA are examples of modifications to help facilitate development of an LGIA for a non-jurisdictional utility.

Study Deposits

Pro forma	FERC's study deposit is tiered based on the MW of the interconnection request as follows: • $35,000 plus $1,000 per MW for interconnection requests < 80 MW; or • $150,000 for interconnection requests ≥ 80 MW < 200 MW; or • $250,000 for interconnection requests ≥ 200 MW.
Modified	Establish a base study deposit with a plus $1,000 per MW of requested generating facility capacity not to exceed $250,000.

Commercial Readiness

Pro forma	• Deposit is equal to two times the study deposit and does not require any additional documentation. • The commercial readiness deposit is subject to withdrawal penalties as outlined in the LGIP. • After any cluster study restudies, an additional deposit that brings the total commercial readiness deposit to 5% of the IC's Network Upgrades cost assignment. • Upon execution of the interconnection Facilities Study agreement, the IC must provide an additional deposit that brings the total commercial readiness deposit to 10% of the IC's Network Upgrades cost assignment.
Modified	Executed contract or reasonable evidence (i.e., bid security held by a Load-Serving Entity) that: • Binds the generating facility to a Load-Serving Entity or to a commercial, industrial, or other large end-use customer. • That the energy term of sale for the generating facility is not less than five (5) years.

Commercial Readiness

	• That the generating facility's ancillary services (e.g., BESS) term of sale is not less than five (5) years; or if the IC does not have commercial readiness, the IC shall provide a deposit in lieu of commercial readiness. The deposit in lieu of commercial readiness is a cash deposit or letter of credit set as a $/MW with a not-to-exceed value and is subject to withdrawal penalties.

Site Control

Pro forma	Documentation establishing: • Ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the generating facility; or • An option to purchase or acquire a leasehold site of sufficient size to construct and operate the generating facility; or • Any other documentation that clearly demonstrates the right of the IC to exclusively occupy a site of sufficient size to construct and operate the generating facility; or • Regulatory limitations that include an affidavit explaining the regulatory limitations and when site control is expected. When submitting an interconnection request, the IC must demonstrate no less than 90% Site Control. If regulatory limitations prohibit the IC from obtaining site control, the IC shall: • Provide a deposit in lieu of site control of $10,000 per MW, subject to a minimum of $500,000 and a maximum of $2,000,000. • Demonstrate that it is taking identifiable steps to secure the necessary regulatory approvals before execution of the Cluster Study Agreement. • Demonstrate 100% site control within 180 days of the effective date of the LGIA. Upon execution of the interconnection Facilities Study agreement, the IC must demonstrate 100% Site control or demonstration of a regulatory limitation and applicable deposit in lieu of site control. The deposit in lieu of site control is refundable and cannot be used for study costs or withdrawal penalties.
Modified	Documentation clearly demonstrates the right of the IC to develop, construct, operate and maintain the generating facility. Documentation required to show that right: • Ownership of, a leasehold interest in, or a right to develop; or • An option to purchase or acquire a leasehold site for such purpose; or • A contract or other agreement demonstrating shared land use for all co-located resources; or • Any other documentation that clearly demonstrates the right of the IC to exclusively occupy a site; or • Regulatory limitations which include an affidavit explaining the regulatory limitations.

Site Control

	If regulatory limitations prohibit the IC from obtaining site control, the IC may submit an additional non-refundable deposit specified by the Transmission Provider by the close of the cluster request window. Once site control is obtained, this deposit will be applied toward future construction costs or Network Upgrades. If site control is not obtained, the IC should pay 100% of its costs identified in the cluster study, Facilities Study report, and POI Facilities Study report.

Supplemental Requirements

Supplemental requirements accompany the LGIA and are essential for ensuring grid reliability, efficiency, and compliance with evolving standards. The supplemental requirements are developed by the Transmission Provider and can address technical, financial, and operational aspects of the interconnection process.

Key areas of additional requirements can include:

- Grid reliability and stability requirements for:
  - Voltage and frequency ride-through capabilities
  - Reactive power and power factor
- Operational coordination and testing such as:
  - Pre-operational testing and commissioning of equipment functionality
  - Real-time monitoring
  - Annual performance validation test
- Compliance with NERC and regional standards such as:
  - MOD-025, MOD-026, and MOD-027 for verification of generator modeling and performance
  - FAC-001 and FAC-002 facility connection requirements
  - PRC-024 and PRC-029 for frequency and voltage protection settings
- Financial and security obligations for:
  - Site control requirements
  - Withdrawal penalties

NATF Practices

4.2 Establish clear business practices, interconnection requirements, technical requirements, and operating requirements to accompany the LGIA.

4.3 Make all accompanying requirements and practices available to prospective ICs.

5. Business Practices

Business practices play an important role in facilitating the LGIA. While the LGIA provides the contractual framework, business practices translate it into operational guidance, stakeholder engagement, and process transparency. It is imperative that the technical requirements governing the capabilities, utilization, and performance of BPS-connected devices and equipment be kept up to date to reflect industry practices. This not only ensures that the requirements are sufficient to ensure reliability of the BPS under rapid change, but also helps ICs and original equipment manufacturers (OEM) understand what is required of them and then to be held to that level of performance fairly and consistently. All parties involved benefit from clear, consistent, concise, and evidence-based requirements to ensure BPS reliability.

A limited set of business practices is further explained in sections of this practice document.

NATF Practices

5.1 Develop business practices to help clarify how LGIA provisions are applied in practice.

- 5.1.1 The requirements are clear, consistent, and effectively communicated.
- 5.1.2 The requirements are sufficient and applicable to different types of technology, with necessary differences clearly defined.
- 5.1.3 The requirements can be easily implemented by the IC in coordination with their OEMs.
- 5.1.4 The requirements are actionable and provide sufficient detail for the IC and/or OEM to design, procure, and implement in the equipment.
- 5.1.5 The requirements avoid ambiguity and vagueness to minimize confusion.
- 5.1.6 The requirements are evidence-based, technically justified, and necessary for reliability.
- 5.1.7 The requirements are implemented via well-defined and clearly connected process.
- 5.1.8 The requirements clearly and explicitly define how changes – both during the interconnection process and during real-time operations – are handled by both parties (e.g., settings changes, etc.).
- 5.1.9 The requirements have been reviewed by stakeholders and there is a well-defined process for addressing comments and feedback (i.e., continuous improvement).

> Use the following references to guide development and enhancement of business practices:
>
> Mid-continent Independent System Operator (MISO) Business Practices [10]
>
> Duke Energy Business Practices [11]
>
> Duke Energy Storage Interconnection Requests [12]

6. Cost Assignment

Cost assignment in the LGIA is an integral part of the transparent, fair, and effective process for interconnecting new generation facilities. The cost assignments should clearly define financial responsibility and outline who (i.e., the IC, Transmission Service Provider (TSP), Transmission Owner (TO), or other stakeholders) is responsible for covering the cost associated with studies, Network Upgrades, and Interconnection Facilities.

Administration of Deposit and Payment Tracking

ICs are required to supply a deposit and payments throughout the interconnection process. Tracking deposits and payments is essential for ensuring financial accountability, maintaining project timelines, and managing risk. Tracking assists the TSP to verify that ICs meet their financial obligations at each milestone. Accurate tracking also prevents delays, supports transparent cost allocation, and enables effective coordination between project stakeholders.

Finance Teams to Support the Interconnection Process

NATF Practices

6.1 Establish dedicated teams (i.e., account managers and business controls) to manage financial aspects and cost allocation in support of the interconnection process lifecycle.

6.2 Provide specific training for accounting and finance teams on the following:

- FERC interconnection process
- Network Upgrades and how they are charged in the interconnection process.
- Interconnection Facilities and how they are charged in the interconnection process.
- Maintenance and replacement of Interconnection Facilities.

6.3 Establish clear roles for account managers using the following as a guide:

- Ensure deposits are received according to agreements.
- Notify business controls of need to calculate final invoice upon withdrawal, FERC Facilities Study completion, or commercial operation.
- Deliver invoices and statements to customers
- Ensure customers pay final invoices and final refunds are sent to customers.
- Pursue missed payments or customer information required for refunds.
- Gather banking information such as W9 or automated clearing house (ACH) for refunds.

6.4 Establish clear roles for business controls using the following as a guide:

- Run weekly treasury report and identify all payments for account managers.
- Monitor accounts-receivable aging
- Maintain database of transmission construction reimbursements and securities.

- Maintain a final accounting report
- Provide support for other departments (i.e., finance or account reconciliation)
- Calculate all invoices and statements
- Allocate actual costs incurred (i.e., study and construction), calculate withdrawal penalties, and distribute penalties and interest.
- Create reports and dashboards to monitor deadlines.

Accounting Process for Study Deposits

A robust account process for the LGIA will assist in transparency, compliance, and financial management throughout the interconnection life cycle. It accurately tracks deposits, upgrades cost, and milestone payments. The process supports internal coordination, reduces risk and potential disputes, while maintaining consistent records. Figure 2 provides an example of the account process for the interconnection life cycle.

6.5 Business controls create specific charge codes and interconnection project identification (ID) upon submittal of interconnection request application.

> The interconnection project ID is charged with the allocated portion of study expenses and any deposits paid throughout the interconnection process.

6.6 Business controls create cluster study project ID for transmission planners and project managers working on cluster studies.

> The cluster study project ID is charged with all time and expenses related to the interconnection cluster study.

6.7 Business controls allocate study expenses from the cluster study project ID to the individual interconnection project IDs.

6.8 Facilities Study expenses are charged directly to the associated interconnection project ID.

6.9 Business controls monitor study costs and generate monthly reports for project managers to ensure all study expenses are captured.

6.10 Business controls assess withdrawal penalties and how penalties are distributed to remaining cluster participants.

Interconnection Request

- Set up IC project ID
- ensure accounting books study deposit to IC project ID.
- Ensure finance has support for account recon.
- Set up cluster study project id – send cluster study charging to T&D

Cluster Study

- Monitor cluster study charging
- Calculate allocation of study costs (90%MW; 10%IRs)
- Send allocation for cluster study costs from cluster study project ID to IC project IDs
- Create customer statements at the end of cluster study
- Calculate penalties for withdrawn customers
- Allocate penalty revenues
- Calculate study cost kpis to monitor spend compared to deposit for the cluster
- Input study report estimates into cost allocation software

Facility Study

- Send IC project IDs to T&D to charge for study
- Calculate penalties for withdrawn customers
- Allocate penalty revenues
- Calculate study cost KPIs to monitor spend compared to deposit for the cluster
- For FERC projects, calculate study true-up after study completion.
- Calculate FERC interest due to customer for refund of excess study deposits.
- Input study report estimates to cost allocation software

Interconnection Agreement

- Create invoices for deposits or security due for LGIA
- Ensure accounting books cash to IC project ID
- Ensure finance has support for account reconciliation
- Input LGIA estimates to cost allocation software

Construction

- Create FERC invoice package monthly to invoice FERC projects monthly based on actuals incurred
- Calculate FERC interest accrual on payments received for network upgrades
- Monitor receipt of payment of invoices
- Maintain construction cost allocation that calculates each IC's allocated proportional share of cost
- Maintain project cost and schedule KPIs comparing projections and in-service dates to LGIA

Commercial Operation

- Perform final true-up and provide final invoice within 6 months of completion.
- Calculate final interest for FERC network upgrade repayment
- Ensure repayment is made per LGIA terms

Figure 2. Example interconnection accounting flow

Construction Charging Methodology

NATF Practices

6.11 Each construction project should have a clearly defined accounting structure before entering the construction phase.

- 6.11.1 Establish unique construction project IDs for each Interconnection Facilities and Network Upgrades during the Facilities Study phase.
- 6.11.2 Map each construction project ID to the relevant interconnection request.
- 6.11.3 Ensure all tracking systems recognize and use these IDs consistently.

6.12 Cost allocation should reflect both direct and Network Upgrades cost fairly and transparently for each interconnection request.

- 6.12.1 Apply the cost allocation model to both forecasts and actuals using mapped project IDs.
- 6.12.2 Validate allocation percentages against LGIA terms and ensure they are consistently applied.
- 6.12.3 Track all changes to cost allocation logic to ensure auditability.

6.13 Implement monitoring and reporting on forecasted vs. actual cost to ensure alignment with IA.

- 6.13.1 Calculate key performance indicators (KPIs) monthly for each interconnection request based on variance from IA cost caps.
- 6.13.2 Investigate and document causes of any forecast overruns.
- 6.13.3 Escalate material deviations to project management and communicate with ICs.

6.14 ICs should be billed accurately and on time while reflecting their allocated share of construction cost.

- 6.14.1 Use cost allocation outputs to prepare and validate monthly billing packages for FERC jurisdictional projects.
- 6.14.2 Reconcile billed amounts with actual costs incurred and LGIA commitments.

Security

Posting security is a necessary step in the interconnection process to demonstrate financial readiness and commitment to the project by the IC. This process guarantees that the IC has the necessary capital to ensure project success and facilitate construction.

NATF Practices

6.15 The TSP should establish criteria for creditworthiness and an aggregate limit for IC parent organization guarantee of funds for an interconnection project [13]. See Table 1.

Table 1 is provided as an example. The guarantee and ratings are determined by the TSP.

Table 1. Credit rating and thresholds

S&P Rating	Moody's Rating	Guarantee
A- or above	A3 or above	$50,000,000
BBB+	Baa1	$40,000,000
BBB	Baa2	$30,000,000
BBB	Baa3	$20,000,000
Below BBB-	Below Baa3	$0

6.16 Letters of credit can be accepted if issued by US commercial bank with total assets of at least $10 billion and a long-term debt rating of no lower than A- (or A3) rating or above.

6.17 Surety bonds should not be considered a form of security.

Surety bonds could be accepted as an interim form of security as deemed acceptable by the TSP.

Software

Software and automation greatly improve efficiency and accuracy when managing cost assignments for many projects.

NATF Practices

6.18 Develop and maintain an interconnection management system considering the following functionality:

- Support intake and process of interconnection applications
- Guide customers through applications, study, and LGIA phase communication
- Monitor milestones for studies and LGIA
- Provide project specific deposit and security requirements.
- Include customized workflow according to interconnection procedures

6.19 Develop and maintain a cost allocation database to assist with accounting for interconnection projects and cluster considering the following functionality:

- Track and report estimate revisions throughout interconnection lifecycle
- Track financial project IDs used for tracking study and construction cost
- Automate cost allocation calculations on actual spend during construction
- Automate withdrawal penalty impact analysis and withdrawal penalty exemptions based on estimate increases.

6.20 Develop a process manual detailing inputs and outputs from the database using Figure 3 as a guide.

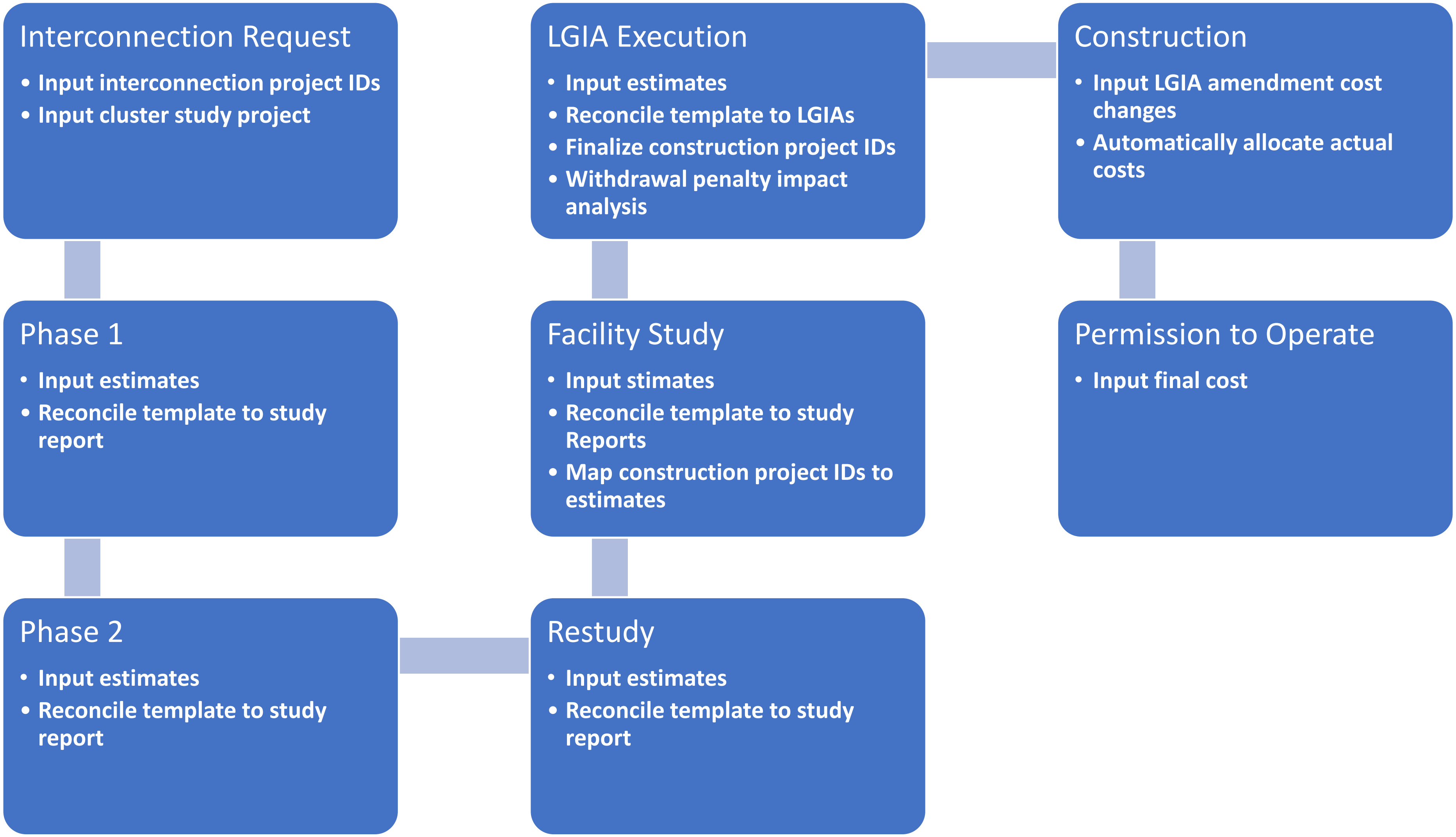

Figure 3. Example interconnection cost tracking software flow

Allocation Methodology for Interconnection Facilities and Network Upgrades

Pro forma LGIP Cost Allocation Language

For each identified Network Upgrade, the allocated share is in proportion to the flow impacts ("MW Impact") on the new facility under normal conditions. A distribution factor (DFax) analysis is conducted to allocate the costs of these facilities to the IC's generator in the cluster. The MW impact is proportional to the generator interconnection MW and can be calculated as:

$$\text{MW Impact} = \text{DFax} * \text{Study Generator Output} \quad (1)$$

The cost of Network Upgrades allocated to each request shall be proportional to the average positive incremental impact of each new interconnection request on such Network Upgrades divided by the total positive incremental impact of all requests included in the Cluster Study on such Network Upgrades.

$$\text{Cost Allocation Factor} = \frac{MW\ impact\ of\ each\ study\ generator}{\Sigma\ MW\ impact\ in\ the\ set} \quad (2)$$

$$\text{Cost Allocated} = \text{Cost Allocation Factor} * \text{Cost of Network Upgrades} \quad (3)$$

The cost allocated for each upgrade is proportional to the cost allocation factor, which is calculated from the MW impact factor. Incremental flows having a negative impact (counter flow) on a Network Upgrade are ignored.

NATF Practices

6.21 Identify Network Upgrades related to thermal and voltage violations.

6.22 Identify Network Upgrades for mitigating stability and voltage constraints.

6.23 Identify Network Upgrades for fault current contributions.

6.24 The Transmission Planner (TP) should calculate each IC's share of cost for Interconnection Facilities and Network Upgrades identified in cluster studies.

6.25 Interconnection Facilities are directly assigned to the IC(s) using the facilities.

> Multiple ICs can connect to the TOs systems through a single Interconnection Facility. Shared Interconnection Facilities are allocated based on the number of ICs sharing the facility on a per capita basis.

6.26 Network Upgrades to substations and switching stations are allocated based on the number of ICs interconnecting at an individual station on a per capita basis.

> Multiple ICs can connect to the TOs systems through a single Interconnection Facility. In this instance, all ICs using a common Interconnection Facility should be considered one IC for purposes of allocating Network Upgrades cost on a per capita basis.

Cost Allocation of Cluster Network Upgrades

Consider an example with six generators interconnecting to the transmission system and studied as part of the same cluster. During the cluster study process, thermal constraints were identified on a high voltage transformer and two high voltage transmission lines, a voltage constraint was identified at a transmission station, and a transmission breaker experienced high fault current.

In this example, the following cluster Network Upgrades are assumed to cost $61.0 million total.

- High voltage transformer replacement: $5.0 million
- High voltage transmission line 1: $20.0 million
- High voltage transmission line 2: $30.0 million
- Transmission station VAR support: $5.0 million
- Over duty breaker replacement: $1.0 million

For the purposes of the example, all costs are simplified and assumed to include engineering, material, labor, rights of way, associated equipment and components, administrative and general, etc.

Table 2 is an example of how to track cost allocation for a transformer replacement or addition.

Table 2. Cost allocation for high voltage transformer

Generator	MW Output	DFax	**MW Impact** (MW Output × DFax)	**Cost Allocation Factor** (MW Impact / Total MW Impact)	**Cost Allocation (M)** (Cost Allocation Factor × Network Upgrade Cost)
Gen1	300	0.25	75	0.44	2.22
Gen2	200	0.25	50	0.30	1.48
Gen3	100	0.25	25	0.15	0.74
Gen4	75	0.25	18.75	0.11	0.56
Gen5	50	0	0	0	0
Gen6	20	0	0	0	0
Total			**168.75**	**1**	**5.0**

Table 3 and Table 4 are examples of how to track cost allocation for a transmission line upgrade or addition.

Table 3. Cost allocation for transmission line 1

Generator	MW Output	DFax	**MW Impact** (MW Output × DFax)	**Cost Allocation Factor** (MW Impact / Total MW Impact)	**Cost Allocation (M)** (Cost Allocation Factor × Network Upgrades Cost)
Gen1	300	0.15	45	0.32	6.38
Gen2	200	0.20	40	0.28	5.66
Gen3	100	0.30	30	0.21	4.24
Gen4	75	0.35	26.25	0.19	3.72
Gen5	50	0	0	0	0
Gen6	20	0	0	0	0
Total			**141.25**	**1**	**20.0**

Table 4: Cost allocation of transmission line 2

Generator	MW Output	DFax	MW Impact (MW Output × DFax)	Cost Allocation Factor (MW Impact / Total MW Impact)	Cost Allocation (M) (Cost Allocation Factor × Network Upgrades Cost)
Gen1	300	0	0	0	0
Gen2	200	0	0	0	0
Gen3	100	0	0	0	0
Gen4	75	0	0	0	0
Gen5	50	0.25	12.5	0.71	21.42
Gen6	20	0.25	5	0.29	8.58
Total			**17.5**	**1**	**30.0**

Table 5 and Table 6 are examples of how to track cost allocation for transmission station upgrades for VAR support.

For this example of VAR support, the voltage at the impacted station is 0.85 p.u. with all generators in-service. Each generator will be removed, and the new station voltage will decrease which indicates a positive impact from the generator or the station voltage will increase which indicates a negative impact from the generator.

Table 5. VAR support of generators

Generator	MW Output	Station Voltage	Voltage Change	Station Voltage Gen Removed	Impact
Gen1	300	0.85	-0.05	0.80	Positive
Gen2	200	0.85	-0.05	0.80	Positive
Gen3	100	0.85	-0.07	0.78	Positive
Gen4	75	0.85	-0.07	0.78	Positive
Gen5	50	0.85	0.04	0.89	Negative
Gen6	20	0.85	0.08	0.93	Negative

Table 6. Cost allocation for VAR support

Generator	MW Output	Impact	Voltage Change	Cost Allocation Factor (Voltage Change / Total Voltage Change)	Cost Allocation (M) (Cost Allocation Factor × Network Upgrades Cost)
Gen1	300	Positive		0	0
Gen2	200	Positive		0	0
Gen3	100	Positive		0	0
Gen4	75	Positive		0	0
Gen5	50	Negative	0.04	0.33	1.67
Gen6	20	Negative	0.08	0.67	3.33
			0.12	**1**	**5**

Table 7 is an example of how to track cost allocation for a breaker replacement.

For this example, the short circuit duty of the impacted breaker is 20kA in the pre cluster case and it does not exceed its breaker duty rating. During the cluster studies a short circuit duty of 20.75kA is identified. Each generator is taken out to identify its portion of the total short circuit contribution.

Table 7. Cost allocation for breaker upgrade

Generator	MW Output	Short Circuit Current (kA) Gen Removed	Short Circuit Current (kA) Change	Short Circuit Impact (%) (Fault Current / Total Fault Current)	Cost Allocation (M) (% Impact × Network Upgrades Cost)
Gen1	300	20.20	0.30	40.00%	0.40
Gen2	200	20.30	0.20	26.67%	0.27
Gen3	100	20.35	0.15	20.00%	0.20
Gen4	75	20.40	0.10	13.33%	0.13
Gen5	50	20.75	0	0	0
Gen6	20	20.75	0	0	0
Total			**0.75**	**100%**	**1**

Table 8 is an example to summarize the cost allocation of Network Upgrades for each generator in the cluster.

Table 8. Cost allocation of cluster network upgrades

Generator	Network Upgrades Allocated	Cost Allocation of Network Upgrades (M)	Total Cost Allocation (M)
Gen1	Transformer Transmission Line 1 Breaker Upgrade	2.22 6.38 0.40	9.00
Gen2	Transformer Transmission Line 1 Breaker Upgrade	1.48 5.66 0.27	7.41
Gen3	Transformer Transmission Line 1 Breaker Upgrade	0.74 4.24 0.20	5.18
Gen4	Transformer Transmission Line 1 Breaker Upgrade	0.56 3.72 0.13	4.41
Gen5	Transmission Line 2 VAR Support	21.42 1.67	23.09
Gen6	Transmission Line 2 VAR Support	8.58 3.33	11.91
			61

Cost Allocation of Interconnection Facilities

Consider the same example with six generators from the previous example interconnecting to the transmission system and studied as part of the same cluster. Generators 1, 2, 3, and 4 interconnect to substation A and generators 5 and 6 interconnect to substation B.

In this example, the following Interconnection Facilities are required:

- Generators 1, 2, 3, and 4 each require a new terminal at substation A
- Generators 5 and 6 each require a new terminal at substation B

Each terminal is identical and is assumed to cost $1.0 million per terminal.

For the purposes of the example, all costs are simplified and assumed to include engineering, material, labor, rights of way, associated equipment and components, administrative and general, etc.

Table 9 is an example to summarize the cost allocation Interconnection Facilities for each generator.

Table 9. Cost allocation for interconnection facilities

Generator	MW Output	Interconnection	Description	Cost Allocation (M)
Gen1	300	Substation A	New Terminal	1.0
Gen2	200	Substation A	New Terminal	1.0
Gen3	100	Substation A	New Terminal	1.0
Gen4	75	Substation A	New Terminal	1.0
Gen5	50	Substation B	New Terminal	1.0
Gen6	20	Substation B	New Terminal	1.0

Cost Allocation of Shared Substation Network Upgrades

Consider the same example with six generators from the previous example interconnecting to the transmission system and studied as part of the same cluster. Generators 1, 2, 3, and 4 interconnect to substation A and generators 5 and 6 interconnect to substation B.

In this example, the following shared substation Network Upgrades are required

- Substation A requires expansion to accommodate the terminals for generators 1, 2, 3, and 4 as well as breakers, switches, instrument transformers, protection and controls, etc. The total cost of the expansion is $15M and is split between the generators equally.
- Substation B requires expansion to accommodate the terminals for generators 5 and 6 as well as breakers, switches, instrument transformers, protection and controls, etc. The total cost of the expansion is $10M and is split between the generators equally.

For the purposes of the example, all costs are simplified and assumed to include engineering, material, labor, rights of way, associated equipment and components, administrative and general, etc.

Table 10 is an example for cost allocation of shared substation Network Upgrades for each generator.

Table 10. Cost allocation of shared substation network upgrades

Generator	MW Output	Interconnection	Description	Cost Allocation (M) (Total Network Upgrades / Interconnections)
Gen1	300	Substation A	Substation Network Upgrades	3.75
Gen2	200	Substation A	Substation Network Upgrades	3.75
Gen3	100	Substation A	Substation Network Upgrades	3.75
Gen4	75	Substation A	Substation Network Upgrades	3.75
Gen5	50	Substation B	Substation Network Upgrades	5.00
Gen6	20	Substation B	Substation Network Upgrades	5.00

Summarized Cost Allocation

In previous practices the cost allocation for cluster Network Upgrades, Interconnection Facilities, and shared substation Network Upgrades were identified. The total cost allocation for the cluster is the sum of each identified cost.

Table 11 is an example to summarize the cost allocation of all generators in the cluster.

Table 11. Summary of cluster cost allocation

Generator	MW Output	Network Upgrades (M)	Interconnection Facilities (M)	Shared Substation Network Upgrades (M)	Total Cost Allocated (M)
Gen1	300	9.0	1.0	3.75	**13.75**
Gen2	200	7.41	1.0	3.75	**12.16**
Gen3	100	5.18	1.0	3.75	**9.93**
Gen4	75	4.41	1.0	3.75	**9.16**
Gen5	50	23.09	1.0	5.00	**29.09**
Gen6	20	11.9	1.0	5.00	**17.91**
		61.0	**6.0**	**25.0**	**92.0**

7. LGIA Modifications

Provisional Interconnection Service

FERC Order 845 [9] defines Provisional Interconnection Service as:

> *"Interconnection service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms on Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff"* [9].

Requesting Provisional Interconnection Service

NATF Practices

7.1 The IC should submit a written request for Provisional Interconnection Service to the TSP including an existing generator interconnection queue position [14].

7.2 All technical data required for a cluster study is also required for Provisional Interconnection Request.

7.3 The TSP reviews the request and provides the following:

- Prior studies that can be used, including one-line drawings and cost estimates that can be used to identify the Interconnection Facilities, or identify if new studies are required.
- Specify additional information required to perform a study, if applicable.
- Study assumptions, study timeframe, and scope of study if existing studies are not applicable. The study will include control technology that will be used to limit the output if the provisional service is less than the nameplate of the generating facility.

Study Methodology

The study methodology for a Provisional Interconnection Request shall follow the same methodology described in *NATF – IBR Interconnection Requests and Studies Practices* [15] or as defined by the TSP. The study should also identify the maximum permissible output of the generating facility and security to be posted for any nonpayment risk associated with Network Upgrades and Interconnection Facilities.

Study Approaches

Provisional Interconnection Service can be achieved using existing studies or by performing new studies based on the TSP discretion and review of the application.

NATF Practices

7.4 The TSP may elect, at their discretion, to use existing studies if the following conditions are met:

- The current system has not changed since existing studies were performed.
- The assumptions used in existing studies are consistent with currently applicable study assumptions.

- The capacity of the generator is consistent with the generator model used in existing studies in terms of reactive power capability, post fault voltage and recovery, etc.
- The existing study evaluated an output and level of interconnection service that is equal to or greater than the Provisional Interconnection Request.

7.5 The TSP may elect, at their discretion, to perform new studies if existing studies are not sufficient to determine Provisional Interconnection Service.

7.6 If the study does not identify any system constraints, the Provisional Interconnection Service will be feasible, and the permissible output will be equal to the requested Provisional Interconnection Service.

7.7 If the study identifies system constraints at the requested Provisional Interconnection Service, the study shall identify the maximum permissible output that can be accommodated before Network Upgrades are necessary for full interconnection service.

Provisional Large Generator Interconnection Agreement (PLGIA)

NATF Practices

7.8 The IC should demonstrate a written commitment to adhere to agreement milestones and achieve interconnection and commercial operation prior to receiving a PLGIA.

7.9 The TSP should ensure the following before a PLGIA:

- Study reports are complete and identify the maximum output and any facilities required for a reliable interconnection.
- The IC agrees to fund any identified facilities and assumes all risks and liabilities associated with changes to the LGIA by posting security for nonpayment risks associated with Network Upgrades and Interconnection Facilities.
- The IC agrees to install protective equipment that limits the output of the generating facility to the permissible output in the PLGIA.

Cost Responsibility

Cost responsibility under Provisional Interconnection Service is equivalent to standard Interconnection Service. The IC is responsible for funding Interconnection Facilities and the construction of Network Upgrades.

Surplus Interconnection Service

FERC Order 845 [9] defines Surplus Interconnection Service as:

> *"Any unused portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the Interconnection Service limit at the Point of Interconnection would remain the same* [9]*."*

Additionally:

> *"…the original Interconnection Customer or one of its affiliates shall have priority to utilize Surplus Interconnection Service. If the existing Interconnection Customer or one of its affiliates does not exercise its*

priority, then that service may be made available to other potential interconnection customers through an open and transparent solicitation process [9]*."*

Surplus Interconnection Service Limitations

NATF Practices

7.10 Surplus Interconnection Service request must be less than or equal to the amount made available by the original IC, cannot exceed the Interconnection Service Level and duration of the original Interconnection Agreement, and is only available through the existing Point of Interconnection provided in the original Interconnection Agreement [16].

> Service level examples are Network Resource Interconnection Service and Energy Resource Interconnection Service as described in *NATF – IBR Interconnection Requests and Studies Practices* [15].

7.11 Surplus Interconnection Service cannot be granted if the current interconnection is scheduled to retire or cease operations prior to when the surplus generating facility can begin or is scheduled to begin operations.

Surplus Availability

NATF Practices

7.12 An IC holding an executed or filed unexecuted Interconnection Agreement may make Surplus Interconnection Service available by contacting the TSP and providing the following:

- The amount and period(s) of time the Surplus Interconnection Service will be available.
- Conditions under which the Surplus Interconnection Service may be used.
- If the IC intends to use the Surplus Interconnection Service or make it available to an unaffiliated IC.
- Contact information of the IC and information necessary to inform potential Surplus Interconnection Service customers.

7.13 The existing IC shall notify the TSP, in writing, when a Surplus IC has been identified and provide the following:

- The Generator Interconnection Agreement number or original queue position of existing interconnection service.
- The identity and capacity of the Surplus Interconnection Service Customer.
- Contact information for the existing IC.

7.14 The Surplus Interconnection Service Customer shall contact the TSP, in writing, with the following:

- Point of Interconnection associated with the existing Interconnection Service, the original Interconnection Agreement number, and original queue position.

- One-line diagrams of the proposed generating facility depicting how the proposed generating facility will connect through the existing Point of Interconnection.

Study Methodology

The study methodology for Surplus Interconnection Service shall follow the same methodology described in *NATF – IBR Interconnection Requests and Studies Practices* [15] or as defined by the TSP.

Surplus Large Generator Interconnection Agreement

7.15 A multiparty Interconnection Agreement between the original IC, the Surplus IC, and the TSP should be executed or filed unexecuted.

7.16 The Surplus Interconnection Agreement should not exceed the life of the original Interconnection Agreement.

7.17 Necessary protection and control systems should be provided to ensure the Surplus Interconnection Service does not exceed the Point of Interconnection capacity defined in the original Interconnection Agreement.

For example, consider an existing solar generating facility with a Surplus Interconnection Service request to add a battery energy storage system (BESS). The BESS can supplement the solar facility during low production periods and charge from solar during high production periods. See Figure 4.

Figure 4. Example of solar with storage

8. Adoption of IEEE 2800

Section 8, "Adoption of IEEE 2800", is based on content from Pathway to Enhancing Interconnection Requirements and Improving Reliable Interconnection of Inverter-Based Resources[1] [17].

Adoption of IEEE 2800-2022 [5] (or latest version) in the TO's (or Authority Governing Interconnection Requirements [AGIR]) interconnection requirements documentation will bolster technical requirement and specification. These requirements are fully in the control of the TO, relatively easily modifiable, and adaptable as grid risks and issues evolve and can be enforced by the TO.

Adoption Methods

IEEE 2800 adoption methods include general reference, detailed reference, detailed specifications, and hybrid integration.

- General reference: This approach involves generally referencing IEEE 2800 in existing requirements. This approach seems straightforward; however, many parts of IEEE 2800 require TO-specific and system-specific details. This approach may leave gaps regarding how IEEE 2800 should be implemented by the IC.
- Detailed reference: This approach involves referencing specific clause of IEEE 2800, which enables a more targeted and potentially phase implementation. This approach may also fail to include the TO-specific and system-specific information necessary for effective adoption.
- Detailed specifications: This approach involves entirely recreating the specifications of IEEE 2800 within existing requirements. This approach is comprehensive, allows targeted enhancement, but is a significant amount of duplicative work.
- Hybrid integration: This approach involves integrating the IEEE 2800 clauses into existing requirements, to the extent possible, and adding additional details such as settings or information that is required to be provided by the TO (referred to in IEEE 2800 as the *TS owner/TS operator*). For example, simply referencing a specific clause of IEEE 2800 in interconnection requirements will leave the IC seeking additional information in places throughout the standard that use phrases such as "as specified by the *TS owner/TS operator*" or "mutually agreed upon between the TS owner and IBR owner." This will cause additional confusion and uncertainty for both the TO and the IC and does not require significantly more effort for the TO to elaborate on the necessary areas of specification required. This will deliver a more comprehensive implementation strategy that further streamlines the ability for resources to connect, eliminates unnecessary back and forth between entities during the scoping meetings, minimizes potential conflicts or areas of disagreement between parties, and reduces the risk of abnormal or unexpected controls being implemented at the actual facility, among other benefits.

NATF Practices

8.1 Leverage IEEE 2800-2022 clauses to the greatest extent possible through the hybrid integration approach, adding necessary clarifying language for system-specific clarity, and ensuring that any conflicting or insufficient requirements in IEEE 2800-2022 can be adequately addressed.

[1] This document was prepared for the NATF by Elevate Energy Consulting with input from NATF staff and members

The TO may have requirements that are more stringent than IEEE 2800.

8.2 Include a clause within interconnection requirements referencing IEEE 2800-2022 that states that the term "mutual agreement" should be interpreted, unless otherwise specified, to mean that that the TO should determine and specify any necessary settings, capability, performance, etc., and the IBR owner should be responsible to meet the defined requirements.

IEEE 2800-2022 clauses use the phrase "mutual agreement" between the IBR owner and the TO many times throughout the standard. It is the responsibility of the TO per NERC FAC-001 [18] to establish interconnection requirements that adequately ensure reliability within their footprint. Per other NERC standards, the TO should establish operating procedures, requirements, data sharing requirements, voltage schedules, and numerous other information for the IC to use during planning and real-time operations.

Prioritization

IEEE 2800-2022 should be implemented into facility interconnection requirements or other business practices that the TO controls. It is highly recommended that the standard be considered in its entirety and implemented after measured and thorough cross-departmental consideration. However, to help emphasize some technical aspects of the standard, Table 12, below, outlines a prioritization of IEEE 2800-2022 clauses.

Table 12. Prioritized IEEE 2800-2022 clauses for adoption

IEEE 2800-2022 Clauses for Adoption		
Priority	**Clause**	**Description**
High	Clause 12	Test and Verification Requirements (until IEEE P2800.2)
High	Clause 10	Modeling Data
High	Clause 7	Response to TS Abnormal Conditions
Medium	Clause 11	Measurement Data for Performance Monitoring and Validation
Medium	Clause 5	Reactive Power – Voltage Control Requirements
Medium	Clause 6	Active Power – Frequency Response Requirements
Medium	Clause 8	Power Quality
Medium	Clause 9	Protection
Medium	Clause 4	General Interconnection Tech Specs and Performance Req's
Informative	Clauses 1–3	Overview, Normative References, Definitions, etc.
Informative	Annexes	Annex A – Annex M

The following are brief justifications for the prioritization provided.

High:

- Clause 12: Test and verification requirements are a critical component of an implementable, verifiable, and enforceable standard. These are often overlooked, which leads to challenges in implementing and enforcing a standard. This section, and its integration with business practices, is a crucial element of IEEE 2800-2022 adoption.
- Clause 10: Accurate, verified, and validated modeling data is foundational to accurate reliability decisions in which important grid reliability decisions are made during the interconnection process and planning and operations horizons. NERC has repeatedly highlighted and identified serious modeling concerns in its disturbance reports and assessments. Issues not addressed during planning activities can unexpectedly manifest during real-time operations and pose a risk to grid reliability.
- Clause 7: Many events are addressed by the ride-through performance requirements in Clause 7. Therefore, it is expected that adopting and implementing Clause 7 should greatly reduce future ride-through performance risks moving forward.

Medium:

- Clause 11: Performance monitoring data for event analysis, performance validation, and model validation are important for ensuring reliability of the IBR facility as well as the BPS. Without this data, it is extremely difficult to conduct root cause analysis for any abnormal or unexpected performance issues identified.
- Clauses 5 and 6: These clauses establish performance requirements for the dynamic and pseudo-steady-state performance of IBRs, which are important considerations and should be clearly articulated and tested against during studies. They form the basis for how the plant will respond to small system disturbances.
- Clauses 8 and 9: Both clauses outline power quality and protection settings that should be considered by the IC and the TO. Many entities already have some degree of requirements in place for power quality and interconnecting equipment protection; therefore, it is important to true up these existing requirements with IEEE 2800 language.
- Clause 4: This clause establishes all the generation interconnection technical specifications such as the reference point of applicability (RPA), nominal voltage levels, etc. Therefore, the details of this clause are used throughout the IEEE 2800 requirements and should not be overlooked. These are foundational elements to effective adoption of the standard.

Informative:

- Clauses 1 – 3: These clauses establish necessary background information, definitions, and references that are used throughout the standard.
- Annexes: All annexes in [5] are informative in nature and provide recommendations. While they may be considered by either the TO or the IC, they do not use "shall" language and therefore are not intended to establish mandatory and enforceable requirements.

NATF Practices

8.3 The TO performs a gap analysis to determine if suitable requirements already exist that either cover or may conflict with the requirements in [5].

9. Interconnection Technical and Performance Requirements

Interconnection requirements are developed by the TO, and all ICs should adhere to those requirements to ensure reliable operation of the bulk electric system. This section is a guide to developing interconnection requirements and an example of adopting IEEE 2800 [5] Clauses. Section 8, "Adoption of IEEE 2800", discusses approaches to incorporating the technical standard into the TO interconnection requirements.

General Requirements

NATF Practices

9.1 The IBR responses are prioritized as stated in Clause 4.7 of [5].

9.2 All IBR interconnecting transmission facilities are designed and operated to meet the voltage level, MW and MVAR capacity as agreed to in the LGIA.

9.3 The IBR should follow the general requirements of [5] for measurement accuracy requirements of Clause 4.4, operational measurement and communication capability requirements of Clause 4.5, and interconnection integrity requirements of Clause 4.11.

Control Capability

NATF Practices

9.4 The TO should consider accepting the control capability requirements in Clause 4.6 [5].

9.5 As described in Clause 4.6 [5], the IBR should cease operation with no intentional time delay when the permit service control is disabled.

9.6 The following associations apply at the Point of Interconnection (POI) for active and reactive power control:

- The maximum active power continuous rating is limited to that defined in the interconnection agreement and shall be the 100% base value (1 p.u.) for controls unless otherwise specified and agreed upon by the TO.
- The maximum reactive power for absorption or injection shall be the 100% base value (1 p.u.) for controls, unless otherwise specified and agreed upon by the TO.
- The maximum apparent power shall be the 100% base value (1 p.u.), unless otherwise specified and agreed upon by the TO. The apparent power rating and any limiters shall allow the plant to operate at the vector sum of the continuous rating and the required reactive power output for absorption or injection.

9.7 When the abnormal event exceeds the ride through requirements (high or low voltage, high or low frequency) and the IBR trips, the inverter shall restart and resume power operation as soon as the enter service and return to service criteria are met.

See subsection "Enter and Return to Service Criteria."

9.8 The plant should not enter a mode that prevents an autonomous return to service. If the necessary power and voltage control setpoints are lost or unavailable, the IBR should restart and resume power operation with default or replacement values. The IBR should use the last valid setpoint prior to the trip. If the IBR equipment cannot be designed or configured to use the last setpoint, then a default replacement value may be used. The Transmission Operator (TOP) and the IBR should mutually agree on the procedure for returning to service and the replacement values.

Enter and Return to Service Criteria

There are two main classifications for an IBR to begin operation. Enter service is when the plant has been off or out of operation for an extended time. Return to service is entering service after being forced out of service (e.g., tripping because of a grid event).

NATF Practices

9.9 When entering service or returning to service, the IBR should not energize the system until the Table 133. Enter service criteria conditions are met at the POI [19]:

Table 133. Enter service criteria

Enter Service value	Settings
Minimum Voltage	≥0.917 p.u.
Maximum Voltage	≤1.05 p.u.
Minimum Frequency	≥59.0 Hz
Maximum Frequency	≤60.3 Hz

9.10 Once the enter service criteria are met, the IBR should not enter service until the system parameters are verified to remain within the enter service criteria for 5 seconds.

After the five second wait time, the IBR should immediately begin return to service process. IBR that have multiple enter, return, and restart timers should notify the TOP of those timers and their settings for proper modeling and commissioning of the plant.

9.11 Ramp rate entering service, returning to service, and during manual or automatic set point changes should follow the following:

- Normal ramp rate = 10 MW / min = 166 kW / sec
- Time for full ramp to continuous rating (1 p.u.) = continuous rating / normal ramp rate
- P.u. continuous rating / sec = normal ramp rate / continuous rating

When restoring output after riding through an abnormal event, the active power recovery should be as fast as possible. Those abnormal events include, but are not limited to, faults and events that cause reduced active power output, gate blocking, or momentary cessation.

9.12 The IBR should submit to the TO the maximum restoration ramp rate capability and the restoration ramp rate setting, both in continuous rating (p.u.) / second. The IBR should provide the technical reason if not using the maximum restoration ramp rate possible. The IBR should be capable of the minimum restoration ramp rate of 1 p.u. continuous rating / second.

Harmonics

NATF Practices

9.13 A power quality meter should be installed for all IBR interconnections connected directly to the transmission system in accordance with the TO metering standards.

9.14 Current and voltage harmonic limits should be applicable in all instances [19].

9.15 Harmonic analysis should be performed to determine:

- The impact of the IBR produced harmonic components on electrically close synchronous generators to ensure that the levels are within the specified machine ratings (i.e., permissible continuous equivalent negative-sequence current capability).
- Whether mitigation measures will be necessary to meet the machine ratings. Note that this analysis could result in stricter harmonic current injection limits than those specified in this and other technical requirement documents. In addition, harmonic planning studies may be conducted to determine the potential impact of IBR plant injected harmonics on existing TO harmonic filter banks (i.e., impact of harmonics on individual filter component ratings). Three-phase analysis may also be performed when necessary.

9.16 Measurement of harmonics and interharmonics should follow the methodology specified in IEEE 519 [20].

9.17 Current and voltage harmonic limits, as specified below, are applicable in all instances.

9.17.1 Current harmonic distortion limits should follow Table 17 and Table 18 of [5]. These values should be a 95th percentile value of the harmonic measurement based on a one-week measurement period.

The current distortion limits are not dependent upon the system voltage distortion. The current distortion limits should not be exceeded, regardless of their impact to the harmonic distortion of the system voltage, unless the IBR is being purposefully used as a planned harmonic filter bank in agreement with the TO. In this case harmonic current limits may exceed those shown in the tables above.

The current distortion limits should not be violated based off the standing system negative sequence voltage.

9.17.2 Harmonic voltage distortion limits outlined in Table 14Table 144. Harmonic voltage distortion limits should not be exceeded. These are inclusive of harmonics and interharmonics that exceed the 50th harmonic, up to 1.5 times the inverter switching frequency, or the highest frequency that is measurable by the installed equipment. These values should be for a 95th percentile value of the harmonic measurement based on a one-week measurement period [19].

Table 144. Harmonic voltage distortion limits

LL Voltage (kV)	Individual harmonic (%)	Total Harmonic Distortion (THD) (%)
<= 69	3.0	5.0
69.001 to 161	1.5	2.5
>161	1.0	1.5

If the base-line harmonic study performed by the IC and the TO indicates that there is already an unacceptable level of harmonic content on the system at the POM. The TO has the right to refuse interconnection as a means of protecting the integrity of the system.

Reactive Power Requirements

All generators are required to achieve minimum power factor requirements. Dynamic reactive power may be provided by the generator or other dynamic source (i.e., statcom, static var compensator [SVC], etc.) [19].

NATF Practices

9.18 Devices (i.e., transformer tap changers, power electronics-based systems, electronically switched devices, or mechanically-switched devices used to provide reactive power compensation in order to meet reactive power capability requirements should meet requirements set forth in Clause 5.1 of [5].

9.19 The IBR should have the required reactive power capability as stated in Clause 5.1 of [5] with Q_{min} defined at 0.95pf or as designated by the TO.

9.20 The leading and lagging minimum reactive power capability should be deliverable to the POI across the entire range of MW output as noted in Figures 6 and 7 of [5].

This includes all active power conditions: injecting, absorbing, or idle (neither injecting nor absorbing). The utilization of reactive power capability when the primary energy source is unavailable will be on a case-by-case basis and under mutual agreement between the IBR and the TOP.

9.21 The required reactive power capability should be available across the full range of transmission system voltages. Therefore, IBR interconnection transformers should have enough taps to cover the whole range of possible transmission system voltages and have less than or equal to 2.5% difference between adjacent taps.

9.22 The IBR should provide 0.98 pf, injection and absorption, across the full operating range of transmission system voltages, and provide the minimum reactive capability, injection and absorption, within the following voltage ranges:

- 0.95 p.u. V – 1.04 p.u. V for injecting
- 0.97 p.u. V – 1.05 p.u. V for absorbing

Voltage and Reactive Power Control

9.23 The IBR should operate in reactive current priority mode during normal operations and abnormal operations, including high voltage and low voltage ride-through events [19].

9.24 The IBR should provide and have available for use all the standard reactive power control functions (i.e., voltage control, power factor control, and reactive power setpoint control). Each control should be designed to measure and control the parameters at the RPA.

9.25 The IBR should meet the requirements stated in Clause 5.2 of [5]. Unless otherwise specified, for this requirement the RPA should be the POI and the plant should be operated in closed-loop automatic voltage control mode to monitor and regulate the voltage at the POI.

9.26 The IBR should implement the voltage reference point, deadband, and droop specified by the TOP for the voltage control.

> The POI voltage setpoint and range will be provided via a voltage schedule issued by the TO during the interconnection process. Voltage schedule setpoint changes may be issued by the TOP on an occasional or periodic basis. The TOP and the IBR will mutually agree on either a remote supervisory control and data acquisition (SCADA) control method or a manual method to implement the setpoint change.

9.27 The IBR should implement an alternate power factor control to use when the voltage control is temporarily out of service. The TOP will specify the power factor setpoint.

9.28 The IBR should meet the voltage control and dynamic response characteristics set forth by Subclause 5.2.2 and Table 5 of [5].

> Dynamic performance requirements should be based on, and only applicable to, a defined range of transmission system equivalent impedance at the POI. The controls should be tuned to meet a one second step response time or the minimum time possible without exceeding maximum overshoot of 5% of setpoint or minimum damping ratio requirement specified in [5]. Unless agreed upon by the TOP, the step response time should not be longer than 30 seconds.

9.29 The IBR should provide all the reactive power control modes specified in the standard, but only the power factor and voltage control modes per Subclause 5.2.3 and 5.2.2 of [5] will be used initially.

Frequency Response and Regulation

Frequency response and frequency regulation are necessary to maintain nominal frequency whenever system load and resources imbalances occur [19].

NATF Practices

9.30 The IBR frequency control system should have a droop characteristic set to five percent and a range between three and seven percent.

9.31 The IBR should regulate output as a function of system frequency and desired MW output to maintain the nominal 60 Hz system frequency.

9.32 The IBR should be in adherence with the primary frequency response capability and performance requirements specified in Clause 6 of [5].

9.33 The IBR should have the capability to respond to under-frequency disturbances and over-frequency disturbances. This capability may also be implemented at the IBR units. The default values for parameters of the primary frequency response including droop and deadband, and the active power-frequency response dynamic performance as given in Tables 7 and 8 of [5], should be used.

9.34 The primary frequency response control functions should always be enabled and should not be blocked or disabled without the permission of the TOP. The IBR plant is not required to reserve headroom to provide primary frequency response.

9.35 The IBR should be in adherence with the fast frequency response (FFR) capability and performance requirements specified in Clause 6.2 of [5].

9.36 The IBR plant should be capable of providing FFR proportional to frequency deviation as specified in Clause 6.2.2.1 of [5].

> An alternate response may be acceptable upon mutual agreement with the TOP. The FFR capability should not be enabled unless directed by the TOP.

Low Short Circuit Strength

Short circuit strength, often quantified by short circuit ratio (SCR) or other related metrics, is a measure of the ability of the system to maintain stability during normal and contingency conditions. As synchronous generators retire and are replaced by increasing levels of IBRs, short circuit strength (i.e., SCR) will decline and conventional grid following (GFL) inverter technology will struggle to maintain this essential reliability service. Low SCR operating conditions pose significant grid stability challenges in the planning and operations horizons and are prevalent in areas with high IBR penetrations, particularly under N-1-1 outage conditions.

The challenge with low short circuit strength conditions is that they can be difficult to detect using root mean square (RMS) positive sequence stability tools in normal contingency or stability analyses. This necessitates the use of detailed and complex electromagnetic transient (EMT) modeling and studies. Therefore, it is increasingly common for the TP to conduct short circuit strength screening studies that can identify areas of relatively low system strength or weakness from a stability perspective. Pockets with relatively high SCR, or related metrics, may not require detailed EMT studies. However, pockets with relatively low SCR likely need additional study work and possible mitigating measures.

System strength information, a range, or expected minimum value is useful to ICs because they can use this information to ensure their resource can reliably operate under all expected system conditions and can ensure that the product that is designed, procured, and installed is configured to meet these grid needs ahead of time. Therefore, the TO should include guidelines, specifications, and system strength requirements for interconnecting IBRs as part of the interconnection process.

NATF Practices

9.37 Establishing a low SCR threshold value for which the IBR should be able to reliably operate, based on expected future worst-case system conditions for each interconnection point.

9.38 The IC should be required to test and verify the stability of the proposed project for the range of system strength conditions, including that all performance requirements are met across the full range. It is important that a verified and validated model of exactly what will be installed in the field is used for these studies.

9.39 The IC and the TP should verify the expected stability performance of the interconnecting IBR.

9.40 The IC and the TP should explore grid-stabilizing solutions collaboratively. This may include using grid forming (GFM) inverter technology, synchronous condensers, or other grid-enhancing technologies (GETs).

Frequency Ride Through Capability and Performance

Frequency ride-through capability and performance for IBRs is increasingly important in maintaining grid reliability, especially as the penetration of IBRs grows. Frequency ride-through capabilities enable IBRs to remain connected to the grid during frequency disturbances, thus supporting system stability. NERC Standard PRC-029-1 [21] emphasizes the need for IBRs to withstand frequency excursions without disconnecting, thereby preventing cascading failures of the grid [19].

NATF Practices

9.41 The IBR plant should adhere to the frequency ride-through capability and performance requirements specified in Clause 7.3, Table 15, and Figure 12 of the [5].

> For frequency excursions outside of the “mandatory operation” and the “continuous operation” regions, the IBR “may ride-through or may trip” and that region of operation should not be construed as a requirement that the IBR “must trip.”

9.42 The IC should provide a frequency ride through capability chart (formatted consistently with Figure 12 of [5]) for each type of inverter and define the regions for each operating mode: continuous, mandatory, permissive, momentary cessation, and trip.

> This chart should include any internal inverter protection trip settings factory-set by the manufacturer.

9.43 The IC should also provide numerical data that defines the operating modes and any internal inverter protection trip settings factory-set by the manufacturer.

Data should be provided in a format like Table 15 of [5]. If the frequency ride through capability of the plant is different than the inverter, the plant capability chart and table should also be provided.

9.44 The IBR should perform according to the requirements specified in Clauses 7.3.2.2 and 7.3.2.3 of [5] for frequency disturbances within the continuous operation and mandatory operation regions, respectively.

9.45 The IBR plant should be capable of the change in voltage phase angle ride-through requirements specified in Clause 7.3.2.4 of [5].

9.46 IBR plant rate of change of frequency (ROCOF) protection described in Clause 9.2 of [5] should be disabled unless it is needed to satisfy an OEM requirement and is reviewed and approved by the TOP.

9.47 A ROCOF protection element should not prevent the IBR plant from riding through all events with a ROCOF of 5 Hertz per second (Hz/s) or less, as outlined in Clause 7.3 of [5]

Voltage Ride Through Capability and Performance

NATF Practices

9.48 The voltage ride-through capability and performance for IBR plant should adhere to requirements specified in Clause 7.2 of [5]with the following exceptions:

- The reference point of applicability (RPA) for the voltage ride-through requirements of an IBR plant should be the Point of Measurement (POM) as specified by the TO.
- The IBR plant should continue mandatory operation when the applicable voltage at the POM is less than 10%.
- The IBR plant should provide 100% of pre-disturbance apparent current (given equivalent power source conditions, i.e., wind and solar) post-disturbance even when the applicable voltage at the POI drops below 50% nominal during the disturbance. From a performance perspective, any issues with individual inverters tripping offline should be corrected in a timely manner.

9.49 The IBR plant should provide a voltage ride through capability chart for each type of inverter and define the regions for each operating mode: continuous, mandatory, permissive, momentary cessation, and trip.

The chart should be formatted consistently with the figures in Appendix D of [5]. This chart should include any internal inverter protection trip settings factory-set by the manufacturer.

9.50 The IBR should provide the numerical data that defines the operating modes and any internal inverter protection trip settings factory-set by the manufacturer.

Data should be formatted similarly to Tables 11 and 12 of [5]. If the voltage ride through capability of the plant is different than the inverter, the plant capability chart and table should also be provided.

9.51 The IBR plant should adhere to consecutive voltage deviation ride-through capability specified in Subclause 7.2.2.4 of [5].

> Additional ride-through requirements for dynamic voltage oscillations will be specified on a case-by-case basis if identified during the interconnection studies or known existing oscillations on the system at the point of interconnection.

9.52 The IBR should adhere to transient overvoltage ride-through capability requirements specified in Clause 7.2.3 of [5]. The reference point of applicability (RPA) for this requirement should be the POM.

9.53 The IBR plant should supply current injection to provide fault ride-through capability when the voltage at the RPA is outside the normal operational range, 90% - 110% nominal voltage.

9.54 The IBR plant should operate in the reactive current priority mode while operating in a voltage ride-through mode, unless otherwise specified by the TOP.

9.55 For unbalanced faults, the IBR should inject negative-sequence current depending on the negative-sequence terminal voltage. Unless specified otherwise in Table 15 [19] below, for fault operations, or by mutual agreement, the current injection from the IBR during a voltage ride-through mode should meet specifications in Subclauses 7.2.2.3.4 and 7.2.2.3.5 of [5]. In addition, the IBR plant should be configured to meet the following requirements:

- While in reactive current priority mode, the IBR unit should be capable of injecting reactive current equal to its maximum current rating when the IBR unit terminal voltage is less than or equal to 50% of nominal voltage. Injection of the maximum current rating for less severe voltage deviation is allowable and is dependent upon the k-factors for fault currents as outlined in the tables and graphs below.
- The IBR unit should prioritize absorption of reactive current equal to 30% of its maximum current rating when the IBR unit terminal voltage is equal to 115% of nominal voltage.

Table 15. Reactive current injection requirements

Parameter	Performance Target
Magnitude	During a balanced, or an unbalanced fault, change in positive sequence reactive current should be proportional to the positive sequence voltage change using a k-factor (slope) of 2 or higher. A higher k-factor may be specified the TOP. During an unbalanced fault, change in negative sequence reactive current should be proportional to the change in negative sequence voltage using a k-factor (slope) of 2 or higher. A higher k-factor may be specified by the TOP. Injection of zero sequence current is not required. Should the IBR total current limit be reached, both reactive positive sequence and reactive negative sequence current should be reduced in equal amounts to stay below the total current limit. At no point should negative sequence current injection exceed positive sequence current injection.
Angle	The negative sequence reactive current angle should lead the negative sequence voltage by an angle of 90 – 100 degrees for full-converter IBRs.

Parameter	Performance Target
Reaction Time	The time between the step change in the voltage and the beginning of the injection of positive and negative sequence reactive current should be less than 16 ms.
Rise Time	The time between the step change in voltage and when the inverter reaches 90% of the new steady state reactive current output should be less than 25 ms.
Settling Time / Settling Band	The settling time should be less than 50 ms. The settling band should be –2.5% / +10% of IBR maximum current.

Grid Forming Inverter Technology

Industry has highlighted the need for GFM technology on the BPS to help ensure a stable and reliable grid of the future [22]. Islanded systems and smaller networked interconnections are already facing serious needs for GFM solutions to help mitigate instability issues.

In September 2023, NERC published *White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems* [23] which enumerated the benefits of enabling GFM controls, particularly in new BESS connecting to the BPS. It also outlined a functional specification (i.e., functional requirements) for GFM BESS as well as a set of test procedures for testing the GFM functionality in BES. The guidance was intended to provide pragmatic and easily implementable requirements within interconnection requirements and to describe basic simulation tests that can be conducted by the IC or the TO to verify the BESS sufficiently behaves as a GFM resource.

NATF Practices

9.56 Incorporate GFM requirements into interconnection requirements.

9.57 Require all BESS ICs to have GFM control capability.

> Requiring GFM control capability during the interconnection process avoids additional re-study costs that would be incurred for any retrofit after commercial operation.

9.58 Changing a BESS control strategy from GFL to GFM should be considered a qualified change and constitute a re-study.

> This change significantly affects the electrical performance of the resource and therefore would need additional stability simulations prior to changes being made to the actual equipment installed.

10. Interactions

Effective communication and interactions with subject matter experts (SMEs) and stakeholders throughout the interconnection process is a key element of success. SMEs possess specialized knowledge that can enhance decision-making and project outcomes. Structured engagement and collaboration can ensure that technical and regulatory requirements are met while aligning with stakeholder expectations. Clear communication helps to identify potential challenges early, allows for proactive solutions, and minimizes delays.

Routine Engagement with Local and Federal Regulators

NATF Practices

10.1 Keep regulators informed about ongoing changes with IBR standards and interconnection requirements (i.e., NERC, IEEE, etc.).

> Regular informational filings should be considered (e.g., annually).

10.2 Coordinate with state regulators to update the LGIA to include the IBR interconnection requirements, integration cost, and procedures.

> Ensure updated IBR interconnection requirements are enforced during the state-governed interconnection project execution.

Inclusion and Interaction with Stakeholders

The engagement of stakeholders is intended to be a forum where the utility's engineering staff and technical personnel can discuss interconnection technical standards, current and developing industry standards, developing technologies, and other technical matters pertinent to the interconnection of IBR.

NATF Practices

10.3 Establish a process to engage stakeholders to review technical standards for interconnection of IBR and other technical topics related to IBR. This could take the form of a periodic stakeholder meetings. Use the following practices as guidance.

10.4 Representation should include the utility members, industry members, guests, and observers.

- Utility members that are selected from departments involved with interconnections (e.g., grid integration, technical standards, transmission planning, etc.). The utilities may choose to invite representatives from other departments relevant to the topics on the agenda.
- Industry members that actively own, operate, or interconnect inverter-based resources within the utilities' region are eligible to serve as members. Industry members are expected to have a basic (i.e., reasonable, foundational, general) understanding of electrical power system engineering principles related to inverter-based resources and interconnections to understand and contribute to the technical discussions. Industry members include stakeholders from organizations such as office of regulatory staff, state utilities commission, and state or region-specific clean energy or renewables associations.

- Guests, non-members, that are invited by the chair and are on the agenda to speak or make a presentation. If an industry member wishes to have a subject matter expert present on a specific agenda item, the member shall obtain prior approval from the chair.
- Observers that do not actively participate in the discussions or take an official part in the meeting. Therefore, there are no qualifications to be an observer. Observers will only participate remotely by phone or internet meeting technology. Observer participation is limited to listening and viewing the meeting contents online.

10.5 Develop a meeting cadence to facilitate an appropriate level of engagement from the representative stakeholders. (e.g., quarterly).

10.6 Develop a formal process for non-utility members to provide input on the utilities' technical standards.

> The members, as a whole or in part, may make proposals or recommendations for updates/modifications to the Technical Standards. These proposals and recommendations are made with the understanding and agreement that the utilities have the final decision and ultimate control over their technical standards.

10.7 Develop meeting topics of technical interest and significance.

> Topics can be specific to the state or states in which the utility operates or to a regional level where applicable under an RTO or ISO.

10.8 Define goals to develop consensus solutions to technical challenges in a collaborate environment.

> The utility has the absolute right to update and modify technical standards to account for changes in the industry based on good utility practice and evolving standards.

10.9 Set clear expectations that the utility has final decision and control over any technical standards that are developed.

> The utility is accountable and responsible for maintaining adequate customer reliability and power quality.

10.10 Institute a form of governance and meeting structure to maintain an effective forum.

> This is intended to facilitate broad technical discussion while allowing adequate input and discussion from technical and nontechnical stakeholders.

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