Summary of the Joint Generator Interconnection Workshop

August 9-11, 2022

October 2022

ESIG

About the Energy Systems Integration Group

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy or info@esig.energy.

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Suggested Citation

Energy Systems Integration Group. 2022. *Summary of the Joint Generator Interconnection Workshop*. Virtual workshop held by the Energy Systems Integration Group, North American Generator Forum, North American Electric Reliability Corporation, and Electric Power Research Institute, August 9-11, 2022. Reston, VA. https://www.esig.energy/event/joint-generator-interconnection-workshop/.

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Overview of the Joint Generator Interconnection Workshop

Interconnection queues around the United States have a backlog of more than 1,400 GW of generation and storage[1] projects facing multi-year study delays (see "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection", a briefing by the Lawrence Berkeley National Laboratory).[2] This large generation interconnection request backlog creates uncertainty for developers and inhibits their ability to interconnect, results in excessive and inefficient use of engineering staff time, slows the energy sector's transition toward low-carbon energy resources, and puts resource adequacy under high risk. The Federal Energy Regulatory Commission (FERC) recently issued two notices of proposed rulemaking (NOPRs) to address some of these challenges—"Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" and "Improvements to Generator Interconnection Procedures and Agreements"—with comments to FERC due this fall.[3,4]

Separately, recent North American Electric Reliability Corporation (NERC) Disturbance Reports have indicated gaps in interconnection studies, modeling, and interconnection requirements for inverter-based resources (IBRs).[5] In addition, the new IEEE 2800 standard for "Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems" has recently been published and, if adopted by independent system operators (ISOs), regional transmission organizations (RTOs), and other authorities governing interconnection requirements, will provide additional benefits for both reliability and the interconnection study process.[6]

Meanwhile, the U.S. Department of Energy (DOE) Solar Energy Technologies Office and Wind Energy Technologies Office recently launched the Interconnection Innovation e-Xchange (i2X) initiative[7]. This effort convenes diverse stakeholders involved in the interconnection of wind, solar, and storage resources to facilitate peer-learning, increase knowledge exchange, and inspire new interconnection ideas and capabilities.

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[1] For brevity, in the remainder of this report the term generator is generally encompasses storage as well.

[2] J. Rand, R. Wiser, W. Gorman, D. Millstein, J. Seel, S. Jeong, and D. Robson, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021*, Lawrence Berkeley National Laboratory, April 2022, https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf

[3] FERC Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, April 21, 2022, https://www.ferc.gov/media/rm21-17-000

[4] FERC Notice of Proposed Rulemaking, *Improvements to Generator Interconnection Procedures and Agreements*, June 16, 2022, https://www.ferc.gov/media/rm22-14-000

[5] NERC, Major Event Analysis Reports, https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

[6] IEEE, Standard Association, *IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems*, April 22, 2022 https://beyondstandards.ieee.org/addressing-grid-reliability-as-renewable-energy-integration-speeds-up/

[7] U.S. Department of Energy, Interconnection Innovation e-Xchange, https://www.energy.gov/eere/i2x/about-interconnection-innovation-e-xchange-i2x

In response to these new initiatives, the Energy Systems Integration Group (ESIG), North American Generator Forum (NAGF), North American Electric Reliability Corporation (NERC), and Electric Power Research Institute (EPRI) organized a joint workshop in June 2022, attended by more than 1,300 industry stakeholders including developers, grid operators, utilities, original equipment manufacturers (OEMs), government agencies, researchers, and others. The workshop covered the important relationships between interconnection process reforms and new capability and performance standards for IBRs. Understanding these relationships will help to expedite the interconnection process for large generators while also supporting a more economic, sustainable, and reliable future power system. The workshop provided technical details on each topic area delivered by distinguished subject matter experts and facilitated industry discussion prior to the upcoming FERC comment-period deadlines.

The main goals of the workshop were to:

- Identify gaps and recommended best practices related to the generation interconnection process, interconnection studies and modeling, and interconnection requirements and standards
- Provide a deeper technical understanding of each topic area in a way that can facilitate fact-based discussion and meaningful feedback to FERC
- Inform industry comments to the FERC NOPR on Improvements to Generator Interconnection Procedures and Agreements
- Bring awareness to the developer community about power system reliability needs shaping the studies, modeling, and interconnection requirements
- Bring awareness to ISOs, RTOs, utilities, and policymakers around challenges facing IBR project developers
- Inform the broader engineering, policymaker, and decisionmaker audience about generation interconnection issues and possible solutions

A recording of the workshop is available on ESIG's YouTube channel (https://www.youtube.com/channel/UCHfBken6UVuCJQmAfGv1vJA) and has been viewed over 1,000 times. Answers to the questions that were not answered during the sessions are posted on the workshop's event page at https://www.esig.energy/event/joint-generator-interconnection-workshop/.

Day 1: The Interconnection Process

The first day of the workshop discussed gaps between the interconnection process for individual generators (or generator clusters) and the long-term transmission needs of a power system with high shares of variable renewable resources. Building additional transmission is essential for the future high-renewables grid; however, while longer-term system planning takes into consideration the broader net benefits of transmission upgrades over a longer time frame, much of today's transmission upgrades stem from generation interconnection processes that are narrowly focused on least-cost upgrades to ensure local reliability over a time frame of only a few years. Participants discussed how upgrades based on generation interconnection may be a sub-optimal, expensive, and ultimately ineffective way to accomplish transmission expansion for tomorrow's electricity system.

Participants discussed best practices in these two areas as well as the benefits of multi-value and proactive transmission planning.

Key Points

- Overall **transmission expansion has declined** in the past decade, and **most of it at present occurs in a piecemeal manner through the generation interconnection process**, which contributes to the complexity and backlog of the interconnection process as well as insufficient transmission being built.

- **Assumptions and criteria usually used in transmission planning are not applied consistently** when identifying transmission upgrades in the generation interconnection process.

- The grid system impacts of a **new generator are assessed as a cost for the grid, while benefits** such as lower energy cost for consumers, contributions to resource adequacy, security of supply, etc., **are usually not considered**. Recent transmission planning initiatives from the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) are including more comprehensive cost benefit analysis of new transmission upgrades.

- **Transmission upgrades identified solely through the generator interconnection process may be both high** (not least-cost solutions) from the system perspective and prohibitively high for generator developers. High costs can **result in project withdrawals followed by restudies and further delays** in the interconnection process, putting excessive burden on developers and transmission engineers.

- **Integrating generation interconnection with transmission planning processes can move the industry toward a more optimized least-regrets, scenario-based, proactive, cost-effective, multi-value transmission solutions**, an approach that can address the wide range of future needs, facilitate competition, and reduce the costs and time necessary to interconnect low-cost, low-carbon generation.

- **The current approach to cost allocation creates a barrier to transitioning to more integrated transmission planning** in which all new generators and loads are studied together for optimized transmission build out. However, cost allocation does not need to dictate the design of the process or be a barrier to the process improvements. If we arrive at a cost-effective integrated generator interconnection and transmission planning methodology, a cost allocation methodology can be developed**. Recent initiatives at SPP, MISO, and a proposal by Enel (discussed below) already offer possible solutions**.

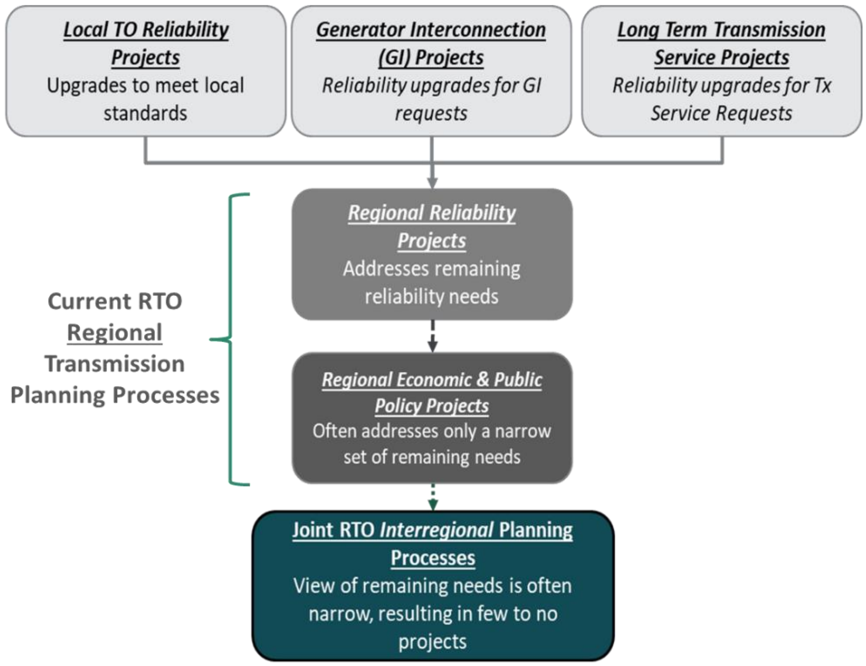
Current Approach to Identifying Transmission Upgrades in the United States

Hannes Pfeifenberger from the Brattle Group spoke about current approaches to identifying transmission upgrades, which include planning processes for local reliability projects, for interconnection projects, for long-term transmission service projects, and for various regional and, occasionally, interregional transmission projects (see Figure 1).

He discussed how more than 90 percent of transmission investments are driven solely by reliability criteria. Reliability projects are transmission projects that are required to reliably serve load (as per NERC and local standards). These projects are evaluated based on effectiveness and estimated cost, rather than an economic analysis of benefit-to-cost ratios. Reliability-driven projects are often reactive in nature, with the majority of these upgrades being driven by the generation interconnection process. This results in siloed transmission planning focused on the impacts of one or a small cluster of generators, not considering the bigger picture—such as other generation development plans and load growth in the region, local or state policy targets, the range of potential futures, the multiple benefits of transmission expansion for consumers, and other factors. Such planning processes fail to arrive at cost-effective transmission solutions in the long term and result in higher overall costs to electricity customers.

FIGURE 1

Overview of Existing Processes Through Which Transmission Upgrades Are Identified



Source: Workshop presentation by H. Pfeifenberger, Brattle Group.

As highlighted by Hannes, the generation interconnection process today takes a long time (see "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection," a briefing by the Lawrence Berkeley National Laboratory)[8] and can trigger deep (further into the grid beyond the local area where generator is interconnecting) and costly transmission upgrades whose costs are usually allocated to the individual generators requesting interconnection. Interconnection study assumptions and criteria vary widely across regions, and as a result, these transmission upgrades may not be least-cost solutions from the system perspective; in addition, the costs of upgrades may be prohibitively high for the developers. During the question and answer period Aaron Van der Vorst from Enel added that the need transmission upgrades is usually evaluated based on just a few discrete snapshots of system conditions and is unable to capture the breadth of a full yearly dispatch of a generating unit. In this case, there is little understanding of how much a proposed transmission upgrade will be utilized and little ability to evaluate potentially infrequent generation curtailments that could serve as an alternative to an expensive transmission upgrade.

High interconnection costs can lead to generation project withdrawals from the queue, which then cause a need for restudies that further delay the process for other generation projects, all of which puts excessive burden on developers and transmission engineers. The need to coordinate with affected

[8] J. Rand, R. Wiser, W. Gorman, D. Millstein, J. Seel, S. Jeong, and D. Robson, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021*, Lawrence Berkeley National Laboratory, April 2022, https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf

neighboring systems significantly increases the complexity of the studies and time required to conclude generation interconnection process. Uncertainty about interconnection costs is also driving up the number of speculative projects, which further increases queue churn, costs, and engineering workload.

Lastly, the current method of allocating transmission upgrade costs constitutes a barrier to improving the transmission planning process. Currently, interconnection study assumptions understand the interconnecting generator as both a cost to the grid (potentially assuming severe loading conditions which may or may not be realistic) and the sole beneficiary of the upgrades required. These assumptions form the basis for the allocation of all costs of the upgrade to that generator. In contrast, if a system operator studies a transmission upgrade as a part of a longer-term transmission planning process and cost-benefit analysis, taking into account the benefits of bringing in lower-cost clean resources that may also improve resilience and resource adequacy, it becomes more difficult to allocate the cost of transmission because there are several beneficiaries. The current approach to cost allocation creates a barrier to transitioning to more integrated transmission planning in which all new generators and loads are studied together for optimized transmission build out. In the end, customers of that generator will pay for interconnection upgrades. If overall interconnection costs could be reduced through a more efficient process, the cost for the entire system will be reduced.

Integration of Generation Interconnection and Transmission Planning

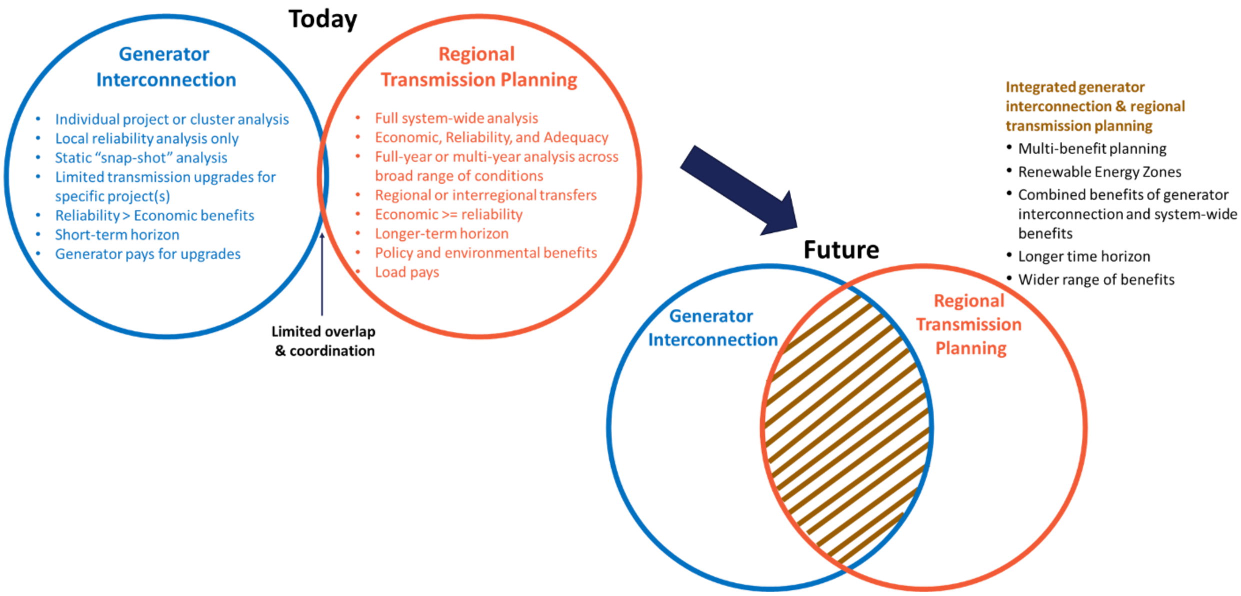
National Grid Electricity System Operator and ERCOT Examples

Hannes pointed out that one option to address the above issues could be for the scope of upgrades triggered by the generation interconnection process to remain focused on local transmission needs only, with the identification of deeper transmission upgrades benefiting the entire system following as a part of comprehensive transmission planning process (see Figure 2). This type of approach is currently used in Great Britain, called Connect and Manage, and helped to drastically reduce the time required for the generation interconnection process. A similar approach is used in the Electric Reliability Council of Texas (ERCOT), where all of the transmission upgrades beyond the point of interconnection are evaluated through transmission planning studies. This leads to faster interconnection due to the absence of interdependencies between generation projects, and, consequently, to no impact from projects withdrawing from the interconnection queue. In addition, since this approach exposes a generator to congestion management, it also provides locational signals to new generation projects—developers avoid areas with considerable congestion and site projects in less congested areas.

For this approach to be effective at defining high-value transmission upgrades in a timely manner, transmission planning processes may also require improvements. For example, the transmission planning process in ERCOT currently does not capture benefits of transmission beyond production cost savings, and it may take long time before a transmission project becomes economically viable in a planning study without capturing other benefits such as resource adequacy and resilience.

FIGURE 2

Need for Better Integration Between Generation Interconnection and Transmission Planning Processes



Source: Workshop presentation by D. Stenclik, Telos Energy.

Enel's Proposal for Interconnection Process Improvements

Aaron Van der Vorst presented and discussed a proposed approach to modernizing and integrating generation interconnection and transmission planning[9] described by Enel Green Power in its response to the FERC Advance Notice of Proposed Rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection."[10] Enel's proposed approach can be implemented either through the complete integration of transmission planning and generation interconnection or by enhancing existing generation interconnection processes by applying assumptions and criteria used in transmission planning. The steps of the proposed process and the accompanying benefits are as follows.

1. Individual Local Impact Study

The local impacts of each generator are studied, using realistic assumptions about the dispatch of the studied resource and load profiles, while dispatching other generation economically. Seasonal variations of load and generation should also be considered. Transfer distribution factors (TDFs) can be used to identify upgrades that are impacted the most by the interconnecting generator. The upgrades identified in this study have no interdependencies with other generation projects, leading

[9] Enel, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, 2021, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf

[10] FERC Advance Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, July 15, 2021, https://www.ferc.gov/media/e-1-rm21-17-000

to reduced impact from project withdrawals from the queue, a reduced need for restudies, efficient processing of the interconnection queue, and an accelerated interconnection process. The results of this study only reflect the requirements for basic interconnection service. Benefits of all other upgrades beyond this step are evaluated in the next step.

Aaron discussed how it would be beneficial to have more specific direction from FERC on the degree of impact (e.g., TDFs) that a generator should have on a transmission constraint for the cost of the upgrade to be assigned to that generator, the types of contingencies to study, and appropriate fuel-based assumptions to use when identifying a local interconnection upgrade. This would lead to consistent study assumptions and criteria nation-wide. Differences in study assumptions and criteria as well as benefits of the fuel-based assumptions were also discussed in detail in the workshop presentation by Horea Catanase from Electric Power Engineers.

2. Regional Study Entry

Individual local impact studies will give generators a high degree of certainty about interconnection costs early in the process and make it reasonable for transmission providers to demand a high degree of project readiness and financial commitment to move forward. While not all transmission upgrade costs are known at this point, any remaining upgrade costs would come with commensurate financial benefit and are not basic interconnection service upgrades.

The second step in Enel’s proposal lays out a framework for an optional competitive bidding process for local impact upgrades. This process could dramatically shorten the schedule and reduce the costs of engineering procurement and construction.

3. Regional Cluster Study

The goal of a regional cluster study would be to determine whether transmission upgrades are economically beneficial based on the value created for both the new generators and for load. The study would capture the value that the new cluster of generation would add to system load if the generation was adequately connected through transmission. This study could be either an integration of the transmission planning and generation interconnection processes, or it could represent a new, enhanced approach to interconnection studies. Transmission upgrades would be identified both for reliability benefit, including resource adequacy and compliance with NERC planning standards, and for economic benefit, reflecting load’s access to new lower-cost generation.

Transmission upgrades would be justified and built if the total value to generation and load exceeded the cost of the transmission. The upgrades would be funded by parties according to the benefits received, where generators would contribute capital funds for the transmission commensurate with their expected benefits for mitigating congestion and curtailment, and load would contribute based on offset fuel costs, and resource adequacy and resilience benefits gained.

The main benefit of this study, compared to designing the grid based on a limited view of exporting power from a single generator or a cluster, is that it identifies the most efficient transmission plan to provide maximum economic, resource adequacy, and reliability benefits.

4. Firm Service Studies

The final stage of the proposed interconnection process is to study higher levels of interconnection and delivery service[11]. Firm service studies would include unit-specific interconnection and transmission service studies and would use more restrictive TDF thresholds and related criteria to expand the potential impact area consistent with the service type. The outcome of these studies would be to increase generator-specific deliverability beyond what was economically beneficial for load customers alone.

Moving the Transmission Planning Process Toward Scenario-based, Proactive, Multi-value Assessment

While there are benefits of identifying deeper transmission upgrades as a part of transmission planning process, Hannes Pfeifenberger discussed how the process itself needs improvements to achieve maximum efficiency in identified transmission solutions.[12] The following improvements were proposed by Hannes and echoed in other presentations during the workshop:

- Proactively plan for future generation and load growth by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and profiles over the lifespan of the transmission investment.
- Account for the full range of benefits from transmission projects, and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
- Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures, including challenging extreme events.
- Use comprehensive transmission network portfolios to address system needs more efficiently than through a project-by-project approach.
- Jointly plan across neighboring systems to recognize interregional dependencies, increase system resilience, and take full advantage of interregional-scale economics and the benefits of geographical diversification.

In the above list of improvements proactive planning refers to planning transmission over longer period, as opposed to taking a one-year view as is generally done in current generation interconnection processes. As discussed by Bruce Tsuchida from the Brattle Group (based on a recent study from ESIG's Proactive Planning Task Force)[13], proactive planning allows changing system needs to be captured as generation is being added across the system and system load continues to grow and change in its

[11] Most transmission providers today provide two distinct services: Energy Resource Interconnection Service (ERIS) allows a generator to use the transmission system on an "as available" basis, and Network Resource Interconnection Service (NRIS) allows the transmission owner to construct the necessary upgrades to integrate the generator in the same manner as Network Resources.

[12] Brattle and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* October 2021, https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

[13] Brattle, *Proactive Planning for Generation Interconnection*, September 2022, https://www.esig.energy/proactive-planning-for-generation-interconnection-a-case-study-of-spp-and-miso/

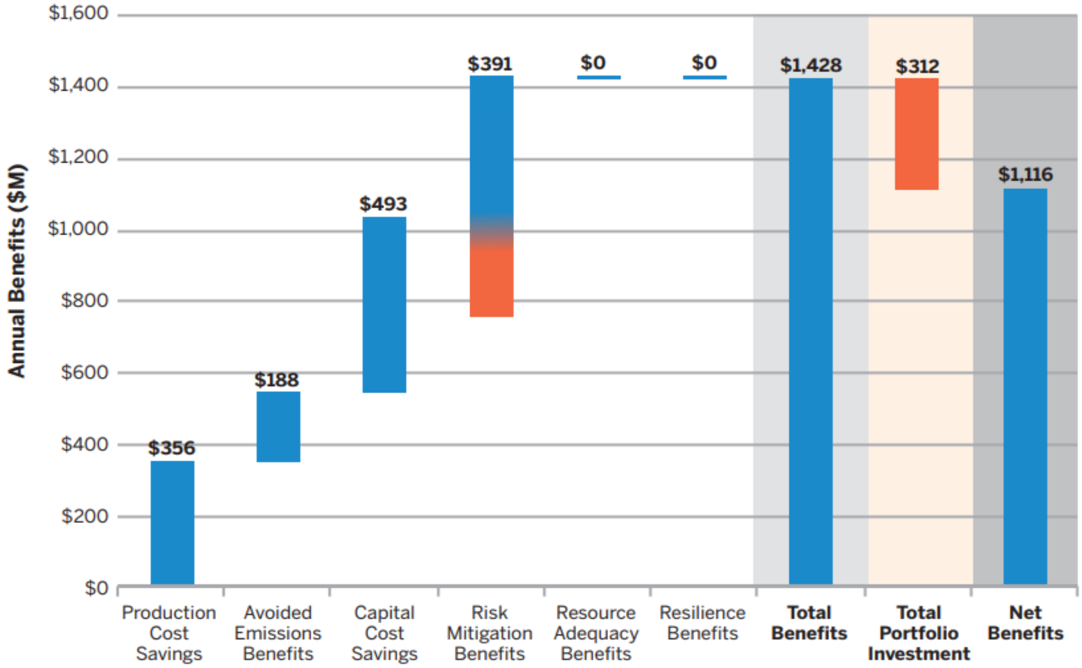
characteristics over the study horizon. Proactive planning allows optimal transmission solutions to be identified that accommodate these changes in a reliable and cost-effective way. This, in turn provides developers with greater certainty around the costs of deeper transmission upgrades and thus could reduce the number of speculative projects and withdrawals from the queue. A proactive planning approach may extend to identifying backbone-types of upgrades to the zones where solar or wind resource potential is strongest, followed by generation project development in the vicinity of such a transmission backbone. This was seen, for example, in the Competitive Renewable Energy Zones (CREZ) in Texas in which transmission was built to areas with high wind and solar potential with generation subsequently developing in those zones. While there might be a concern that proactive planning could result in stranded transmission assets, Bruce noted that previous proactively identified and built transmission projects, such as Texas's CREZ, MISO's Multi-Value Project, SPP's Priority project, and several others are now fully subscribed. Bruce presented results from a case study that quantified three levels of proactiveness of generator interconnection. He showed significant cost savings in generator interconnection as proactiveness increased.

Multi-value planning refers to considering several important benefits of transmission in the planning process. As highlighted by Derek Stenclik from Telos Energy, currently, when the economics of a transmission project are analyzed in transmission planning, production cost savings (i.e., savings of fuel costs and other variable costs) are used as evaluation criteria. However, as the amount of renewables on the system grows and production costs are driven down, production cost *savings* are also reduced when looking at the future generation interconnection, even as more transmission is needed on the system. Thus, as low- or zero-fuel-cost generation continues to be added to the system, it becomes difficult to justify transmission expansion based solely on production cost savings. However, there are many other benefits to transmission beyond production cost savings, and their quantification can and should be used to justify the needed transmission expansion. These benefits include:

- **Capital cost savings:** savings from more efficient generation interconnection (lower cost of generation resources)
- **Emission benefits:** the public and economic benefit (in some markets) of reducing greenhouse gas emissions
- **Risk mitigation:** large-scale transmission infrastructure's ability to reduce regions' risk from outages, including those caused by extreme weather, by allowing sharing between neighboring grids
- **Resource adequacy:** the sharing of energy facilitated by large-scale transmission expansion that allows neighboring regions to rely on generation capacity from other regions to support local needs, dramatically reducing the investment in new generation capacity in both neighboring regions
- **Resilience:** transmission can help reduce the frequency and magnitude of load shedding during extreme events

FIGURE 3

Multi-Value Benefit Stacking for the Transmission Line Relieving the West Texas Export Constraint, 2030



The six bars on the left represent benefits that are added together to arrive at the total benefits of $1.428 billion. After investments are subtracted (red bar), the net annual benefits of the transmission line are calculated to be $1.116 billion.

Source: Energy Systems Integration Group, *Multi-Value Transmission Planning for a Clean Energy Future* , a Report of the Transmission Benefits Valuation Task Force (Reston, VA, 2022), https://www.esig.energy/multi-value-transmission-planning-report.

The Energy Systems Integration Group performed a study of a wider range of benefits from multi-value transmission planning, quantifying the benefits of a large-scale transmission line within ERCOT and of a line connecting ERCOT to Southern Company in the U.S. Southeast.[14] Figure 3 shows an example of multi-benefit transmission planning for a large-scale transmission project relieving the West Texas export constraint.

[14] Energy Systems Integration Group, *Multi-Value Transmission Planning for a Clean Energy Future,* a report of the Transmission Benefits Valuation Task Force (Reston, VA, 2022), https://www.esig.energy/multi-value-transmission-planning-report.

Examples of Integration Between Transmission Planning and Generation Interconnection

Some regions have already started on the path to more closely integrating transmission planning and generation interconnection. Below are brief descriptions of several recent examples highlighted during the workshop.

Hannes Pfeifenberger pointed out that ERCOT's generation interconnection process is probably the most effective in the U.S. While some areas of the country added only 1 to 4 percent more generation capacity in 2021, ERCOT added 10 percent of its total generation capacity. As mentioned earlier, upgrades in ERCOT are focused only on local generator interconnection needs. Network constraints (i.e., congestion) are managed through market dispatch, and transmission planning processes are used to assess system-wide upgrade needs. The transmission planning process, however, needs further improvement to recognize transmission benefits beyond production cost savings.

Hannes also highlighted, PJM's recent Offshore Wind Transmission Study that proactively evaluated all existing state public policy needs and identified upgrades that would accommodate almost five times more renewable generation than individual generator interconnection studies would, for half the transmission upgrade cost. It identified $3.2 billion in onshore transmission upgrades for more than75 GW of renewables compared to individual generator interconnection studies that required $6.4 billion in onshore upgrades for only 15.5 GW of renewables.

SPP and MISO's Joint Targeted Interconnection Queue (JTIQ) study was highlighted by Hannes presentation and also presented in further detail by Andy Witmeier from MISO.[15] The study showed that proactively studying a larger set of generation interconnection requests offers substantial cost and time savings, identifies more optimized network upgrades, and eliminates uncertainty for the developers. The JTIQ identified seven projects, representing $1.65 billion in transmission investments that are able to support 9 GW of existing generator interconnection requests and enable an additional 20 GW of projects in both territories, as well as provide around $1 billion of production cost savings. SPP and MISO are currently working on a cost allocation approach, considering assigning $/MW charge for a generator interconnecting into each zone. This approach will to provide certainty for new generators with regard to affected system charges. Moving forward, the plan is to conduct a JTIQ study every few years to identify the optimal transmission projects by proactively planning for generation interconnection requests over multiple years. The cost of identified transmission upgrades will be distributed among zones commensurate with the benefits received, and assigned as $/MW charge to the projects that are built in each zone. This approach will provide certainty to developers with regard to total transmission costs at the locations of their planned projects. The need for a cost-sharing mechanism between future resources and loads based on benefits received has been recognized and is under development.

The MISO Long Range Transmission Planning effort simultaneously evaluated 20-year reliability, economic, and public policy needs for a diverse set of future scenarios and identified a least-regrets

[15] SPP and MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes*, white paper, August 2022, https://cdn.misoenergy.org/20220822%20MISO%20SPP%20JTIQ%20DRAFT%20Study%20White%20Paper626025.pdf

portfolio of multi-value transmission projects: this $10 billion portfolio supports 53 GW of generator interconnection and reduces other costs (based on estimates for seven categories of benefits) by $37 to $70 billion. Since study was done in parallel to the JTIQ, there are some commonalities in the upgrades identified.[16]

Lastly, SPP's Consolidated Planning Process Task Force, described by Matt Pawlowski from NextEra Energy Resources and Sunny Raheem from SPP, recognizes interdependencies between generation interconnection and transmission planning and seeks to integrate these processes into one annual scenario-based study encompassing regional needs, generation interconnection, transmission planning, load additions, and responsibility for meeting NERC reliability standards.[17] This approach is designed to ensure timely and accurate planning studies, consistency in study criteria and assumptions, fair cost-sharing, increased efficiency through the automation of data management and study processes, cost savings to customers, improved generation interconnection schedules, and more efficient use of engineering time. The challenges are to ensure cost certainty to developers, ensure that the new generation interconnection and transmission planning processes comply with FERC's final filing, and keep the study duration manageable.

[16] MISO, Long Range Transmission Planning, https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning/

[17] SPP, Consolidated Planning Process Task Force, https://spp.org/stakeholder-groups/organizational-groups/board-of-directorsmembers-committee/consolidated-planning-process-task-force/

Day 2: Interconnection Studies and Modeling

The second day of the workshop identified gaps in the interconnection study processes and the need for validated models both for the phasor domain and time domain simulations, discussed challenges from the perspectives of developers and transmission service providers, and provided recommendations for ways to improve the study and modeling processes.

Key Points

- Several widespread disturbances analyzed by NERC over the past six years identified gaps in interconnection requirements and standards as well as in interconnection studies and models. **To improve system reliability, the timing of interconnection studies needs to be better aligned with the availability of accurate models that are representative of the equipment that will be installed in the field.** This will reduce need for restudies and increase the fidelity and usefulness of the study results.

- Given that project development, especially for offshore wind, takes a long time and faces many uncertainties related to permitting, interconnection costs, equipment procurement, etc., **better coordination between the grid operator and the developer is needed** to provide an earlier indication of onshore equipment requirements and associated permitting in order to reduce project development timelines. While **hosting capacity maps** proposed by the FERC NOPR **are helpful**, **information about short circuit strength and harmonics** at prospective points of interconnection would further help to reduce iterations of project design.

- **Stability impacts from generation projects coming online around the same time should be assessed in concert**, using accurately parametrized models that reflect the equipment to be installed in the field. Where relevant (e.g., oscillatory behavior under weak grid conditions), the grid operator should work in collaboration with OEMs and the developer to consider control parameter tuning of a plant under study as an alternative to costly transmission upgrades, in order to reduce costs and time required for implementation.

- The discussion in this set of presentations emphasized that all models have their limitations: generic models are not necessarily inaccurate, and more detailed electromagnetic transient (EMT) models are not necessarily more accurate. **All models need proper validation and parametrization, and the appropriate type of models should be used for the appropriate studies.** For example, sub-cycle phenomena and unbalanced conditions are not captured in phasor-domain simulations; therefore, EMT models and tools are needed to study these phenomena.

- Recommendations were made that **grid operators should start collecting, quality testing, and validating EMT models now, ahead of EMT studies being needed**. For example, the Independent System Operator of New England (ISO-NE) and ERCOT have been doing this collecting, testing, and validating for a number of years and over time have significantly improved their EMT skills and model quality, and model validation requirements.

- One area where further model improvements and improvements to model validation processes are needed pertains to the **inability of present models (both phasor domain and EMT) to capture some of the causes of inverter tripping (or power output reduction) in the disturbance events** analyzed by NERC. This is because not all control loops and protective functions relevant for a studied phenomenon are included in the models. In addition, it is problematic that only limited model validation against field tests is possible at commissioning. To address this, **IBR unit type-testing** (lab tests carried out by an OEM on a single inverter or a wind turbine and subsequent unit model validation) **combined with careful plant design evaluation can be used to gain fidelity in the models, followed by post-commissioning disturbance monitoring** to validate the models for large-signal disturbances.

Background

Complexities of the interconnection process are leading to challenges with interconnection studies and potential reliability concerns once projects become operational. Developers do not have sufficient information about the equipment that will be available and used in their project because of the long delay typically involved in completing interconnection studies and identifying their interconnection upgrade costs, as discussed during Day 1 of the workshop. Additionally, because of the length of the interconnection process, equipment that is ordered for eventual implementation in the project may still be under development by the OEM. This can cause discrepancies between the plant models used during the interconnection studies and the equipment that is ultimately commissioned in the field. Improvements to the study processes are needed to align interconnection process milestones, OEM equipment lifecycles, project development timelines, and reliability study needs.

NERC Disturbance Reports

Over the last six years NERC identified and analyzed a number of widespread disturbance events involving power reduction or disconnection of primarily IBRs (as well as a small number of synchronous generator trips in some of the events) in California and Texas in areas with high concentrations of these resources (see Figure 4). These disturbance events are increasing in frequency and magnitude, potentially creating reliability concerns.

Disturbance event analysis carried out by NERC identified the following needs, as presented at the workshop by Ryan Quint:

- The need for accurate modeling—models that reflect equipment and settings in the field and that match actual equipment behavior
- The need for the models to include controls, modes of operation, settings, and protections that could affect the resource’s ability to ride through grid disturbances and provide essential reliability services
- The need for appropriate models to study appropriate phenomena (steady state, phasor-domain, and EMT models)

- The need for more detailed, clear, harmonized interconnection requirements among all ISOs/RTOs and utilities. During the question and answer period Alex Shattuck from Vestas added that harmonized interconnection and modeling requirements in Europe is the reason why such widespread events are not common there. Harmonization needs were further discussed during Day 3 of the workshop.
- The need for better alignment of interconnection studies with project development timelines.

FIGURE 4
NERC Disturbance Reports Illustrating Increasing Frequency of Widespread Disturbance Events

Source: North American Electric Reliability Corporation.

Ryan highlighted the need for the industry to adopt existing NERC reliability guidelines and to modernize and enhance FERC's generation interconnection process and agreements in order to ensure that high fidelity validated models are available for reliability studies. These models should be trued up against "as built" equipment and settings during or shortly after the project's commissioning. Establishing a path toward the adoption of the recently approved IEEE 2800 standard for "Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems" through the FERC Large Generator Interconnection Agreement (LGIA) would provide uniformity of interconnection requirements across regions. NERC is working to enhance existing and develop new reliability standards to address concerns related to model quality, the inadequacy of reliability studies, and the need for post-event performance validation and mitigation of performance issues. Ryan concluded with comments on the FERC NOPR related to modeling. These included:

- During the interconnection study process prior to conducting any reliability studies, a full suite of appropriately parametrized, validated models should be required. The models should be reflective of equipment and its settings as will be installed in the field.
- All control modes, settings, and protective functions that could affect generator's ability to ride through disturbances and provide essential reliability services should be included in the models.
- The availability of these models should be used as a readiness criterion prior to conducting reliability studies. A process should be developed to accommodate restudies from a reliability perspective in case of changes or modification to a plan during the interconnection process.

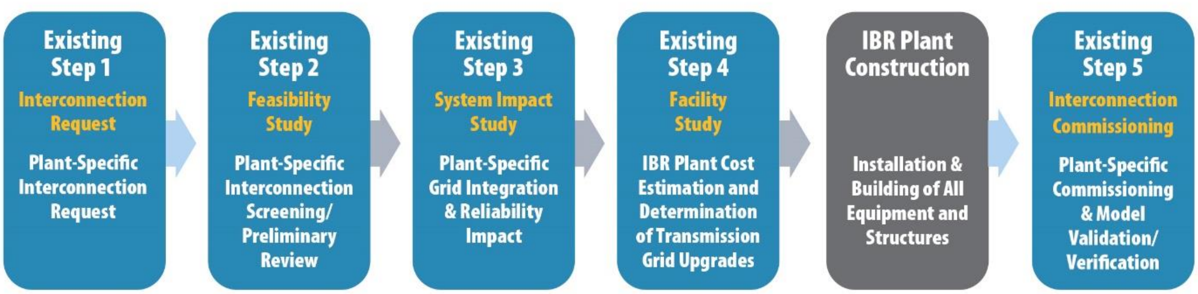
Generation Interconnection Studies

Currently, the FERC Large Generator Interconnection Process (LGIP) includes the following steps (see Figure 5):

- A feasibility study with the purpose of identifying thermal and voltage limit violations and estimating grid upgrade costs required to ensure local reliability. The scope of these studies includes power flow and short circuit analysis (steady state).
- System impact studies with the purpose of evaluating the reliability impact on the transmission grid. The scope of these studies includes power flow, short circuit, and stability studies.
- A facility study with the purpose of estimating the cost of equipment, engineering procurement, and construction work, and identifying substation equipment. The facility study also identifies the nature and estimated cost of any transmission upgrades needed.

FIGURE 5

Existing Interconnection Procedure as shaped by the FERC Large Generator Interconnection Process



Source: Workshop presentation by J. Boemer, Electric Power Research Institute.

Backlogs, Lack of Technical Standards, and Large Variations Among Studies

Jens Boemer from EPRI discussed current interconnection processes and gaps that may lead to reliability concerns, and proposed potential solutions. Regarding feasibility studies, he described how screening for weak grid conditions is limited (or nonexistent), even as these conditions in the field may result in reliability problems if equipment is not designed for it. Regarding system impact studies, he discussed how the equipment has usually not yet been selected early in the interconnection process; therefore, these studies are often done with insufficient or invalid models that are not site-specific and may be configured with generic parameters providing limited value to understanding of reliability impacts.

Jens added that in many regions there are no detailed or sufficient technical interconnection requirements available. This may lead to the installation of equipment that is not state of the art and result in inadequate performance of the plants during grid disturbances. In regions where interconnection requirements do exist, there is no assessment of a plant design's conformity with these requirements. In only some areas is there an "as build" evaluation to ensure that the plant is built as it was designed. Moreover, during plant commissioning, large disturbance performance testing is not practicable, resulting in no verification of ride-through performance at all. In some areas models are used to verify this performance; however, again, the value is contingent upon the availability of high-fidelity models. There is limited collection of data in the field post-commissioning for model validation and verification of plant performance.

As a result of these gaps, the interconnection process is lengthy and backlogged, lacks technical standards, and includes studies that vary significantly in terms of assumptions, scope, and modeling rigor. These processes as they exist today fail to ensure streamlined and reliable interconnection of IBRs.

Recommended Improvements to the Interconnection Process

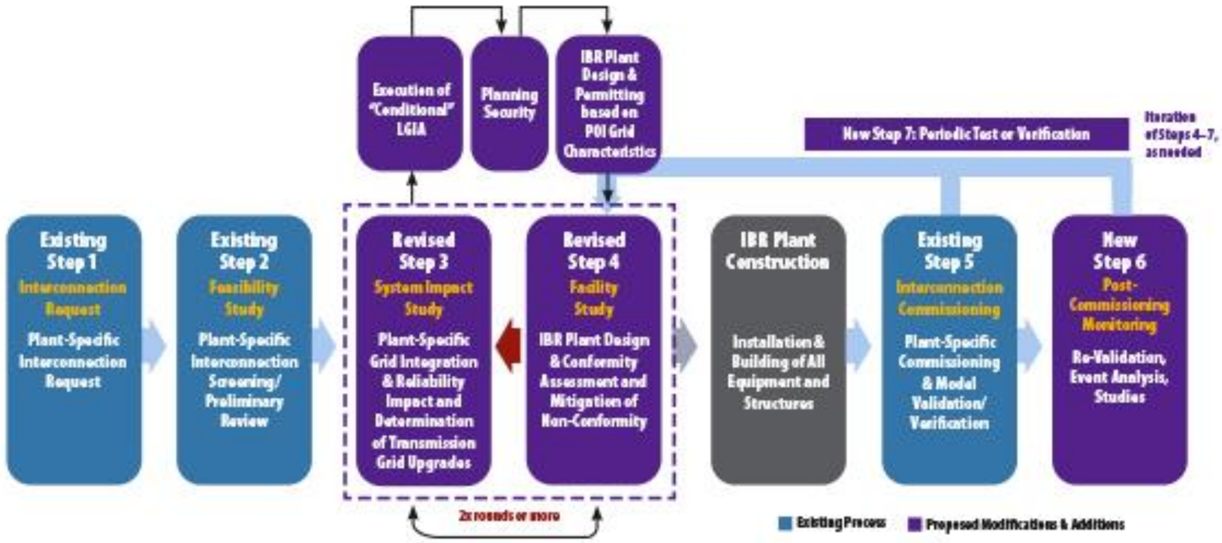
Jens continued by discussing the NERC Inverter-based Resource Performance Subcommittee's (IRPS) Work Item #8, which is focused on improvements to the interconnection process, specifically with regard to studies, modeling, interconnection requirements, and conformity assessment to improve reliability. The group has proposed following broad recommendations:

1. A paradigm shift is needed toward IBRs integrating a unified minimum set of capabilities. The IEEE 2800 standard should be adopted as soon as possible, with additional guidance on how IEEE 2800 conformity should be assessed before IEEE 2800.2 is available. Jens noted that large developers welcome this recommendation, because knowing interconnection requirements in advance provides certainty for project design and reduces number of iterations (a point also made by Divya Kurthakoti from Orsted in her presentation).
2. The interconnection process should include plant-level performance conformity assessment and verification before and after commissioning. The recommendation is being made to revise the FERC LGIP and ISO/RTO/utility interconnection processes to include these steps and harmonize studies across the U.S.
3. Education should be provided and collaboration facilitated for continual and iterative improvements of performance requirements, plant-level modeling, and model validation. All stakeholders should engage in the development of IEEE 2800.2. This recommendation was echoed by OEMs, developers, and ISOs during Day 3 of the workshop.

The proposed improvements to the existing interconnection process included improvements to data and information exchange in the existing steps of the process, and also revised the system impact study and facility study step as well as introduced a new step around post-commissioning monitoring (see Figure 6).

FIGURE 6

Recommended Improvements to the Interconnection Process



Source: Workshop presentation by J. Boemer, Electric Power Research Institute.

Jens discussed how, by agreeing on the set of requirements, the expected performance of plants is defined more specifically than it is today, and this, in turn, informs some of the modeling to be done, even when there is still uncertainty about the actual equipment. He welcomed transmission hosting capacity maps, as proposed in the FERC NOPR, but added that grid strength metrics for the point of interconnection (both conventional and more advanced) are extremely important to inform equipment selection and level of detail of modeling required in impact studies.

System impact studies and facility studies are where there may be a need to iterate to capture and re-assess the impacts from equipment changes or modifications that affect a plant's ride-through performance or provision of essential reliability services.[18] This is where high-fidelity models, representative of the equipment and settings that will be used in the field, become extremely important.

On the other hand there is an urgent need to reduce the number of iterations and shorten the associated delays in order to resolve the problem that arises when developers cannot order equipment without knowing the full extent of interconnection costs (as discussed in Day 1), and ISOs/RTOs/utilities are using impact studies to identify those costs with models that are not representative of the equipment that will be installed. The session chair, Roberto Favela from El Paso Electric Company, added that to both improve system reliability and reduce restudies in the interconnection process, system impact studies can be split into two steps: a steady state impact assessment, where very basic

[18] The FERC NOPR recognizes this need for restudies due to equipment modification, but only with regard to hybrid plants (where battery storage is added to a wind or solar plant) and not for other modifications.

information about the plant is required, and stability studies, where more detailed and accurate models are needed. The former can be used early in the interconnection process to inform interconnection cost estimates, and the latter can be carried out later in the process once detailed information about procured equipment becomes available. Some areas have already implemented this approach.

Jens continued with discussing the need for post-commissioning work. Once a plant is constructed, verification should be done to make sure that the plant “as built” corresponds to the design that was studied. System impact and facility studies may need to be repeated if changes to IBRs or supplemental equipment have been made. Post-commissioning monitoring, model validation, and periodic testing needs to continue through lifetime of the project. Pouyan Pourbeik from Power and Energy, Analysis, Consulting and Education (PEACE) added that generator owners would be the most appropriate entity for such monitoring, and they should work together with ISOs/RTOs and utilities to provide required evidence of conformity with applicable performance and modeling requirements.

In conclusion, Jens underscored that that proposed improvements to the existing interconnection process are only one possible solution to ensure that interconnection studies accurately assess reliability impacts of new generation on the grid, while not introducing unnecessary delays to an already lengthy interconnection process. There may be other solutions that are equally or more effective and practicable. He noted a number of forums working on this issue, including ESIG’s Reliability Working Group, NERC Inverter-based Resource Performance Subcommittee, the IEEE 2800.2 Working Group, and NERC Reliability Standard Drafting Teams, as great sources of education and collaboration. The new Interconnection Innovation e-Xchange (i2X) initiative that was recently launched by DOE is also specifically focusing on the improvement of all facets of the interconnection process and was introduced on Day 3 of the workshop.

Similarly to Ryan Quint, Jens welcomed FERC’s initiative to update modeling and performance requirements for system reliability, but recommended referring to the existing standards IEEE 2800 and IEEE 1547 for specific language, as these were created through standard drafting processes and were thoroughly vetted by industry. There is precedence in FERC orders, NERC reliability standards, and state public utility commissions’ regulations of referencing IEEE standards. A similar framework exists in other countries. Referring to IEEE standards can increase specificity and provide uniformity of requirements across the country and internationally.

Challenges Faced by Developers, Especially Offshore

Divya Kurthakoti from Orsted discussed challenges with development of large and complex offshore wind projects, in which any changes to project design may lead to iterations with ISO/RTO and federal permitting process. For example, a simple re-routing of a cable changes the needs for reactive power compensation and short circuit strength at wind turbine terminals, which, in turn, may necessitate additional reactive compensation equipment onshore (such as synchronous condensers or STATCOMs) and trigger another iteration of the federal permitting process, further delaying the project. Late-stage understanding of stability concerns from the grid side may also result in a need for additional grid-supporting equipment, trigger a new federal permitting process, and trigger restudies from the ISO/RTO. This additionally results in the challenge of obtaining project-specific models from an OEM within the needed timeframe.

Divya concluded that to design an offshore project with the minimum number of iterations with ISOs/RTOs and the federal permitting process, accurate information about the grid is vital (including the grid model, short circuit data and harmonics). Standardized interconnection requirements such as IEEE 2800, if adopted across the U.S., remove uncertainty for the developers and OEMs and make the design of the projects more streamlined. The offshore wind farm transmission system plays a vital role in providing grid stability and significantly impacts the plant's interaction with the grid. Dynamic devices like STATCOMs and HVDC converters, if present, must be modeled in the planning studies using high-fidelity models reflective of equipment in the field. All other passive balance-of-plant equipment must be modeled adequately depending on the study type (stability, power quality). These conclusions were in line with Jens Boemer's presentation as well.

ERCOT Interconnection Process

Mario Hayden from Enel presented on ERCOT's interconnection process. While ERCOT has one of the most stringent modeling and interconnection requirements in the country, the process takes only about three years on average—the fastest in the country by a large margin[19]. This timeline is inclusive of possible inverter selection changes during the process, which trigger a repeat of a full interconnection study. The following steps are included in the interconnection process:

- The **screening study** is performed to look at steady-state congestion impacts from the new generator. No generator-specific model is necessary at this stage (only project size, fuel-type, location). ERCOT also performs at a minimum a topology screening of the point of interconnection to determine whether there is a risk for sub-synchronous resonance (SSR).
- The **full interconnection study** consists of steady state, short circuit, stability, and facility studies. The full interconnection study requires more details than the screening study, including both a detailed and equivalent plant model with valid collector system connectivity, to be approved. The stability study additionally requires a plant-level phasor-domain model and a model quality test report.
- The **facility study** describes the engineering procumbent and construction scope to interconnect the generator.
- A **reactive power study** is required from a generator developer (or its consultants) to demonstrate conformity with ERCOT interconnection requirements for voltage support and dynamic reactive capability.
- If required, the transmission service provider will perform the **SSR study** and submit the completed study for ERCOT approval. Regardless of whether an SSR study is needed, all IBRs in ERCOT are required to provide EMT models at this stage. This package also includes a unit model validation report (one for each unique inverter or turbine model) on a hardware-specific basis and a plant model quality test. ERCOT is collecting EMT models and runs broad-area EMT studies on as needed; these are not part of the interconnection process but require model fidelity similar to SSR studies.
- ERCOT then performs a **quarterly stability assessment** for groups of generators likely to interconnect in a given study area within a similar timeframe. Generators have to meet stringent readiness criteria including modeling requirements to be included in the quarterly stability

[19] Day 1 of the workshop covered some of the reasons for the speed of ERCOT's interconnection process.

assessment. The date of inclusion in this assessment defines when the project will be able to synchronize to the grid.

ERCOT manages stability concerns through Generic Transmission Constraints (GTCs)[20]. These are constraints enforced on one or a group of transmission elements to monitor and control power flows against in market dispatch tools in order to maintain stability and other nonthermal reliability limits. The identification and implementation of GTCs in recent years is a result of the analysis performed in the quarterly stability assessment in conjunction with a subsequent GTC assessment, and further analysis in the operational time horizon.

Recent improvements have been introduced to model quality testing and validation for all plant phasor-domain and EMT models, including requirements for unit model validation against lab tests of the underlying hardware. ERCOT also introduced parameter verification requirements to ensure that the model parameters match field settings shortly after commissioning and periodically during the lifetime of the project. This is in line with recommendations that Ryan Quint and Jens Boemer offered.

Mario concluded by reflecting on the interconnection study process from the developer's side. Developers need to understand the timeline for provision of various models, when in the interconnection process those become mandatory, and impacts that this may have on delaying interconnection, and should work on a compromise between project development timelines and timelines defined by the FERC LGIA.

Control Tuning as an Alternative to Transmission Reinforcement

Control tuning was another focus of Day 2 of the workshop, as control tuning can be used as a non-transmission alternative to costly transmission reinforcements related to weak grid issues. The ability to evaluate control tuning as an option is contingent upon the availability of (1) high-fidelity models with tunable parameters that are representative of equipment in the field for existing and new IBRs in the area under consideration, and (2) an accurate model of the studied grid segment. Multiple nondisclosure agreements may be required to enable tight collaboration between all involved stakeholders: OEMs, developers, and the grid operator. This option can help to reduce costs to ratepayers, as fewer unnecessary and potentially underutilized transmission elements will need to be constructed. In his presentation Alex Shattuck from Vestas discussed an example in which control tuning on a new generation project helped to resolve oscillatory behavior (~20% voltage swings at the point of interconnection) of the project in weak grid conditions (short circuit ratio of 1.75 at the point of interconnection). With that solution in place, there was no longer a need for the costly and time-consuming transmission upgrade alternatives proposed by the local utility, including the possible construction of a new 138 kV transmission line, grid side STATCOM, or synchronous condenser.

Alex concluded that control tuning option should be considered in generator interconnection and planning studies as one of the non-wire alternatives to help optimize transmission system build-out and reduce cost to customers by utilizing features available in IBRs. Detailed coordination of involved stakeholders is absolutely vital for the effective application of this solution.

[20] ERCOT, *Use of Generic Transmission Constraints in ERCOT,* white paper, July 2020, https://www.ercot.com/files/docs/2020/11/27/The_Use_of_GTCs_in_ERCOT_July_2020.pdf

Models and Modeling Needs

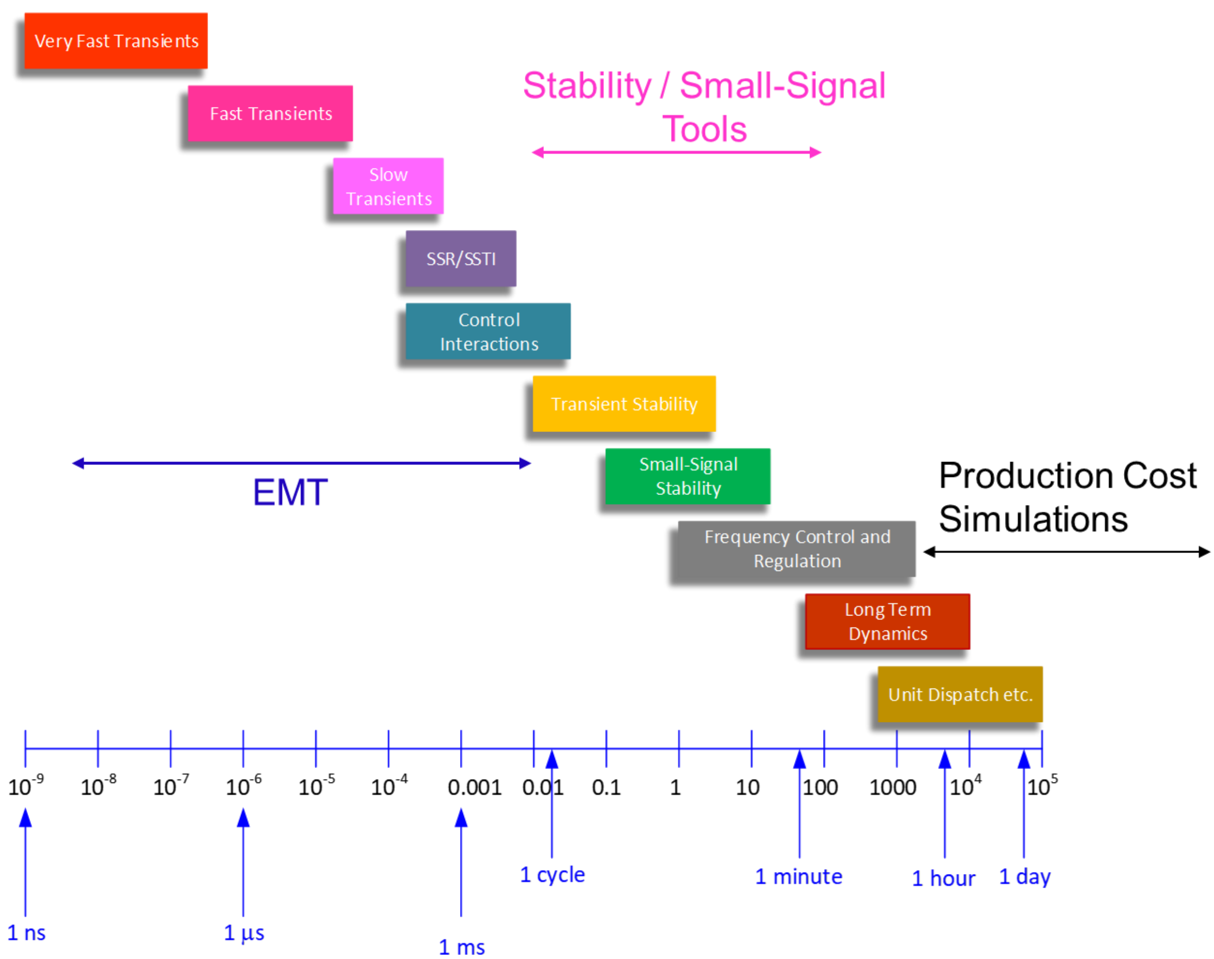
The previous session of the workshop alluded to the importance of high-fidelity models, and this modeling session offered a deeper dive into the topic.

Importance of Model Validation and Applicability

Pouyan Pourbeik from PEACE provided an overview of modeling needs. He described how models have various uses depending on the focus, whether power system planning, post-disturbance analysis, or equipment and plant design. For example, generic models with generic parameters may be used in long-term planning studies, while in plant design very detailed models of the plants are necessary; in system reliability studies these models are site-specific but aggregated (e.g., a single wind turbine, collector network equivalent, single transformer). No one type of model fits all situations.

FIGURE 7

Wide Spectrum of Phenomena Existing in Power Systems



Source: Workshop presentation by P. Pourbeik, PEACE®.

Pouyan discussed how, when studying the wide spectrum of phenomena existing in power systems (shown in Figure 7), we must always ask ourselves what model is appropriate for what studies, selecting from among the major model types:

- Hardware-in-the-loop models
- EMT models
- User-written “real-code”–based models
- User-written models developed in a native software tool’s language
- Standard-library (“generic”) parametrized models

Pouyan also spoke about the importance of model validation, including:

- Doing unit-level IBR type-testing and model validation
- Building a plant model (based on the validated unit model from the previous step) and an aggregated collector model (both in power flow and dynamics), and using evidence that aggregation from IBR unit level was done appropriately.
- Testing the power plant controller (voltage step test and frequency step test) and validating the model for this test performance. Large-disturbance ride-through behavior is impracticable to test at commissioning, so we have to rely on unit-level type-testing and simulations with a plant model until data from disturbance events in the field become available, as per the next step.
- Continuing with monitoring and post-commissioning updates and validating the models based on actual disturbance events.

He concluded by noting that engineering judgment should be used instead of getting bogged down in small details that may not be relevant for the type of the model and phenomena studied, while at the same time, simple yet important details should disregarded.

Model Capabilities and Limitations

Deepak Ramasubramanian from EPRI presented the following table to highlight that all models have their limitations: generic models are not necessarily inaccurate, and more detailed EMT models are not necessarily more accurate. Similar to Pouyan Pourbeik, Deepak reinforced the point that the appropriate type of models should be used for the appropriate studies (see Table 1). Parametrization of the model is very important, as generic parameters should not be used to study the reliability impacts of a specific plant. Sufficient evidence of model validation needs to be available.

TABLE 1
Misconceptions About Model Types

Generic model	Does not always imply a bad model
User defined model from manufacturer	Does not always imply a good model
RMS/Positive sequence model	Does not always imply a bad model
Electromagnetic transient (EMT) model	Does not always imply a good model

Possible Improvements to Phasor-Domain Models

In the present state-of-the-art IBR models, IBRs are represented as current sources. In the phasor domain these models, especially an earlier generation of them, have the limitation of not capturing fast control dynamics or interactions in weak grid conditions. Advanced control features may not be modeled, and numerical robustness issues may arise (non-convergence in simulation software). However, every inverter used in power system applications today is a voltage source inverter, controlled to behave as current source interphase. If an IBR is represented using a voltage source interphase, this allows greater accuracy and characterization of IBR dynamic behavior and allows representation of the inverter's current control loops and phase-locked loop (PLL), as implemented in the latest generation of generic models. There are still simplifications here compared to more detailed EMT models, and this approach does not replace EMT models; however, it provides better representation of IBRs in phasor-domain tools and broadens these tools' usability.

Deepak closed out with a table listing causes of IBR tripping and active power reduction in recent disturbance events analyzed by NERC. He pointed out that certain types of tripping such as sub-cycle overvoltage and overcurrent, unbalanced conditions etc. are certainly in the realm of EMT simulation domain. But other causes, such as phase jump, PLL loss of synchronism, plant controller interactions, etc., can be captured in phasor-domain simulations with further improvements to phasor-domain models. He also pointed out that even EMT models of the plants involved the disturbance events analyzed by NERC were not able to capture some of these issues, due to inaccuracies, which corroborates his point from the table above that "EMT" does not necessarily imply a good model. Diligent parametrization and rigorous model validation is needed both for phasor-domain and EMT models.

With regard to the FERC NOPR and EMT modeling requirements language, Deepak noted that a collection of EMT models is needed ahead of EMT studies being required in a given area. This will ensure that by the time an EMT study is necessary, high-fidelity models of existing and planned equipment are readily available. The use of EMT models alongside phasor-domain models is recommended to comprehensively assess the reliability impacts of IBRs.

ISO New England's Experience with EMT Modeling

Brad Marszalkowski from ISO-NE concluded the modeling session of the workshop by sharing ISO-NE's experience with EMT modeling. He described how EMT studies are required when there are concerns about certain grid conditions, interactions, or phenomena, as listed below:

- Weak system conditions (low short-circuit strength)
- Sub-synchronous oscillations such as sub-synchronous torsional interactions (SSTI) or sub-synchronous control interactions (SSCI)
- Control interactions
- Concerns about ride-through or performance following large-signal disturbance
- Performance verification
- Voltage transients

For the most part, IBR behavior for these phenomena is dependent on highly specialized controllers, unique to each OEM, and can be missed in the phasor domain studies. ISO-NE requires an EMT study for each inverter-based generating facility or transmission upgrade that utilizes power electronics and carries out EMT studies as a part of the system impact study. Models are required at the interconnection request stage and are vetted for accuracy, useability, and efficiency. An EMT study's case area includes all electrically relevant transmission and generating facilities. Initial conditions are informed by the steady state and phasor-domain studies. To understand what phenomena are being missed in each of the tools, ISO-NE is doing benchmarking between EMT and phasor-domain tool results.

Brad shared lessons learned from their experience with EMT studies, which echoed those of other presenters on Day 2. He noted how EMT studies are much more computationally and time-intensive than traditional transient stability studies; the models used are much more complicated. But EMT studies can show IBR behavior that may have been missed in stability studies, as they include sub-cycle phenomena and capture fast controls in the models. Starting EMT studies early and in parallel with other studies can help stay on track with FERC interconnection timelines, but this process is contingent on having good-quality models. Investing in more powerful hardware will be crucial as more IBRs are being added to the grid. Echoing Deepak Ramasubramanian and Ryan Quint, Brad strongly recommended that ISOs/RTOs/utilities begin familiarizing themselves with EMT software, procuring the necessary computer hardware and collecting EMT models in advance of the widespread need for EMT studies, because it may be too late to begin those efforts at the time that EMT studies are needed.

Day 3: IBR Interconnection Requirements and Next Steps

The third day of the workshop focused on the ongoing gap analysis between existing interconnection requirements and the recently approved IEEE 2800 standard for "Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems," and discussed the path forward with improvements to existing interconnection requirements and IEEE2800 adoption.

Key Points

- **The equipment manufacturers** who presented at the workshop **welcomed the effort to harmonize interconnection requirements**, as it provides certainty, provides cost-efficiency, and improves grid reliability. They agreed t**hat state-of-the art equipment already has the majority of the capabilities required by IEEE 2800;** however, **there are requirements for some capabilities that are more challenging to develop and test in their equipment**, especially ahead of IEEE 2800.2, which is currently under development. Nevertheless, equipment manufacturers are working on improvements for their equipment and, in parallel, participating in IEEE 2800.2 development. Since IEEE 2800 is not an equipment standard but applies to an IBR plant at a point of interconnection, collaboration between OEMs and developers will be needed to ensure conformity of an entire plant.

- **Some ISOs**, including ISO-NE and ERCOT, **have already started the piecemeal adoption of IEEE 2800 to address high priority gaps in their existing interconnection requirements**. Wholesale adoption of this standard is also possible, both now and, especially, at a later stage once IEEE 2800.2 becomes available.

- **Smaller developers**, especially of solar and battery storage plants, **need additional education about interconnection requirements and performance expectations for IBRs**. Grid operators need to be proactive to keep developers well informed on interconnection requirements, modeling requirements, and performance expectations.

- **The voltage ride-through requirement proposed in the FERC NOPR needs revision to encourage IBR behavior that is more helpful for the grid recovery**. Recognizing that IEEE 2800 and NERC's PRC-024 standard have been developed by industry experts through a standard development process with a high approval rate by the industry, the harmonization of the FERC NOPR's proposed ride-through requirements with these standards would be highly beneficial.

- **The DOE i2X initiative will convene a broad range of industry stakeholders to enable simpler, faster, fairer interconnection** of wind and solar resources while boosting the reliability, resilience, and security of the grid.

Background

Currently, there is no consistency in interconnection requirements for IBRs between regions. Some areas already have comprehensive, stringent requirements, while others are still lacking requirements. Recent NERC Disturbance Reports, as presented in Day 2 of the workshop, have identified gaps in existing interconnection requirements and incorrect application of existing interconnection requirements, leading to multi-generator disturbance events. Since state-of-the-art inverters today are developed with the most stringent interconnection requirements in mind, widespread disturbance events are not a technology issue per se but are rather due to a lack of comprehensive interconnection requirements and conformity assessment before, during, and after projects' commissioning. The recently approved IEEE 2800 standard is the minimum capability requirement for IBRs interconnecting to transmission and sub-transmission level. It was developed by 175 industry experts and was accepted with a 94% approval rate by IEEE Standard Association balloters. The standard was developed with state-of-the-art IBR capabilities and system reliability needs in mind. Through the adoption of IEEE 2800, the industry can take advantage of the state-of-the-art technology capabilities to ensure reliable operation of IBRs in the future grids.

Need for Harmonization of Requirements: The Example of Ride-Through Capability

Today, some areas in the U.S. adopt requirements from the FERC Large Generator Interconnection Agreement and NERC standards alone, while others have more advanced requirements, with the requirements differing significantly between regions. Balanced and harmonized interconnection requirements will play a critical role in the deployment of advanced technology capabilities to meet grid needs in a cost-effective way, while providing certainty to OEMs and improving grid reliability. Examples of such harmonized requirements include the European Network of Transmission System Operators for Electricity's (ENTSO-E's) Requirements for Generators[21] that were approved in 2016, NERC's Reliability Guidelines[22], and the IEEE 2800 standard.

Active vs. Reactive Power Injection During Ride-Through

Jason MacDowell from GE Energy Consulting highlighted need for harmonization reflecting on the FERC NOPR and proposed Clause 9.7.3: Ride Through Capability and Performance:

> During abnormal frequency conditions and voltage conditions within the "no trip zone" defined by Reliability Standard PRC-024-2 or its successor standards, non-synchronous Generating Facilities must **maintain real power production at pre-disturbance levels** unless providing primary frequency response or fast frequency response and must **provide dynamic reactive power to maintain system voltage in accordance with the Generating Facility's voltage schedule** [emphasis added] (p. 389).

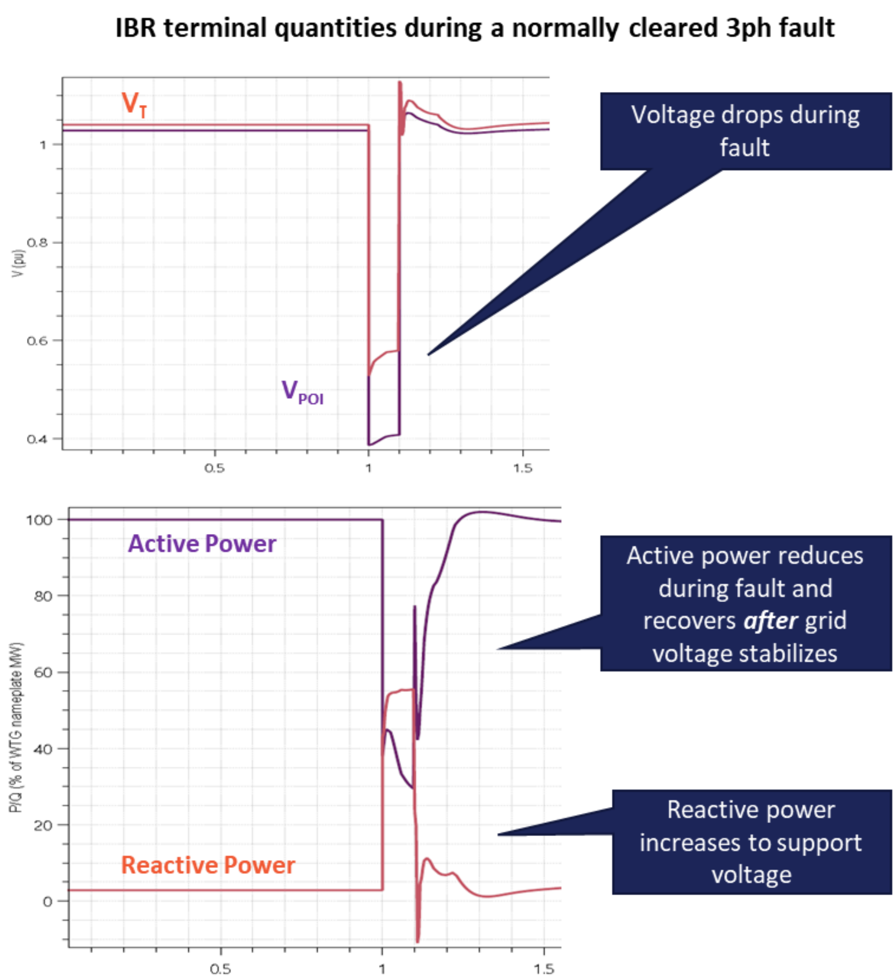
While it is understood that the intent of this requirement for keeping active power at pre-disturbance levels was to avoid momentary cessation of IBRs (the reduction to 0 MW of their total current during

[21] ENTSO-E, *Requirements for Generators*, April 2016 https://www.entsoe.eu/network_codes/rfg/

[22] NERC, Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers, https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

faults) that was observed when NERC analyzed disturbances events, the requirement as formulated in the NOPR may pose a further reliability challenge. During a fault condition, as shown in Figure 8, the voltage is reduced. If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop—thus preventing further voltage collapse—while reactive power is prioritized and increased to support grid and terminal voltage. The degree to which active power is reduced during faults is configurable by control gain settings, if reducing active power to 0 MW is a concern for grid reliability. Once the fault is cleared and voltage recovers, then active power should recover quickly. The required speed of active power recovery should be evaluated based on grid strength and network topology. Steady state active power ramp limitations should not be applied during ride-through situations.

FIGURE 8
IBR Behavior During a Fault



Source: Workshop presentation by J. MacDowell, GE Energy Consulting.

Maintaining Voltage During Ride-Through

Another aspect of the ride-through requirement proposed in the FERC NOPR is "maintaining system voltage in accordance with the voltage schedule." This is desirable behavior in steady-state and quasi-steady-state conditions and is managed by a plant controller adjusting reactive power from all units with response time on the order of seconds to tens of seconds. However, during a fault, voltage at the point of interconnection is depressed, and IBR behavior is dominated by individual inverter controls managing inverter terminal voltage (on the order of tens of ms) injecting reactive current to quickly and effectively aid voltage recovery. It is therefore not possible to maintain voltage in accordance with the steady-state voltage schedule at the point of interconnection during a fault. Eventually, when the fault is cleared, a plant controller will take over to recover the voltage as is needed and coordinate individual units to maintain voltage in accordance with voltage schedule once the system reaches a steady state again.

Recommended Harmonization with NERC and IEEE Standards

Jason noted that FERC could coordinate and harmonize the proposed ride-through requirement language with NERC standard PRC-024-3 and IEEE 2800, which have been developed through a standard drafting process and gone through a thorough industry approval process. PRC-024-3 states that:

> Each Generator Owner shall set its applicable frequency protection in accordance with PRC-024 Attachment 1 such that the applicable protection **does not cause the generating resource to trip or cease injecting current within the "no trip zone"** during a frequency excursion.… [emphasis added]

PRC-024-3 states that "no trip or cease injecting current" is more advantageous for voltage recovery during faults than to "maintain active power to the pre-fault levels," because it allows for reactive priority and provision of reactive current injection much needed for fast voltage recovery.

According to IEEE 2800:

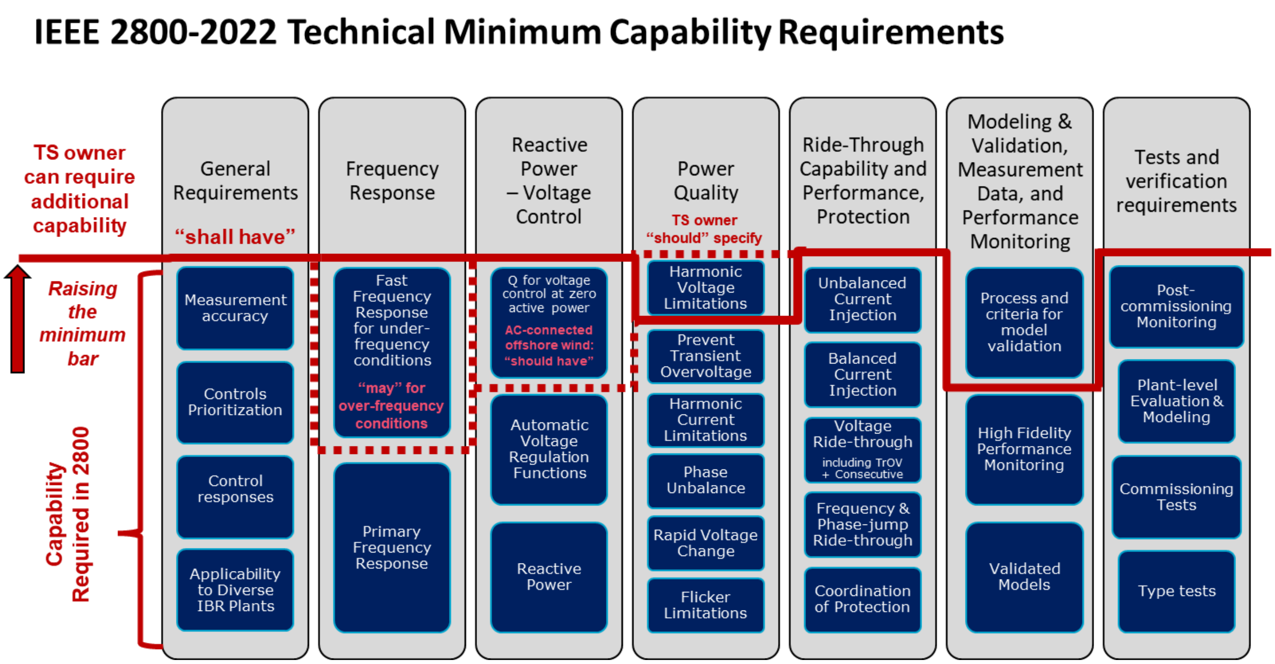
> The active power recovery time shall be configurable within a range between 1.0 s and 10 s. The default active power recovery time is 1 s; however, **in weak grids**, in order to reduce oscillatory behavior of the IBR plant upon fault recovery and maintain system stability, **it may be desirable to reduce the average rate of active power recovery** in consultation with the TS [transmission system] owner.
>
> The IBR unit shall have capability to select operation in either **active current priority mode** or **reactive current priority mode** during high- or low-voltage ride-through events. **By default, the IBR unit shall operate in reactive current priority mode during high- and low-voltage ride-through events.** If requested by the TS [transmission system] owner, and mutually agreed with the IBR owner, the IBR unit may operate in active current priority mode for both the high- and low-voltage ride-through events [emphasis added].

The IEEE requirement acknowledges that active power will be reduced from the pre-disturbance level during a fault and will then recover after the fault is cleared. It also acknowledges that slow recovery may be desirable in weak grid conditions. IEEE 2800 calls out the capability to set active or reactive current priority mode depending on system needs, with reactive current priority as the default setting. This is because in a large interconnected system, loss of megawatts during a fault is not the main concern, and it is more important to aid voltage recovery by providing reactive current injection. It can be the case that active power priority has higher importance for a system, for example, in small islanded systems with low inertia, however additional dynamic reactive power equipment may be needed on the grid in these situations to aid voltage recovery during faults.

IEEE 2800 Standard

Andy Hoke of the National Renewable Energy Laboratory presented further details about the IEEE 2800 standard. The standard defines the minimum capability requirements deemed necessary from IBRs connected to sub-transmission and transmission levels (namely, wind, solar, storage, and HVDC voltage source converters). The standard does not specify the utilization of these capabilities, leaving this to specific markets and jurisdictions. For example, IEEE 2800 specifies primary frequency response capability in terms of deadband and droop settings and response times; however, it does not specify keeping reserved headroom/legroom for provision of this response. For each of the requirements (see Figure 9), IEEE 2800 defines ranges of acceptable settings and default settings. It also specifies performance monitoring needs, modeling and model validation requirements, and the types of verifications needed, but does not detail procedures for the verification and model validation. These will be developed in IEEE 2800.2.

FIGURE 9



Source: Workshop presentation by A. Hoke, National Renewable Energy Laboratory.

Andy described that IEEE 2800 was developed by 175 industry experts over two years and was approved in April 2022 with over 90 percent participation from IEEE Standard Association balloters and a more than 94 percent approval rate. The goal of the standard is to have harmonized interconnection requirements across different regions and jurisdictions. The standard is, however, 100 percent voluntary, and does not take effect until it has been adopted by the by the entity that governs interconnection requirements in a given region. As was mentioned by Jens Boemer during Day 2 of the workshop, if adopted, these requirements will help to speed up generation interconnection and improve grid reliability.

Andy also pointed out potential conflicts between IEEE 2800 and the language proposed in the FERC NOPR related to ride-through requirement (as covered earlier by Jason MacDowell) and the modeling requirement.

IEEE 2800.2 is under development and will take a couple of years to develop and approve. In contrast to IEEE 2800, which is a standard whose requirements must be met, IEEE 2800.2 will be a recommended practice. The adoption of IEEE 2800 is not contingent upon the finalization of 2800.2, and it can be applied as soon as the entity is ready, based on existing verification methods already used in the industry. As presented by Stephen Solis and Brad Marszalkowski later in the workshop, this approach is being followed by ERCOT and ISO-NE, as they prepare to adopt some of the IEEE 2800 requirements in their areas.

Andy concluded by noting that the longer the industry waits to adopt IEEE 2800, the harder it will be, because it would mean increasingly high shares of legacy equipment on the grid that does not have capabilities needed for reliable operation of a high-renewables grid.

OEMs' and Developers' Views of IEEE 2800 Readiness

A panel of equipment manufacturers and developers discussed the topic of IEEE 2800 readiness. The panel participants were Lukas Meubrink from the solar and battery inverter manufacturer SMA; Samir Dahl from the wind turbine manufacturer Siemens Gamesa Renewables; Alex Shattuck from the wind turbine manufacturer Vestas; Sid Pant from GE Power Conversion, a manufacturer of all types of IBRs and HVDC VSCs; and Rajat Majumder from the large offshore-wind developer Orsted. The discussion was led by Manish Patel from Southern Company.

The first topic of discussion covered the challenges of designing equipment to IEEE 2800 requirements. The OEMs and developers on the panel unanimously saw a harmonized interconnection standard as a long-awaited and welcome change. Until now, there has been a lack of consistency across existing requirements, and individual requirements themselves can even be a moving target. There is also little guidance or consistency with post-event mitigations, causing many challenges for OEMs and developers alike. Rajat expressed the concern, supported by other OEMs throughout the discussion, that without having test procedures fully developed, conformity with IEEE 2800 is open to interpretation. However, he agreed that IEEE 2800.2 may not need to be finalized prior to the adoption of some IEEE 2800 requirements because existing procedures can be used in the interim.

Sid brought up the same point made by Jens Boemer from EPRI in his Day 2 presentation, that there may be a scope for guidance for equipment design and testing before 2800.2 is complete. During the question and answer session Brad Marszalkowski from ISO-NE mentioned that, currently, simulations are extensively used along with some limited commissioning testing and verification of plant settings to verify a plant's conformity with existing interconnection requirements. Stephen Solis from ERCOT countered that model-based performance validation is highly dependent on the model accuracy, and if the model does not reflect the reality or does not capture some of the inverter protection settings, the performance issues will be missed.

The next question was posed to OEMs. Manish asked about any hurdles to designing and self-certifying equipment that meets IEEE 2800 requirements. All OEMs on the panel agreed that without proper guidance from 2800.2, it is challenging for an OEM to self-certify, especially because IEEE 2800 applies at the point of interconnection and certifying OEM equipment alone does not guarantee plant conformity with IEEE 2800. However, the OEMs confirmed that most of the requirements in IEEE 2800 can already be met with existing state-of-the-art equipment, although a few requirements are more challenging and may have additional cost implications for equipment development and testing**.** During the question and answer period, participants specifically called out multiple-ride through, transient overvoltage, and reactive power provision at zero MW for wind generation as more challenging requirements.

Samir stated that some requirements are ambiguous, and self-certification may have infinite possibilities for testing in the absence of clear guidance from IEEE 2800.2. Sid added that in such cases, once IEEE 2800.2 is approved there may be a need to retest some equipment. Alex noted that while some requirements, such as response to a small voltage or frequency change, can be done in the lab with software in loop-type testing, other requirements call for hardware testing. However, there is a very limited number of testing facilities in the world suitable for hardware testing, and they have very busy schedules.

Another challenge discussed was equipment development cycles, which will lead to a time lag with implementation of any additional capabilities (to conform with IEEE 2800) in new equipment and a backlog of legacy equipment. For example, in wind turbines new capabilities will undergo a four-year development cycle until a product with these capabilities is market-ready. In addition, turbines are normally procured about two years prior to energization, and this again will result in a two-year backlog of legacy equipment. The same issue applies to "safe harbor equipment" (currently, there are wind turbines that were sold as early as 2016 that has not been energized yet). The adoption strategy for IEEE 2800 should consider grandfathering in equipment that has already been sold.

Lukas noted that SMA is planning to focus on IEEE 2800 requirements in developing its future equipment, in parallel with 2800.2 development. Having its engineers on the 2800.2 team will keep the company informed about what will be expected in order to demonstrate the conformity with IEEE 2800.

Manish asked whether it is possible in the short term to comply with a subset of requirements and not self-certify for ones that are more stringent or ambiguous. The OEMs again pointed out that that this could be possible but will require in collaboration between OEMs and developers so that the plant design can meet that subset of IEEE 2800 requirements at a point of interconnection.

The last question was in regard to educational opportunities. It was highlighted that there is a big difference in the understanding of transmission system needs between wind turbine OEMs and developers, who have been business for more than 20 years, and solar OEMs and developers, who have been interconnecting equipment at the transmission level for a shorter period of time. OEMs also have the opportunity to educate developers about the importance of compliance at the plant level, although system operators have a larger role to play providing education to developers because interconnection requirements are going to be mandated by them. ERCOT is a good example of collaboration around educational needs, having started an IBR task force in which the adoption of some IEEE 2800 requirements is being discussed, among other topics, and developers can start conversations with OEMs.

ISOs' Efforts to Adopt IEEE 2800

No entity has fully adopted IEEE 2800 yet, but ERCOT, ISO-NE, Southern Company, Florida Power and Light, and others are looking into adopting it either partially or in full. Two ISOs, ERCOT and ISO-NE, discussed their efforts around the adoption of IEEE 2800. In spring 2022, following several large disturbance events in West Texas, ERCOT was looking to improve its interconnection requirements and focused on IEEE 2800, which had just been approved. EPRI carried out a gap analysis on ERCOT's interconnection requirements and identified 13 gaps. Due to time constraints and given that IEEE 2800.2 is still under development, ERCOT is planning a partial adoption of IBR interconnection requirements related to three main priorities for ensuring the reliable operation of the ERCOT grid:

1. Requirement for provision of reactive support at zero active power output (for example, at night for solar power plants)
2. Adding details such as phase jump and transient overvoltage withstand thresholds to the ride-through requirements to address the issues observed in recent disturbances
3. Adding more details such as expected response times to the primary frequency response requirements.

In early 2022, ERCOT formed its Inverter-based Resource Task Force (IBRTF), which meets monthly to discuss the disturbance events, proposed mitigation plans, IEEE 2800, and proposed changes to ERCOT's requirements, as well as relevant industry updates to foster education and collaboration.

ISO-NE plans to develop minimum performance specifications for newly interconnecting IBRs using IEEE 2800. Similar to ERCOT, ISO-NE will pursue piecemeal adoption of this standard based on its need to enhance existing reliability requirements. Verification and testing procedures will be developed in conjunction with the development of or after the publication of IEEE 2800.2. In the interim, it will be deemed sufficient to have developer-provided verification and validation together with a conformity assessment currently performed by ISO-NE. This effort began in April 2022, with a strawman to be developed internally by September, the draft presented to stakeholders in fall 2022, and updated specs defined by the end of 2022. ISO-NE is currently updating its modeling procedures. ISO-NE is planning to have a grandfathering period for newly interconnecting resources.

Both ISOs consider the biggest challenge to be their inability to prove conformity with IEEE 2800 in the absence of the testing standard IEEE 2800.2. However, they believe that IEEE 2800 is a way to more quickly and reliably interconnect IBRs, because it provides a harmonized set of requirements across the country.

DOE's Interconnection Innovation e-Xchange (i2X) Initiative

The workshop concluded with an overview of DOE's new Interconnection Innovation e-Xchange (i2X) that was recently begun by its Wind Energy Technologies Office and Solar Energy Technologies Office for a duration of four years.[23] This initiative recognizes the complexity of the interconnection process driven by zero-carbon future goals, the rapid grid transformation involved, and the number of stakeholders and processes involved. The project kicked off with several interconnection workshops conducted by both offices to understand concerns and challenges of all stakeholders involved in the interconnection process. As a result of these workshops, the interconnection process was divided into a number of milestones and challenges to be addressed. This, in turn, informed the roadmap developed by DOE to examine these areas and offer solutions.

Cynthia Bothwell from the Wind Energy Technologies Office described the mission of the i2X initiative as to enable simpler, faster, and fairer interconnection of wind and solar resources while boosting the reliability, resilience, and security of the grid. She discussed four pillars that form the foundation of the program:

- To convene diverse stakeholders involved in the interconnection of solar, wind, and energy storage resources (government, utilities, grid operators, nonprofits, for-profits) through a number of working groups by region, by sector, and by topic
- To support data collection and transparency, and the development of meaningful metrics for transmission and distribution grids (for example, Lawrence Berkeley National Laboratory's analysis of generator interconnection queues, and more)
- To provide access to various interconnection technical assistance opportunities to support the partners in their implementation of developed reforms: implementing queue management methods, accelerated tool development and deployment, and direct access to interconnection experts, best practices, and training
- To develop a five-year Strategic Interconnection Roadmap

Interested parties can get involved by visiting the i2X website https://www.energy.gov/eree/i2x, joining the partnership, and participating in upcoming events, including "interconnection office hours" offered by i2X project leadership. The initiative already has 570 individual partners representing many organizations.

Tom McDermott from Pacific Northwest National Laboratory provided a deeper dive into the five-year Strategic Interconnection Roadmap, describing its goal of seeing a 50 percent reduction in cost and 50 percent reduction in schedule for interconnecting resources in five years without negatively impacting grid resilience and reliability. The outline of the roadmap has begun and a draft is expected in March 2023. The team includes the Wind Energy Technologies Office and Solar Energy Technologies Office at DOE and three national labs, the Pacific Northwest National Laboratory, Lawrence Berkeley National Laboratory, and National Renewable Energy Laboratory. The baseline for the roadmap will be built around the FERC NOPR and the final order, and also work on additional improvements to the interconnection process and its efficiency. The roadmap will cover data collection plans, sprint studies (fast development and testing of improvements to the interconnection process), models, pilots possible

[23] U.S. Department of Energy, Interconnection Innovation e-Xchange, https://www.energy.gov/eere/i2x/about-interconnection-innovation-e-xchange-i2x.

within FERC regulations, gaps in standards, regulations, and policies, as well as yearly targets and metrics. Technical interconnection study guides for transmission and distribution will be developed as a part of the roadmap but referenced as a separate document.

Conclusion

To conclude this summary, some of the key messages from the workshop are given below:

- **Integrating generation interconnection processes with transmission planning processes can move the industry toward more optimized least-regrets, scenario-based, proactive, cost-effective, multi-value transmission solutions**, an approach that can address the wide range of future needs, facilitate competition, and reduce the costs and time necessary to interconnect low-cost, low-carbon generation.

- **Cost allocation does not need to dictate the design of the process or be a barrier to the process improvements**. If we arrive at a cost-effective, integrated generator interconnection and transmission planning methodology, a cost allocation methodology can be developed**.** Recent initiatives presented at the workshop offer possible solutions.

- **System impact studies need to align better with project development timelines to ensure that reliability studies are carried out with models reflective of the equipment as will be installed in the field.** This will increase the value of these studies and benefit the reliability of the power system. Carrying out stability assessment later in the interconnection process is recommended.

- While **hosting capacity maps** proposed by the FERC NOPR **are helpful**, **information about short circuit strength and harmonics** at prospective points of interconnection would further help to reduce iterations of project design.

- Further **model improvements and improvements to model validation processes are needed** to ensure that models are reflective of the equipment in the field and include controls and protective functions relevant for studied phenomena. **All types of models need proper validation and parametrization, and the appropriate type of models should be used for the appropriate studies.**

- **Widespread disturbance events are not a technology issue per se** but are rather **due to a lack of comprehensive interconnection requirements and conformity assessment** before, during, and after projects' commissioning.

- **The equipment manufacturers and developers** who participated in the workshop **welcome the effort to harmonize interconnection requirements in the form of the IEEE 2800 standard**, as it provides certainty, provides cost-efficiency, and improves grid reliability.

- **State-of-the art equipment already has the majority of the capabilities required by IEEE 2800;** however, **there are requirements for some capabilities that are more challenging to develop and test in their equipment** ahead of IEEE 2800.2, which is currently under development.

- **Some ISOs**, including ISO-NE and ERCOT, **have already started the piecemeal adoption of IEEE 2800 to address high priority gaps in their existing interconnection requirements**. Wholesale adoption of this standard is also possible, both now and, especially, at a later stage once IEEE 2800.2 becomes available.

- **Tight collaboration between developers, OEMs, and grid operators is needed** to ensure conformity of new plant design with applicable standards and interconnection requirements, to share necessary data and models in a timely manner, and to reduce the number of interconnection study iterations, while ensuring reliable interconnection and efficient use of engineering time.
- ESIG's Reliability Working Group, NERC's Inverter-based Resource Performance Subcommittee, the IEEE 2800.2 Working Group, and the NERC Reliability Standard Drafting Teams are great **resources for education and collaboration**.
- **The recently launched DOE i2X initiative will convene a broad range of industry stakeholders to enable simpler, faster, fairer interconnection** of wind and solar resources while boosting the reliability, resilience, and security of the grid.

Summary of the Joint Generator Interconnection Workshop

August 9-11, 2022

This workshop summary is available at
https://www.esig.energy/reports-briefs2/

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at info@esig.energy and https://www.esig.energy/

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