INTERCONNECTION INNOVATION e-XCHANGE
U.S. DEPARTMENT OF ENERGY

Queue Management & Cost Allocation
Interconnection Studies (BPS) | 7/12/23

An initiative spearheaded by the Solar Energy Technologies Office and the Wind Energy Technologies Office

Meeting Notes

Notes synthesizing keys points, insights and questions from the meeting can be found here: Box Link

The first half of this Teams call is being recorded and may be posted on DOE's website or used internally. If you do not wish to have your voice recorded, please do not speak during the call. If you do not wish to have your image recorded, please turn off your camera or participate by phone. If you speak during the call or use a video connection, you are presumed consent to recording and use of your voice or image.

Agenda

- Introduction to i2X Solution e-Xchanges (5 min)
- Stakeholder Presentations (45 min)
  - Impact Study Assumption and Criteria – EPE
  - Interconnection Study Improvements – EPRI
  - Transmission Options – Smart Wires
  - Affected System Studies and JTIQ Study – SPP
- Interactive Group Discussion (70 min)
  - Interconnection Studies Assumptions & Criteria
  - Updating Study Processes
  - Transmission Upgrade Options
  - Affected System Studies

Interconnection Innovation e-Xchange (i2X)

Mission: To enable a **simpler**, **faster**, and **fairer** interconnection of clean energy resources while enhancing the **reliability**, **resiliency**, and **security** of our **distribution and bulk-power electric grids**

Stakeholder Engagement

Nation-wide engagement platform and collaborative working groups

Data & Analytics

Collect and analyze interconnection data to inform solutions development

Strategic Roadmap

Create roadmap to inform interconnection process improvements

Technical Assistance

Leverage DOE laboratory expertise to support stakeholder roadmap implementation

Key Outcomes from Our e-Xchange Meetings

- Inform and formulate a ***publicly available***, strategic roadmap for interconnection
    - Topical challenges and issues
    - Practical solutions to implement and scale
    - Knowledge and data gaps and new solutions to pilot
    - Success goals and measures of success

- Summary documentation for each meeting regarding ideas discussed and opportunities for targeted stakeholder action

- Provide platform for ongoing engagement before and after meetings

- **Longer term vision →** Solution e-Xchanges to continue building a national forum for all stakeholders as a community of practice, excellence, and innovation

Key Themes from 6/7 Meeting on BPS Cost Allocation

- Mix of perspectives whether participant funding should be unchanged, reformed, or eliminated, though there appear to be opportunities to make changes in transmission planning and interconnection that would improve cost allocation outcomes
- Overall concern that, ultimately, end users (ratepayers) bear the costs of interconnection and discussion of cost allocation needs to acknowledge that ultimate choice is not solely about who pays but also how to manage incentives to minimize overall system costs
- Some interest in allowing generators to be able to connect to transmission system without upgrades via energy-only interconnection, in areas where not already possible, though currently many developers are selecting capacity interconnection
- Less interest in making major changes to current generator cost sharing mechanisms
- Proactive planning related to affected systems remains attractive, MISO/SPP JTIQ initiative is key model

Review a more detailed notes document here:
https://app.box.com/s/n60l9pdqpjdc5l3jckguq538wofqgxin

Upcoming Solution e-Xchanges to Consider Joining

1. July 19, 2-4 p.m. ET: Collecting and Considering EEJ Feedback in Public Policy
2. July 20, 2-4 p.m. ET: Scaling the Interconnection Workforce: Identifying the Growth Needs and the Challenges with Hiring, Retention, and Training
3. July 26, 2-4 p.m. ET: DER Interconnection implantation planning and agreements
4. August 2, 2-4 p.m. ET: Defining Distribution, Sub-transmission, Transmission, and the Bulk System for Interconnection

Follow the schedule of events on the i2X website.

https://www.energy.gov/eere/i2x/i2x-solution-e-xchanges

Virtual Meetings Code of Conduct

1. *Assume good faith and respect differences*
2. *Listen actively and respectfully*
3. *Use "Yes and" to build on others' ideas*
4. *Please self-edit and encourage others to speak up*
5. *Seek to learn from others*

Mutual Respect . Collaboration . Openness

Introduction of Stakeholder Presentations

Interactive Group Discussion Topics

Topic #1: Interconnection Studies: Methodologies/Assumptions/Criteria – Background

Today

- Different study years
- Study snapshots based on hours that historically been considered high risk
- Different dispatch assumptions for:
  - existing generation
  - new gen
  - generator rebalancing
- Different criteria to identify need for upgrade
- No assessment of frequency and duration of violations in a study year and beyond

Future

- Study years coordinated with transmission planning years
- Study snapshots, based on highest risk hours in a planning year
- Harmonized dispatch assumptions for:
  - existing gen
  - new gen in each study snapshot
  - generator rebalancing approaches
- Harmonized criteria to identify need for upgrade
- Assessment of frequency and duration of violations in a study year and beyond

Topic #1: Interconnection Studies: Methodologies/Assumptions/Criteria

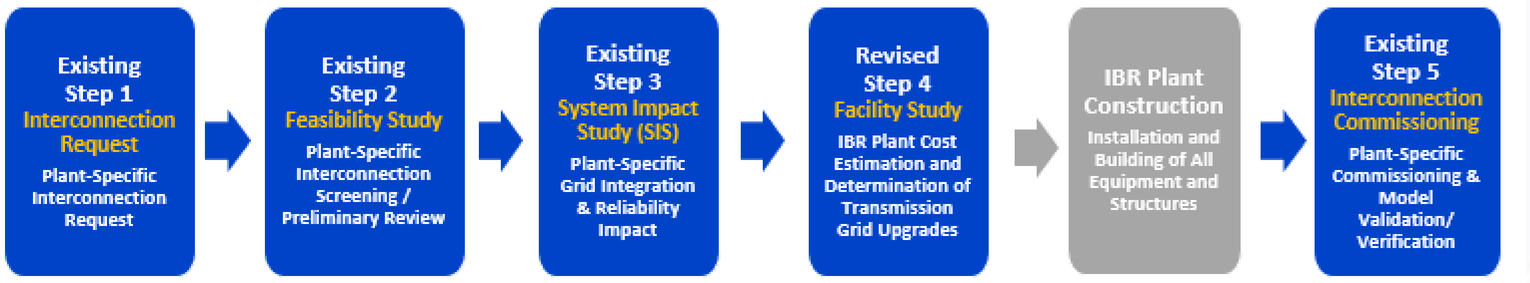
- Can/Should dispatch assumptions, study methodologies, and study criteria be harmonized?
  - What are the reasons for differentiating study methodologies, assumptions, criteria across the U.S.?
  - Will harmonized set of methodologies, assumptions, criteria help improve and streamline interconnection process?
  - How should these assumptions/methodologies/criteria be developed?
  - Is it possible/beneficial to include production cost simulation runs for the study year into the interconnection study to inform generation dispatch for system impact study snapshots and assess frequency and duration of violations?

For verbal commentary, please use the raise hand feature and we will call on you

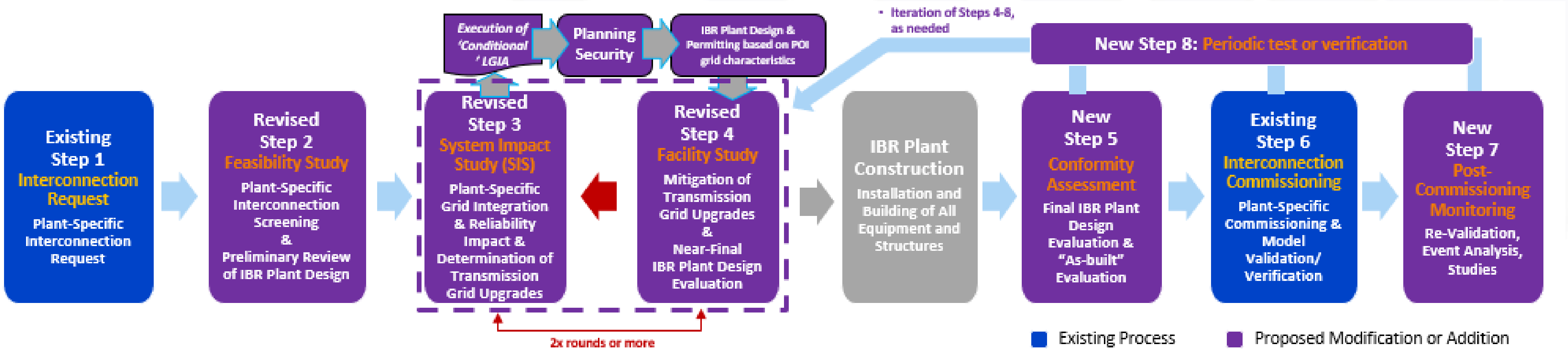
To make a written comment, please go to the slido poll: **slido.com** and enter event code **i2x12**

Topic #2: Updating Study Processes to Ensure Reliability– Background

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



Recommended Improvements to the Interconnection Process



Topic #2: Updating Study Processes to Ensure Reliability

- Do we need to improve the impact assessment of generators during the interconnection study process to ensure reliability?
  - How to ensure that interconnection studies are done with validated plant models reflective of a plant as will be built in the field?
  - Are there ways of improving quality/rigor of reliability assessment without further prolonging interconnection process?
  - Could separating steady-state and stability study steps help to improve and speed up interconnection process?
  - Would having a set of harmonized interconnection requirements help to streamline interconnection studies?

For verbal commentary, please use the raise hand feature and we will call on you

To make a written comment, please go to the slido poll: **slido.com** and enter event code **i2x12**

Topic #3: Transmission Upgrade Options – Background

- A variety of technologies offer potential alternatives to standard network upgrades that can be deployed both quicker and at lower costs, e.g.:
  - Advanced power flow control devices,
  - Transmission switching,
  - Dynamic line ratings,
  - Static synchronous compensators and static volt-ampere reactive (VAR) compensators,
  - Electric storage in specific use cases
  - Plant control parameter tuning.
- Current generation interconnection process does not require transmission providers to consider such alternatives
- FERC NOPR proposed to require transmission providers, upon request of the interconnection customer, to evaluate the requested alternative transmission solution(s) during the system impact study and facilities study within the generator interconnection process

Topic #3: Transmission Upgrade Options – Examples

Example #1: 600 MW CC in PJM interconnecting at a 345 kV substation	
Interconnection Problem	Violation of transient stability criteria
PJM proposal	• Two 56-mile Byron-Wayne 345 kV Lines. **Cost $210M** • 33-mile Nelson-Byron 345kV Line. **Cost: $70M**
Proposed developer solution	Replace one 345kV breaker and update relaying at 345kV substation to achieve faster fault clearing times to mitigate transient stability issue. **Cost $2.3M**
Outcome / Conclusion	Accepted by PJM

Example #2: 340 MW wind in NYISO interconnecting at a 345 kV substation	
Interconnection Problem	Thermal degradation of PJM – NYISO Interface Transfer Capability. Overload of East Towanda – Hillside 230kV line (33 miles).
NYISO proposal	498/574/653 MVA Phase Angle Regulator (PAR) **Cost: $24M**
Proposed developer solution	Power flow control device (SmartValve) that could have reduced the cost compared to the PAR.
Outcome / Conclusion	NYISO successfully identified a non-wire solution (the PAR) instead of rebuilding an existing 33-mile line. But, did not accept the Smartvalve, due to lack of familiarity with the technology.

Topic #3: Transmission Upgrade Options

- What upgrade options should be evaluated within the interconnection study methods?
  - Discuss the pros and cons of assessing alternative transmission technologies within the interconnection study process (e.g. dynamic line rating, power flow control, controller tuning etc.)
  - What are the main barriers for evaluating alternative transmission technologies in the interconnection process?
  - What can be done to improve and streamline evaluation of alternative transmission technologies during the interconnection process?

For verbal commentary, please use the raise hand feature and we will call on you

To make a written comment, please go to the slido poll: **slido.com** and enter event code **i2x12**

Topic #4: Affected System Studies – Background

Today

- Lag behind the host system studies
- Causing interconnection process delays
- Causing prolonged cost uncertainty for the developers
- May drive late withdrawals and need for re-studies (both in host and affected systems)
- Suffer from similar gaps as the host system interconnection studies, i.e. differences in study methodologies, dispatch assumptions, criteria etc.

Future

- Coordinated set of modeling procedures, tools and data amongst neighbor systems
- Combined host and affected systems studies
- Consistency of study methodologies, dispatch assumptions, criteria etc.
- Standardized framework for affected system studies consistent with that for host systems.
- Supported by joint interregional planning efforts

Topic #4: Affected System Studies

- What limits effective coordination on performing affected system studies?
  - Would a standardized framework (e.g. methodologies, assumptions, criteria) for affected system studies improve interconnection process?
  - Can efficiency be gained by combining host and affected systems studies? What are pros and cons of this approach?
  - Is inability to control the studied generator output driving transmission upgrade needs in affected systems? Can these issue be addressed by improving congestion management?
  - Why don't affected system studies focus on energy-only service?
  - Can periodic joint transmission planning between neighboring regions help address some of the affected systems issues?

For verbal commentary, please use the raise hand feature and we will call on you

To make a written comment, please go to the slido poll: **slido.com** and enter event code **i2x12**

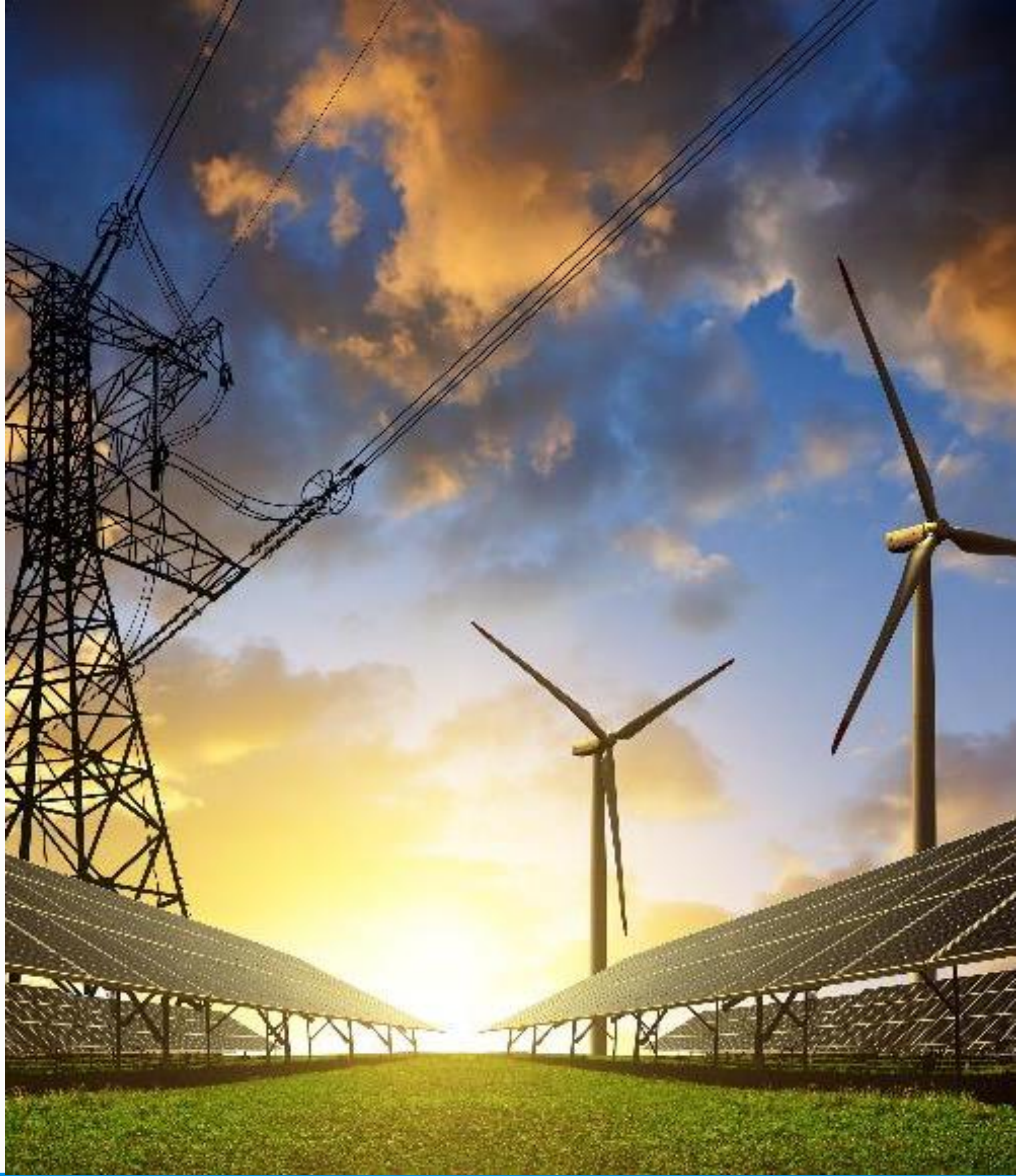
Cost Allocation and Study Assumptions Focusing on Thermal Studies

Presented by: Horea Catanase & Kalyan Chilukuri

12th of July 2023

INTERCONNECTION INNOVATION e-XCHANGE
U.S. DEPARTMENT OF ENERGY

ELECTRIC POWER ENGINEERS



Agenda

Part 1 Horea & Kalyan BIOs

Part 2 Terminology and Definitions

Part 3 ISO Comparison: Queue Processing, Cases & Analysis

Part 4 ISO Comparison: Cost Allocation

ELECTRIC POWER ENGINEERS

Horea & Kalyan BIOs

https://www.linkedin.com/in/horeacatanase/
hcatanase@epeconsulting.com

Electric Power Engineers
Permanent Full-time · 1 yr 7 mos

- **Associate Director - Energy Resources Integration and Interconnection**
  Jul 2023 - Present · 1 mo
  EPE is a leading power engineering consulting firm offering expertise in power system planning, design, and grid integration in North America and international markets.... ...see more
- **Senior Manager - Energy Resources Integration and Interconnection**
  Jul 2022 - Jul 2023 · 1 yr 1 mo
- **Manager - Energy Resources Integration and Interconnection**
  Jan 2022 - Jul 2022 · 7 mos

PSC - Power Systems Consultants
Permanent Full-time · 3 yrs
Vancouver, British Columbia, Canada

- **Team Lead - System Studies**
  Mar 2021 - Dec 2021 · 10 mos
  PSC is an independent global consulting organization providing solutions and expertise to the energy industry. ... ...see more
- **System Studies Consultant III & Account Lead**
  Jun 2020 - Mar 2021 · 10 mos
- **System Studies Consultant I & Project Manager**
  Jan 2019 - Jun 2020 · 1 yr 6 mos

Power Systems Studies Engineer
ESB International
Sep 2017 - Dec 2018 · 1 yr 4 mos
Ireland
ESB International is a leading engineering consultancy firm to the power industry. It has a large global footprint, having completed projects in 120 countries since their establishment. ESB International is wholly owne ...see more

https://www.linkedin.com/in/kalyanchilukuri/
Kchilukuri@epeconsulting.com

VP - Energy Resources
Electric Power Engineers, Inc · Permanent Full-time
Dec 2021 - Present · 1 yr 8 mos
Vancouver, British Columbia, Canada
Lead Generation, Merchant Transmission and Load services.
Skills: Renewable Energy · Business Strategy · Sales · Recruiting · Leadership · Business Development

General Manager - Power Networks NA
PSC - Power Systems Consultants
Oct 2019 - Nov 2021 · 2 yrs 2 mos
Vancouver, Canada Area
PSC helps utilities and energy companies overcome the challenges of a rapidly changing industry by providing independent consulting and engineering solutions that allow them to innovate and thrive.... ...see more
Skills: Renewable Energy · Business Strategy · Sales · Recruiting · Leadership · Business Development

PSC - Power Systems Consultants
6 yrs 7 mos

- **Technical Lead - Power Networks NA**
  Nov 2017 - Apr 2019 · 1 yr 6 mos
  Greater Boston Area
  - Accountable for project delivery and client engagement for PSC NA - Power Networks group.
  - Technical lead for generation and transmission interconnection studies - Focus on PJM, ISO-NE and ...see more
  Skills: Renewable Energy · Business Strategy · Sales · Leadership · Business Development
- **Sr Engineer**
  Aug 2015 - Nov 2017 · 2 yrs 4 mos
  Greater Boston Area
  - Project delivery and client engagement management
  - Technical lead for generation and transmission interconnection studies, focus on PJM, ISO-NE and N ...see more
  Skills: Renewable Energy · Sales
- **Power Systems Engineer**
  Oct 2012 - Aug 2015 · 2 yrs 11 mos
  Wellington, NZ and Brisbane Area, Australia
  - Generator and transmission interconnection studies
  - Harmonics and power quality studies... ...see more
  Skills: Renewable Energy

ELECTRIC POWER ENGINEERS

Terminology & Definitions

ELECTRIC POWER ENGINEERS

Serial vs Cluster Interconnection Queues

- Serial Interconnection – This typically involves studying queue projects on a first-come first served basis. Each project is normally studied individually based on the time of the request and is typically dependent on prior interconnection requests and the outcome of their studies.

- Cluster Interconnection – This refers to the process of "clustering" a group of interconnection requests which will be studied together instead of serially. Typically, ISOs/RTOs and Utilities which have a cluster interconnection queue will have a "queue window" and all projects which apply in the same window will be studied together.

ERIS & NRIS

- Energy Resource Interconnection Service (ERIS) shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service

- Network Resource Interconnection Service (NRIS) shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

https://www.ferc.gov/sites/default/files/2020-04/LGIP-procedures_0.pdf

Fuel Based Dispatch & Flowgate Screening

- Fuel Based Dispatch – Resource are dispatched at predefined levels based on technology type and the load levels of cases used (e.g. wind resources will be dispatched at different levels compared to solar resources depending on the season and loading level of the case used)

- Flowgate Screening – Dynamic dispatch whereby generators are re-dispatched in order to overload a flowgate (monitored element / contingency pair). Several methods available (harmers to reference, harmers to helpers, etc).

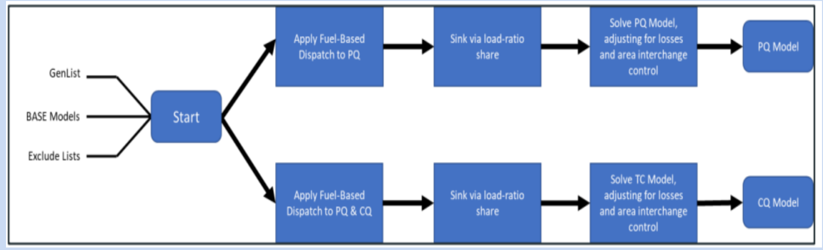
ISO Comparison

Queue Processing, Cases & Analysis

ELECTRIC POWER ENGINEERS

**Changes will happen under new process

Queue Processing, Cases & Analysis

	SPP	MISO	PJM**	ISO NE
Queue Type	Cluster	Cluster	Used to be serial but adopted a cluster-based approach post transition	Primarily serial, however ISO may decide to cluster requests
Cases Used	Light Load, Summer Peak & Winter Peak HVER | LVER | NR Cases	Summer Peak and Shoulder	Summer Peak and Light Load	Peak, Shoulder, Light and Minimum and yearly FCA cases for capacity (CRIS) requests.
Case Development	ERIS and NRIS Cases are both developed based utilizing the ITP models as a starting point. Models are dispatched in accordance with fuel-based dispatch tables. Both Prior Queued (PQ) and Current Queued (CQ) projects are dispatched in accordance with these tables 	**ERIS Cases** Bench Case (pre-cluster) – existing generators and generators with signed IA dispatched based on MTEP 5 year out LBA dispatch Study Case (post-cluster) based on bench case with study generators dispatched based on fuel type **NRIS Case** Based on ERIS model with upgrades included. ERIS only generators turned off and NRIS generation set to at least pgen = 0. Algorithm ramps up generators based on flowgate screening.	Based on RTEP cases, study generators are typically ramped up by the algorithm based on the flowgate screening methodology.	**ERIS** Typically, pre-project and a post-project cases are developed and stresses on nearby interfaces are applied to create onerous conditions. Cases will typically include all relevant prior queued requests in the area. **CRIS** Yearly case developed by ISO NE for each FCA – these are posted on ISO NE's website.

ELECTRIC POWER ENGINEERS

**Changes will happen under new process

Analysis

	SPP	MISO	PJM**	ISO NE
Analysis Performed	Run NERC TPL -001 (P0, P1, P2, P4, P5, P7) contingencies on all PQ and CQ cases and cross compare results. Any system constraints that are exacerbated in the CQ models will have to be mitigated if they meet criteria, regardless if the equipment was constrained in the PQ models.	**ERIS Analysis** Run NERC TPL -001 (P0, P1, P2, P4, P5, P7) contingencies on bench and study cases and cross compare results to determine necessary upgrades. Criteria for cost allocation is discussed in the next section **NRIS Analysis** The analysis is based on the flowgate screening approach: ->Dynamic dispatch for each flowgate (monitored element / contingency pair) to identify worst possible dispatch. Top 30 list is created with 8000 MW cap is used and a 5% DFAX Cutoff ->P0 and P1 contingencies only ->Adders are turned on and dispatched if they meet criteria	The analysis is based on the flowgate screening approach: ->Dynamic dispatch for each flowgate (monitored element / contingency pair) to identify worst possible dispatch ->Harmer generators are ramped up while the rest of the generators in the PJM system are uniformly dispatched down ->Adders are turned on and dispatched if they meet criteria ->Selection criteria is based on DFAX and availability of harmer generators (1- EEFORd) Single contingencies (P1) as well as common mode outages (P2, P4 and P7 contingencies are considered.	**ERIS** Perform N-1 and N-1-1 contingency analysis on the pre-project and post project stressed cases **CRIS** Group study based on a flowgate screening approach.

ISO Comparison

Cost Allocation

ELECTRIC POWER ENGINEERS

Cost Allocation

	SPP	MISO	PJM	ISO NE
Cost Allocation	Based on MW impact. This is calculated by multiplying the system intact DFAX on new upgrade with the MW request. Wind projects are cost allocated for Network Upgrades using the light load model. All others are cost allocated for Network Upgrades using the summer peak model. Cost allocation criteria below: **ERIS** i. DFAX ⩾20% under contingency conditions or ⩾3% under system intact ii. MW impact of al CQ requests ⩾20% of facility rating and study project project DFAX⩾5%. **NRIS** i. DFAX ⩾3% under system intact and contingency	Based on MW impact if queue project meets criteria: **ERIS** i. iDFAX ⩾20% under contingency conditions or ⩾5% under system intact ii. If LRTP projects included DFAX > 10% under contingency conditions or DFAX > 5% under system intact. iii. The overloaded facility or the overload-causing contingency is at generator's outlet, or iv. If the first 3 criteria not met and the total MW and MW impact of entire group ⩾20% of facility rating and study project MW impact ⩾5% of facility rating as well as project DFAX⩾5%. **NRIS** 5% DFAX cutoff	Based on MW impact if queue project meets criteria: i. MW impact > 5MW and 1% Rating Increase (RI) or DFAX > 5% and 3% RI. Contribution is determined by voltage level as follows: • 5% DFAX or 5% RI for facilities below 500 kV & 10% DFAX or 5% RI for facilities over 500 kV ii. If no queue projects meet the thresholds, all non-zero contributors are pooled. If cumulative impact > 1% of the rating, projects with contribution > 0.25% of rating will share cost . If no projects meet this, the 5 highest contributors in the pool will receive some cost allocation.	**ERIS** N-1: 2% difference between pre and post project case and at least a 2% overload above appropriate rating (normal for all lines in service and LTE for contingency) . N-1-1 Analysis: intent is to document restrictions project may be subjected to. Check that no more than 1200 MW is required to re-secure the system between first and second contingency Generator redispatch may be used to mitigate observed overloads. **CRIS** List of new and exacerbated overloads will be created based on below thresholds Study generator will be responsible for recorded overloads if it has at least a 3% DFAX or 3% impact. i. Overload > 10 MVA above thermal limit ii. Overload ⩾2% above thermal rating iii. Transfer above the interface transfer capability

ELECTRIC POWER ENGINEERS

Need for Plant-Level Conformity Assessment in Interconnection Process

And Potential Use Cases for a Generic EMT Model Conforming with IEEE 2800-2022

Jens C. Boemer, Technical Executive

i2X Solution e-Xchange-Queue Management & Cost Allocation: Improving Interconnection Study Methodologies in the Bulk Power System

July 12, 2023

Classification: public

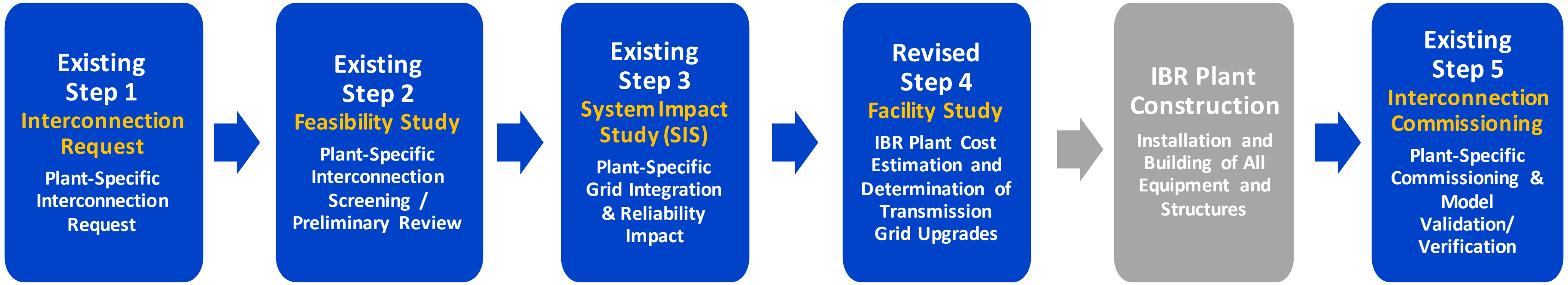
www.epri.com

Acknowledgements and Disclaimers

- EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. **EPRI does not provide recommendations or regulatory advice related to the contents of this presentation.** EPRI reserves the right to submit comments to ongoing and future FERC solicitations related to the contents of this presentation and these comments may or may not be identical to the content presented here. **All comments provided reflect only the view of the EPRI technical experts** performing the review and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development.
- **The views presented in this presentation are the personal views of the individuals presenting it and shall not be considered the official position of the IEEE Standards Association** or any of its committees and shall not be considered to be, nor be relied upon as, a formal position of IEEE, in accordance with IEEE Standards Association Standards Board Bylaws 5.2.1.6. The content on IEEE-2800-2022 presented here is adapted and reprinted with permission from IEEE. Copyright IEEE 2022. All rights reserved. Some content presented here is based on an unapproved proposed IEEE Standard (e.g., IEEE P2800.2). As such, the document are subject to change, any draft requirements and figures shown in this presentation may change.
- Part of this work was **supported in part by the National Renewable Energy Laboratory**, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office and Wind Energy Technologies Office. Part of this work is **supported by the U.S. Department of Energy, Solar Energy Technologies Office** under Award Number DE-EE0009019 Adaptive Protection and Validated MODels to Enable Deployment of High Penetrations of Solar PV (PV-MOD). The views expressed in the presentation do **not necessarily represent the views of the DOE or the U.S. Government**.

Status Quo

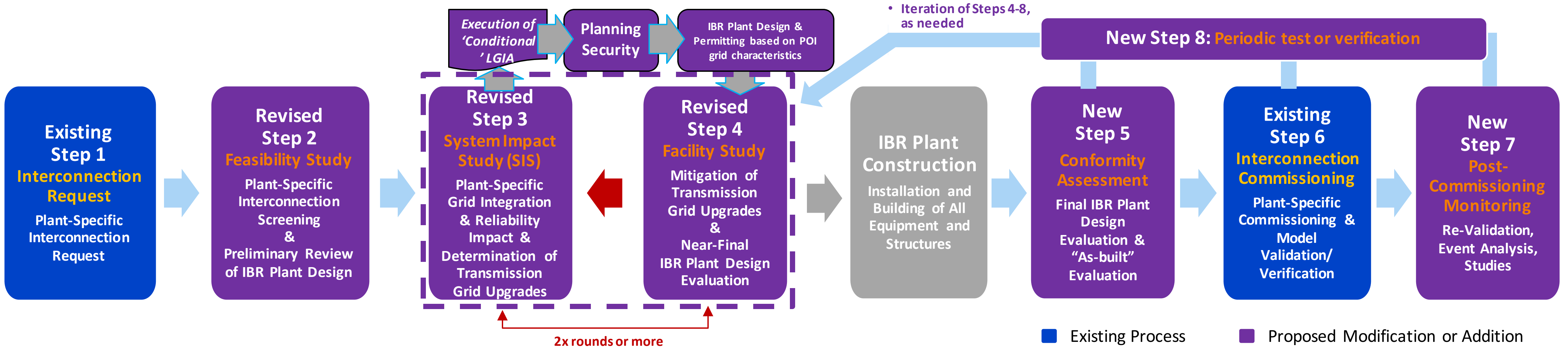
Existing Interconnection Procedure as shaped by the FERC Large Generator Interconnection Process



Further Reading:
J. Boemer, A. Shattuck, J. Matevosyan, "*Need for North American Interconnection Process Review*", ESIG Blog Article, December 13, 2022.

One Possible Future

Recommended Improvements to the Interconnection Process



Further Reading:
J. Boemer, A. Shattuck, J. Matevosyan, "*Need for North American Interconnection Process Review*", ESIG Blog Article, December 13, 2022.

EPRI's Generic EMT Model Conforming with IEEE 2800-2022

Model Specification

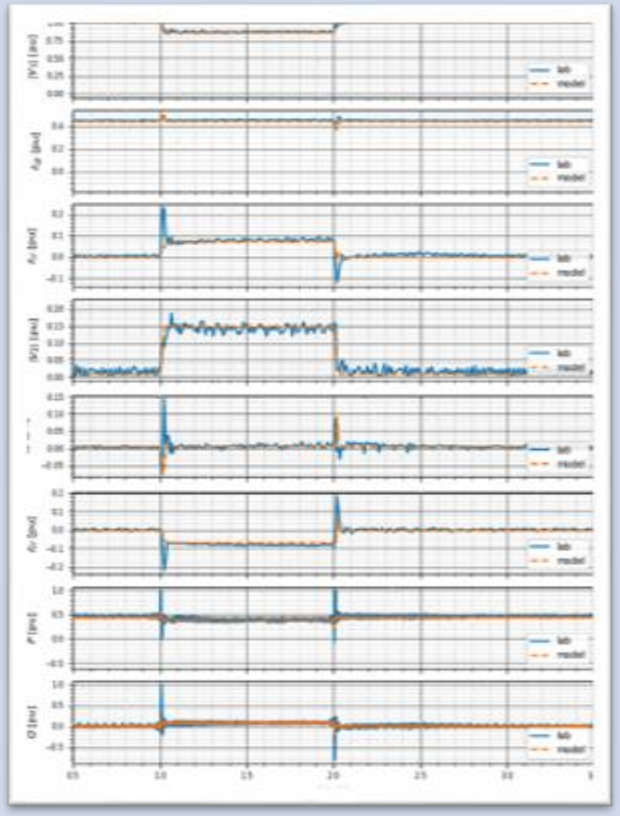
- *Generic Photovoltaic Inverter Model in an Electromagnetic Transients Simulator for Transmission Connected Plants: PV-MOD Milestone 2.7.3.* EPRI, Palo Alto, CA: 2022.

Model Prototype

- *PRE-SW: Generic Photovoltaic Inverter Model in an Electromagnetic Transients Simulator for Transmission Connected Plants (PVMOD-EMT-IBR) v1.0 Beta.* EPRI, Palo Alto, CA: 2023. 3002025889

Model Validation

- Report forthcoming



Public availability; developed in the PV-MOD Project: https://www.epri.com/pvmod*
*supported by DOE, NERC, and EPRI members

Potential Use Cases for a Generic EMT Model Conforming with IEEE 2800-2022

- Awareness of **IEEE 2800-2022 as technical minimum requirements**
  - **Education** to facilitate interaction between utility and IBR developer
- **Study the range of capabilities** IBRs conforming with IEEE 2800 have
  - Investigate and screen for **how to best utilize** the IBR capability for a specific system

Revised Step 2 Feasibility Study

- **Screen for additional capabilities** that can potentially provide improved benefit with high IBR systems
  - Investigate **what additional requirements to require** beyond and above IEEE 2800

Revised Step 3 System Impact Study (SIS)

- **Produce a reference response** for IBRs conforming with IEEE 2800
  - Assess **conformity of IBR plant** by comparison of *verified* IBR plant model* with reference response

New Step 5 Conformity Assessment

*** Important terms per conformity assessment steps in IEEE P2800.2:**

verified IBR plant model = *validated* IBR unit and supplemental IBR device models + design evaluation + *as-built* and *as-configured* IBR plant evaluation

EPRI's Comments to FERC NOPRs No. RM22-12 (IBRs Reliability Standards) and No. RM22-14 (Interconnection Process)

- EPRI recommends the **adoption of IEEE Standards like 2800-2022** to set clear expectations for IBRs' technical minimum capabilities.
  - Supported—to a different extent—by 7 other entities, including NERC, CAISO, SPP, ACP, SEIA, AEU, NYSRC, AEP, PUCO.
- EPRI recommends **all models** should be **validated** and **appropriately parameterized**; modeling as a method for **pre-commissioning conformity assessment**.
- To include **comprehensive** and holistic **ride-through capability and performance requirements** instead of explicitly mentioning causes of trips (i.e., loss of PLL synchronism) or causes of slow recovery (i.e., slow ramp rate)

https://ieeexplore.ieee.org/browse/standards/reading-room/page

- IEEE makes selected standards publicly available:
  - Standards are available in recognition of their incorporation by reference in the U.S. Code of Federal Regulations (CFR)
  - Standards in the Reading Room are available in "view only" format to anyone who registers with a **free-of-charge** IEEE account
  - If FERC ruled with a reference to IEEE 2800-2022, the standard would be made public

181 FERC ¶ 61,125
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM22-12-000]

Reliability Standards to Address Inverter-Based Resources

(Issued November 17, 2022)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to develop new or modified Reliability Standards that address the following reliability gaps related to inverter-based resources (IBR): data sharing; model validation; planning and operational studies; and performance requirements. Further, the Commission proposes to direct NERC to submit to the Commission a compliance filing within 90 days of the effective date of the final rule in this proceeding that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the Commission within 36 months of Commission approval of the plan.

EPRI's comments on Generation Interconnection NOPR (RM22-14): https://www.epri.com/research/products/000000003002025703
EPRI's comments on IBRs' Reliability Standards NOPR (RM22-12): https://elibrary.ferc.gov/eLibrary/filedownload?fileid=C8BEC1F9-05AE-CD0A-936F-862891800000

EPRI


Together…Shaping the Future of Energy®

Status Quo

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

Existing Step 1
Interconnection Request
Plant-Specific Interconnection Request

Existing Step 2
Feasibility Study
Plant-Specific Interconnection Screening / Preliminary Review

Existing Step 3
System Impact Study (SIS)
Plant-Specific Grid Integration & Reliability Impact

Revised Step 4
Facility Study
IBR Plant Cost Estimation and Determination of Transmission Grid Upgrades

IBR Plant Construction
Installation and Building of All Equipment and Structures

Existing Step 5
Interconnection Commissioning
Plant-Specific Commissioning & Model Validation/ Verification

Step 1:
- **Insufficient**, diverse, or vague RTO/ISO/TP's technical interconnection requirements (**TIRs**)
- Submission of **any available models,** often **inappropriately configured**
- **Vague model 'acceptance criteria'**

Step 2:

Limited screening for:
- Grid strength metrics (neither conventional nor advanced)

that could help determine **whether at all, and what type of models and system impact studies** would be needed to reliably connect the IBR.

Step 3:
- System impact studies often use **insufficient and invalid models** that may **not** be **site-specific** and **may be configured with generic** parameters
- May **not represent** IBR units, supplemental IBR devices, and **the IBR plant design** ultimately commissioned in the field

Step 4:
- **No common assessment of IBR plant-level conformity** with regard to RTO/ISO/TP's technical interconnection requirements (TIRs)
- Detailed **IBR plant design may change** after Interconnection Agreement (IA) is executed

IBR Plant Construction:
- What is built in the field does often not match what had been previously studied/modeled
- **No "as-built" plant-level evaluation**

Step 5:
- Only a (limited) set of field tests are performed to validate/verify IBR plant model.
  - Limited to small-signal disturbances.
  - Often **no verification of** large-signal disturbances such as **ride-through**
- **Limited collection of field data** to validate/verify IBR plant model.
  - Often not for large-signal disturbances.

IEEE 2800-2022
IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

&

P2800.2
Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems
Active PAR

IEEE SA: https://standards.ieee.org/ieee/2800.2/10616/

P2800.2 WG: https://sagroups.ieee.org/2800-2/

One Possible Future

Recommended Improvements to the Interconnection Process

* 2x rounds or more for iterating Step 3 and Step 4:

- If a site-specific, sufficiently parameterized model is not available, then conduct 1st round of Step 3 (SIS) with generic models valid for IEEE 2800
- Use site-specific, sufficiently parameterized models for 2nd and additional rounds of Step 3 & 4

Execution of 'Conditional' LGIA → Planning Security → IBR Plant Design & Permitting based on POI grid characteristics

- Iteration of Steps 4-8, as needed

New Step 8: Periodic test or verification

Existing Step 1 – Interconnection Request
Plant-Specific Interconnection Request

Revised Step 2 – Feasibility Study
Plant-Specific Interconnection Screening & Preliminary Review of IBR Plant Design

Revised Step 3 – System Impact Study (SIS)
Plant-Specific Grid Integration & Reliability Impact & Determination of Transmission Grid Upgrades

2x rounds or more*

Revised Step 4 – Facility Study
Mitigation of Transmission Grid Upgrades & Near-Final IBR Plant Design Evaluation

IBR Plant Construction
Installation and Building of All Equipment and Structures

New Step 5 – Conformity Assessment
Final IBR Plant Design Evaluation & "As-built" Evaluation

Existing Step 6 – Interconnection Commissioning
Plant-Specific Commissioning & Model Validation/ Verification

New Step 7 – Post-Commissioning Monitoring
Re-Validation, Event Analysis, Studies

Step 1

- Submit **sufficient models*** configured to match applicable standards and/or TO's minimum performance requirements
- Specify **model 'acceptance criteria'**

* Such models should be as sufficient as possible based on the information available at the time, possibly a **common plant design based on applicable standards (e.g., IEEE 2800-2022)**

Step 2

- Preliminary IBR plant design evaluation for **conformity with TECHNICAL MINIMUM requirements** (e.g., IEEE 2800-2022)

Possible **screening criteria** may include:

- Steady state deliverability, e.g., based on "transmission hosting capacity" maps
- Grid strength metrics (both conventional and advanced)

➔ Outcomes:

- **IEEE 2800-2022 conforming model**
- Either **Permission to proceed** into IBR Plant Study & Design
- Or **Request for re-submission of more detailed sufficient models**, as needed, if found necessary under the screening

Step 3

- Study system impact **using latest available, sufficient, site-specific** equipment models and parameters, including a description of the model limitations
- As Step 3 and Step 4 progress, update the models for IBR units, supplemental IBR devices, and the IBR plant as design choices are made
- Changes in the design could trigger either
  - a "reset in the inter-connection queue position", or
  - a "restudy of the IBR plant design"?

➔ Can informs definition of "material modification" per FERC LGIP/LGIA

Step 4

- **Near-final design evaluation** to assess conformity of IBR unit & plant capability & performance with RTO/ISO/TP's TIRs **which may exceed IEEE 2800-2022 requirements**, using **sufficient, site-specific** equipment **models** and parameters
- **Design freeze** for Interconnection Agreement (IA)
  - Any changes to the IBR or supplemental units require repeat of Steps 3 and 4

➔ Outcomes:

- Either **Permission to proceed** into IBR plant construction
- Or **Request for re-design** to mitigate system impact and/or meet conformity

Step 5

- **Final pre-commissioning design evaluation** to assess conformity of IBR unit & plant capability & performance using **verified site-specific IBR plant models** and parameters with **validated IBR unit models**
- **"As-built" plant-level evaluation** (see IEEE P2800 & 1547-2018) could show that what is installed matches what was studied/ designed.
  - Any changes to the IBR units or supplemental IBR devices could require repeat of Step 3-5

➔ MOD 026/027 IBR plant large-signal disturbance model verification

Step 6

- Perform a (limited) set of field tests to validate/verify IBR plant model.
  - Likely limited to small-signal disturbances.

➔ Final MOD 026/027 IBR plant small-signal disturbance model verification

Step 7

- Collect field data to validate/verify IBR plant model.
  - Especially for large-signal disturbances.

➔ Continuous MOD 026/027 IBR plant large-signal disturbance model verification

Guiding Principle

Open and timely communication

Disclaimer

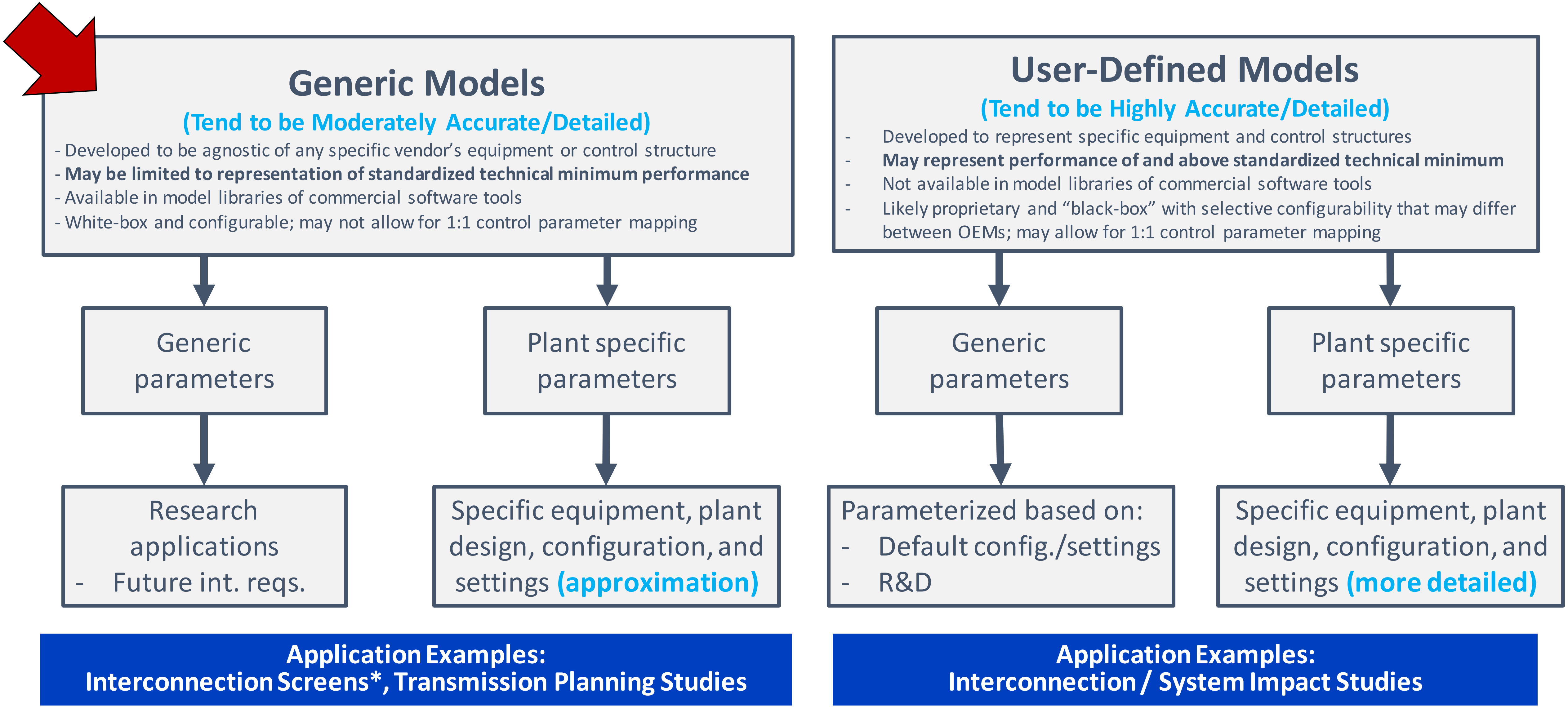
The shown process improvement is one possible solution; there may be other solutions that are equally or more effective, equitable, and practicable.

Legend

■ (blue)	Existing Process
■ (purple)	Proposed Modification or Addition
TIRs	Technical Interconnection Requirements

EPRI

Focus of PV-MOD Project is on Generic Models



* Only if interconnection performance requirements are well defined (e.g., IEEE Stds)

Model limitation versus simulation domain limitation

- Present models in planning base cases (both positive sequence and EMT) have been unable to capture causes of inverter tripping
- Limitation of a model should not be confused with limitation of the simulation domain itself
- Models (such as REGC_C and other future models) can help bring about added capability that can be leveraged

Cause of observed behavior	Simulation domain limitation	Most of today's model incorrectly parameterized	Most of today's model do not represent	
Unbalanced conditions	✓			
Sub-cycle ac over voltage	✓			
Sub-cycle ac over current	✓			
Momentary cessation		✓		Future model can represent as capability exists in simulation domain
Error in frequency measurement		✓		
PLL loss of synchronism		✓		
Collector network level under frequency		✓		
Phase jump			✓	
dc reverse current			✓	
dc low voltage			✓	
Plant controller interactions			✓	

(a) Positive sequence simulation domain

Cause of observed behavior	Simulation domain limitation	Most of today's model incorrectly parameterized	Most of today's model do not represent	
Unbalanced conditions		✓		Future model can represent as capability exists in simulation domain
Sub-cycle ac over voltage		✓		
Sub-cycle ac over current		✓		
Momentary cessation		✓		
Error in frequency measurement		✓		
PLL loss of synchronism		✓		
Collector network level under frequency		✓		
Phase jump			✓	
dc reverse current			✓	
dc low voltage			✓	
Plant controller interactions			✓	

(b) EMT simulation domain

Differentiating between Applicability of Simulation Domains and Inverter Mathematical Models in these Domains. EPRI, Palo Alto, CA: 2022.3002025063. [Online] https://www.epri.com/research/products/000000003002025063

IEEE 2800-2022 Technical Minimum Capability Requirements

TS owner can require additional capability

Raising the minimum bar

Capability Required in 2800

General Requirements

"shall have"

- Measurement accuracy
- Controls Prioritization
- Control responses
- Applicability to Diverse IBR Plants

Frequency Response

- Fast Frequency Response for under-frequency conditions — **"may" for over-frequency conditions**
- Primary Frequency Response

Reactive Power – Voltage Control

- Q for voltage control at zero active power — **Ac-connected offshore wind: "should have"**
- Automatic Voltage Regulation Functions
- Reactive Power

Power Quality

TS owner "should" specify

- Harmonic Voltage Limitations
- Prevent Transient Overvoltage
- Harmonic Current Limitations
- Phase Unbalance
- Rapid Voltage Change
- Flicker Limitations

Ride-Through Capability and Performance, Protection

- Unbalanced Current Injection
- Balanced Current Injection
- Voltage Ride-through including TrOV + Consecutive
- Frequency & Phase-jump Ride-through
- Coordination Of Protection

Modeling & Validation, Measurement Data, and Performance Monitoring

- Process and criteria for model validation
- High Fidelity Performance Monitoring
- Validated Models

Tests and verification requirements

- Post-commissioning Monitoring
- Plant-level Evaluation & Modeling
- Commissioning Tests
- Type tests

Utilization of these capabilities is outside the purview of 2800

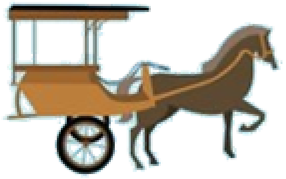
Capability versus **Utilization**

Capability:

"Ability to Perform"

Scope of IEEE 2800

- Functions
- Ranges of available settings
- Minimum performance specifications



<u>Examples</u>

- Frequency Response
  - Primary frequency response
  - Fast frequency response
- Ride-Through
  - Voltage ride-through
  - Current injection during ride-through
  - Consecutive voltage ride-through
  - Frequency ride-through
  - ROCOF ride-through
  - Phase angle jump ride-through

Utilization of Capability:

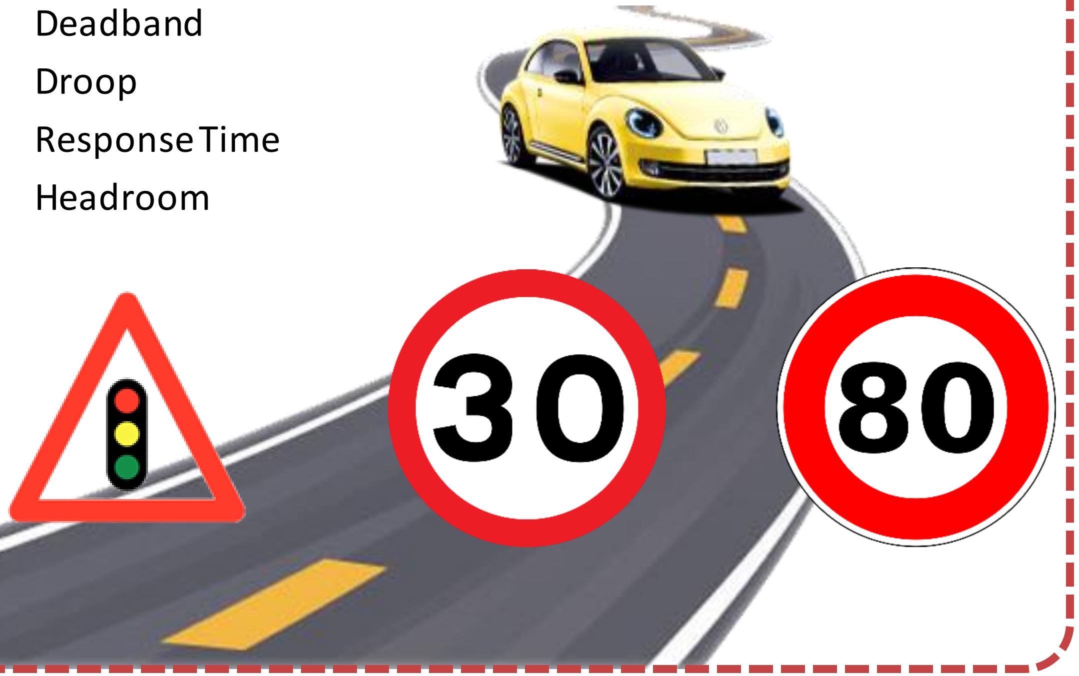
"Delivery of Performance"

Scope of Interconnection or Ancillary Services Agreement

- Enable/disable functions
- Functional settings / configured parameters
- Operate accordingly (e.g., maintain headroom, if applicable)

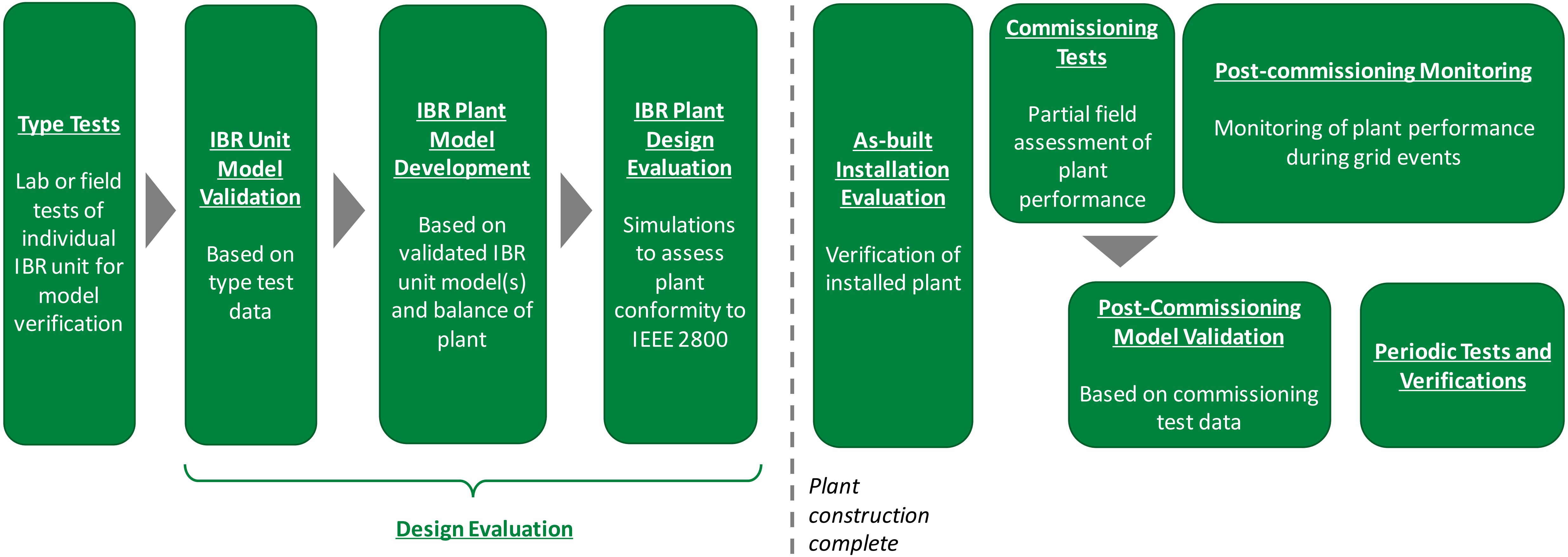
<u>Examples</u>

- Deadband
- Droop
- Response Time
- Headroom



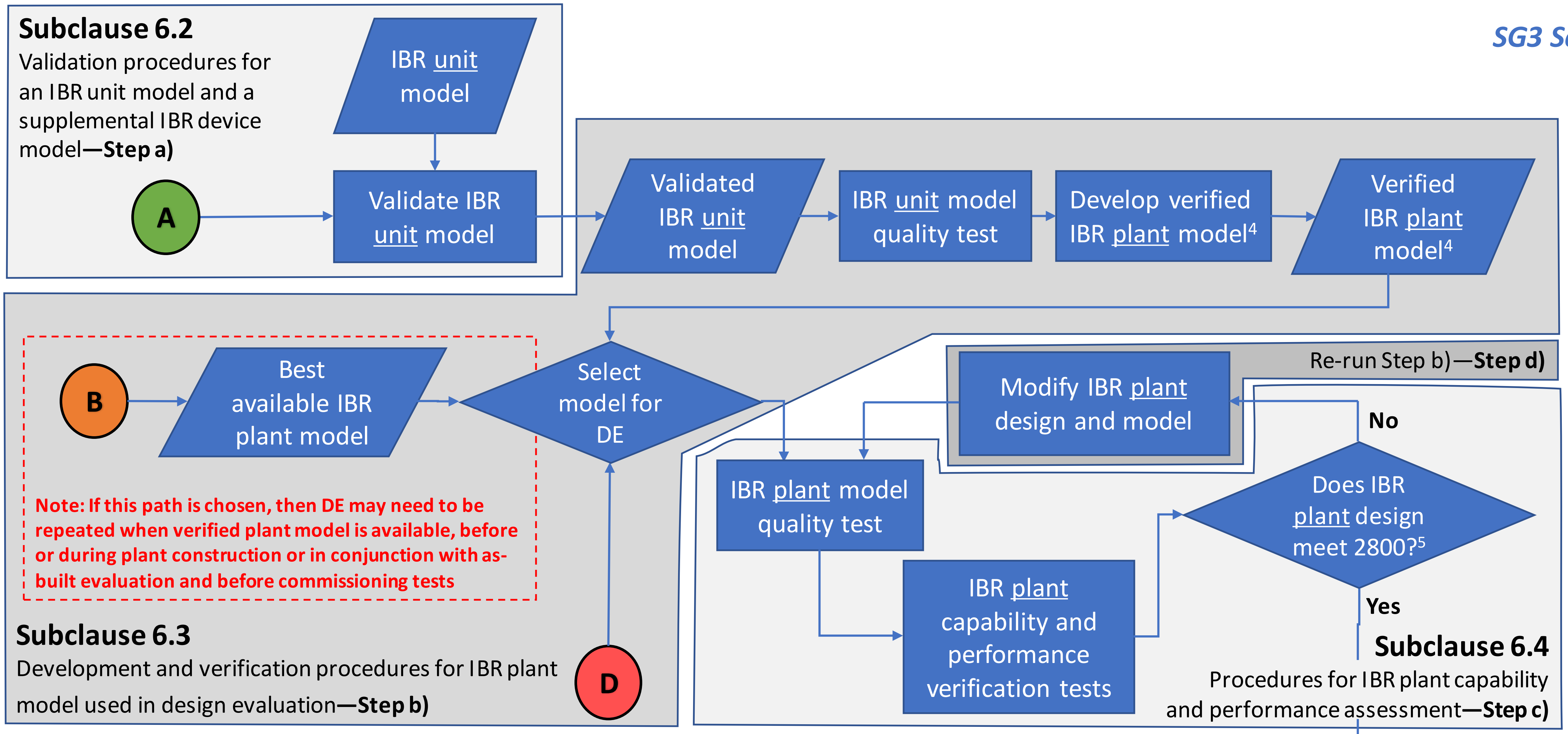
EPRI

Overview of conformity assessment steps in IEEE P2800.2



This is a general diagram of the process. Details are under development in [IEEE P2800.2](). Some variations permitted.

A. Hoke et al.: *The IEEE 2800 Conformity Assessment Paradigm*, presented to ERCOT Inverter-based Resource Performance Task Force, April 14, 2023 [Online]



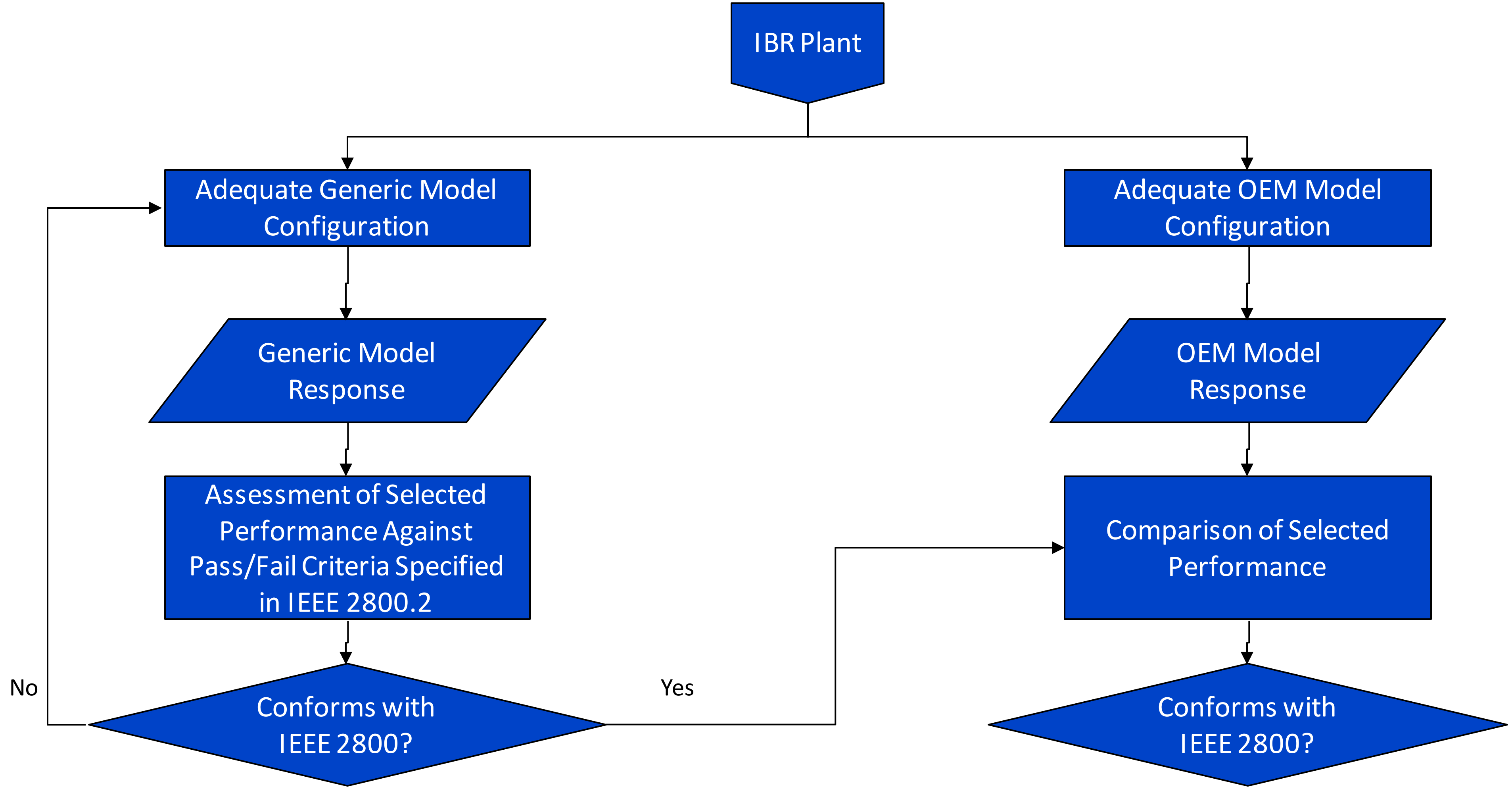
Notes:

4. Verified IBR Plant model is developed using IBR plant design and validated IBR Unit/Supplemental IBR device models. The plant model in this step is not validated.

5. Passes IBR Plant design evaluation steps listed as R or D in Design Evaluation column of IEEE 2800 Table 20

Open Questions: 1) test system: single-machine vs. more detailed?; 2) plant model: disaggregated vs. aggregated?

Application of Generic EMT Model to Produce Reference Response for IBR Plant Conformity Assessment



EPRI Activities To Date Supporting IEEE 2800-2022 Adoption

- **March 2022 – ongoing:** work with two early-interest EPRI members

- **May 3, 2022:** Joint NERC-NATF-NAGF-EPRI Webinar on Publication of IEEE 2800-2022 ~ 1,000 attendees
  - Slide deck and recording available to the public at https://www.epri.com/research/programs/067417/events/621D26F1-00A5-4F90-8AA8-C68959393DBC
- **August 9-11, 2022:** Joint ESIG-NAGF-FERC-NERC-EPRI Interconnection Workshop ~ 700 attendees
  - Slide decks, recordings, and summary report available to the public at https://www.esig.energy/event/joint-generator-interconnection-workshop/
- **September 22, 2022:** EPRI Informational Webinar on FERC NOPR on Generator Interconnection (Transmission) ~ 130 attendees
  - Slide deck and recording available to EPRI members at https://www.epri.com/research/programs/067417/events/33867756-483F-47E9-9ABF-B6235342F9FE
- **October 12, 2022:** EPRI Utility Field Experience Interest Group on FERC's Small Generator Interconnection Procedure (SGIP) ~ 120 attendees
  - Slide deck and recording available to EPRI members at https://www.epri.com/research/programs/067418/events/351679F6-DEB7-470C-96CA-292CC96FD8FD

- **October 13, 2022:**
  EPRI Comments filed on
  FERC's Improvements to Generator Interconnection Procedures and Agreements NOPR issued on June 16, 2022
  - available in FERC's eLibrary at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=AD71793A-769B-C856-91EB-83D327900000

- Milestone reports from DOE- and EPRI member-funded **PV-MOD project** substantiate many of EPRI's comments.
  - These are available at https://www.epri.com/pvmod.
- EPRI recommends **adoption of IEEE Standards like 1547-2018 for SGIP/SGIA and 2800-2022 for LGIP/LGIA** to set clear expectations for DER and Large IBR plants' technical minimum capabilities.
  - Supported—to different extent—by 7 other entities, including NERC, SEIA, ACP, IREC, Orsted, SoCo, AEP.
- EPRI recommends all **models should be validated** and appropriately parameterized; modeling as a **method for pre-commissioning conformity assessment**.

AFFECTED SYSTEM STUDIES & JOINT TARGETED INTERCONNECTION QUEUE

JULY 12, 2023

PURPOSE

- SPP's Generator Interconnection Affected System Studies (GI AFS) Process Overview

- SPP-MISO Joint Targeted Interconnection Queue (JTIQ) Update

WHAT IS AN AFFECTED SYSTEM?

In Generator Interconnection, there are three scenarios where Affected Systems impacts are assessed:

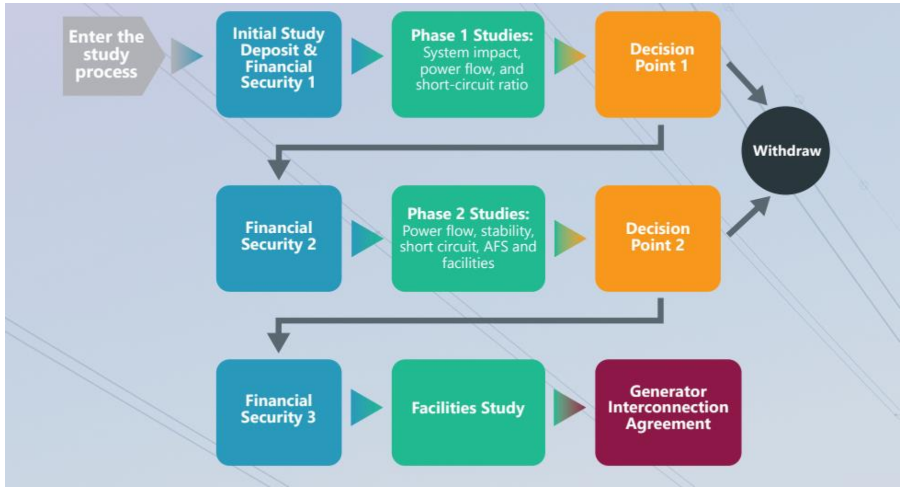
1. SPP GI Requests impacting neighboring systems
2. Neighboring GI Requests impacting SPP Facilities
3. Non-Jurisdictional GI Requests impacting the SPP Transmission System

RELATIVE QUEUE PRIORITY

- How relative queue priority is identified?
  - Queue windows and priorities differ between regions (cluster study vs. serial study)
  - TPs that use cluster study - queue priority is determined by end date of first decision point
  - TPs with serial studies - queue priority is determined by date of queue entry

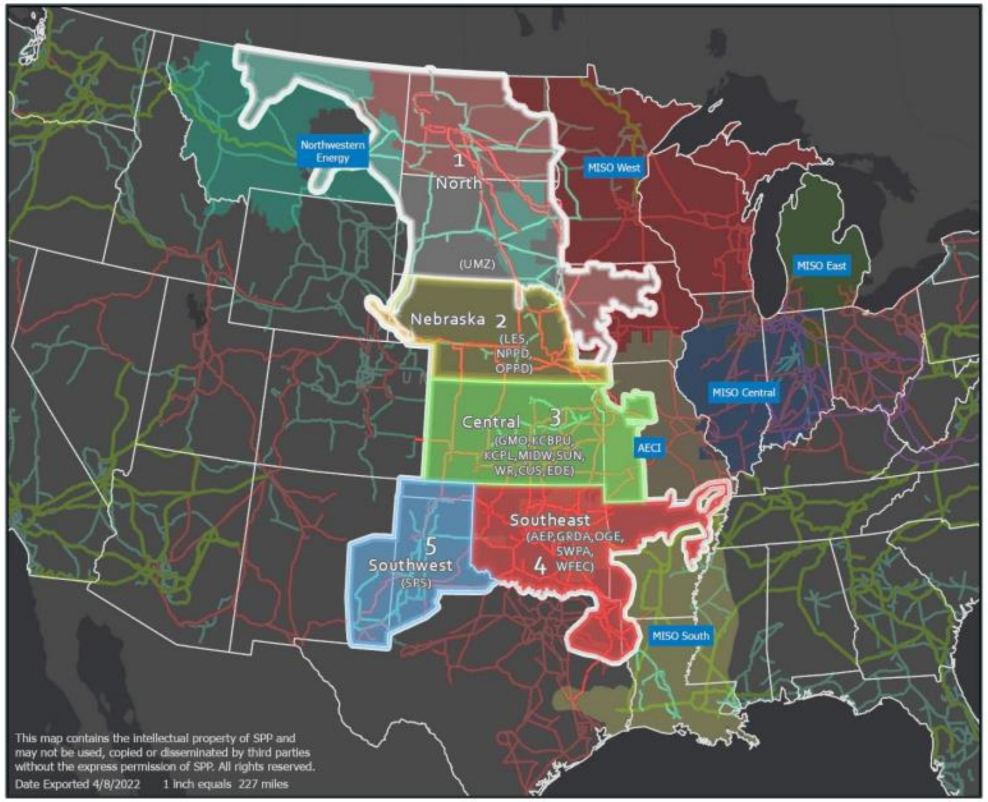
SPP GI REQUESTS IMPACTING NEIGHBORING SYSTEMS

- How are AFS triggered?
  - The AFS study process is done in coordination with the Definitive Interconnection System Impact Study (DISIS).
    - Pre-Study: SPP provides bus number for DC Screen
    - Phase 1: Perform DC Screen using 3% TDF criteria
    - Phase 2: Perform AFS Study
    - Phase 3: Restudy if needed
      - AFS Entity Network Upgrade Facility Study
      - Facility Construction Agreement



AFS STUDIES PERFORMED

- Steady State Studies To Identify
  - Thermal, voltage and non-convergence violations
- Cases
  - Summer Peak (Near Term and Long Term)
  - Winter (Long Term)
  - Light (Long Term)
- SPP Groups
  - Based on the geographical location of their POI
    - North, Nebraska, Central, Southeast and Southwest Regions



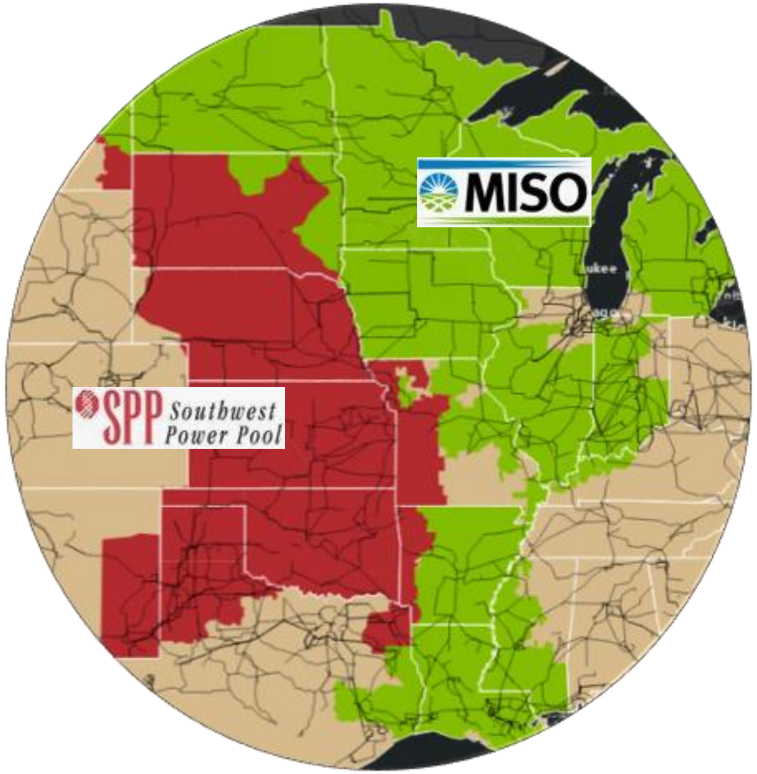
JOINT TARGETED INTERCONNECTION QUEUE (JTIQ)

A MISO - SPP COLLABORATION

MISO

SPP Southwest Power Pool

WHY JTIQ



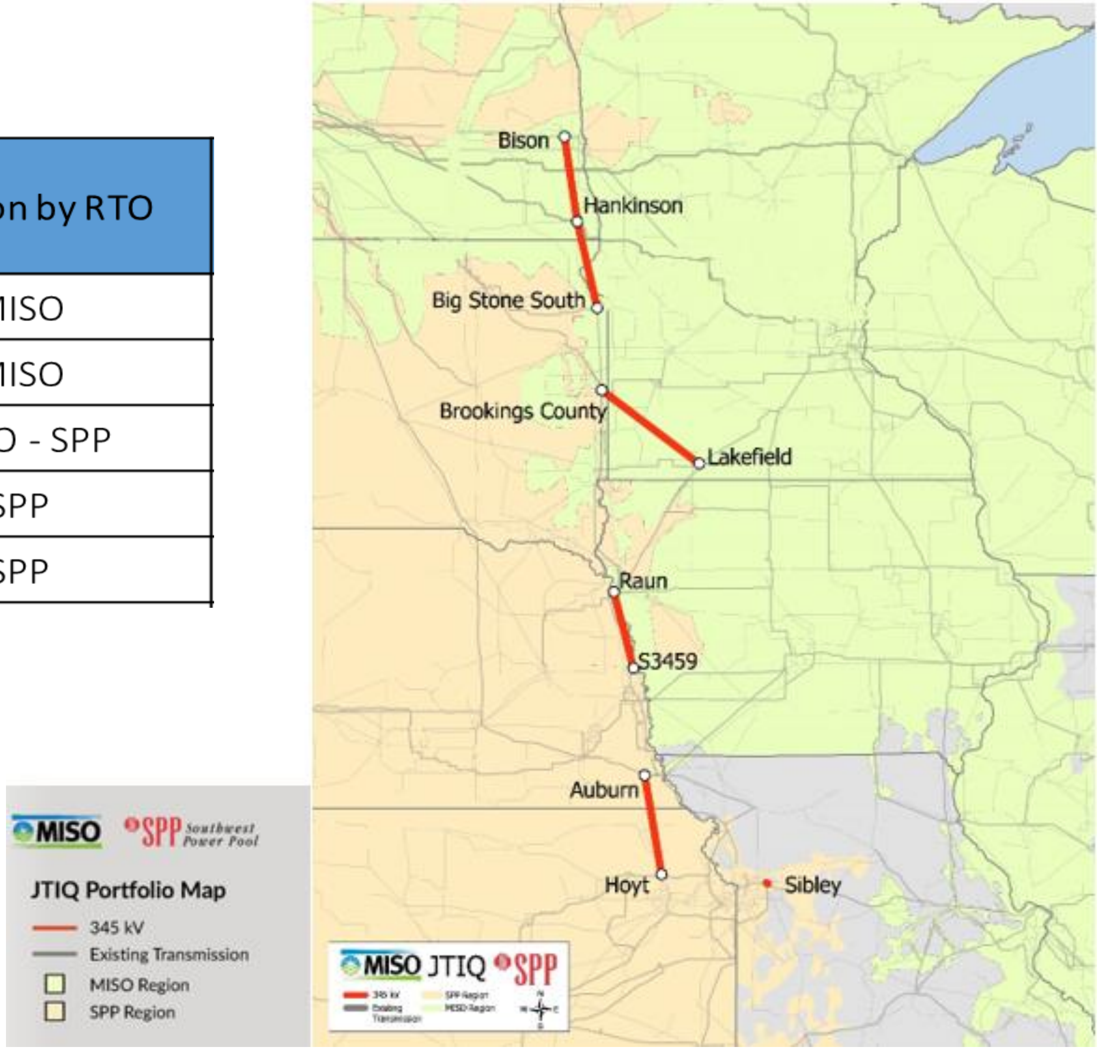
- SPP and MISO are experiencing similar resource mix shifts with significant queue sizes
- The transmission system is at capacity along the SPP-MISO seam
- Upgrades are too costly for small groups of interconnection customers, contributing to churn in the queue which leads to delays

JTIQ STUDY

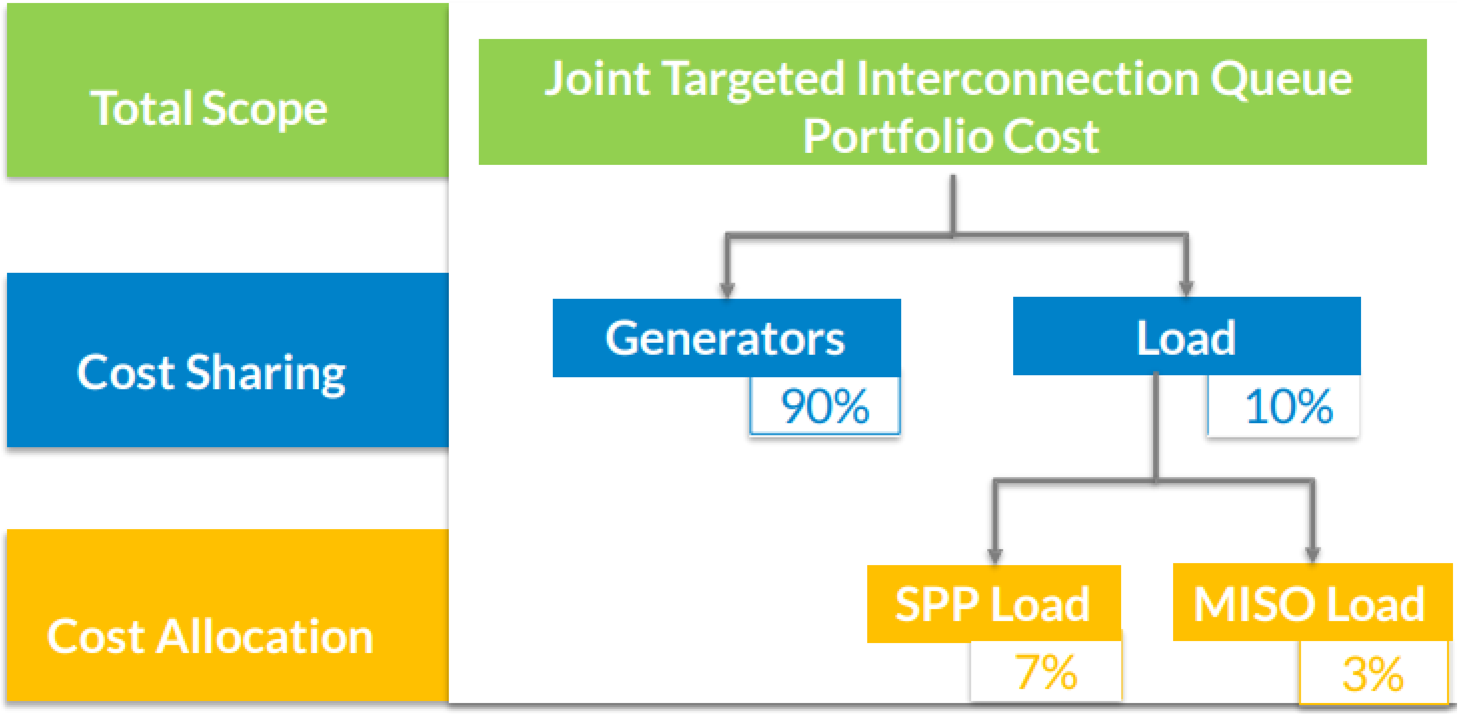
- **JTIQ** targeted constraints that are **significant barriers** to interconnecting new generation near the seam and that are contributing to **clogged interconnection queues**
- Although the primary goal is to unlock queues and facilitate interconnection, the JTIQ transmission also provides **benefit to load in each RTO**, which supports **novel cost sharing** between generation and load
- Initial JTIQ study potentially serves as a model for **transformational improvement** to GI Affected System Study processes

CURRENTLY PROPOSED JTIQ PORTFOLIO

JTIQ Portfolio	Location by RTO
Bison – Hankinson – Big Stone South 345 kV	MISO
Brookings Co – Lakefield 345 kV	MISO
Raun – S3452 345 kV	MISO - SPP
Auburn – Hoyt 345 kV	SPP
Sibley 345 Bus Reconfiguration	SPP



JTIQ COST SHARING OVERVIEW



- Engineering & Construction (E&C) and Transmission Owner carrying costs will be shared by Generators (90%) and Load (10%)
  - The 10% Load share will be allocated between SPP and MISO Load based on Adjusted Production Cost (APC) benefits
- 100% of Operation & Maintenance (O&M), Administrative & General (A&G), etc. costs will be borne by Load

CURRENT INTERCONNECTION QUEUE PROCESS VS JTIQ

	Current Interconnection Queue Process	JTIQ Process
Network Upgrade Identification Process	• MISO DPP and SPP DISIS identify Network Upgrades required by new generation in Host Region • MISO performs Affected System Study (AFS) for SPP DISIS and SPP performs AFS for MISO DPP to identify Network Upgrades required across the seams by new generation in Host Region	• Focuses on backbone projects rather than POI injection Network Upgrades
Generation Interconnection Assumption	• Utilizes actual generation sites in interconnection queues	• Utilizes future generation representing multiple DISIS and DPP study clusters
Network Upgrade Scope	• Identifies Network Upgrades sufficient only for a particular SPP DISIS or MISO DPP study cycle	• Identifies larger/longer term optimized system needs across seams and across study clusters

BENEFITS OF JTIQ REPLACING AFS PROCESS

- **Improves cost certainty** for GI requests in MISO and SPP
  - Provides GI customers affected system cost at the start of DPP or DISIS
  - Eliminates unknown AFS Network Upgrades
  - Eliminates AFS study cost
- **Improves timing certainty** for GI requests in MISO and SPP
  - Concludes study process for requests with the completion of DPP or DISIS without having to wait for separate AFS study results
  - Eliminates timing delays on AFS study coordination
- **Enhances alignment with FERC** interconnection initiatives
  - Builds on notion of interconnection zones contemplated by FERC's transmission planning NOPR
- **Optimizes Network Upgrades** along the seams
  - Identifies optimized Network Upgrades that address larger/longer-term system needs across seams and across study clusters as compared to individual MISO+SPP AFS processes

TIMELINE/NEXT STEPS

- SPP and MISO working through stakeholder processes
- Coordinate FERC filing with MISO following both stakeholder body approvals
- Seek Board approval of portfolio
- Issue NTCs

JILL PONDER
INTERREGIONAL STRATEGY AND ENGAGEMENT

Please feel free to contact me at jponder@spp.org

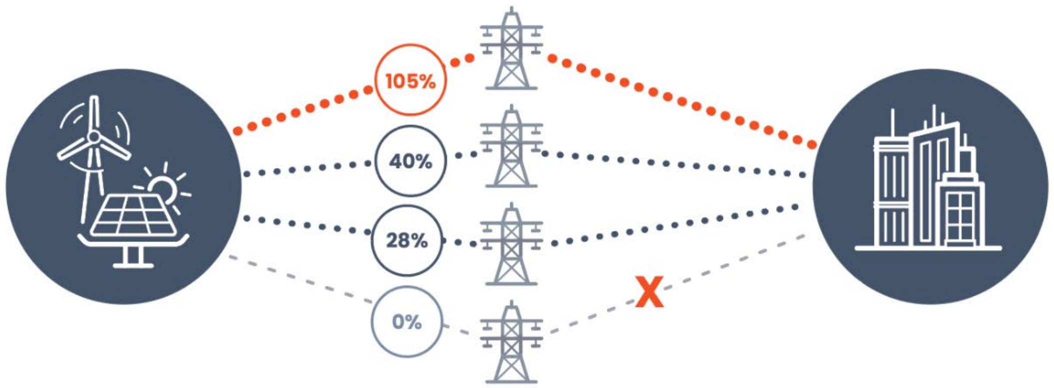
SMART WIRES
REIMAGINE THE GRID

DOE i2x Presentation

July 12 2023

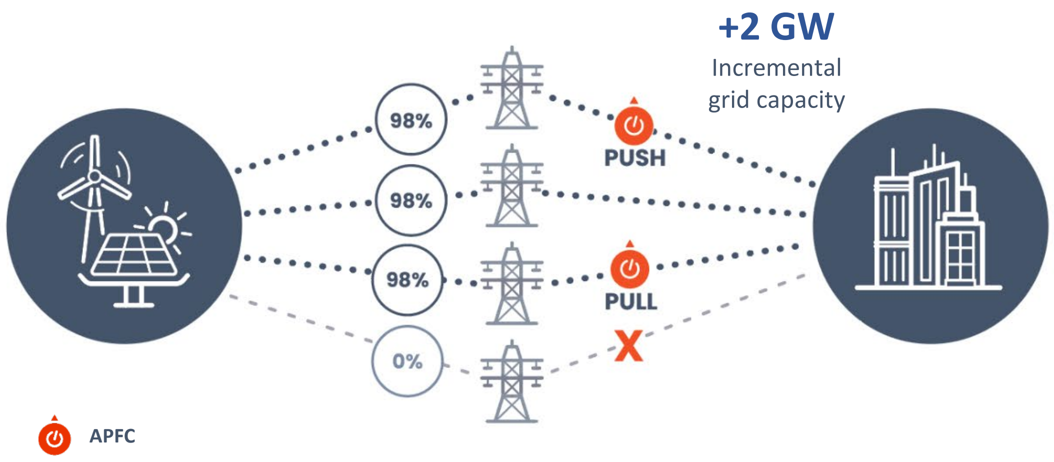
Advanced Power Flow Control optimizes existing infrastructure and maximizes grid potential

Before APFC



- x Renewable proliferation is bottlenecked by the electric grid
- x Transmission subject to path of least resistance
- x Once one line exceeds capacity, the line path is curtailed, even if incremental capacity exists on adjacent lines

After APFC

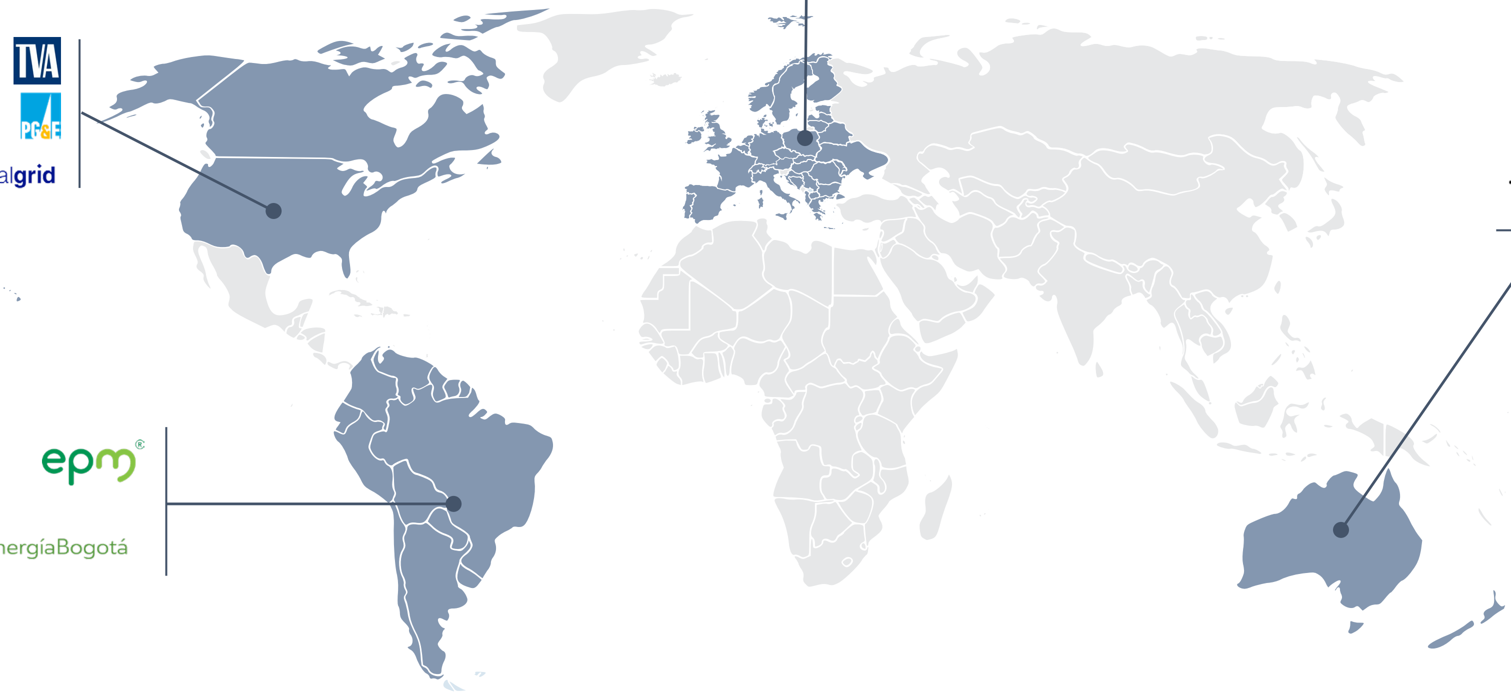


- ✓ Reducing renewables curtailment
- ✓ Reduced need for new expensive transmission lines
- ✓ Reducing long and growing interconnection queues
- ✓ Reduced operational grid challenges

Note: U.K. assessment of NGET project estimates 2 GW of total incremental grid capacity.

Proven technology serving the most respected utilities

In use or being installed on live projects with 25+ grid operators on four continents



"This clever technology benefits both customers and the environment and will allow renewable energy from Victoria to flow into NSW and the ACT when demand is greatest. By using power flow controller technology, we can unlock additional energy without needing to build new lines or upgrade existing transmission lines, which minimizes environmental and community impact."

Brett Redman | CEO – Transgrid

"Advanced technological solutions like SmartValve enable us to unlock extra capacity on our existing network – ensuring stable, reliable supply, more renewable energy, and less requirement for new infrastructure. Essentially this technology is improving utilization of our current network; the result being lower prices for our customers, less impact on the environment and our communities, and an increase in the amount of renewables we can safely integrate."

Steven Neave | Executive General Manager of Network Management & Digital – Ausnet

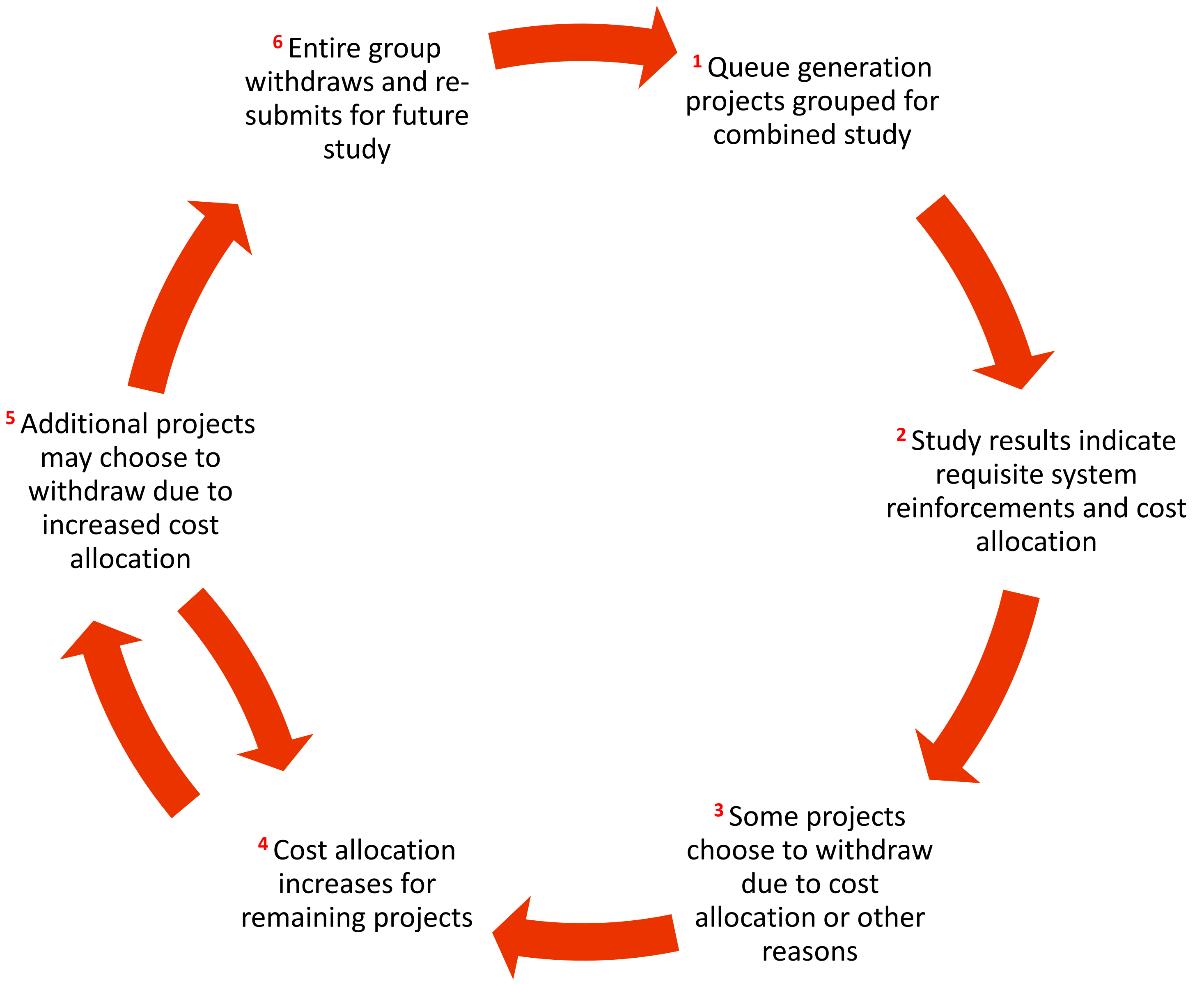
"Modular solutions such as SmartValve enable NGET to adapt the solution as the network needs change over time, scaling up or down the deployment or relocating it to another area of the network… When the system has bottlenecks due to limited network capability, the system operator needs to constrain generation so that flows are within the capability of the network. The £380m [cost saving] reflects the reduction in constraint costs for consumers due to the additional network capacity provided by the SmartValve installations."

Zac Richardson | Director of New Infrastructure – NGET

"With the implementation of these innovative devices, the Group contributes to the country's energy security. In addition, among their functional advantages, [SmartValve devices] offer wide environmental and economic benefits, as they provide solutions to different needs in the short, medium, and long term for the country, since they reduce the obligation to carry out new transmission projects, such as lines and substations, to adequately dispatch the energy generated."

Fredy Zuleta | General Manager of Transmission – Grupo Energía Bogotá

Why are interconnection queues broken?



Traditional system reinforcements scoped in GI studies are binary solutions:

- Do/don’t build a new line
- Do/don’t reconductor an existing line

Sophisticated modular APFC models have been developed but not fully incorporated into native modules by all planning system software providers

Modular APFC modeling and solution identification training for system planners is not widespread

How do advanced technologies help?

[1] Queue generation projects grouped for combined study

[2] Study results indicate requisite system reinforcements and cost allocation

[3] Some projects choose to withdraw due to cost allocation or other reasons

Modular APFC solutions in place of and along with traditional system reinforcements mean generators can progress through the queue faster and at lower cost.

Modular APFC solutions are redeployable and scalable:

- If projects withdraw (for any reason), deployment can be re-sized to meet the need driven by the remaining projects
- Cost allocation remains the same (or even goes down) due to reduced modular APFC solution size

Opportunities for IPPs and developers include:

Connect generation and load faster	**Alleviate congestion on curtailed assets**
Reduce upfront project costs	**Improve asset acquisition strategy**
Increase flexibility of site selection	

How do advanced technologies help?

Dynamic Line Rating offers probabilistic capacity increases, like wind or solar forecasts

- Periods of high wind can also create opportunity for increased line rating and power delivery
- Study process changes required to allow DLR network upgrade mitigations for infrequent, minor thermal constraints

[1] Queue generation projects grouped for combined study

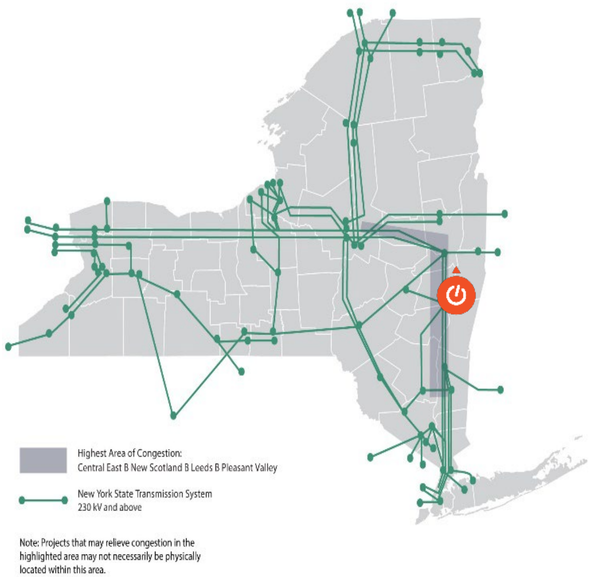
[2] Study results indicate requisite system reinforcements and cost allocation

[3] Some projects choose to withdraw due to cost allocation or other reasons

Targeted use of Dynamic Line Rating for infrequent, minor thermal constraints can be highly cost-effective.

Central Hudson Gas & Electric

Leeds-Hurley Avenue project, New York



Pilot project installed in 2019, with large project to be commissioned in mid 2023

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Challenge

- NYISO study identified that transfer capacity of UPNY-SENY **Interface needed to be increased by 185 MW to support integration of renewables**.
- New York has target of 70% of electricity from renewable sources by 2030.

Technology

- **Multiple series compensation solutions considered, including the use of a FSC**.
- After detailed analysis, **modular APFC was selected as preferred network option**.
- **Devices** recently installed at 345 kV to pull power onto the underutilized Leeds-Hurley Ave circuit, **unlocking 185 MW of additional capacity**.

Why modular APFC?

- Required significantly less substation work which **delivered cost savings of $10M compared to the FSC** project cost and resulted in **quicker installation timeframe**.
- Deployed with **25% smaller footprint**, minimizing the use of substation space but still providing flexibility to expand over time.
- Provides **series compensation without SSR risk**, compared to the high SSR risk of a FSC.
- **Future-proofed solution** that eliminated risk of stranded asset as **SmartValves can be easily added or relocated, unlike a FSC which is permanently built in full size from the outset**.

Customer collaboration

- Collaboration over several years, starting with a pilot project at 115 kV in 2019 to gain operational experience with SmartValve before this large-scale Leeds-Hurley Avenue project in 2023.
- FACTS that provide power flow control included as key solutions for addressing transmission bottlenecks and optimizing use of existing grid in the 'New York Power Grid Study' in future years.

ComEd

Shady Oaks II network upgrade project, Illinois

Existing wind farm expanded in central Illinois, APFC installation planned for 2025

ComEd® An Exelon Company

Challenge

- PJM study identified a stability limit in central Illinois **Interface needed to be increased by 185 MW to support integration of renewables**.
- Illinois Climate and Equitable Jobs Act (2021) has target of 40% of electricity from renewables by 2030.

Technology

- **Initial solution involved a new 230 kV line build**
- After detailed analysis, **modular APFC was selected as preferred network option**.
- **Facilities studies recently posted**, **enabling 210 MW of additional capacity**.

Why modular APFC?

- Required significantly less transmission line work which **delivered cost savings of approximately $50M compared to the new line** project cost and resulted in **quicker installation timeframe**.
- Provides **series compensation without SSR risk**, compared to the high SSR risk of a fixed series capacitor.
- **Future-proofed solution** that eliminated risk of stranded asset as **devices can be easily added as needed to accommodate future generation growth in the area**.

Customer collaboration

- Collaboration with ComEd, IPP, and PJM over 18 months, starting with alternative solution modeling and culminating in interconnection service agreement
- Installation planned for 2025