Agenda
Reliability and Security Technical Committee

September 9, 2021 | 11:00 a.m.–4:30 p.m. Eastern
Virtual Meeting via WebEx

Attendee WebEx Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement*

Introductions and Chair's Remarks

Agenda

1. **Reliability Guideline DER Forecasting* – Accept to Post for 45-Day Comment Period** - Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The NERC SPIDERWG has developed a Reliability Guideline to provide guidance on DER forecasting. There is a growing need to ensure the accuracy of Interconnection-wide planning cases, especially as some states are enacting policy that targets a specific level of Distributed Energy Resource (DER) integration. Those cases contain detailed information on transmission level elements, as well as the impact of aggregated load, DER, and other distribution equipment has on the transmission system. The policies highlight the need for the bulk power system's planning assessments and future Interconnection-wide studies to have forecasted DER integration levels with reasonable accuracy so that any planning decisions, such as transmission projects or Corrective Action Plans (CAPs), are enacted in high confidence. The SPIDERWG requests authorization to post this Reliability Guideline for a 45-day industry comment period per the RSTC charter.

2. **White Paper – Survey of DER Modeling Practices* – Approve** - Kun Zhu, SPIDERWG | Wayne Guttormson, Sponsor Chair

   The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices. The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry. The SPIDERWG is requesting RSTC approval of the white paper.

3. **White Paper – Simulation Improvements* – Request RSTC Reviewers** – Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The NERC SPIDERWG has developed a number of guidelines and studies relating to distributed energy resource (DER) integration. Tracking DERs will add significant level of complexity to the planning process, stressing data fidelity, modeling accuracy, and computational limitations. This document provides a distilled version of the NERC SPIDERWG that may be pertinent to power system software developers, and outlines some of the related literature that may aid in developing further software improvements and techniques. The SPIDERWG is requesting RSTC members for review of the White Paper.

4. **Synchronized Measurements Working Group (SMWG) Scope Document* – Approve** – Tim Fritch, SMWG Chair | Todd Lucas, RTOS Sponsor

   The SMWG updated their scope document to reflect the transition from a subcommittee to a working group reporting to the Real Time Operating Subcommittee. Other clarifying edits for the scope and deliverables for the SMWG were made. The SMWG is requesting RSTC approval of the revised scope document.

5. **Supply Chain Standard Effectiveness Survey* – Information** – Tony Edelman, SCWG Chair | Chris Shepherd, Sponsor

   When NERC's Board of Trustees (Board) adopted the Supply Chain Standards in August 2017, it concurrently adopted additional resolutions related to the implementation and evaluation of the Supply Chain Standards, as well as other actions to address potential supply chain risks.

   One of those resolutions directed NERC management, collaborating with NERC technical committees and other experts, to develop a plan to evaluate the effectiveness of the Supply Chain Standards and report to the Board. At the Board meeting in December 2019, NERC outlined its plans to measure the effectiveness of the Supply Chain Standards.

   The Supply Chain Working Group (SCWG) developed a voluntary industry survey that will be used to help gather information relevant to the effectiveness of the Supply Chain Standards. The survey is being provided for information purposes to RSTC and industry prior to its publication.

6. **Nominating Subcommittee (NS) Update* – Information** – Rich Hydzik, RSTC Vice-Chair

   The NS will report on upcoming activities and timelines for Sector elections and At-Large nominees to fill RSTC terms ending in 2022.

12:55 -1:15 p.m. – LUNCH BREAK – 20 mins

7. **RSTC Subordinate Group Review Process* – Information** – Robert Reinmuller

   Per the RSTC Charter, the RSTC "will conduct a "sunset" review of each working group every year" and "review the task force scope at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired." The RSTC Executive Committee has developed a draft process and template for these reviews to be conducted prior to the December 2021 RSTC meeting.

   The draft process for this review will include the RSTC Sponsors in coordination with subordinate group leadership and NERC Staff Liaisons review the working group or task force deliverables and work plans to complete the information in the template. Once the templates are complete, the RSTC EC and Sponsors will review them to make a recommendation on the status of the subordinate group. This will be reviewed with the full RSTC at the December RSTC meeting for approval.

8. **Reliability Assessments Subcommittee (RAS) Update – Information –** Lewis De La Rosa, RAS Chair | Kayla Messamore, Sponsor

   The RAS is coordinating the development of both the Winter Reliability Assessment (WRA) and the Long-Term Reliability Assessment (LTRA). An overview of the production of each assessment as well as anticipated RSTC actions will be reviewed.

9. **Energy Reliability Assessments Task Force (ERATF) Update – Information –** Peter Brandien, ERATF Chair

   The ERATF will assess risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The ERATF serves the RSTC in providing a formal process to analyze and collaborate with stakeholders to address the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources Whitepaper. This whitepaper identified energy availability concerns related to operations/operations planning and mid- to long-term planning horizons.

10. **Standing Committee Coordination Group (SCCG) Update* – Information –** Rich Hydzik, RSTC Vice-Chair

    Per the SCCG scope document, the SCCG is to "provide quarterly reports to the standing committees for inclusion in their public Agenda posting on cross-cutting initiatives addressing risks to the reliability, security, and resilience of the BPS. This report shall be prepared in advance and voted on by the SCCG at the SCCG's quarterly meetings."

2:35 p.m. BREAK – 15 mins

11. **Event Analysis Subcommittee – Lessons Learned – Information –** Rick Hackman, NERC Staff | Patrick Doyle, Sponsor

    The EAS, in coordination with NERC subcommittees and working groups, will share information, identify trends through analysis of events, and make recommendations to the industry which address lessons learned. This presentation will review lessons learned that were developed in 2021.

12. **3:10 p.m. Impact of Proposed Wi-Fi Operations on Microwave Links AT 6 GHz – Information –** Jennifer Flandermeyer, CCC Chair

    In 2020, a consortium of electric industry associations published a report on the *Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz*. The 6 GHz band of the radio spectrum is widely used by a broad array of industries responsible for critical infrastructure such as electric, gas and water utilities, railroads, and wireless carriers, as well as by public safety and law enforcement officials. Those industries rely on the 6 GHz band to operate their equipment, and it is their main source of both primary communication, and in-some cases back-up communications, during emergencies and disasters. The report identifies impacts to electric power operations. Additional follow-on work by EPRI and various affected stakeholders have shown—through testing--impacts to their critical electric infrastructure communications due to increased congestion and interference on the 6GHz wireless communication band. As adoption of the new technology increases, the risk to BPS operations increases.

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13. Forum and Group Reports – Information

a. North American Generator Forum* – Allen Schriver

b. North American Transmission Forum* – Roman Carter

14. RSTC 2020 Calendar Review – Stephen Crutchfield

2021 Meeting Dates	Time	Location	Hotel
December 14, 2021 December 15, 2021	Please reserve entirety of both days	TBD	TBD

2022 Meeting Dates	Time	Location	Hotel
March 8, 2022 March 9, 2022	Please reserve entirety of both days	TBD	TBD
June 7, 2022 June 8, 2022	Please reserve entirety of both days	TBD	TBD
September 13, 2022 September 14, 2022	Please reserve entirety of both days	TBD	TBD
December 14, 2022 December 15, 2022	Please reserve entirety of both days	TBD	TBD

15. Chair's Closing Remarks and Adjournment

*Background materials included.

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Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

RSTC Meetings – Governance Management

Chair will state the governance management of the meeting as follows:

- For each topic, the Chair will state the primary motion, ask for first/second, speaker will present, committee then has discussion.
- **At the conclusion of the discussion,** a secondary motion can be offered, the Chair will ask for first/second, discussion/debate; the Chair will then call for a vote.
- If the secondary motion does not receive a second or is voted down, the Chair will go back and restate the primary motion. At this point, the following actions may proceed:
    - Debate on that primary motion again;
    - Another secondary motion can be offered;
    - Motion could be offered to postpone, table, etc. Management of next action will follow the first two bullets.

The Chair is able to initiate a motion to end a debate.

Motions can encompass accepting minor revisions as provided during the discussions and reflected in the words of the motion.

Guiding principle is one thing at a time.

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Types of Documents

Reliability & Security Guidelines	*Reference Documents, Whitepapers and Technical Reports*	*Implementation Guidance*	*Standard Authorization Request*
• *Formulated from best and/or optimal practices* • *Suggested approaches or behaviors* • *"HOW" certain objectives can be met* • *Recommendations for how objectives "could" or "should" be accomplished*	• *Documented technical concepts* • *Definitions of technical terms* • *Defined methods or approaches* • *Can be used as justification to support "WHY" certain practices are needed*	• *Provides examples or approaches for "HOW" Registered Entities could demonstrate compliance with Reliability Standard requirements.* • *Used in Compliance Monitoring and Enforcement activities* Submitted to ERO	• *Defines scope, reliability benefit, and technical justification for a new or modified Reliability Standard or definition.* • *Identifies "WHAT" requirements are needed to ensure the reliable operation of the BPS* Submitted to SC

Reliability Assessment Reports

- Independent and objective evaluations of BPS reliability conducted by the ERO
- Subgroup used to gain industry perspectives, expertise, and validation
- Requires BOT approval

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Types of Documents: Member Considerations

Reliability & Security Guidelines	*Reference Documents, Whitepapers and Technical Reports*	*Implementation Guidance*	*Standard Authorization Request*

• *ACCEPT for public comment*
  • *Is guidance needed on this topic?*
  • *Are there major flaws?*
• *APPROVE*
  • *Has the public and committee comments been sufficiently addressed?*
  • *Do you agree with the recommended guidance?*
	• *APPROVE*
	  • *Does it provide sufficient detail to support technical, security, and engineering SMEs?*
	  • *Has it been peer reviewed and supported by a technical subgroup?*
	  • *Is it foundational and/or conceptual*
	  • *Does it contain specific recommendations?*
		• *ENDORSE*
		  • *Does it provide examples or approaches on how to implement a Reliability Standard?*
		  • *Does it meet the expectations identified in the Implementation Guidance Development and Review Aid?*
			• *ENDORSE*
			  • *Is the SAR form complete?*
			  • *Does it contain technical justification?*

Reliability Assessment Reports

- ENDORSE
  - Is there general agreement with findings and recommendations?
  - Was the process followed?

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RSTC Actions

- **Approve:** The RSTC has reviewed the deliverable and supports the content and development process, including any recommendations.
- **Accept:** The RSTC has reviewed the deliverable and supports the development process used to complete the deliverable.
- **Remand:** The RSTC remands the deliverable to the originating subcommittee, refer it to another group, or direct other action by the RSTC or one of its subcommittees or groups.
- **Endorse:** The RSTC agrees with the content of the document or action, and recommends the deliverable for the approving authority to act on. This includes deliverables that are provided to the RSTC by other NERC committees. RSTC endorsements will be made with recognition that the deliverable is subject to further modifications by NERC Executive Management and/or the NERC Board. Changes made to the deliverable subsequent to RSTC endorsement will be presented to the RSTC in a timely manner. If the RSTC does not agree with the deliverable or its recommendations, it may decline endorsement. It is recognized that this does not prevent an approval authority from further action.

Reliability Guideline DER Forecasting

Action
Accept to post for 45-day comment period.

Summary
The NERC SPIDERWG has developed a Reliability Guideline to provide guidance on DER forecasting. There is a growing need to ensure the accuracy of Interconnection-wide planning cases, especially as some states are enacting policy that targets a specific level of Distributed Energy Resource (DER) integration. Those cases contain detailed information on transmission level elements, as well as the impact of aggregated load, DER, and other distribution equipment has on the transmission system. The policies highlight the need for the bulk power system's planning assessments and future Interconnection-wide studies to have forecasted DER integration levels with reasonable accuracy so that any planning decisions, such as transmission projects or Corrective Action Plans (CAPs), are enacted in high confidence. The SPIDERWG requests authorization to post this Reliability Guideline for a 45-day industry comment period per the RSTC charter.

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Reliability Guideline

DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies

September 2021

RELIABILITY | RESILIENCE | SECURITY




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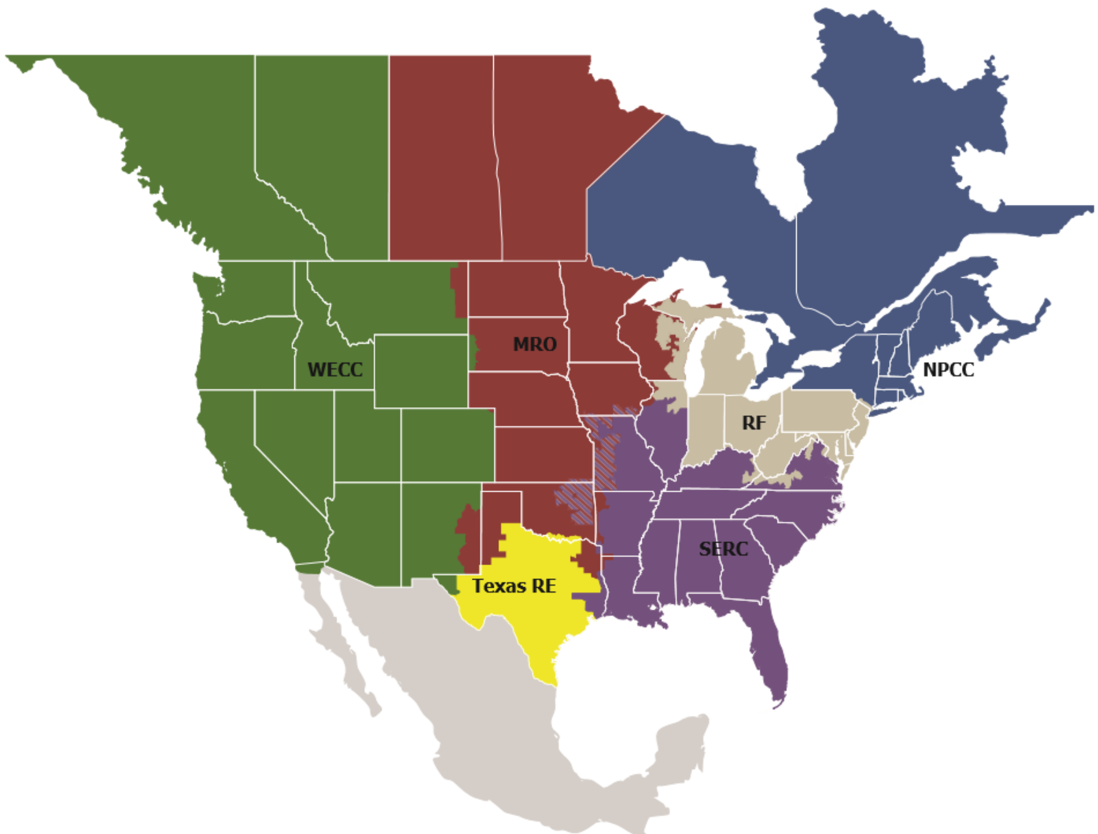
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The RSTC, through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

- Performance of the BPS prior to and after a Reliability Guideline, as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments);
- Use and effectiveness of a Reliability Guideline as reported by industry via survey; and
- Industry assessment of the extent to which a Reliability Guideline is addressing risk as reported via survey.

Specific Metrics
The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness.

- No additional metrics

Executive Summary

There is a growing need to ensure the accuracy of Interconnection-wide planning cases, especially as some states are enacting policy that targets a specific level of Distributed Energy Resource (DER) integration. Those cases contain detailed information on transmission level elements, as well as the impact of aggregated load, DER, and other distribution equipment has on the transmission system. The policies highlight the need for the bulk power system's planning assessments and future Interconnection-wide studies to have forecasted DER integration levels with reasonable accuracy so that any planning decisions, such as transmission projects or Corrective Action Plans (CAPs), are enacted in high confidence. DER forecasts have historically started with a company's Interconnection Queue, which provided an easy way to plan for areas with rapidly increasingly levels of DER, and usually used augmenting assumptions such as a relative certainty of resource delivery[1] to finalize the forecast[2]. Once a projection was considered to be the most reasonable projection out of a multitude of others, it was determined to be the forecast and decisions were made on those values. Now, many utilities perform Integrated Resource Plans (IRPs) that use many data sources and feed into many differing studies at both the transmission or distribution level. As these plans develop, each Transmission Planner (TP) or Planning Coordinator (PC) has varying procedures to produce a load or DER forecast that is used within these plans. Because of the complexity of projecting DER growth, there is not an objective way to determine what projection is more "correct" in its capability to predict the future until such future is realized. Because of this, there exist qualitative ways to condition the projections, depicted as a probability or relative likelihood, to describe the trustworthiness of a DER forecast[3].

While novel as a separate forecast, the DER forecasts would follow similar procedures used in load forecasting. Indeed, it may be the case that the DER capacity values are already embedded into the load forecast; however, the increasing growth of DER highlights the possibility for directly accounting for DERs as a separate item to be projected and studied by transmission entities. This does not mean; however, that all entities must have an elaborate forecasting procedure. It does, mean that entities should be aware of how the differing projections in their area, can impact their planning decisions.

In this document, the terms "projection" and "forecast" can have similar meaning in most cases. However, it should be noted that the term projection typically refers to a possible future path and useful for "what-if" scenarios and the term "forecast" typically refers to the path expected to be taken for the future based on reasonable assumptions and actions. This distinction becomes very evident when looking at the likelihood of materialization of such resources. A low likelihood projection with minimal changes is not one to perform rigorous study; however, the higher likelihood and higher impact projections are of interest to the TP and PC.

This Reliability Guideline identifies the two large categories of forecasting strategies used in load forecasting: top down and bottom up. The top down approach creates projections over a wide area and can ignore local behavior to focus on the behavior of the whole, while the bottom up approach focuses creates projections of individual component behavior before aggregating those impacts to the level desired. When using a top down approach, there are many disaggregation techniques that can be used, two of which are mentioned in this Reliability Guideline: the proportional allocation method and the geographic distribution method. For bottom up approaches that build the forecast up from individual substations or smaller electrical boundaries (e.g. individual circuits), there is no need for such disaggregation. For both large categories, however, a large amount of data typically feeds the projection. If this data is not of high quality, the projection, if used as the forecasted values, will provide misleading, useless results.

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[1] As an example, the NERC Reliability Assessment Subcommittee defines different tiers for future interconnection to distinguish resources that are near certain to be constructed from those that are uncertain.

[2] In this document, the term "forecast" typically to the path expected to be taken for the future based on reasonable assumptions and actions. It should also be noted that the term "projection" refers to a possible future path and useful for "what-if" scenarios.

[3] Some items, such as an expected or future policy, are non-quantifiable as a probability or likelihood of occurrence. These are capturedin a forecast by projection or scenario studies.

It should be the goal of a TP or PC to ensure the data and projection used in their forecasts is useful in their studies[4] performed under TPL-001 or otherwise. To help provide guidance to those entities, the SPIDERWG has identified a few key high-level recommendations when entering in values for future long-term planning studies:

- TPs and PCs should attend and contribute to current forums where DER forecasting is discussed. Further, TPs and PCs should coordinate with Resource Planners (RPs) to discuss forecasting of DER in their region.
- TPs and PCs should coordinate between their load forecasting and planning departments to ensure forecasts meet the TP/PC requirements, namely for development of base cases, and TPs/PCs have a better understanding of forecast assumptions.
- TPs and PCs should improve their relationship with distribution entities (e.g., DER developers, DER owners, and DPs) to gather data to be used in forecasting; or use a trustworthy outside entity that can perform DER forecasting for them.
- TPs and PCs should develop checklists as in **Figure 2.2**, altered to fit their needs, and use the list when incorporating forecasted data in their planning studies.
- TPs and PCs should utilize a variety of projections in order to determine whether such projections should be the basis of the DER values for the study. This may mean a forecasted value is used for only a portion of all studies performed by the TP or PC.

[4] Or, for TPs and PCs that use external forecasts, that the forecast chosen is useful for their study's objective. Some studies may require lower likelihood projections opposed to those chosen for a DER forecast.

Introduction

Many utilities perform an Integrated Resource Plan (IRP), which utilizes the growing consumer demands, load shapes, and the resource acquisitions in the long-term planning realm. These IRPs are performed at the utility level and are separated into capacities of coal, natural gas, solar, etc. as it pertains to the utility. In this process, the whole system electricity demand is projected across the region with the generation and demand side projects evaluated on their impact to the demand. For the purposes of DER, these IRPs focus on the utility's obligation to meet the demand across all times, and to procure resources to meet forecasted demand. This indicates that if the demand number does not have adequate consideration for the resources behind the load, the transmission level resource acquisition may not be fully sufficient to meet demand. In particular, this is true for areas with high DER penetrations with little to no data. This accounts for regional differences in the number of utilities attempting to collect and forecast DER data due to their current DER penetrations.

Recently, entities have moved from this historic IRP process into a multi-use, detailed forecasting procedure. See **Figure I.1** that illustrates this move. On the distribution side, these forecasts can be much different, as their objective is to address physical and operational changes to maintain safe, reliable, and affordable service on a different scale, design, and load flow than the transmission system. As such, the DER impacts are more direct in the distribution process as small local changes can dramatically change a distribution level forecast. For the same change of a transmission level forecast, a larger amount of widespread DER would be needed. For both the transmission and distribution systems, DER inclusion into these numbers is critical for building predictive study cases that represent the resources at future times. This guideline covers both the forecasting practice assumptions and data quality that goes into these practices as they play a vital role in providing high quality BPS transmission studies.

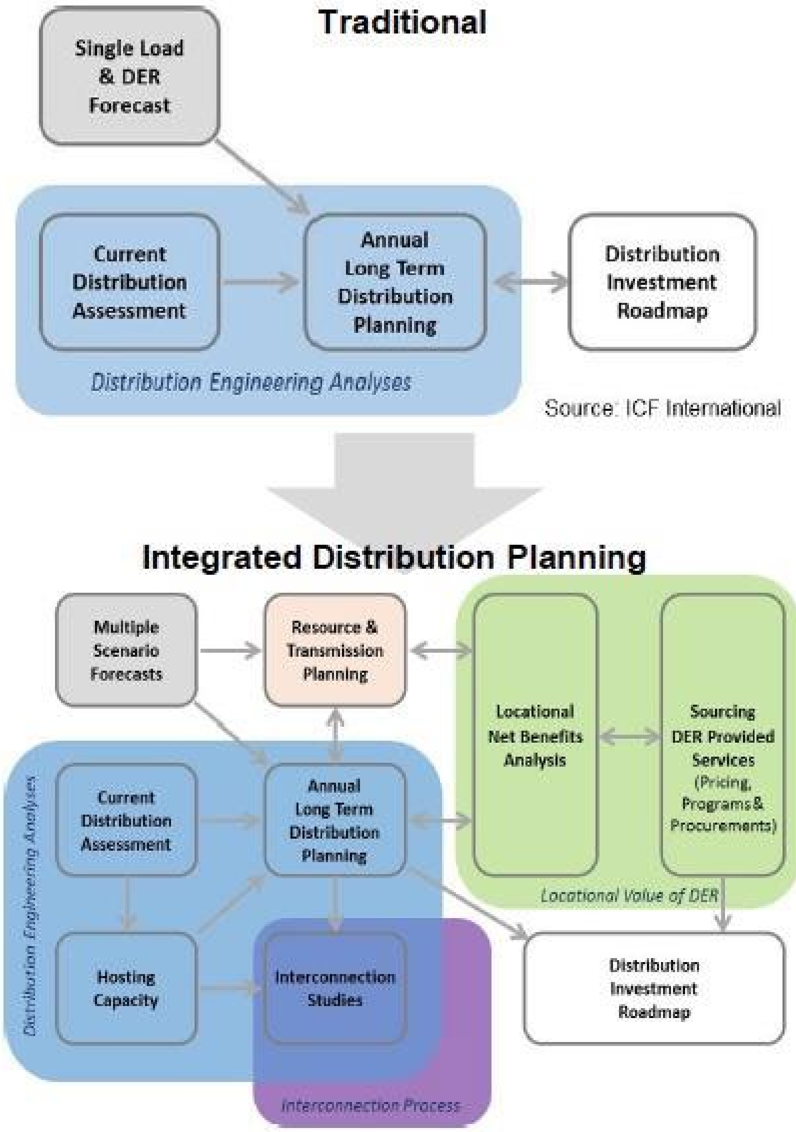

Figure I 1: Move to Integrated Distribution Planning [Source: Minnesota Public Utilities Commission]

In this document, the terms "projection" and "forecast" can have similar meaning in most cases. However, it should be noted that the term projection typically refers to a possible future path and useful for "what-if" scenarios and the term "forecast" typically refers to the path expected to be taken for the future based on reasonable assumptions and actions. This distinction becomes very evident when looking at certain ways to enter in DER values for study. For example, if the TP or PC determines that it is highly likely that given the surrounding conditions their DER growth will triple by the end of the decade, then they may invest in their system to ensure reliability during this period of growth. However, if that same tripling was to be very unlikely to occur, the TP and PC would want to know the risk associated with it, but may only propose transmission upgrades to developing their transmission system until such resources became more firm. The former case is indicative of a forecast, while the latter, a projection.

Both transmission and distribution entities are also moving towards another type of forecasting done at the utility, PC, or ISO/RTO level. Those entities are incorporating more variation of scenarios (i.e. Energy forecasts of solar PV, load growth, energy efficiencies) and placing it into a dual, long-term Distribution and Transmission Planning scenarios. The incorporation of such extra scenarios transforms the original IRP process into a new forecasting method that can incorporate the end-uses better rather than looking at a net peak load, thus enabling explicit accounting of the drivers and risks behind long-term forecasts used for Interconnection-wide base cases. These scenarios and transformation from the original IRP process is to overcome the limitations of using a single data point for all transmission and distribution requirements. These changes allow for a forecast to provide use in both transmission and distribution system planning, operation, and risk assessment.

If assuming any load forecasts do not have DER associated with them, any correlations or changes to normalize load may not be correct[5]. This limitation arises because historical data, while it provides opportunities for regressive mathematical techniques that are looking at peak load in each hour or day, does not have a robust data source for DER as it does for gross load. For the purposes of DER, however, this poses a major limitation in the forecast as the loading of the feeder and T&D bank will not explicitly track DER for input into the TP's long-term planning assessments and their studies, or other BPS-level studies.

Alternatively, the limitations of utilizing multiple scenarios for their projections, such as separating a solar PV DER forecast from other forecasts, arise when considering the additional data burden. Simply adding in multiple scenarios will already require the process take in a larger amount of data to complete, and such additional refinements will provide the Planning Coordinator (PC) or Transmission Planner (TP) added "trust" to use the number in studying their system's future conditions. Regardless of the computational limitations, the need for a trustworthy DER forecast becomes important especially when PCs and TPs are looking for guidance on modeling and study procedures for their system. These aim to look into future year's projects and any additional projects required to achieve reliability in the long term, and to subsequently plan their system to alleviate any identified risk. In the case of DER, many TPs and PCs may not be aware that tracking the capacity, vintage, and location of DER can have the same impact in these future scenarios as the typical load forecasts. SPIDERWG has already provided ample amount of resources regarding the modeling, studying, and verification of the DER models for placement into BPS level transmission studies; however, many of the SPIDERWG documents emphasize engineering judgement as a method for projecting the changing landscape of DER. This document aims to provide some validation checks to assist the TP and PC in finding a good forecast to base their long-term planning studies on. Additionally, this document aims to demonstrate current forecasting methods that may be able to capture DER growth in order to provide a common basis of understanding on the types of methods to project DER for use in future studies, as well as when to use differing projections.

[5] For instance in producing a load duration curve for use in reliability studies.

Chapter 1: Long-Term DER Forecasting Practices

It is crucial that load and DER forecasts provide adequate and reasonable projections for future studies within the context of comprehensive integrated resource planning. Generally, a resource adequacy assessment requires information on future firm capacity increases in order to determine any deliverability upgrades necessary to meet generation and load needs at a variety of future conditions. These studies generally contain a base case and accompanying sensitivities. Including a trustworthy projection of DER in the Interconnection-wide planning cases is critical, as the lack of a trustworthy DER capacity will create concern on the validity of decisions supported by studies on those cases. Distribution entities need information from load and DER forecasts in order to plan future projects to meet net load on their systems at times when DER is and is not able to supply the local load. Similarly, transmission entities need a trustworthy information on future load and DER projections to plan their system, especially given the long lead times for such projects.

Key Considerations DER Forecast Use in BPS Planning

Load and DER forecasts are used in more than just BPS planning processes. Therefore, prior to developing and using DER forecasts, it is important to consider the key dependencies and relationships between DER forecasting practices and the use of resulting DER projections in BPS planning. These dependencies are important because they can affect how the entity chooses an acceptable DER forecast. Key considerations and dependences between DER forecasts and BPS planning are highlighted below.

Planning Model and Study Inputs: Even with a hypothetically perfect forecast, it is necessary to understand how the forecast will be used as an input to the planning model. These inputs can be as simple as a MW rating in the load record that represents a single T-D interface, or as complex as a separate data object that allows planners to specify a multitude of DER parameters in a powerflow case. When forecasting for this equipment, the DER forecast should take into account what TP model inputs are needed. An example of this is the 'Dgen' value in PSLF's load record or 'Distributed Generation' value in PSS®E's load record. These modeled values affect any post-processing or method selection depending on the desired model input.

The type of study is also an important factor that impacts the applicability of a particular forecast method, acceptable level of uncertainty, or even if a projection should be used in lieu of a forecasted value. For instance, a resource adequacy study[6] in the planning realm assesses the deliverability of the DER and other resources to the load, especially in areas where the transmission system is used to deliver the DER to load. In power system stability studies, such as under frequency load shedding studies, the TP tries to determine how the total DER plays into the dispatch at different scenarios and how their transient performance impacts the stability of the grid. In the former study, the DER magnitude and location are important, while the latter study requires additional information on known variations in transient response to grid transients such as voltage or frequency events.

In general, the expected transient performance of distribution connected DER depends on the version of IEEE 1547 that was in effect when the DER was installed. DER installed to IEEE 1547-2003 is required to cease output during grid voltage and frequency excursions, this is commonly referred to as "momentary cessation". DER installed to IEEE 1547-2018 must continue output during frequency and voltage excursions with what is known as "ride-through". Equipment manufacturers are expected to design equipment to the current IEEE 1547 standard and it is reasonable to consider that future DER installations will ride through voltage and frequency events.

[6] Resource adequacy studies have historically been performed using Monte-Carlo or Convolution-deconvolution methods in packages separate from the positive sequence loadflow software. Some entities perform a composite study that takes information from both the positive sequence software and the resource adequacy software.

Additionally, understanding the modeled composition of the DERs are needed to ensure accuracy of the forecasts. If many of the facilities could be modeled as U-DER in the study, these will likely have a significant sway in the distribution of the DERs in the study[7]. Additionally, U-DER is broadly categorized as a larger installation closer to the distribution substation. As larger projects, forecasting these DERs as smaller, end-use customers does not capture their characteristics in the forecast correctly. Similarly, forecasting DER modeled as R-DER will lend towards other types of forecasting methods that lend to modeling individual customers in the forecast. Determining the modeling practice of the DER may affect the way the forecast is performed. When modeled together as one value in the forecast, some disaggregation will be needed to decompose the forecast into the PC's modeling practice if such practice requires separation of the DER into R-DER and U-DER in their planning models. However, if the forecast contains accurate and explicit representations of R-DER modeled DER and U-DER modeled DER, the disaggregation will not be needed.

Level of load: Forecasters at various industry and regulatory entities are experienced at projecting the seasonal peak load values, but with seasonal off-peak load values, higher variances can be at play due to the nature of how the low load is attained. In these seasonal off-peak load forecasts, care must be taken to fully understand if that load is gross or net. Many forecasting agencies will provide values to use directly in planning studies; however, this does not mean that their data is utilizing gross load as the historic data can have varying values of DER masking load. This is especially true if the entity utilizes a baseline measurement of load today as opposed to many years ago. Today's load mix can include large amounts of DER in certain regions, and care about changing the forecasting value from only load to DER plus load should be taken in order to differentiate between the load portion and DER portion of historically produced load. There are two key concerns related to load masking of DER that is mostly solar PV. First, given the probabilistic capacity value (e.g. given weather variability) the TP or PC needs to characterize the probability or likelihood of cloud cover during peak load. This is compounded as the planning criteria may be very different than what is seen in historical data. Secondly, the time of the net peak load shifts as PV penetrations increase.[8]

Uncertainty in data: As with future long-term projections, there exists a level of uncertainty in the projection. In terms of load, this is a load forecast uncertainty (LFU) that quantifies the year over year deviations possible in terms of a final number. In any forecasting procedure, a certain level of certainty is prescribed to the load level presented. This is called a "50/50" or "90/10" load level and assigns a certain level of certainty that such level will not be higher than the listed amount, mimicking a Cumulative Distribution Function (CDF) of the load. Uncertainties in load data are prescribed in this manner due to the nature of how aggregate load behavior is tracked. As of today, most DER forecasting practices do not use probabilistic modeling[9] to perform scenarios or predictions as historic data is not widely available to support such methods; however, DER forecasting will likely have the same dependency as the load forecast when using historical data for their projections.

Resource Profiles: In some forecasting methods, production data for a specific resource type (namely solar PV) is useful in adding confidence in a forecast. This is largely important with solar PV that has a proven temporal correlation to the power produced by the resource, shown in the resource profile. Resource profiles provide installation specific or aggregate data to how the total DER output changes in time. These shapes can also inform a sensitivity to check different hours of the day. In some transmission planning studies, the objective is to ensure deliverability of resources to load, and this type of study heavily relies upon knowledge of the operational profile of the resources, which can include DER. In operations type planning, such profiles are more valuable to determine the total expected power produced by installed capacity. Additionally, long-term planning studies may desire to know how the profile interacts

[7] To understand the modeling of DER as U-DER and R-DER, see modeling guidance here, here, here, and here

[8] For Example, at high enough penetration levels, even with little cloud cover, the net peak load will eventually shift towards night-time hours. This is a well known phenomena that the capacity value of solar diminishes as penetrations increase

[9] Weather-based probabilistic models, or probabilistic models in general, require a significant amount of data and computational burden in order to provide an accurate result.

with shifting base case assumptions. In short, these profiles provide a way to transfer capacity based projections into power production at a given time, which allows a TP to enter DER generation into their future cases.

DER Forecasting Approaches

Considering DER forecasts are developed for a variety of uses other than BPS planning, it important to understand the various approaches and methods in order to adequately use the forecasts within a particular BPS planning study. Depending on the primary use of the forecast and data availability, there are several different approaches and methods that can be used for producing DER forecasts. For example, many states provide DER forecasts to utilities, while others provide supplemental information that can be used to enhance a given forecast. A few approaches and methods in use today are detailed below. Note that these approaches and methods are not mutually exclusive and a single forecast can use a combination of multiple approaches and methods. Further note that these methods can be used to model the behavior of DER that can be modeled as R-DER or as U-DER. As always, engineering judgement is needed to assign forecasted quantities to values for R-DER and U-DER in the recommended modeling framework.

Top Down Approaches

Top down approaches forecast DER at a high level – typically regional, state, balancing area, or utility service territory – and allocate portions of the forecast to smaller areas. Please see the section on DER Forecasting Methods to determine which approach would best fit for the projection or forecast. The top down approach is characterized by formulating a widespread characteristic to determine the DER capacity, location, or other quantity tracked. In order to be useful to individual TPs, this high-level approach needs to be broken down by some disaggregation technique. Some of which are described in the section below.

Disaggregation Techniques

Geographic Distribution: This technique allocates future DER projects in close proximity to the current installed capacity (MW) in each geographic region. Any capacity projection can be allocated based off the geographic distribution formulated before. This method works best under similar sized geographic regions that are not expected to change in future years. However, certain methods can mitigate against the shrinking or increasing of geographic boundaries in the forecast. After each of the geographic regions has allocated its final capacity (MW) for the case, these capacities are further allocated across all of the buses in the planning model that represent that region via some allocation method[10]. An example of some of those regions using a direct proportionality are included for ISO-NE in Table 1.1.

Table 1.1: Sample Geographic Distribution by ISO-NE

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.7
	CT	NorthernCT	18.6
	CT	Norwalk_Stamford	7.3
	CT	WesternCT	55.4
ME	ME	BangorHydro	14.6
	ME	Maine	49.9
	ME	PortlandMaine	35.5
MA	NEMA	Boston	11.9
	NEMA	NorthShore	5.8
	SEMA	LowerSEMA	15.1
	SEMA	SEMA	21.2
	WCMA	CentralMA	14.0

[10] Commonly this is a direct proportion, and if so, is combined with the proportional allocation method; however, these allocations do not have to be directly proportional but can be some other allocation method.

	WCMA	SpringfieldMA	7.1
	WCMA	WesternMA	24.9
NH	NH	NewHampshire	90.6
	NH	Seacoast	9.4
RI	RI	RhodeIsland	100
VT	VT	NorthwestVermont	62.3
	VT	Vermont	37.7

Proportional Allocation: This method allocates DER forecasts using a ratio based on some other metric or measurement at each circuit/substation along with knowledge of the system topology, irrespective of geographic distribution. See the sample diagram found in Figure 1. 1 that describes one mathematical composition and calculations to perform this method. Example measures that can be used for proportional allocation include number of customers, customer propensity scores used for modeling end-use customer behavior, energy, peak demand, and other system level measurements. For example, a DER projection by county can be allocated to each circuit or substation based on the proportion of the number of customers on each circuit/substation to the number of customers in that county. This method, however, does not take into account geographic diversity, which plays a part in capturing solar irradiation for solar PV devices.

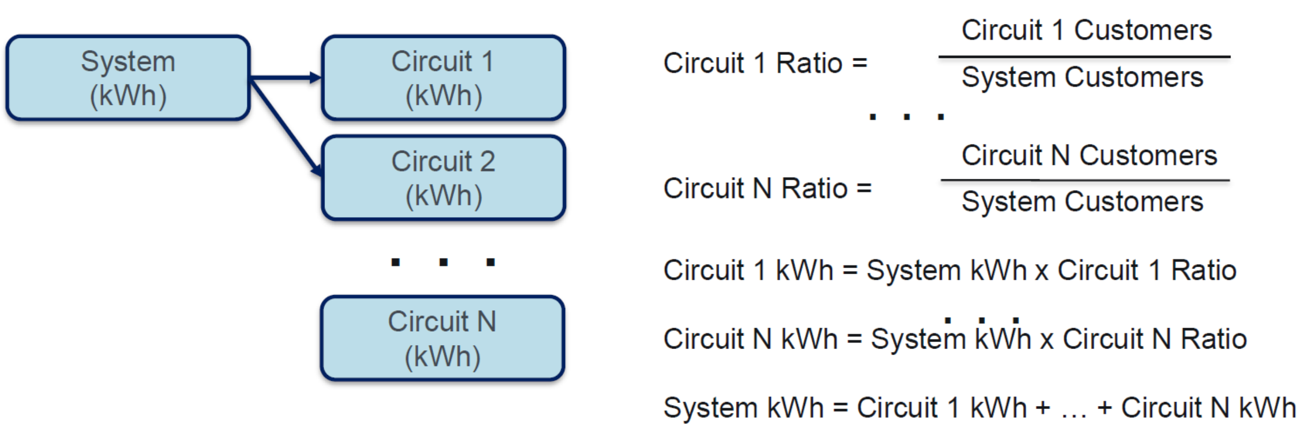

Figure 1. 1: Proportional Allocation Flowchart

Bottom Up Approaches

Companies that have access to appropriate data can use certain approaches to aggregate forecasts up to a specific point (i.e. at each substation, or geographic region). These strategies are typically called bottom up as they use specific information and aggregate the projections to the point desired.[11]

Traditional Load Peak forecasting method: This method is relatively simple and involves utilizing operational data to track the feeder or T&D load bank peak active power in the year, and adding those up to gather a full system peak. Adjustments are typically made to aggregate any non-coincident peak values from each substation to yield the coincident peak for a whole system. See Figure 1.2 for how this method can produce a projection. The aggregation of these values represent the system peak, with forecasts performed on each load record[12] to demonstrate expected growth in each area. The disadvantage of this method is the possibility of load masking; where as an explicit projection of DER can alleviate this concern. As DER is a resource, this method assumes that the peak historical output is the

[11] Bottom-up modeling in this document refers to the buildup of forecasts and projections by electrical boundary areas (e.g., substations, distribution circuits, customer meters, etc.) as opposed to other types of "bottom up" approaches (e.g., by end devices or by customer classes).
[12] Which can represent one T-D interface. Some of these records are a single feeder, many feeders, or a large region served by a distribution company

maximum capacity capable, which is not necessarily correct. In order for it to be the true capacity, the DER would have to be producing at the inverter nameplate rating for all inverters connected to the feeder. For a variety of reasons, that assumption may not hold. Furthermore, projections or forecasts that are based on a measured peak load are susceptible to error. Without visibility into the production of DER during a measured peak load condition, planners lack the ability to measure the native load and account for the explicit impacts of DER for projecting to their future cases.

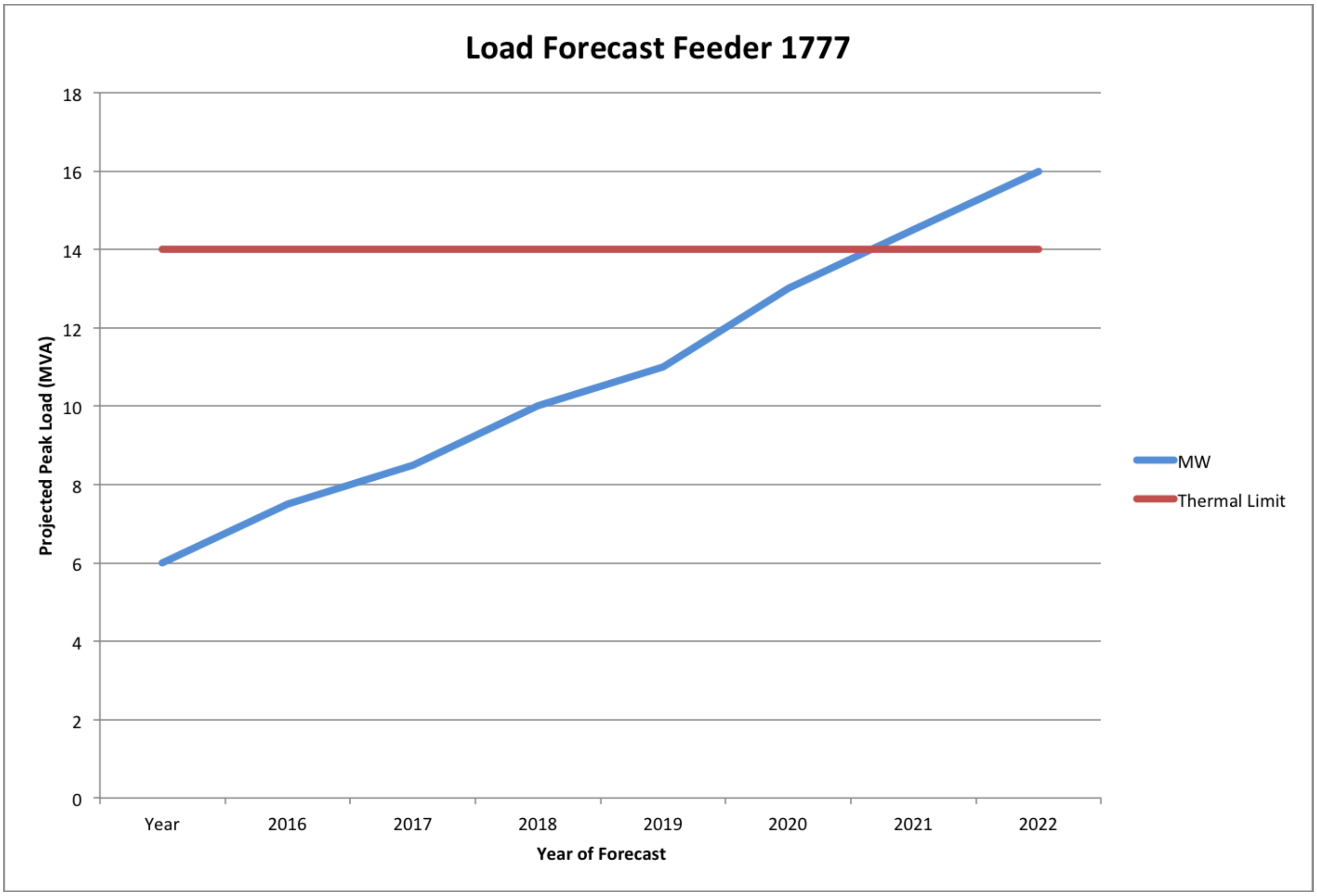

Figure 1.2: An Example of Peak Load Forecasting [Source: NREL]

Net Load simulation method: To align the high-level forecast with the planning models, future net load scenarios can be based on disaggregating the net load into component parts. As such, the native load is separated from the DER, and the DER resource profile is developed from coincident, historical hourly load and production data. Rather than using the peak data and projecting based on expectations, this method performs a simulation on the resource profiles to provide a final expected DER capacity for the projection. A variety of assumptions regarding the types of load, DER (if accounted for), and expected conditions typically accompany the simulation. If historical measured production data is used to create forecasted production profiles of DER, an underlying assumption is that the system design and technology trends are not anticipated to change significantly over the forecast period. If significant changes are anticipated, a simulation explicitly accounting for impacts can be performed.

DER Forecasting Methods

Regardless whether the forecast uses a top down or bottoms up approach, if the forecast explicitly accounts for DER as a component of the net forecast, a variety of methods can be used to develop a DER projection. As DER is being tracked, this produces a variety of differing methods from the traditional peak load forecasting method, and using these methods are recommended for entities producing forecasts.. A few different types of methods are described below, which include time series extrapolation, policy-based approaches, macroeconomic simulation, bass diffusion models, and adoption models.

Time Series Extrapolation: This approach uses historical adoption rates of a period of time and extrapolates that growth rate into the future. While this method is easy to develop and communicate, it does not account for potential adjustments based on changing economic conditions or other drivers.

Policy-Based Approaches: This method leverages known or stated policy target or other established goals and assumes an adoption forecast will successfully achieve some percentage of the stated target by a given date. While this method is straightforward and easy to implement, it requires a stated policy and assumes measures are in place to reach the policy goal.

Macroeconomic Simulation: With adequate data, these methods simulate economic activity at the macro level by taking into account supply cost curves, availability, population growth, policy impacts in the form of tax incentive or capacity limits and some are even co-optimized with capacity expansion models to determine optimal resource portfolios. These approaches, however, typically generalize the decision-making capabilities of the DER owners and assumes that all the expected changes in the market structure are included in the simulation, and may represent unexpected changes as an uncertainty. Additionally, this method assumes that the optimized macroeconomic solution is predictive of the changes to DER; however, some willingness-to-pay charts may not be indicative of changes in mindset for the end-use customers.

Bass Diffusion Models: This method has several variants which models aggregate diffusion of new technologies into society. While the model is relatively straightforward and simple to solve without advanced software, they are limited in the ability to project dynamic changes in adoption overtime due to changing policy and market conditions. Further, they often require additional information from other sourced to assume or predict the level of full market saturation.

Adoption Models: Adoption models attempt to model customer adoption behavior based on number of influencing factors including electricity rates, DER technology costs, or customer demographics such as income level. These models use many different inputs, such as policy impacts, economic impacts, and other socio-economic trends to determine the adoption rate. Adoption models can make granular forecasts at the premise or circuit level where they can be aggregated up to each substation bus. Alternatively, they can create forecasts at a higher zip code or county level where additional disaggregation techniques may be needed to allocate of forecasted values to individual substations for use in planning models. **Figure 1.3** illustrates how this can be done on a circuit level and then aggregated up for use as a projection, or can be used at the circuit level and not aggregated depending on the needs of the study[13].

[13] For TPs and PCs, this circuit level is not an anticipated need. However, if done at a T-D interface, this may be of use to TPs and PCs.

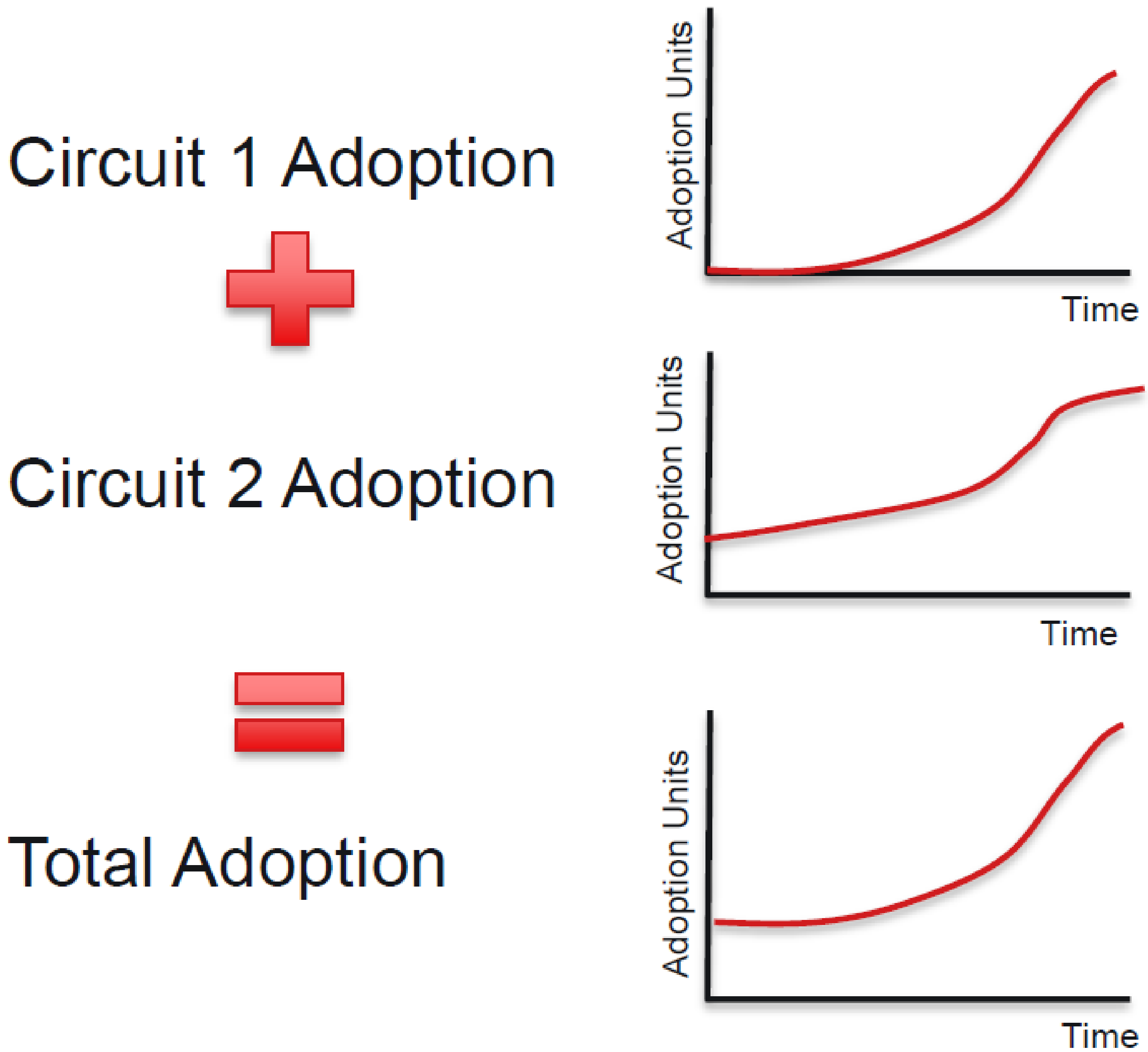

Figure 1.3: Adoption Model High Level Summary [Source: Itron]

Agent Based Models (ABMs): A variant of granular adoption models, ABMs model decision making of each customer as a set of specific preferences based on demographics, geographic locations, behavioral attributions, social networks, and other socioeconomic parameters. ABMs attempt to bridge the cultural attributes of DER adoption to the market data on DER, and depended on the specific attributes assigned to individual agents and assumes that the list of attributes in question can quantify the customer perspective of DER. Granular models require large amounts of data at the premise level of circuit level in order to provide a wide-area forecast; however, it does allow the planner flexibility in modeling each circuit explicitly, which can transfer over to the load bank representation in their planning model used in their studies.

Customer Behavior Modeling[14]: As each of DER installation represents an owner's decision to purchase the equipment, future installations can be modeled by estimating future customer purchases decisions. In aggregate, these look like a total customer behavior in a geographic region. As each electrical end-user can choose between distribution providers in some markets, and between self-generation in areas of regional monopolies, the choice can be simulated in a market. By using market or survey data, the modeler characterizes the preferences of these owners to each of the technology attributes. In relationship to DER, key attributes could be the local price of electricity, emissions, provider reputation, geographic location, and appearance of the installation. As purchase, decisions vary, and markets shift with time, these models must be updated accordingly. The total number of customers purchasing DER then can relate to the inputs to the powerflow programs depending on how specific the geographic data is. There are two primary methods for modeling customer behavior:

Econometrics: this approach uses some form of a regression model to quantify the impact of key drivers on customer adoption behavior using historical purchase data and actual choices made by customers in the market. While it is good to validate key drivers of actual purchases, for ancient technologies with little historical adoption, preferences or demographic characteristics of future adoption populations may differ from historical data sets.

Stated Preferences: This approach estimates customer preferences using surveys asking questions about hypothetical purchase decisions among a set of alternative choices. While this method is useful for gathering information on emerging technologies and enables the creation of scenario-based outcomes, the lack of validation from actual purchase decisions can cloud results.

Current Forecasting Entities

In the present state, there is a lot of forecasting being done at the state-by-state level, with varying methods. National Labs have also helped by stepping in to perform the load forecasting process for some entities, and those forecasts can be useful to help identify the procedures similar to DER forecasting. This move to the multiple scenarios allow the utility to garner more information about exactly how their forecasting practices can involve; however, not many utilities will have the capabilities to produce such a detailed listing of scenarios for their area. To fill this out, contractors and other state regulators have provided energy forecasts to the utilities. Some examples of utility originated forecasting practices are summarized below. The utilities below have a major penetration of DER, and as such, have had some years to begin looking at different methods of forecasting.

NVEnergy

Currently, NVEnergy does not get a forecasted capacity or spread of DER from their state or Public Utilities Commission. Their forecasting practices are generated internally for many different DER types, including rooftop solar, wind, and battery technologies. Additional inputs are gathered from their departments that look at net-metering and renewable energy incentive programs to adjust this forecast in addition to any state and federal policies, local or state mandates, and additional publicly available information. When performing this forecasting, NVEnergy assumes that the driving factor for these forecasts is based on federal incentives and growth of historical applications for both rooftop solar and batteries. Because their method is not only based on customer class level (residential versus non-residential) but also on a system level, NVEnergy is able to use those classes to determine the placement of DER into their models. They anticipate using a geographic distribution method for future efforts and will adjust their procedures accordingly if the process change fits their needs better.

IID

IID has their own internal process that determines their DER MWs rather than relying upon a state commission or other state body to provide these numbers. Their general method for forecasting either load or DER breaks apart differing sets of assumptions and attempts to relate everything to either market incentives or weather. Then, they take a model and apply it against historical projections and the model that has the lowest Mean Absolute Percentage

[14] Guidance on Solar PV Adoption Forecasting Methods for Distribution Planning. EPRI. Palo Alto, CA: 2018. 3002014724

Error (MAPE) is chosen to forecast both load and DER. By doing so, they are able to model very complex relationships in their region and vary their own incentives for rooftop PV (both U-DER and R-DER). IID estimates that their saturation point[15] if they do not incentivize DER to be 110.5 MW, and if they do incentivize the technology, 184.5MW in 2033. Every time they perform these predictions and forecasts, they revise their projections and ensure the process is accurately capturing the growth of many different technologies. For instance, they break out lighting; electric vehicle, PV, and other load technologies and ensure that each is tracked in aggregate, much like the adoption model strategy. In their 2018 report[16], they have changed their Bass Diffusion Method from linear to non-linear when projecting Solar PV as the growth no longer follows that pattern. The results of their DER projection can be found in **Figure 1.4.** The figure demonstrates that between the two projections, the Base Case annual installations do not go higher than the ~19 MW per year historic annual installations. However, the High Case that has the market saturation point at 184.5 MW in 2033 projects the annual rooftop PF capacity additions to reach just over 20 MW per year.

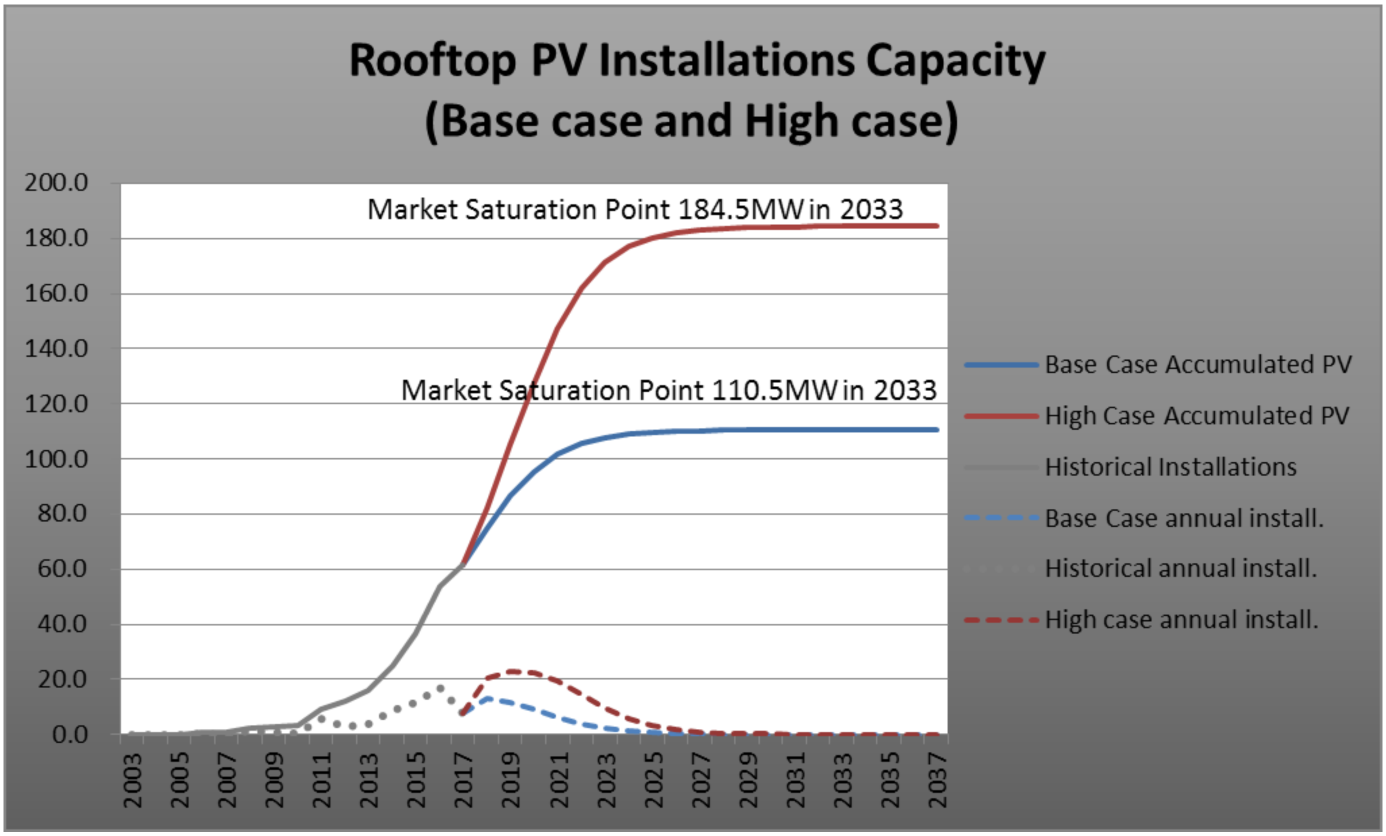

Figure 1.4: IID Projected PV forecast from 2018 Load Forecast

PNM

Like NVEnergy and IID, PNM does not receive state input for their forecasts, but rather completes their DER forecast internally. For their method, they do not explicitly track the total DER MW capacity for each year but rather track the incremental changes. Any existing DER is rolled up into their load forecast methods, rather than a specific DER forecast. Due to a lack of locational information, PNM distributes their DER additions across all their loads rather than targeting a specific bus for their additional incremental DER.

[15] These saturation points are limitations of capacity and are assumed values going into the forecast.
[16] IID's 2018 Load Forecast can be found here

DER Forecast and Modeling at the California ISO

California ISO (CAISO) considers and explicitly models DER in the transmission planning studies, since DER constitute a large portion of the CAISO power supply. The CAISO load forecast utilizes the latest Energy Demand Forecast developed by the CEC. This forecast includes applicable Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) scenarios from CEC. It also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) areas (Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric).

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts may not contain bus-level load forecasts, which are necessary for reliability assessments. Consequently, the augmented local area load forecasts that are needed for reliability assessments are developed by the Participating Transmission Owners (PTOs) These allocation methods are an integrative processes that extract, adjust and modify the information from the transmission and distribution systems and municipal utility forecasts, and include methodologies for modeling distributed generation (DG).

Behind-the-meter solar PV are modeled as a component of the load model. In the power flow load table, using the DG field on the PSLF load model, the total nameplate capacity of the DG is represented under PDGmax field. Actual output of the DG is based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest Distribution Resource Plan (DRP) filed with the CPUC as provided by Distribution Planning. Public Utilities Code 769 requires the electrical corporations to file distributed resources plan proposals. According to the Code, these plan proposals will "identify optimal locations for the deployment of distributed resources." It defines "distributed energy resources" as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."

The Code also requires the CPUC to "review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources." The ISO includes distributed resources in its power flow and dynamic stability models according with this CPUC ruling and with the Distribution Resource Plans provided by the participating utilities. Throughout the modeling process, there are several different sources and methods used for various DER forecasts as shown in Table 1.2 below.

Table 1.2: CAISO Data Sources for DER

Distributed Energy Resource	Source/Method
Behind the meter PV and non-PV generation	CEC demand forecast
Supply-side DG in front of the customer meter	PTO Wholesale Distribution Access Tariff (WDAT)and CPUC Renewable Portfolios Standard (RPS) portfolio
Energy Efficiency[17]	CEC demand forecast using a load modifier
Demand Response	CEC demand forecast for load modifying DR
Energy Storage	Procured storage from Load Serving Entities informed by CPUC targets

San Diego Gas and Electric (SDG&E) Further Modification

SDG&E's load growth forecast begins with the most recent approved CEC SDG&E Load Modifier Mid Baseline-Low AAEE-AAPV CED forecast. Known new loads, e.g., specific requests for new electrical service, are deducted from the CEC system load growth forecast. The resultant system-level growth is allocated by customer class (residential, industrial, and commercial), proportional to the customer class' forecasted annual energy consumption. The system-

[17] While this is not included in the SPIDERWG definition of DER, as CPUC Code 769 identifies this as a required item to study and forecast.

level customer class distribution is then allocated to SDG&E's distribution circuits using geospatial analysis using satellite imagery and vendor specific proprietary data analytics to score each acre in SDG&E's territory for the likelihood of increased load by customer. The output of the geo-spatial program is an annual SDG&E peak MW growth by circuit, by customer class for the forecast period. This growth is then uploaded into a vendor supplied forecasting program which uses customer-class load shapes to turn the allocated customer class growth amount into a 576-hour load shape that can then be applied to the circuit or bank load shape. This profile is then weather normalized to an adverse 1-in-10-year (90^{th} percentile of high loading) weather event forecast as the basis for making decisions regarding planned capital upgrades and permanent load transfers.

Chapter 2: Forecasting Practices and MOD-031

NERC standard MOD-031[18] serves as the primary NERC standard associated with DER forecasting. It exists to "provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." In the standard, it calls out that a PC or Balancing Authority (BA) that identified a need to collect data is able to do so pursuant to the requirement language. As MOD-031 calls out, the standards is to ensure that the "planners and operators have access to complete and accurate load forecasts." This chapter explores the mechanisms for data flow from different regional entities to the TP and PC.

Data Requests and Data Transfers in MOD-031-3

Currently, MOD-031-2 is the latest version of the MOD-031 standard that covers gathering of demand side information for future and prior years. As demonstrated in Figure 2.1, the MOD-031-2 process is a cyclical one in which the PC or BA is able to request certain data from other NERC registered entities. The data, in brief, is Total Internal Demand, Net Energy for Load, and Demand Side management data in the timeframe of one year prior to ten years in the future. Some of the data can be integrated to be an hourly demand profile (the one year prior) or, for the future cases, a monthly or annual number to be used alongside their studies. As this is not an hourly load profile, these values are useful in Interconnection-wide base case building and parameterizing various values in the positive sequence loadflow records.

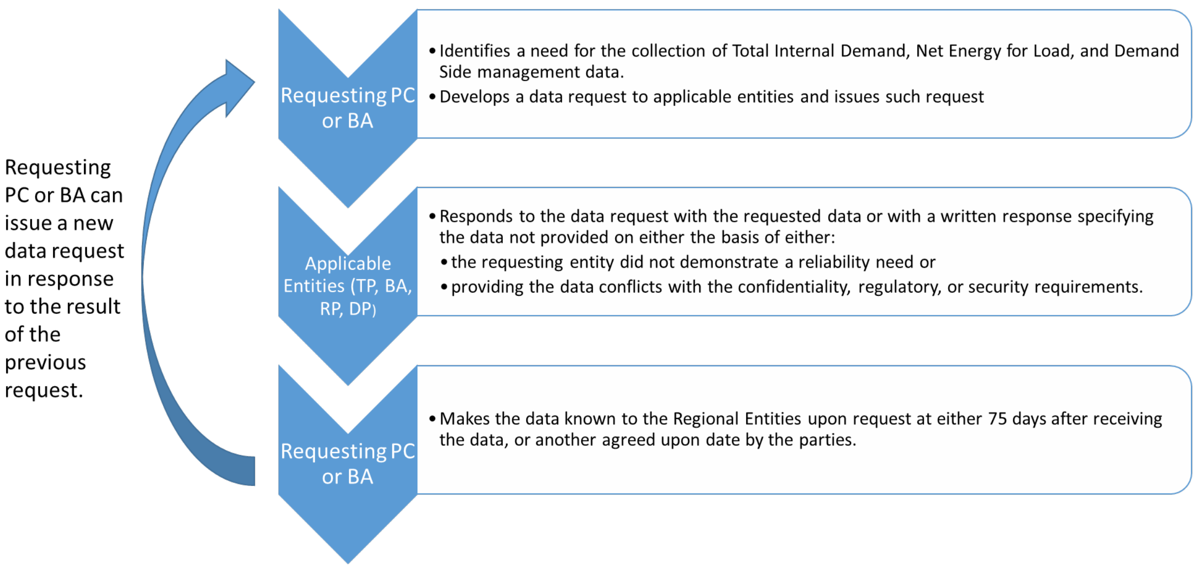

Figure 2.1: MOD-031 Logic Flowchart

As demonstrated in the graph, this data flow is only possible if the entities applicable are able to transfer the data to the requesting PC or BA for their use. The standard calls out that confidentiality, regulatory, or security requirements may make this data not available to be transferred, but procedures exist to alleviate or negate many of the concerns surrounding the data. Additionally, if the reliability need is not demonstrated, the entity can send notice to the PC or BA and the process can continue again. While this method of collection on forecasted values poses a simplistic cycle and vehicle to collect data to fill out load records, there does exist the collection of demand response type data clearly articulated in the standard requirements. SPIDERWG additionally reviewed this standard as part of their review of NERC standards.

[18] MOD-031-3 available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-031-3.pdf

SPIDERWG Standards Review White Paper Considerations

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has worked to develop a White Paper analyzing NERC Reliability Standards[19] to ensure the impacts of DER are adequately covered. The White Paper suggests revisions to MOD-031-2 for improving the DER data transfer between Planning Coordinators (PCs), Transmission Planners (TPs), and Distribution Providers (DPs). The SPIDERWG recommends TPs act as the intermediary for DER information data transfer between PCs and DPs. As the MOD-031-2 standard currently stands PCs can request data from either the TP or the DP, and with the suggested revision the PC would request DER information from the TP and the TP would make the request to the DP. The increasing levels of penetration from DERs will greatly effect MOD-031-2 and it will be critical to for TPs and DPs to communicate the forecasting information required for the PC to produce high quality and fidelity planning cases for their transmission studies. This Reliability Guideline covers the procedures and practices of a DER forecast, and is not dependent on this change occurring or not occurring.

MOD-031 and Interconnection-wide Base Case Creation

While a majority of the Interconnection-wide Base Case Creation procedures are handled by MOD-032, the information gathered as part of MOD-031 allow for the PC to either forecast or use a forecasted value in developing future base cases, scenarios, or other studies by the PC. When creating a base case, certain assumptions are placed based on the composition of the multiple elements and resources in order to produce a starting position where the PC (or TP in some studies) can apply a method to in order to produce a result. These assumptions are validated by the forecasted values with the data under MOD-031 If using MOD-031 to ask for DER information, an explicit item should be placed in the data request to be clear that it is requesting DER.

For a hypothetical example, a PC found that in aggregate, their data request under MOD-031 resulted in a value of load higher than the base case used for the next year, then the PC can adjust and validate their system-wide set up such that the base case represents such load. In a similar manner, a PC may determine that their previous base case assumptions contained too much DER capacity on the system for future year four from a previous request, and refines their system model to become more in line with the submitted data. Outside sources can supplement the forecasted value outside of a MOD-031 data request. Figure 2.2 shows the California Energy Commission (CEC) providing an expected solar PV rooftop forecast for public use, and should be used to help refine the base case assumptions used for future case setups.

[19] Draft is available here [link if published draft/final]

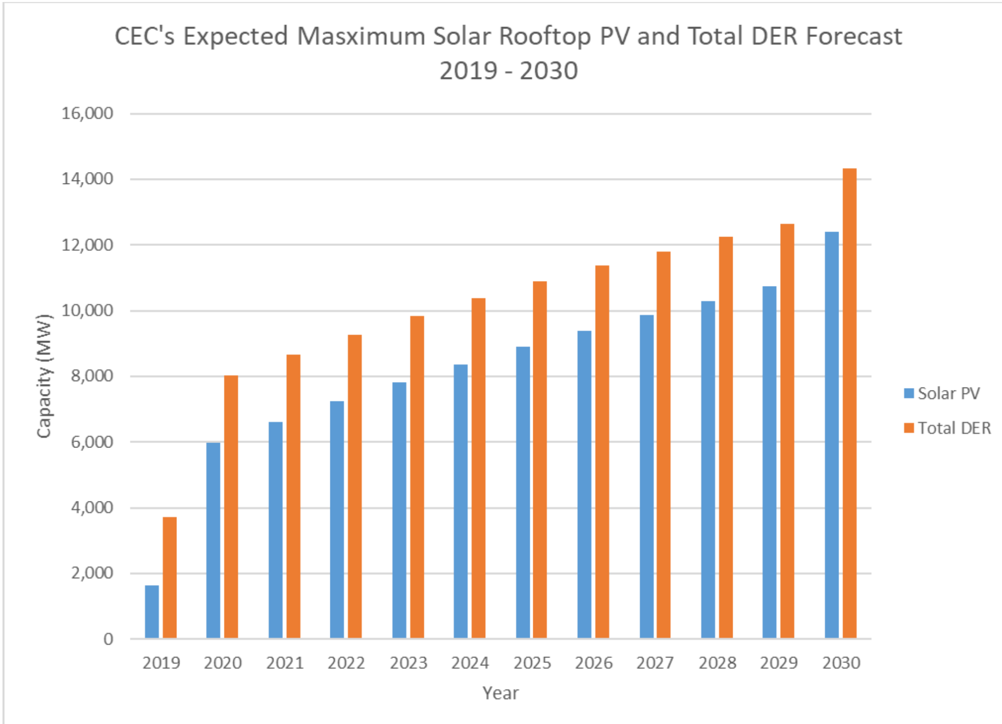

Figure 2.2 Example of Values to Build Base Cases

Best Practices and Forecasting Procedures

As the end result of this data for a TP or PC is to use in order to effectively plan their system, a few best practices come to light throughout the various forecasting methods in Chapter 1, and current vehicle to pass forecasted values to the PC to build future year base cases. As today's load mix can include a large amount of DER in a specific region, a TP or PC using forecasted values in aggregate should take care on how the disaggregation of the value in their region is applied. This is specifically concerning the disaggregation of DER from load; DER in a region from an aggregate, study-level DER value; and DER types from the total amount of DER represented at the specific region. Figure 2.3 shows how disaggregation of a forecasted value may occur. Assumptions and methods surrounding these separations should be based on latest available engineering judgement and documented in the base case building assumptions.

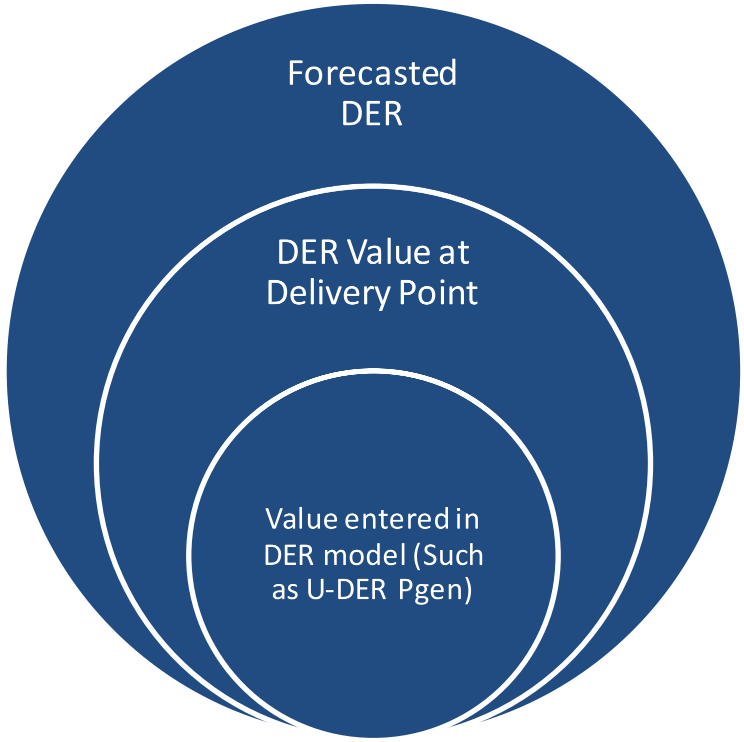

Figure 2.3: Disaggregation of DER into a Useful Study Value.

In order to better accomplish the task of entering high fidelity values in future base cases built by the PC, the TPs and PCs should improve their relationship with distribution entities in order to gather useful ancillary information that is useful to interpret forecasted values provided in MOD-031 (or another vehicle) and adjust their base case building practices and values accordingly. In the current list of NERC Registered Entities, the DP is the functional entity that contains a direct relationship with the DER associated with the distribution system they oversee.

Trusted sources, specificity of the region (e.g., substation specific versus region specific), and expected DER growth from the TP/PC are a few important factors when using the DER information to adjust the base case practices. As forecast approaches and methods are not mutually exclusive, a single forecast can use a combination of approaches and methods to also assist in verifying the values provided. As such, a TP or PC should fully understand the methods and approaches when provided with a forecasted value and take the most suitable one for their base case creation procedures. An instance of this can be seen when Arizona Public Service (APS) began implementing a different rate structure (Figure 2.4) based on the net load of their service area. This created a differing adoption rate (and thus forecast) of DER growth. APS worked with an entity to assess the potential solar adoption of rooftop solar in their service territory and forecasted their adoption using an S curve Bass diffusion model. The model added constraints by both customer segments as well as physical characteristics like shading, structural adequacy, and rooftop orientation. Such a model allowed the forecast to project hourly values when coupled with historic production and the forecast Global Horizontal Irradiance (GHI) from a typical meteorological year[20] in their area. The results of the simulation included annual production, capacity, and number of installs. In this instance, APS was able to provide the Western Electric Coordinating Council (WECC) their forecast values at specific substations in the base case creation process[21]. As their procedure forecasted the T-D operational profile, the location, capacity, and expected production

[20] This method of forecasting the GHI to produce an expected production profile allows for a forecasted capacity value to also produce an expected operational profile.

[21] To be clear, a forecast that does use exponential growth using the same data may have a different purpose and may still be useful in other instances than base case creation such as the development of a scenario case. However, for the submittals, this value was used in the forecast.

from that capacity, APS was able to send to WECC the major values needed when adding DER into a future planning base case.

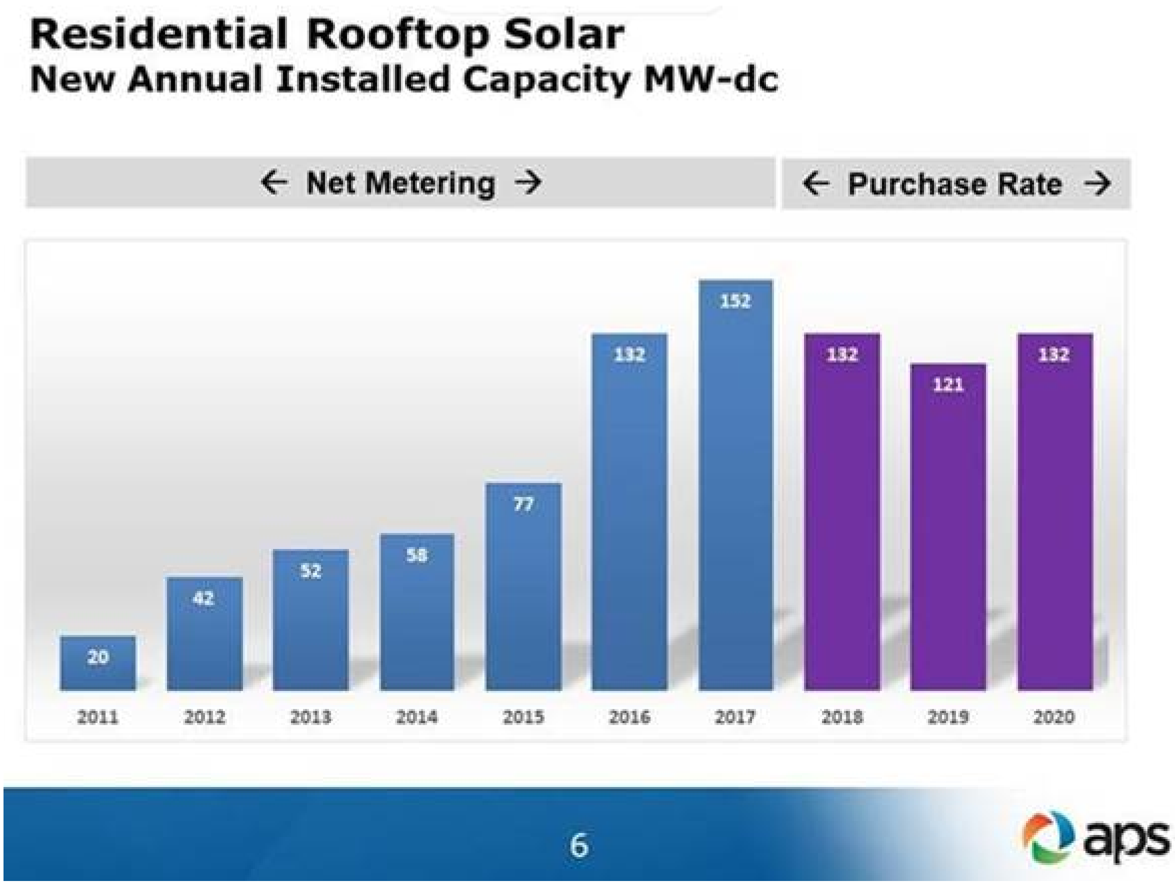

Figure 2.4: APS's Change in Annual Rooftop Solar Growth

Example Checklist to Verify Forecasted DER Values

Currently, some entities look at forecasts developed 4-5 years ago and see what it looks like today. Seeing a difference between these projections provides entities visibility to possible improvements in their process; however, a more proactive approach is recommended when producing, obtaining, or altering forecasted penetrations. An example checklist of questions a TP, PC, or other entity can ask regarding the DER quantities found in Table 2.1 is in **Figure 2.5** Answering these questions allows a TP, PC, or other entity a method to qualify their level of confidence in the future studies and base cases containing high quality data. It is recommended that TPs, PCs, and DPs coordinate on the more important questions to help improve the transmission system models and case development practices to ensure the information gathered in MOD-031 and other forecast entities is incorporated into such models and practices.

Did you find a reputable source?

- Was the data filled out completely?
- Are there any suspicious values?
- Is this an aggregate level forecast?

Are you tracking DER location in the forecast?

- DER Capacity
- DER dispatch and assumptions depending on base case
- Is there a link to base case inputs?

Are you taking into account expected operational profiles?

- Did you assume one profile?
- What are the profiles based on?

Do you understand the method, inputs, and outputs of the forecast?

- Did you need weather data?
- Did the forecast use more than one method?
- Did the forecast use sensitivities?

Does the forecast "make sense" from a high level and T-D perspective?

- Is the forecast coordinated with neighboors?
- Does the output of the DER match with assumptions?
- Did the forecast sensitivities include policy/market/economic changes?
- How sensitive was the forecast?

Figure 2.5: Example Checklist Questions for MOD-031

Depending upon the relative size of the area being forecasted, the above questions may have a differing role of their severity and other questions may also be added. For instance, in CAISO the TPs submit their powerflow data with the forecasted values in the steady state models. For CAISO, it would take more “error” to raise suspicion in the data received than for the TP forecasting their own set of DER penetrations. As such, the above questions do not have a size limitation or threshold associated with them, as they are applicable for entities that have a large or small penetration of DER.

Additionally, a T-D perspective may want to emphasize local factors that accentuate larger DER projections for use by the DP in performing distribution planning studies; however, a TP/PC may want to emphasize larger geographic projections for use in their studies. These forecasts may align in terms of DER capacity and location; however, this may not always be the case. TPs/PCs are encouraged to emphasize understanding the forecast assumptions and their base case assumptions to determine if forecasted values from the T-D perspective and the higher-level, geographic perspective need to align for use in their base case development process.

Key Points of a DER Forecast with Relationship to Planning Studies

Forecasts play into the base case creation process for future years for PCs and TPs to predict future risk and demonstrate the impact specific projects have to BPS level performance. These future studies should have high quality and fidelity information associated with them, as well as be representative of the conditions under study. In terms of the data, a few pieces of information come to the forefront when dealing with long term planning studies. In particular, MOD-031 already has a list of minimum values associated with the data request in its first requirement; however, an additional set of points, in Table 2.1, should be requested to validate the setup of future year base cases.

While having high quality data feed into future BPS planning studies is important, effectively using it in future studies has other considerations. SPIDERWG is developing a separate guideline on this particular topic. In light of this, the forecast values provided from MOD-031, or a separate source, should at least account for the key values in Table 2.1 as well as any other quality control checklists the TP or PC uses based on the sample in Figure 2.5.

Table 2.1: Key Values to Include in MOD-031 Data Requests and their Importance in Planning Studies

Item Requested	Information in Planning Study	Key Points
DER Capacity and Type (MW)	In order to fill out the steady state modeling tables, the total DER capacity would need to be accounted, as well as what amount of DER is expected to be contributing for the base case assumptions. Additionally, knowing which type of the DER was built during the historic years and projected future years will provide TPs a way to view the operational profiles of their local T-D interface and how such changes impact the way they study their area.	When building an Interconnection-wide base case, capacity information, dispatch patterns, and other assumptions are used to provide the starting cases. The DER capacity, type, and dispatch provides these BPS level studies a starting point for the expected future conditions. For other future assessments, distributing a larger region (i.e. state level) forecasted capacity with a type based on historical adoption can provide TPs a higher sense of trust for the expected future operational profile.
DER Location (Load Bus)	TPs and PCs want to know the geographic spread of the DER penetration and the electrical bus in their model represents that geographic region. At both a coarse and fine regional level, the TP/PC would want to know the proximity of DER to other load buses and any reconfiguration schemes that may change the DER location.	Knowing the existing locations of DER, combined with forecasted locations from a larger geographic level allows the TP to compare to a smaller geographic level[22] and gain more trust in their placement of DER in their planning models. In instances where the T-D interface depends on feeder configuration for DER, this can also impact the power flow of the associated Load Bus in the forecast.

[22] i.e. from a state down to a specific Transmission Owner or utility

T-D Operational Profile	TPs/PCs would want to know the expected type profile to determine their more risky hours. To do so, they would want to know the expected outputs for the aggregate DER modeled at the T-D interface between current conditions and future conditions. This is above and beyond simple capacity values and types.	DER forecasting entities have some level of assumptions tied to how the operational profile changes due to how much extra DER of specific types are deployed. TPs and PCs are looking at optimizing the case creation process based on many targets; however, the adjustments from T-D operational profiles may require the TP/PC to review how they expect the dispatch pattern or other characteristics of the DER in future base cases.[23]

[23] For example, DER forecasts that identify an increase of BESS DER in a region historically dominated by Solar PV would have the output of the aggregated DER at the T-D interface not be limited by irradiance in this future case.

Chapter 3: Long-Term DER Forecast Impacts to BPS Level Studies

In addition to the items listed in Table 2.1, the policy and market trends at the state or federal level will also be useful to consider when both developing the assumptions for the base case as well as forecasting the level of DER in those base cases. They may inform the TP or PCs sensitivity cases or even for studying of a long-term future for some policy targets. For example, policy that may promote specific DER development in certain areas. In recent years, a few types of these policies have been adopted regarding Battery Energy Storage Systems (BESSs), and would inform the types of long term study assumptions and accentuate portions of Table 2.1.

Implications and "Probabilities" of Different Projections

While discussed also in Chapter 1, the differences between the DER projections versus the forecasts come to light when looking at how differing projections implicate the end forecast. As each projection is a "what-if" scenario to determine the logical outcome of a particular impact, the forecast can be altered depending on the projection chosen to follow. Some scenarios, or projections, have a certain likelihood of occurring, which can be expressed as a probability.[24] These probabilities are difficult to obtain quantitatively, but are more easily expressed qualitatively or with relationship to each other. For projections based on non-policy items, a mathematical expression may be able to provide a probability; however, some policies pursued may have a greater impact on the end forecast. Some policies to consider are the renewable benchmarks in each state that project a specific percentage by a date. Relatively, some policy targets are more likely to be achieved than others are, and certain non-policy projections will have a higher likelihood of occurrence. A projection that focuses on solely the higher likelihood policies is well suited to use in a holistic forecast; however, sometimes a TP or PC needs to study the lower likelihood, high impact situations. In order to do so, the TP or PC will need to find a projection that focuses on these lower probability impacts for use in their future studies to determine the impact the differing projections have on their areas. To illustrate with a hypothetical example, say a TP uses a state-level forecast and disaggregates the forecast into their models. After ensuring and understanding the data taken from the forecast, the TP determines that under this forecast that looked at high and medium likelihood projections on adoption of DER in their area. The TP also noticed that this forecast occurred prior to a pledge for 20% more of their resources in a near-future date should come from DER. In order to meet that goal, the TP produces a separate projection for rapid deployment of DER; however, after careful study notices that this would be a lower likelihood than the forecast received from the state. This is useful to the TP to understand any risk this lower projection has on their area; however, their studies determined that the impact to their system under this lower likelihood projection requires upgrades to station service in a location that when using the forecast results did not occur. As a result, the TP produces a plan to upgrade that station, even though it used a lower likelihood projection, opposed to the forecast.

Long-Term Dispatch Considerations

Dispatch patterns vary according to the various kinds of resources. For instance, a T-D interface dominated by Solar PV DER will have different dispatch assumptions than one that contains Solar PV and BESS. Since they are behaving differently, forecasting just one DER value for study will require some engineering judgement or considerations of expected output at the future modeled conditions. An example of these conditions changing can be found in Table 3.1, where the historic DER installation has been estimated and then forecasted for future BPS level studies. Just by looking at the capacity changes, a determination on the expected flow or impact to the T-D interface cannot be reached without also looking at the changes that has to the dispatch profile. A sample using hypothetical data of how this may be altered is shown in **Figure 3.1** that takes the capacity changes and, assuming the changes are like the historic, visibly alters the aggregate DER output. As demonstrated in the figure, both the maximum MW produced and the times where those maximums are likely to occur shift depending on the expected resource changes. As such, long-term dispatches should be examined when many differing resources make up the aggregate DER.

[24] Some items, such as an expected or future policy, are non-quantifiable as a probability or likelihood of occurrence. These are captured in a forecast by projection or scenario studies. Extreme weather scenarios, on the other hand, are an example of a probabilistically quantifiable projection.

Table 3.1: Example Dispatch Changes Affecting Future T-D Flows		
Item	**Historical Output**	**Future Conditions**
Resource Profiles	Obtained a historic output profile from SCADA system sampling near or at the T-D interface	Assumed same historic resource profiles
BESS MW Value	A 5 MW total of BESS were found to be on the feeder.	It is anticipated three new 4 MW BESSs are installed on this feeder, bringing the total to 17 MW
Solar PV MW Value	15 MW of U-DER DER is associated with historic T-D penetrations	5 MW additional U-DER is planned to be added for this future case. Total of 20 MW
Microturbine Value	A 1 MW microturbine was added before the large expansion of Solar PV and BESS in this feeder. It runs between 0700 and 1800 hours	Assumed same 1 MW turbine exists in the future case.
Other	A residual amount of data was not directly metered or associated with the BESS or Solar PV quantities. Its value can rapidly change and was associated with non-metered U-DER or R-DER	Same values applied in future case.

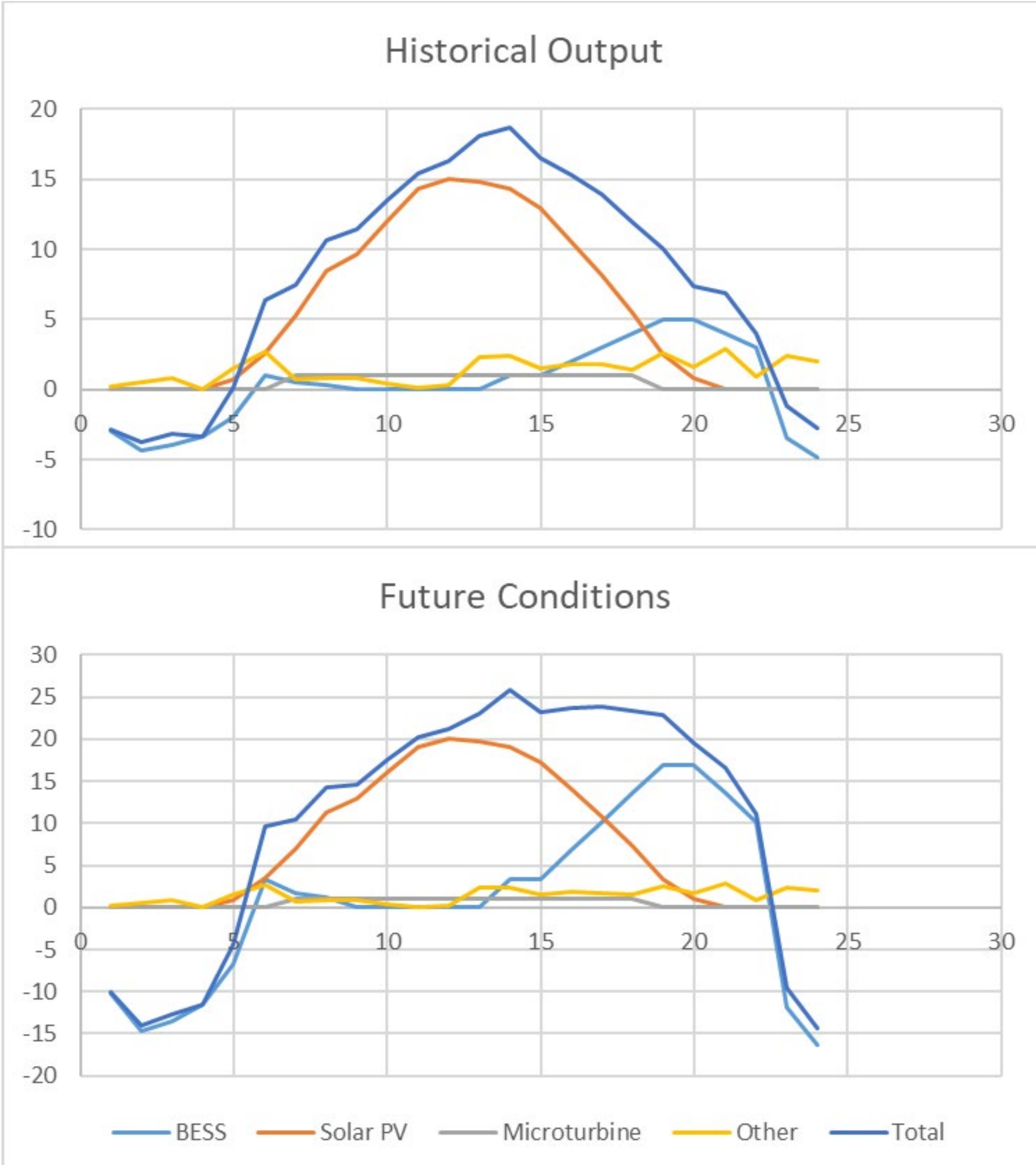

Figure 3.1: Example forecasting example at a T-D interface

Provided as an example, Figure 2.1 demonstrates just one of the differing types of profiles the future installations predicted for this T-D interface. This future operational profile may change depending on the types of services and interconnection agreements the installations will have. The point of this example, however, is that a TP or PC can use their engineering judgement to determine the risk hours for a T-D interface based on the forecast value, historic operating profiles, and anticipated changes to the aggregate behavior of the T-D interface.

Example from DER Forecast to BPS studies

A relevant example that follows through the approaches and recommendations from the previous chapters was supplied by ISO-NE. ISO-NE's load forecast department performs their load forecasting, which uses a top-down approach for each state. This way, they are able to capture the various different state incentives for differing load, and DER, programs. Based on previous studies, they altered their percentages to those found in Table 1.2 in order to distribute into their study zone. This provides a way to geographically distribute the DER forecast into the geographic zones in their study. They further disaggregate their forecast by proportionally distributing the growth already spread by geographic proportions into each load record according to how much it makes up the total load in that dispatch zone. **Figure 3.2** describes how they were able to build the percentages in Table 1.2 and allocate to their predefined dispatch zones.

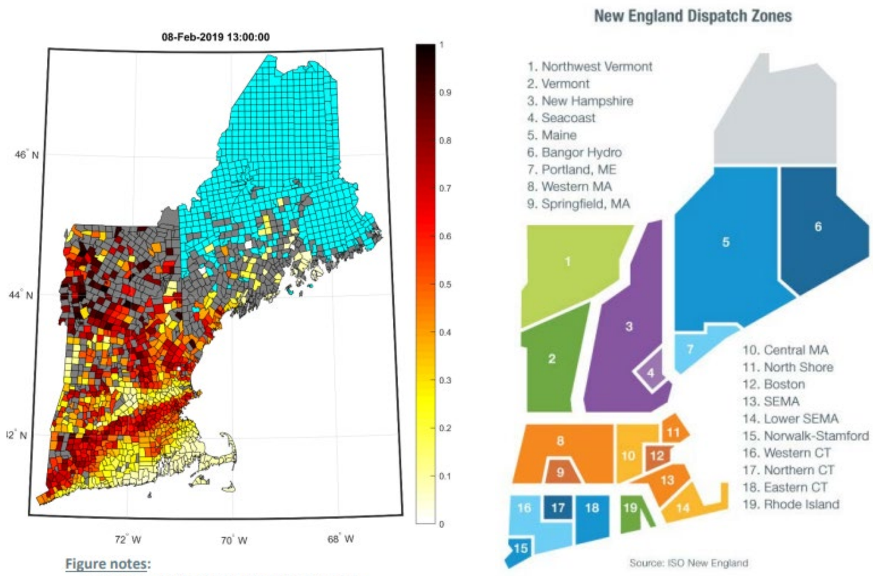

Figure notes:
1. Graphic developed by ISO New England
2. Data source: Quantitative Business Analytics, Inc.

Figure 3.2: ISO-NE Geographic Distribution Breakdown

After ISO-NE built out the expected zones, they are now able to adjust their study values based on the values they use for their DER forecast in future studies. Their expected growth is captured in **Figure 3.3**. The figure also contains previous year's forecasts and the historical growth to demonstrate how ISO-NE kept refining their process after previous forecasts proved to contain much different DER growth numbers than current forecasts.

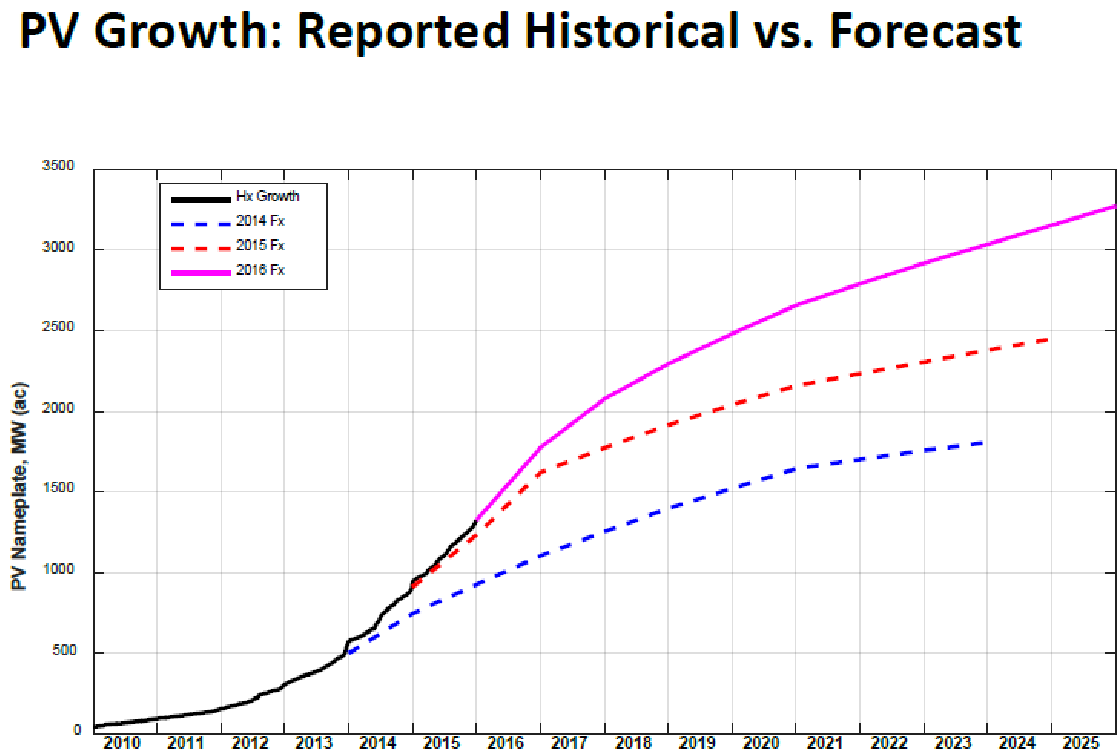

Figure 3.3: ISO-NE Future DER predictions from past forecasts.

As seen from the figures above, the geographic distribution method done through ISO-NE allows for future studies to be altered based on their ongoing forecasting methods. While a local area or bus may only see 1 MW or so of difference, the studies performed at the ISO-NE are able to account for the large differences in the projections. For the projection graphs found in Figure 3.3 and the geographic distribution in Figure 3.2, it can readily be seen that a significant amount of DERs are coming online in multiple different regions and that the initial forecasts were lacking. In this ISO-NE example, the difference between their 2014 forecast and their 2016 forecast for the 2020 year is almost 1 GW. Spread throughout the many busses, this impact is reduced; however, on a system level perspective, 1 GW of load now served locally and displaces large BPS level generation facilities for future BPS level reliability studies. It is recommended then, that TPs and PCs use DER forecasts that contain a high level of confidence in their accuracy and that the studies conducted by the TP/PC are able to use these high confidence forecasts. In ISO-NE's example, they were able to find a reputable source that tracked their DER information that "made sense" to them for use in their studies. They understood the limitations and assumptions of the forecast and overall, had a successful refinement to their future forecasting procedures. In all, this type of approach exudes a higher confidence in the DER future values.

Procedure Refinements and High Level Recommendations

Based on an informal poll of SPIDERWG members, a few of the TPs performed some sort of procedural refinement for their forecasting practices. Based on that informal poll, there were three main camps that arose. They were as follows:

1. Entities that manual checked actuals against previous years' forecasts.
2. Entities that perform automated checking of forecasts via playback into their procedure.
3. Entities that do not perform any refinement to their forecasting strategy or projection.

For number one, the entities that were in that category generally took their current year DER queue and compared it with the previous years' forecast to make changes to the forecasting procedures. For the second camp, those entities generally used playback of a model to match their forecasts with other types of projections to see how their forecast aligned with their past and current projections. This generally took the form of an in depth forecasting study, and the automated refinement is one part of the study. In addition, a large majority of entities did not refine their forecasting methods, but would either change based on directives or other strategies that did not try to align historic information. Based on these responses, the SPIDERWG has identified a few key high-level recommendations when entering in values for future long-term planning studies:

- TPs and PCs should attend and contribute to current forums where DER forecasting is discussed. Further, TPs and PCs should coordinate with Resource Planners (RPs) to discuss forecasting of DER in their region.
- TPs and PCs should coordinate between their load forecasting and planning departments to ensure forecasts meet the TP/PC requirements, namely for development of base cases, and TPs/PCs have a better understanding of forecast assumptions.
- TPs and PCs should improve their relationship with distribution entities (e.g., DER developers, DER owners, and DPs) to gather data to be used in forecasting; or use a trustworthy outside entity that can perform DER forecasting for them.
- TPs and PCs should develop checklists as in **Figure 2.2**, altered to fit their needs, and use the list when incorporating forecasted data in their planning studies.
- TPs and PCs should utilize a variety of projections in order to determine whether such projections should be the basis of the DER values for the study. This may mean a forecasted value is used for only a portion of all studies performed by the TP or PC.

Additionally, if an entity desires to perform a forecast for DER, those entities are encouraged to improve their relationship with DER developers and other distribution entities in order to obtain important capacity, location, and operational profiles.

Appendix A: Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG).

Name	Entity
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Dan Kopin	VELCO
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Parag Mitra	Electric Power Research Institute
Steven Coley	TVA
James Manning	North Carolina Electric Membership Corporation
John Pearson	ISO-NE
Bill Quantance (SPIDERWG Vice-Chair	Duke Energy
Kun Zhu (SPIDERWG Chair)	MISO
Ryan Quint (SPIDERWG Coordinator)	North American Electric Reliability Corporation
John Skeath (SPIDERWG Coordinator)	North American Electric Reliability Corporation

White Paper – Survey of DER Modeling Practices

Action
Approve

Summary
The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices. The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry. The SPIDERWG is requesting RSTC approval of the white paper.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Survey of DER Modeling Practices

NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) - White Paper

April 2021

RELIABILITY | RESILIENCE | SECURITY




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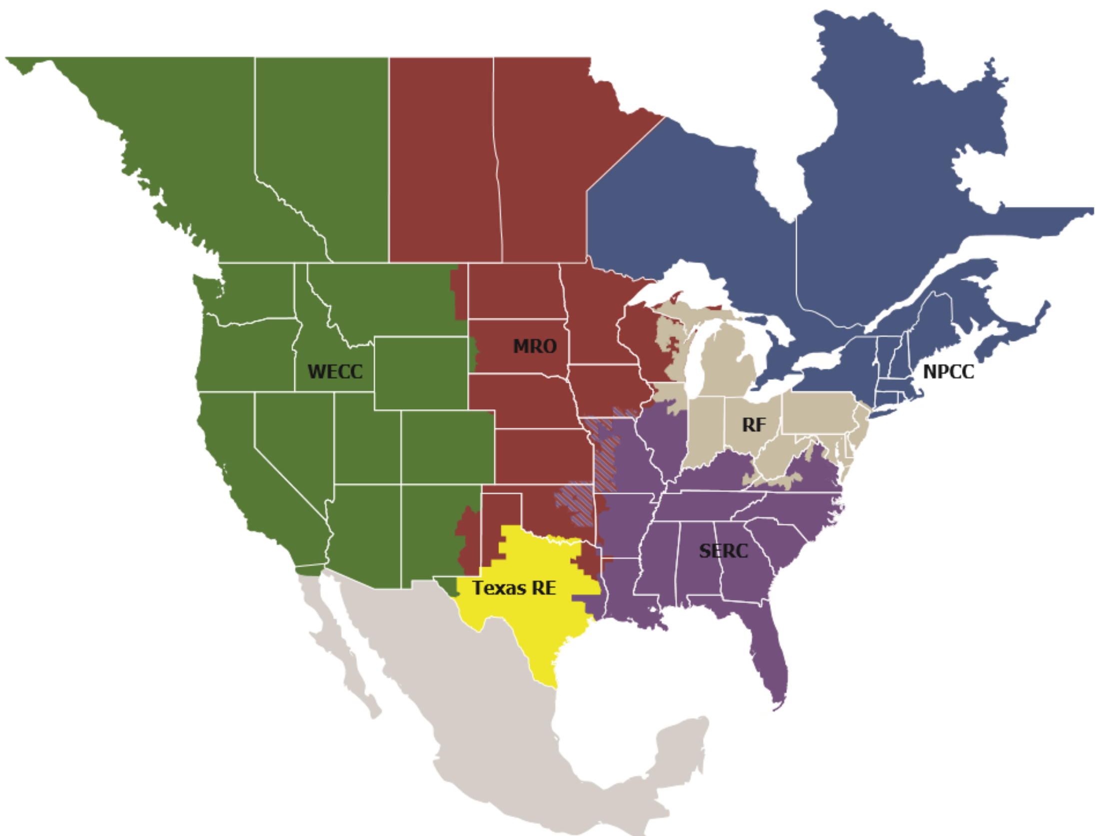
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices.[1] The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

Key Findings

The following key findings were identified from this survey:

- **Questions 2 and 3:** Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.
- **Question 5:** Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.
- **Question 6:** Forecasted DER penetration levels are likely to increase in the coming years, particularly in the planning horizon. Responses shifted towards increased penetration levels by 2024. 16% of respondents, however, did not have a DER forecast out to 2024.
- **Question 7:** 40% of respondents reported observing DER tripping during fault events on the electrical grid. Few entities were able to report a quantitative amount of DER tripping due to limited data available.
- **Question 8:** 40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon. Shifts in peak or light net load hours has an impact on the planning assumptions used for BPS reliability assessments, which impacts how NERC TPL-001 reliability studies are executed.
- **Question 9:** About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner.
- **Question 10:** 45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no explicit dynamic behavior representation of DER in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.
- **Question 11:** About 50% of respondents do not have a threshold for modeling utility-scale DERs (U-DERs), i.e., larger DERs that are three-phase installations, and do not model U-DERs in their studies. The remaining respondents use some threshold ranging from less than 1 MW to above 10 MW.

[1] For this survey and its results, distributed energy resources are defined as "any source of electric power located on the distribution system," as defined in the NERC SPIDERWG Terms and Definitions Working Document: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document%20rev%201.docx.pdf

- **Question 12:** 62% of respondents stated that they do not model retail-scale DER (R-DER) to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.
- **Question 13:** Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.
- **Question 14:** 73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.
- **Question 15:** Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.
- **Questions 16 and 17:** About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage. For those that do model distributed energy storage, about 70% stated that they model both full injection and full absorption scenarios; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

Recommendations and Next Steps

The survey highlights that DER penetrations are rising yet DER data collection, modeling, and modeling practices need to improve across the industry. SPIDERWG will continue to support industry education of DER modeling and studying their impacts to BPS reliability through workshops, webinars, guidelines, and technical reports. SPIDERWG recommends the following to all TPs and PCs to improve DER modeling practices:

1. **TPs and PCs with minimal DER penetration:** TPs and PCs with minimal levels of DERs should continue monitoring DER forecasts and be prepared to incorporate DER models explicitly into planning assessments to understand their potential impacts to BPS reliability for steady-state and dynamic studies. Regardless of DER penetration level, all entities should ensure that DER tracking and data collection is in place such that the penetration of DERs can be accounted for in studies and forecasts appropriately.
2. **TPs and PCs with DER penetrations but lack of available DER modeling information:** TPs and PCs in this situation should incorporate the recommendation in NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*,[2] and work with their respective Distribution Providers to ensure that DER information is collected and made available for the purposes of BPS reliability studies. Without sufficient information regarding DER penetration levels, TPs and PCs cannot execute accurate reliability assessments in the planning horizon. Distribution Providers are strongly recommended to review NERC *Reliability Guideline: Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*[3] and ensure DER data is being collected and provided to the TP and PC for the purposes of BPS planning assessments.
3. **TPs and PCs seeking guidance for recommended DER modeling practices:** All TPs and PCs should review the recommendations provided in NERC reliability guidelines[4] pertaining to recommended DER modeling practices, and improve their modeling capabilities for representing aggregate levels of DERs. Modeling DERs is paramount to identifying any potential reliability issues that may be presented with increasing levels of DERs; hence, entities cannot assess impact with DER information and models to study those impacts.

SPIDERWG recommends that the NERC Reliability and Security Technical Committee (RSTC) should consider the current state[5] of DER modeling practices and ensure that barriers to the collection of DER information for the purposes of executing planning assessments are addressed and broken down appropriately.

[2] This document is available here
[3] This document is available here
[4] This document is available here
[5] This white paper illustrates that DERs are having an impact on the BPS, particularly tripping during fault events, and that entities are using limited or no DER modeling practices in some cases. Further, the extent of DER modeling in dynamic studies is fairly minimal considering the current and projected forecasts of DERs in many footprints. Limitations to DER modeling include lack of information regarding DER installations and limited DER modeling capability.

Introduction

Many areas of the North American bulk power system (BPS) are experiencing an increasing penetration of DERs, and this is already affecting TP and PC modeling practices and planning assessments. Representing DERs in planning assessments becomes increasingly important as the penetration of DERs rises across many TP and PC footprints. NERC SPIDERWG has developed reliability guidelines and recommendations for modeling DERs in planning assessments, and continues to support industry awareness and voluntary adoption of these recommendations. Unlike BPS elements that are often modeled explicitly, DERs are usually represented in aggregate due to the small size of individual units. While these resources are located on the distribution system, their growing impact to the BPS cannot be neglected and this is especially true in BPS planning assessments. DER models are needed to perform steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies. TPs and PCs may need information and data that enable them to develop models of aggregate DERs for planning purposes.

In addition to issuing recommendations and guidelines, SPIDERWG conducted an informal survey of its members to analyze the DER modeling practices of different entities. Understanding the different modeling practices across entities helps identify any gaps and develop a strategy for DER modeling as part of the overall reliable integration of these resources. This white paper discusses the survey questions and the results of the survey.

DER Survey Setup

The Modeling Subgroup of the NERC SPIDERWG developed and executed an informal survey of its membership. The survey questions were developed by the subgroup and reviewed by the overall SPIDERWG. The survey was specifically geared towards TPs and PCs regarding their modeling practices, and 63 entities within SPIDERWG were asked to participate. A total of 45 of those entities provided a response to the survey. At the time of the survey, the NERC Compliance Registry consists of 75 entities registered as PCs and 206 entities as TPs.[6] Some respondents did not provide completed surveys or answers to specific questions, which is believed to be due to the lack of information. Detailed descriptions of the survey setup and questions are in Appendix A.

[6] Note that the registration criteria for these types of entities is not mutually exclusive.

Chapter 1: Review and Analysis of DER Survey Responses

The section briefly describes the key findings and takeaways from the analysis of the survey results. Appendix B provides a summary of the responses to the survey questions. Information regarding specific entities' responses are withheld for confidentiality reasons. Relevant Key Findings are summarized in **Table 1.1**

Table 1.1: Key Findings from Survey Questions

#	Related Questions	Key Finding
1	Question 6	From responses to this question and from comparison of the existing and future amounts of DER, it is seen that in the future with the DER growth, some entities will have an increase in amount of DER that will move them to a higher category. For example, currently, there are eleven entities with the DER capacity between 1000 and 5000 MW, and in the future there will be nine entities in this category. This is because for two entities, the increase in the DER will move them to the category of entities with the DER capacity larger than 5000 MW. The same is true for entities with other DER amounts.
2	Question 7	Five respondents observed widespread tripping of the DER with faults[7], none of them has provided the amounts of the DER that were tripped. Although not many of the respondents observed widespread DER tripping with faults, this may be due to lack of visibility on the distribution systems and thus, insufficient data on the DER output and tripping. Other prevailing inferences could be that faults didn't occur in their regions or that the DER penetration is so low that any trip of DER is lost in the "noise" of the response. Any of these would result in no observed widespread DER tripping.
3	Questions 16 and 17	The reasons for not modeling energy storage explicitly[8] were absence of such storage, absence or lack of data on distribution-connected energy storage, or absence of appropriate tools. The largest category of "No" responses was due to the absence of distribution-connected energy storage, followed by the category of lack of data on distribution-connected energy storage.

Based on the results of the survey, there are still not many entities that model DER, especially in dynamic stability studies. Significant number of entities model DER netted with load even if the amount of DER in the system is substantial and represents noticeable percentage of the system load. Such amount of DER would have impact on the system performance, but this impact is not considered if the DER are not modeled explicitly in the studies undertaken by TPs, PCs, and other transmission entities. With the growing penetrations of renewable resources, which is currently focused on distribution-connected growth in many electric utilities, modeling DER is becoming more important. Based on the attention to growing penetrations of DER, the SPIDERWG modeling subgroup identified categories of percentage penetration of DER to system peak load based on the responses to Questions 2, 5, and 6. These can be found in **Table 1.2**[9]. The prominent modeling practices along with the number of entities that fall into this category are also provided in **Table 1.2**.

[7] As this question was put generally, the five responses could indicate either five different faults seen by the different survey responders or it could be a single fault seen by the five different entities.

[8] Responses to the survey varied between assuming an implicit or explicit representation based on inference between the questions. Most assumed explicit representation from the survey question.

[9] One survey result did not have both Questions 5 and 6 completed, which may skew this data slightly.

Table 1.2: DER Penetration based on Questions 5 and 6		
Penetration Percentage	**# of Entities**	**Prominent Modeling Practices**
Over 100 Percent	1	In this entity DERs were modeled as generators, both in power flow and in dynamic simulations
Between 50 percent and 100 percent	1	DERs were modeled as negative load due to lack of appropriate modeling tools
Between 20 percent and 50 percent	2	One entity modeled DERs as negative load, again due to lack of modeling tools. The other modeled DERs as a generator as part of the composite load. DERs were modeled with second generation renewable dynamic models.
Between 10 percent and 20 percent	11	Out of these 11 entities, three modeled all DER in power flow regardless of size, three others modeled only DER that are larger than 1 MW, two entities modeled in power flow only DER that are larger than 5 MW, one entity modeled DER larger than 10 MW, and two modeled all DER as negative load. As for dynamic simulations, five entities out of these eleven didn't model DER due of absence of data or lack of tools, and six entities modeled DER. Out of these six, five modeled DER as generators with renewable models and one modeled DER some as generators and some as a part of composite load model.
Between 5 percent and 10 percent	20	In power flow, two entities modeled all DER regardless of size, one modeled only DER that are larger than 1 MW and five modeled them as negative load. In dynamic stability, eight entities modeled DER. The explanations of that were absence of tools and absence of DER data and for some entities, that they haven't observed visible impact of the DER on transmission system that would justify modeling DER in dynamic stability. Out of these entities, two modeled DER in power flow as generators or as a part of composite load model, and the ten modeled DER as negative load. In dynamic stability, ten entities did not model DER and the other two modeled DER with the DER_A model. Not modeling DER was explained by the absence of tools, absence of DER data and negligible impact of the DER on transmission system.
Less than 1 percent	9	Out of these nine entities, seven did not model DER, and two modeled DER in power flow and stability as generators with DER_A model. The survey respondents provided the following reasons for not modeling DER: ▪ Low amount of DER in the system ▪ Lack of data on the DER locations, and their output ▪ Lack of tools to model DER ▪ Lack of knowledge of the models

Significant amount of entities reported that they observed shifting of the system peak because of the DER output. Peak shifting causes TPs and PCs to study more system conditions than the ones that were studied before, and as the current dominant DER technology is solar photovoltaic (PV), creates a need for DER models of high quality and fidelity[10]. In addition to the system peak and off-peak conditions, such conditions as net system peak when DER output is low and the system load is still high will also need to be studied[11]. These cases may represent hours 18 or 19 on summer weekdays when sun goes down, but the load is high due to air-conditioners. Off-peak system conditions with high DER output and low load, which represent spring weekend afternoons, may also appear to be critical. System conditions with high gross load and high DER output (when these conditions are coincident) may be a challenge for dynamic stability system performance because of stalling of single-phase induction motor load with faults and possible tripping of DER because of low voltages. In all these cases, adequate modeling of the DER is becoming more and more important.

This shifting of system peak because of DER output should be taken into account when attempting to correlate the responses related to Question 3 (minimum gross load) and Question 5 (DER capacity) as shown below in **Figure 1.1** Nevertheless, it is significant and important to recognize that there are many jurisdictions where the ratio of maximum DER capacity to minimum gross load is above 20 percent.

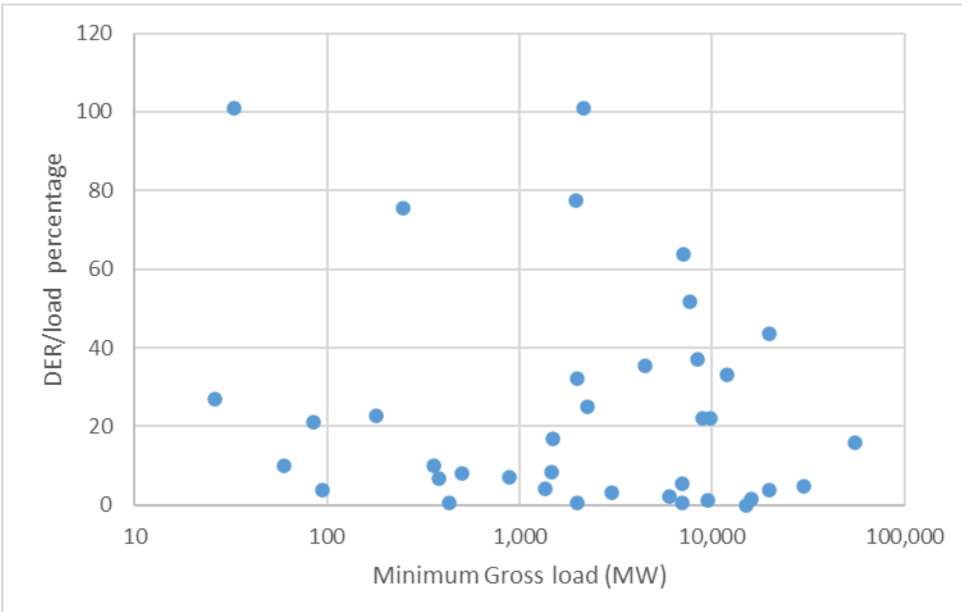
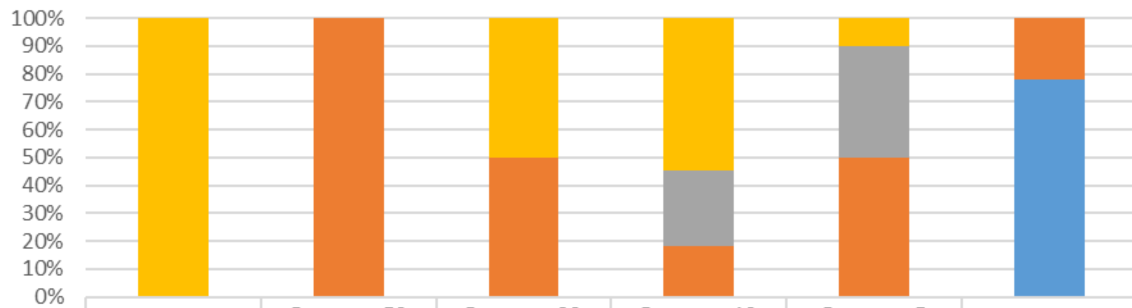


Figure 1.1: Ratio of Maximum DER capacity to Gross Minimum Load

From the results in the survey, the SPIDERWG categorized the number of entities by their modeling practices based on their penetration level in **Figure 1.2**. Entities that did not model in powerflow or dynamics were recorded as "no modeling", entities that had powerflow models, but no dynamic models or were modeled as negative load were recorded as "limited modeling", entities that had a dynamic record associated with the DER were recorded with "moderate modeling", and entities that used a dynamic record modeled according to latest guidance available were recorded as "exceptional modeling".

[10] This also applies to BPS-connected solar PV models. To reiterate, all solar PV models will need to modify their available power output based on the time of day selected for the study.

[11] This point is emphasized in "Verification Process for DER Modeling in Interconnection-wide Base Case Creation," published in the June 2020 CIGRE journal: https://e-cigre.org/publication/CSE018-cse-018.



	Over 100 Percent	Between 50 percent and 100 percent	Between 20 percent and 50 percent	Between 10 percent and 20 percent	Between 5 percent and 10 percent	Less than 1 percent
Exceptional Modeling	1	0	1	6	2	0
Moderate Modeling	0	0	0	3	8	0
Limited Modeling	0	1	1	2	10	2
No modeling	0	0	0	0	0	7

DER Penetration Percentage

Figure 1.2: Modeling Practice Percentage by DER Penetration

Although the respondents used their best knowledge in responses to the survey questions, the responses to the question regarding total amount of the DER in the system may make conclusions of the survey to be less accurate. Since different entities included different types of technologies in the DER definition, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system. These DER were counted differently in different entities. Some included only solar PV, some included also energy storage, and some entities included all kind of generation, and also demand response.

Appendix A: Detailed Survey Process with Questions

SPIDERWG determined that the best approach would be to conduct the DER survey in several phases, with the first phase containing general questions regarding DER penetrations and basic modeling practices for each entity. The first phase did not include questions about the DER model parameterization or forecasting, and only included data sources in a cursory manner. SPIDERWG recommends conducting a more detailed follow-up survey of modeling practice upon completion and findings from this phase one survey.[12] The following questions were asked in this phase one survey:

1. What is your company's function(s)?[13]
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What technologies are included in the DER definition used when answering this survey?
5. What is the total capacity of DER connected to your system [MW]?
6. What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?
7. Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped? (can be estimated from change in net load if detailed data is not available)
8. Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?
9. Do you receive any DER operational data (e.g., output of DERs)? On what level?
10. How do you model DERs in load flow studies?
11. What is the MW threshold to explicitly model individual (or multiple) U-DERs in the base case?
12. What is the MW threshold to explicitly model aggregate R-DERs in load flow studies?
13. How are DERs being aggregated in your system?
14. Do you model DERs in dynamic studies?
15. Which DER model do you use in your dynamic studies?
16. Do you model distribution-connected energy storage in your system?
17. How do you model energy storage in your system?

[12] Such questions include DER forecasting methods, sources of DER data, impacts of DERs on base case creation, considerations of DERs in special studies, and study impacts of DERs.
[13] Based on the entity's NERC Registration: https://www.nerc.com/pa/comp/Pages/Registration.aspx.

Appendix B: DER Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values in the charts that follow show the number of respondents and the percentage of total respondents, respectively, for each question.

Question 1

"What is your company function?"[14]

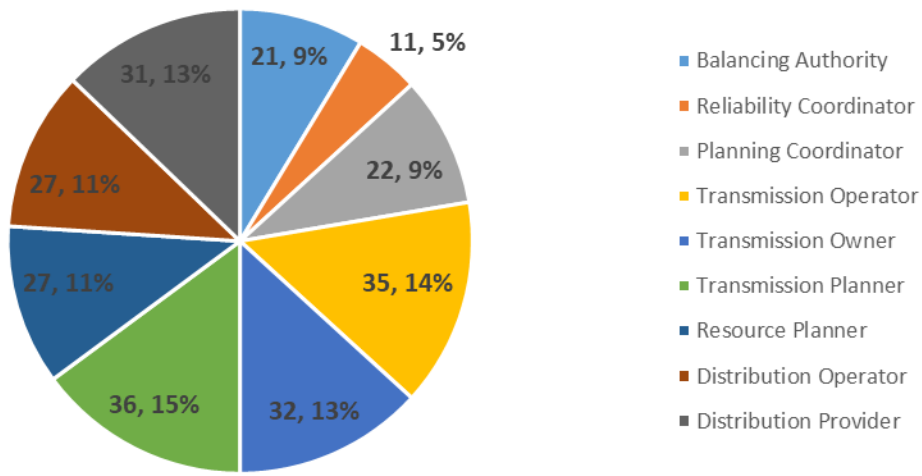


Figure B.1: Responses to Question 1

Key Takeaway – Question 1:
A wide array of SPIDERWG members responded to this survey, 36 and 22 entities identifying as TPs and PCs, respectively (not mutually exclusive).

[14] Respondents were requested to mark all that apply; hence the higher response count. 45 entities responded to the survey.

Question 2

"What is the peak gross load of your area [MW]?"

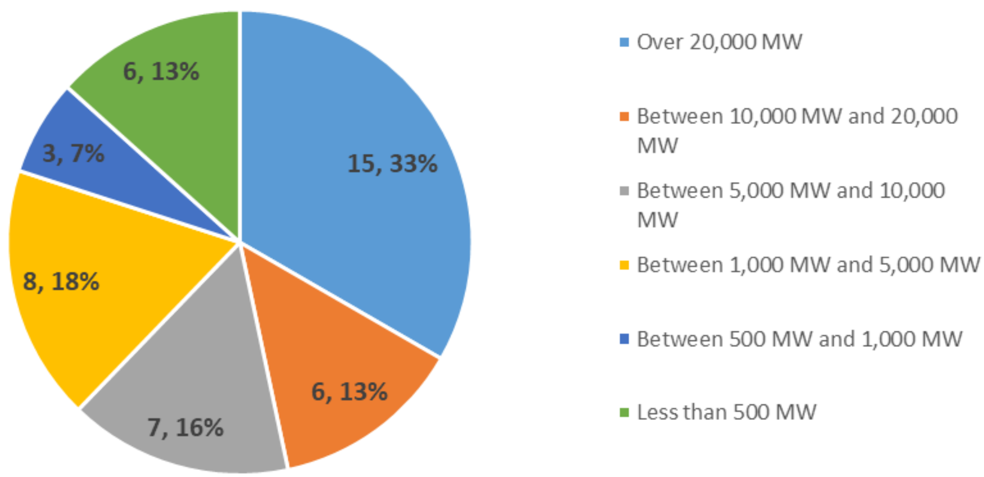


Figure B.2: Responses to Question 2.

Key Takeaway – Question 2:
Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW.

Question 3

"What is the minimum gross load of your area [MW]?"

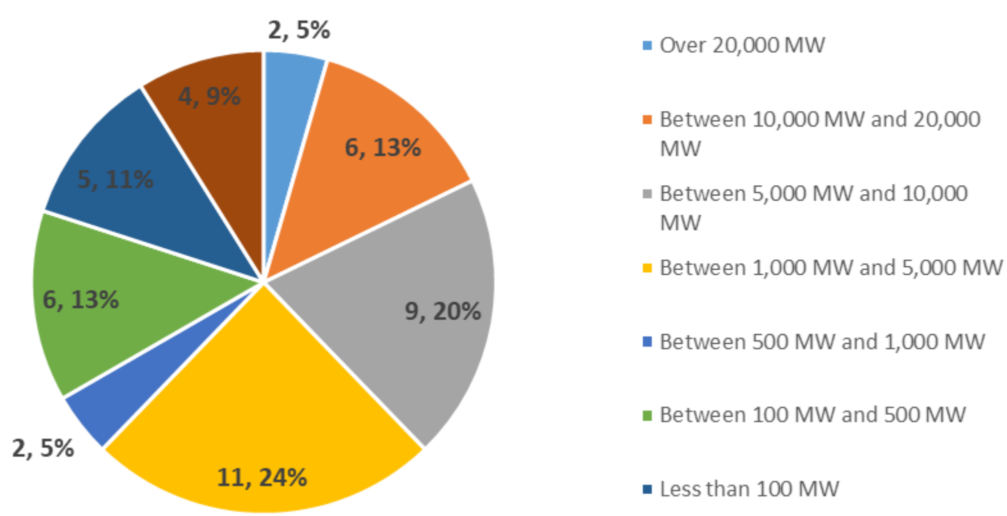


Figure B.3: Responses to Question 3

Key Takeaway – Question 3:
Entities also ranged in their minimum gross load. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.

Question 4

"What technologies are included in the DER definition used when answering this survey?"

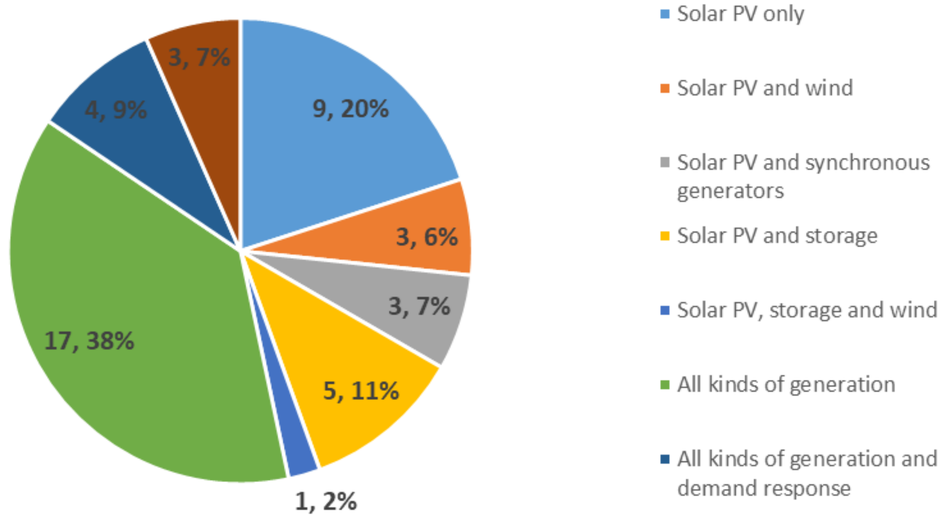


Figure B.4: Responses to Question 4

Key Takeaway – Question 4:
Some entities included demand response in their definition of DER; however, the majority of respondents focused on "sources of electric power" with most focusing specifically on inverter-based DERs such as solar PV, wind, and battery energy storage.

Question 5

"What is the total capacity of DER connected to your system [MW]?" [15]

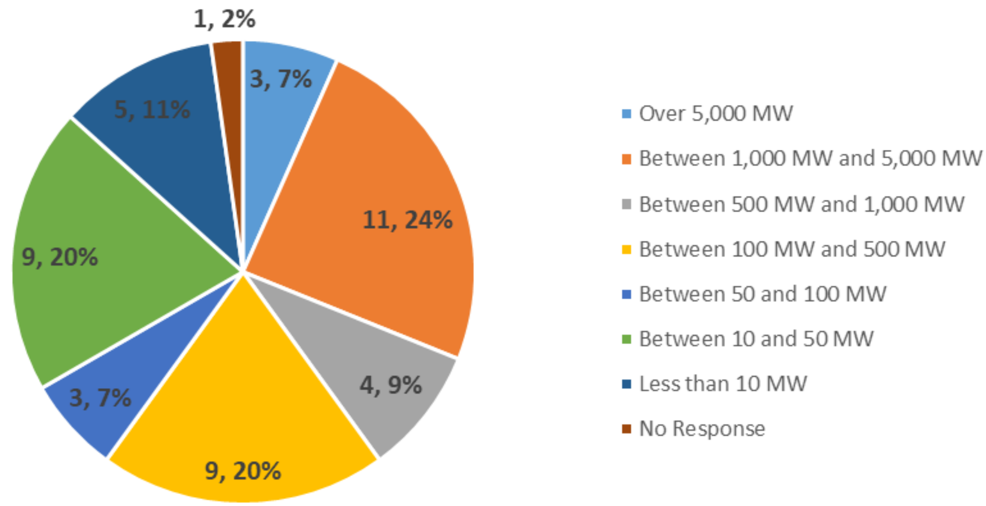


Figure B.5: Responses to Question 5

Key Takeaway – Question 5:
Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.

[15] Regarding this question, since different entities include different types of technologies in the DER definition, as seen from the responses to the previous question, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system based on the SPIDERWG definition.

Question 6

"What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?"[16]

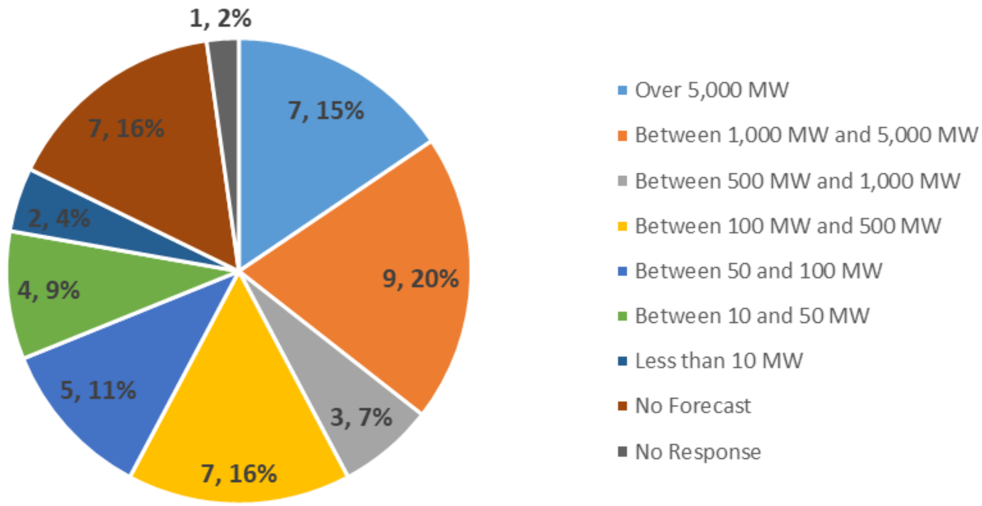


Figure B.6: Responses to Question 6

Key Takeaway – Question 6:
In 2024, over 35% of respondents reported having over 1,000 MW of installed DER in their footprint, about 60% reported having more than 100 MW, and about 24% reported having less than 100 MW. About 15% of respondents reported having no DER forecast out to 2024.

[16] In summarizing the responses to this question, the DER forecast was compared with the existing amount of DER.

Question 7

"Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped?"[17]

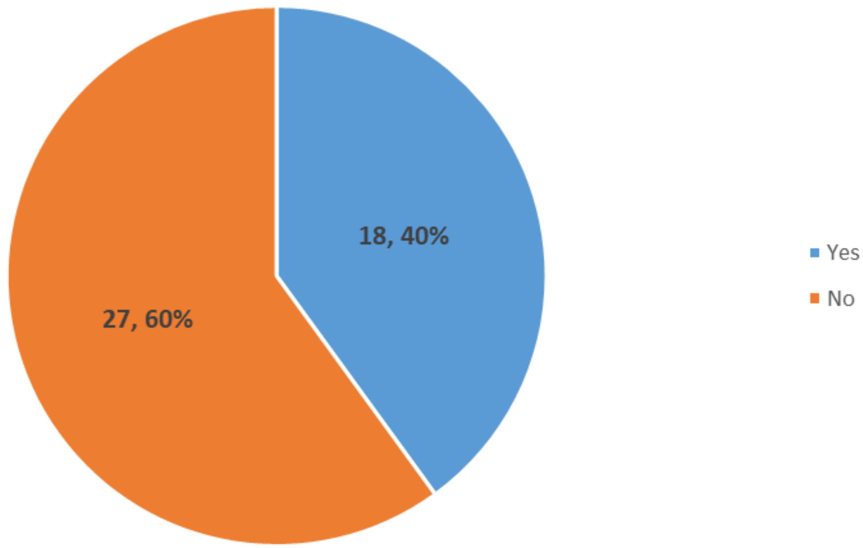


Figure B.7: Responses to Question 7

Key Takeaway – Question 7:
40% of respondents reported observing widespread tripping of DERs during fault events in their footprint; the remaining 60% had not observed any DER-related tripping events so far.

[17] Note that the response to this question can be estimated from the change in net load if detailed data is not available.

Question 8

"Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?"

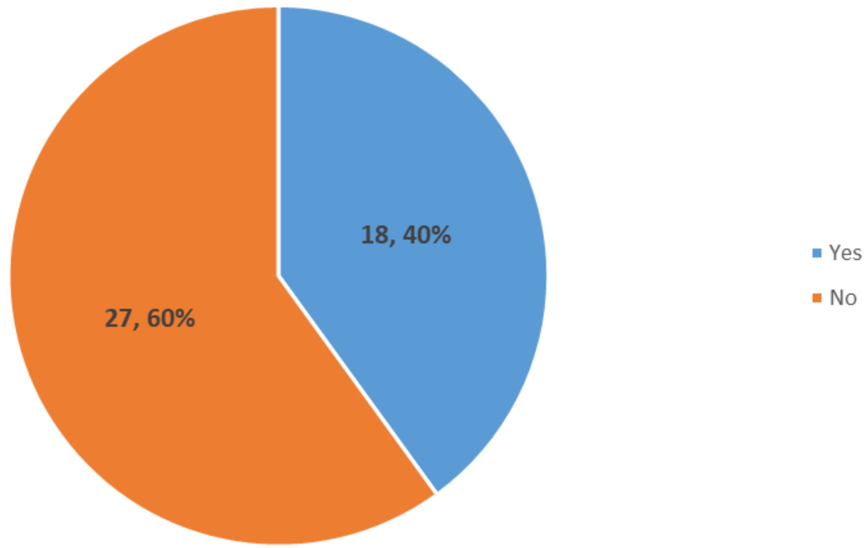


Figure B.8: Responses to Question 8

Key Takeaway – Question 8:
40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon; the remaining 60% had not observed any shift in net loading on their system.

Question 9

"Do you receive any DER operational data (e.g., output of DERs)?"

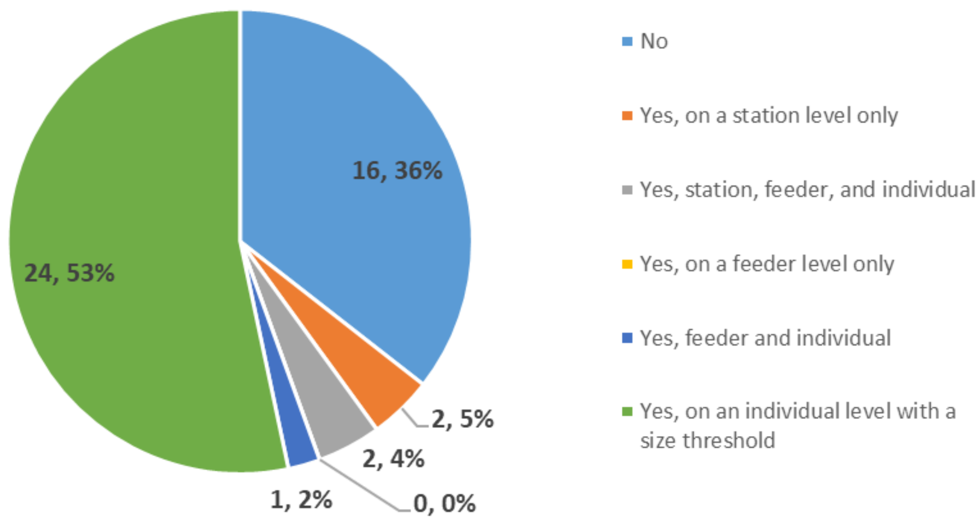


Figure B.9: Responses to Question 9

Key Takeaway – Question 9:
About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner. Some respondents receive limited DER information on a station- or feeder-level.

Question 10

"How do you model DERs in load flow studies?"[18]

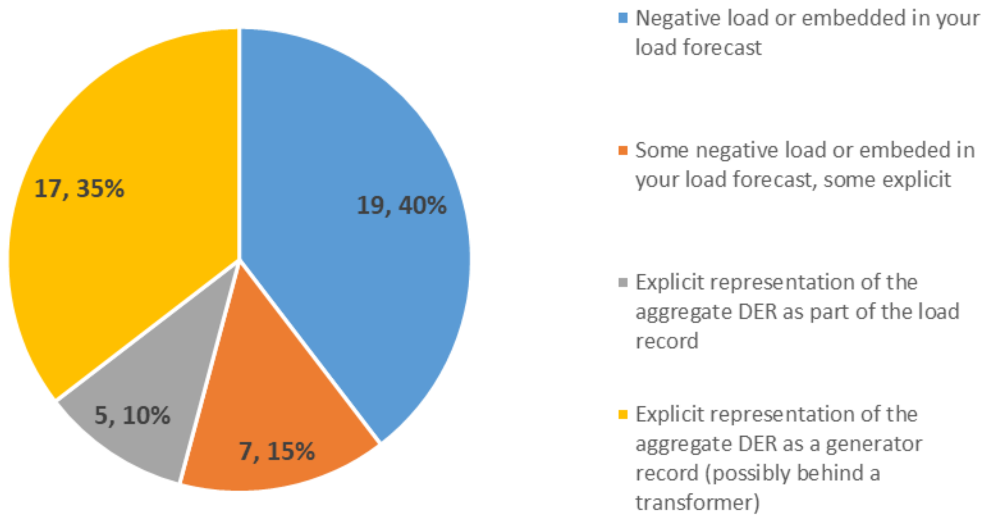


Figure B.10: Responses to Question 10

Key Takeaway – Question 9:
45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no DER representation in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.

[18] Note that the response to this question include some overlap as respondents reported more than one option.

Question 11

"What is the MW threshold to explicitly model individual (or multiple) utility-scale (U-DERs) in the base case?" [19]

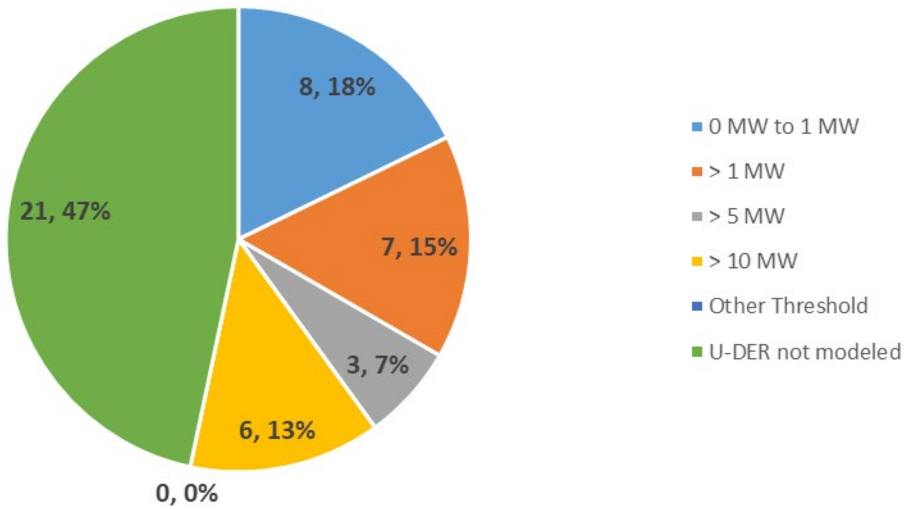


Figure B.11: Responses to Question 11

Key Takeaway – Question 11:
About 50% of respondents do not have a threshold for modeling utility-scale DERs (i.e., larger DERs that are often three-phase installations), and do not model U-DERs in their studies. 13% use a threshold over 10 MW, 7% use a threshold between 5 MW and 10 MW, 15% use a threshold between 1 MW and 5 MW, and 18% use a threshold less than 1 MW.

Question 12

"What is the MW threshold to explicitly model aggregate retail-scale (R-DERs) in load flow studies?"

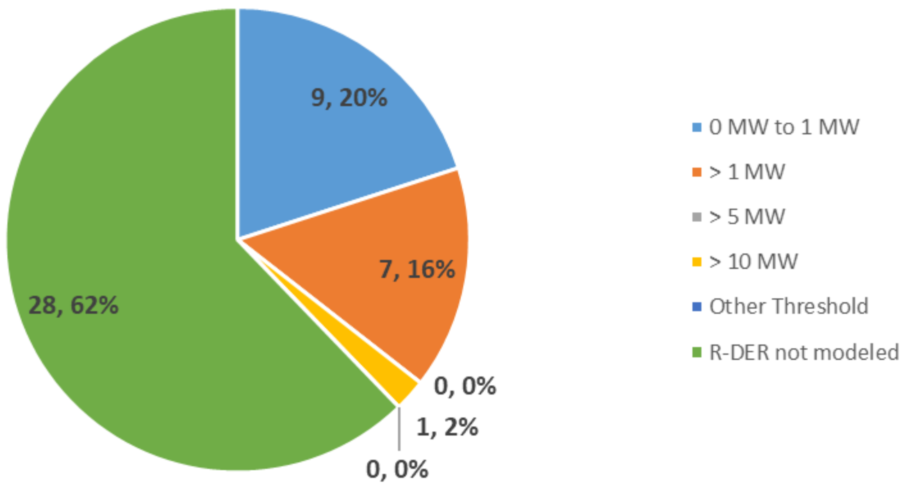


Figure B.12: Responses to Question 12

Key Takeaway – Question 12:
62% of respondents stated that they do not model R-DER to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.

Question 13

"How are DERs being aggregated in your system?"

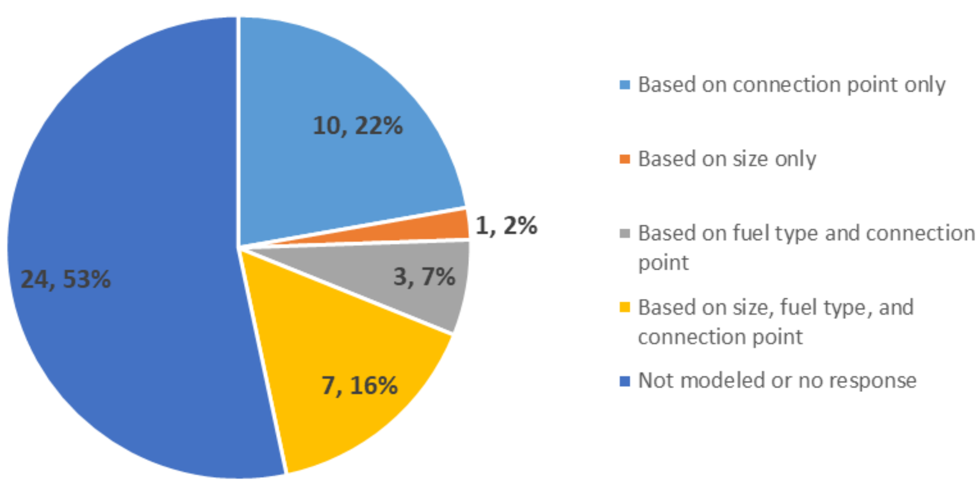


Figure B.13: Responses to Question 13

Key Takeaway – Question 13:
Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.

Question 14

"Do you model DERs in dynamic studies?"

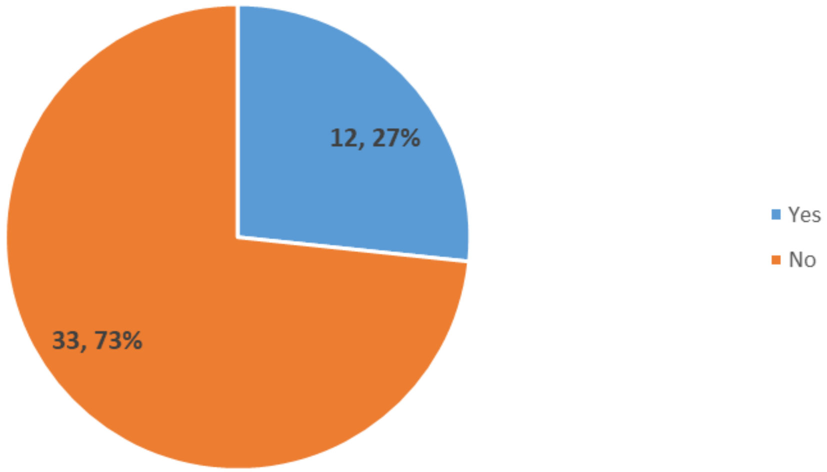


Figure B.14: Responses to Question 14

Key Takeaway – Question 14:
73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.

Question 15

"Which DER model do you use in your dynamic studies?"

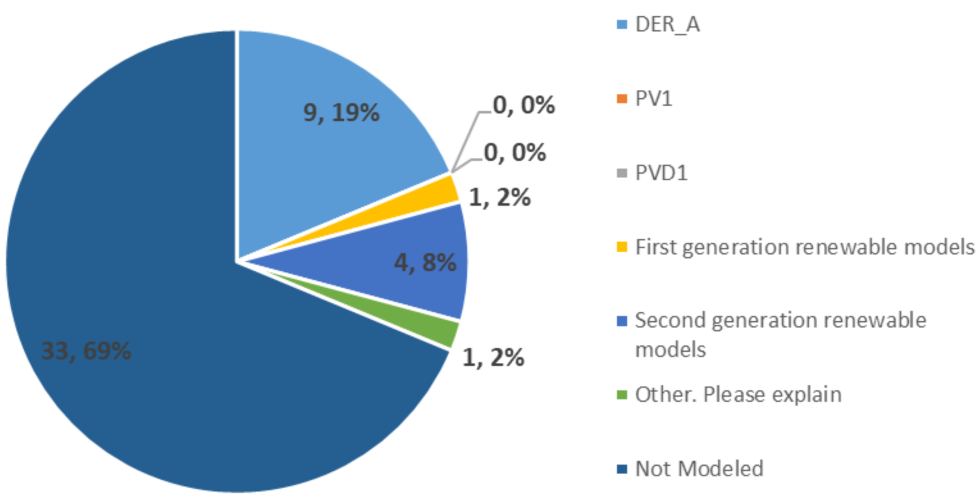


Figure B.15: Responses to Question 15

Key Takeaway – Question 15:
Most respondents reported not modeling DERs in dynamic studies. Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.

Question 16

"Do you model distribution-connected energy storage in your system?"

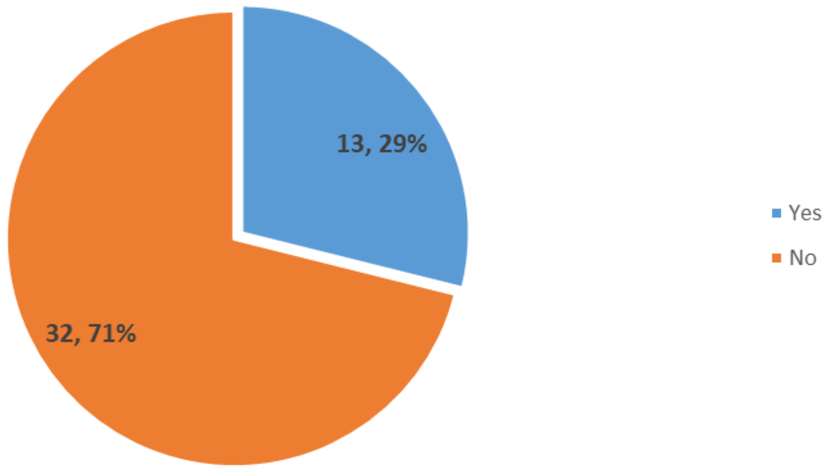


Figure B.16: Responses to Question 16

Key Takeaway – Question 16:
About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage.

Question 17

"How do you model energy storage in your system?"

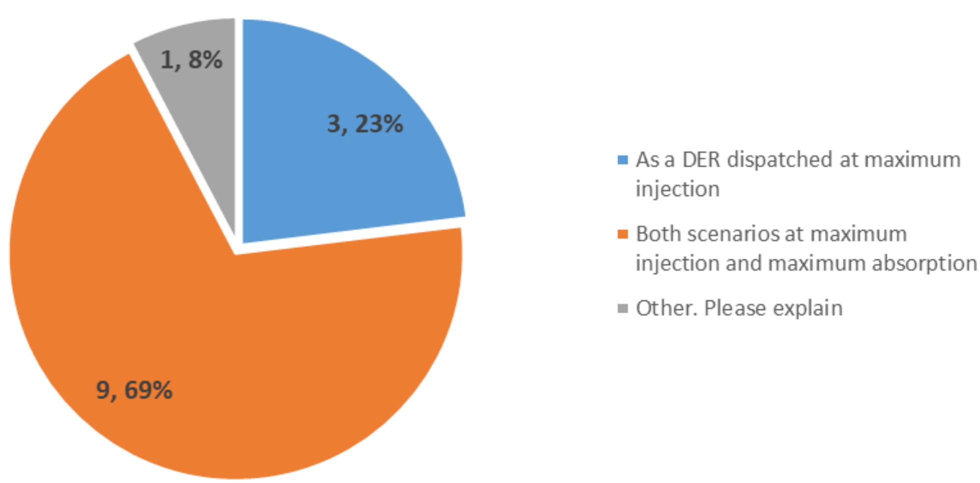


Figure B.17: Responses to Question 17

Key Takeaway – Question 17:
About 70% of respondents stated that they model both scenarios for full injection and full absorption for the distributed battery output; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

White Paper – Simulation Improvements

Action

Request for RSTC reviewers.

Summary

The NERC SPIDERWG has developed a number of guidelines and studies relating to distributed energy resource (DER) integration. Tracking DERs will add significant level of complexity to the planning process, stressing data fidelity, modeling accuracy, and computational limitations. This document provides a distilled version of the NERC SPIDERWG that may be pertinent to power system software developers, and outlines some of the related literature that may aid in developing further software improvements and techniques. The SPIDERWG is requesting RSTC members for review of the White Paper.

Recommendations for Simulation Improvement and Techniques Related to DER Planning White Paper

NERC System Planning Impacts of Distributed Energy Resources (SPIDERWG)

_____ 2021

Disclaimer: This document is intended to be a resource for software vendors to help guide the next generation of software tools and techniques that will aid power system planners as they contend with increased proliferation of distributed energy resources. This document is not intended to be an endorsement of any particular software platform, nor as a critique of the existing capabilities of any software program. Screenshots of various software tools appear in the document only as a means of offering further clarity on the topic at hand.

Purpose

The NERC System Planning Impacts of Distributed Energy Resources (SPIDER) working group has developed a number of guidelines and studies relating to distributed energy resource (DER) integration. Tracking DERs will add significant level of complexity to the planning process, stressing data fidelity, modeling accuracy, and computational limitations. This document provides a distilled version of the NERC SPIDER working group recommendations that may be pertinent to power system software developers, and outlines some of the related literature that may aid in developing further software improvements and techniques.

The white paper is broken down into three sections. **Part I** provides an overview of SPIDER working group efforts to quantify and qualify the manner in which DERs are changing the system planning process. This section also provides a review of related literature from government, industry, academic sources. **Part II** identifies a number of issues related to DERs that may strain the existing capabilities of power system software. **Part III** discusses the seams that exist between typical power system analysis (transmission versus distribution studies, positive-sequence load flow versus electromagnetic transient analysis, etc.), and how DERs may necessitate new software solutions that stitch these seams together.

PART I: Overview of NERC SPIDERWG and Related Efforts

When distributed energy resources (DERs) were introduced on the power system, they were initially viewed as a distribution system concern only. DER interconnection requirements such as IEEE 1547-2003 tended to recommend immediate tripping for DERs during abnormal system conditions, in order to protect utility workers and avoid unexpected distribution system voltage dynamics.

However, the profusion of DER throughout the power system has led planning engineers to reconsider the bulk system impacts of these devices. Recent events have highlighted the effects that a large amount of inverter-based resources can have on the transmission system. For instance, the Blue Cut Fire incident in 2016 involved the loss of roughly 1200 MW of solar generation during in Southern California due to a fault on a nearby transmission line. This sudden drop in generation was not anticipated by operators at the time, and emphasized the need for better system visibility in both the planning and operations horizon.

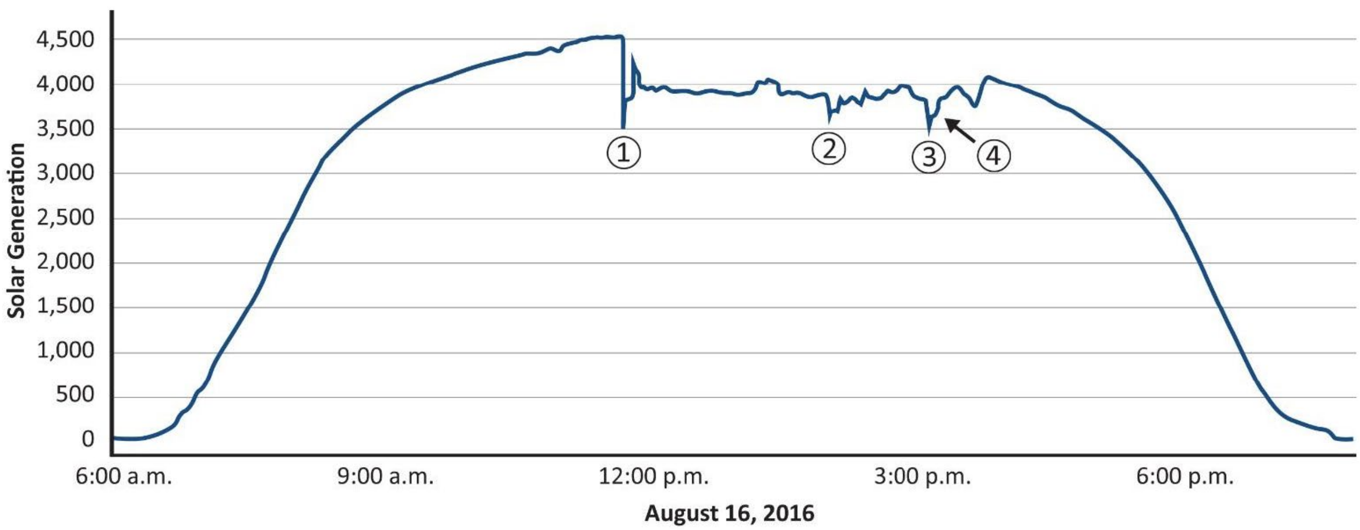


Figure 1 – Utility Scale Solar PV Output in SCE Footprint on August 16, 2016[1]

While the reduction in generation during the Blue Cut Fire was primarily driven by utility-scale solar, this incident highlights the concerns that system planners have as DERs continue to proliferate. If a large number of DERs were to trip off simultaneously during a fault or other abnormal system condition, it could trigger transient instability, inadequate contingency reserves, unanticipated thermal overloads, and potential voltage collapse.

Even without tripping, DERs will cause significant change to system-wide power flows (both in magnitude and direction), rising feeder voltage profiles, and potential reduction in the effectiveness of underfrequency and undervoltage load shed schemes, to name a few issues. It is therefore imperative that system planning engineers have the visibility, via accurate and up to date models, to adequately catalog the distributed energy resources deployed on their systems.

[1] 1200 MW Fault Induced Solar Photovoltaic Resource Interruption Final.pdf

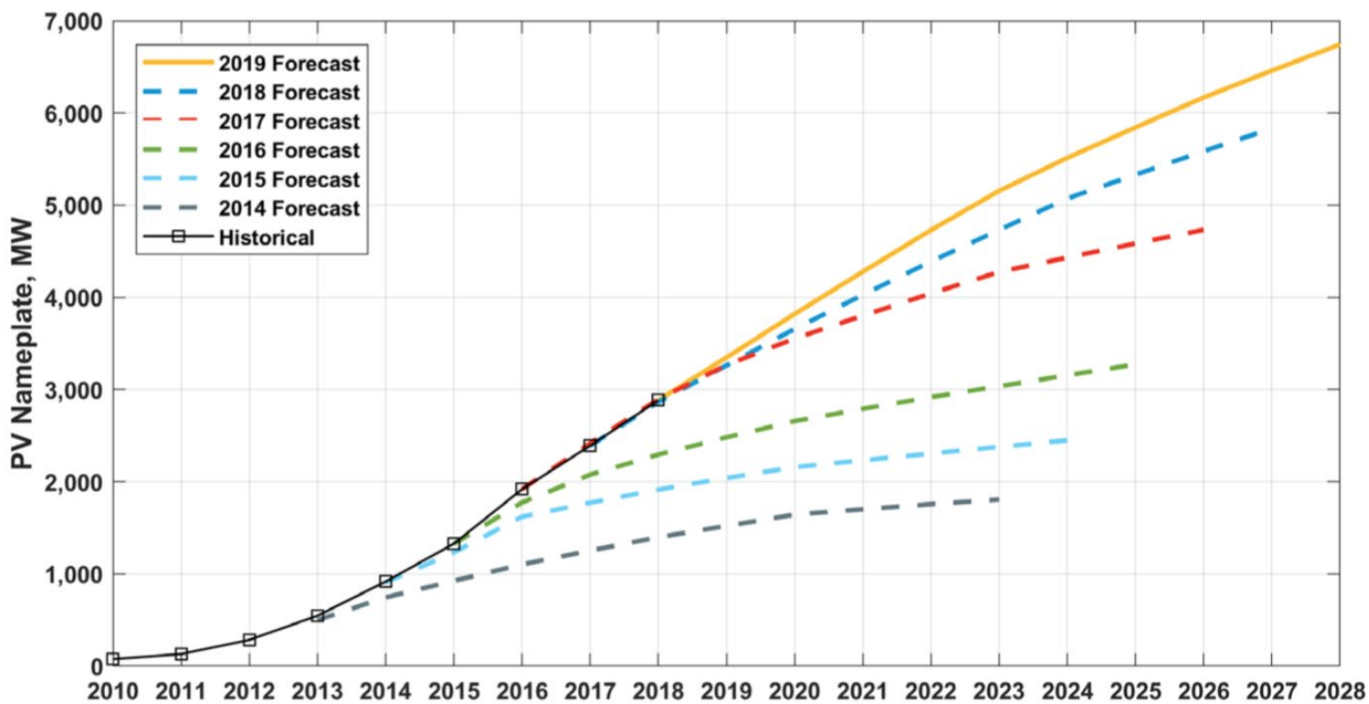


Figure 2 –DER deployment continues to outpace projections in many areas. Shown above are ISO-NE distributed solar PV annual forecasts. [Source: ISO-NE][2]

The NERC System Planning Impacts from Distributed Energy Resources (SPIDER) working group was created to address aspects of these key points of interest related to system planning, modeling, and reliability impacts to the Bulk Power System (BPS). It builds on related work from the NERC Inverter-based Resource Task Force[3] and the NERC Distributed Energy Resource Task Force.[4]

The NERC SPIDER working group has authored a number of documents related to system planning impacts of DERs. A few which may be of interest to power system software vendors include:

- **NERC System Planning Impacts from Distributed Energy Resources Working Group – Scope Document**[5] - Provides an overview of the purpose, activities, and deliverables of the SPIDER working group
- **NERC Reliability Guideline – Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018**[6] – Discusses how the inverter trip settings and reactive power control modalities described in IEEE Standard 1547-2018 are expected to impact the bulk electrical system

[2] https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf
[3] Summary of IBRTF Activities
[4] NERC DERTF Final Report
[5] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG_Scope_Document_-_2018-12-12.pdf
[6] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

- **NERC White Paper – Assessment of DER impacts on NERC Reliability Standard TPL-001**[7] - The NERC Reliability Standard TPL-001 specifies how transmission planers evaluate the performance of the transmission system, including the types of studies that are considered (steady-state load flow, PV/QV, transient stability) and the acceptable criteria for each of the studies. This NERC White Paper provides a context for how the proliferation of DERs may affect transmission studies going forward, and provides guidance on potential touchpoints involving DERs and the TPL-001 document.
- **NERC Reliability Guideline – DER Data Collection for Modeling in Transmission Planning Studies**[8] - Provides guidance when conducting NERC Reliability Standard MOD-32 data collection efforts involving DERs
- **NERC Reliability Guideline - Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources**[9] - A reference for planning engineers that includes a range of example studies incorporating DERs, as well as suggested best practices for accounting for DERs in various system planning efforts
- **NERC SPIDER WG Terms and Definitions Working Document**[10] – Useful resource for terms and definitions contained herein as well as in related SPIDER working group documents

[7] (In development)
[8] (In development)
[9] (In development)
[10] (In development)

PART II: DER Impacts on Power System Software Tools

Continued proliferation of DERs is expected to cause a number of impacts to the BES.[11, 12, 13] Future power system studies will require software tools that can track a large number of distributed resources (typically aggregated up to the feeder or substation bus level), while providing the ability to both observe and adjust the output of these resources globally.

The recommendations in this section relate to how best to account for DERs in transmission system base case models. Given the sheer size of BES base case planning studies (often >10,000 load serving nodes), it will be crucial that power system software can programmatically handle a large number of DER models while simultaneously presenting information on overall DER behavior to the user in a comprehensible format.

Organizing DER information in load flow models

Tracking distributed generation is becoming an increasingly important component of the base case building process and general transmission planning analysis. Future planning scenarios are likely to include large amounts of DER that will significantly affect the power flow of the transmission network, and it will be critical for planners to have easily accessible information on the amount of dispatched DER in a particular case.

Previous Guidance

The **NERC Reliability Guideline: Modeling Distributed Energy Resources in Dynamic Load Models**[14] provides guidance for modeling DER. Two points of the guideline are emphasized here:

- The guide delineates between two types of DER representations, referred to as **U_DER** and **R_DER**. To generalize, U_DER represents utility-scale resources above a specific MW threshold (usually located near the substation), while R_DER represents an aggregation of smaller, often behind-the-meter resources dispersed across one or more feeders.
- Two of the three following quantities should be accounted for in transmission planning base case load models: **gross load, net load, and DER generation**, with the third component being automatically calculated from the other two.

Per the modeling guideline, U_DER is modeled as a discrete generator model. As such, information about these resources can be tracked within the existing generator modeling framework available in load flow software.

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11 Planning Hawai'i's Grid for Future Generations – Integrated Grid Planning Report https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20180301_IGP_final_report.pdf

12 Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid https://www.caiso.com/Documents/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

13 Impact of Distributed Energy Resources on the Bulk Electric System Combined Modeling of Transmission and Distribution Systems and Benchmark Case Studies https://www.osti.gov/biblio/1433502-impact-distributed-energy-resources-bulk-electric-system-combined-modeling-transmission-distribution-systems-benchmark-case-studies

14 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

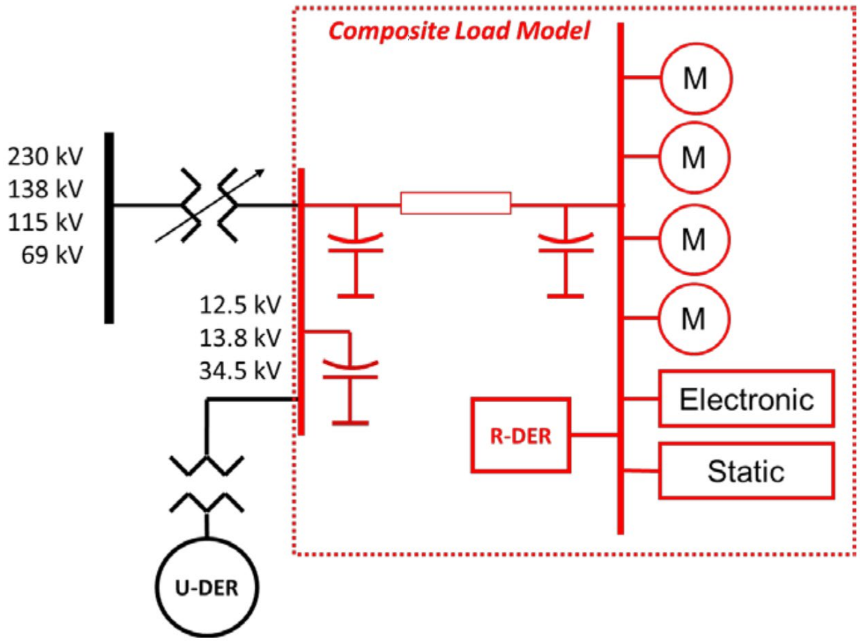


Figure 3: The U_DER and R_DER model representation

However, it is not feasible to include information on every individual DER dispersed across a distribution feeder in a transmission planning base case model. As such, the R_DER representation is used to aggregate a group of DER in an effort to approximate the combined behavior of these resources.

Tracking Distributed Generation Output

As originally discussed in the **NERC Reliability Guideline: Distributed Energy Resource Modeling**[15], it is recommended that Distributed Generation fields be provided within power flow software load models, and that the Distributed Generation dispatch be sortable by Area, Zone, Owner, and related fields. An example of R_DER data accounting in PowerWorld (Version 21) is shown in **Figure 3**, **Figure 4**, and **Figure 5**, while **Figure 6** and **Figure 7** demonstrate DER tracking in the PSS/E environment (v34.6).

[15] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

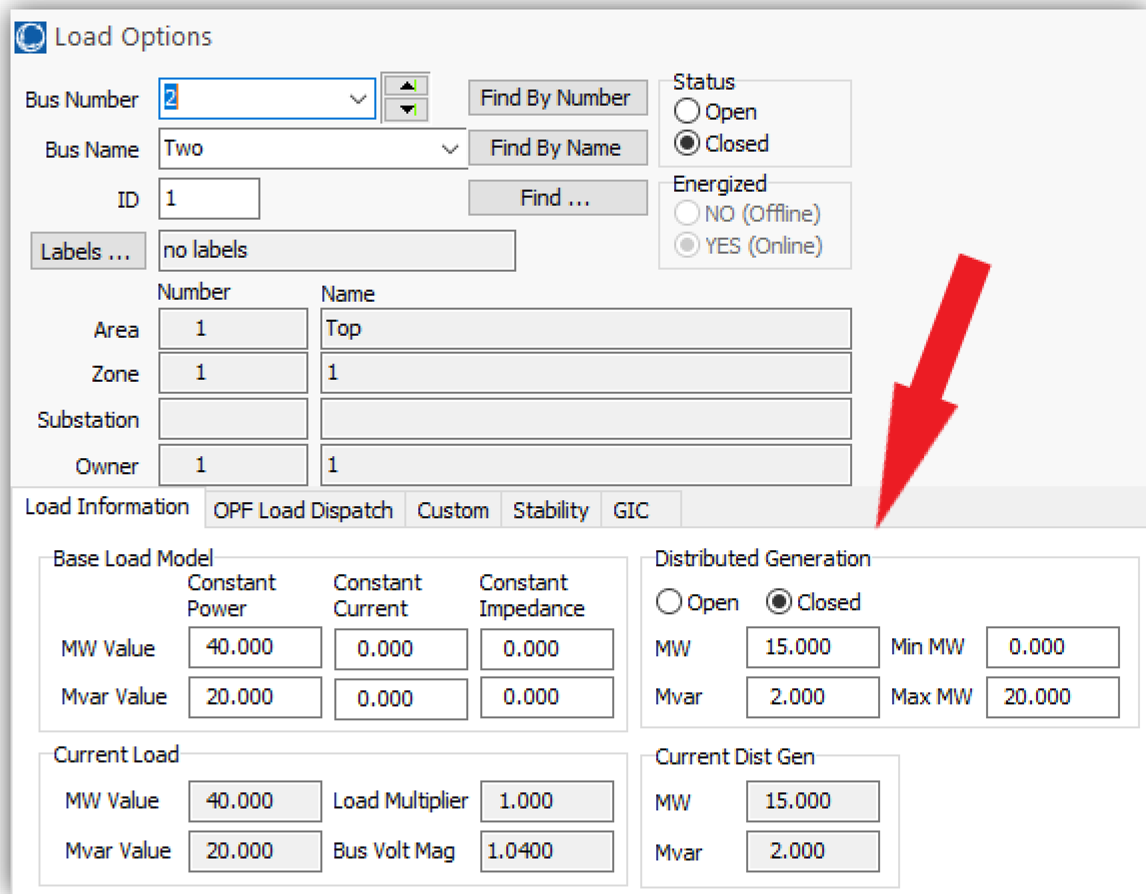


Figure 4: Load model dialog with Distributed Generation section [Source: PowerWorld]

Area Num	Area Name	Gen MW	Load MW	Dist MW	Dist Mvar
1	Top	345.38	360.00	25.00	12.00
2	Left	201.18	200.00	0.00	0.00
3	Right	199.45	200.00	0.00	0.00

Figure 5: DER deployment listed by area [Source: PowerWorld]

Owner Number	Owner Name	Num Buses	Num Loads	Num Gens	Gen MW	Gen Mvar	Load Dist MW	Load Dist Mvar
1	1	3	2	2.0	278.05	43.56	0.00	0.00
2	2	4	4	3.0	467.96	63.30	25.00	12.00

Figure 6: DER deployment listed by owner [Source: PowerWorld]

	Bus Number	Bus Name	Id	Term Node Num	Term Node Name	Code	Area Num	Area Name	Zone Num	Zone Name	Owner Num	Owner Name	In Service	Scalable	Interruptible	Pload (MW)	Qload (Mvar)	IPload (MW)	IQload (Mvar)	YPload (MW)	YQload (Mvar)	Distributed Gen (MW)	Distributed Gen (Mvar)	Distributed Gen Mode	Grounding flag
	2	XXAXCCOA	1			1	1	BMRXZ	1		1			Yes	Yes	88.2000	22.0000	0.0000	0.0000	0.0000	0.0000	2.5000	0.5000	On	Grounded
	3	XXOOYOAO	1			1	1	BMRXZ	1		1			Yes	Yes	23.2000	7.5000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Off	Grounded

Figure 7: DER deployment listed by bus [Source: Siemens PSS/E version 34.6]

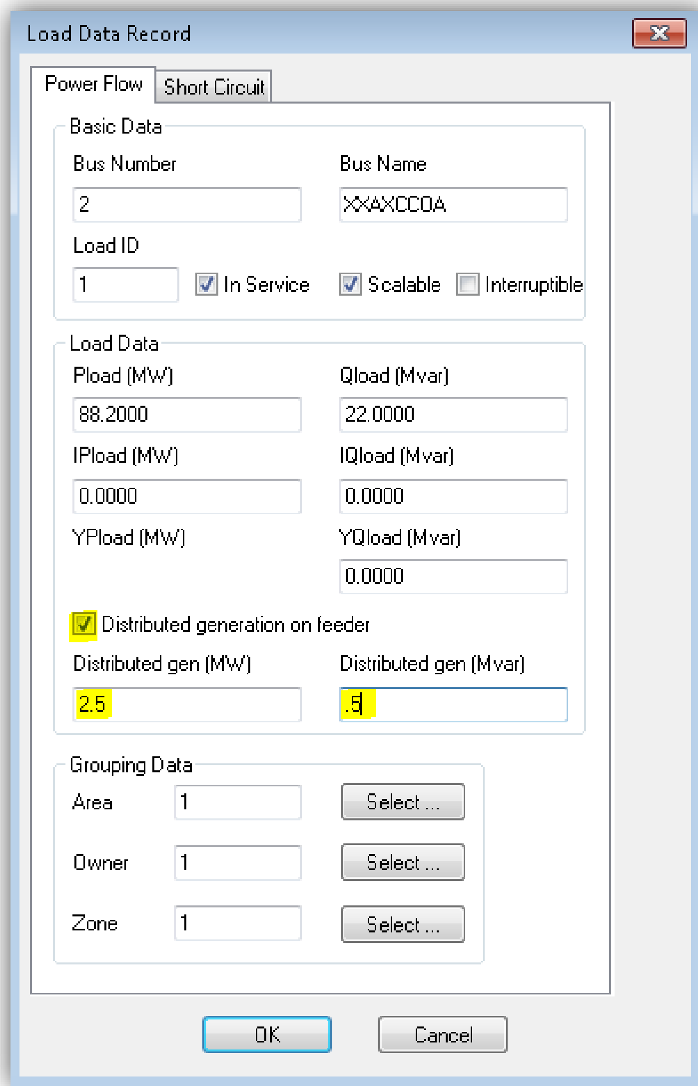


Figure 8: Data Record for DER [Source: Siemens PSS/E version 34.6]

Reactive power capabilities of DER

Behind-the-meter DER in power flow are modeled as a part of load with active and reactive power. Currently, limits on the upper and lower bounds on DER reactive capability (here denoted Q_{min} and Q_{max}) are not typically available in positive-sequence software.

The increasing penetration of inverter-based resources in the generation mix will in turn spur increased participation in voltage control and reactive power injection from these same inverters. Increased use of volt-var support and other voltage control methods may eventually lead to a need to model the available reactive power of a set of distributed resources. It is recommended that software vendors be aware of the implications of DER-supplied reactive power and consider how best to model any reactive power limitations.

Data Tracking Implications of FERC Order 2222

In September 2020, the Federal Energy Regulatory Commission (FERC) adopted Order No. 2222 - Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. Order No. 2222 directs RTOs/ISOs to submit tariff revisions that open wholesale electricity markets to DER aggregations, specifically requiring them to allow distributed energy resource aggregations to participate directly in the organized wholesale electric markets.

According to Order 2222:

Paragraph 294. *"…this final rule in no way prevents state and local regulators from amending their interconnection processes to address potential distribution system impacts that the participation of distributed energy resources through distributed energy resource aggregations may cause. In addition, coordination between RTOs/ISOs, distributed energy resource aggregators, relevant electric retail regulatory authorities, and distribution utilities during the registration and distribution utility review processes should provide RTOs/ISOs with the information they need to study the impact of distributed energy resource aggregations on the transmission system."*

The implications of FERC Order 2222 are still being established within ISO/RTO environments. It is recommended that software vendors stay abreast of the topic and be prepared to support planning engineers with future tools that describe the behavior of DER Aggregators once their behavior is better understood.

Key Takeaways

- Smaller aggregations of DER dispersed across a feeder (denoted R_DER) should be accounted for using the Distributed Generation MW and MVAR fields in power flow load models, in order to separate these resources from gross load.
- Load values in tables, reports, and GUI's should always be labeled as Net or Gross.
- Information on the total Distributed Generation MW and MVAR for a particular Area, Zone, Owner, etc. should be made available within the power flow software structure.
- It is recommended that software vendors be aware of the implications of DER-provided reactive power and consider how best to model any reactive power limitations.
- Vendors should stay abreast of developments surrounding FERC Order 2222 and be prepared to support planning engineers with future tools that describe the behavior of DER Aggregators, once the behavior of these resources is better understood.

Organizing DER dynamics modeling data

A number of dynamics models such as REGC_A, REEC_A REPC_A, and PVD1[16] are available to capture the dynamic behavior of DERs.[17] This guide recommends that power system software supports the recently designed **DER_A** model for DER dynamic behavior.

In dynamic simulation, the DER_A model provides a number of modeling capabilities[18]:

- Multiple control modalities, including constant power factor and constant reactive power control
- Active power-frequency control with droop and asymmetric deadband
- Voltage control with proportional control and asymmetric deadband
- Fraction of resources tripping or entering momentary cessation at low and high voltage, includes a timer feature
- Fraction of resources restoring output following a low or high voltage or frequency condition
- Active power ramp rate limits during return to service after trip or enter service following a fault or during frequency response
- Active-reactive current priority options

[16] The REEC_B model is no longer recommended as a model for dynamic simulations, as it does not capture the momentary cessation behavior of inverter-based resources. For more information, see https://www.wecc.org/Reliability/Converting%20REEC_B%20to%20REEC_A%20for%20Solar%20PV%20Generators.pdf

[17] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

[18] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Modeling-DER_Modeling_Guideline_IG.pdf

- Capability to represent generating or energy storage resources. Thus DER MW values in power flow data should be allowed to be negative for storage.

The DER_A model should be usable as part of the composite load model or as a standalone model.

Regardless of the DER dynamics model used, the ability to conduct transient simulations of DER behavior will be increasingly important as the power system transitions to greater reliance on these resources. Some desired features of dynamic DER data tracking include:

1. Tabular organization of post-contingency DER model states and statuses. For instance, PSLF provides the statuses of DER following dynamic simulation, which can be tracked with the output table view as shown in **Figure 9**. The difference between the initial and final values of each DER listed in the table provides information about the tripping actions of DER following an event.

E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W
'Type'	'-MdName	'--BUS--'	'--NAME--	'--KV--'	'--TO---'	'-ToNAME	'--KV--'	'ID'	'CK'	'SEC'	'-ARE'	'-ZON'	'---CMIN--	'---CMAX-	'INIT_VAL	'FINAL_VA	'INIT-FINA	'--VMIN--
Pdg	cmpldwg	xxxxx	Bus	115	0		0	1		0	30	305	0	50	30.78	30.589	0.191	26.645
Pdg	cmpldwg	xxxxx	Bus	115	0		0	2		0	30	314	0	50	35.042	34.887	0.155	32.544
Pdg	cmpldwg	xxxxx	Bus	115	0		0	3		0	30	305	0	50	24.889	24.736	0.153	21.969
Pdg	cmpldwg	xxxxx	Bus	115	0		0	1		0	30	304	0	50	23.206	23.062	0.144	20.947
Pdg	cmpldwg	xxxxx	Bus	115	0		0	7		0	30	315	0	50	40.088	39.948	0.14	38.923
Pdg	cmpldwg	xxxxx	Bus	230	0		0	2		0	30	304	0	50	32.265	32.126	0.139	28.819
Pdg	cmpldwg	xxxxx	Bus	115	0		0	2		0	30	305	0	50	20.998	20.868	0.13	18.211

Figure 9: DER_A dynamic model post-simulation state values, listed for a number of Composite Load Models [Source: GE PSLF]

2. It is suggested that the same variables that track the behavior of DER (such as MW output, MVAR output, and tripping characteristics) be accessible in the plotting tools associated with transient stability software. Being able to quickly assess, for example, the percentage of DER that tripped in a specified Area following a system disturbance would aid in power system dynamic analysis.

3. In some transient stability programs, when the results of transient stability are reviewed and plotted, there is no option to see and to plot the gross load, only the net load. Because of this, plots of load may look somewhat counter-intuitive, for example, load sharply increases with reduction in voltage, which is actually occurring because of the behind-the-meter DER trip. It would be useful to have an option to plot gross load as well as net load.

4. There is interest from planning engineers in being able to take information on DER (for instance, determining percentage of DER that tripped at each model) from the final system state in transient stability runs and import this information back into the power flow case in order to study the post-contingency power dispatch. While it is understood that importing all of the information in the dynamic simulation back into the power flow may not be possible (for instance, if the system frequency was off nominal in the dynamic simulation, this would alter many of the resulting impedances in the steady state simulation), importing DER-specific information would be useful for studying certain situations, such as assessing post-contingency behavior of the system for thermal limit monitoring and PV/QV analysis.

5. If this functionality were to be implemented, it would be helpful if the post-contingency aggregate DER active and reactive power output at each load bus was available to be imported back into the

load flow case as well. For example, if a transmission fault causes 5 MW of DER generation to trip off at a particular bus, it would be helpful to generate a script file that could be applied to the steady-state case that described this resulting 5 MW change in distributed generation at this bus.

Key Takeaways

- The DER_A model is recommended for use in dynamics studies to quantify the behavior of DER. The model should be supported in power flow software, both as a standalone model and as a component of the Composite Load Model
- Post-contingency information on the behavior of the DERs, including the fraction of generation that tripped and was restored, should be made available in a tabular format
- Plotting tools associated with dynamic simulations should provide accessible ways to display DER behavior, both at individual buses and in aggregate (by Owner, Area, Zone, etc.)
- Plotting tools should also provide the ability to view both gross load and net load values
- The ability to import DER tripping behavior from dynamic simulation back into the power flow model would be useful
- It is recommended that software vendors continue to be cognizant of computational time required for dynamic runs, even as DERs increase modeling complexity

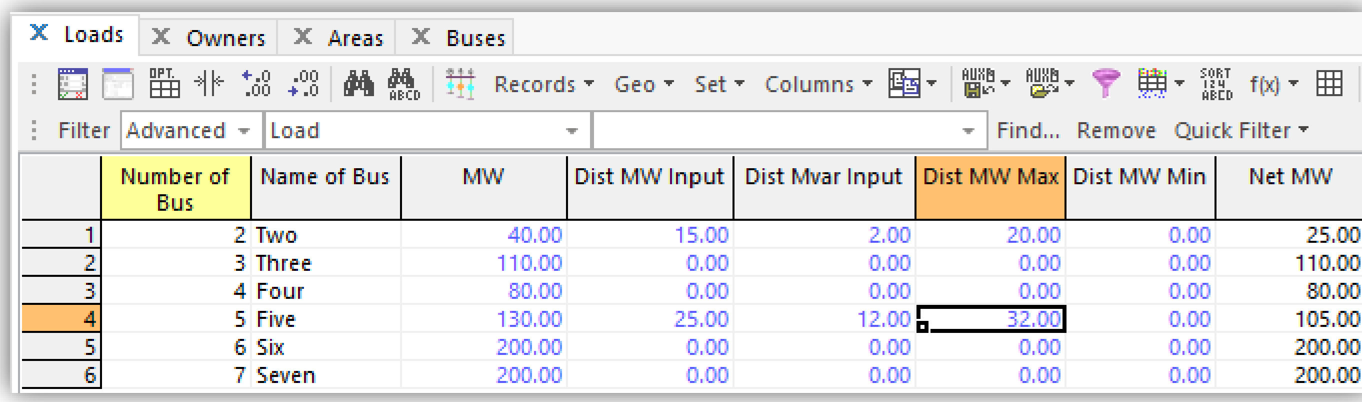
Off-Peak Dispatch of Solar DER

Power Flow Modeling

In transmission planning base case models, all generators have a specified P_{max} that designates the maximum output of the facility, regardless of season or time of day, i.e. the rated capacity of the facility. Some distributed generation, especially photovoltaic (PV) solar generation, will have a range of active power output values that will be at or below this P_{max} level, depending on the season and time of day. For instance, a PV resource with a peak capacity of 1 kW at noon in the summer may only be generating 0.5 kW at 4pm in the fall.

The base case building process is moving towards a paradigm in which the specified time of day will have a large impact on the generation dispatch profile. In the future, a Heavy Summer case at noon may look very different than a Heavy Summer case at 7pm, given the large change in solar generation (both DER and utility-scale) between these two times.

In order to provide the ability to adjust DER output to off-peak values, power flow software will need to maintain minimum and maximum active power output capability for each DER model. As shown in **Figure 4**, PowerWorld provides an example of these parameters, by tracking the 'Min MW' and 'Max MW' value within the Distributed Generation section of the load model dialog. These minimum and maximum values enforce limitations on the active power output of the specified DER.



	Number of Bus	Name of Bus	MW	Dist MW Input	Dist Mvar Input	Dist MW Max	Dist MW Min	Net MW
1	2	Two	40.00	15.00	2.00	20.00	0.00	25.00
2	3	Three	110.00	0.00	0.00	0.00	0.00	110.00
3	4	Four	80.00	0.00	0.00	0.00	0.00	80.00
4	5	Five	130.00	25.00	12.00	32.00	0.00	105.00
5	6	Six	200.00	0.00	0.00	0.00	0.00	200.00
6	7	Seven	200.00	0.00	0.00	0.00	0.00	200.00

Figure 10: Distributed Generation maximum and minimum active power limit fields [Source: PowerWorld]

Furthermore, it will be useful to determine an aggregate "headroom" between the dispatched active power of a group of DER, and the total possible active power generation of this group. For instance, the PowerWorld 'Loads' tab displays a 'Dist MW Input' and 'Dist MW Max' value for each load (see **Figure 10)**. However, in aggregation tabs such as 'Areas,' it is not possible to view the total 'Dist MW Max' across all DER by Area. This functionality would allow planners to quickly view how much of the potential DER active power is currently dispatched in a case.

Adding the ability to adjust the ratio of DER active power that is dispatched in a case would also be helpful. This could involve a controllable variable that represented the ratio of dispatched DER active power to total available DER active power. Since the DER dispatch may vary across geographic regions or in particular regulatory environments as well, providing the ability to adjust this ratio by Area, Zone, Owner, etc. would also be useful.

However, care must be taken when adjusting DER active power output globally. Non-PV DER, such as distributed wind, may have active power outputs that should not be adjusted based on the time of day. In this case, it might be necessary to track PV DER separately from non-PV DER, and only adjust the PV DER active generation setpoints. It will be up to software vendors to determine how best to provide this functionality.

Key Takeaways

- Power flow software should provide minimum and maximum active power generation fields within DER models that enforce limits on the active power output of DER devices
- The combined active power setpoints and the combined maximum active power of all DER in a particular Area, Zone, etc. should be easily viewable in a tabular format, in order to provide a measure of "headroom" between existing DER dispatch and maximum potential dispatch
- Functionality should be added to power flow software to easily adjust the ratio of dispatched DER active power to total available DER active power. This functionality should be available to apply to the entire base case, or a particular Area, Zone, Owner, etc.
- Care must be taken when providing global DER adjustments, as it may not be appropriate to adjust non-PV DER.

Transient Modeling

When adjustments are made to DER active power setpoints, they may require corresponding changes to the DER dynamic modeling parameters. For instance, the **NERC Modeling Notification "Dispatching DER Off of Maximum Power during Study Case Creation"**[19] describes how to set parameters of the DER_A model (specifically *Freq_flag*, *Ddn*, and *Dup*) in cases where DER is dispatched at off-peak output levels.

A major concern is the possible disconnect between the power flow and dynamic models, since modeling maintenance or updates might not occur if data needs to be updated in both the power flow model and the dynamic model. For many planners, tracking and changing dynamic model parameters in each scenario is more challenging than changing power flow data.

This is especially true when an engineer has to adjust a large set of data for individual models, and may not provide transparency across utilities detailing under what scenario their DER can be dispatchable or not. In

[19] NERC, "Dispatching DER Off of Maximum Power during Study Case Creation." (Initial Distribution)

general, planners adjust their own DER model parameters but are hesitant to make changes to neighboring systems.

One way to prevent these issues would be to flag dynamics data that does not agree with steady state parameters. As an example, PSS/E automatically highlights some of the parameters that are outside typical ranges in both power flow and dynamic cases for conventional power system elements. It would be helpful if such capability can be added for DER modeling.

For example (see **Figure 11**) the V_{max} and V_{min} fields are highlighted by PSS/E in the power flow. This is due to the fact their values are greater than 1.5 per unit (default maximum number). There is also a warning message when loading the power flow case, as shown in **Figure 12**.

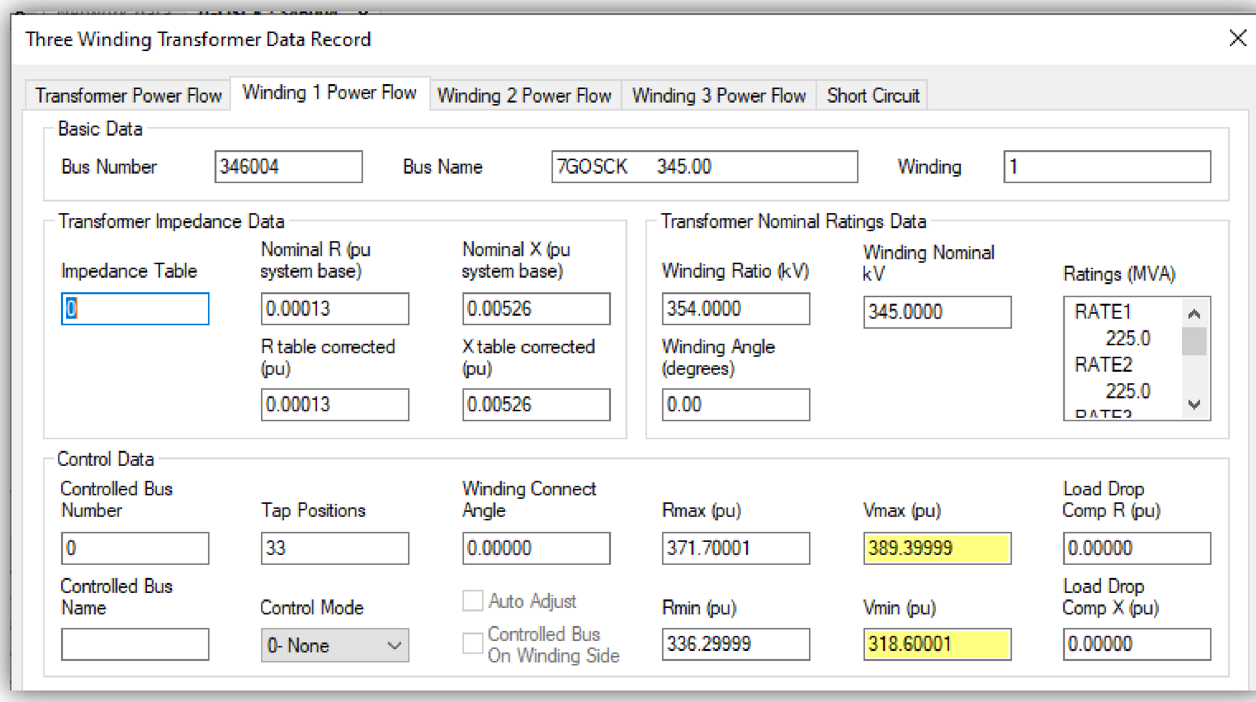


Figure 11: Potential out-of-range parameters are highlighted as a warning to the user [Source: Siemens PSS/E]

Study Explorer | Network Tree | Plot Tree

Output Bar

```
Messages for three-winding transformer circuit "1" from 346004 [7GOSCK      345.00]
Messages for winding 1 connected to bus 346004 [7GOSCK      345.00]:   (004583)
 Warn: Voltage VMAX in per unit (389.400) is greater than 1.5    (004610)
 Warn: Voltage VMIN in per unit (318.600) is greater than 1.5    (004612)
Messages for winding 2 connected to bus 345998 [1GOSCK 1    13.800]:   (004583)
 Warn: Voltage VMAX in per unit (13.8000) is greater than 1.5    (004610)
 Warn: Voltage VMIN in per unit (13.8000) is greater than 1.5    (004612)
Messages for winding 3 connected to bus 345999 [1GOSCK 2    13.800]:   (004583)
 Warn: Voltage VMAX in per unit (13.8000) is greater than 1.5    (004610)
 Warn: Voltage VMIN in per unit (13.8000) is greater than 1.5    (004612)
```

Figure 12: The log provides the user with feedback on potential out-of-range parameters [Source: Siemens PSS/E]

Similar capability exists when working with dynamic models. Figure 13 shows an example of the EXST1 model with parameters outside typical ranges being highlighted.

Edit Model Parameters

Model EXST1 Model 11340 '16'

Model CONS | Model ICONS | Model VARS

	Con Value	Con Description
1	0.0000	TR
2	0.1000	VIMAX
3	-0.1000	VIMIN
4	1.0000	TC
5	10.0000	TB
6	200.0000	KA
7	0.0200	TA
8	8.7300	VRMAX
9	0.0000	VRMIN
10	0.1100	KC
11	0.1000	KF
12	1.0000	TF (> 0)

Figure 13: Dynamics modeling parameters flagged for potential out-of-range data [Source: Siemens PSS/E]

The most likely parameter to be misaligned between power flow and dynamic studies is the DER MVA base value (for DER modeled as standalone U_DER generators). It will be particularly important to flag when there is a discrepancy between this value in the power flow and dynamic models.

Another potential solution to this issue may be to automatically adjust certain dynamic modeling parameters as the steady state values are changed. For any automated adjustments, the user should be made aware via the program log that a change to the data has been conducted.

Automating such a process requires a detailed understanding of the DER dynamics models and how they should be parameterized. Sources such as the **NERC Modeling Notification "Dispatching DER Off of Maximum Power during Study Case Creation"** and **NERC Reliability Guideline "Parameterizing the DER_A Model"**[20] provide information to planning engineers regarding how best to determine the DER_A parameters. These references may also be of interest to power system software vendors to provide guidance on automatically adjusting certain DER_A dynamic model parameters in order to match steady-state DER dispatch modeling data.

Key Takeaways

- Adjustments to certain DER power flow parameters will necessitate corresponding changes to the associated DER dynamics model. Per NERC documentation
- Given the large amount of DER information likely to present in future base case models, it will not be feasible for planning engineers to adjust all of the DER dynamics data after DER power flow adjustment have been made
- Power flow and dynamics models should visually flag, and report via the log, parameters that are suspected of being out-of-range
- When DER is modeled as standalone U_DER generator, particular care should be taken to flag or otherwise communicate when there is a discrepancy between the power flow and dynamic model "MVA base" parameter
- It may be beneficial to consider automating certain DER dynamics modeling parameter adjustments as the DER steady state values are changed (while providing feedback to the user that this is occurring)

[20] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

Battery energy storage system modeling

U-DER Energy Storage Models

Modeling approaches for larger U-DER energy storage resources will depend on recommendations from other groups, including the SPIDER modeling group and other industry and regional planning organizations. In general, it is recommended that power system software provide the ability to model energy storage resources as independent generators (with the ability to output a negative load).

From a power flow perspective, this representation is an acceptable modeling approach. However, in the absence of an identifying field, it may make it difficult for planners to observe power system base cases and determine which generation resources offer the flexibility of energy storage resources. Therefore, an "energy storage" in the "unit type" or "turbine type" field for generators that represent energy storage resources is recommended.

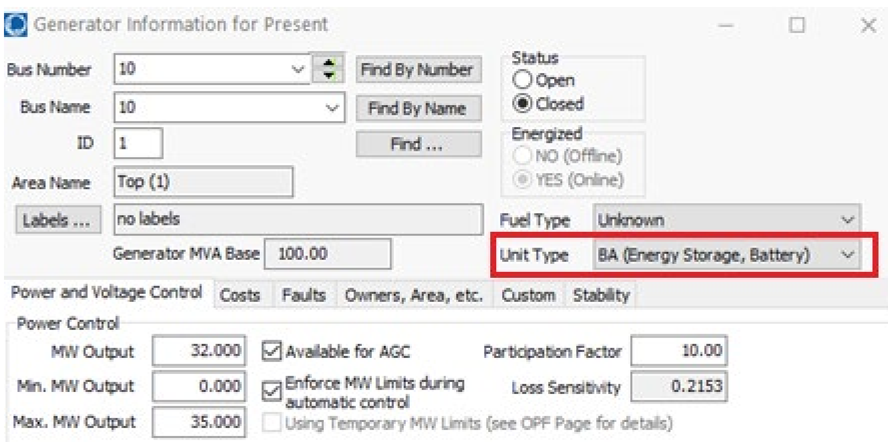


Figure 14: An example dialog box for generator information. The "Unit Type" parameter designates that this is an energy storage resource. [Source: PowerWorld]

Additionally, a separate energy storage symbol on the one line diagrams could potentially make the distinction between these resources and traditional generators or loads more apparent.

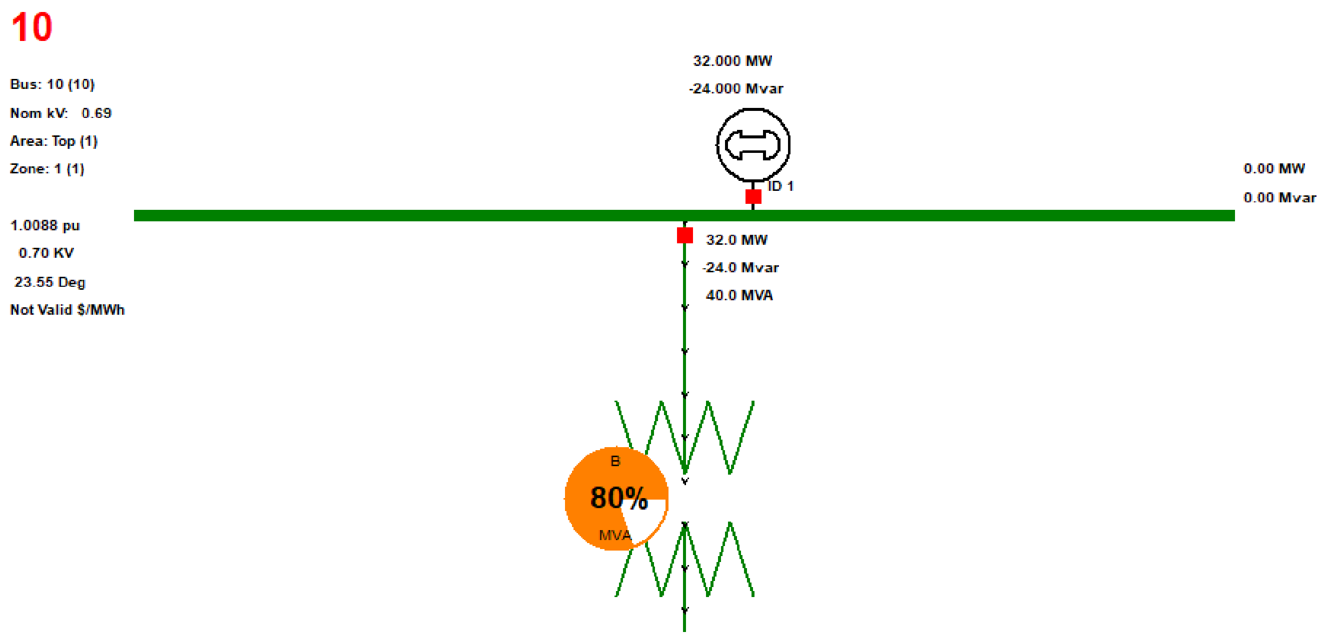


Figure 15: An auto-generated one-line diagram of a bus with connected energy storage element. It is not apparent from the diagram that the generator is an energy storage resource. [Source: PowerWorld]

R-DER Energy Storage Models

R-DER energy storage resources represent a difficult modeling challenge that system planners are still in the process of grappling with. In general, DER storage devices may be deployed alone along a distribution feeder or collocated with generating DER devices on the same feeder. Best practices are still under development for tracking energy storage separately on the same feeder, and determining whether the energy storage devices should be dispatched in the power flow case.

This guideline recommends that future distributed generator sub-models within the load model provide the ability to divide the distributed generation into multiple "turbine types" or "unit types," in order to account for the feeders that contain both energy storage and generating resources. This will allow planners to better track which resources should be deployed depending on the scenario.

Key Takeaways

- Distributed generation models should include the ability to separate resources into multiple "turbine types" or "unit types" in order to track energy storage resources separately from generation resources

PART III: Seams Between Power System Studies

The prevalence of DERs will stress the "seams" that exist between various types of power system studies. For instance, DER active power injection will affect distribution voltage and current dynamics, while also changing power flows at the bulk transmission level. It will be necessary to quantify the impacts that DERs have in both distribution and transmission models, either by creating data structures that can be easily ported between distribution and transmission software programs, or by developing co-simulation platforms that can capture the behavior of the combined systems.

Part III highlights some of the known seams between power system studies, and discusses how both interoperability between software programs and development of new co-simulation platforms will aid future planning efforts.

Transmission versus Distribution Studies

For a number of reasons, transmission and distribution planners have traditionally run separate studies for their portions of the power system.

Transmission planners deal with a highly interconnected grid, where the magnitude and direction of flow over transmission lines can change significantly based on the season and system conditions. They are often beholden to numerous federal and state requirements on how the transmission system should be planned. NERC Standard TPL-001[21] specifies the single- and multiple-element contingencies that must be studied using power flow analysis to determine whether specified thermal and voltage criteria are met. Since transmission systems are relatively balanced across all three phases, positive-sequence programs that ignore phase imbalance are the tool of choice.

The TPL-001 standard also requires that transient stability analysis is used to determine whether the transmission system will maintain stability during specified faults and outages. This involves choosing the applicable industry-standard mathematical dynamic model for each system component (generator, exciter, stabilizer, etc.) and parameterizing it based on testing methods specified in NERC Standards MOD-25[22], -26[23], and -27[24]. These block diagram models provide the differential equations that drive the transient

[21] NERC Standard TPL-001-4 – Transmission System Planning Performance Requirements, NERC.
[22] NERC Standard MOD-25-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
[23] NERC Standard MOD-26 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
[24] NERC Standard MOD-27 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

behavior within dynamic simulations. The same positive-sequence transmission planning models are used in transient analysis in order to determine the voltage and current profiles within the network at each timestep of the simulation.

In contrast, distribution planners deal with a radial network topology, where phases are no longer balanced. Distribution networks also tend to change much more rapidly than transmission, with daily reconfiguration not uncommon to mitigate outage impacts or offload customers to other feeders. While distribution planners also employ thermal and voltage analysis, it is not typical to study transients at the distribution level. Thus, the software tools used by distribution planners can accurately model phase imbalance and handle reconfiguration seamlessly; however, these tools typically are less robust at handling meshed networks and do not typically provide transient analysis capabilities.

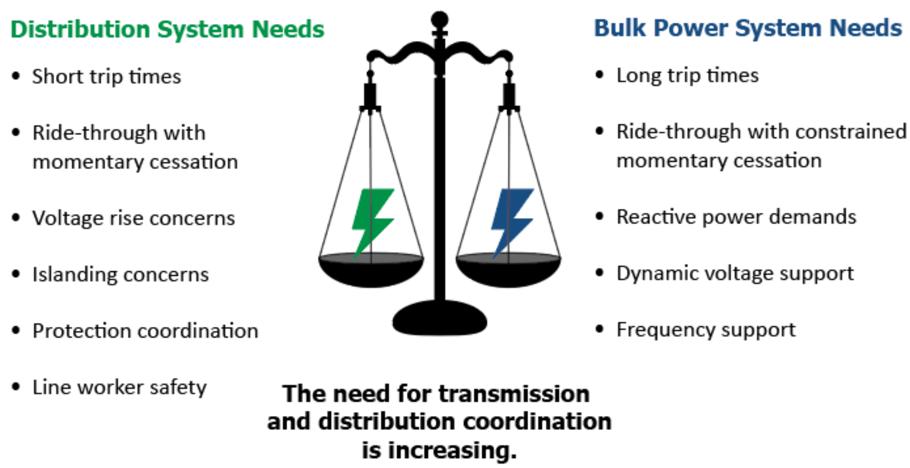


Figure 16: Transmission and Distribution System Needs – Drivers for Coordination [Source: Adapted from EPRI]

As described throughout this white paper, DERs are blurring the lines between transmission and distribution analysis, requiring a shift in how the power system is planned. The dynamics of distribution system operation, now more than ever, have to be carefully considered within the context of their impacts to bulk system reliability.

Tools such as the DER_A model provide a positive-sequence approximation of DER tripping behavior. This is a useful model for describing aggregate DER behavior. As DERs proliferate, further tools will be required to provide higher-fidelity models that accurately capture the minutia of distribution operations. Table 1 below lists several types of planning studies that must consider both transmission and distribution impacts.

Table 1.1: Overlapping Transmission and Distribution Planning Studies Related to DERs

Focus of Study	Distribution Impacts	Bulk System Impacts
Steady-state injection of DER real and reactive power	Voltage rise/droop concerns Developing metering strategies to separate net and gross system load Feeder and service transformer upgrades may be required	Large-scale changes to bulk system power flow that may defy traditionally observed patterns
DER trip settings	Coordination with other protection devices on the feeder Preventing DER energization of feeders during maintenance/outage work Adherence to applicable standards such as IEEE 1547-2018	Tripping behavior of DERs during faulted system conditions affects transient stability analysis
Distribution Automation and Recloser Operation	Coordination with downstream protection devices Continuity of electrical service for impacted customers	Distribution automation dynamics may alter distributed generator output and load profiles, in turn affecting bulk system transient stability analysis
Under-frequency and Under-voltage load shed schemes[25]	Excluding critical loads from UFLS/UVLS enabled feeders	Determining an adequate amount of load shed in order to maintain system voltage and frequency stability while accounting for distributed generation losses at UFLS/UVLS enabled feeders

The studies listed in Table 1.1 may be difficult to analyze with a single software tool. Planners will increasingly rely on collaboration between existing tools, for instance, running full three-phase unbalanced analysis on a distribution platform, and then importing the salient information from the distribution system into a transmission planning tool. In this environment, the more that separate industry tools can "talk" amongst each other, the better off the resulting studies will be.

Furthermore, there is increasing interest in the development of new software platforms that can model both distribution and transmission systems on one unified software setting. Such tools would provide planners with comprehensive tools to describe the full behavior of the system, although most appear to be

[25] NERC Reliability Guideline – Recommended Approaches for Developing Underfrequency Load Shedding Programs With Increasing DER Penetration. System Planning Impacts of Distributed Energy Resources Working Group.

in the earlier development stages. For a full discussion of Transmission and Distribution co-simulation tools and techniques, refer to the NERC White Paper "Beyond Positive Sequence."[26]

Key Takeaways

- Providing the ability to import data between transmission and distribution software tools will be increasingly important to power system planners
- Co-simulation tools are in development. NERC SPIDER working group stresses that these tools will fulfill a critical role in future planning studies. The NERC White Paper "Beyond Positive Sequence" provides a deeper inspection of this topic

Positive-Sequence Power Flow versus Electromagnetic Transient Studies

DERs, and inverter based resources in general, are also stressing the need for increased use of electromagnetic transient (EMT) analysis in planning studies. Fast timescale interactions between power electronics, switching devices, and electromechanical generator elements drive transients that positive-sequence software cannot accurately capture.

Engineering are increasingly relying on both positive-sequence and full EMT analysis when performing planning studies, with data from one platform often having to be reproduced in the other. It would greatly aid planners if this data exchange was ironed out. For instance, it should be possible identify a portion of the transmission system in a positive-sequence environment, and create a corresponding transmission model in an EMT environment, while automatically calculating the Thevenin-equivalent parameters at the boundaries of the system, and auto-populating the initial power flow in the EMT simulation. Such integration provides planners with a faster and more accessible way to run EMT and positive-sequence studies.

Key Takeaways

- Planning engineers use electromagnetic transient analysis now more than ever, but it is not always a smooth process to import load flow and transmission modeling data from positive-sequence programs into EMT tools. It would be helpful if a portion of the transmission system could be identified in positive-sequence software, and the information on Thevenin-equivalent boundaries of the selected system, as well as the initialized power flow information, could be easily imported into an EMT environment

[26] NERC White Paper – Beyond Positive Sequence. System Planning Impacts of Distributed Energy Resources Working Group. (Working document).

Contributors

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this White Paper. NERC also would like to acknowledge all the contributions of the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) to the development of this document.

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Synchronized Measurements Working Group (SMWG) Scope Document

Action
Approve

Summary
The SMWG updated their scope document to reflect the transition from a subcommittee to a working group reporting to the Real Time Operating Subcommittee. Other clarifying edits for the scope and deliverables for the SMWG were made. The SMWG is requesting RSTC approval of the revised scope document.

Synchronized Measurement Working Group Scope

Purpose

The purpose of the NERC Synchronized Measurement Working Group (SMWG) is to provide technical guidance and support for the use of synchronized and high-resolution measurements of the bulk power system (BPS) across North America.

Activities

The working group will support the development, implementation, and utilization of synchronized and high-resolution measurement systems. This includes engineering analysis techniques and real-time tools for improved planning, operation, and reliability of the North American BPS. This includes the following tasks:

1. Formulate and guide the NERC vision and activities to promote the advancement of wide-area time synchronized and high resolution measurement systems and applications, including standards where and when needed.
2. Support the development and use of standardized data sharing, data quality, and data cleaning protocols and practices for time synchronized and high resolution measurement data.
3. Support any data collection or analysis of power system performance following selected events and significant disturbances. Coordinate with other NERC groups such as the Event Analysis Subcommittee and the System Analysis and Modeling Subcommittee, as applicable.
4. Maintain recommendations, guidelines, technical reference documents, and training materials to help advance the use of applications driven by time synchronized and high resolution measurements across the industry.
5. Develop and maintain appropriate procedures and guidelines for base line power system performance analysis using time synchronized and high resolution measurement data.
6. Provide a forum for operating entities to discuss activities and experiences related to the development, deployment, and use of measurement data for the purposes of improving reliability of the bulk power system.
7. Coordinate with other industry organizations related to high resolution and synchronized measurement data, including the North American Synchrophasor Initiative (NASPI), WECC Joint Synchronized Information Subcommittee (JSIS), IEEE, and IEC, as applicable.
8. Review and coordinate proposed new synchrophasor applications with any appropriate NERC committees to support coordinated advancement of synchronized measurement technologies to assure effectiveness and to limit duplication of efforts.

Deliverables

SMWG will develop guidelines, technical reports, white papers, and recommendations to the NERC Real Time Operating Subcommittee (RTOS) on the following topics:

1. Ongoing review and analysis of existing and new BPS oscillation events; other technical assessments of power system reliability using time synchronized measurement data
2. Enhanced operating procedures using synchronized measurement data; improved operator and real-time tools and applications
3. Innovative engineering analysis tools and applications
4. Baselining power system performance
5. Effective and efficient data sharing, data quality, and data cleaning methods
6. Design and operation of time synchronized measurement network and data architectures, leveraging other technical groups such as IEEE and NASPI
7. Use of industry technology standards (IEEE, IEC, etc.) and NERC Reliability Standards
8. Other topics as prioritized by the NERC SMWG and NERC RTOS membership

Membership

SMWG will include industry members who have technical expertise in the following areas:

- Development and deployment of high-resolution, time-synchronized measurement systems
- Use of real-time and off-line advanced applications
- Analysis of high resolution disturbance data for event analysis

A NERC staff member will be assigned as a coordinator. The working group will consist of a chair and vice chair appointed by the RTOS leadership for one two-year term. The vice chair should be available to succeed the chair. Decisions will be consensus-based, led by the chair and staff coordinator. Minority views can be included in an addendum.

Reporting

The NERC SMWG administratively reports to the NERC RTOS. SMWG will coordinate with other subcommittees and working groups within the Reliability and Security Technical Committee (RSTC), as appropriate.

Meetings

Two to four open meetings per year, as needed. Meetings may be either in-person or remote.

Synchronized Measurement ~~Subcommittee~~ Working Group ~~(SMWGS)~~ Scope Document

Purpose

The purpose of the NERC Synchronized Measurement Working Group (SMWG) ~~subcommittee~~working group is to provide technical guidance and support for the use of synchronized and high-resolution measurements of the bulk power system (BPS) across North America.

Activities

The ~~subcommittee~~working group will support the development, implementation, and utilization of synchronized and high-resolution measurement systems. This includes engineering analysis techniques and real-time tools for improved planning, operation, and reliability of the North American BPS. This includes the following tasks:

1. Formulate and guide the NERC vision and activities to promote the advancement of wide-area time synchronized and high resolution measurement systems and applications, including standards where and when needed.
2. Support the development and use of standardized data sharing, data quality, and data cleaning protocols and practices for time synchronized and high resolution measurement data.
3. Support any data collection or analysis of power system performance following selected events and significant disturbances. Coordinate with other NERC groups such as the Event Analysis Subcommittee and the System Analysis and Modeling Subcommittee, as applicable.
4. Maintain recommendations, guidelines, technical reference documents, and training materials to help advance the use of applications driven by time synchronized and high resolution measurements across the industry.
5. Develop and maintain appropriate procedures and guidelines for base line power system performance analysis using time synchronized and high resolution measurement data.
6. Provide a forum for operating entities to discuss activities and experiences related to the development, deployment, and use of measurement data for the purposes of improving reliability of the bulk power system.
7. Coordinate with other industry organizations related to high resolution and synchronized measurement data, including the North American Synchrophasor Initiative (NASPI), WECC Joint Synchronized Information Subcommittee (JSIS), IEEE, and IEC, as applicable.
8. Review and coordinate proposed new synchrophasor applications with any appropriate NERC committees to support coordinated advancement of synchronized measurement technologies to assure effectiveness and to limit duplication of efforts.

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Deliverables

The SMWG~~S~~ will develop guidelines, technical reports, white papers, and recommendations to the NERC Real-Time Operating Subcommittee ~~C Planning Committee (PC)~~ on the following topics:

Ongoing review and analysis of

1. ~~Updates on~~ existing and new BPS ~~grid~~ oscillation ~~excursions~~events~~.~~; other t-echnical assessments of power system reliability using time synchronized measurement data
2. Enhanced operating procedures using synchronized measurement data; improved operator and real-time tools and applications
3. Innovative engineering analysis tools and applications
4. Baselining power system performance
5. Effective and efficient data sharing, data quality, and data cleaning methods
6. ~~1.~~ Design and operation of time synchronized measurement network and data architectures, leveraging other technical groups such as IEEE and NASPI
7. ~~2.~~ Use of industry technology standards (IEEE, IEC, etc.) and NERC Reliability Standards

~~3.1. Effective and efficient data sharing, data quality, and data cleaning methods~~

~~4. Operator and real-time tools and applications~~

~~5. Engineering analysis tools and applications~~

~~6. Baselining power system performance~~

~~7. Technical assessments of power system reliability using time synchronized measurements~~

8. Other topics as prioritized by the NERC ~~SMS~~SMWG and NERC ~~PC~~RTOS membership

Membership

The NERC ~~SMS~~SMWG will include industry members who have technical expertise in the following areas:

- Development and deployment of high-resolution, time-synchronized measurement systems
- Use of real-time and off-line advanced applications
- Analysis of high resolution disturbance data for event analysis

A NERC staff member will be assigned as a Coordinator. The ~~subcommittee~~working group will consist of a chair and vice chair appointed by the NERC ~~PC~~ Real-Time Operating Subcommittee (RTOS) leadership for one two-year term. The vice chair should be available to succeed the chair. Decisions will be consensus-based~~d of the membership~~, led by the chairperson(s)~~men~~ and ~~staff~~ C~~c~~oordinator~~s~~. ~~Any m~~Minority views can be included in an addendum.

Reporting

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The NERC SMWG~~MS~~ administratively reports to the NERC Real-Time Operating Subcommittee (RTOS) ~~PC, with liaisons to the NERC Operating Committee~~. SMWG~~S~~ will coordinate with ~~the NERC Critical Infrastructure Protection Committee and its associated sub-group~~other subcommittees and working groups within the Reliability and Security Technical Committee (RSTC)~~s~~, as appropriate.

Meetings
Two to four open meetings per year, as needed. Meetings may be either in-person or remote.

Approved by the NERC Reliability and Security Technical Committee~~Planning Committee~~: ________ __, ____

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Synchronized Measurements Working Group (SMWG) Scope Document

Action
Information

Summary
When NERC's Board of Trustees (Board) adopted the Supply Chain Standards in August 2017, it concurrently adopted additional resolutions related to the implementation and evaluation of the Supply Chain Standards, as well as other actions to address potential supply chain risks.

One of those resolutions directed NERC management, collaborating with NERC technical committees and other experts, to develop a plan to evaluate the effectiveness of the Supply Chain Standards and report to the Board. At the Board meeting in December 2019, NERC outlined its plans to measure the effectiveness of the Supply Chain Standards.

The Supply Chain Working Group (SCWG) developed a voluntary industry survey that will be used to help gather information relevant to the effectiveness of the Supply Chain Standards. The survey is being provided for information purposes to RSTC and industry prior to its publication.

SCWG Supply Chain Effectiveness

NERC Supply Chain Working Group (SCWG)

The NERC Supply Chain Risk Management (SCRM) Reliability Standards are considered to be CIP-013 and applicable portions of CIP-005 (parts 2.4 and 2.5) and CIP-010 (part 1.6), and initially effective on October 1, 2020. The SCRM requirements (or simply the Supply Chain requirements) represent a principle of supply chain security that is not limited to compliance but also security measures that help mitigate the associated risks. The NERC Supply Chain Working Group (SCWG) is requesting your feedback through this survey to gather information on the effectiveness of the supply chain requirements. This is a voluntary survey and your participation is very much appreciated.

Links to the applicable Reliability Standards for your reference:

CIP-005-6

CIP-010-3

CIP-013-1

Click Next to begin survey

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SCWG Supply Chain Effectiveness

*** 1. Are the NERC Supply Chain Risk Management (SCRM) Reliability Standards applicable to you as a registered entity?**

- ◯ Yes
- ◯ N o

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SCWG Supply Chain Effectiveness

2. Are you applying the SCRM principles from the SCRM standards to your operational, business and/or contract language?

- ○ Yes
- ○ No

3. If yes, check all that apply:

- ☐ Transmission Cyber Assets and/or services
- ☐ Generation Cyber Assets and/or services
- ☐ Control Center Cyber Assets and/or services
- ☐ Other operational systems
- ☐ Business systems
- ☐ Contract language

Comments (rationale for implementing (or not) and specifics related to the extent implemented if you feel comfortable responding)

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SCWG Supply Chain Effectiveness

4. In addition to required scope (High and Medium Impact assets) are you applying the SCRM principles from the standards to:
(Check all that apply)

- [ ] Low impact Transmission Cyber Assets and/or services?
- [ ] Low impact Generation Cyber Assets and/or services?
- [ ] Control Center Cyber Assets and/or services?
- [ ] Any other operational systems?
- [ ] Business systems

Comments (rationale for implementing (or not) and specifics related to the extent implemented if you feel comfortable responding):

5. Please select the statement that best describes your opinion regarding the clarity of the Supply Chain Risk Management (SCRM) requirements:

- ◯ The SCRM requirements are clear. Our program is on track and our security objectives are being met.
- ◯ The SCRM requirements are clear, however I am unsure of how we will be audited against them and what evidence will be acceptable
- ◯ The SCRM requirements are somewhat unclear
- ◯ The SCRM requirements are not clear
- ◯ Other (please explain)

6. Do you have a clear understanding of what constitutes a violation of the requirements?

- ◯ Yes
- ◯ N o

Comments

7. Do you believe there are gaps in the SCRM requirements?

- ◯ Yes
- ◯ N o

If Yes, please explain and, if appropriate, list the specific standard or requirement

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SCWG Supply Chain Effectiveness

8. Have you reached out to the Electric Reliability Organization (ERO) Enterprise with questions or concerns on the SCRM requirements?

- ◯ Yes
- ◯ N o

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SCWG Supply Chain Effectiveness

9. Have you reached out to the Electric Reliability Organization (ERO) Enterprise with questions or concerns on the SCRM requirements. Please select the statement that best reflects your experience

- ◯ The guidance from the ERO Enterprise was helpful in clarifying the SCRM requirements
- ◯ The guidance from the ERO Enterprise was somewhat helpful in clarifying the SCRM requirements
- ◯ The guidance from the ERO Enterprise was unhelpful in clarifying the SCRM requirements
- ◯ Other (please explain)

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SCWG Supply Chain Effectiveness

10. Have you reached out to the Electric Reliability Organization (ERO) Enterprise with questions or concerns on the SCRM requirements, please select the statement that best reflects your experience.

- I did not seek guidance from the ERO Enterprise because I understand the SCRM requirement expectations and have no questions
- I did not seek guidance from the ERO Enterprise because I leveraged other industry guidelines and have no questions
- I did not seek guidance from the ERO Enterprise because I have concerns with using these resources
- Other (please explain)

11. Select the statement that most accurately reflects your experience with vendors receptivity to your SCRM program

- Most vendors from whom we procure software, hardware, or cyber services are reasonably supportive (timeliness, completeness of information in responding to our risk assessment.
- Several key vendors from whom we procure software, hardware, or cyber services are resistant to responding to our risk assessment.
- Other (please explain)

12. Does your risk assessment of a vendor provide you adequate information to determine the risks of the vendor's product or services?

- Yes
- No

Comments

13. Do the vendors provide enough information to determine risks from components or products the vendor procures from others?

- Yes
- No

Comments

14. Do you support vendors providing a Software Bill of Materials (SBoM)?

- Yes
- No

Comments

15. Has CIP-013 enabled you to identify previously unknown supply chain risk?

- Yes
- No

Comments

16. Have you implemented supply chain mitigations based on your risk assessment that previously you had not implemented?

- Yes
- N o

Comments

17. Have you implemented compensating security measures other than specification and procurement activities to address security issues because of implementing your CIP-013-1 Risk Management Plan?

- Yes
- N o

Comments

18. Select the statement that most accurately reflects how you conduct a risk assessment of a vendor

- My company gathers the information and performs the risk assessment.
- My company contracts for services of others to gather the information and then my company performs the risk assessment.
- My company contracts for services of others to gather the information and perform the risk assessment.
- Other (please specify)

19. Have you added new or updated contract language to your procurements because of the SCRM requirements?

- ◯ Yes
- ◯ No

Comments

20. Have you renegotiated the terms of existing contracts within the scope of CIP-013? Select the most appropriate answer

- ◯ All existing contracts were renegotiated
- ◯ Some existing contracts were renegotiated
- ◯ No existing contracts were renegotiated
- ◯ Other (please specify)

21. Have your vendors been agreeable to renegotiating existing contracts?

- ◯ Most vendors have been agreeable
- ◯ Some vendors have been agreeable
- ◯ Did not attempt to renegotiate any existing contracts
- ◯ Not applicable

Comments

22. Please estimate the percentage of your overall CIP compliance program resources dedicated to the NERC Supply Chain Risk Management (SCRM) Reliability Standards and the percentage growth of your CIP Compliance Program as a result of implementing SCRM compliance, including those specifically involved from the procurement/contracting office for both percentages.

Percentage of your CIP Compliance Program resources dedicated to SCRM compliance:

Percentage growth of your CIP Compliance Program because of implementing SCRM compliance:

Comments

23. Do you have any comments/concerns/thoughts/ideas on the Supply Chain requirements?

Nominating Subcommittee (NS) Update

Action
Information

Summary
The NS will report on upcoming activities and timelines for Sector elections and At-Large nominees to fill RSTC terms ending in 2022.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Reliability and Security Technical Committee Sector Election and At-large Selection Process

Fall/Winter 2021

The Reliability and Security Technical Committee (RSTC) is a standing committee that strives to advance the reliability and security of the interconnected BPS of North America by:

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission; and,
- Leveraging such expertise to identify solutions to study, mitigate, and/or eliminate emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees (Board) and ERO Enterprise staff and leadership.; and,
- Overseeing the implementation of subgroup work plans that drive risk-mitigating technical solutions.

The RSTC has a hybrid representation model consisting of the following types of memberships:

- Sector members;
- At-large members; and,
- Non-voting members.

Election of Sector Members

NERC members in each sector will annually elect members for expiring terms or open seats using a nomination and election process that is open, inclusive, and fair. In the event that a sector has no nominations for one or both sector seats at the annual election, the RSTC will convert those empty sector seats to at-large seats until the end of the term.

Sector elections will be completed in time for the Nominating Subcommittee to identify and nominate at-large representatives as well as for the secretary to send the full RSTC membership list to the NERC Board for its approval at its annual February meeting.

For the 2021 Sector election cycle, one voting member shall be elected to each of the following membership sectors:

- Sector 1 - Investor-owned Utility;
- Sector 2 - State/Municipal Utility;
- Sector 3 - Cooperative Utility;
- Sector 4 - Federal or Provincial Utility/Power Marketing Administration;
- Sector 5 - Transmission-Dependent Utility;
- Sector 6 - Merchant Electricity Generator;

- Sector 7 - Electricity Marketer;
- Sector 8 - Large End Use Electricity Customer;
- Sector 9 - Small End Use Electricity Customer;
- Sector 10 - ISO/RTO; and,
- Sector 12 - Government Representatives.

A notice will sent to industry with specific dates for individuals to self-nominate or nominate another individual for a specific Sector. Nominations will be vetted by NERC Staff to ensure that the nominees qualify for the stated Sector. Sector elections will be conducted as follows:

1. Sector nominations will occur October 15-November 12, 2021.
2. NERC Staff will notify each RSTC member whose term is to expire in 2022 for awareness prior to the nomination period.
3. If more than one nominee is submitted for a Sector, elections will be held November 15-30, 2021. The election process is as follows:
    a. An announcement is made identifying the candidates and the voting dates.
    b. Each sector voter will rank order their preferences for the sector representatives. For example, if there are four candidates, a voter will assign a 1, 2, 3, or 4 to each candidate with 1 being their most preferred candidate and 4 being their least preferred candidate.
    c. Once all votes are cast, the number assigned by sector voters for each candidate will be added up.
    d. The candidate with the lowest number will be elected.
    e. If there is a tie, there will be a runoff election between the tied candidates. This step will be repeated if necessary until there is a winner.
    f. If a candidate is elected and withdraws their nomination prior to Board appointment, the second ranked candidate will be the elected candidate.
4. The sector nominations/elections will follow newly approved NERC Bylaws here. https://www.nerc.com/gov/Annual%20Reports/Amended%20and%20Restated%20Bylaws%204-5-21.pdf

After sector elections, the RSTC Nominating Subcommittee (NS) will evaluate the attributes of all sector reps to determine the additional expertise/diversity we need to seek for the at-large nominees to meet the goals of the Charter:

- Selection of at-large members will allow for better balancing of representation on the RSTC of the following:[1]
- Regional Entity and Interconnection diversity (i.e., goal of having at least one representative from each Interconnection and Regional Entity footprint);
- Subject matter expertise (Planning, Operating, or Security);

[1] *See,* NERC Sector 13 in the NERC Bylaws (2021).

- Organizational types (Cooperatives, Investor-Owned Utilities, Public Power, Power Marketing Agencies, etc.); and,
- North American countries, consistent with the NERC bylaws (Canada, Mexico, and U.S.).

This evaluation will occur December 1-8, 2021. There will be six open at-large seats. The NS will announce the expertise/diversity they are seeking via e-mail (industry-wide) and seek nominations for at-large members. The nomination period will be December 10-24, 2021.

The current chair and vice chair terms expire in June 2022 (per NERC Board minutes from November, 2019, page 8).

Once at-large nomination period ends, the NS will review all nominations and develop a slate of recommended candidates by January 13, 2022 to be presented to NERC Board of Trustees for appointment.

At the February 2022 Board meeting, sector and at-large members will be appointed. The first RSTC meeting for newly appointed Sector and At-large members will be in March 2020 (specific dates TBD).

RSTC Subordinate Group Review Process

Action
Information

Summary
Per the RSTC Charter, the RSTC "will conduct a "sunset" review of each working group every year" and "review the task force scope at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired." The RSTC Executive Committee has developed a draft process and template for these reviews to be conducted prior to the December 2021 RSTC meeting.

The draft process for this review will include the RSTC Sponsors in coordination with subordinate group leadership and NERC Staff Liaisons review the working group or task force deliverables and work plans to complete the information in the template. Once the templates are complete, the RSTC EC and Sponsors will review them to make a recommendation on the status of the subordinate group. This will be reviewed with the full RSTC at the December RSTC meeting for approval.

DRAFT

RSTC *Task Force* Self Evaluation Template
(Rev.0 – August 2021)

Task Force Name:	**Date of Self-Evaluation:** DD-MM-YYYY	
Background: As per RSTC Charter – section 6 The RSTC *may assign specific work* to a task force. The RSTC *will approve the scope* of each task force it forms. The chair of the RSTC *will appoint the task force officers* (typically a chair and a vice chair). Each task force *will have a finite duration*, normally less than one year. The RSTC *will review the task force scope* at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired. Action of the RSTC is required to continue the task force past its defined duration. The RSTC should consider promoting to a working group any task force that is required to work longer than one year.		
Actions to Complete		Complete
Action 1: Each Task Force (TF) will *complete a Self-Evaluation* once a year and *submit 60 days prior to the last RSTC meeting* occurring before the completion of the TF mandate (expected last day)		Yes/No
Action 2: The RSTC will request 6 volunteers to review all TF Self-Evaluations submitted with a broad view of understanding the current status, meeting its specific scope of work and completion of the task. Consideration will be given to the impact of ongoing tasks that are critical to reliability, security, operability, planning as well as close alignment to RISC. The review findings and recommendations will be tabled 30 days before the RSTC meeting and included for discussion.		Yes/No
Action 3: The RSTC to review recommendations in Action 2 and decide if the FT will retire, continue work or will be promoted to a working group.		Yes/No
TF Self-Evaluation Questions	**Explanations**	
1. Did the TF complete the specific work assignment?	Yes / No	*If Yes STOP the evaluation*
2. Task is still on track to meet the due date?	Yes / No	
3. Are the objectives and goals still valid and clear?	Yes / No	
4. The priority of the work was confirmed?	Yes / No	*Explain the priority*
5. Alignment with RISC is confirmed?	Yes / No	*Explain to alignment*
6. Did the TF identify required future steps?	Yes / No	*Explain steps*
7. Is the TF requesting a new due date?	Yes / No	*Provide details on the request*
8. Is the TF requesting to stand down?	Yes / No	*Provide details on the date*
RSTC Review and Recommendation	**Explanations**	
Recommendation # 1 – continue, retire or promote	*Are objectives and goals still met and the TF assignment provides the expected value?*	
Recommendation # 2 – etc		
RSTC Final Decision – Meeting Date DD-MM-YYYY	**Explanations**	
Based on the Self-Evaluation and RSTC review discussed at large at the meeting, the TF status is ………………………..	*Additional explanation as required*	

Reliability Assessments Subcommittee (RAS) Update

Action
Information

Summary
The RAS is coordinating the development of both the Winter Reliability Assessment (WRA) and the Long-Term Reliability Assessment (LTRA). An overview of the production of each assessment as well as anticipated RSTC actions will be reviewed.

Energy Reliability Assessments Task Force (ERATF) Update

Action
Information

Summary
The ERATF will assess risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The ERATF serves the RSTC in providing a formal process to analyze and collaborate with stakeholders to address the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources Whitepaper. This whitepaper identified energy availability concerns related to operations/operations planning and mid- to long-term planning horizons.

Agenda Item 10
Reliability and Security
Technical Committee Meeting
September 9, 2021

Standing Committee Coordination Group (SCCG) Update

Action
Information

Summary
Per the SCCG scope document, the SCCG is to "provide quarterly reports to the standing committees for inclusion in their public Agenda posting on cross-cutting initiatives addressing risks to the reliability, security, and resilience of the BPS. This report shall be prepared in advance and voted on by the SCCG at the SCCG's quarterly meetings."

Event Analysis Subcommittee – Lessons Learned

Action
Information

Summary
The EAS, in coordination with NERC subcommittees and working groups, will share information, identify trends through analysis of events, and make recommendations to the industry which address lessons learned. This presentation will review lessons learned that were developed in 2021.

Impact of Proposed Wi-Fi Operations on Microwave Links AT 6 GHz

Action
Determination if this is an emerging risk that should be added to the RSTC Work Plan.

Background
In April 2020, the Federal Communications Commission adopted rules that make spectrum in the 6 GHz band available for unlicensed use. The rules usher in Wi-Fi 6, the next generation of Wi-Fi, and play a major role in the growth of the Internet of Things. Wi-Fi 6 will be over two-and-a-half times faster than the current standard and will offer better performance for American consumers. Opening the 6 GHz band for unlicensed use will also increase the amount of spectrum available for Wi-Fi by nearly a factor of five and help improve rural connectivity. The 6 GHz band is currently populated by, among others, microwave services that are used to support utilities, public safety, and wireless backhaul. Unlicensed devices will share this spectrum with incumbent licensed services. The rule included provisions to protect those licensed services and enable both unlicensed and licensed operations to utilize the band, however, those protections have not been fully realized to date.

In addition to the April 2020 decision, there is a pending Further Notice of Proposed Rulemaking to expand the use of the 6 GHz band for additional unlicensed devices. The FCC has not acted on this rulemaking as of today.

In 2020, a consortium of electric industry associations published a report on the IMPACT OF PROPOSED Wi-Fi OPERATIONS ON MICROWAVE LINKS AT 6 GHz[1]. The 6 GHz band of the radio spectrum is widely used by a broad array of industries responsible for critical infrastructure such as electric, gas and water utilities, railroads, and wireless carriers, as well as by public safety and law enforcement officials. Those industries rely on the 6 GHz band to operate their equipment, and it is their main source of both primary communication, and in-some cases back-up communications, during emergencies and disasters. The report identifies impacts to electric power operations. Additional follow-on work by EPRI and various affected stakeholders have shown—through testing--impacts to their critical electric infrastructure communications due to increased congestion and interference on the 6GHz wireless communication band. As adoption of the new technology increases, the risk to BPS operations increases.

Summary

Risk Identification
The draft 2021 RISC Report identifies "Critical Infrastructure Interdependencies" as a priority risk for NERC to address. The report states:

> *Recent BPS events have highlighted that sector interdependence is becoming more critical particularly during emergency events. Digital communications for electric system protection and*

[1] https://utc.org/wp-content/uploads/2020/01/CII-User-Report-and-Ex-Parte-Final-10-Jan-2020_FINAL_USE.pdf

control, and voice communications, particularly cellular, for emergency response and restoration are critical.

The report also recommends a number of activities and prioritizes coordination with cross-industry partners and regulators.

RSTC Consideration
We are bringing this discussion to the RSTC today for industry awareness and consideration of additional actions, as necessary. An initial presentation was made to the Real-Time Operations Subcommittee.

Should NERC and the RSTC consider this emerging risk within its risk mitigation process and add to its Work Plan, if yes then:

- Where within the RSTC would this live for the evaluation of:
    - What should or can the RSTC do?
    - How quickly would the mitigation be needed?

If it's not considered a risk, why?

North American Generator Forum RSTC Update

Allen D. Schriver, P.E.
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NextEra Energy
and
COO North American Generator Forum
Allen.Schriver@nexteraenergy.com
September 8, 2021

NAGF Mission

The NAGF mission is to promote the safe, reliable operation of the generator segment of the bulk electric system through generator owner and operator collaboration with grid operators and regulators.

Agenda

- **NERC Standard Projects**
- **Resilience**
- **NAGF 2021 Annual Meeting**

➢ NERC Standard Projects

➢ NERC Standards Projects

- The NAGF is actively engaged in the following NERC Projects to help ensure the generator sector perspective is heard and understood:
  - NERC Project 2017-01: Modifications to BAL-003
  - NERC Project 2019-04: Modifications to PRC-005-6
  - NERC Project 2021-01: Modifications to MOD-025 and PRC-019
  - NERC Project 2021-02: Modifications to VAR-002
  - NERC Project 2021-04: Modifications to PRC-002

➢ NAGF Quarterly Member Webinar

- The NAGF has quarterly webinars to enhance communication and engage NAGF membership regarding recent NAGF activities, upcoming initiatives, and to acquire feedback regarding activities of interest. The NAGF 2Q2021 Member Webinar was held on June 17, 2021 with over 90 participants.

Resilience

- The NAGF presented at the following Resilience virtual events:
  - ReliabilityFirst (RF) Operational Resilience Webinar held on June 8, 2021
  - NAES NERC Guiding Compliance - Improving Reliability Conference held on August 3-5, 2021
  - RF/SERC Cold Weather Preparedness Webinar held on August 24, 2021

- NAGF continuing to:
  - Collaborate with the NATF on opportunities to enhance resilience based on information from the southwest cold weather event of 2021

NAGF 2021 Annual Meeting

- NAGF Annual Meeting
  - The NAGF 2021 Annual Meeting WebEx is scheduled for October 12th, 13th and 14th
  - If the RSTC would like the opportunity to present or have a discussion with the NAGF please contact Al Schriver or Wayne Sipperly (wsipperly@generatorforum.org)

Q & A

Thank you!

www.GeneratorForum.org

North American Transmission FORUM

Community *Confidentiality* *Candor* *Commitment*

To: NERC Reliability and Security Technical Committee (RSTC)

From: Roman Carter, Director-Peer Reviews, Assistance, Training and Knowledge Management

Date: August 13, 2021

Subject: NATF Periodic Report to the NERC RSTC (September 2021)

Attachments: NATF External Newsletter (July 2021)

The NATF interfaces with the industry as well as regulatory agencies on key reliability, resiliency, security, and safety topics to promote collaboration, alignment, and continuous improvement, while reducing duplication of effort. Some examples are highlighted below and in the attached NATF External Newsletter (July 2021), which is also available on our public website: www.natf.net/news/newsletters .

NATF-NERC Leadership Meetings

NATF and NERC leadership meet periodically to discuss collaborative work and industry topics. The most recent call, held on June 28, included discussions on facility ratings, vegetation management practices, cyber security, supply chain, cold-weather events, grid security emergencies, 6 Ghz band, and distributed energy resources.

Facility Ratings

The NATF is working with its members to socialize and review member implementation of facility ratings practices developed by a team of subject-matter experts from NATF member companies. The NATF facility ratings practices are consistent with and align with practices and controls suggested by the ERO Enterprise in its November 2019 facility ratings problem statement.

The NATF periodically surveys its members to learn the extent to which NATF members have implemented and/or enhanced their facility ratings practices and processes. A summary report on the overall member implementation status as of April 2021 will soon be provided to NERC and regional entity leadership. Future updates are planned approximately every six months. See more about NATF work in the attached newsletter.

NATF Security and Supply Chain Work

NATF staff and members are coordinating on multiple security topics, including threats and responses. A few activities are noted below and described futher in the attached newsletter.

Working with the Industry Organizations Team, the NATF continues to promote supply chain security through the use of the NATF assessment model as well as industry alignment on supplier information. The NATF recently posted updates to the "Supply Chain Security Assessment Model," "NATF Supply Chain Security Criteria," and "Energy Sector Supply Chain Risk Questionnaire" for industry use.

NATF staff continues to evaluate government actions (e.g., executive orders, requests for information, and the DOE-CISA 100-day initiative), provide updates and clarifying information to our members, and make any needed modifications to the NATF supply chain model. The NATF submitted a response to the April 20, 2021, Department of Energy request for information on "Ensuring the Continued Security of the United States Critical Electric Infrastructure." The NATF and members are also reviewing potential implementation guidance for tools used in continuous ICS/OT system cybersecurity monitoring, detection, and response, as identified in the DOE-CISA 100-day initiative.

NATF Vegetation Management Document Summary

The vegeation management document summary is a collection of documents developed by NATF members describing strategies and practices necessary for effective and efficient vegetation management programs. The document is available to the industry on our public facing website, www.natf.net/documents. The following topics are addressed in the summary:

- Vegatation Clearances
- Inspection Practices
- Handling Imminent Threats
- Off Right-of-Way Hazard Trees
- Maintenance Techniques
- Work Quality Inspections
- Landowner Notifications
- Managing Work Constraints
- Budget Development and Cost Forecasting
- Work Management System Reference
- LiDAR Specificaiton Reference Document

NERC Extreme Cold Weather Alert

The NATF appreciates NERC providing the trades and forums the opportunity to comment on its alert on extreme cold weather events. The NATF utilized this opportunity to share feedback to NERC that improved the quality and effectiveness of the alert. We look forward to additional collaboration opportunities on future alerts.

North American Transmission Forum External Newsletter

July 2021

NATF Posts Updated Supply Chain Documents for Industry

The "Supply Chain Security Assessment Model," "NATF Supply Chain Security Criteria," and "Energy Sector Supply Chain Risk Questionnaire" version 2.0 documents have been posted for industry use on the Supply Chain Cyber Security Industry Coordination page of the NATF public website. These postings reflect changes suggested by industry during the annual revision cycle.

Using the Assessment Model, Criteria, and Questionnaire

The five-step model provides a solid foundation for identifying, assessing, and mitigating supply chain risks; provides for inclusion of suppliers and solution providers depending upon each entity's needs; and provides for flexibility of each entity's implementation.

The criteria and questionnaire support the first three steps in the assessment model. The graphic to the right depicting the model provides a streamlined view of the process; however, it is important to review the detail for each of the steps so the intent of the model is not misconstrued and full value of the model can be realized. A full, yet concise, description is provided in the "Supply Chain Security Assessment Model," and the basic actions for each step are provided here.

Supply Chain Security Assessment Model

Collect (and Validate) Information

Use existing means to obtain information regarding a supplier's adherence to the NATF criteria or questionnaire:

- *Validated responses:* Obtain a certification (e.g., IEC 62443 or ISO 27001) or assessment (e.g., SOC 2 Type II) that maps to the criteria. *This would provide validated information.*
- *Supplier attestation (not validated):* Obtain a supplier-completed questionnaire or responses to the criteria. *This could be validated by a review of evidence or supporting certifications/assessments.*
- *Shared assessment:* Obtain an assessment conducted by another entity. *This may or may not be validated information.*

Collect additional information from public sources as necessary.

Evaluate the Information and Address Risks

Evaluate three levels, considering the product or service to be purchased: adherence, assurance, and ability to mitigate risks:

- *Supplier's security posture:* Determine if the supplier's level of adherence to the NATF criteria or questionnaire is appropriate for the product or service being purchased.

- *Validation of information:* What level of assurance was provided for the accuracy of the supplier information and is the level of confidence provided appropriate for the product or service?

- *Mitigate identified risks:* Did the above two questions identify risks, and can those risks be mitigated or accepted?

Conduct Risk Assessment (of Supplier's Supply Chain Security)

- Based on the information obtained in the prior two steps, including any risk mitigations, conduct a supply chain security assessment for the supplier.

Note that the criteria and questionnaire are not "frameworks" in the same manner as security frameworks such as an IEC 62443, ISO 27001, or a SOC 2 Type II, among others. Those frameworks are audited by qualified third-party assessors, and suppliers receive either a certification or assessment report indicating their performance. Entities can use these security frameworks to validate information provided by the supplier.

When using a security framework audit or certification to validate supplier responses, an entity should verify that the certification or assessment report addresses all of questions or criteria needed to analyze risk for the purchase, which can be done by reviewing the report's statement of applicability. Mapping to selected security frameworks is provided in the NATF criteria.

Next Steps

The NATF continues to work externally on supply chain risk management with the Industry Organizations Team consisting of electric utilities, energy industry trade and forum representatives, suppliers, third-party assessors, and solution providers. The team has established goals to guide 2021 activities, including the following:

- Adoption of the NATF "Supplier Cyber Security Assessment Model"

- Monitoring of threat and governmental/regulatory landscapes

Central Repository/Library

As the industry adopts the assessment model, the need for additional assistance in obtaining validated supplier information has been identified. The NATF and the Industry Organizations Team are taking actions to help, exploring the development of a central repository for supplier information. The objective is to provide an affordable, easy-to-access library of information for suppliers to the electric industry. Entities will continue to have the ability to conduct a risk assessment for a potential supplier, identify risks and mitigations, and make a risk-informed purchase decision.

Regulatory Endorsement

The NATF, with support from the Industry Organizations Team, is working towards obtaining endorsement of the model, criteria, and questionnaire from the ERO Enterprise. The supply chain security assessment model is focused on security; however, obtaining assurance that the model provides a solid framework for compliance will provide additional confidence for adoption. These documents are examples of work that originated based on a request from the NERC Board of Trustees.[1]

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[1] In its August 2017 resolution adopting the supply chain standards, the NERC board of trustees requested NATF and other industry organizations to develop and share "best and leading practices in cyber security supply chain risk management, including procurement, specification, vendor requirements, and managing existing equipment activities." (*See* NERC Board of Trustees' Resolution)

Learn more about the Industry Organizations Team and projects supporting the 2021 goals at https://www.natf.net/industry-initiatives/supply-chain-industry-coordination

***

Response to U.S. Department of Energy (DOE) Request for Information (RFI)

The NATF submitted a response to the April 20, 2021, DOE RFI on "Ensuring the Continued Security of the United States Critical Electric Infrastructure." The NATF's response highlights that it is uniquely positioned and prepared to assist in protecting the security, integrity, and reliability of the bulk power system through the elimination of compromises introduced through supply chains, and references the long-standing, collaborative supply chain risk management efforts led by the NATF.

At a high level, the NATF recommended "…continued collaboration and coordination among governmental agencies and between the government and the private sector, measured use of clear prohibition orders if needed to address risks requiring immediate action, increased sharing of risk information identified by intelligence agencies, support for private sector collaboration (such as the NATF activities), and continued use of the existing regulatory framework."

Responses to the RFI are posted on the DOE's "Securing Critical Electric Infrastructure" web page: https://www.energy.gov/oe/securing-critical-electric-infrastructure.

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Facility Ratings Practices Implementation

The NATF and members representing approximately 83% of the total transmission mileage at 100 kV and above in the United States and Canada continue work and reporting on enhancements to members' facility ratings practices and processes, with guidance from the "NATF Facility Ratings Practices Document" developed by a team of subject-matter experts from NATF member companies.

The NATF periodically surveys its members to learn the extent to which NATF members have implemented and/or enhanced their facility ratings practices and processes. A summary report on overall member implementation status as of April 2021 will be provided by the NATF to NERC and regional entity leadership in August or September. Future updates are planned approximately every six months.

In addition, NATF staff participates in the joint Compliance and Certification Committee / Reliability and Security Technical Committee Facility Ratings Task Force (FRTF) to help ensure the NATF and FRTF efforts are complementary and not duplicative.

> The "NATF Facility Ratings Practices Document"—published for members in mid-2020—provides guidance for establishing sustainable programs, processes, and internal controls to help ensure that facility ratings are accurate and that ratings for equipment and facilities are documented and communicated.
>
> The NATF facility ratings practices are consistent with and align with practices and controls suggested by the ERO Enterprise in its November 2019 facility ratings problem statement and in reports and webinars presented by NERC and the regional entities.

***

For more information about the NATF, please visit www.natf.net.